BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 29888
ORDER NO. 32474

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATION OF BLUE FLINT SEQUESTER COMPANY, LLC REQUESTING CONSIDERATION FOR THE GEOLOGIC STORAGE OF CARBON DIOXIDE IN THE BROOM CREEK FORMATION FROM THE BLUE FLINT ETHANOL FACILITY IN THE STORAGE FACILITY LOCATED IN SECTIONS 11, 12, 13, 14, AND 24, TOWNSHIP 145 NORTH, RANGE 83 WEST AND SECTIONS 6, 7, 8, 17, 18, AND 19, TOWNSHIP 145 NORTH, RANGE 82 WEST, MCLEAN COUNTY, NORTH DAKOTA PURSUANT TO NORTH DAKOTA ADMINISTRATIVE CODE SECTION 43-05-01.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause came on for hearing at 9:00 a.m. on the 21st day of March, 2023.

(2) Blue Flint Sequester Company, LLC (Blue Flint) made application to the Commission for an order requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol (BFE) facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, pursuant to North Dakota Administrative Code (NDAC) Chapter 43-05-01.

(3) Blue Flint submitted an application for a Storage Facility Permit and attachments pursuant to NDAC Section 43-05-01-05 and all other provisions of NDAC Chapter 43-05-01 as necessary.

(4) Case Nos. 29888, 29889, and 29890 were combined for the purposes of hearing.

(5) Case No. 29889, also on the March 21, 2023 docket, is a motion of the Commission to consider the amalgamation of storage reservoir pore space, pursuant to a Storage Agreement by Blue Flint for use of pore space falling within portions of Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, and to determine it has been signed, ratified, or approved by owners of interest owning at least sixty percent of the pore space interest within said lands, pursuant to North Dakota Century Code (NDCC) Section 38-22-10.

(6) Case No. 29890, also on the March 21, 2023 docket, is a motion of the Commission to consider to determine the amount of financial responsibility to be required of Blue Flint for the geologic storage of carbon dioxide from the BFE facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to NDAC Section 43-05-01-09.1

(7) The record in these matters was left open to receive additional information from Blue Flint. Such information was received on May 1, 2023, and the record was closed.

(8) The Commission received a notice of filing of the application from Blue Flint, addressed to Bradley Schafer, on February 6, 2023. Blue Flint was questioned by Commission staff at the hearing on March 21, 2023, if proper notice pursuant to NDCC Section 38-22-06 and NDAC Section 43-05-01-08 was given to Bradley Schafer. Blue Flint provided a supplemental affidavit on April 14, 2023, indicating Bradley Schafer was provided a notice out of an abundance of caution because he was listed as a potential heir on a Proof of Death and Heirship document, even though he does not own any interests of record within the notice area. Exhibit A of the supplemental affidavit is the Proof of Death and Heirship filed with McLean County on May 20, 2013, by The Falkirk Mining Company for the NW/4 of Section 4 and NW/4 of Section 13, Township 145 North, Range 83 West, and the SE/4 of Section 32, Township 146 North, Range 83 West, McLean County, North Dakota. Only the NW/4 of Section 13, Township 145 North, Range 83 West, is within the hearing notification area as shown by Figure 1-1 of the application and Exhibit 2 provided by Blue Flint at the hearing on March 21, 2023, shows The Falkirk Mining Company to be the owner of the pore space.

Pursuant to NDCC Section 38-22-06 and NDAC Section 43-05-01-08, the notice of filing of the application and petition and the time and place of hearing thereof was given, and that at least 45 days prior to the hearing, Blue Flint, as the applicant, did give notice of the time and place of said hearing and the Commission has accepted the notice as adequate, and that the applicant did, at least 45 days prior to the hearing, file with the Commission engineering, geological, and other technical exhibits to be used and which were used at said hearing, and that the notice so given did specify that such material was filed with the Commission; that due public notice having been given, as required by law, the Commission has jurisdiction of this cause and the subject matter.

(9) The Commission gave at least a thirty-day public notice and comment period for the draft storage facility permit and issued all notices using methods required of all entities under NDCC Section 38-22-06 and NDAC Section 43-05-01-08. Publication was made February 1,

2023, and the comment period for written comments ended at 5:00 PM CDT March 20, 2023. The hearing was open to the public to appear and provide comments.

(10) The Commission received a letter from the State Historical Society of North Dakota on March 13, 2023, indicating it reviewed the application of Blue Flint and recommends a Class III (pedestrian survey) in the project area for portions of Sections 6, 8, 17, 18, and 19, Township 145 North, Range 82 West, and portions of Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, McLean County, North Dakota. Blue Flint committed to the State Historical Society of North Dakota, in a letter dated April 10, 2023, that a commissioned analysis of cultural resources proximate to the areas of surface disruptions shows no recorded sites are anticipated to be impacted, that several Class III surveys have already been completed within the project area, and project construction will include protocols for immediate stoppage of work in the event of cultural resource discovery.

(11) Steven Heger (Heger) appeared on March 21, 2023, to provide testimony, and submit a letter supplementing his testimony. Heger testified to owning surface acreage directly south of the power plant within the hearing notice area and being a tenant for Falkirk Mine within the storage facility area, including farming around the MAG #1 (File No. 37833) well location.

Heger testified both verbally and in his letter that he is not against the project but that the project falls short of the intent of NDCC Section 38-22-07 of the Carbon Storage Underground Storage Rules [sic; Heger meant to reference 38-22-08], that requires the applicant to get consent of at least 60% of the pore space owners to go forward with the project. Heger states in his letter that within the Hearing Notification Area, the land ownership is as follows: Falkirk Mine 56%; Rainbow Energy/Midwest Ag 23%; and private landowners 21%. Heger states he heard during the hearing that the applicant spoke about having approximately 91% consent. Heger testified to and stated in his letter that within the Project Storage Area, the land ownership is as follows: Falkirk Mine 64%; Rainbow Energy/Midwest Ag 26%; and private landowners 10%. Heger testified that with such a small percentage of private land ownership in the proposed area there is no incentive for the energy industry to work with local private landowners. Heger questioned what percent of private landowners have signed the leases or if only the corporations have signed the leases.

Heger stated there could be more collaboration on where they placed what he thought were groundwater test wells located east of the MAG #1 well, because it is not conducive to agricultural production to have to farm around all of them.

Heger is concerned with the amount of kochia, a noxious weed, located on the MAG #1 well location and would like to see it addressed.

Heger questioned what effect the project would have on Falkirk Mine's bond release and the value of the land. He stated that after the mining is done the land is supposed to go back to the public and that it is a joint goal between his family and the mine that the land return to his family's ownership.

(12) The Commission notes the following in response to Heger's testimony:

NDCC Section 38-22-08(4) requires the storage operator to make a good-faith effort to get the consent of all persons who own the storage reservoir's pore space and NDCC Section 38-22-08(5) requires the storage operator to obtain the consent of persons who own at least sixty percent of the storage reservoir's pore space. Exhibit 2 shows Blue Flint has leased approximately 91.3% of the pore space acreage, with 1.6% attributable to private landowners. Blue Flint testified they have made multiple efforts to communicate with the pore space owners throughout the development of the project and have made a good-faith effort to get the consent of all persons who own pore space in the storage area. Blue Flint also provided that Exhibit 2 indicates which members have signed a lease and a copy will be mailed to Heger.

A soil gas profile station located on the MAG #1 wellsite and a Fox Hills groundwater well located directly south of the southwest corner of said wellsite, are the only soil gas and groundwater monitoring test wells to be located near the MAG #1 wellsite, as shown by Figures 5-3 and 5-5 of the application. Blue Flint testified the test wells located east of the MAG #1 well are not associated with their carbon storage project but instead are associated with a project between the mine and Rainbow Energy.

NDAC Section 43-02-03-28 states in part, "Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least one hundred fifty feet from the vicinity of wells and tanks… All vegetation must be removed a safe distance from any production or injection equipment to eliminate a fire hazard."

Exhibit 2 indicates The Falkirk Mining Company has signed the pore space lease for all acreage it owns within the storage facility area. Figures 3-21 and 5-5 of the application show the location of surface infrastructure planned for the project will not be located on reclaimed mine land. Blue Flint testified the project facilities and infrastructure locations would not impact current or future mining activities and surface agreements for the locations of the MAG #1, MAG #2, and flow line have been executed with the mine.

(13) Michael Johnson (Michael) appeared on March 21, 2023, to provide testimony. Michael testified to owning property west of the power plant, specifically 50 acres in Section 18, Township 145 North, Range 82 West; having shared ownership of a quarter (160 acres) that is divided between his family members; he owned the property under Falkirk Power Plant but it was taken from him by eminent domain in the past; two years ago Midwest Ag Energy made him an offer of five-thousand dollars ($5,000) an acre to lease his property which he declined; but they continue to ask him to sign a lease, stating if he signs, he will get a five-hundred dollar ($500.00) bonus and if he does not they will go through the state process and he does not get the bonus; and Blue Flint is offering him fifty cents a metric ton to store carbon dioxide, while the US government gives corporations eighty-five dollars ($85.00) a metric ton.

Michael testified there is no incentive for Blue Flint to clean up and produce less carbon dioxide if it is allowed to pump it underground.

Michael testified he owns the mineral rights for his property and questioned if the carbon dioxide underneath his property will be his and if he would be paid if they decided in the future to pump it back out.

(14) The Commission notes the following in response to Michael's testimony:

NDCC Section 38-22-10 states "If a storage operator does not obtain the consent of all persons who own the storage reservoir's pore space, the Commission may require that the pore space owned by nonconsenting owners be included in a storage facility and subject to geologic storage." NDCC Section 38-22-08(14) states "That all nonconsenting pore space owners be equitably compensated." Blue Flint testified that all pore space owners would be compensated in the same fashion regardless of if they signed a pore space lease.

NDCC Section 38-22-01 states in part, "It is in the public interest to promote the geologic storage of carbon dioxide. Doing so will benefit the state and the global environment by reducing greenhouse gas emissions."

NDCC Section 38-22-16 states in part, "The storage operator has title to the carbon dioxide injected into and stored in a storage reservoir and holds title until the Commission issues a certificate of project completion." NDCC Section 38-22-17(6) states in part, that once a certificate is issued, the title is acquired by the state.

(15) Margo Johnson (Margo) appeared on March 21, 2023, to provide testimony. Margo testified she does not own land across from the power plant but was born and raised in North Dakota. Margo stated her brother (Michael) spoke mostly about what she had to say. Margo stated she has no issue with carbon capture but has an issue with companies not reducing their carbon footprint and being held accountable.

Margo questioned if society honestly knows the results carbon will have when it is stuck underground. Margo questioned the reliability of modeling and asked if a forty-year study had been done on carbon capture.

(16) The Commission notes the following in response to Margo's testimony:

The equation of state reservoir simulator used by Blue Flint is Computer Modelling Group LTD.'s GEM software, a United States Environmental Protection Agency (EPA) acknowledged existing software used for the development of geologic sequestration models. Commission staff reviewed all inputs for Blue Flint's reservoir model and also used Computer Modelling Group LTD.'s GEM software to verify the outputs given by Blue Flint.

NDAC Section 43-05-01-05.1, states in part, that the reevaluation date of the area of review is not to exceed five years from the date of first injection. Monitoring and operational data will be used to inform the reservoir model used during the reevaluation of the area review.

(17) Blue Flint's application provides adequate data to show suitability of the Broom Creek Formation for geologic storage of carbon dioxide in the facility area.

(18) Blue Flint's application provides adequate modeling of the storage reservoir for delineation of the facility area, and adequate monitoring to detect if carbon dioxide is migrating into properties outside of the facility area pursuant to NDAC Section 43-05-01-11.4. Vertical release of carbon dioxide is addressed by the application pursuant to NDAC Section 43-05-01-13, and lateral release of carbon dioxide from the facility area is addressed by the application pursuant to NDAC Section 43-05-01-05.

Blue Flint was questioned by Commission staff on March 21, 2023, on how the pressure and temperature parameters in the GEM model were derived. Blue Flint provided supplements on April 11, 2023, and May 1, 2023 and the Commission finds these supplements adequately account for how the pressure and temperature values used in the GEM model were derived and that the values used in the GEM model produce a conservative plume boundary.

(19) The amalgamated storage reservoir pore space to be utilized is not hydrocarbon bearing as determined from test data included with the application. There has been no historic hydrocarbon exploration, production, or studies suggesting there is an economic supply of hydrocarbons from formations above or below the Broom Creek Formation within the proposed storage facility area. Lignite coal is mined in the area from the Sentinel Butte Formation in the area above the proposed facility area. Coal seams exist in the Bullion Creek Formation. All coal seams present in the Fort Union Group above the facility area will not be impacted by this project as there are no current or future planned mining activities with the proposed facility area. Blue Flint testified that should operators decide to drill wells for hydrocarbon exploration or production in the future, the lateral extent of the stabilized plume and the pressure differential are minor enough to allow for either horizontal drilling without penetrating the stored carbon dioxide or vertical drilling with proper controls, for hydrocarbon exploration under the Broom Creek Formation. The Commission agrees.

(20) The BFE facility is a dry mill ethanol production plant located in McLean County, North Dakota, near the city of Underwood. Carbon dioxide is emitted from the fermentation process during ethanol production. Blue Flint testified that the BFE facility is operated by Blue Flint Ethanol LLC; and that Blue Flint Ethanol LLC, Blue Flint Sequester Company, LLC, and Midwest AgEnergy Group, LLC are all subsidiaries of Harvestone Low Carbon Partners.

(21) The BFE facility currently emits an annual average of 200,000 metric tons of carbon dioxide that is expected to be captured, dehydrated, compressed, transported to a Class VI well by a flow line, and then injected. Blue Flint testified that 220,000 metric tons would be the maximum anticipated volume the BFE facility could produce in a year. Blue Flint testified that in addition to the dynamic reservoir simulation for an anticipated scenario of 200,000 metric tons a year, an additional scenario was run to determine the maximum amount of carbon dioxide that could be injected using the bottom hole pressure and wellhead pressure constraints. The results of this maximum case scenario indicated a volume exceeding the 220,000 metric tons annual volume being proposed would be obtainable without exceeding the maximum bottom hole pressure

constraint, derived as ninety percent of the fracture pressure gradient for the Broom Creek Formation.

(22) The entire length of the 3-mile flow line to be utilized for carbon dioxide transportation from the capture facility (carbon dioxide injection facility) to the wellhead falls within the facility area delineation and is under the jurisdiction of the Commission.

(23) The flow line will be constructed using FlexSteel, a 3-layer flexible steel pipe product with inner and outer layers containing a carbon dioxide resistant polyethylene liner and other materials that will be carbon dioxide resistant in accordance with API 171J (2017) requirements. Blue Flint testified the flow line will be rated at 2,250 psi and 150 degrees Fahrenheit, and the anticipated liquefaction pressure will be approximately 1,760 psi.

(24) The flow line will be equipped with flowmeters, pressure gauges, and a Supervisory Control and Data Acquisition (SCADA) system to detect leaks. Carbon dioxide detection stations will be located on the flow line risers and wellhead.

(25) The projected composition of the carbon dioxide stream is greater than 99.98% carbon dioxide with trace quantities of water, oxygen, nitrogen, methane, acetaldehyde, hydrogen sulfide, dimethyl sulfide, ethyl acetate, isopentyl acetate, methanol, ethanol, acetone, n-Propanol, and n-Butanol.

(26) The MAG #1 well is a stratigraphic test well that was used for reservoir characterization and constructed to Class VI requirements, located 295 feet from the north line and 740 feet from the west line of Section 18, Township 145 North, Range 82 West, McLean County, North Dakota. This well is to be converted to a Class VI injection well.

(27) The MAG #2 well is proposed to be located approximately 820 feet from the south line and 165 from the east line of Section 7, Township 145 North, Range 82 West, McLean County, North Dakota. This well is to be utilized as a direct method of monitoring the injection zone pursuant to NDAC Section 43-05-01-11.4.

(28) Blue Flint created a geologic model based on site characterization as required by NDAC Section 43-05-01-05.1 to delineate the area of review. Data utilized included seismic survey data, geophysical logs from nearby wells, and core data. Structural surfaces were interpolated with Schlumberger's Petrel software, and included formation top depths, data collected from the MAG #1, the Flemmer #1 (File No. 34243), the J-LOC #1 (File No. 37380), the BNI #1 (File No. 34244), the ANG #1 (Class I well), and two 3D seismic surveys conducted at the Flemmer #1 and MAG #1 locations. Due to uncertainty in sonic log values related to washouts in the Broom Creek Formation in the MAG #1 well, publicly available variograms from the Minnkota Center MRYS Broom Creek Storage Facility #1 (Facility No. 90000330) were used to inform lithofacies and petrophysical properties in the geologic model. The variograms were selected as they provided a generalized representation of property distributions expected in the Broom Creek Formation. Based on the reservoir pressure obtained from the MAG #1 well, critical threshold pressure for this storage facility exists in the Broom Creek Formation prior to injection. Critical threshold

pressure has the same meaning as pressure front, defined in NDAC Section 43-05-01-01, for area of review delineation purposes. EPA's "UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance" lists several methods to estimate an acceptable pressure increase for over-pressurized reservoirs, including a multiphase numerical model designed to model leakage through a single well bore, or through multiple well bores in the formation. Blue Flint used this method to determine cumulative leakage potential along a hypothetical leaky wellbore without injection occurring, estimated to be 0.019 cubic meters over 20 years. Incremental leakage with injection occurring was estimated to be a maximum of 0.005 cubic meters over 20 years. A value of 1 cubic meter is the lowest meaningful value that can be produced by the Analytical Solution for Leakage in Multilayered Aquifers (ASLMA) model as smaller values likely represent statistical noise. An actual leaky wellbore or transmissive conduit would likely communicate with the Inyan Kara Formation. Blue Flint's application noted no indications of communication between the Broom Creek Formation and Inyan Kara Formation were observed, and that nothing in fluid samples indicated communication to USDWs. The predicted extent of the carbon dioxide plume from beginning to end of life of the project, at the time when the carbon dioxide plume ceases to migrate into adjacent cells of the geologic model, was used to define the area of review in this case. Pursuant to NDAC Section 43-05-01-05(1)(b)(2) the area of review included a one-mile buffer around the storage facility boundaries. Time lapse seismic surveys will be used to monitor the extent of the carbon dioxide plume.

(29) The area proposed to be included within the storage facility is as follows:

<u>TOWNSHIP 145 NORTH, RANGE 83 WEST</u>
ALL OF SECTIONS 12 AND 13, THE SE/4 OF SECTION 11, THE NE/4 OF SECTION 14, AND THE NE/4 OF SECTION 24,

<u>TOWNSHIP 145 NORTH, RANGE 82 WEST</u>
ALL OF SECTIONS 7, 8, 17, AND 18, THE S/2 OF SECTION 6, AND THE N/2 OF SECTION 19.

ALL IN MCLEAN COUNTY AND COMPRISING OF 4,953.71 ACRES, MORE OR LESS.

(30) In the MAG #1 well, the undifferentiated Spearfish and Opeche Formations, hereinafter referred to as the Spearfish Formation, unconformably overlie the Broom Creek Formation. The Picard and Poe members of the Piper Formation, hereinafter referred to as the Lower Piper Formation, overlie the Spearfish Formation. The Broom Creek Formation, the upper confining Lower Piper-Spearfish Formations, and the lower confining Amsden Formation are laterally extensive throughout the area of review.

(31) Core analysis of the Broom Creek Formation shows sufficient permeability to be suitable for the desired injection rates and pressures without risk of creating fractures in the injection zone. Thin-section investigation shows the Broom Creek Formation is dominated by quartz, dololmite, anhydrite, and clay (mainly illite/muscovite) minerals. Within the Broom Creek Formation, feldspar and iron oxide intervals are present. Anhydrite obstructs the intercrystalline porosity in the upper part of the formation and dolomite in the middle and lower parts. Porosity is

due to the dissolution of anhydrite in the upper part and the dissolution of quartz and feldspar in the middle and lower parts. Microfracture in situ tests were not attempted in the MAG #1 well due to unstable wellbore conditions. A one-dimensional mechanical earth model (1D MEM) was used to compensate for the lack of microfracture data within the storage facility area. Log data from MAG #1 well was used to determine ductility and rock strength to characterize stress in the storage complex to calculate the fracture pressure gradient. Side wall core samples collected in the MAG #1 well were horizontally oriented and inadequate for multistage triaxial testing. The Matthew and Kelly method was utilized in Schlumberger's Techlog software to calculate a fracture gradient of 0.69 psi/ft. This method calculates the fracture gradient from pore pressure and overburden gradient and was used due to the absence of closure pressure measurements in the Broom Creek Formation from microfracture testing. Pressure and temperature sensors were set at depths of 4,735 feet and 4,741 feet to record values from the Broom Creek Formation yielding a pore pressure gradient of 0.512 psi/ft. An overburden gradient of 0.911 psi/ft was extrapolated from the bulk density log.

Core analysis of the overlying Lower Piper-Spearfish Formations show sufficiently low permeability to stratigraphically trap carbon dioxide and displaced fluids. Thin-section investigation shows the siltstone intervals are dominated by clay, quartz, and anhydrite minerals. Throughout these intervals are occurrences of dolomite, feldspar, and iron oxides. Microfracture in situ tests were not attempted in the MAG #1 well due to unstable wellbore conditions. A fracture gradient of 0.69 psi/ft was calculated from the Matthew and Kelly method. The maximum allowable bottomhole pressure of 2,970 psi is estimated to be ninety percent of the fracture gradient of the Broom Creek Formation multiplied by the depth of the top perforation in the injection zone. Injection formation breakdown would be observed and recorded if permitted operational pressures were exceeded before compromising the confining zone.

Core analysis of the underlying Amsden Formation shows sufficiently low permeability to stratigraphically contain carbon dioxide and displaced fluids. Thin-section investigation shows the Amsden Formation is comprised of dolostone, sandstone, anhydrite, and limestone.

(32) The in situ fluid of the Broom Creek Formation in this area is in excess of 10,000 parts per million of total dissolved solids.

(33) Investigation of wells within the area of review found no vertical penetrations of the confining or injection zones requiring corrective action. The area of review will be reevaluated at a period not to exceed five years from beginning of injection operations.

(34) The Fox Hills Formation is the deepest underground source of drinking water (USDW) within the area of review. Its base is situated at a depth of 955 feet at the location of the MAG #1 well, leaving approximately 3,773 feet between the base of the Fox Hills Formation and the top of the Broom Creek Formation.

(35) Fluid sampling of shallow USDWs has been performed to establish a geochemical baseline, with additional baseline sampling proposed for the Fox Hills Formation and other shallow wells under investigation. Future sampling is proposed in Blue Flint's application pursuant to NDAC Section 43-05-01-11.4.

(36) Soil sampling is proposed pursuant to NDAC Section 43-05-01-11.4. A baseline of soil gas concentrations was initiated in September 2022 and is anticipated to be completed by July 2023. A baseline of soil gas concentrations will be established and submitted to the Commission for review prior to injection operations. Soil gas profile stations will be located near the MAG #1 well and proposed MAG #2 well locations.

(37) The top of the Inyan Kara Formation is at 3,574 feet, approximately 2,619 feet below the base of the Fox Hills Formation at the location of the MAG #1 well and it provides an additional zone of monitoring between the Fox Hills Formation and the Broom Creek Formation to detect vertical carbon dioxide or fluid movement.

(38) No known or suspected regional faults or fractures with transmissibility have been identified during the site-specific characterization. Formation imaging logs showed drilling induced fractures were observed in the Lower Piper Formation. The Spearfish Formation log was dominated by what appear to be conductive fractures. Seismic data used to characterize the subsurface within the project area showed no indication of faulting with sufficient vertical extent to transect the storage reservoir and confining zones. Blue Flint testified that the Spearfish Formation fractures were filled with precipitated minerals, primarily anhydrite, and all fractures lack sufficient permeability or vertical extent to act as fluid pathways.

(39) Fluid samples from the Inyan Kara Formation and Broom Creek Formation suggest that they are hydraulically isolated from each other, supporting that the confining formations above the Broom Creek Formation are not compromised by migration pathways.

(40) Geochemical simulation performed with the injection stream and data obtained from the confining and injection zones determined no observable change in injection rate or pressure. Simulations of conservatively high carbon dioxide exposure to the cap rock determined that geochemical changes will be minor and will not cause substantive deterioration compromising confinement.

(41) Risk of induced seismicity is not a concern based on existing studies of major faults within the area of review, tectonic boundaries, and relatively stable geologic conditions surrounding the proposed injection site.

(42) NDAC Section 43-05-01-11.3(3) requires the storage facility operator to maintain pressure on the annulus that exceeds the operating injection pressure, unless the Commission determines that such a requirement might harm the integrity of the well or endanger USDWs. Blue Flint testified their intention is to submit a variance request with the injection permit. The Commission believes placing this pressure on the annulus will create a risk of micro annulus by debonding of the long string casing–cement sheath during the operational life of the well. A micro

annulus would harm external mechanical integrity and provide a potential pathway for endangerment of USDWs.

(43) Both the injection and monitoring well are proposed to be equipped with DTS fiber optic cables enabling continuously monitored external mechanical integrity.

(44) The approval of this application is in the public interest by promoting the policy stated in NDCC Section 38-22-01.

IT IS THEREFORE ORDERED:

(1) The creation of the Blue Flint Underwood Broom Creek Storage Facility #1 in McLean County, North Dakota, is hereby authorized and approved.

(2) Blue Flint Sequester Company, LLC, its assigns and successors, is hereby authorized to store carbon dioxide in the Broom Creek Formation in the Blue Flint Underwood Broom Creek Storage Facility #1.

(3) The Blue Flint Underwood Broom Creek Storage Facility #1 shall extend to and include the following lands in McLean County, North Dakota:

<u>TOWNSHIP 145 NORTH, RANGE 83 WEST</u>
ALL OF SECTIONS 12 AND 13, THE SE/4 OF SECTION 11, THE NE/4 OF SECTION 14, AND THE NE/4 OF SECTION 24,

<u>TOWNSHIP 145 NORTH, RANGE 82 WEST</u>
ALL OF SECTIONS 7, 8, 17, AND 18, THE S/2 OF SECTION 6, AND THE N/2 OF SECTION 19.

ALL IN MCLEAN COUNTY AND COMPRISING OF 4,953.71 ACRES, MORE OR LESS.

(4) Injection into the Blue Flint Underwood Broom Creek Storage Facility #1 shall not occur until Blue Flint Sequester Company, LLC has met the financial responsibility demonstration pursuant to Order No. 32476.

(5) This authorization does not convey authority to inject carbon dioxide into the Blue Flint Underwood Broom Creek Storage Facility #1; an approved permit to inject for the MAG #1 well (File No. 37833) shall be issued by the Commission prior to injection operations commencing.

(6) The authorization granted herein is conditioned on the operator receiving and complying with all provisions of the injection permit issued by the Oil and Gas Division of the Industrial Commission and complying with all applicable provisions of NDAC Chapter 43-05-01 and this order.

(7) Definitions.

"Area of review" in this case means an area encompassing a radius around the facility area of one mile.

"Cell" in this case means individual cell blocks of the geologic model; each cell is approximately 1,000 feet by 1,000 feet.

"Facility area" means the areal extent of the storage reservoir as defined in paragraph (3) above, that includes lands within the lateral boundary of the carbon dioxide plume from beginning of injection to the time the carbon dioxide plume ceases to migrate into adjacent geologic model cells.

"Storage facility" means the reservoir, underground equipment, and surface facilities and equipment used or proposed to be used in the geologic storage operation. Pursuant to NDCC Section 38-22-02, it does not include pipelines used to transport carbon dioxide to the storage facility.

(8) The storage facility operator shall comply with all conditions of this order, the permit to inject, and applicable provisions of NDAC Chapter 43-05-01. Any noncompliance constitutes a violation and is grounds for enforcement action, including but not limited to termination, revocation, or modification of this order pursuant to NDAC Section 43-05-01-12.

(9) In an administrative action, it shall not be a defense that it would have been necessary for the storage facility operator to halt or reduce the permitted activity in order to maintain compliance with this order, the permit to inject, and applicable provisions of NDAC Chapter 43-05-01.

(10) The storage facility operator shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this order, the permit to inject, and applicable provisions of NDAC Chapter 43-05-01.

(11) The storage facility operator shall implement and maintain the provided emergency and remedial response plan pursuant to NDAC Section 43-05-01-13.

(12) The storage facility operator shall cease injection immediately, take all steps reasonably necessary to identify and characterize any release, implement the emergency and remedial response plan approved by the Commission (insofar as the Commission has jurisdiction), and notify the Commission within 24 hours of carbon dioxide detected above the upper confining zone.

(13) The storage facility operator shall at all times properly operate and maintain all storage facilities which are installed or used by the storage facility operator to achieve compliance with the conditions this order, the permit to inject, and applicable provisions of NDAC Chapter 43-05-01. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including

appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems only when necessary to achieve compliance.

(14) This order may be modified, revoked and reissued, or terminated pursuant to NDAC Section 43-05-01-12. The filing of a request by the storage facility operator for and order modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any condition contained herein.

(15) The injection well permit or the permit to operate an injection well does not convey any property rights of any sort of any exclusive privilege.

(16) The storage facility operator shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this order, or to determine compliance thereof. The storage facility operator shall also furnish to the Director, upon request, copies of records required to be kept by this order, the permit to inject, and applicable provisions of NDAC Chapter 43-05-01.

(17) The storage facility operator shall allow the Director, or an authorized representative, upon presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the storage facility premises where records must be kept pursuant to this order and NDAC Chapter 43-05-01.

(b) At reasonable times, have access to and copy any records that must be kept pursuant to this order and NDAC Chapter 43-05-01.

(c) At reasonable times, inspect any facilities, equipment, including monitoring and control equipment, practices, or operations regulated or required pursuant to this order, the permit to inject, and NDAC Chapter 43-05-01.

(d) At reasonable times, sample or monitor for the purposes of assuring compliance, any substances or parameters at any location.

(18) The storage facility operator shall maintain and comply with the proposed testing and monitoring plan pursuant to NDAC Section 43-05-01-11.4

(19) The storage facility operator shall comply with the reporting requirements provided in NDAC Section 43-05-01-18. The volume of carbon dioxide injected, the average injection rate, surface injection pressure, and down-hole temperature and pressure data shall be reported monthly to the Director on or before the fifth day of the second succeeding month once injection commences regardless of the status of operations, until the injection well is properly plugged and abandoned.

(20) The storage facility operator must obtain an injection well permit under NDAC Section

43-05-01-10 and injection wells must meet the construction and completion requirements in NDAC Section 43-05-01-11.

(21) The storage facility operator shall notify the Director at least 48 hours in advance to witness all mechanical integrity tests of the tubing-casing annulus in the injection well. The packer must be set within 100 feet of the upper most perforation and in the chrome enhanced casing, as an exception to NDAC Section 43-05-01-11. However, the packer must also be set within confining zone lithology, within carbon dioxide resistant cement, and not interfere with down-hole monitoring equipment.

(22) The storage facility operator shall maintain and comply with the prepared plugging plan pursuant to NDAC Section 43-05-01-11.5.

(23) The storage facility operator shall establish mechanical integrity prior to commencing injection and maintain mechanical integrity pursuant to NDAC Section 43-05-01-11.1.

(24) The storage facility operator shall implement the worker safety plan pursuant to NDAC Section 43-05-01-13.

(25) The storage facility operator shall comply with leak detection and reporting requirements pursuant to NDAC Section 43-05-01-14.

(26) The storage facility operator shall implement the proposed corrosion monitoring and prevention program pursuant to NDAC Section 43-05-01-05.1.

(27) The storage facility operator shall maintain financial responsibility pursuant to NDAC Section 43-05-01-09.1 and Order No. 32476.

(28) The storage facility operator shall maintain and comply with the proposed post-injection site care and facility closure plan pursuant to NDAC Section 43-05-01-19.

(29) The storage facility operator shall notify the Director within 24 hours of failure or malfunction of surface or bottom hole gauges in the MAG #1 injection well.

(30) The storage facility operator shall implement surface air and soil gas monitoring as proposed.

(31) This storage facility authorization and permit shall be docketed for a review hearing at least once every five years from commencement of injection to determine whether it should be modified, revoked, or minor modification made, pursuant to NDAC Section 43-05-01-05.1(4).

(32) The storage operator shall file minor modification to the permit requests pursuant to NDAC Section 43-05-01-12.1 through a Facility Sundry Notice form.

(33) The storage facility operator shall pay fees pursuant to NDAC Section 43-05-01-17 annually, on or before the last business day in June, for the prior year's injection, unless otherwise approved by the Director.

(34) This order shall remain in full force and effect until further order of the Commission.

Dated this 25th day of May, 2023.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Doug Burgum, Governor

/s/ Drew H. Wrigley, Attorney General

/s/ Doug Goehring, Agriculture Commissioner

SFN 5729

STATE OF NORTH DAKOTA

AFFIDAVIT OF MAILING

COUNTY OF BURLEIGH

I, Jeanette Bean, being duly sworn upon oath, depose and say: That on 5/31/2023 enclosed in separate envelopes true and correct copies of the attached Order No. 32474 of the North Dakota Industrial Commission, and deposited the same with the United States Postal Service in Bismarck, North Dakota, with postage thereon fully paid, directed to the following persons by the Industrial Commission in Case No. 29888:

Lawrence Bender
FREDRIKSON & BYRON
PO BOX 1855
Bismarck, ND 58502-1855

Steven Heger
2896 3rd St NW
Underwood, ND 58576

Michael Johnson
8230 Green Meadow
Helena, MT 59602

Margot Johnson
2100 Nagel Drive
Bismarck, ND 58501

Jeanette
Jeanette Bean
Oil & Gas Division

On this 5/31/2023 before me personally appeared Jeanette Bean to me known as the person described in and who executed the foregoing instrument and acknowledged that she executed the same as her free act and deed.

TRUDY HOGUE
NOTARY PUBLIC
STATE OF NORTH DAKOTA
MY COMMISSION EXPIRES JUN. 19, 2024

Trudy Hogue
Notary Public
State of North Dakota,
County of Burleigh

NORTH Dakota | Mineral Resources
Be Legendary.™

June 1, 2023

**Blue Flint Underwood Broom Creek Storage Facility #1**
**McLean County, North Dakota**
**Order No. 32474**
**STORAGE FACILITY PERMIT**
**CERTIFICATE OF ISSUANCE**

Blue Flint Sequester Company, LLC made application to the Commission, on September 30, 2022, for an order authorizing geologic storage of carbon dioxide from the Blue Flint Ethanol facility in the amalgamated storage reservoir pore space of the Broom Creek Formation, in portions of Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, pursuant to North Dakota Administrative Code (NDAC) Chapter 43-05-01, and such other relief as is appropriate.

The Commission approved this application May 25, 2023.

Order No. 32474 attached establishes the Blue Flint Underwood Broom Creek Storage Facility #1 to include the following lands:

TOWNSHIP 145 NORTH, RANGE 83 WEST
ALL OF SECTIONS 12 AND 13, THE SE/4 OF SECTION 11, THE NE/4 OF SECTION 14, AND THE NE/4 OF SECTION 24,

TOWNSHIP 145 NORTH, RANGE 82 WEST
ALL OF SECTIONS 7, 8, 17, AND 18, THE S/2 OF SECTION 6, AND THE N/2 OF SECTION 19.

Order No. 32475 attached establishes amalgamation of the storage reservoir pore space.

Order No. 32476 attached establishes financial responsibility for the storage facility permit.

Pursuant to North Dakota Century Code Section 38-22-11, this certificate of issuance is to be filed with the county recorder in McLean County.

Sincerely,

Lynn D. Helms
North Dakota Industrial Commission
Department of Mineral Resources
Oil and Gas Division

Bruce E. Hicks
ASSISTANT DIRECTOR
OIL AND GAS DIVISION

Lynn D. Helms
DIRECTOR
DEPT. OF MINERAL RESOURCES

600 E Boulevard Ave – Dept 405 | Bismarck, ND 58505-0840 | PHONE 701-328-8020 | FAX 701-328-8022 | dmr.nd.gov/oilgas

# INDUSTRIAL COMMISSION OF NORTH DAKOTA

| Doug Burgum | Drew H. Wrigley | Doug Goehring |
|---|---|---|
| Governor | Attorney General | Agriculture Commissioner |

I, Karen Tyler, Interim Executive Director for the Industrial Commission of North Dakota, do hereby certify that the attached documents are true and correct copies of the following records on file in the Office of the Industrial Commission, Department of Mineral Resources, Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota.

- Blue Flint Sequester Company, LLC – Permit Certificate
- Order No. 32474 issued in Case No. 29888
- Order No. 32475 issued in Case No. 29889
- Order No. 32476 issued in Case No. 29890

STATE OF NORTH DAKOTA SEAL INDUSTRIAL COMMISSION

Karen Tyler
Interim Executive Director to the Commission
May 31, 2023

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 29888
ORDER NO. 32474

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATION OF BLUE FLINT SEQUESTER COMPANY, LLC REQUESTING CONSIDERATION FOR THE GEOLOGIC STORAGE OF CARBON DIOXIDE IN THE BROOM CREEK FORMATION FROM THE BLUE FLINT ETHANOL FACILITY IN THE STORAGE FACILITY LOCATED IN SECTIONS 11, 12, 13, 14, AND 24, TOWNSHIP 145 NORTH, RANGE 83 WEST AND SECTIONS 6, 7, 8, 17, 18, AND 19, TOWNSHIP 145 NORTH, RANGE 82 WEST, MCLEAN COUNTY, NORTH DAKOTA PURSUANT TO NORTH DAKOTA ADMINISTRATIVE CODE SECTION 43-05-01.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause came on for hearing at 9:00 a.m. on the 21st day of March, 2023.

(2) Blue Flint Sequester Company, LLC (Blue Flint) made application to the Commission for an order requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol (BFE) facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, pursuant to North Dakota Administrative Code (NDAC) Chapter 43-05-01.

(3) Blue Flint submitted an application for a Storage Facility Permit and attachments pursuant to NDAC Section 43-05-01-05 and all other provisions of NDAC Chapter 43-05-01 as necessary.

(4) Case Nos. 29888, 29889, and 29890 were combined for the purposes of hearing.

(5) Case No. 29889, also on the March 21, 2023 docket, is a motion of the Commission to consider the amalgamation of storage reservoir pore space, pursuant to a Storage Agreement by Blue Flint for use of pore space falling within portions of Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, and to determine it has been signed, ratified, or approved by owners of interest owning at least sixty percent of the pore space interest within said lands, pursuant to North Dakota Century Code (NDCC) Section 38-22-10.

(6) Case No. 29890, also on the March 21, 2023 docket, is a motion of the Commission to consider to determine the amount of financial responsibility to be required of Blue Flint for the geologic storage of carbon dioxide from the BFE facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to NDAC Section 43-05-01-09.1

(7) The record in these matters was left open to receive additional information from Blue Flint. Such information was received on May 1, 2023, and the record was closed.

(8) The Commission received a notice of filing of the application from Blue Flint, addressed to Bradley Schafer, on February 6, 2023. Blue Flint was questioned by Commission staff at the hearing on March 21, 2023, if proper notice pursuant to NDCC Section 38-22-06 and NDAC Section 43-05-01-08 was given to Bradley Schafer. Blue Flint provided a supplemental affidavit on April 14, 2023, indicating Bradley Schafer was provided a notice out of an abundance of caution because he was listed as a potential heir on a Proof of Death and Heirship document, even though he does not own any interests of record within the notice area. Exhibit A of the supplemental affidavit is the Proof of Death and Heirship filed with McLean County on May 20, 2013, by The Falkirk Mining Company for the NW/4 of Section 4 and NW/4 of Section 13, Township 145 North, Range 83 West, and the SE/4 of Section 32, Township 146 North, Range 83 West, McLean County, North Dakota. Only the NW/4 of Section 13, Township 145 North, Range 83 West, is within the hearing notification area as shown by Figure 1-1 of the application and Exhibit 2 provided by Blue Flint at the hearing on March 21, 2023, shows The Falkirk Mining Company to be the owner of the pore space.

Pursuant to NDCC Section 38-22-06 and NDAC Section 43-05-01-08, the notice of filing of the application and petition and the time and place of hearing thereof was given, and that at least 45 days prior to the hearing, Blue Flint, as the applicant, did give notice of the time and place of said hearing and the Commission has accepted the notice as adequate, and that the applicant did, at least 45 days prior to the hearing, file with the Commission engineering, geological, and other technical exhibits to be used and which were used at said hearing, and that the notice so given did specify that such material was filed with the Commission; that due public notice having been given, as required by law, the Commission has jurisdiction of this cause and the subject matter.

(9) The Commission gave at least a thirty-day public notice and comment period for the draft storage facility permit and issued all notices using methods required of all entities under NDCC Section 38-22-06 and NDAC Section 43-05-01-08. Publication was made February 1,

2023, and the comment period for written comments ended at 5:00 PM CDT March 20, 2023. The hearing was open to the public to appear and provide comments.

(10) The Commission received a letter from the State Historical Society of North Dakota on March 13, 2023, indicating it reviewed the application of Blue Flint and recommends a Class III (pedestrian survey) in the project area for portions of Sections 6, 8, 17, 18, and 19, Township 145 North, Range 82 West, and portions of Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, McLean County, North Dakota. Blue Flint committed to the State Historical Society of North Dakota, in a letter dated April 10, 2023, that a commissioned analysis of cultural resources proximate to the areas of surface disruptions shows no recorded sites are anticipated to be impacted, that several Class III surveys have already been completed within the project area, and project construction will include protocols for immediate stoppage of work in the event of cultural resource discovery.

(11) Steven Heger (Heger) appeared on March 21, 2023, to provide testimony, and submit a letter supplementing his testimony. Heger testified to owning surface acreage directly south of the power plant within the hearing notice area and being a tenant for Falkirk Mine within the storage facility area, including farming around the MAG #1 (File No. 37833) well location.

Heger testified both verbally and in his letter that he is not against the project but that the project falls short of the intent of NDCC Section 38-22-07 of the Carbon Storage Underground Storage Rules [sic; Heger meant to reference 38-22-08], that requires the applicant to get consent of at least 60% of the pore space owners to go forward with the project. Heger states in his letter that within the Hearing Notification Area, the land ownership is as follows: Falkirk Mine 56%; Rainbow Energy/Midwest Ag 23%; and private landowners 21%. Heger states he heard during the hearing that the applicant spoke about having approximately 91% consent. Heger testified to and stated in his letter that within the Project Storage Area, the land ownership is as follows: Falkirk Mine 64%; Rainbow Energy/Midwest Ag 26%; and private landowners 10%. Heger testified that with such a small percentage of private land ownership in the proposed area there is no incentive for the energy industry to work with local private landowners. Heger questioned what percent of private landowners have signed the leases or if only the corporations have signed the leases.

Heger stated there could be more collaboration on where they placed what he thought were groundwater test wells located east of the MAG #1 well, because it is not conducive to agricultural production to have to farm around all of them.

Heger is concerned with the amount of kochia, a noxious weed, located on the MAG #1 well location and would like to see it addressed.

Heger questioned what effect the project would have on Falkirk Mine's bond release and the value of the land. He stated that after the mining is done the land is supposed to go back to the public and that it is a joint goal between his family and the mine that the land return to his family's ownership.

(12) The Commission notes the following in response to Heger's testimony:

NDCC Section 38-22-08(4) requires the storage operator to make a good-faith effort to get the consent of all persons who own the storage reservoir's pore space and NDCC Section 38-22-08(5) requires the storage operator to obtain the consent of persons who own at least sixty percent of the storage reservoir's pore space. Exhibit 2 shows Blue Flint has leased approximately 91.3% of the pore space acreage, with 1.6% attributable to private landowners. Blue Flint testified they have made multiple efforts to communicate with the pore space owners throughout the development of the project and have made a good-faith effort to get the consent of all persons who own pore space in the storage area. Blue Flint also provided that Exhibit 2 indicates which members have signed a lease and a copy will be mailed to Heger.

A soil gas profile station located on the MAG #1 wellsite and a Fox Hills groundwater well located directly south of the southwest corner of said wellsite, are the only soil gas and groundwater monitoring test wells to be located near the MAG #1 wellsite, as shown by Figures 5-3 and 5-5 of the application. Blue Flint testified the test wells located east of the MAG #1 well are not associated with their carbon storage project but instead are associated with a project between the mine and Rainbow Energy.

NDAC Section 43-02-03-28 states in part, "Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least one hundred fifty feet from the vicinity of wells and tanks... All vegetation must be removed a safe distance from any production or injection equipment to eliminate a fire hazard."

Exhibit 2 indicates The Falkirk Mining Company has signed the pore space lease for all acreage it owns within the storage facility area. Figures 3-21 and 5-5 of the application show the location of surface infrastructure planned for the project will not be located on reclaimed mine land. Blue Flint testified the project facilities and infrastructure locations would not impact current or future mining activities and surface agreements for the locations of the MAG #1, MAG #2, and flow line have been executed with the mine.

(13) Michael Johnson (Michael) appeared on March 21, 2023, to provide testimony. Michael testified to owning property west of the power plant, specifically 50 acres in Section 18, Township 145 North, Range 82 West; having shared ownership of a quarter (160 acres) that is divided between his family members; he owned the property under Falkirk Power Plant but it was taken from him by eminent domain in the past; two years ago Midwest Ag Energy made him an offer of five-thousand dollars ($5,000) an acre to lease his property which he declined; but they continue to ask him to sign a lease, stating if he signs, he will get a five-hundred dollar ($500.00) bonus and if he does not they will go through the state process and he does not get the bonus; and Blue Flint is offering him fifty cents a metric ton to store carbon dioxide, while the US government gives corporations eighty-five dollars ($85.00) a metric ton.

Michael testified there is no incentive for Blue Flint to clean up and produce less carbon dioxide if it is allowed to pump it underground.

Michael testified he owns the mineral rights for his property and questioned if the carbon dioxide underneath his property will be his and if he would be paid if they decided in the future to pump it back out.

(14) The Commission notes the following in response to Michael's testimony:

NDCC Section 38-22-10 states "If a storage operator does not obtain the consent of all persons who own the storage reservoir's pore space, the Commission may require that the pore space owned by nonconsenting owners be included in a storage facility and subject to geologic storage." NDCC Section 38-22-08(14) states "That all nonconsenting pore space owners be equitably compensated." Blue Flint testified that all pore space owners would be compensated in the same fashion regardless of if they signed a pore space lease.

NDCC Section 38-22-01 states in part, "It is in the public interest to promote the geologic storage of carbon dioxide. Doing so will benefit the state and the global environment by reducing greenhouse gas emissions."

NDCC Section 38-22-16 states in part, "The storage operator has title to the carbon dioxide injected into and stored in a storage reservoir and holds title until the Commission issues a certificate of project completion." NDCC Section 38-22-17(6) states in part, that once a certificate is issued, the title is acquired by the state.

(15) Margo Johnson (Margo) appeared on March 21, 2023, to provide testimony. Margo testified she does not own land across from the power plant but was born and raised in North Dakota. Margo stated her brother (Michael) spoke mostly about what she had to say. Margo stated she has no issue with carbon capture but has an issue with companies not reducing their carbon footprint and being held accountable.

Margo questioned if society honestly knows the results carbon will have when it is stuck underground. Margo questioned the reliability of modeling and asked if a forty-year study had been done on carbon capture.

(16) The Commission notes the following in response to Margo's testimony:

The equation of state reservoir simulator used by Blue Flint is Computer Modelling Group LTD.'s GEM software, a United States Environmental Protection Agency (EPA) acknowledged existing software used for the development of geologic sequestration models. Commission staff reviewed all inputs for Blue Flint's reservoir model and also used Computer Modelling Group LTD.'s GEM software to verify the outputs given by Blue Flint.

NDAC Section 43-05-01-05.1, states in part, that the reevaluation date of the area of review is not to exceed five years from the date of first injection. Monitoring and operational data will be used to inform the reservoir model used during the reevaluation of the area review.

(17) Blue Flint's application provides adequate data to show suitability of the Broom Creek Formation for geologic storage of carbon dioxide in the facility area.

(18) Blue Flint's application provides adequate modeling of the storage reservoir for delineation of the facility area, and adequate monitoring to detect if carbon dioxide is migrating into properties outside of the facility area pursuant to NDAC Section 43-05-01-11.4. Vertical release of carbon dioxide is addressed by the application pursuant to NDAC Section 43-05-01-13, and lateral release of carbon dioxide from the facility area is addressed by the application pursuant to NDAC Section 43-05-01-05.

Blue Flint was questioned by Commission staff on March 21, 2023, on how the pressure and temperature parameters in the GEM model were derived. Blue Flint provided supplements on April 11, 2023, and May 1, 2023 and the Commission finds these supplements adequately account for how the pressure and temperature values used in the GEM model were derived and that the values used in the GEM model produce a conservative plume boundary.

(19) The amalgamated storage reservoir pore space to be utilized is not hydrocarbon bearing as determined from test data included with the application. There has been no historic hydrocarbon exploration, production, or studies suggesting there is an economic supply of hydrocarbons from formations above or below the Broom Creek Formation within the proposed storage facility area. Lignite coal is mined in the area from the Sentinel Butte Formation in the area above the proposed facility area. Coal seams exist in the Bullion Creek Formation. All coal seams present in the Fort Union Group above the facility area will not be impacted by this project as there are no current or future planned mining activities with the proposed facility area. Blue Flint testified that should operators decide to drill wells for hydrocarbon exploration or production in the future, the lateral extent of the stabilized plume and the pressure differential are minor enough to allow for either horizontal drilling without penetrating the stored carbon dioxide or vertical drilling with proper controls, for hydrocarbon exploration under the Broom Creek Formation. The Commission agrees.

(20) The BFE facility is a dry mill ethanol production plant located in McLean County, North Dakota, near the city of Underwood. Carbon dioxide is emitted from the fermentation process during ethanol production. Blue Flint testified that the BFE facility is operated by Blue Flint Ethanol LLC; and that Blue Flint Ethanol LLC, Blue Flint Sequester Company, LLC, and Midwest AgEnergy Group, LLC are all subsidiaries of Harvestone Low Carbon Partners.

(21) The BFE facility currently emits an annual average of 200,000 metric tons of carbon dioxide that is expected to be captured, dehydrated, compressed, transported to a Class VI well by a flow line, and then injected. Blue Flint testified that 220,000 metric tons would be the maximum anticipated volume the BFE facility could produce in a year. Blue Flint testified that in addition to the dynamic reservoir simulation for an anticipated scenario of 200,000 metric tons a year, an additional scenario was run to determine the maximum amount of carbon dioxide that could be injected using the bottom hole pressure and wellhead pressure constraints. The results of this maximum case scenario indicated a volume exceeding the 220,000 metric tons annual volume being proposed would be obtainable without exceeding the maximum bottom hole pressure

constraint, derived as ninety percent of the fracture pressure gradient for the Broom Creek Formation.

(22) The entire length of the 3-mile flow line to be utilized for carbon dioxide transportation from the capture facility (carbon dioxide injection facility) to the wellhead falls within the facility area delineation and is under the jurisdiction of the Commission.

(23) The flow line will be constructed using FlexSteel, a 3-layer flexible steel pipe product with inner and outer layers containing a carbon dioxide resistant polyethylene liner and other materials that will be carbon dioxide resistant in accordance with API 171J (2017) requirements. Blue Flint testified the flow line will be rated at 2,250 psi and 150 degrees Fahrenheit, and the anticipated liquefaction pressure will be approximately 1,760 psi.

(24) The flow line will be equipped with flowmeters, pressure gauges, and a Supervisory Control and Data Acquisition (SCADA) system to detect leaks. Carbon dioxide detection stations will be located on the flow line risers and wellhead.

(25) The projected composition of the carbon dioxide stream is greater than 99.98% carbon dioxide with trace quantities of water, oxygen, nitrogen, methane, acetaldehyde, hydrogen sulfide, dimethyl sulfide, ethyl acetate, isopentyl acetate, methanol, ethanol, acetone, n-Propanol, and n-Butanol.

(26) The MAG #1 well is a stratigraphic test well that was used for reservoir characterization and constructed to Class VI requirements, located 295 feet from the north line and 740 feet from the west line of Section 18, Township 145 North, Range 82 West, McLean County, North Dakota. This well is to be converted to a Class VI injection well.

(27) The MAG #2 well is proposed to be located approximately 820 feet from the south line and 165 from the east line of Section 7, Township 145 North, Range 82 West, McLean County, North Dakota. This well is to be utilized as a direct method of monitoring the injection zone pursuant to NDAC Section 43-05-01-11.4.

(28) Blue Flint created a geologic model based on site characterization as required by NDAC Section 43-05-01-05.1 to delineate the area of review. Data utilized included seismic survey data, geophysical logs from nearby wells, and core data. Structural surfaces were interpolated with Schlumberger's Petrel software, and included formation top depths, data collected from the MAG #1, the Flemmer #1 (File No. 34243), the J-LOC #1 (File No. 37380), the BNI #1 (File No. 34244), the ANG #1 (Class I well), and two 3D seismic surveys conducted at the Flemmer #1 and MAG #1 locations. Due to uncertainty in sonic log values related to washouts in the Broom Creek Formation in the MAG #1 well, publicly available variograms from the Minnkota Center MRYS Broom Creek Storage Facility #1 (Facility No. 90000330) were used to inform lithofacies and petrophysical properties in the geologic model. The variograms were selected as they provided a generalized representation of property distributions expected in the Broom Creek Formation. Based on the reservoir pressure obtained from the MAG #1 well, critical threshold pressure for this storage facility exists in the Broom Creek Formation prior to injection. Critical threshold

pressure has the same meaning as pressure front, defined in NDAC Section 43-05-01-01, for area of review delineation purposes. EPA's "UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance" lists several methods to estimate an acceptable pressure increase for over-pressurized reservoirs, including a multiphase numerical model designed to model leakage through a single well bore, or through multiple well bores in the formation. Blue Flint used this method to determine cumulative leakage potential along a hypothetical leaky wellbore without injection occurring, estimated to be 0.019 cubic meters over 20 years. Incremental leakage with injection occurring was estimated to be a maximum of 0.005 cubic meters over 20 years. A value of 1 cubic meter is the lowest meaningful value that can be produced by the Analytical Solution for Leakage in Multilayered Aquifers (ASLMA) model as smaller values likely represent statistical noise. An actual leaky wellbore or transmissive conduit would likely communicate with the Inyan Kara Formation. Blue Flint's application noted no indications of communication between the Broom Creek Formation and Inyan Kara Formation were observed, and that nothing in fluid samples indicated communication to USDWs. The predicted extent of the carbon dioxide plume from beginning to end of life of the project, at the time when the carbon dioxide plume ceases to migrate into adjacent cells of the geologic model, was used to define the area of review in this case. Pursuant to NDAC Section 43-05-01-05(1)(b)(2) the area of review included a one-mile buffer around the storage facility boundaries. Time lapse seismic surveys will be used to monitor the extent of the carbon dioxide plume.

(29) The area proposed to be included within the storage facility is as follows:

TOWNSHIP 145 NORTH, RANGE 83 WEST
ALL OF SECTIONS 12 AND 13, THE SE/4 OF SECTION 11, THE NE/4 OF SECTION 14, AND THE NE/4 OF SECTION 24,

TOWNSHIP 145 NORTH, RANGE 82 WEST
ALL OF SECTIONS 7, 8, 17, AND 18, THE S/2 OF SECTION 6, AND THE N/2 OF SECTION 19.

ALL IN MCLEAN COUNTY AND COMPRISING OF 4,953.71 ACRES, MORE OR LESS.

(30) In the MAG #1 well, the undifferentiated Spearfish and Opeche Formations, hereinafter referred to as the Spearfish Formation, unconformably overlie the Broom Creek Formation. The Picard and Poe members of the Piper Formation, hereinafter referred to as the Lower Piper Formation, overlie the Spearfish Formation. The Broom Creek Formation, the upper confining Lower Piper-Spearfish Formations, and the lower confining Amsden Formation are laterally extensive throughout the area of review.

(31) Core analysis of the Broom Creek Formation shows sufficient permeability to be suitable for the desired injection rates and pressures without risk of creating fractures in the injection zone. Thin-section investigation shows the Broom Creek Formation is dominated by quartz, dololmite, anhydrite, and clay (mainly illite/muscovite) minerals. Within the Broom Creek Formation, feldspar and iron oxide intervals are present. Anhydrite obstructs the intercrystalline porosity in the upper part of the formation and dolomite in the middle and lower parts. Porosity is

due to the dissolution of anhydrite in the upper part and the dissolution of quartz and feldspar in the middle and lower parts. Microfracture in situ tests were not attempted in the MAG #1 well due to unstable wellbore conditions. A one-dimensional mechanical earth model (1D MEM) was used to compensate for the lack of microfracture data within the storage facility area. Log data from MAG #1 well was used to determine ductility and rock strength to characterize stress in the storage complex to calculate the fracture pressure gradient. Side wall core samples collected in the MAG #1 well were horizontally oriented and inadequate for multistage triaxial testing. The Matthew and Kelly method was utilized in Schlumberger's Techlog software to calculate a fracture gradient of 0.69 psi/ft. This method calculates the fracture gradient from pore pressure and overburden gradient and was used due to the absence of closure pressure measurements in the Broom Creek Formation from microfracture testing. Pressure and temperature sensors were set at depths of 4,735 feet and 4,741 feet to record values from the Broom Creek Formation yielding a pore pressure gradient of 0.512 psi/ft. An overburden gradient of 0.911 psi/ft was extrapolated from the bulk density log.

Core analysis of the overlying Lower Piper-Spearfish Formations show sufficiently low permeability to stratigraphically trap carbon dioxide and displaced fluids. Thin-section investigation shows the siltstone intervals are dominated by clay, quartz, and anhydrite minerals. Throughout these intervals are occurrences of dolomite, feldspar, and iron oxides. Microfracture in situ tests were not attempted in the MAG #1 well due to unstable wellbore conditions. A fracture gradient of 0.69 psi/ft was calculated from the Matthew and Kelly method. The maximum allowable bottomhole pressure of 2,970 psi is estimated to be ninety percent of the fracture gradient of the Broom Creek Formation multiplied by the depth of the top perforation in the injection zone. Injection formation breakdown would be observed and recorded if permitted operational pressures were exceeded before compromising the confining zone.

Core analysis of the underlying Amsden Formation shows sufficiently low permeability to stratigraphically contain carbon dioxide and displaced fluids. Thin-section investigation shows the Amsden Formation is comprised of dolostone, sandstone, anhydrite, and limestone.

(32) The in situ fluid of the Broom Creek Formation in this area is in excess of 10,000 parts per million of total dissolved solids.

(33) Investigation of wells within the area of review found no vertical penetrations of the confining or injection zones requiring corrective action. The area of review will be reevaluated at a period not to exceed five years from beginning of injection operations.

(34) The Fox Hills Formation is the deepest underground source of drinking water (USDW) within the area of review. Its base is situated at a depth of 955 feet at the location of the MAG #1 well, leaving approximately 3,773 feet between the base of the Fox Hills Formation and the top of the Broom Creek Formation.

(35) Fluid sampling of shallow USDWs has been performed to establish a geochemical baseline, with additional baseline sampling proposed for the Fox Hills Formation and other shallow wells under investigation. Future sampling is proposed in Blue Flint's application pursuant to NDAC Section 43-05-01-11.4.

(36) Soil sampling is proposed pursuant to NDAC Section 43-05-01-11.4. A baseline of soil gas concentrations was initiated in September 2022 and is anticipated to be completed by July 2023. A baseline of soil gas concentrations will be established and submitted to the Commission for review prior to injection operations. Soil gas profile stations will be located near the MAG #1 well and proposed MAG #2 well locations.

(37) The top of the Inyan Kara Formation is at 3,574 feet, approximately 2,619 feet below the base of the Fox Hills Formation at the location of the MAG #1 well and it provides an additional zone of monitoring between the Fox Hills Formation and the Broom Creek Formation to detect vertical carbon dioxide or fluid movement.

(38) No known or suspected regional faults or fractures with transmissibility have been identified during the site-specific characterization. Formation imaging logs showed drilling induced fractures were observed in the Lower Piper Formation. The Spearfish Formation log was dominated by what appear to be conductive fractures. Seismic data used to characterize the subsurface within the project area showed no indication of faulting with sufficient vertical extent to transect the storage reservoir and confining zones. Blue Flint testified that the Spearfish Formation fractures were filled with precipitated minerals, primarily anhydrite, and all fractures lack sufficient permeability or vertical extent to act as fluid pathways.

(39) Fluid samples from the Inyan Kara Formation and Broom Creek Formation suggest that they are hydraulically isolated from each other, supporting that the confining formations above the Broom Creek Formation are not compromised by migration pathways.

(40) Geochemical simulation performed with the injection stream and data obtained from the confining and injection zones determined no observable change in injection rate or pressure. Simulations of conservatively high carbon dioxide exposure to the cap rock determined that geochemical changes will be minor and will not cause substantive deterioration compromising confinement.

(41) Risk of induced seismicity is not a concern based on existing studies of major faults within the area of review, tectonic boundaries, and relatively stable geologic conditions surrounding the proposed injection site.

(42) NDAC Section 43-05-01-11.3(3) requires the storage facility operator to maintain pressure on the annulus that exceeds the operating injection pressure, unless the Commission determines that such a requirement might harm the integrity of the well or endanger USDWs. Blue Flint testified their intention is to submit a variance request with the injection permit. The Commission believes placing this pressure on the annulus will create a risk of micro annulus by debonding of the long string casing–cement sheath during the operational life of the well. A micro

annulus would harm external mechanical integrity and provide a potential pathway for endangerment of USDWs.

(43) Both the injection and monitoring well are proposed to be equipped with DTS fiber optic cables enabling continuously monitored external mechanical integrity.

(44) The approval of this application is in the public interest by promoting the policy stated in NDCC Section 38-22-01.

IT IS THEREFORE ORDERED:

(1) The creation of the Blue Flint Underwood Broom Creek Storage Facility #1 in McLean County, North Dakota, is hereby authorized and approved.

(2) Blue Flint Sequester Company, LLC, its assigns and successors, is hereby authorized to store carbon dioxide in the Broom Creek Formation in the Blue Flint Underwood Broom Creek Storage Facility #1.

(3) The Blue Flint Underwood Broom Creek Storage Facility #1 shall extend to and include the following lands in McLean County, North Dakota:

TOWNSHIP 145 NORTH, RANGE 83 WEST
ALL OF SECTIONS 12 AND 13, THE SE/4 OF SECTION 11, THE NE/4 OF SECTION 14, AND THE NE/4 OF SECTION 24,

TOWNSHIP 145 NORTH, RANGE 82 WEST
ALL OF SECTIONS 7, 8, 17, AND 18, THE S/2 OF SECTION 6, AND THE N/2 OF SECTION 19.

ALL IN MCLEAN COUNTY AND COMPRISING OF 4,953.71 ACRES, MORE OR LESS.

(4) Injection into the Blue Flint Underwood Broom Creek Storage Facility #1 shall not occur until Blue Flint Sequester Company, LLC has met the financial responsibility demonstration pursuant to Order No. 32476.

(5) This authorization does not convey authority to inject carbon dioxide into the Blue Flint Underwood Broom Creek Storage Facility #1; an approved permit to inject for the MAG #1 well (File No. 37833) shall be issued by the Commission prior to injection operations commencing.

(6) The authorization granted herein is conditioned on the operator receiving and complying with all provisions of the injection permit issued by the Oil and Gas Division of the Industrial Commission and complying with all applicable provisions of NDAC Chapter 43-05-01 and this order.

(7) Definitions.

"Area of review" in this case means an area encompassing a radius around the facility area of one mile.

"Cell" in this case means individual cell blocks of the geologic model; each cell is approximately 1,000 feet by 1,000 feet.

"Facility area" means the areal extent of the storage reservoir as defined in paragraph (3) above, that includes lands within the lateral boundary of the carbon dioxide plume from beginning of injection to the time the carbon dioxide plume ceases to migrate into adjacent geologic model cells.

"Storage facility" means the reservoir, underground equipment, and surface facilities and equipment used or proposed to be used in the geologic storage operation. Pursuant to NDCC Section 38-22-02, it does not include pipelines used to transport carbon dioxide to the storage facility.

(8) The storage facility operator shall comply with all conditions of this order, the permit to inject, and applicable provisions of NDAC Chapter 43-05-01. Any noncompliance constitutes a violation and is grounds for enforcement action, including but not limited to termination, revocation, or modification of this order pursuant to NDAC Section 43-05-01-12.

(9) In an administrative action, it shall not be a defense that it would have been necessary for the storage facility operator to halt or reduce the permitted activity in order to maintain compliance with this order, the permit to inject, and applicable provisions of NDAC Chapter 43-05-01.

(10) The storage facility operator shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this order, the permit to inject, and applicable provisions of NDAC Chapter 43-05-01.

(11) The storage facility operator shall implement and maintain the provided emergency and remedial response plan pursuant to NDAC Section 43-05-01-13.

(12) The storage facility operator shall cease injection immediately, take all steps reasonably necessary to identify and characterize any release, implement the emergency and remedial response plan approved by the Commission (insofar as the Commission has jurisdiction), and notify the Commission within 24 hours of carbon dioxide detected above the upper confining zone.

(13) The storage facility operator shall at all times properly operate and maintain all storage facilities which are installed or used by the storage facility operator to achieve compliance with the conditions this order, the permit to inject, and applicable provisions of NDAC Chapter 43-05-01. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including

appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems only when necessary to achieve compliance.

(14) This order may be modified, revoked and reissued, or terminated pursuant to NDAC Section 43-05-01-12. The filing of a request by the storage facility operator for and order modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any condition contained herein.

(15) The injection well permit or the permit to operate an injection well does not convey any property rights of any sort of any exclusive privilege.

(16) The storage facility operator shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this order, or to determine compliance thereof. The storage facility operator shall also furnish to the Director, upon request, copies of records required to be kept by this order, the permit to inject, and applicable provisions of NDAC Chapter 43-05-01.

(17) The storage facility operator shall allow the Director, or an authorized representative, upon presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the storage facility premises where records must be kept pursuant to this order and NDAC Chapter 43-05-01.

(b) At reasonable times, have access to and copy any records that must be kept pursuant to this order and NDAC Chapter 43-05-01.

(c) At reasonable times, inspect any facilities, equipment, including monitoring and control equipment, practices, or operations regulated or required pursuant to this order, the permit to inject, and NDAC Chapter 43-05-01.

(d) At reasonable times, sample or monitor for the purposes of assuring compliance, any substances or parameters at any location.

(18) The storage facility operator shall maintain and comply with the proposed testing and monitoring plan pursuant to NDAC Section 43-05-01-11.4

(19) The storage facility operator shall comply with the reporting requirements provided in NDAC Section 43-05-01-18. The volume of carbon dioxide injected, the average injection rate, surface injection pressure, and down-hole temperature and pressure data shall be reported monthly to the Director on or before the fifth day of the second succeeding month once injection commences regardless of the status of operations, until the injection well is properly plugged and abandoned.

(20) The storage facility operator must obtain an injection well permit under NDAC Section

43-05-01-10 and injection wells must meet the construction and completion requirements in NDAC Section 43-05-01-11.

(21) The storage facility operator shall notify the Director at least 48 hours in advance to witness all mechanical integrity tests of the tubing-casing annulus in the injection well. The packer must be set within 100 feet of the upper most perforation and in the chrome enhanced casing, as an exception to NDAC Section 43-05-01-11. However, the packer must also be set within confining zone lithology, within carbon dioxide resistant cement, and not interfere with down-hole monitoring equipment.

(22) The storage facility operator shall maintain and comply with the prepared plugging plan pursuant to NDAC Section 43-05-01-11.5.

(23) The storage facility operator shall establish mechanical integrity prior to commencing injection and maintain mechanical integrity pursuant to NDAC Section 43-05-01-11.1.

(24) The storage facility operator shall implement the worker safety plan pursuant to NDAC Section 43-05-01-13.

(25) The storage facility operator shall comply with leak detection and reporting requirements pursuant to NDAC Section 43-05-01-14.

(26) The storage facility operator shall implement the proposed corrosion monitoring and prevention program pursuant to NDAC Section 43-05-01-05.1.

(27) The storage facility operator shall maintain financial responsibility pursuant to NDAC Section 43-05-01-09.1 and Order No. 32476.

(28) The storage facility operator shall maintain and comply with the proposed post-injection site care and facility closure plan pursuant to NDAC Section 43-05-01-19.

(29) The storage facility operator shall notify the Director within 24 hours of failure or malfunction of surface or bottom hole gauges in the MAG #1 injection well.

(30) The storage facility operator shall implement surface air and soil gas monitoring as proposed.

(31) This storage facility authorization and permit shall be docketed for a review hearing at least once every five years from commencement of injection to determine whether it should be modified, revoked, or minor modification made, pursuant to NDAC Section 43-05-01-05.1(4).

(32) The storage operator shall file minor modification to the permit requests pursuant to NDAC Section 43-05-01-12.1 through a Facility Sundry Notice form.

(33) The storage facility operator shall pay fees pursuant to NDAC Section 43-05-01-17 annually, on or before the last business day in June, for the prior year's injection, unless otherwise approved by the Director.

(34) This order shall remain in full force and effect until further order of the Commission.

Dated this 25th day of May, 2023.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Doug Burgum, Governor

/s/ Drew H. Wrigley, Attorney General

/s/ Doug Goehring, Agriculture Commissioner

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 29889
ORDER NO. 32475

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE AMALGAMATION OF THE STORAGE RESERVOIR PORE SPACE, IN WHICH THE COMMISSION MAY REQUIRE THAT THE PORE SPACE OWNED BY NONCONSENTING OWNERS BE INCLUDED IN THE GEOLOGIC STORAGE FACILITY AND SUBJECT TO GEOLOGIC STORAGE, AS REQUIRED TO OPERATE THE BLUE FLINT SEQUESTER COMPANY, LLC STORAGE FACILITY LOCATED IN SECTIONS 11, 12, 13, 14, AND 24, TOWNSHIP 145 NORTH, RANGE 83 WEST AND SECTIONS 6, 7, 8, 17, 18, AND 19, TOWNSHIP 145 NORTH, RANGE 82 WEST, MCLEAN COUNTY, NORTH DAKOTA, IN THE BROOM CREEK FORMATION, PURSUANT TO NORTH DAKOTA CENTURY CODE SECTION 38-22-10.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause came on for hearing at 9:00 a.m. on the 21st day of March, 2023.

(2) Case No. 29889 is a motion of the Commission to consider the amalgamation of storage reservoir pore space, pursuant to a Storage Agreement by Blue Flint Sequester Company, LLC (Blue Flint) for use of pore space falling within portions of Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, and to determine it has been signed, ratified, or approved by owners of interest owning at least sixty percent of the pore space interest within said lands, pursuant to North Dakota Century Code (NDCC) Section 38-22-10.

(3) Case Nos. 29889, 29888, and 29890 were combined for purposes of hearing.

(4) Case No. 29888, also on the March 21, 2023 docket, is an application by Blue Flint for an order requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol (BFE) facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, pursuant to North Dakota Administrative Code (NDAC) Chapter 43-05-01.

(5) Case No. 29890, also on the March 21, 2023 docket, is a motion of the Commission to consider to determine the amount of financial responsibility to be required of Blue Flint for the geologic storage of carbon dioxide from the BFE facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to NDAC Section 43-05-01-09.1

(6) The record in these matters was left open to receive additional information from Blue Flint. Such information was received on May 1, 2023, and the record was closed.

(7) Pursuant to NDCC Section 38-22-06 and NDAC Section 43-05-01-08, the notice of filing of the application and petition and the time and place of hearing thereof was given, and that at least 45 days prior to the hearing, Blue Flint, as the applicant, did give notice of the time and place of said hearing and the Commission has accepted the notice as adequate, and that the applicant did, at least 45 days prior to the hearing, file with the Commission engineering, geological, and other technical exhibits to be used and which were used at said hearing, and that the notice so given did specify that such material was filed with the Commission; that due public notice having been given, as required by law, the Commission has jurisdiction of this cause and the subject matter.

(8) The Commission gave at least a thirty-day public notice and comment period for the draft storage facility permit and issued all notices using methods required of all entities under NDCC Section 38-22-06 and NDAC Section 43-05-01-08. Publication was made February 1, 2023, and the comment period for written comments ended at 5:00 PM CDT March 20, 2023. The hearing was open to the public to appear and provide comments.

(9) Order No. 32474 entered in Case No. 29888 created the Blue Flint Underwood Broom Creek Storage Facility #1.

(10) The plan for amalgamation proposed by Blue Flint includes a Storage Agreement for the Broom Creek Formation for certain lands in McLean County, North Dakota.

(11) The area proposed to be included within the amalgamation area of the storage facility is as follows:

<u>TOWNSHIP 145 NORTH, RANGE 83 WEST</u>
ALL OF SECTIONS 12 AND 13, THE SE/4 OF SECTION 11, THE NE/4 OF SECTION 14, AND THE NE/4 OF SECTION 24,

TOWNSHIP 145 NORTH, RANGE 82 WEST
ALL OF SECTIONS 7, 8, 17, AND 18, THE S/2 OF SECTION 6, AND THE N/2 OF SECTION 19.

ALL IN MCLEAN COUNTY AND COMPRISING OF 4,953.71 ACRES, MORE OR LESS.

(12) Blue Flint is proposing a one-phase formula for the calculation of tract participation, allocating 100% to surface acres.

"Surface acres" means the number of acres within each respective tract.

(13) Pursuant to NDCC Section 47-31-03, title to pore space in all strata underlying surface lands and waters is vested in the owner of the overlying surface estate.

No pore space has been leased out by pore space owners prior to this agreement. Blue Flint did not find instances of pore space being severed from the surface estate as allowed prior to April 9, 2009.

(14) A one-phase formula based on surface acres will fairly compensate owners farther away from the injection well that will eventually have pore space occupied by carbon dioxide. Blue Flint testified The Falkirk Mining Company owns the pore space where the injection well is located. Blue Flint indicates that the majority of carbon dioxide stored will remain in close proximity to the wellbore for an extended period of time, making The Falkirk Mining Company the primary beneficiary of a pore volume formula. Computational modeling performed by Blue Flint and the Commission supports Blue Flint's assessment.

The Commission believes capillary trapping, relative permeability hysteresis, and a lack of local area history matching data from injection of carbon dioxide into the saline Broom Creek Formation reservoir provides reasonable doubt for the utility of a pore volume formula. The Commission believes the 100% weighting on surface acreage is acceptable and that the one-phase formula is protective of correlative rights and should not be modified.

(15) Blue Flint delineated the tracts to be utilized through computational modeling based on site characterization as required by NDAC Section 43-05-01-05.1. The data acquired during site characterization as well as the reservoir model and all inputs were provided to the Commission. The Commission evaluated the storage reservoir utilizing data acquired during site characterization and other publicly available data before performing computational simulation. The Commission concludes that Blue Flint's inclusion of pore space that will be affected by the project has been adequately delineated.

(16) The Storage Agreement contains fair, reasonable, and equitable provisions for:

(a) The amalgamation of pore space interests for the storage of carbon dioxide within said pore spaces of the storage reservoir.

(b) The division of interest or formula for the apportionment and allocation of carbon dioxide to be stored.

(c) The measurement of quantity of carbon dioxide injected into the pore spaces underlying the delineated storage facility.

(d) The enlargement or reduction of the delineation of pore space utilized for geologic storage of carbon dioxide which may be warranted by review pursuant to NDAC Section 43-05-01-05.1(4).

(e) The time when the Storage Agreement shall become effective.

(f) The time when, conditions under, and the method by which the Storage Agreement shall be or may be terminated and its affairs wound up.

(17) Blue Flint testified that Article 14.2 is insignificant to the Storage Agreement because over sixty percent of the pore space owners have executed a pore space lease and recommended that the language be stricken from the Storage Agreement.

(18) Such amalgamation of the storage reservoir's pore space and the Storage Agreement are in the public interest, and require procedures that promote, in a manner fair to all interested, cooperative management, thereby ensuring the maximum use of natural resources, and that said Storage Agreement, as contained therein, appears to conform and comply with the provisions and requirements of NDCC Section 38-22-08.

(19) NDCC Section 38-22-10 provides that the Commission may require that the pore space owned by nonconsenting owners be included in a storage facility and subject to geological storage, if a storage operator does not obtain the consent of all persons who own the storage reservoir's pore space.

(20) Pursuant to NDAC Section 43-05-01-08(2)(e), the required notice given by Blue Flint included a statement that amalgamation of the storage reservoir's pore space is required to operate the storage facility, that the Commission may require that the pore space owned by nonconsenting owners be included in the storage facility and subject to geologic storage, and that the amalgamation of pore space will be considered at the hearing.

(21) The approval of this application is in the public interest by promoting the policy stated in NDCC Section 38-22-01.

IT IS THEREFORE ORDERED:

(1) The amalgamation of pore space in the Blue Flint Underwood Broom Creek Storage Facility #1 in McLean County, North Dakota, is hereby approved.

(2) The Storage Agreement for the Broom Creek Formation is hereby incorporated in this order by reference insofar as the Commission has jurisdiction and said Storage Agreement for the amalgamated pore space therein is approved; and that if said Storage Agreement does not in all respects conform to and comply with the provisions and requirements under NDCC Chapter 38-22, the statute shall prevail.

(3) The amalgamated pore space is hereby defined as the following described tracts of land in McLean County, North Dakota:

TOWNSHIP 145 NORTH, RANGE 83 WEST
ALL OF SECTIONS 12 AND 13, THE SE/4 OF SECTION 11, THE NE/4 OF SECTION 14, AND THE NE/4 OF SECTION 24,

TOWNSHIP 145 NORTH, RANGE 82 WEST
ALL OF SECTIONS 7, 8, 17, AND 18, THE S/2 OF SECTION 6, AND THE N/2 OF SECTION 19.

ALL IN MCLEAN COUNTY AND COMPRISING OF 4,953.71 ACRES, MORE OR LESS.

(4) The Storage Agreement for the Broom Creek Formation identified the storage reservoir as the interval containing the amalgamated pore space defined as the stratigraphic interval from below the top of the Picard Member of the Piper Formation, found at an average depth of 4,553 feet, to above the base of the Amsden Formation, found at an average depth of 5,053 feet, as identified within the limits of the facility area, hereinbefore described in paragraph (3) above, by the well logging suite performed on the MAG #1 well (File No. 37833) and from a 3D seismic survey.

(5) The Commission defines the storage reservoir containing the amalgamated pore space as the stratigraphic interval from below the top of the Picard Member of the Piper Formation, found at a depth of 4,558 feet below the Kelly Bushing, to above the base of the Amsden Formation, found at a depth of 5,035 feet below the Kelly Bushing, as identified by the Array Induction Gamma log run performed in the MAG #1 well (File No. 37833), located in LOT 1 of Section 18, Township 145 North, Range 82 West, McLean County, North Dakota.

(6) The injection of carbon dioxide into the amalgamated pore space by the operator for the purpose of storage of carbon dioxide is authorized through the MAG #1 well (File No. 37833), located 295 feet from the north line and 740 feet from the west line of Section 18, Township 145 North, Range 82 West, McLean County, North Dakota; provided, however, that prior to the commencement of such injection the operator shall obtain permits as required under NDAC Chapter 43-05-01.

(7) The termination of the amalgamation of lands hereinbefore described in paragraph (3) above shall be as prescribed in the Storage Agreement or at project completion as provided by NDCC Section 38-22-17; and that notwithstanding any provisions to the contrary, in the event that the operator fails to commence or ceases storage operations, the Commission, upon its own motion,

after notice and hearing, may consider rescinding this order, or any portion thereof, so that this order of amalgamation will terminate and cease to exist.

(8) The effective date of the amalgamation of pore space in the lands hereinbefore described in paragraph (3) above shall be at 7:00 a.m. on the 1st day of June, 2023.

(9) No well, other than those proposed in Order No. 32474, shall be hereafter drilled and completed in or inject into the amalgamated pore space, as defined herein, or otherwise penetrate the amalgamated pore space, without order of the Commission after due notice and hearing.

(10) This order shall be reviewed when a review of Order No. 32474 is conducted.

(11) This order shall cover all of the amalgamated pore space, as defined herein, and continues in full force and effect until further order of the Commission.

Dated this 25th day of May, 2023.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Doug Burgum, Governor

/s/ Drew H. Wrigley, Attorney General

/s/ Doug Goehring, Agriculture Commissioner

BEFORE THE INDUSTRIAL COMMISSION

OF THE STATE OF NORTH DAKOTA

CASE NO. 29890
ORDER NO. 32476

IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER TO DETERMINE THE AMOUNT OF FINANCIAL RESPONSIBILITY FOR THE GEOLOGIC STORAGE OF CARBON DIOXIDE FROM THE BLUE FLINT ETHANOL FACILITY IN THE STORAGE FACILITY LOCATED IN SECTIONS 11, 12, 13, 14, AND 24, TOWNSHIP 145 NORTH, RANGE 83 WEST AND SECTIONS 6, 7, 8, 17, 18, AND 19, TOWNSHIP 145 NORTH, RANGE 82 WEST, MCLEAN COUNTY, NORTH DAKOTA, IN THE BROOM CREEK FORMATION, PURSUANT TO NORTH DAKOTA ADMINISTRATIVE CODE SECTION 43-05-01-09.1.

ORDER OF THE COMMISSION

THE COMMISSION FINDS:

(1) This cause came on for hearing at 9:00 a.m. on the 21st day of March, 2023.

(2) Case No. 29890 is a motion of the Commission to consider to determine the amount of financial responsibility to be required of Blue Flint Sequester Company, LLC (Blue Flint) for the geologic storage of carbon dioxide from the Blue Flint Ethanol (BFE) facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code (NDAC) Section 43-05-01-09.1, and such relief as is appropriate.

(3) Case Nos. 29890, 29888, and 29889 were combined for purposes of hearing.

(4) Case No. 29888, also on the March 21, 2023 docket, is an application by Blue Flint for an order requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the BFE facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, pursuant to NDAC Chapter 43-05-01.

(5) Case No. 29889, also on the March 21, 2023 docket, is a motion of the Commission to consider the amalgamation of storage reservoir pore space, pursuant to a Storage Agreement by Blue Flint for use of pore space falling within portions of Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West, and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, and to determine it has been signed, ratified, or approved by owners of interest owning at least sixty percent of the pore space interest within said lands, pursuant to North Dakota Century Code (NDCC) Section 38-22-10.

(6) The record in these matters was left open to receive additional information from Blue Flint. Such information was received on May 1, 2023, and the record was closed.

(7) Order No. 32474 entered in Case No. 29888 created the Blue Flint Underwood Broom Creek Storage Facility #1; and Order No. 32474 entered in Case No. 29889 determined said storage facility will become effective June 1, 2023.

(8) Blue Flint outlined its proposed qualifying financial responsibility instruments to be utilized to demonstrate financial responsibility pursuant to NDAC Section 43-05-01-09.1.

(9) Pursuant to NDAC Section 43-05-01-09.1 the qualifying financial responsibility instruments must cover the cost of:

(a) Corrective action that meets the requirements of NDAC Section 43-05-01-05.1.

(b) Injection well plugging that meets the requirements of NDAC Section 43-05-01-11.5.

(c) Postinjection site care and facility closure that meets the requirements of NDAC Section 43-05-01-19.

(d) Emergency and remedial response that meets the requirements of NDAC Section 43-05-01-13.

(10) Blue Flint demonstrated that corrective action pursuant to NDAC Section 43-05-01-05.1 is not necessary within the delineated area of review. The Commission agrees with Blue Flint's demonstration.

(11) Blue Flint estimates the injection well plugging cost pursuant to NDAC Section 43-05-01-11.5 to be $100,000 total for one well. The Commission accepts this as a conservative estimate.

(12) The Blue Flint Underwood Broom Creek Storage Facility #1 will have one injection well, the MAG #1 well (File No. 37833), located 295 feet from the north line and 740 feet from the west line of Section 18, Township 145 North, Range 82 West, McLean County, North Dakota. Blue Flint proposes covering the plugging of the injection well by filing one $100,000 single-well

bond to meet the injection well plugging financial responsibility requirements. Bonds are a qualifying financial responsibility instrument under NDAC Section 43-05-01-09.1.

(13) Blue Flint estimates the postinjection site care and facility closure financial responsibility pursuant to NDAC Section 43-05-01-19 is $2,467,550, and is proposed to be covered by a third-party insurance policy. The insurance policy is a qualifying financial responsibility instrument under NDAC Section 43-05-01-09.1.

(14) The postinjection site care and facility closure financial responsibility is proposed to cover the costs associated with monitoring during the postinjection phase, the surface reclamation and plugging of one reservoir monitoring well, the proposed MAG #2 well, the surface reclamation of one injection well, the MAG #1 well, the proper abandonment of the MAG #1 well flow line, the plugging and surface reclamation of the Fox Hills monitoring well, and the plugging and surface reclamation of two soil gas stations as shown in Section 12.3.3 of the application.

(15) Blue Flint estimates the emergency and remedial response costs pursuant to NDAC Section 43-05-01-13, by considering a conservative scenario where carbon dioxide migration to the surface combined with groundwater interferences. Technical manuscripts by Bielicki and others (2014) and Trabucchi and others (2012) were used to identify and estimate the costs of mitigation and remediation technologies to address undesired migration of carbon dioxide from a geological storage reservoir. Blue Flint testified this dollar amount was calculated by scaling a high cost well blowout failure scenario down to a project proposing to inject a relatively low volume of approximately 200,000 metric tons of carbon dioxide a year. Blue Flint's estimate for emergency and remedial response actions is $9,000,000 and is proposed to be covered by a third-party insurance policy, that is deemed a qualifying financial responsibility instrument under NDAC Section 43-05-01-09.1.

(16) The Commission should set minimum amounts of qualifying financial responsibility for injection well plugging, postinjection site care and facility closure, and emergency and remedial response.

IT IS THEREFORE ORDERED:

(1) Blue Flint Sequester Company, LLC, its assigns and successors, is hereby required to maintain financial responsibility with qualifying instruments in the minimum amounts specified in paragraph (2) below, pursuant to NDAC Section 43-05-01-09.1, covering the Blue Flint Underwood Broom Creek Storage Facility #1 in McLean County, North Dakota.

(2) The minimum amount for injection well plugging that meets the requirements of NDAC Section 43-05-01-11.5 is a $100,000 for one injection well.

The minimum amount for postinjection site care and facility closure that meets the requirements of NDAC Section 43-05-01-19 is $2,467,550.

The minimum amount for emergency and remedial response that meets the requirements of NDAC Section 43-05-01-13 is $9,000,000.

(3) This order shall be reviewed when a review of Order No. 32474 is conducted.

(4) This order shall remain in full force and effect until further order of the Commission.

Dated this 25th day of May, 2023.

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA

/s/ Doug Burgum, Governor

/s/ Drew H. Wrigley, Attorney General

/s/ Doug Goehring, Agriculture Commissioner

OFFICIAL SEAL
McLEAN COUNTY RECORDER
STATE OF NORTH DAKOTA

RECORDER'S OFFICE, MCLEAN COUNTY, ND 6/21/2023 9:42 AM
I CERTIFY THAT THIS INSTRUMENT WAS FILED FOR RECORD THIS DATE.
HEIDI J. ANDERSON, COUNTY RECORDER

3409849

6/21/2023 9:42 AM $119.00
NORTH DAKOTA ATTORNEY GENERAL

3409849



McLean Co., ND

OFFICIAL SEAL
McLEAN COUNTY RECORDER
STATE OF NORTH DAKOTA

RECORDER'S OFFICE, MCLEAN COUNTY, ND 6/21/2023 9:42 AM
I CERTIFY THAT THIS INSTRUMENT WAS FILED FOR RECORD THIS DATE.
HEIDI J. ANDERSON, COUNTY RECORDER

3409849

3409849

6/21/2023 9:42 AM $119.00
NORTH DAKOTA ATTORNEY GENERAL

Page: 28 of 28
McLean Co., ND

## Kadrmas, Bethany R.

| | |
|---|---|
| **From:** | Entzi-Odden, Lyn <lodden@fredlaw.com> |
| **Sent:** | Monday, May 1, 2023 10:18 AM |
| **To:** | Kadrmas, Bethany R. |
| **Subject:** | Blue Flint Cases 29888, 29889 and 29890 supplemental filings |
| **Attachments:** | Blue Flint letter filing additional.pdf; Supplemental Table_V5.pdf |

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Bethany,

Please see the attached and the following link.

https://fredriksonandbyron.sharefile.com/d-sf880b5c3e85f4d25bea2c5df06da0b70

Thank you.

Fredrikson

**Lyn Entzi-Odden**
**Executive Legal Assistant**
1133 College Drive | Suite 1000 | Bismarck, ND 58501
Ph: 701.221.8700|lodden@fredlaw.com

Fredrikson

Fredrikson & Byron, P.A.
Attorneys and Advisors

1133 College Drive, Suite 1000
Bismarck, ND 58501-1215
Main: 701.221.8700
fredlaw.com

May 1, 2023

***VIA EMAIL***

Mr. Bruce Hicks
Assistant Director
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

**RE: Case Nos. 29888, 29889 and 29890**
**Blue Flint Sequester Company, LLC**

Dear Mr. Hicks:

In follow up to my letter dated April 11, 2023, please find enclosed herewith an updated Supplement Table. Additionally, included in the email submitting this letter is a link to a ShareFile which contain Shapefiles and other documentation to also supplement the record in the captioned matters.

With regard to the request to change the depths in the storage agreement, my client indicates that changing the current description in the Storage Agreement may impact other existing contracts relating to pore space use. Therefore, the EERC will not be providing an updated Storage Agreement document.

Should you have any questions or require additional information, please advise.

Sincerely,

LAWRENCE BENDER

LB/leo
Enclosure
cc: Mr. Adam Dunlop - (w/o enc.) *Via Email*
Ms. Amanda Livers-Douglas - (w/o enc.) *Via Email*
79007101 v1

<table>
<tr><th>Supplement No.</th><th>Supplemental Requested</th><th>Notes/Actions</th></tr>
<tr><td></td><td>No response was given to the following question from the hearing:<ul><li>Addition or an explanation of the ramifications of providing a type log definition using the MAG 1 well to Article 1.15 – Storage Reservoir in the Storage Agreement. The reference to a type log would be providing top depth and bottom depth for the stratigraphic interval as picked in the MAG 1 from the Kelly Bushing elevation as identified by called-out open hole log run.</li></ul></td><td>Changing the current description in the Storage Agreement may impact other existing contracts relating to pore space use.</td></tr>
<tr><td>29</td><td>GIS Shapefiles<ul><li>Shapefiles for the hearing notice area (HNA) boundary still need to be submitted.</li><li>Check the locations of the Proposed Soil Gas Profile Stations and add their numbers (1 & 2) to the name.<ul><li>SGPS 1 (red circle) appears to be on the SE corner of the MAG 1 (green diamond) well site instead of the SW corner as shown in Figure 5-3.</li><li>SGPS 2 (red circle) appears further north than expected from the proposed location of the MAG 2 (green circle).</li><li>Locations of the proposed soil gas probes should be checked, and labels added (1 through 5) to match as shown in Figure 5-5. The only location that matches up with Figure 5-5 is SG-2. Colors shown below were matched as close as possible to Figure 5-5 from SFP application. The red circles are soil gas probe and soil gas probe stations.</li><li>Provide shapefiles for the soil gas probe locations and alternate soil gas probe locations as shown in Supplement 28 – Figure 1. For soil probe locations that did change from what was proposed in Figure 5-5 of the SFP application (such as SG-2) are there plans to place a soil gas probe in the original proposed location as shown in Figure 5-5?</li></ul></li></ul></td><td>New shapefiles have been provided. Explanation of the shapefiles has been provided in new Supplement (Supplement 29).</td></tr>
</table>

| Supplement No. | Supplemental Requested | Notes/Actions |
|---|---|---|
| 9 | Resubmit Supplement 9 with Rierdon (depth below USDW) column fixed. The supplement shows 3,3162 instead of 3162. | Updated Supplement 9. |
| 10 | On Supplement 11 (Equation 5) you have a note that the Uniaxial Strain Modulus (P) label in Table 2-19 in the SFP application should say unconfined compress strength (UCS). Supplement 10 (Pg 2-84) still has it labeled as Uniaxial Strain Modulus (P) label. | Updated Supplement 10: Table 2-19 changed to show unconfined compress strength (UCS). |
| 29 | Supplement 10 – Figures 2-66, 2-67, and 2-68. Can you provide an equivalent figure to what is represented in figures 2-67 and 26-8 for the legacy 2D line (boxed in pink below) that runs EW across the Suspected Stanton Fault and near the MAG 1 and MAG 2 as shown on Figure 2-66? If not, could a similar figure be provided using the 3D seismic? | Response provided in new Supplement (Supplement 29). |
| 29 | Supplement 10 – Figure 2-71. The original intent of the request to extend Figure 2-71 to show the full Fort Union Group is that we would receive a similar figure as the original Figure 2-71 that would show and label all the coal beds within the Fort Union Group. The replacement Figure 2-71 does not meet this request because it no longer shows the individual coal beds. | Response provided in new Supplement (Supplement 29). |
| 12 and 29 | Supplement 12 – We have the following subsequent questions on the supplemental language that was added on Pg 3-11 to explain where the pressure and temperature data from the model was derived from.<br>• Why was the temperature gradient calculated for use in the model done with the assumption of an average annual temperature of 0°F? Table 2-2 was calculated using an annual temperature of 40°F which is a more acceptable average temperature for North Dakota.<br>• How is the 4782.7 ft reference point depth calculated? The CMG model is using a reference depth of 2806.204 ft (SSTVD). Using a ground elevation of 1905 ft and KB of 19.5 ft for the | Response provided in new Supplement (Supplement 29).<br><br>Updated Supplement 12. |

| Supplement No. | Supplemental Requested | Notes/Actions |
|---|---|---|
| | MAG 1, we calculate the reference point depth to be 4730.704 ft. This reference depth is approximately the top of the first perforation in the model and in Figure 9-2, the planned perforations are stated to be 4735-4830 ft, which is more in line with our calculated reference point depth of 4730.704 ft instead of 4782.7 ft stated in Supplement 12. If the depth reference used is incorrect the expectation would be that the pressure and temperature values used in the model are corrected and sent as a supplemental. | |
| | Provide updated Exhibit 3 (Summary of Testing and Monitoring Plan) to reflect the following changes. Provide PDF and Excel copy.<br>• Frequency for corrosion coupon monitoring.<br>• PNL frequency for above-zone monitoring and storage reservoir monitoring, to match with any changes made to Table 6-2. | Updated Exhibit 3 provided. |
| 27 | Supplement 27 – Shouldn't the last sentence in the last paragraph of 12.3.4.1 also be changed to reference Table 7-4 and Table 7-5? | Updated Supplement 27. |
| 29 | Section 9 question response on wellbore schematics. Is the response of, no action, because you are indicating that the wellbore schematics and tables from the SFP application is the most accurate record to date? | Response provided in new Supplement (Supplement 29). |

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

| Name of Formation | Lithology | Formation Top Depth, ft | Thickness, ft | Depth below Lowest Identified USDW, ft |
|---|---|---|---|---|
| Pierre | Shale | 1,092 | 1,316 | 0 |
| Niobrara | Shale | 2,408 | 328 | 1,316 |
| Carlile | Shale | 2,736 | 261 | 1,644 |
| Greenhorn | Shale | 2,997 | 53 | 1,905 |
| Belle Fourche | Shale | 3,050 | 250 | 1,958 |
| Mowry | Shale | 3,300 | 58 | 2,208 |
| Skull Creek | Shale | 3,375 | 229 | 2,282 |
| Swift | Shale | 3,831 | 423 | 2,739 |
| Rierdon | Shale | 4,254 | 178 | 3,162 |
| Piper (Kline Member) | Limestone | 4,434 | 147 | 3,342 |

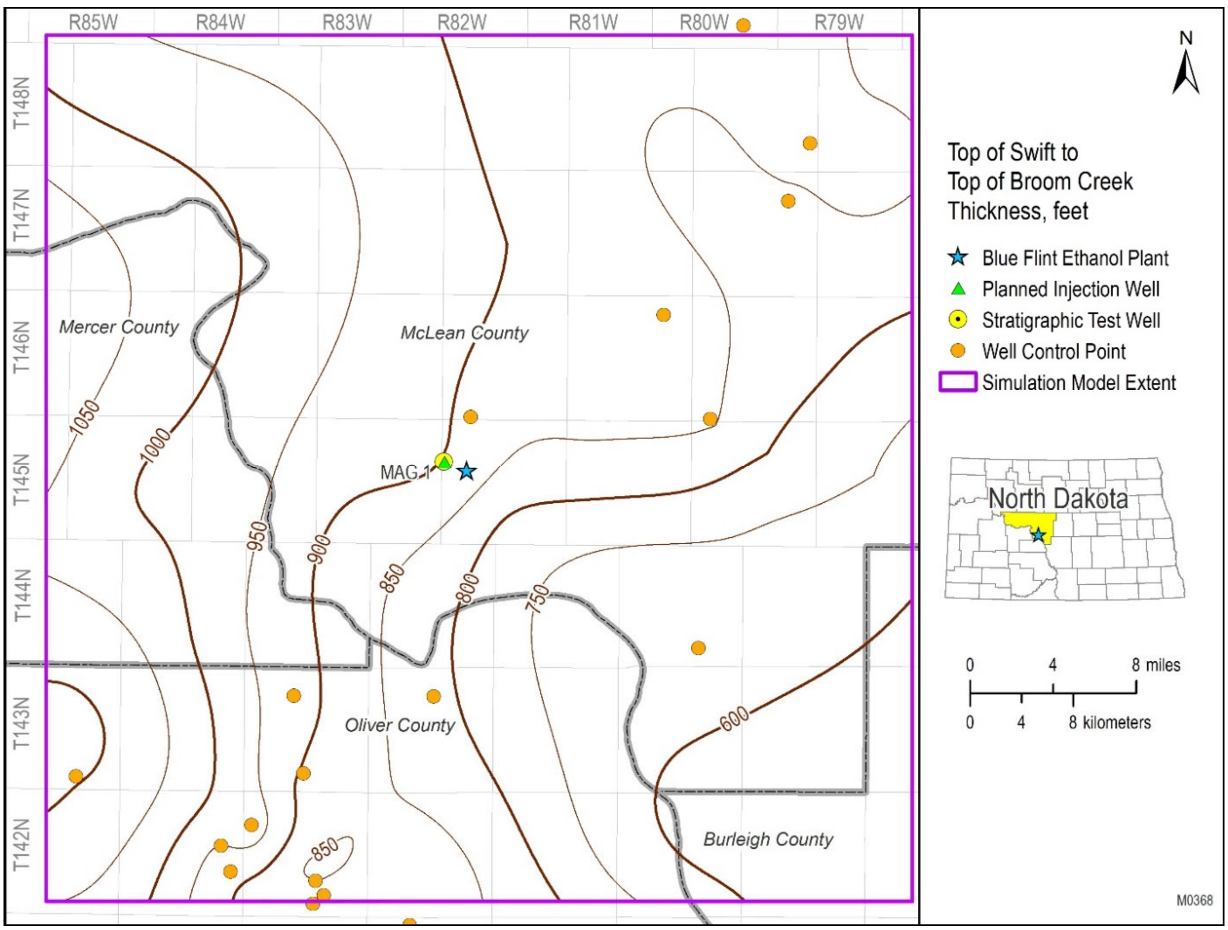



Figure 2-42. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

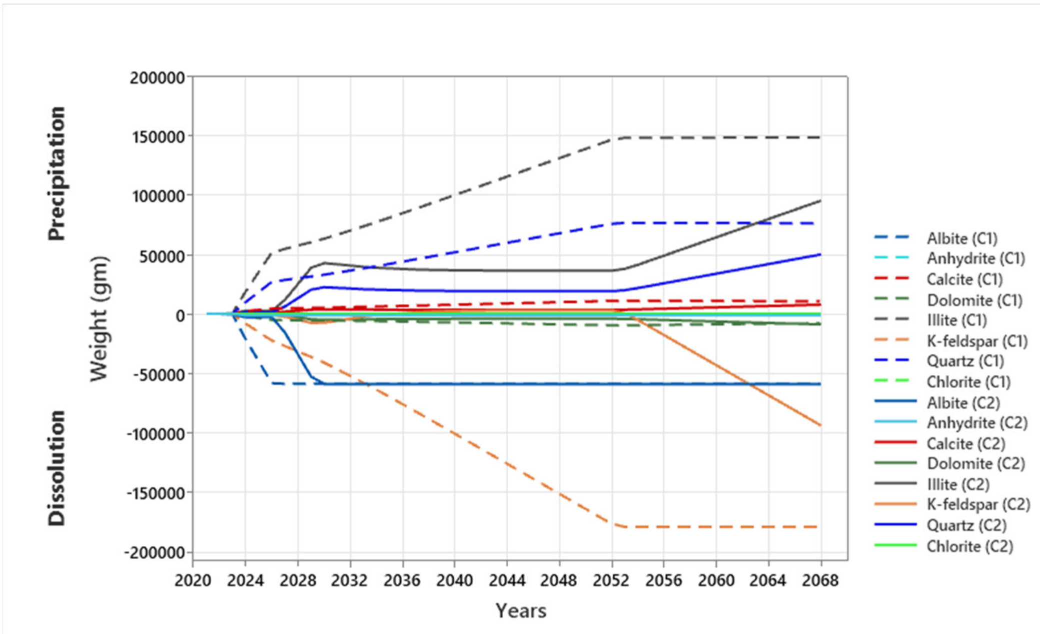



Figure 2-52a. Dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for Cell C1, 0 to 1 meter below the Amsden top. Solid lines show results for Cell C2, 1 to 2 meters below the Amsden top.

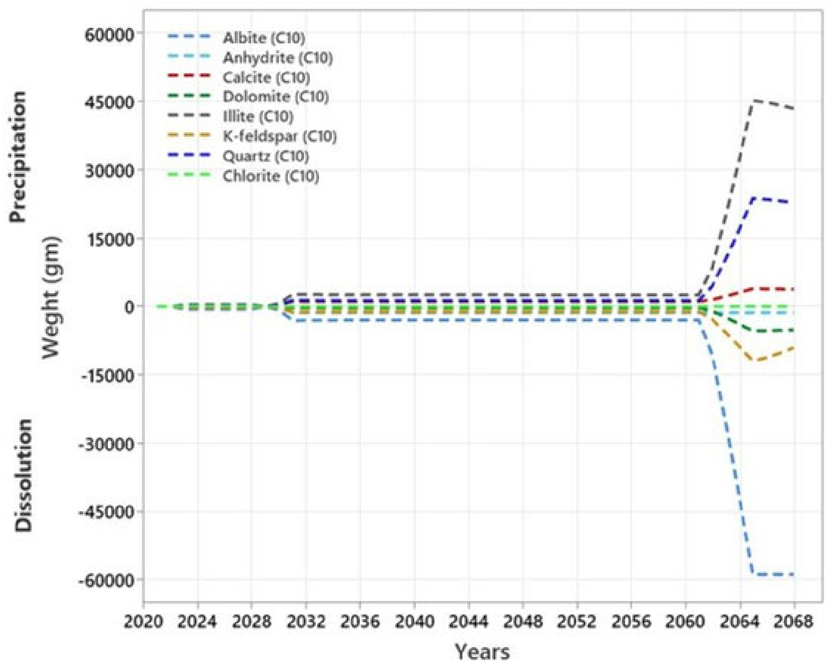



Figure 2-52b. Dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for Cell 10 (C10), 9 to 10 meters below the Amsden top.

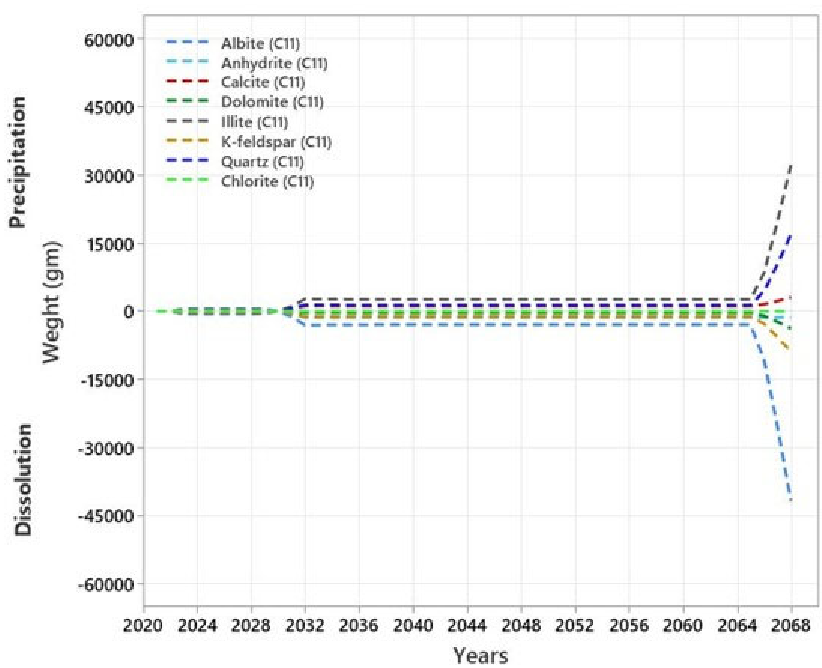



Figure 2-52c. Dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for Cell 11 (C11), 10 to 11 meters below the Amsden top.

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

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

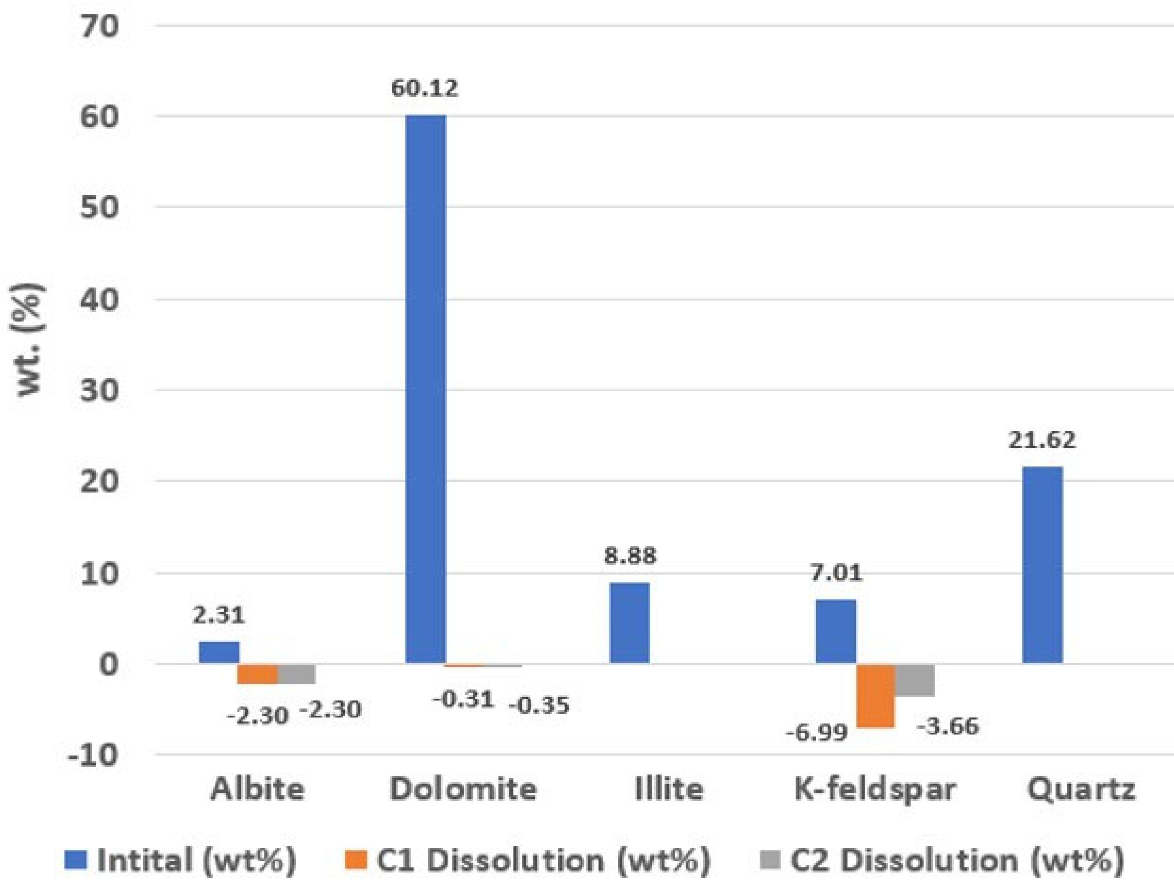



Figure 2-53. Weight percentage (wt%) of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time. Negative values represent total wt%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

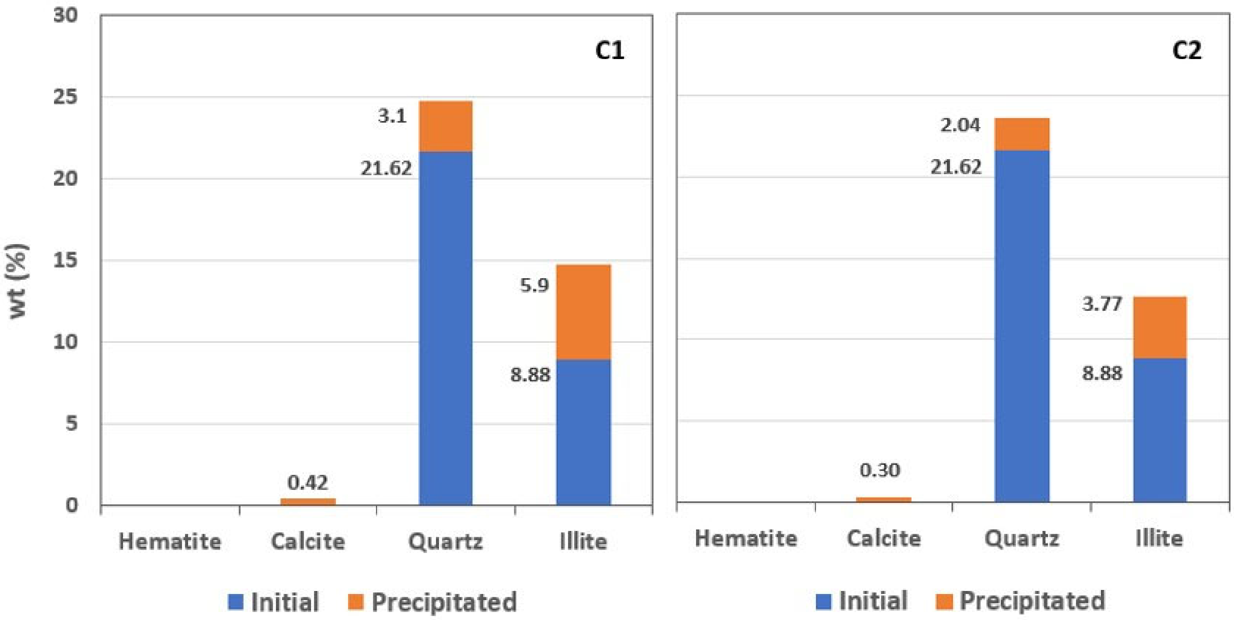



Figure 2-54. Weight percentage (wt.%) of initial (blue) and precipitated (orange) minerals in the C1 (left) and C2 (right) normalized based on total solid (initial – dissolution + precipitation) present in the C1 and C2 after 20 years of injection and 25 years of postinjection. Hematite precipitation in C1 and C2 is too small to see in the figure.

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

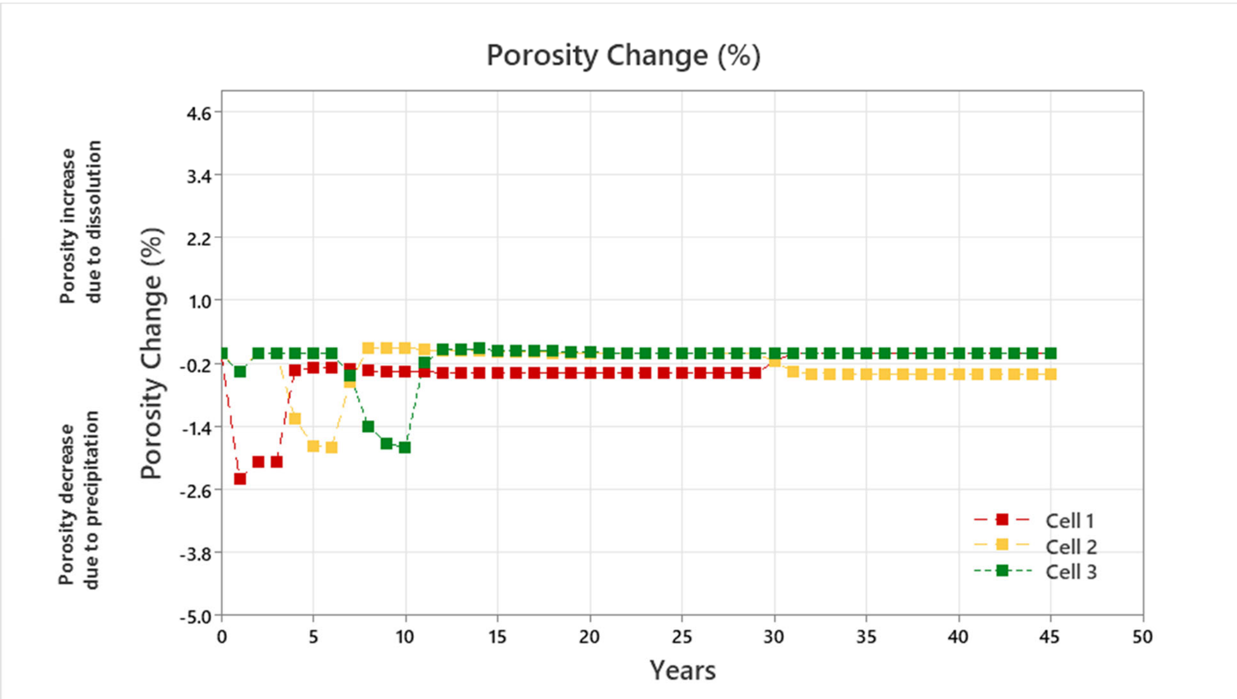



Figure 2-55. Change in percent porosity in the Amsden Formation underlying confining layer. Red line shows porosity change for Cell C1, 0 to 1 meter below the Amsden Formation top. Yellow line shows Cell C2, 1 to 2 meters below the Amsden Formation top. Green line shows Cell C3, 2 to 3 meters below the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

### *2.4.4 Geomechanical Information of Confining Zone*

#### *2.4.4.1 Borehole Image Fracture Analysis*

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

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

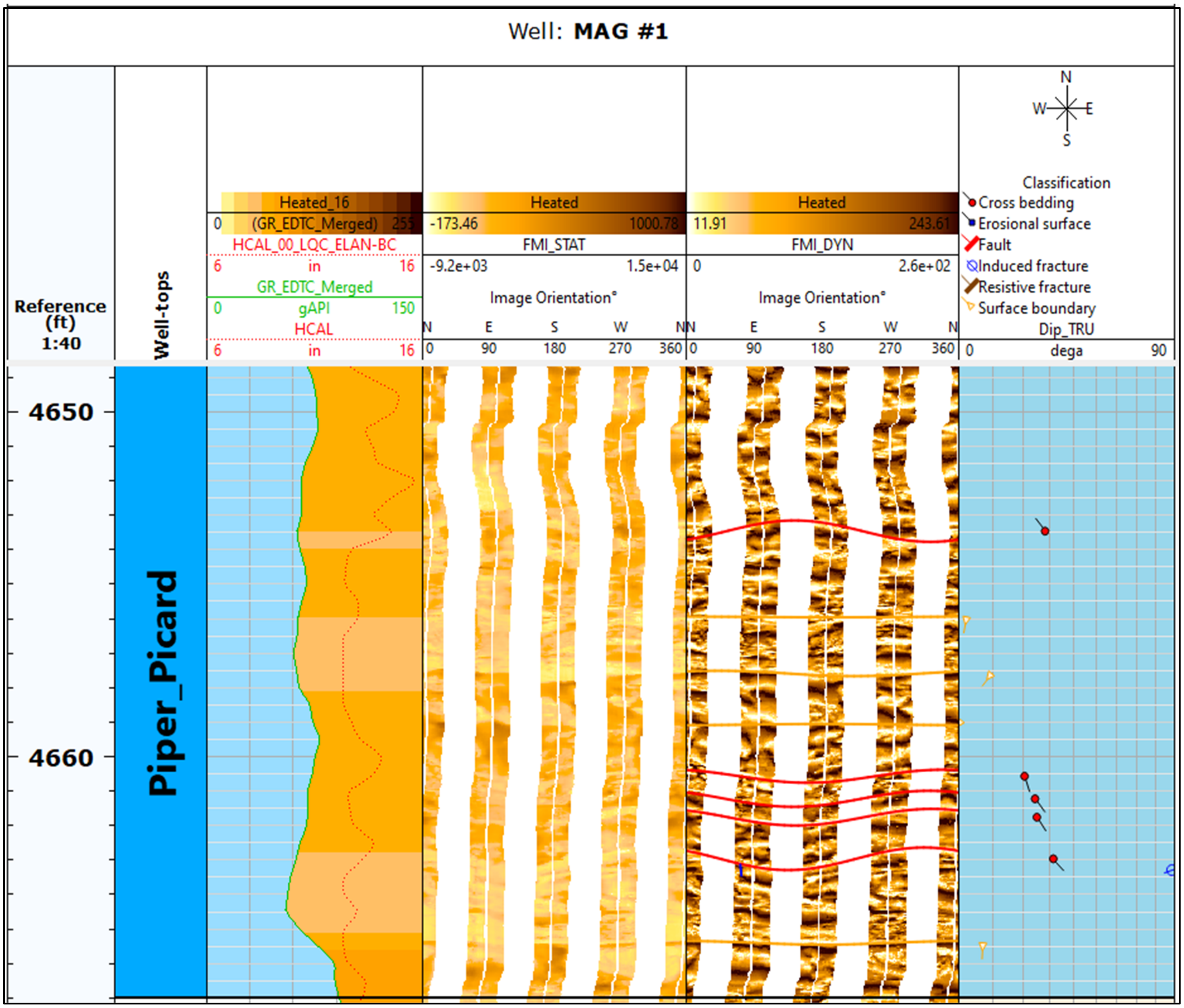



Figure 2-56a. Examples of the interpreted FMI log for the MAG 1 well showing one of the drilling induced fractures observed in the Piper Formation.

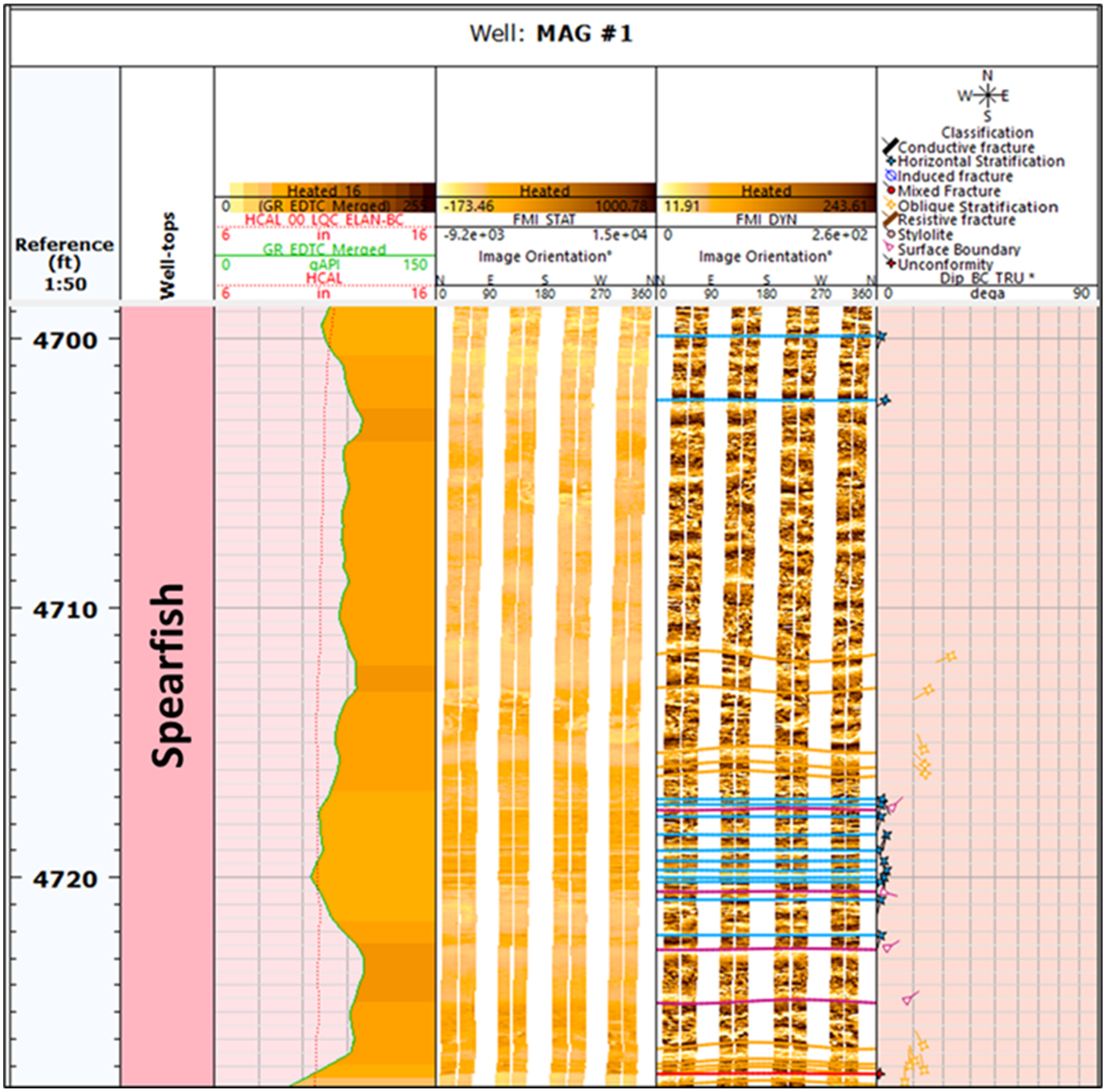



Figure 2-56b. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Spearfish Formation FMI image analysis.

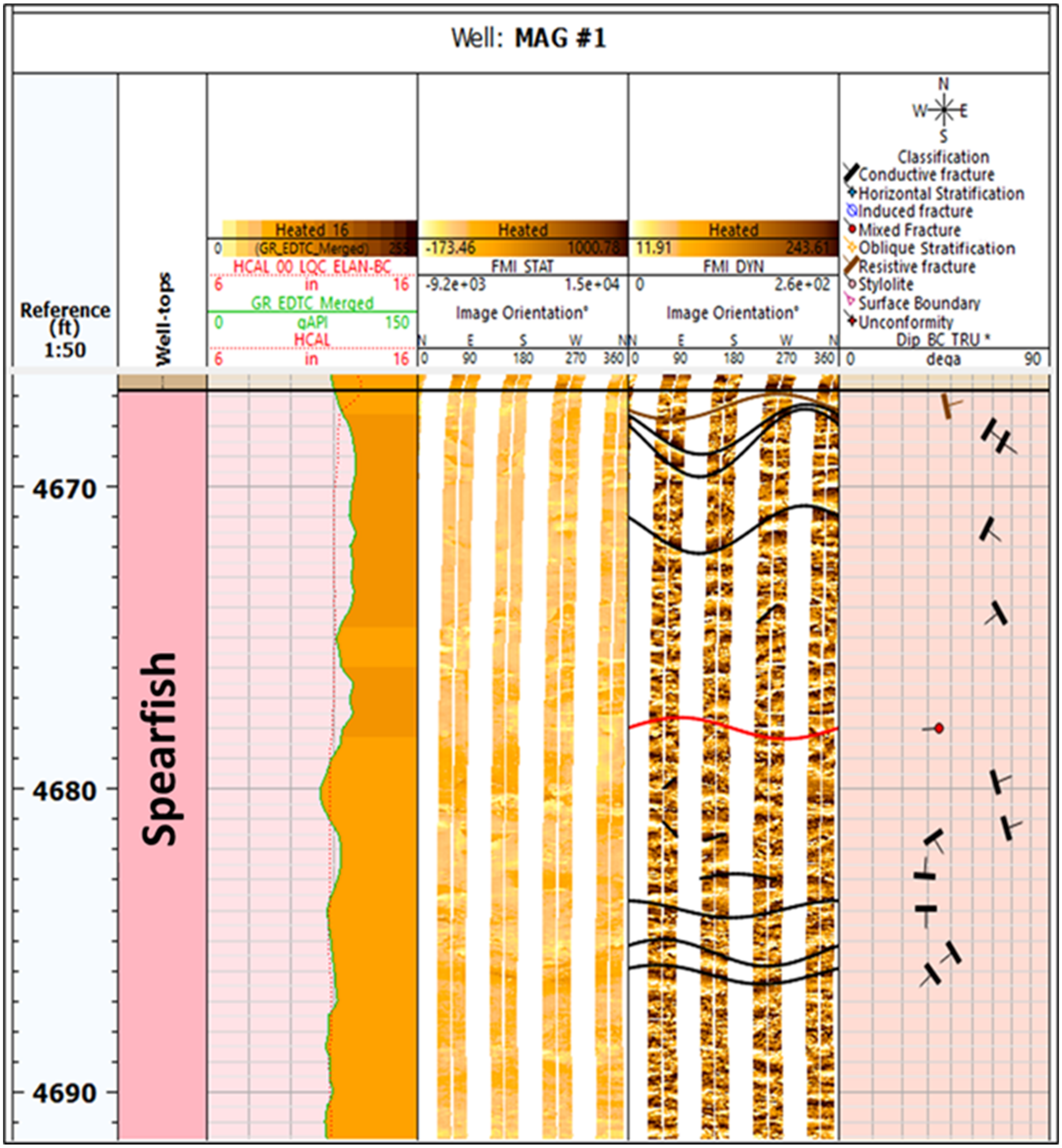



Figure 2-57. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, resistive fracture, mixed fracture, horizontal stratification, and oblique stratification) seen in Spearfish Formation FMI image analysis.

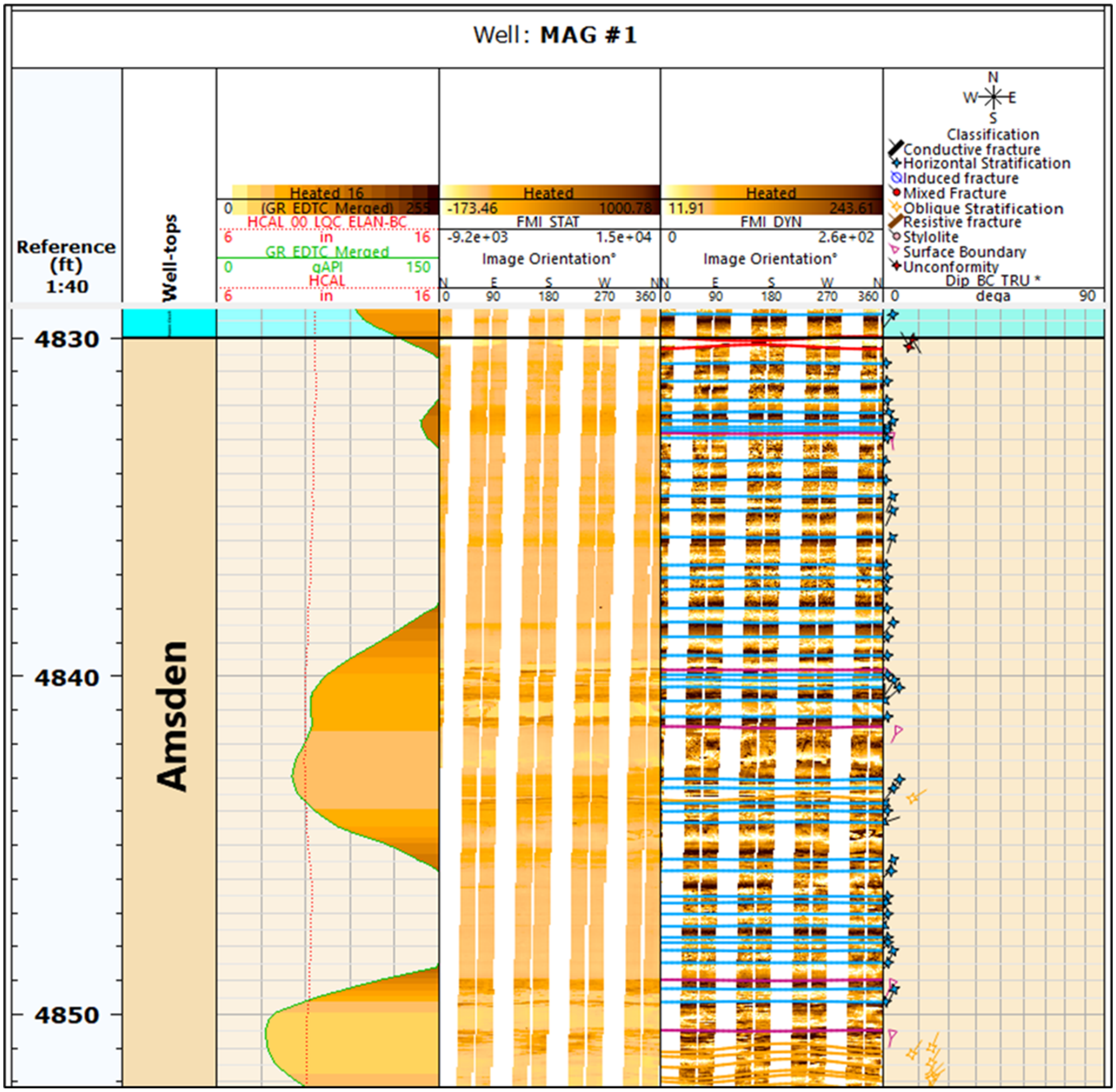



Figure 2-58. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis.

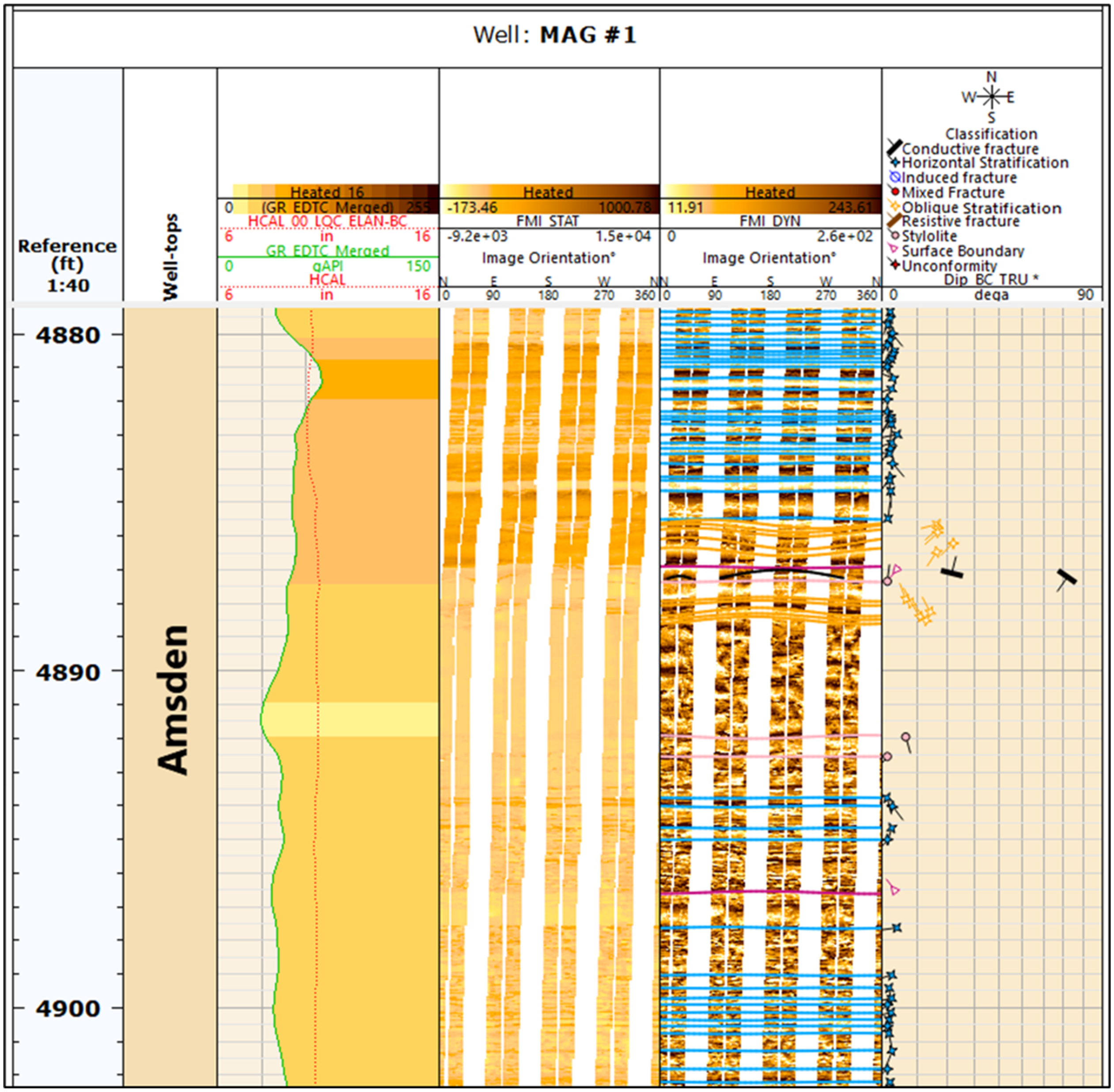



Figure 2-59. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, stylolites, horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis.

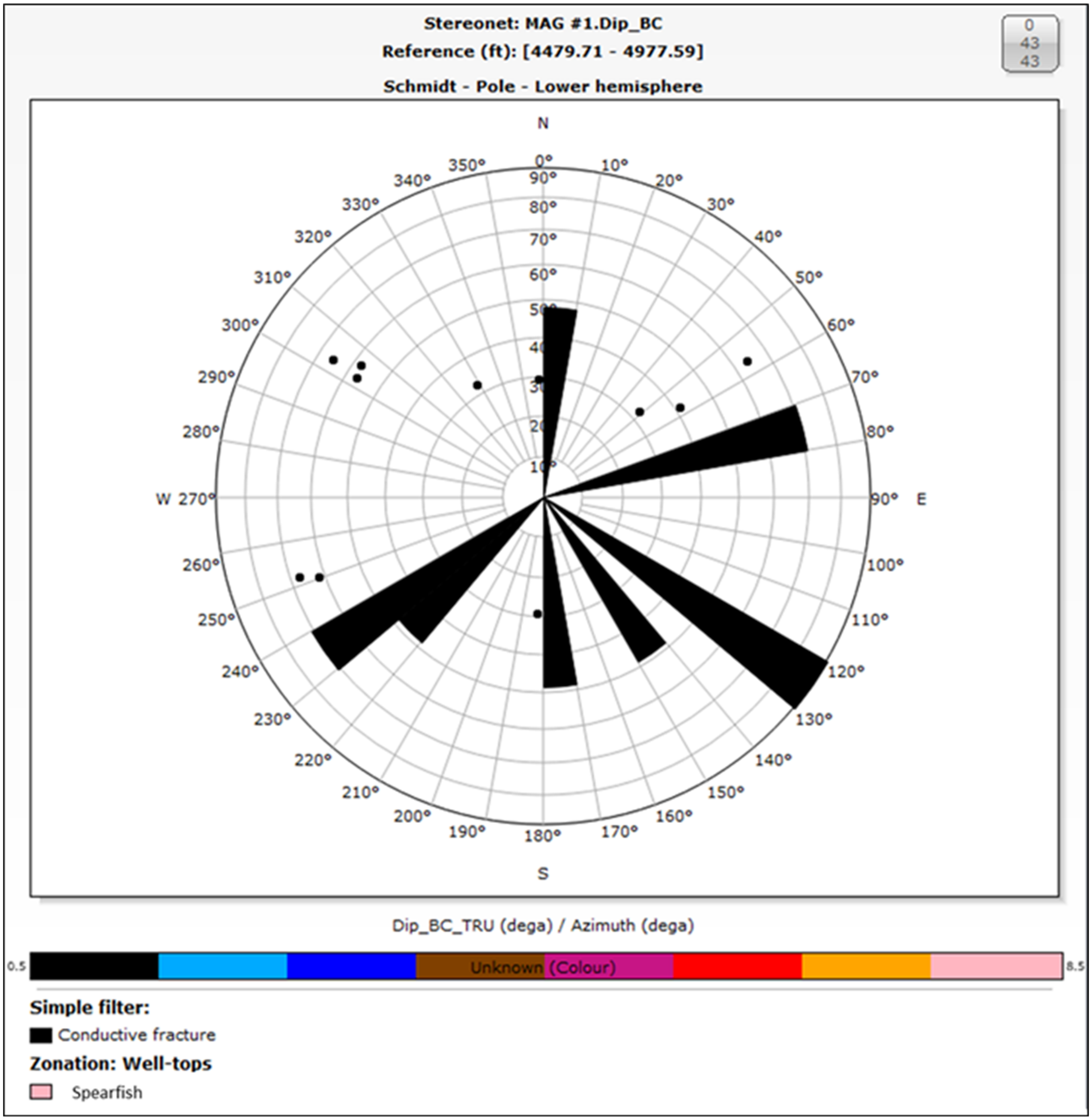



Figure 2-60. This example shows the dip azimuth and dip angle for conductive fractures seen in the Spearfish Formation.

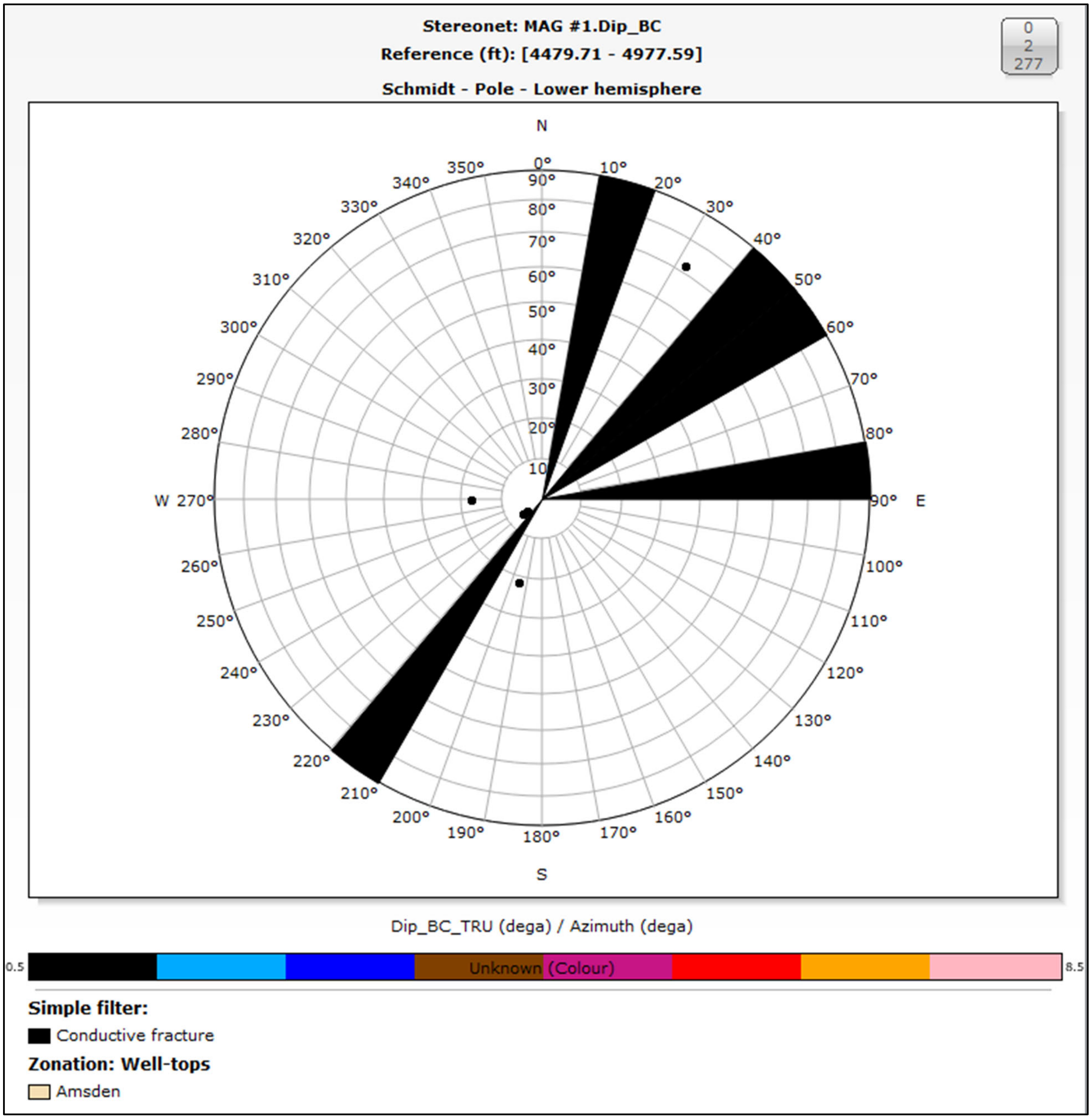



Figure 2-61. This example shows the dip azimuth and dip angle for conductive fractures seen in the Amsden Formation.

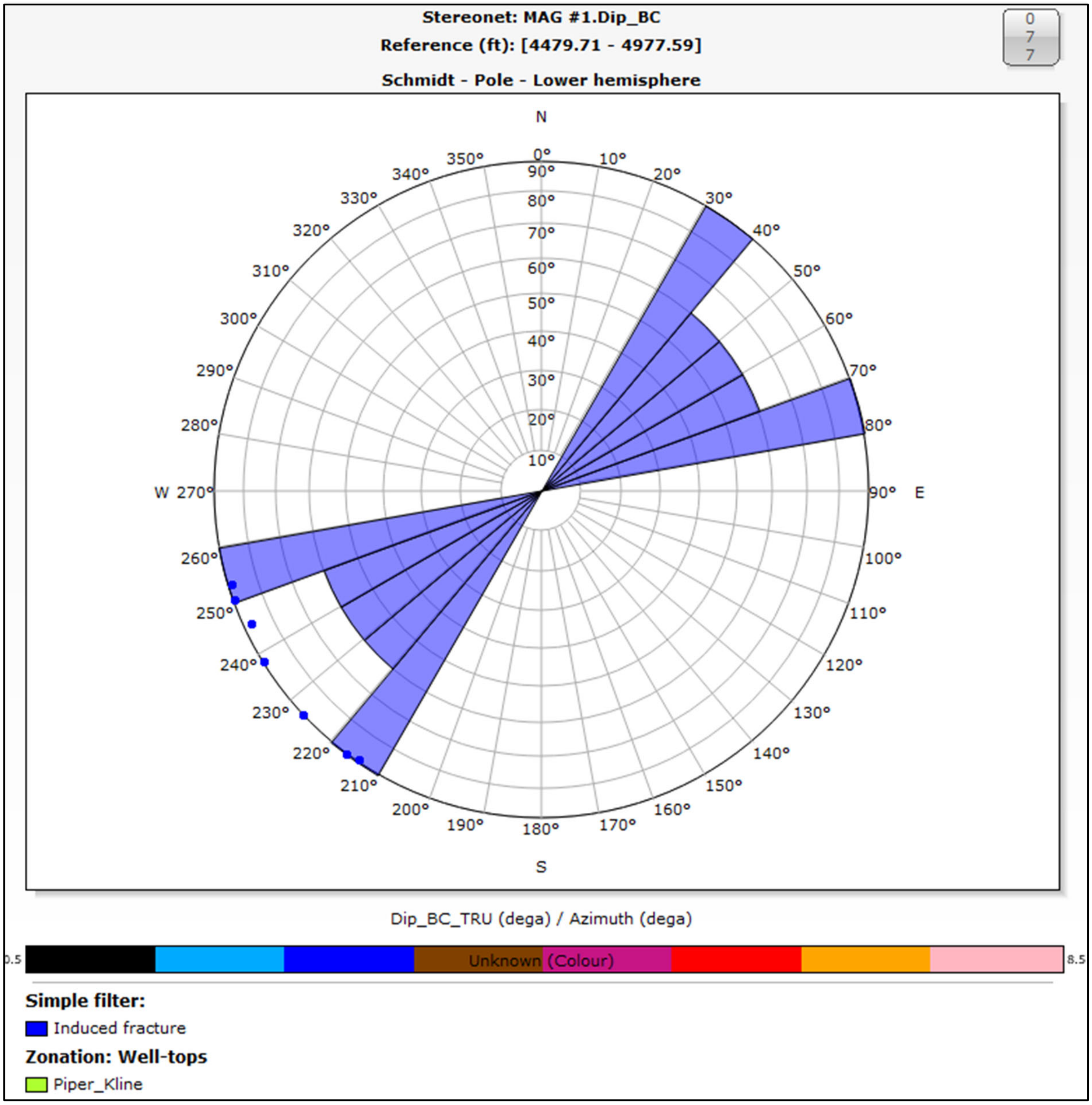



Figure 2-62. This example shows the orientation of drilled-induced fractures in the Piper Formation.

*2.4.4.2 Stress, Ductility and Rock Strength*

A 1D MEM was derived using the log data from MAG 1 well. Logs were edited to account for washouts in the Broom Creek and Amsden Formation sections using multilinear regressions. Geomechanical parameters in the Spearfish, Broom Creek, and Amsden Formations were estimated using the 1D MEM. The 1D MEM was used to estimate the vertical stress, pore pressure, minimum and maximum horizontal stresses (Shmin, SHmax), Poisson's ratio, Young's modulus,

shear and bulk moduli, tensile, uniaxial compressive strength, and friction angle (Figure 2-63, Figure 2-64, and Figure 2-65). Table 2-19 shows the average and range of elastic and dynamic parameters, and stresses in the Spearfish, Broom Creek, and Amsden Formations.

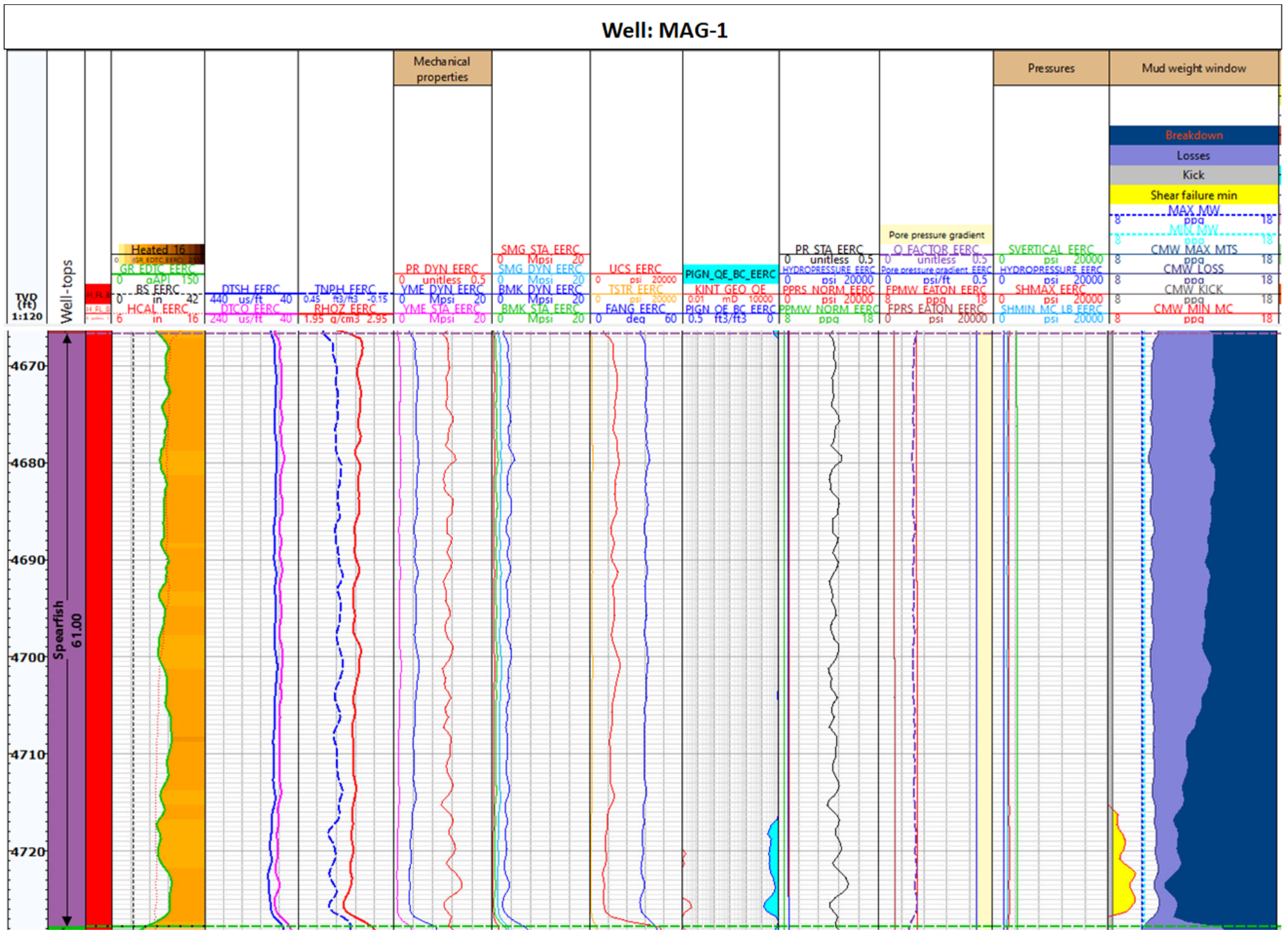



Figure 2-63. Geomechanical parameters in the Spearfish Formation. Track 1, bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, and dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static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

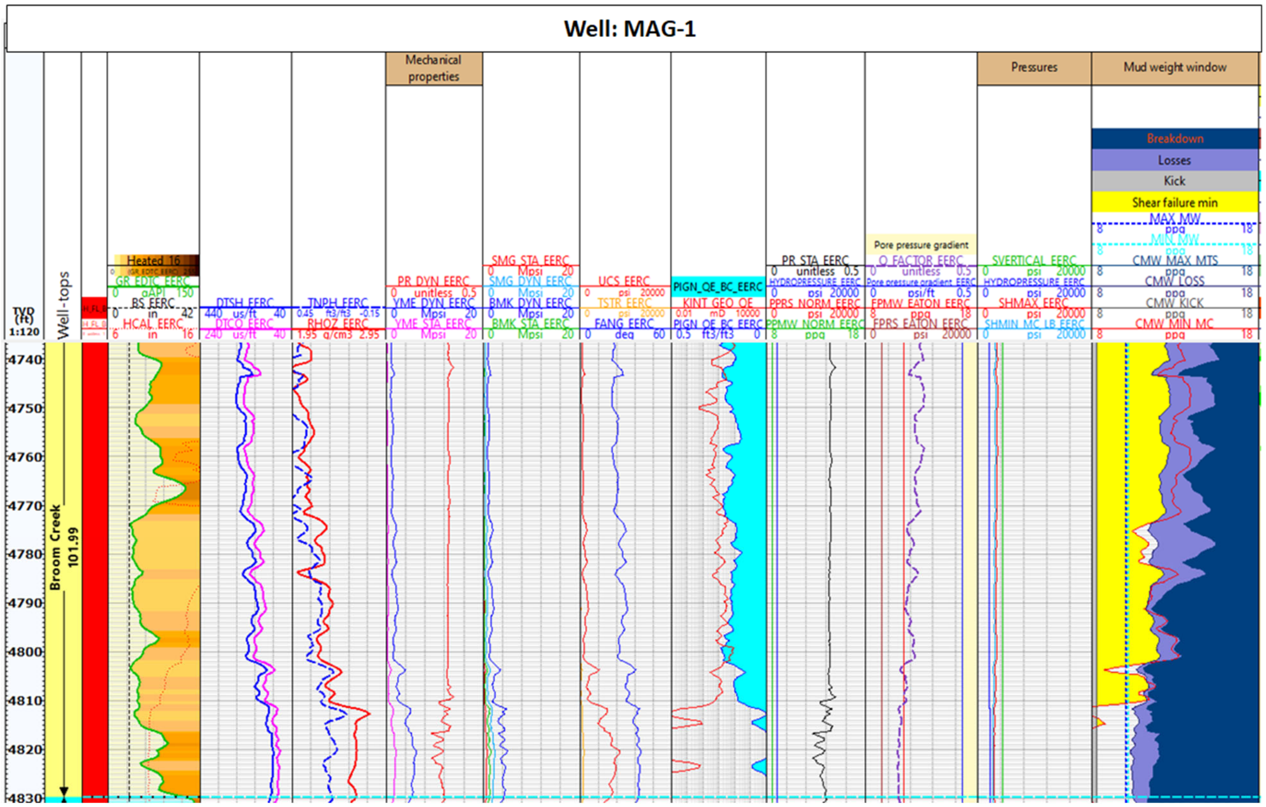



Figure 2-64. Geomechanical parameters in the Broom Creek Formation. Track 1, bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static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

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

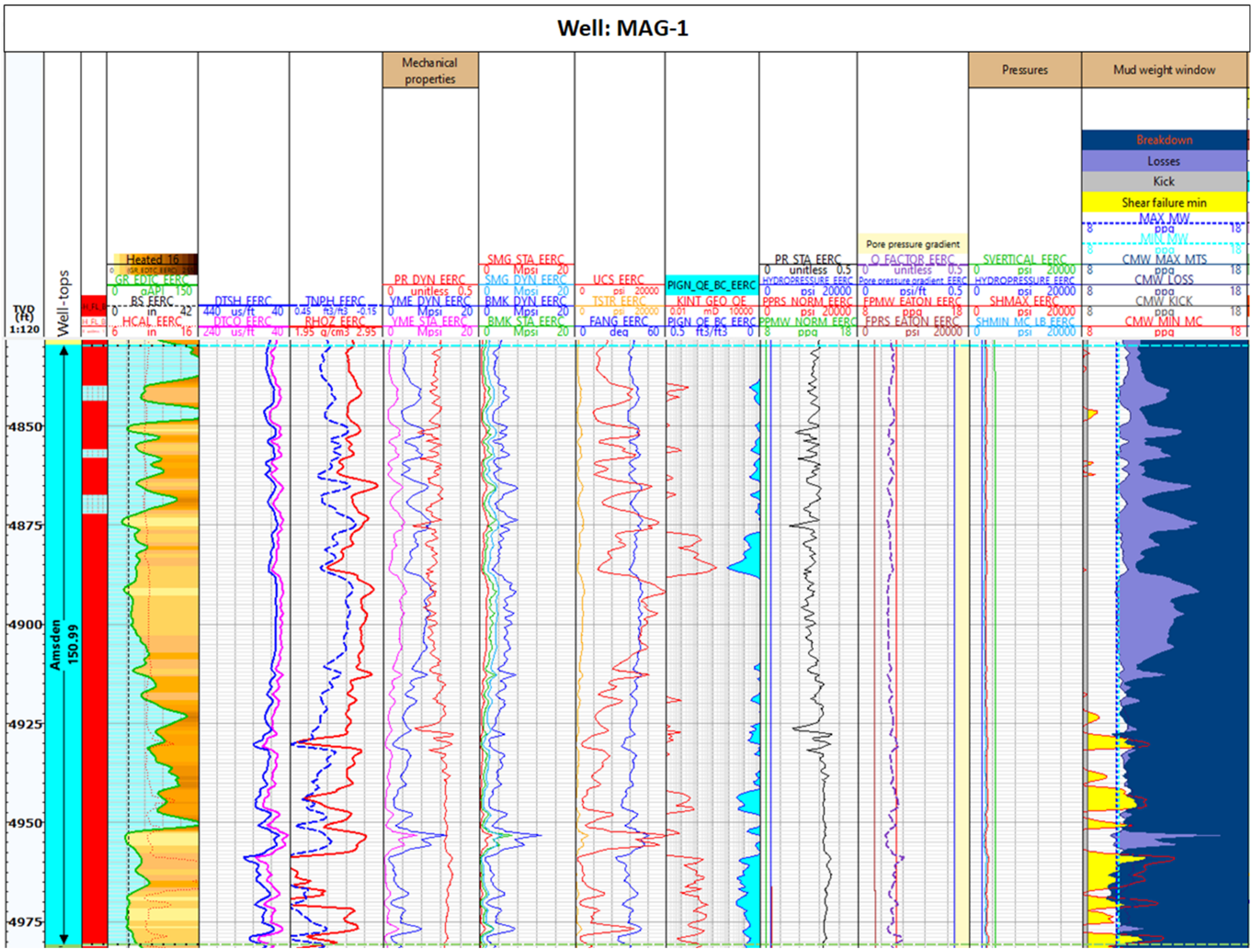



Figure 2-65. Geomechanical parameters in the Amsden Formation. Track 1, Bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static bulk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

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

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

Log data were used to characterize stress in the storage complex to determine the fracture pressure gradient. In the injection zone, the parameters used to calculate stress were determined from the sand intervals in the Broom Creek Formation section. Rock strength defines the limit at which the stress conditions might induce the rock to mechanically fail. The unconfined compressive strength can be determined directly from rock mechanics tests, but in the MAG 1 well case, it was empirically estimated from well log data. Poisson's ratio was estimated using the available well logs, which resulted in an average value for the Broom Creek Formation of 0.313. The Biot factor was calculated using the effective porosity, static bulk modulus, and permeability, resulting in a range of 0.89-1. The pore pressure and hydropressure gradient were estimated using the true vertical depth (TVD), vertical stress (Sv), compressional slowness, and compressional velocity, respectively. The pore pressure and hydropressure gradients are equal to 0.448 and 0.429 psi/ft, respectively. In situ stresses such as Sv, maximum horizontal stress (SHmax), and minimum horizontal stress (Shmin) were calculated using specific parameters and methods (Table 2-20). Sv, which is related to the overburden or lithostatic pressure, is an important parameter in geomechanical modeling. In the Broom Creek Formation, overburden pressure was estimated through the bulk density log to the surface using the extrapolation method, resulting in an overburden gradient of 0.911 psi/ft. The poroelastic horizontal strain model is the most used method for horizontal stress calculation. The poroelastic horizontal strain model can be expressed using static Young's modulus, Poisson ratio, Biot's constant, overburden stress, and pore pressure. The poroelastic horizontal strain model was used to estimate the minimum horizontal stress (Plumb and Hickman, 1985; Aadnoy, 1990; Aadnoy and Bell, 1998; Brudy and Zoback, 1999). The SHmax is estimated from Shmin and process zone stress (as function of porosity). Based on the calculated stresses, the stress regime that can be seen in the Spearfish, Broom Creek, and Amsden Formations is a normal stress regime where Sv > SHmax > Shmin. Shmin magnitude could not be calibrated using the closure pressure measurements obtained from the openhole MDT microfracture in situ stress test because it was not performed in the MAG 1 well because of the large washout in the vicinity of the intervals of interest. The fracture gradient (FG) is calculated from pore pressure and overburden gradient. With the absence of closure pressure measurements

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

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

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

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

Where:

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

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

Where:

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

## 2.5 Faults, Fractures, and Seismic Activity

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

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

### *2.5.1 Stanton Fault*

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

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

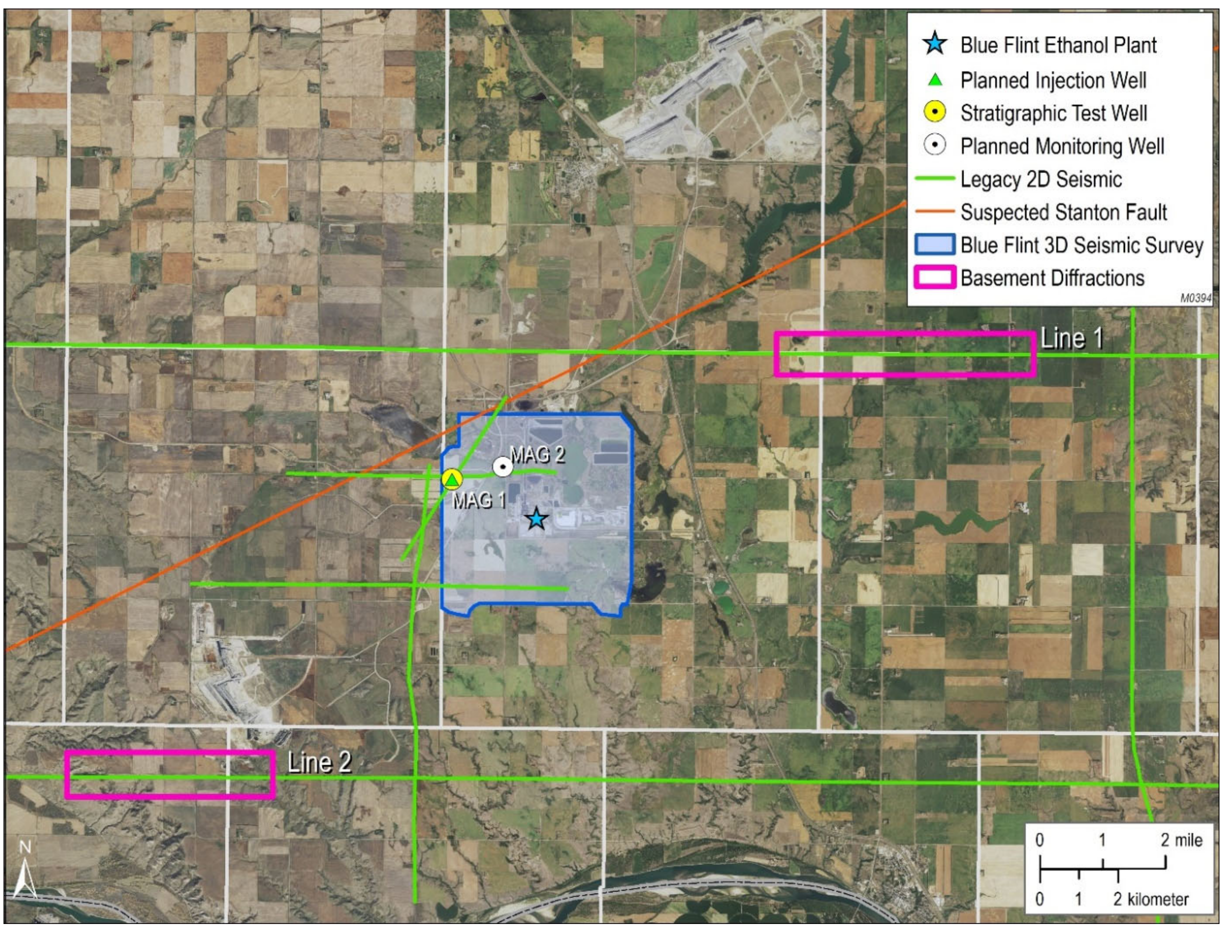



Figure 2-66. Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016).

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

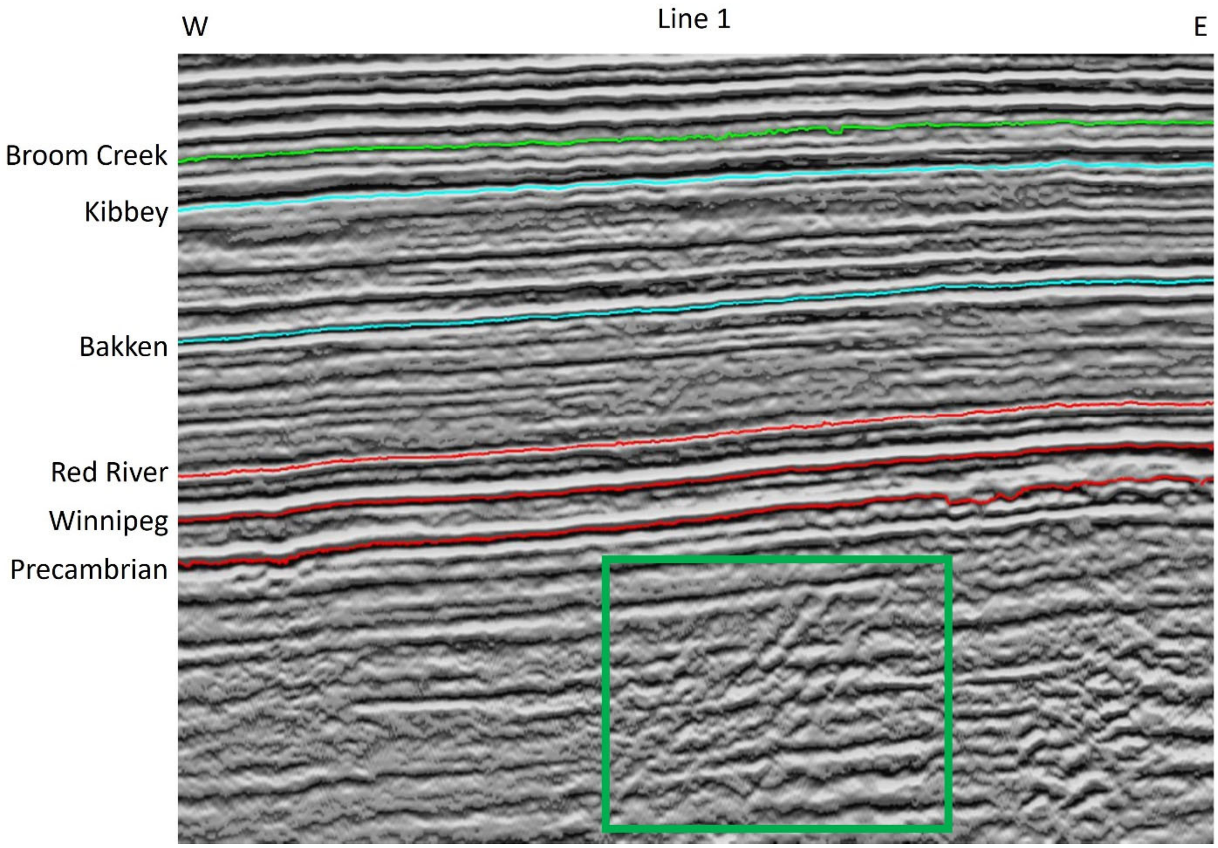



Figure 2-67. Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box).

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

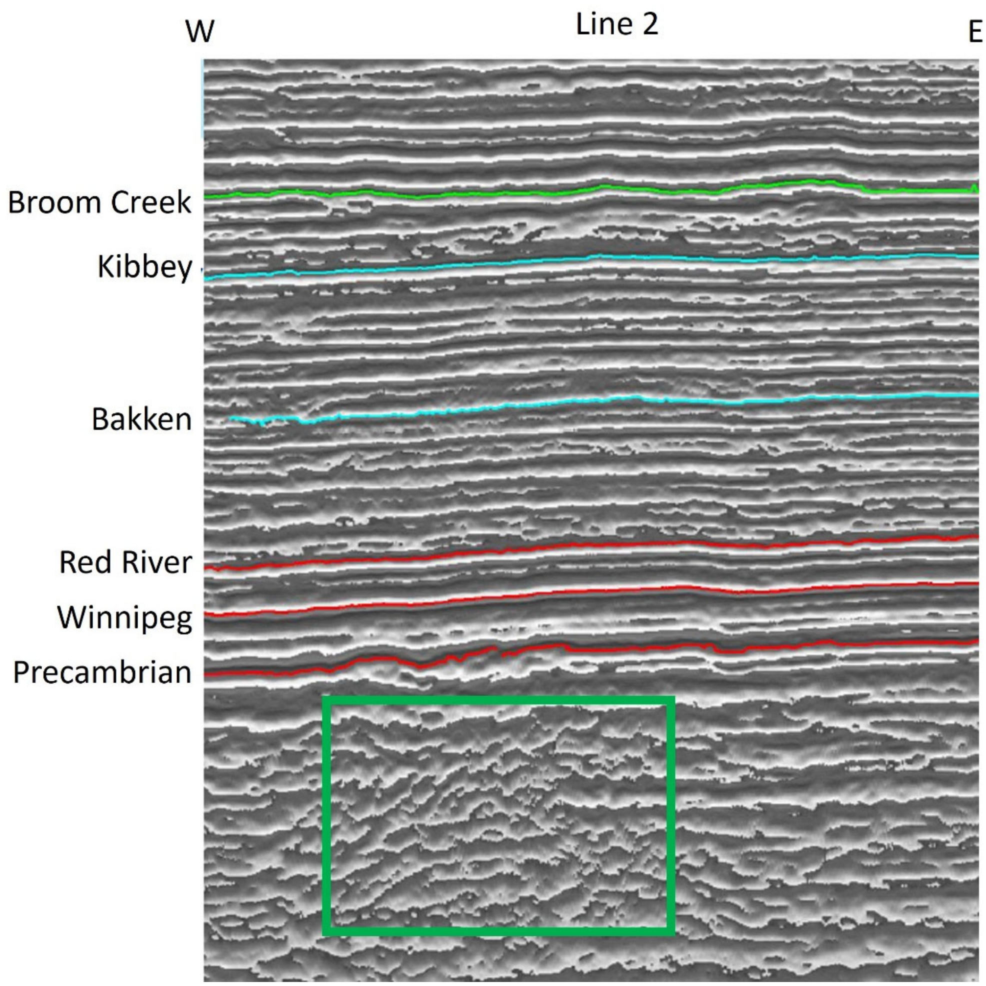



Figure 2-68. Cross section of Line 2 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box).

### *2.5.2 Seismic Activity*

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

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

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

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

* Estimated depth.

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

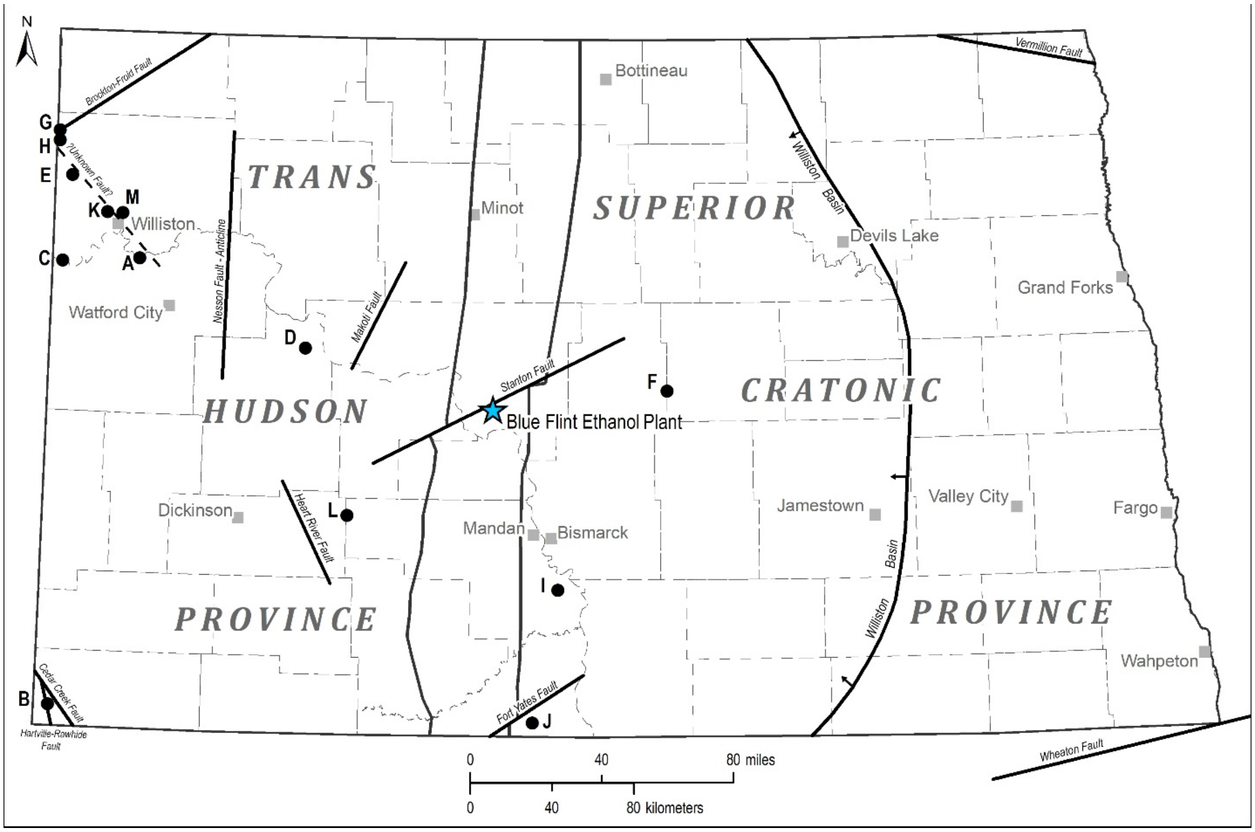



Figure 2-69. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-21.

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

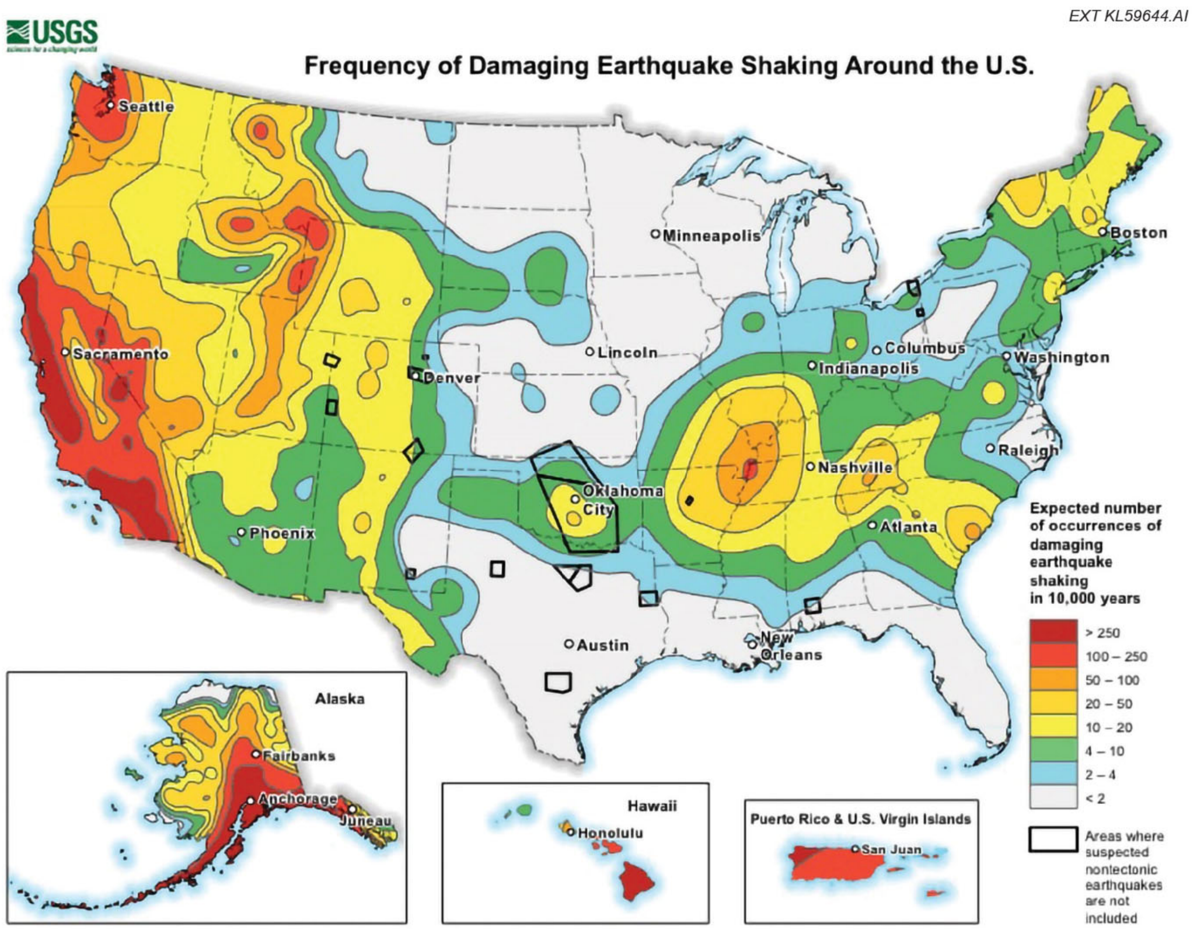



Figure 2-70. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

## 2.6 Potential Mineral Zones

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

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a horizontal well could be used to produce the hydrocarbon while avoiding drilling through the $CO_2$ plume, or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available while the MAG 1 well is in operation, which will allow prospective operators to design an appropriate well control strategy via increased

drilling mud weight. Pressure increase in the Broom Creek caused by injection of $CO_2$ will relax postinjection as the area returns to its preinjection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the $CO_2$ should be designed to include an intermediate casing string placed across the storage reservoir, with $CO_2$-resistant cement used to anchor the casing in place.

Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC § 57-51-01(11)) define a shallow gas zone as gas produced from a zone that consists of "strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation [Jurassic], from which gas may be produced."

Lignite coal is currently mined at the Falkirk Mine, operated by the Falkirk Mining Company, a wholly owned subsidiary of North American Coal Corporation, which is located within the project area. The Falkirk Mine produces from the Hagel coal seam for power generation feedstock at Rainbow Energy's Coal Creek Station. The Hagel coal seam is the lowermost major lignite present in the area in the Sentinel Butte Formation (Figure 2-71).

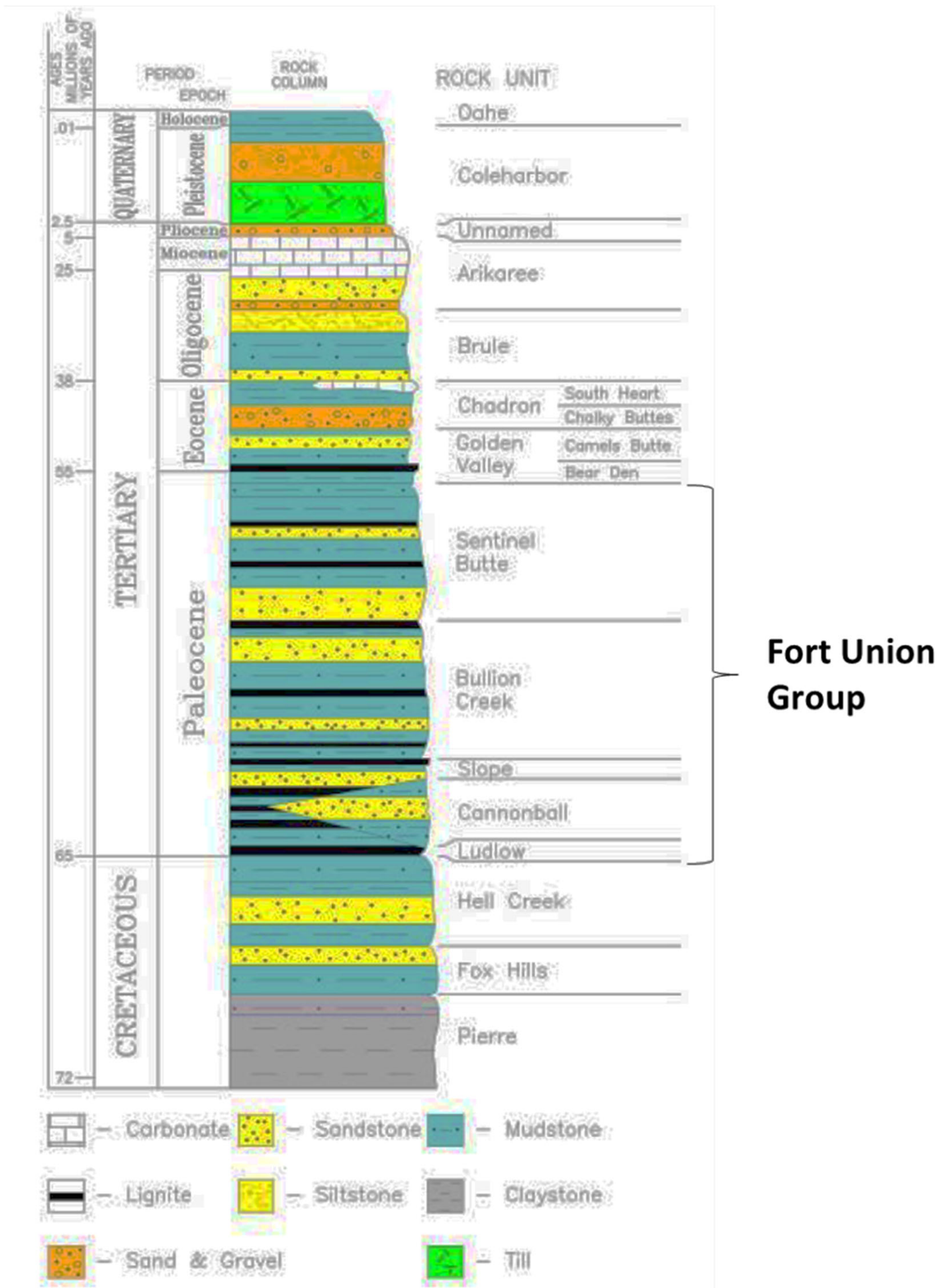



Figure 2-71. Coal beds of the Forth Union Group including the Sentinel Butte and Bullion Creek (Tongue River) Formations showing the lignite coals in western North Dakota (Murphy, 2006).

The Hagel coal seam is divided into two seams: the Hagel A and the Hagel B. The Hagel A lignite bed averages 5.7 ft thick with a range from 0.5 to 11.5 ft. The Hagel B bed has a mean thickness of approximately 1.8 ft, ranging in thickness from 0.5 to 6.3 ft. (Figure 2-72) (Zygarlicke and others, 2019). Coal seams in the Bullion Creek Formation exist in the area below the Hagel seam (Figure 2-71) but are too deep to be economically mined.

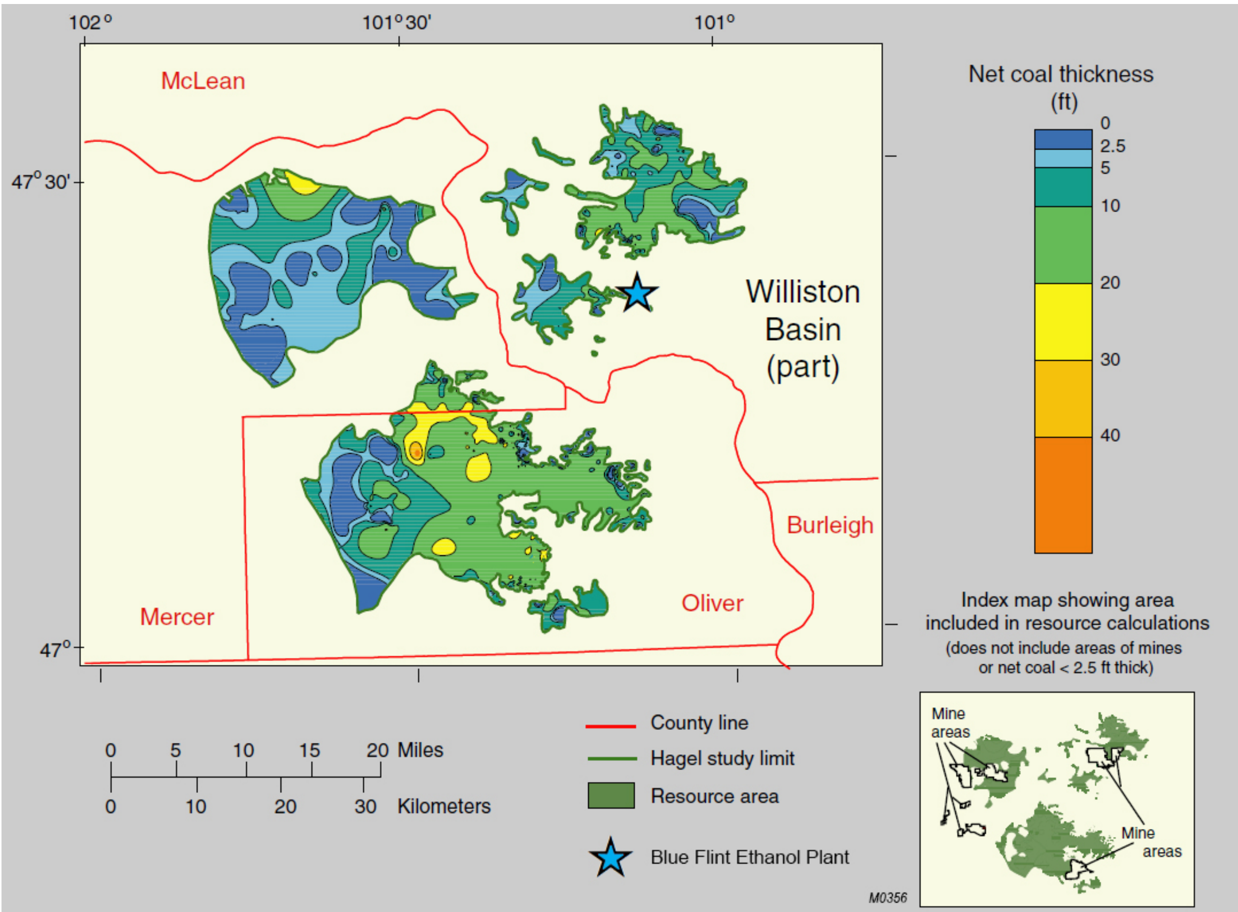



Figure 2-72. Hagel net coal isopach map (modified from Ellis and others, 1999).

## 2.7 References


Aadnoy, B.S., 1990, Inversion technique to determine the in-situ stress field from fracturing data: Journal of Petroleum Science and Engineering, v. 4, no. 2, p. 127–141.

Aadnoy, B.S., and Bell, J.S., 1998, Classification of drilling-induced fractures and their relationship to in-situ stress directions: The Log Analyst, v. 39, no. 6, p. 27–42.

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

Brudy, M., and Zoback, M.D, 1999, Drilling-induced tensile wall-fractures: implications for determination of in-situ stress orientation and magnitude: International Journal of Rock

Mechanics and Mining Sciences, v. 36, no. 2, p. 191–215. doi:10.1016/s0148-062(98)00182-x.

Carlson, C.G., 1993, Permian to Jurassic redbeds of the Williston Basin: North Dakota Geological Survey Miscellaneous Series 78, 21 p.

Downey, J.S., 1986, Geohydrology of bedrock aquifers in the northern Great Plains in parts of Montana, North Dakota, South Dakota and Wyoming: U.S. Geological Survey Professional Paper 1402-E, 87 p.

Downey, J.S., and Dinwiddie, G.A., 1988, The regional aquifer system underlying the northern Great Plains in parts of Montana, North Dakota, South Dakota, and Wyoming—summary: U.S. Geological Survey Professional Paper 1402-A.

Ellis, M.S., Gunther, G.L., Ochs, A.M., Keighin, C.W., Goven, G.E., Schuenemeyer, J.H., Power, H.C., Stricker, G.D., and Blake, D., 1999, Coal resources, Williston Basin: U.S. Geological Survey Professional Paper 1625-A, Chapter WN.

Espinoza, D.N., and Santamarina, J.C., 2017, $CO_2$ breakthrough—caprock sealing efficiency and integrity for carbon geological storage: International Journal of Greenhouse Gas Control, v. 66, p. 218–229.

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

Glazewski, K.A., Grove, M.M., Peck, W.D., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2015, Characterization of the PCOR Partnership Region: Plains $CO_2$ Reduction (PCOR) Partnership topical report for U.S. Department of Energy and multiclients, Grand Forks, North Dakota, Energy & Environmental Research Center, January.

Murphy, E.C., 2006, The lignite reserves of North Dakota: North Dakota Geological Survey, Report of Investigation No. 104.

Murphy, E.C., Nordeng, S.H., Juenker, B.J., and Hoganson, J.W., 2009, North Dakota stratigraphic column, E.C. Murphy and L.D. Helms, Eds., North Dakota Geological Survey, Bismarck, North Dakota.

North Dakota Industrial Commission, 2022, Overview of petroleum geology of the North Dakota Williston Basin: www.dmr.nd.gov/ndgs/resources/ (accessed July 2022).

North Dakota Industrial Commission, 2021a, NDIC Case No. 29029 – draft permit, fact sheet, and storage facility permit application: Minnkota Power Cooperative supplemental information, Grand Forks, North Dakota, www.dmr.nd.gov/oilgas/C29029.pdf (accessed July 2022).

North Dakota Industrial Commission, 2021b, NDIC Case No. 29032 – draft permit, fact sheet, and storage facility permit application: Minnkota Power Cooperative supplemental information, Grand Forks, North Dakota, www.dmr.nd.gov/oilgas/C29032.pdf (accessed July 2022).

North Dakota Industrial Commission, 2021c, NDIC Case No. 28848 – draft permit, fact sheet, and storage facility permit application: Red Trail Ethanol, LLC, supplemental information, www.dmr.nd.gov/oilgas/C28848.pdf (accessed July 2022).

Nowakowski, A., 2005, The static and dynamic elasticity constants of sandstones and shales from the hard coal mine "Jasmos" determined in the laboratory conditions, *in* Eurock 2005 – impact of human activity on the geologic environment: Konecy, Taylor & Francis Group, London, Eds.

Peck, W.D., Liu, G., Klenner, R.C.L., Grove, M.M., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2014, Storage capacity and regional implications for large-scale storage in the basal Cambrian system: Plains $CO_2$ Reduction (PCOR) Partnership Phase III Task 16 Deliverable D92 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2014-EERC-05-12, Grand Forks, North Dakota, Energy & Environmental Research Center, https://edx.netl.doe.gov/dataset/storage-capacity-and-regional-implications-for-large-scale-storage-in-the-basal-cambrian-system (accessed 2022).

Plumb, R.A., and Hickman, S.H., 1985, Stress-induced borehole elongation—a comparison between the four-arm dipmeter and the borehole televiewer in the Auburn Geothermal Well: Journal of Geophysical Research Atmospheres, v. 90, p. 5513–5521.

Rygh, M.E., 1990, The Broom Creek Formation (Permian), in southwestern North Dakota—depositional environments and nitrogen occurrence [Master's Thesis]: University of North Dakota, Grand Forks, North Dakota.

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

Tutuncu, A.N., and Sharma, M.M., 1992, Relating static and ultrasonic lab measurements to acoustic log measurements in tight gas sands: Presented at 67th SPE ATCE, Washington, D.C., October 1998. SPE-24689.

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

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

Yale, D.P., and Jamieson, W.H. Jr., 1994, Static and dynamic mechanical properties of carbonates, *in* Rock Mechanics – Models and Measurements Challenges from Industry: Nelson and Laubach, Eds., Balkema, Rotterdam.

Yale, D.P., and Walters, D.A., 2016, Integrated, logbased, anisotropic geomechanics analysis in unconventional reservoirs: Presented at SPE Unconventional Reservoir Fracturing Workshop, Muscat, Oman, February 2016.

Yale, D.P., Nieto, J.A., and Austin, S.P., 1995, The effect of cementation on the static and dynamic mechanical properties of the Rotliegendes sandstone, *in* Rock Mechanics – Proceedings of the 35th U.S. Symposium: Daemen and Schultz, Eds., Balkema, Rotterdam.

Zhang, J.J., and Bentley, L.R., 2005, Factors determining Poisson's ratio: CREWES Research Report, v. 17.

Zhang, J., and Yin. S.-X., 2017, Fracture gradient prediction—an overview and an improved method: Petroleum Science, v. 14, no. 4, p. 720–730. DOI 10.1007/s12182-017-0182-1.

Zhou, X.J., Zeng, Z., and Belobraydic, M., 2008, Geomechanical stability assessment of Williston Basin Formations for petroleum production and $CO_2$ sequestration: Presented at the 42nd U.S. Rock Mechanics Symposium and 2nd U.S.–Canada Rock Mechanics Symposium, San Francisco, California, June 29 – July 2, 2008.

Capillary pressure curves calculated from MICP data were modified to the model scale based on the permeability and porosity values of the simulation model and used in the numerical simulations. These modified capillary pressure curves are also shown in Figures 3-6–3-8. The capillary entry pressure values applied in the model were determined by deriving a ratio between the reservoir quality index of core samples and modeled properties to scale the capillary entry pressure value derived from core testing (Table 3-2).

Temperature and pressure data recorded in the MAG 1 wellbore were used to derive a temperature and pressure gradient to initialize the numerical simulation model for the proposed injection site. In combination with depth, a temperature gradient of 0.025°F/ft was used to calculate subsurface temperatures throughout the study area. The temperature gradient was calculated using the temperature measurements listed in Table 2-2. Average annual surface temperature was not included in calculation of the 0.025°F/ft temperature gradient. A pressure gradient of 0.512 psi/ft was used to calculate initial pressure in the model. The pressure gradient was calculated using the pressure measurements listed in Table 2-3. Standard atmospheric pressure of 14.7 psi was not used to calculate the pressure gradient as CMG uses PSIC instead of PSIA. The calculated pressure and temperature gradients were not used as direct inputs for simulation but rather used to calculate the pressure and temperature of a reference point at the corresponding reference depth which are the direct inputs for simulation. For a reference point at a depth of 4782.7 ft in the simulation model, the temperature and pressure values input were 119.6°F (4782.8 ft*0.025°F/ft) and 2448.8 psi (4782.8 ft*0.0512 psi/ft), respectively to correctly distribute the temperature and pressure data, that are in line with the measured temperature and pressure values reported in Section 2. The fracture gradient was obtained from a geomechanical analysis, resulting in an average of 0.69 psi/ft. The maximum allowable BHP of 2,970 psi was estimated to be 90% of the fracture gradient multiplied by the depth of the top perforation in the injection zone, the Broom Creek Formation, and used as the injection constraint in the numerical simulation of the expected injection scenario.

### *3.3.2 Sensitivity Analysis*

Because the availability of data for this study included well logs, core sample data, and rock–fluid properties, the need for typical sensitivity studies of influential reservoir parameters has been reduced. A preliminary sensitivity analysis made to the wellbore model parameters suggested, at the given injection volume rates and BHP conditions, the wellhead temperature played a prominent role in determining WHP response. Sensitivity simulations of different wellhead temperatures indicated that injection at a higher wellhead temperature would require a higher WHP. For evaluating the expected injection design, a wellhead temperature value of 60°F was chosen that most closely represents the expected operational temperature.

## 3.4 Simulation Results

The target injection rate of 200,000 tonnes per year (tpy) (548 tonnes per day) was consistently achievable over 20 years (Figure 3-9), translating to a cumulative 4 MMt of $CO_2$ injection (Figure 3-10). Simulations of $CO_2$ injection with the given well constraints, listed in Table 3-3, predicted the BHP would not reach the maximum BHP constraint of 2,970 psi (90% of the formation fracture pressure) as a result of injecting the target $CO_2$ volume of 200,000 tpy. The predicted maximum BHP and the average BHP during the 20 year injection period were 2,661 and 2,570 psi (Figure 3-11), respectively.

### *12.3.4 Implementation of Emergency and Remedial Response Actions*

*12.3.4.1 Emergency Response Actions*

A review of the technical risk categories for Blue Flint identified a list of events that could potentially result in the movement of injected $CO_2$ or formation fluids in a manner that may endanger a USDW and require an emergency response. These events are as follows:

- Injectivity
- Storage capacity
- Containment – lateral migration of $CO_2$
- Containment – pressure propagation
- Containment – vertical migration of $CO_2$ or formation water brine via injection wells, other wells, or inadequate confining zones
- Natural disasters (induced seismicity)

If it is determined that one or more of these events have occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7). These response actions are summarized in Tables 7-4 and 7-5.

*12.3.4.2 Estimation of Costs of Emergency Response Actions*

Estimating the costs of implementing the emergency response actions in Tables 7-4 and 7-5 is challenging since remediation measures specifically dedicated to $CO_2$ storage impacts are poorly documented, with one of the more important data gaps being the lack of precise knowledge of the leakage mechanisms and associated impacts (Manceau and others, 2014). Without this knowledge, it is not possible to design appropriate remedial measures. Furthermore, to date, no remediation action following $CO_2$ leakage after geologic storage has ever been implemented mainly because of the absence of established impacts (Manceau and others, 2014). Consequently, the degree of maturity of remediation measures in the carbon capture and storage (CCS) field is low, making it necessary to rely on literature that is primarily based on modeling or analogies with other pollutants, e.g., the analogy between $CO_2$ and volatile organic compounds, the latter having been addressed extensively in the literature. Additionally, for the remedial measures, costs and time for adequate removal are generally site-dependent, and no information is specifically available in this area in the CCS field.

Based on this current situation, two key technical manuscripts were relied upon to identify and estimate the costs of mitigation/remediation technologies to address undesired migration of $CO_2$ from a geological storage unit (Manceau and others, 2014; Bielicki and others, 2014).

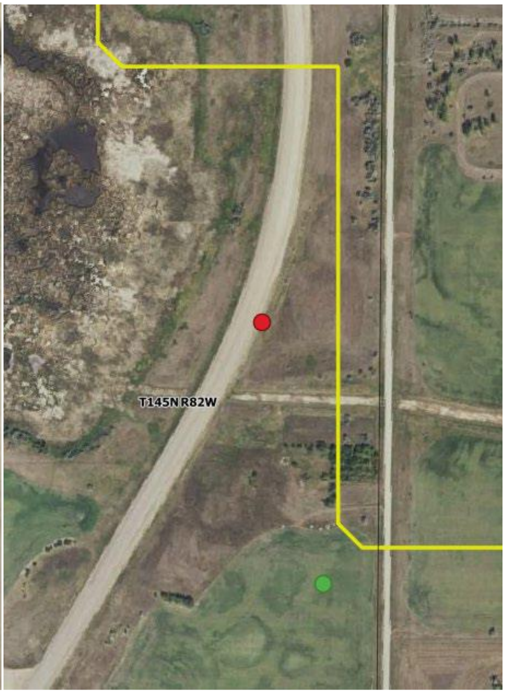
<u>12.3.4.2.1 Identification of Remediation Technologies</u>

Manceau and others (2014) identified several remediation technologies/strategies that are available to address the potential impacted media that may result from an emergency event. These impacted media and remediation measures are listed in Table 12-3. The impacted media in Table 12-3 include surface and groundwater/USDWs, vadose zone, indoor settings, and atmosphere; the

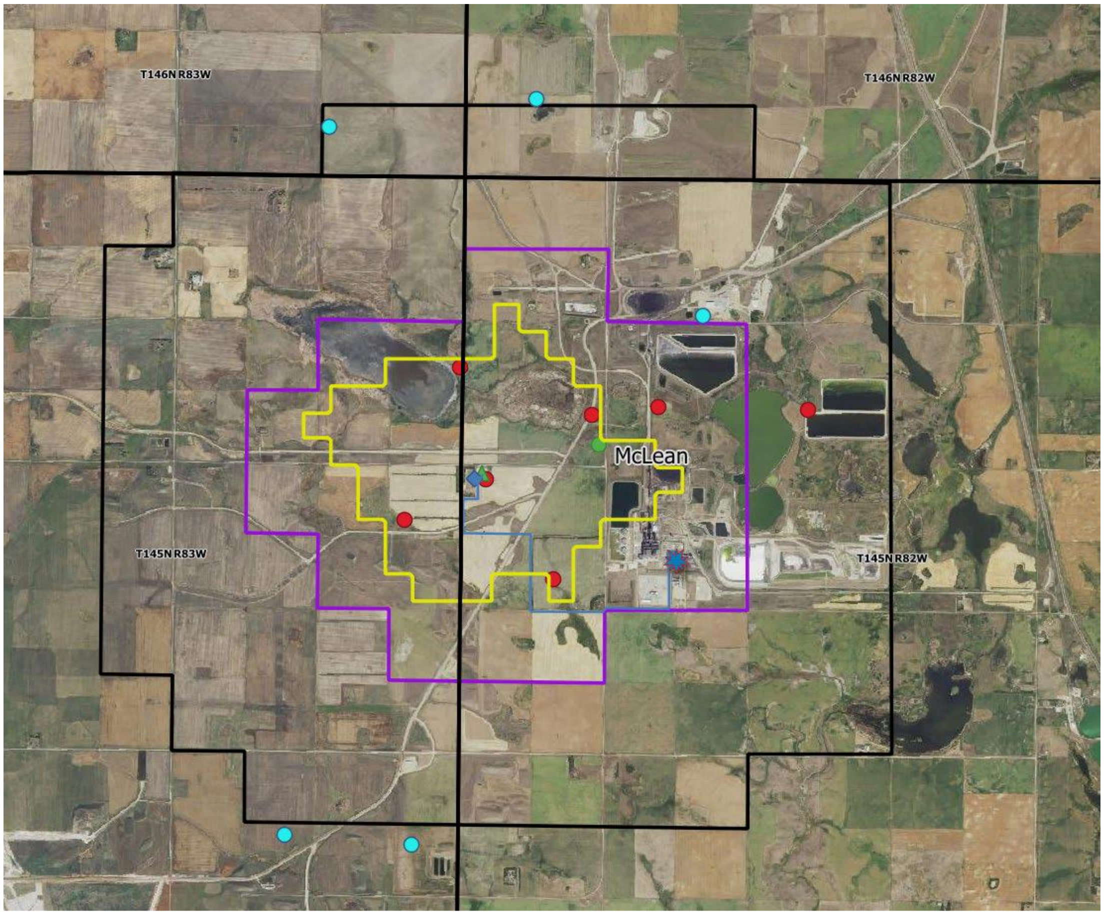
**GIS Shapefiles:**

*Question: Check the locations of the Proposed Soil Gas Profile Stations and add their numbers (1 & 2) to the name.*

- *SGPS 1 (red circle) appears to be on the SE corner of the MAG 1 (green diamond) well site instead of the SW corner as shown in Figure 5-3.*
- *SGPS 2 (red circle) appears further north than expected from the proposed location of the MAG 2 (green circle).*


- *Locations of the proposed soil gas probes should be checked, and labels added (1 through 5) to match as shown in Figure 5-5. The only location that matches up with Figure 5-5 is SG-2. Colors shown below were matched as close as possible to Figure 5-5 from SFP application. The red circles are soil gas probe and soil gas probe stations.*




- *Provide shapefiles for the soil gas probe locations and alternate soil gas probe locations as shown in Supplement 28 – Figure 1. For soil probe locations that did change from what was proposed in Figure 5-5 of the SFP application (such as SG-2) are there plans to place a soil gas probe in the original proposed location as shown in Figure 5-5?*

Soil Gas Profile Stations (SGPSs) 1 and 2 are not part of the baseline sampling program; therefore, SGPS 1 and 2 were not included in Figure 1 from Supplement 28.

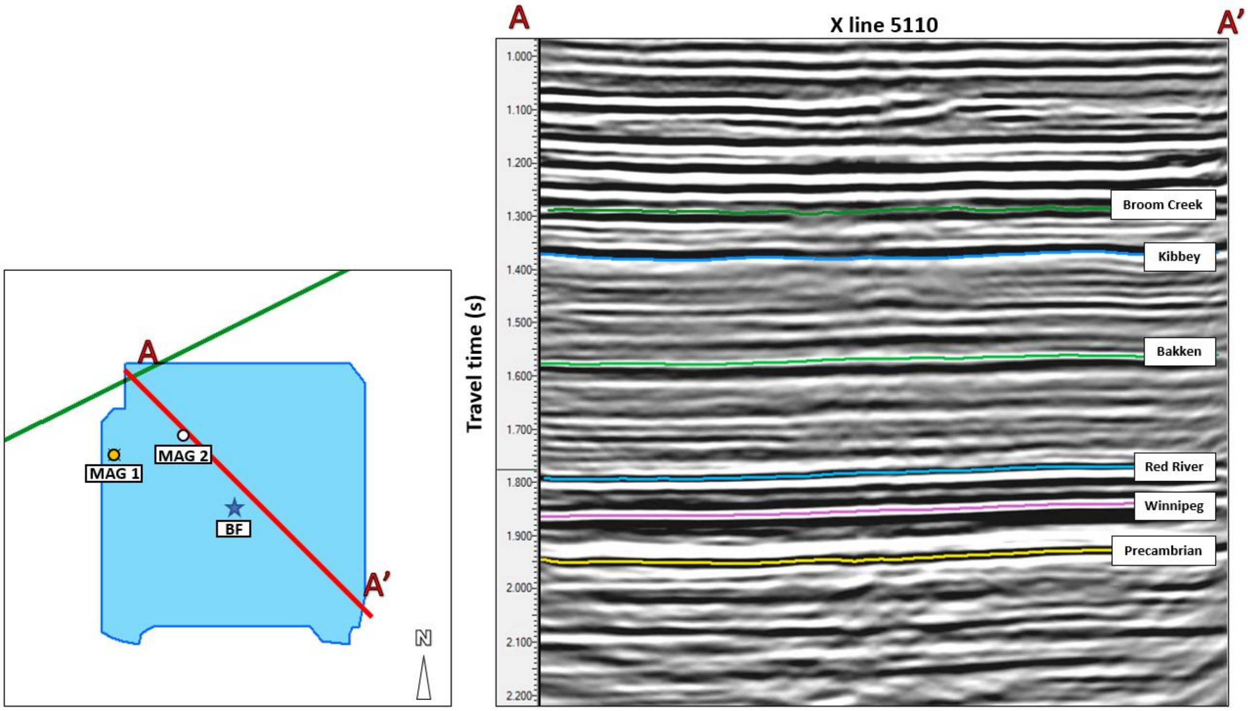
A new shapefile for the correct soil gas probe and profile station locations (as shown in Figures 5-3 through 5-5) is included with this supplement, with names provided for all data points. The shapefile provided previously contained errors in the locations of the soil gas probes. A separate shape file is included, showing the locations and names of the alternate soil gas probe locations.

All five of the original (proposed) soil gas probes (SG-1 through SG-5) have been installed. Many of the original soil gas probe locations were sampled as part of the baseline sampling activities, as discussed in Supplement 28. Weather permitting, the original soil gas probe locations will continue to be the preferred sampling locations for the remainder of the baseline phase of the Blue Flint $CO_2$ storage project.

**Supplemental 10:**

*Question: Figures 2-66, 2-67, and 2-68. Can you provide an equivalent figure to what is represented in Figures 2-67 and 26-8 for the legacy 2D line (boxed in pink below) that runs EW across the Suspected Stanton Fault and near the MAG 1 and MAG 2 as shown on Figure 2-66? If not, could a similar figure be provided using the 3D seismic?*

The figure below shows a cross section (red line) from the 3D seismic data that intersect the location of the Stanton Fault (green line) described by Sims and others (1991). There is no indication from the 3D seismic data that this suspected fault is located within the 3D seismic survey area (blue polygon). The location of the MAG 1 and MAG 2 wells are denoted by circles, and the location of the Blue Flint Ethanol facility is denoted by the blue star.




*Question: Figure 2-71. The original intent of the request to extend Figure 2-71 to show the full Fort Union Group is that we would receive a similar figure as the original Figure 2-71 that would show and label all the coal beds within the Fort Union Group. The replacement Figure 2-71 does not meet this request because it no longer shows the individual coal beds.*

A review of existing literature was conducted, and we were unable to find a stratigraphic column that shows the lignite coals of the Fort Union Group in the Williston Basin with all the seams named. Original Figure 2-71 is adapted from the NDGS RI-104 publication titled "The Lignite Reserves of North Dakota" and is a generalized stratigraphic column where the coal seams listed have been mined. In that publication, the coals of the Fort Union Group in North Dakota are described as having variable thicknesses and lateral extents; the publication noted the presence of numerous, thin, discontinuous coals because of its depositional nature. These numerous coal seams have limited lateral extent and variable thickness in North Dakota.

Section 2.6 discusses the economic coal seams present in the storage facility area. In the storage facility area, no seams present above the Hagel are economically recoverable. There are no economically recoverable coal seams below the Hagel within the storage facility area because of the thickness of the seams and the overburden thickness.

**Supplement 12:**
*We have the following subsequent questions on the supplemental language that was added on Pg 3-11 to explain where the pressure and temperature data from the model was derived from.*

*Question 1: Why was the temperature gradient calculated for use in the model done with the assumption of an average annual temperature of 0°F? Table 2-2 was calculated using an annual temperature of 40°F which is a more acceptable average temperature for North Dakota.*

The language in Supplement 12 implying 0°F is an average annual surface temperature has been removed.

Only the reference temperature at depth is used as an input into the model. Whether the gradient and associated reference temperatures are calculated using the average annual surface temperature of 40°F or not, represented by 0°F in the equation in Supplement 12, there is little difference in the resulting temperature. For example, the difference in the resulting reference temperature is 1.7°F using a temperature gradient rounded to three decimal places (the difference would be 0.6°F if four decimal places for gradients were used). These examples are shown below.

*Example Calculations Using Three Decimal Places for Temperature Gradient*

Section 2 calculations incorporating average annual surface temperature (40°F).
Temperature measurements and their corresponding depths are shown in Table 2-2. Please note the calculated temperature gradient shown in Table 2-2 was rounded to two decimal places.

$$temp.gradient = (\,avg.temp. \;-\; avg.annual\ surface\ temp.)/avg.depth$$

$$temp.gradient = 0.017°\,F/ft = (\tfrac{118.9° - 118.6°F}{2} - 40°F)\Big/\tfrac{4735\ - 4741\ ft}{2} = 78.75°F/4738\ ft$$

$$Ref.temp. = (ref.depth * temp.gradient) + avg.annual\ surface\ temp.$$

$$Ref.temp. = 121.3°F = 4782.7\ ft * 0.017\ °F/ft + 40°F$$

Section 3 calculations that do not incorporate average annual surface temperature.

Note 0°F is included in these examples for ease of comparison of the two calculation methods. 0°F represents the fact that no average annual surface temperature was used.

$$temp.gradient = 0.025°\,F/ft = \frac{118.9° - 118.6°F}{2} - 0°F\Big/\frac{4735\ \ - 4741\ ft}{2}$$
$$= 118.75°F/4738\ ft$$

$Ref.temp. = 119.6°\text{F} = 4782.7\text{ ft} * 0.025°\text{F/ft} + 0°\text{F}$

*Example calculations using four decimal places for temperature gradient.*

Section 2 calculations incorporating average annual surface temperature (40°F).

$$temp.gradient = 0.0166° F/ft = \left(\frac{118.9° - 118.6°\text{F}}{2} - 40°\text{F}\right) \Big/ \frac{4735 - 4741\, ft}{2} = 78.75°\text{F}/4738\, ft$$

$Ref.temp. = 119.4°\text{F} = 4782.7\text{ ft} * 0.0166°\text{F/ft} + 40°\text{F}$

Section 3 calculations that do not incorporate average annual surface temperature.

Note 0°F is included in these examples for ease of comparison of the two calculation methods. 0°F represents the fact that no average annual surface temperature was used.

$$temp.gradient = 0.0251° F/ft = \frac{118.9° - 118.6°\text{F}}{2} - 0°\text{F} \Big/ \frac{4735 \ - 4741\text{ ft}}{2}$$
$$= 118.75°\text{F}/4738\, ft$$

$Ref.temp. = 120.0°\text{F} = 4782.7\text{ ft} * 0.0251°\text{F/ft} + 0°\text{F}$

*Question 2: How is the 4782.7 ft reference point depth calculated? The CMG model is using a reference depth of 2806.204 ft (SSTVD). Using a ground elevation of 1905 ft and KB of 19.5 ft for the MAG 1, we calculate the reference point depth to be 4730.704 ft. This reference depth is approximately the top of the first perforation in the model and in Figure 9-2, the planned perforations are stated to be 4735-4830 ft, which is more in line with our calculated reference point depth of 4730.704 ft instead of 4782.7 ft stated in Supplement 12. If the depth reference used is incorrect the expectation would be that the pressure and temperature values used in the model are corrected and sent as a supplemental.*

The 4782.7' depth comes from the first permeable cell that the MAG 1 well penetrates in the 3D exocellular model from the measured depth property. This measured depth property is the distance between the center of each cell in the model and the ground surface. The cells are 1000' by 1000', and the cell shape along with changes in the surface elevation give the depth value of 4782.7' for the whole cell, which differs from the depth at the MAG 1 well.

**Other:**

*Question: Section 9 question response on wellbore schematics. Is the response of, no action, because you are indicating that the wellbore schematics and tables from the SFP application is the most accurate record to date?*

The wellbore schematics and tables from the SFP application are the most accurate record to date. The completions report will be updated at a later date.

# EXHIBIT 3

# TESTING AND MONITORING SUMMARY TABLE

**Table E3-1. Summary of Blue Flint's Testing and Monitoring Plan**

| SFP Reference | Monitoring Type | | Parameter | Activity Description | Sampling Location/Equipment | Sampling Frequency: Preinjection | Sampling Frequency: Injection (20 years) | Sampling Frequency: Postinjection (10 years minimum) | Primary Purpose(s) of Activity |
|---|---|---|---|---|---|---|---|---|---|
| 5.1 | $CO_2$ Stream Analysis | | Volume/mass | Real-time, continuous data recording via Supervisory Control and Data Acquisition (SCADA) system | Mass flowmeter near the injection wellhead | None | Continuous | None | $CO_2$ accounting and operational safety assurance |
| | | | Flow rate | | | | | | |
| | | | Pressure | | Surface pressure/temperature (P/T) gauges | | | | |
| | | | Temperature | | | | | | |
| | | | Composition | $CO_2$ stream sampling | Sample port near injection wellhead | At least once | Quarterly | None | $CO_2$ accounting and assurance of stream compatibility with project materials in contact with $CO_2$ |
| 5.2 | Surface Facilities Leak Detection Plan | | Mass balance | Real-time, continuous data recording via SCADA system and remote-controlled shutoff devices | Dual P/T gauges and flowmeters placed at the liquefaction outlet and near the injection wellhead | None | Continuous | None | $CO_2$ accounting, leak detection, and operational safety assurance |
| | | | $CO_2$ concentrations | Real-time, continuous data recording via SCADA system | $CO_2$ detection stations placed on injection wellhead, flowline risers, and inside and outside enclosures | None | Continuous | None | |
| 5.3.2 and 5.6 | $CO_2$ Flowline and Wellbore Corrosion Detection Plan | | Mass/thickness loss | Corrosion coupon testing | Corrosion coupon sample port near the liquefaction outlet | None | Quarterly | None | Corrosion detection of project materials in contact with $CO_2$ and operational safety assurance |
| | | | Pitting | | | | | | |
| | | | Cracking | | | | | | |
| 5.4 and Table 5-4<br>6.2 and Table 6-1 | Wellbore Mechanical Integrity Testing (external) | | Material wall thickness (casing) | Ultrasonic logging (or alternative casing inspection logging (CIL) method) | MAG 1 and MAG 2 | Once per well | During workovers but no less than once every 5 years | During workovers but no less than once every 5 years (MAG 2 only) | Mechanical integrity confirmation and operational safety assurance |
| | | | Radial cement bond | | | | | | |
| | | | Temperature profile | Real-time, continuous data recording via SCADA system | Distributed temperature sensing (DTS) fiber in MAG 1 and MAG 2 | Install at well completion | Continuous | Continuous (MAG 2) | |
| | | | Temperature profile | Temperature logging | MAG 1 and MAG 2 | Once per well | Annually (backup if DTS fails) | Annually (backup if DTS fails) | |
| | Wellbore Mechanical Integrity Testing (internal) | | Pressure/temperature | Tubing-casing annulus pressure testing | MAG 1 and MAG 2 | Once per well | During workovers but no less than once every 5 years | During workovers but no less than once every 5 years (MAG 2) | |
| | | | | Real-time, continuous data recording via SCADA system | Surface and tubing-conveyed P/T gauges in MAG 1 and MAG 2 | Install at well completion | Continuous | Continuous (MAG 2) | |
| | | | Material wall thickness (tubing) | Ultrasonic logging (or alternative CIL method) | MAG 1 and MAG 2 | Once per well | During workovers but no less than once every 5 years | During workovers but no less than once every 5 years (MAG 2) | |
| 5.7.1 and Table 5-6 | Atmosphere Monitoring | Ambient | Ambient air conditions | Sample blanks from soil gas sampling | Probe locations SG-1–SG-5 and permanent stations SGPS 1 and SGPS 2 | Sample 3–4 events at SG-1–SG-5 | Sample 3–4 events per year at SGPS 1 and SGPS 2 | None | Leak detection and worker safety |
| | | Workplace | $CO_2$ concentrations | Real-time, continuous data recording via SCADA system | $CO_2$ detection stations placed inside and outside enclosures | None | Continuous | None | |
| 5.7.2 and Table 5-6<br>6.2.1 and Table 6-2 | Near-Surface Monitoring | Soil Gas | Soil gas composition (e.g., $CO_2$, $N_2$, and $O_2$) | Soil gas sampling | Probe locations SG-1–SG-5 and permanent stations SGPS 1 and SGPS 2 | 3–4 seasonal samples per probe (SG-1–SG-5) | 3–4 seasonal samples per station (SGPS 1 and SGPS 2) | Sample SGPS 1 prior to MAG 1 reclamation. Sample SGPS 2 annually until facility closure. Sample probe locations at postinjection start and before facility closure | Protection of near-surface environments |
| | | | Soil gas isotopes | | | | | | Source attribution |
| | | Groundwater | Water composition (e.g., pH, total dissolved solids [TDS], and conductivity) | Existing shallow groundwater well sampling | Up to five groundwater well locations (shown in Figure 5-5) | 3–4 seasonal samples per well | At start of injection, shift sampling program to dedicated Fox Hills monitoring well location near MAG 1 | Sampling may be performed on active and accessible shallow groundwater wells in the area of review (AOR) prior to site closure | Protection of underground sources of drinking water (USDWs) |
| | | | Water isotopes | | | | | | Source attribution |
| | | | Water composition (same as above) | Fox Hills Aquifer sampling | Dedicated Fox Hills monitoring well near MAG 1 | 3–4 seasonal samples | 3–4 seasonal samples annually | Annually until facility closure | Protection of USDWs |
| | | | Water isotopes | | | | | | Source attribution |

Continued…

**Table E3-1. Summary of Blue Flint's Testing and Monitoring Plan (continued)**

| SFP Reference | Monitoring Type | | Parameter | Activity Description | Sampling Location/Equipment | Sampling Frequency | | | Primary Purpose(s) of Activity |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Preinjection | Injection (20 years) | Postinjection (10 years minimum) | |
| 5.7.3 and Table 5-6<br><br>6.2.1 and Table 6-2 | Deep Subsurface Monitoring | Above-Zone Monitoring Interval | Temperature profile (from Spearfish through Inyan Kara) | Real-time, continuous data recording via SCADA system | DTS fiber optics in MAG 1 and MAG 2 | Install at well completion | Continuous | Continuous (MAG 2) | Assurance of containment in the storage reservoir |
| | | | Saturation profile (from Spearfish through Inyan Kara) | Pulsed-neutron logging | MAG 2 | Once per well | Year 4 and every 5 years thereafter (Year 9, Year 14, and Year 19) | Annually until full $CO_2$ saturation reached; once every 4 years thereafter (MAG 2) | |
| | | Storage Reservoir (direct) | Temperature profile (from Amsden through Spearfish) | Real-time, continuous data recording via SCADA system | DTS fiber optics in MAG 1 and MAG 2 | Install at well completion | Continuous | Continuous (MAG 2) | Determination of storage reservoir performance |
| | | | Saturation profile (from Amsden through Spearfish) | Pulsed-neutron logging | MAG 2 | Once per well | Year 4 and every 5 years thereafter (Year 9, Year 14, and Year 19) | Annually until full $CO_2$ saturation reached; once every 4 years thereafter (MAG 2) | |
| | | | Pressure/temperature | Real-time, continuous data recording via SCADA system | Tubing-conveyed P/T gauge in MAG 1 and MAG 2 to monitor the Broom Creek | Install at well completion | Continuous | Continuous (MAG 2) | $CO_2$ pressure front tracking to ensure conformance with model and simulation projections |
| | | | Injectivity | Pressure falloff testing | MAG 1 | Once in MAG 1 | Once every 5 years in MAG 1 | None | Assurance of storage reservoir performance |
| | | Storage Reservoir (indirect) | $CO_2$ saturation | Vertical seismic profiles | $CO_2$ plume extents | May collect baseline | To be determined | To be determined | $CO_2$ plume tracking to ensure conformance with model and simulation projections |
| | | | | Time-lapse 2D seismic surveys | $CO_2$ plume extents (see Figure 5-6) | Collect baseline | Repeat 2D seismic survey in Year 1 and Year 4. At Year 4, reevaluate frequency based on plume growth and seismic results. | To be determined | |
| | | | Seismicity | Real-time, continuous data recording | U.S. Geological Survey's (USGS's) existing network | Utilize USGS existing network | Utilize USGS existing network and supplement with additional equipment as necessary | None | Seismic event detection and operational safety assurance |

Digital data files available upon request

This letter was not received in accordance with NDAC § 43-02-03-90.2. Therefore, it is not part of the evidentiary record of this case.

Brian W. Boppre | Attorney At Law
North Dakota Lic. #07482
bboppre@bopprelawfirm.com

Morgan R. Glines | Attorney At Law
North Dakota Lic. #08853
mglines@bopprelawfirm.com

BOPPRE LAW FIRM

Anthony J. Cooper | Attorney At Law
North Dakota Lic. #09252
acooper@bopprelawfirm.com

RECEIVED
APR 17 2023
N.D. INDUSTRIAL COMMISSION

2151 36th Ave SW, Suite B, Minot, ND 58701
Telephone (701) 852-5224 | Fax (701) 852-5229
www.bopprelawfirm.com

April 14, 2023

NDIC Oil and Gas Division
1016 East Calgary Ave.
Bismarck, ND 58503

**SENT VIA CERTIFIED MAIL**

Re. Concern for Mineral Owners regarding Flint Sequester Company, LLC

Dear Commission,

I hope this letter finds you all well. I represent Matt Johnson and his siblings in this matter. They are all mineral owners in the land therein described. I sat in on the hearing on March 21, 2023, for my clients' behalf. I am very concerned, as I hope you are all as well, at the lack of forethought and care that Flint Sequester Company, LLC (hereinafter "Flint") portrayed towards the owners of the land in question. Flint lacks the forethought and care not only for the surface owners, but the mineral owners as well.

The fact of the matter is that the data submitted to the Industrial Commission by Flint was done so by humans. Unfortunately, which means there is huge room for error. Especially, when this is brand new to North Dakota and there are no studies to base their tests and assumptions upon. Basically, I heard that liquified CO2 is going to be placed in the ground between an impermeable layer of rocks with no faults; however, there is no telling or tests that that can show that there may not be a leak one day. Flint explained the liability/consequences regarding a leak regarding the surface owners, but not the mineral owners.

If there is someday a leak and liquified CO2 travels downward to chemically react with the below layers, that is detrimental to the mineral owners as well. It should not matter if the mine is not currently drilling in this location or that potential coal may be difficult to mine at this time. The fact is, Flint has a liability to the mineral owners and should be compensated as well.

Respectfully,

Morgan R. Glines
Attorney At Law
Boppre Law Firm, PLLC

CERTIFIED MAIL®

M. JOHNSON

**SENDER: *COMPLETE THIS SECTION***

- Complete items 1, 2, and 3.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

NDIC OIL and GAS DIVISION
1016 EAST CALGARY AVE.
BISMARCK, ND 58503

9590 9402 7193 1284 5749 55

2. Article Number *(Transfer from service label)*

7022 3330 0002 2702 7767

***COMPLETE THIS SECTION ON DELIVERY***

A. Signature

X Jessica Koch

☐ Agent
☐ Addressee

B. Received by *(Printed Name)*
Jessica Koch

C. Date of Delivery
4-17-2023

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type

☐ Adult Signature
☐ Adult Signature Restricted Delivery
☐ Certified Mail®
☐ Certified Mail Restricted Delivery
☐ Collect on Delivery
☐ Collect on Delivery Restricted Delivery
☐ Insured Mail
...ail Restricted Delivery
☐ Priority Mail Express®
☐ Registered Mail™
☐ Registered Mail Restricted Delivery
☐ Signature Confirmation™
☐ Signature Confirmation Restricted Delivery

PS Form 3811, July 2020 PSN 7530-02-000-9053

Domestic Return Receipt

E
RM

2151 36th Ave. SW
Suite B
Minot, ND 58701

7022 3330 0002 2702 7767

BISMARCK ND 585
14 APR 2023

UNITED STATES POSTAL SERVICE

RDC 99

58503

U.S. POSTAGE PAI
FCM LETTER
MINOT, ND
58701
APR 14, 23
AMOUNT
**$8.13**
R2304M111671-06

NDIC Oil and Gas Division
1016 East Calgary Ave.
Bismarck, ND 58503

**RETURN RECEIPT REQUESTED**

58503-551216

BOPPRE
LAW FIRM

2151 36th Ave. SW
Suite B
Minot, ND 58701

7022 3330 0002 2702 7767

BISMARCK ND

14 APR 2023

UNITED STATES POSTAL SERVICE

RDC 99

58503

U.S. POSTAGE PAID
FCM LETTER
MINOT, ND
58701
APR 14, 23
AMOUNT
$8.13
R2304M111671-06

NDIC Oil and Gas Division
1016 East Calgary Ave.
Bismarck, ND 58503

RETURN RECEIPT
REQUESTED

58503-551216

**Kadrmas, Bethany R.**

---

| | |
|---|---|
| **From:** | Kadrmas, Bethany R. |
| **Sent:** | Monday, April 17, 2023 4:08 PM |
| **To:** | Bender, Lawrence |
| **Cc:** | Nelson, Steve; Entzi-Odden, Lyn |
| **Subject:** | NDIC Case Nos. 29888-29890 |
| **Attachments:** | Commission Staff Questions on Supplements for Blue Flint Hearing.pdf |

Mr. Bender,

At this time, Commission staff requests additional information outlined in the attached regarding Case Nos. 29888-29890.

Please let me know if you have any questions.

Thank you,


Bethany Kadrmas
*Legal Assistant, Oil and Gas Division*

701.328.8020 • brkadrmas@nd.gov • www.dmr.nd.gov

NORTH Dakota Be Legendary. | Mineral Resources

600 E Boulevard Ave, Dept. 405 • Bismarck, ND 58505

## Commission Staff Questions on Supplements

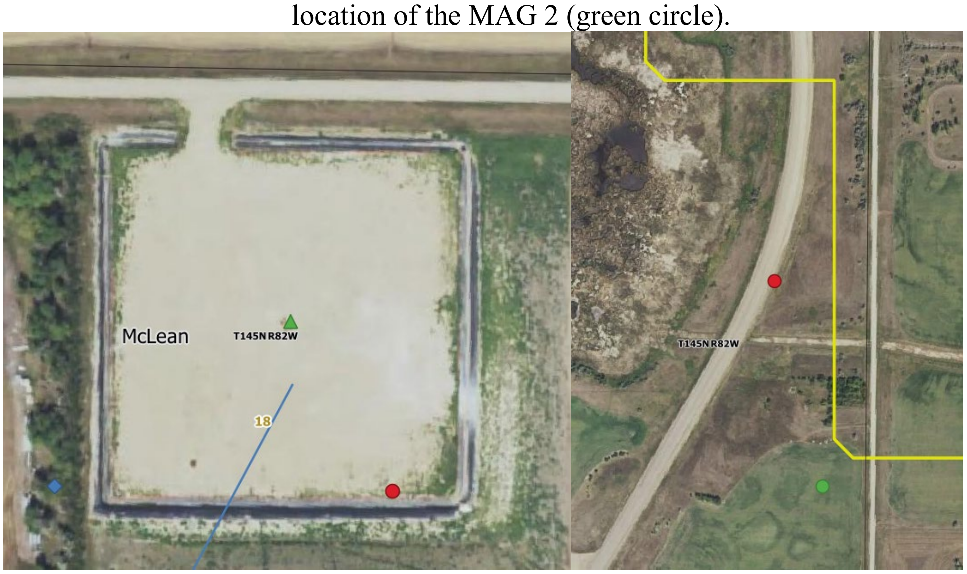
<u>Missing Supplementals</u>

- No response was given to the following question from the hearing:
    - Addition or an explanation of the ramifications of providing a *type log* definition using the MAG 1 well to Article 1.15 – Storage Reservoir in the Storage Agreement. The reference to a type log would be providing top depth and bottom depth for the stratigraphic interval as picked in the MAG 1 from the Kelly Bushing elevation as identified by called-out open hole log run.

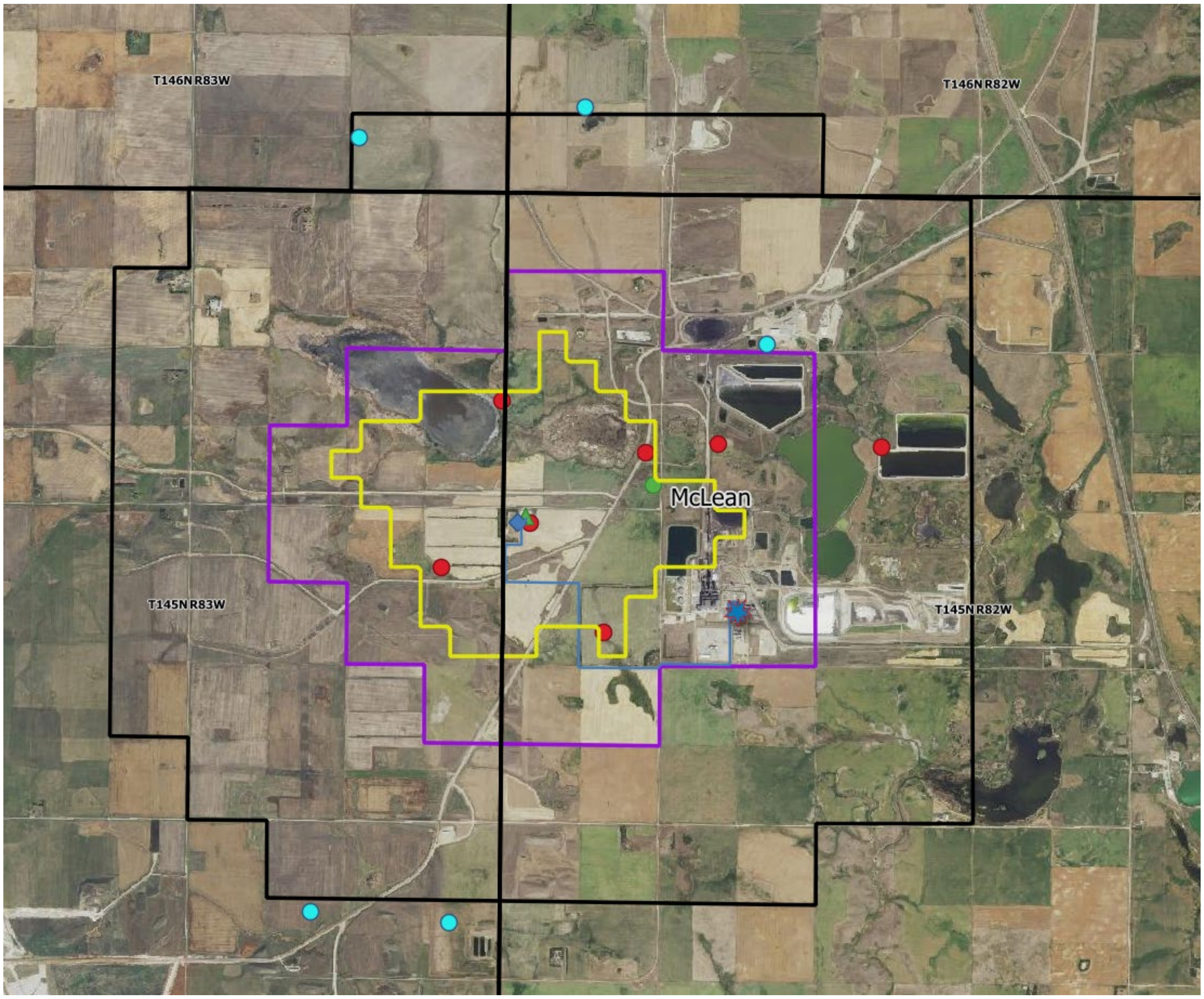
> 1.15 **<u>Storage Reservoir</u>** consists of the Pore Space and confining subsurface strata underlying the Facility Area described as the lower Piper Picard and Spearfish(Upper Confining Zone), Broom Creek (Storage Reservoir/Injection Zone), and Amsden (Lower Confining Zone) Formation(s) and which are defined as identified by the well logging suite performed at the stratigraphic well, the MAG 1 well (File No. 37833). The log suites included caliper, spontaneous potential (SP), gamma ray (GR), density, porosity (neutron, density), dipole sonic, resistivity, and a full-bore formation microimager (FMI) log. Further, the logs were used to pick formation top depths and interpret lithology, petrophysical properties, and time-to-depth shifting of seismic data obtained from a 3D seismic survey covering an area totaling 9-mi$^2$ in and around the MAG 1 (located in Section 18, Township 145 North, Range 82 West) stratigraphic well located in Mclean County, North Dakota. Formation top depths were picked from the top of the lower Piper Picard Formation to the top of the Tyler Formation. These logs and data which encompass the stratigraphic interval from an average depth of 4,553 feet to an average depth of 5,053 feet within the limits of the Facility Area.

<u>Questions on Supplements Provided on April 11, 2023</u>

- GIS Shapefiles
    - Shapefiles for the hearing notice area (HNA) boundary still need to be submitted.
    - Check the locations of the Proposed Soil Gas Profile Stations and add their numbers (1 & 2) to the name.
        - SGPS 1 (red circle) appears to be on the SE corner of the MAG 1 (green diamond) well site instead of the SW corner as shown in Figure 5-3.
        - SGPS 2 (red circle) appears further north than expected from the proposed location of the MAG 2 (green circle).




        - Locations of the proposed soil gas probes should be checked, and labels added (1 through 5) to match as shown in Figure 5-5. The only location that matches up with Figure 5-5 is SG-2. Colors shown below were matched as close as possible to Figure 5-5 from SFP application. The red circles are soil gas probe and soil gas probe stations.




- Provide shapefiles for the soil gas probe locations and alternate soil gas probe locations as shown in Supplement 28 – Figure 1. For soil probe locations that did change from what was proposed in Figure 5-5 of the SFP application (such as SG-2) are there plans to place a soil gas probe in the original proposed location as shown in Figure 5-5?

- Resubmit Supplement 9 with Rierdon (depth below USDW) column fixed. The supplementt shows 3,3162 instead of 3162.
- On Supplement 11 (Equation 5) you have a note that the Uniaxial Strain Modulus (P) label in Table 2-19 in the SFP application should say unconfined compress strength (UCS). Supplement 10 (Pg 2-84) still has it labeled as Uniaxial Strain Modulus (P) label.

- Supplement 10 – Figures 2-66, 2-67, and 2-68. Can you provide an equivalent figure to what is represented in figures 2-67 and 26-8 for the legacy 2D line (boxed in pink below) that runs EW across the Suspected Stanton Fault and near the MAG 1 and MAG 2 as shown on Figure 2-66? If not, could a similar figure be provided using the 3D seismic?


- Supplement 10 – Figure 2-71. The original intent of the request to extend Figure 2-71 to show the full Fort Union Group is that we would receive a similar figure as the original Figure 2-71 that would show and label all the coal beds within the Fort Union Group. The replacement Figure 2-71 does not meet this request because it no longer shows the individual coal beds.
- Supplement 12 – We have the following subsequent questions on the supplemental language that was added on Pg 3-11 to explain where the pressure and temperature data from the model was derived from.
  - Why was the temperature gradient calculated for use in the model done with the assumption of an average annual temperature of 0°F? Table 2-2 was calculated using an annual temperature of 40°F which is a more acceptable average temperature for North Dakota.
  - How is the 4782.7 ft reference point depth calculated? The CMG model is using a reference depth of 2806.204 ft (SSTVD). Using a ground elevation of 1905 ft and KB of 19.5 ft for the MAG 1, we calculate the reference point depth to be 4730.704 ft. This reference depth is approximately the top of the first perforation in the model and in Figure 9-2, the planned perforations are stated to be 4735-4830 ft, which is more in line with our calculated reference point depth of 4730.704 ft instead of 4782.7 ft stated in Supplement 12. If the depth reference used is incorrect the expectation would be that the pressure and temperature values used in the model are corrected and sent as a supplemental.
- Provide updated Exhibit 3 (Summary of Testing and Monitoring Plan) to reflect the following changes. Provide PDF and Excel copy.
  - Frequency for corrosion coupon monitoring.
  - PNL frequency for above-zone monitoring and storage reservoir monitoring, to match with any changes made to Table 6-2.
- Supplement 27 – Shouldn’t the last sentence in the last paragraph of 12.3.4.1 also be changed to reference Table 7-4 and Table 7-5?
- Section 9 question response on wellbore schematics. Is the response of, no action, because you are indicating that the wellbore schematics and tables from the SFP application is the most accurate record to date?

## Kadrmas, Bethany R.

**From:** Entzi-Odden, Lyn <lodden@fredlaw.com>
**Sent:** Friday, April 14, 2023 3:32 PM
**To:** Kadrmas, Bethany R.
**Cc:** Forsberg, Sara L.; Nelson, Steve
**Subject:** filing of Affidavit of Adam Dunlop CASES 29888-890
**Attachments:** S Nelson letter 29888-890.pdf

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Bethany,

Please see the attached. The original affidavit was hand delivered to Assistant Attorney General Nelson.

Thank you.

Fredrikson

**Lyn Entzi-Odden**
**Executive Legal Assistant**
1133 College Drive | Suite 1000 | Bismarck, ND 58501
Ph: 701.221.8700|lodden@fredlaw.com

Fredrikson

**Fredrikson & Byron, P.A.**
Attorneys and Advisors

1133 College Drive, Suite 1000
Bismarck, ND 58501-1215
Main: 701.221.8700
fredlaw.com

April 14, 2023

***VIA HAND DELIVERY***

Mr. Steven Nelson
Assistant Attorney General
Office of the Attorney General
500 N. Ninth St.
Bismarck, ND 58501-4509

**RE: Case Nos. 29888, 29889 and 29890**
**Blue Flint Sequester Company, LLC**

Dear Assistant Attorney General Nelson:

In follow-up to my letter dated April 11, 2023 with regard to the captioned matter and the supplemental materials filed therewith, please find attached herewith an AFFIDAVIT OF ADAM DUNLOP for filing.

Should you require additional information or have any questions, please advise.

Sincerely,

/s/ Lawrence Bender
LAWRENCE BENDER

LB/leo

Enclosure

cc: Ms. Bethany Kadrmas – (w/enc.) *Via Email*
Mr. Adam Dunlop – (w/enc.) *Via Email*

78888350 v1

**BEFORE THE INDUSTRIAL COMMISSION**

**OF THE STATE OF NORTH DAKOTA**

**CASE NO. 29888**

**Application of Blue Flint Sequester Company, LLC requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01.**

**CASE NO. 29889**

**A motion of the Commission to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Blue Flint Sequester Company, LLC storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West,**

**CASE NO. 29890**

**A motion of the Commission to determine the amount of financial responsibility for the geologic storage of carbon dioxide from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.**

## AFFIDAVIT OF ADAM DUNLOP

STATE OF NORTH DAKOTA )<br>
) ss.<br>
COUNTY OF MCLEAN )

Adam Dunlop, being first duly sworn, deposes and states as follows:

1. I am the Executive Vice President for Harvestone Low Carbon Partners, the parent company of Blue Flint Sequester Company, LLC ("Blue Flint"), the applicant in the above-captioned matters.

2. My business address is 2841 3rd Street SW, Underwood, ND 58576.

3. Pursuant to § 38-22-06 of the North Dakota Century Code, Blue Flint provided notice of the hearing in the above-caption matters ("Hearing Notice") to certain owners, operators and lessees of the surface, pore space and minerals located within the storage facility area and within one-half mile of the storage facility's boundaries (collectively, the "Notice Area").

4. At the hearing on March 21, 2023 before the North Dakota Industrial Commission ("Commission"), Commission staff indicated that it had received, and signed for, the Hearing Notice addressed to one Bradley Schafer with an address of 600 East Boulevard Avenue, Suite 405, Bismarck, North Dakota 58505, which is the Commission's address.

5. Bradley Schafer is named as a potential heir in the Proof of Death and Heirship attached hereto and marked as Exhibit A.

6. To the best of my knowledge and belief, and after consulting with the firm retained by Blue Flint to ascertain the owners, operators and lessees located within the Notice Area (the "Title Firm"), the Proof of Death and Heirship references lands located within the

proposed storage facility; however, it does not grant to Bradley Schafer any interest in the surface, pore space or minerals located within the Notice Area.

7. The Proof of Death and Heirship does not list a street address for Bradley Schafer.

8. To the best of my knowledge and belief, and after consulting with the Title Firm, it is my understanding that Bradley Schafer does not appear in any other instrument indexed against the lands located within the Notice Area.

9. To the best of my knowledge and belief, and after consulting with the Title Firm, it is my understanding that Bradley Schafer was mailed a Hearing Notice out of an abundance of caution because he was listed as a potential heir in the attached Proof of Death and Heirship, even though he does not own any interests of record within the Notice Area.

10. To the best of my knowledge and belief, and after consulting with the Title Firm, it is unclear as to why the Hearing Notice for Bradley Schafer was mailed to the Commission at 600 E. Boulevard Avenue, Suite 405, Bismarck, ND 58505.

DATED this 14th day of April, 2023.

Adam C Dunlop

Adam Dunlop

STATE OF NORTH DAKOTA )
) ss.
COUNTY OF MCLEAN )

The foregoing instrument was acknowledged before me this 14th day of April, 2023, by Adam Dunlop, the Executive Vice President of Harvestone Low Carbon Partners.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden

Notary Public
My Commission Expires: ____________

78881893 v1

3378559
5/20/2013 2:39 PM $16.00
THE FALKIRK MINING COMPANY
Page: 1 of 3
McLean Co., ND

# PROOF OF DEATH AND HEIRSHIP

STATE OF NORTH DAKOTA )
) ss:
COUNTY OF BURLEIGH )

GAIL I. SCHAFER of 203 E. ARBOR AVE. # 107F, of lawful age, after first being duly sworn, deposes and states:

1. That the statements hereinafter set forth, including answers to questions, constitute a true and correct and complete statement of the family history of the person hereinafter named as "decedent" and of the estate of such decedent.

2. Name of decedent: Donald D. Schafer

3. Date of death: December 26, 2004 Where? Bismarck, Burleigh County, North Dakota

4. Was decedent married or single at time of death? MARRIED
Did decedent leave a Will? NO If yes, attach copy
Has estate been probated? N/A If yes, County & State N/A

5. If decedent was married one or more times, give the following information (list names in order of marriage):

| NAME OF SPOUSE | LIVING OR DECEASED (IF DECEASED – DATE OF DEATH) | IF DIVORCED - DATE | PLACE OF DEATH OR DIVORCE (CITY, COUNTY & STATE) |
|---|---|---|---|
| GAIL IRENE ENGEL | LIVING | N/A | N/A |

6. If decedent had any children by any spouse, give following information:

| NAME OF CHILD | ADDRESS | PRESENT AGE | SON OR DAUGHTER | LIVING OR DECEASED (IF DECEASED-DATE) |
|---|---|---|---|---|
| BRIAN SHAFER | BISMARCK ND | 51 | SON | LIVING |
| BRADLEY SCHAFER | MCALISTER OK | 48 | SON | LIVING |
| BRUCE SCHAFER | BISMARCK ND | 46 | SON | LIVING |
| BRENT SCHAFER | BISMARCK ND | 45 | SON | LIVING |

EXHIBIT A

7. If decedent had any children by adoption, give following information: NONE

| NAME OF CHILD | ADDRESS | PRESENT AGE | SON OR DAUGHTER | LIVING OR DECEASED (IF DECEASED-DATE) |
|---|---|---|---|---|
| N/A | — | — | — | — |

8. The above named children who have died had only the following children (natural or adopted) and other heirs:

| NAME OF DECEASED CHILD | NAMES OF SPOUSE & CHILDREN | ADDRESS | AGE | LIVING OR DECEASED (IF DECEASED-DATE) |
|---|---|---|---|---|
| N/A | — | — | — | — |

9. In case decedent left no surviving spouse and no children or children of deceased children, give the following information:

| | NAME | ADDRESS | LIVING | DATE OF DEATH |
|---|---|---|---|---|
| FATHER MOTHER | N/A | — | — | — |
| BROTHER(S) SISTER(S) | N/A | — | — | — |

10. Affiant states he/she was well acquainted with financial condition of decedent and knows that decedent died solvent and that all debts against the estate were paid.

State your relationship or acquaintance with decedent and how long and how well you knew the decedent and the decedent's family. I HAVE KNOWN, AND BEEN FRIENDS WITH, DON & GAIL SCHAFER FOR MORE THAN 20 YEARS; AND I CONTINUE TO HAVE A CLOSE RELATIONSHIP WITH GAIL.

Further affiant saith not.

Signed Barbara A. Deibert

Subscribed and sworn to before me this 8 day of May, 2013.

[signature]
Notary Public

SARA SCHUMACHER
Notary Public
State of North Dakota
My Commission Expires May 17, 2017

03283
03550
03600

RECORDING INSTRUCTIONS:

Please index against the following described lands:

**Township 145 North, Range 83 West**
Section 04: NW4
Section 13: NW4
**Township 146 North, Range 83 West**
Section 32: SE4

McLean County, North Dakota

Please return recorded document to:

Attn: The Falkirk Mining Company
2000 Schafer Street, Suite D
Bismarck, ND 58501-1204

7583

McLEAN COUNTY RECORDER ★ STATE OF NORTH DAKOTA ★ OFFICIAL SEAL

INDEXED ________
CHECKED ________

RECORDER'S OFFICE, MCLEAN COUNTY, ND 5/20/2013 2:39 PM
I CERTIFY THAT THIS INSTRUMENT WAS FILED FOR RECORD THIS DATE.
BETH A. KNUTSON, COUNTY RECORDER
Beth A. Knutson
3378559

3378559
5/20/2013 2:39 PM $16.00
THE FALKIRK MINING COMPANY
Page: 3 of 3
McLean Co., ND

## Kadrmas, Bethany R.

| | |
|---|---|
| **From:** | Entzi-Odden, Lyn <lodden@fredlaw.com> |
| **Sent:** | Tuesday, April 11, 2023 4:32 PM |
| **To:** | Kadrmas, Bethany R. |
| **Cc:** | Bender, Lawrence |
| **Subject:** | additional filings for Blue Flint Cases 29888, 29889 and 29890 |
| **Attachments:** | Blue Flint additional filing Cases 29888-890.pdf |



Bethany,

Please see the attached letter and the following link.

https://fredriksonandbyron.sharefile.com/d-sc43630fb702b4f85b0f2c70900117721

Fredrikson

**Lyn Entzi-Odden**
**Executive Legal Assistant**
1133 College Drive | Suite 1000 | Bismarck, ND 58501
Ph: 701.221.8700|lodden@fredlaw.com

Fredrikson

Fredrikson & Byron, P.A.
Attorneys and Advisors

1133 College Drive, Suite 1000
Bismarck, ND 58501-1215
Main: 701.221.8700
fredlaw.com

April 11, 2023

***VIA EMAIL***

Mr. Bruce Hicks
Assistant Director
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

**RE: Case Nos. 29888, 29889 and 29890**
**Blue Flint Sequester Company, LLC**

Dear Mr. Hicks:

In follow up to my filing earlier today, included in the email submitting this letter is a link which contains Shapefiles and Field Data to also supplement the record in the captioned matters.

Should you have any questions or require additional information, please advise.

Sincerely,

/s/ Lawrence Bender
LAWRENCE BENDER

LB/leo
Enclosure
cc: Mr. Adam Dunlop - (w/o enc.) *Via Email*
Ms. Amanda Livers-Douglas - (w/o enc.) *Via Email*

78851785 v1

Digital data files are available upon request.

## Kadrmas, Bethany R.

**From:** Entzi-Odden, Lyn <lodden@fredlaw.com>
**Sent:** Tuesday, April 11, 2023 9:20 AM
**To:** Kadrmas, Bethany R.
**Cc:** Bender, Lawrence
**Subject:** Blue Flint Cases 29888, 29889 and 29890
**Attachments:** Blue Flint cover letter filing supplementals.pdf; Blue Flint - Cases 29888 29889 and 29890 - ND SHPO Response Letter.pdf



Bethany,

Please see the attached for filing. The following is the link referenced in said letter.

https://fredriksonandbyron.sharefile.com/d-seb0a7ea1750d4074889c59ebf2b1f2eb

Fredrikson

**Lyn Entzi-Odden**
**Executive Legal Assistant**
1133 College Drive | Suite 1000 | Bismarck, ND 58501
Ph: 701.221.8700|lodden@fredlaw.com

Fredrikson

Fredrikson & Byron, P.A.
Attorneys and Advisors

1133 College Drive, Suite 1000
Bismarck, ND 58501-1215
Main: 701.221.8700
fredlaw.com

April 11, 2023

***VIA EMAIL***

Mr. Bruce Hicks
Assistant Director
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

**RE: Case Nos. 29888, 29889 and 29890**
**Blue Flint Sequester Company, LLC**

Dear Mr. Hicks:

As requested at the hearing held for the captioned matters on March 21, 2023, please find attached herewith the following:

1. A link to a ShareFile, included in the email submitting this letter, which contains supplements for the Blue Flint Sequester Company, LLC Storage Facility Permit. The “Supplemental Table V2” document lists all of supplements in numerical order and the changes that were made per the Commissions staff’s request during the March 21, 2023 hearing. Also included is a “Corrections Table” and corresponding corrections PDFs. We realize these changes were not requested by Commission staff at the hearing but are included in the event the same are needed; and
2. A letter from Blue Flint Sequester Company addressed to the State Historical Society explaining why there will be minimal surface disruptions.

An affidavit addressing the issue of notice sent to Bradley Schafer will be submitted by Friday, April 14, 2023.

Should you have any questions or require additional information, please advise.

Sincerely,

/s/ Lawrence Bender
LAWRENCE BENDER

LB/leo
Enclosure
cc: Mr. Adam Dunlop - (w/o enc.) *Via Email*
Ms. Amanda Livers-Douglas - (w/o enc.) *Via Email*

78839053 v1

BLUE FLINT
A HARVESTONE COMPANY

Blue Flint
2841 3rd St SW
Underwood, ND 58576
(701) 442-7513

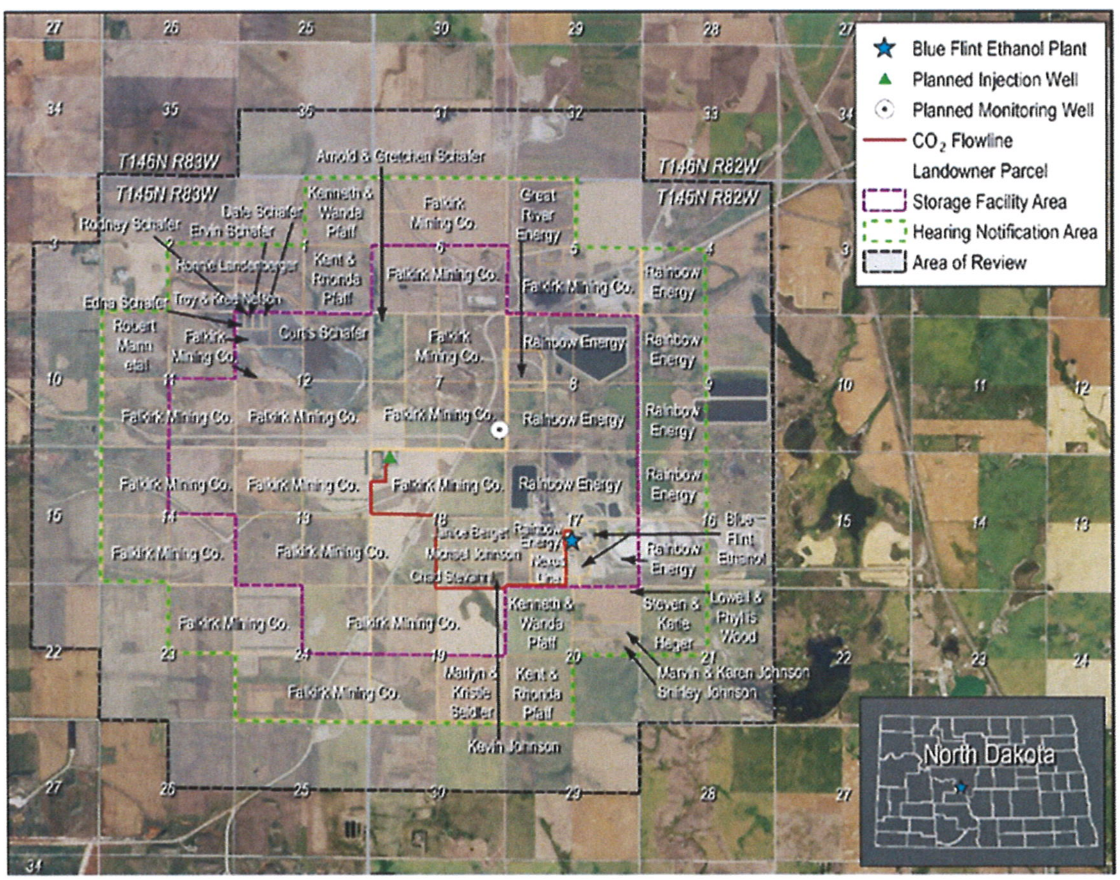
April 10, 2023

William D. Peterson, PhD
State Historical Society
North Dakota Heritage Center & State Museum
612 East Boulevard Avenue
Bismarck, ND 58505-0830

**RE: ND SHPO Ref 23-0123 Blue Flint Ethanol Facility, Case No. 29888**

Dear Mr. Peterson,

Thank you for your comments regarding the Blue Flint Carbon Dioxide Storage permit application. As discussed with Ms. Meidinger of your staff, there will be minimal new surface disruptions as part of the proposed storage project. Case No. 29888 appropriately describes the storage area as being composed of T145N R82W Sections 6/8, 17 and 19 and T145N R83W Sections 11-14 and 24. Actual surface activities will only be completed at locations where injection and monitoring wells are installed and along the flow line as identified in the figure below.



The flow line leaves the Blue Flint industrial property and then travels in a road ditch adjacent to county road until it enters Falkirk Mine property where it travels through land currently in crop production. The injection and monitoring well locations are also located on property recently under active mine permit and that have been actively farmed.

Blue Flint commissioned KLJ to perform an analysis of cultural resources proximate to the areas of surface disruption and no recorded sites are anticipated to be impacted. Analysis noted that several Class III surveys have already been completed within the project area including manuscript no. 006285 – Falkirk Mine Riverdale Expansion.

Project construction includes protocols for immediate stoppage of work in the event of cultural resource discovery.

Please let me know if you have additional questions regarding this matter.

Sincerely,

Adam C Dunlop

Executive Vice President
Blue Flint Sequester Company

| Correction No. | Page Number | Correction Needed | Notes |
|---|---|---|---|
| 1 | 5-2 | Table correction<br>• Table 5-1<br>• Mentions of capture facility should be liquefaction outlet:<br>  ○ 2nd row, 3rd column<br>  ○ 3rd row, 3rd column<br>  ○ 4th row, 2nd column | Correction Provided |
| 2 | 5-3 | Table correction<br>• Table 5-2<br>• Capital C in "captured CO2" is needed. | Correction Provided |
| 3 | 5-4 | Capture facility should be liquefaction outlet in first paragraph, 3rd sentence | Correction Provided |
| 4 | 5-5 | 5.3.2 2nd sentence<br><br>"A coupon sample port will be located near the liquefaction outlet <u>and injection wellhead</u>, and sampling will occur quarterly"<br><br>and injection wellhead added to orginal sentence | Correction Provided |
| 5 | 5-7 and 5-8 | There is mention of elemental capture spectroscopy. Description added to Table 5-5 | Correction Provided |
| 6 | 5-10 and 5-11 | Table 5-6 – Specified MAG 1 as the test well for falloff testing; updated reference to Figure 5-5 to 5-6 under Time-Lapse 2D Seismic line item | Correction Provided |
| 7 | 6-7 | 6.3.1 Beginning of 2nd paragraph<br><br>Specified that the flowline will be flushed as part of reclamation work as well as the timing for reclaiming the flowline. | Correction Provided |
| 8 | C-1 | C1.3.1 2nd sentence of 1st paragraph<br><br>Sampling frequency for corrosion coupons needed updating to match Section 5.3.2. (Sampling quarterly) | Correction Provided |
| 9 | 4-5 | Table 4-2 updated with corrected information for ND-UIC-106 | Correction Provided |

**Table 5-1. Overview of Blue Flint's Testing and Monitoring Plan**

| | Monitoring Type | Equipment/Testing | Target Area |
|---|---|---|---|
| Surface Monitoring | $CO_2$ Stream Analysis | Compositional and isotopic testing | $CO_2$ liquefaction outlet at the capture facility |
| | Surface Facilities Leak Detection | $CO_2$ detection stations on flowline risers and wellheads, pressure gauges, dual flowmeters, and SCADA* system | Flowline from liquefaction outlet to injection wellhead |
| | Flowline Corrosion Detection | Flow-through corrosion coupon system | Flowline from liquefaction outlet to injection wellhead |
| | Continuous Recording of Injection Pressure, Rate, and Volume | Surface pressure-temperature gauges and flowmeters installed at the liquefaction outlet and injection wellhead with shutoff alarms | Surface-to-reservoir ($CO_2$ injection well) |
| Wellbore Monitoring | External Mechanical Integrity Testing | Ultrasonic imaging tool (USIT) or electromagnetic casing inspection log and distributed temperature sensing (DTS) | Well infrastructure |
| | Internal Mechanical Integrity Testing | Tubing-conveyed pressure–temperature gauges, surface digital gauges, and annulus pressure testing | Well infrastructure |
| | Downhole Corrosion Detection | Flow-through corrosion coupon system | Well materials |
| Environmental Monitoring | Atmosphere | $CO_2$ detection stations outside injection wellhead enclosure and gas analyzer sample blanks at soil gas profile stations | Well pads |
| | Near Surface | Compositional and isotopic analysis of soil gas and shallow groundwater down to the Fox Hills | Vadose zone and lowest USDW |
| | Above-Zone Monitoring Interval | DTS and pulsed-neutron logs (PNLs) over the Inyan Kara and Spearfish intervals | Downhole tubing and casing strings |
| | Direct Reservoir | DTS, PNLs, tubing-conveyed bottomhole pressure-temperature-(BHP/T) gauges, and pressure falloff testing | Storage reservoir |
| | Indirect Reservoir | Time-lapse 2D seismic and surface seismometer stations | Entire storage complex |

* Supervisory control and data acquisition.

## 5.1 $CO_2$ Stream Analysis

Prior to injection, Blue Flint determined the chemical content of the captured $CO_2$ stream via laboratory testing performed by Salof, Ltd. The chemical content is 99.98% dry $CO_2$ (by volume) and 0.02% other chemical components, as specified in Table 5-2. The $CO_2$ stream will be sampled at the liquefaction outlet quarterly and analyzed using methods and standards generally accepted by industry to determine its chemical and physical characteristics, including composition, corrosiveness, temperature, and density.

**Table 5-2. Chemical Content of the Captured $CO_2$**

| Chemical Content | Volume % |
|---|---|
| Carbon Dioxide | 99.98 |
| Water, Oxygen, Nitrogen, Hydrogen Sulfide, $C_2^+$, and Hydrocarbons | Trace amounts of each (0.02 total) |
| Total | 100.00 |

## 5.2 Surface Facilities Leak Detection Plan

The purpose of this leak detection plan is to monitor the surface facilities from the liquefaction outlet to the injection wellsite during the operational phase of the Blue Flint $CO_2$ storage project. Figure 5-1 is a map showing the surface facilities layout. Figure 5-2 illustrates a generalized flow diagram of surface connections from the liquefaction outlet to the MAG 1 injection wellsite.

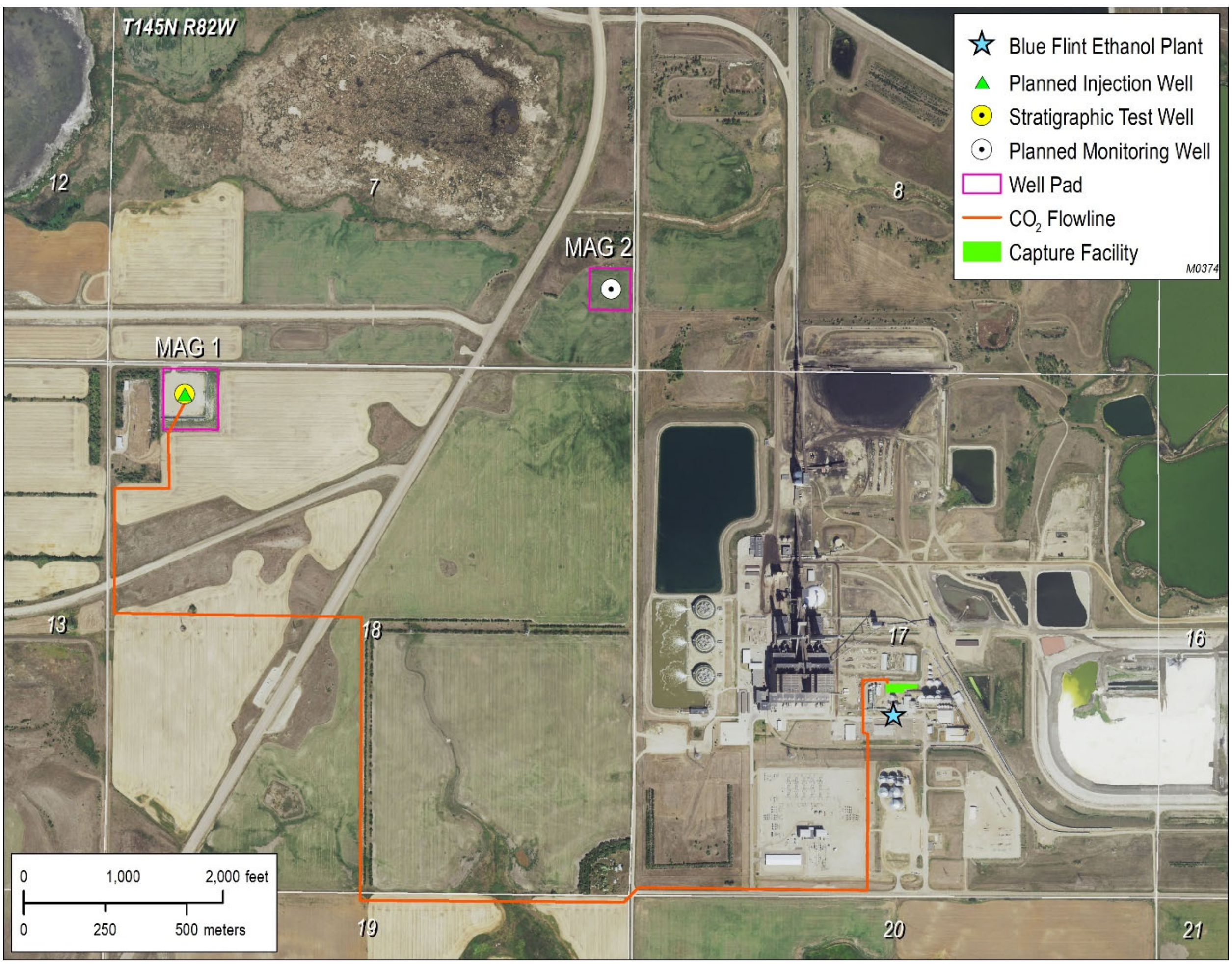



Figure 5-1. Site map showing the surface facilities layout for the Blue Flint $CO_2$ storage project.

**Table 5-3. Performance Targets for Detecting Leaks in Surface Equipment with SCADA**

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

* Thousand standard cubic feet per day.

$CO_2$ detection stations will be mounted on the inside of the wellhead enclosures to detect any potential indoor leaks. An additional $CO_2$ detection station will be mounted outside the injection wellhead enclosure to detect any potential atmospheric leaks at the wellsite. The stations can detect $CO_2$ concentrations as low as 2% by volume and have an integrated alarm system for increases of from 0% to 0.4% and 0.4% to 0.8% by volume. The stations are further described in Appendix C (Attachment A-2).

Field personnel will have multigas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multigas detectors will primarily monitor $CO_2$ levels in workspace atmospheres.

Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be made available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

## 5.3 Flowline Corrosion Prevention and Detection Plan

The purpose of this corrosion prevention and detection plan is to monitor the flowline and well materials during the operational phase of the project to ensure that all materials meet the minimum standards for material strength and performance.

### *5.3.1 Corrosion Prevention*

The chemical composition of the $CO_2$ stream is highly pure and dry (Table 5-2), and the target moisture level for the $CO_2$ stream is estimated to be up to 12 ppm by volume. These factors help to prevent corrosion of the surface facilities. In addition, the flowline construction materials will be $CO_2$-resistant in accordance with API 17J (2017) requirements. The flowline will be constructed using FlexSteel, a 3-layer flexible steel pipe product. The inner and outer layers contain a $CO_2$-resistant polyethylene liner, and the middle layer comprises reinforcing steel. FlexSteel product specifications can be found in Appendix C (Attachment A-3).

### *5.3.2 Corrosion Detection*

The flowline will use the corrosion coupon method to monitor for corrosion throughout the operational phase of the project, focusing on the loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. A coupon sample port will be located near the liquefaction outlet and injection wellhead, and sampling will occur quarterly. The process that will be used to conduct each coupon test is described in Appendix C under Section 1.3.

**Table 5-4. Overview of Blue Flint's Mechanical Integrity Testing Plan**

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

* The baseline monitoring effort has been initiated as of the writing of this permit application.

## 5.5 Well Testing and Logging Plan

Table 5-5 describes the testing and logging plan developed for the MAG 1 wellbore (exclusive of any coring) to establish baseline conditions. Included in the table is a description of fluid sampling and pressure testing performed. The logging and testing plan for the MAG 2 wellbore will be the same as what is presented in Table 5-5, with the addition of a PNL but excluding dipole, elemental capture spectroscopy (ECS), fluid swab, and FMI. Table 5-4 and Table 5-6 (see Section 5.7) detail the frequency with which logging data will be acquired and in which wellbores throughout the operational period of the project.

Wellbore data collected from MAG 1 have been integrated with the geologic model and to inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations (Section 3). The simulated $CO_2$ plume extents informed the timing and frequency of the application of the direct and indirect monitoring methods of the testing and monitoring plan.

**Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore**

| OH/CH* Depth, ft | Logging/Testing | Justification | NDAC § 43-05-01 |
|---|---|---|---|
| **Surface Section** | | | |
| OH 1340-0 | Triple combo (resistivity, bulk density, density and neutron porosity, GR, caliper, and spontaneous potential [SP]) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. | 11.2(1)(b)(1) |
| CH 1260-0 | Ultrasonic, casing collar locator (CCL), variable-density log (VDL), GR, and temperature log | Identified cement bond quality radially. Interpreted minor cement channeling throughout several isolated intervals and determined good azimuthal cement coverage and zonal isolation. | 11.2(1)(b)(2) |
| **Intermediate Section** | | | |
| OH 4170-1334 | Triple Combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for geomodeling and predictive simulation of $CO_2$ injection into the interest zones to improve test design and interpretations. Generated core-log correlations. | 11.2(1)(c)(1) |
| OH 4170-1334 | Dipole sonic | Identified mechanical properties in intermediate section. | 11.2(1)(c)(1) |
| OH 4138-3840 | ECS | Quantified mineralogical and clay content properties in intermediate section | 11.2(4) |
| OH 4170-3070 | Dielectric scanner | Quantified petrophysical properties and salinity calculations within the intermediate zones (Inyan Kara Formation). Provided information on rock properties and fluid distribution as inputs for reservoir evaluation and management. | 11.2(4) |
| CH 4070-30 | Ultrasonic, CCL, VDL, GR, and temperature log | Identified cement bond quality radially. Interpreted good azimuthal cement coverage and casing condition. Evaluated the cement top and zonal isolation. | 11.2(1)(c)(2) |
| **Long-string Section** | | | |
| OH 7068-4163 | Triple combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. | 11.2(1)(c)(1) |
| OH 7556-4163 | Dipole sonic | Identified mechanical properties of the rock including stress anisotropy. Provided compression and shear waves for seismic tie in and quantitative analysis of seismic data. | 11.2(1)(c)(1) |
| OH 5250-4250 | Fullbore FMI | Verified no fracture networks exist in the Broom Creek Formation or confining layers to ensure safe storage of $CO_2$. | 11.2(1)(c)(1) |
| OH 4741, 4735 | BHP/T survey | Measured Broom Creek Formation pressure and temperature in the wellbore. | 11.2(2) |
| OH 4740-4733 | Fluid swab | Collected fluid sample from the Broom Creek Formation for analysis. | 11.2(2) |
| CH** TBD | Ultrasonic, CCL, VDL, and GR | Will identify cement bond quality radially and determine azimuthal cement coverage. Will evaluate the cement top and zonal isolation. | 11.2(1)(b)(2) |

* OH/CH – openhole/cased-hole
** Planned activity at the time of writing this permit to be completed prior to injection.

**Table 5-6. Summary of Environmental Baseline and Operational Monitoring**

| Activity | Baseline Frequency* | Operational Frequency (20-year period) |
|---|---|---|
| **Atmosphere** | | |
| Wellsite (workplace) Atmosphere Sampling (Figures 5-3 and 5-4) | At start-up, install $CO_2$ detection stations placed outside well enclosures at the MAG 1 location. | Stations provide continuous monitoring of $CO_2$ conditions at the well pad. |
| Ambient Atmosphere Sampling (Figure 5-4) | Sample 3–4 events at each soil gas probe location (SG-1 through SG-5) prior to injection. | Sample 3–4 events per year at each soil gas profile station (SGPS 1 and SGPS 2).<br><br>Sampling will piggyback on the planned soil gas monitoring plan (described below). |
| **Soil Gas Monitoring** | | |
| Soil Gas Sampling (Figures 5-3 through 5-5) | Sample 3–4 events per probe location (i.e., SG-1 through SG-5) prior to injection.<br><br>Perform concentration and isotopic testing on all samples. | Sample 3–4 events per year at each soil gas profile station (i.e., SGPS 1 and SGPS 2).<br><br>Perform concentration and periodic isotopic testing on all samples. |
| **Shallow Groundwater** | | |
| Up to 5 Stock Wells (3 Operated by Falkirk Mining Company) (Figure 5-5) | Sample 3-4 events per well prior to injection.<br><br>Perform water quality and isotopic testing on all samples. | Shift sampling program to the dedicated Fox Hills monitoring well near the MAG 1 well. |
| **Lowest USDW** | | |
| Dedicated Fox Hills Monitoring Well Sampling at MAG 1 (Figure 5-5) | Sample 3–4 events per well.<br><br>Perform water quality and isotopic testing on all samples | Sample 3–4 events per well annually.<br><br>Perform water quality and periodic isotopic testing on all samples. |
| **AZMI** | | |
| DTS | Install during completion of MAG 1 and MAG 2. | Monitor temperature changes continuously in the MAG 1 and MAG 2. |
| PNL | Perform in MAG 2 prior to injection.<br><br>Run log from the Spearfish Formation through the Inyan Kara Formation to establish baseline conditions. | Collect PNL in MAG 2 at Year 4 and every 5 years thereafter until end of injection.<br><br>Run log from the Spearfish Formation through the Inyan Kara Formation to confirm containment in the storage reservoir. |
| **Storage Reservoir (direct)** | | |
| DTS | Install during completion of the MAG 1 and MAG 2. | Monitor temperature changes continuously in the MAG 1 and MAG 2. |
| PNL | Perform in MAG 2 prior to injection.<br><br>Run log from the Amsden Formation through the Spearfish Formation to establish baseline conditions. | Collect PNL in MAG 2 at Year 4 and every 5 years thereafter until end of injection.<br><br>Run log from the Amsden Formation through the Spearfish Formation to determine the Broom Creek Formation's saturation profile. |
| BHP/T Readings | Install BHP/T gauges over the storage reservoir in MAG 1 and MAG 2 prior to injection. | Collect BHP/T readings continuously from the storage reservoir in MAG 1 and MAG 2. |
| Pressure Falloff Testing | Conduct once prior to injection in MAG 1. | Perform at least once every five years in MAG 1. |

* The baseline (preinjection) monitoring effort has not yet begun as of the writing of this permit application.

Continued…

**Table 5-6. Summary of Environmental Baseline and Operational Monitoring (continued)**

| Activity | Baseline Frequency | Operational Frequency (20-year period) |
|---|---|---|
| **Storage Reservoir (indirect)** | | |
| Time-Lapse 2D Seismic Surveys (Figure 5-6) | Collect baseline fence 2D seismic survey. | Repeat 2D seismic survey in Year 1 and Year 4. At Year 4 following the start of injection, reevaluate frequency based on plume growth and seismic results. |
| Passive Seismicity Monitoring (Figure 5-7) | Utilize existing U.S. Geological Survey's network. | Utilize existing U.S. Geological Survey's network and supplement with additional equipment as necessary. |

### *5.7.1 Atmospheric Monitoring*

Figures 5-3 and 5-4 illustrate the planned well pad design at MAG 1 and MAG 2 and the locations of the $CO_2$ detection stations that will be used to monitor workspace atmospheres to ensure a safe work environment. As mentioned in Section 5.2 of this testing and monitoring plan, field personnel will be equipped with multigas detectors with them for wellsite visits or flowline inspections to detect potential leaks as an added safety precaution.

### 6.3 Schedule for Submitting Postinjection Monitoring Results

All PISC-monitoring data and monitoring results will be submitted to NDIC in annual reports. These reports will be submitted within 60 days of the anniversary date on which the $CO_2$ injection ceased.

The annual reports will contain information and data generated during the reporting period, including seismic data acquisition, formation monitoring data, soil gas and groundwater sample analytical results, and simulation results from updated site models and numerical simulations.

#### *6.3.1 PISC Plan*

Blue Flint will submit a final site closure plan and notify NDIC at least 90 days prior to its intent to close the site. The site closure plan will describe a set of closure activities that will be performed, following approval by NDIC, at the end of the PISC period. Site closure activities will include the plugging of all wells that are not planned for continued use in monitoring the closed site; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring; the reclaiming of the surface land of the site to as close as is practical to its original condition; and abandonment of flowlines pursuant to NDAC Section 43-02-03-34.1.

At the start of the PISC period, any flowlines buried less than 3 feet below final contour will be flushed and removed (e.g., the planned flowline segment at the capture facility on Blue Flint Ethanol property and the above-ground portion of the flowline at the injection wellsite). Associated costs during the PISC period are outlined in Section 12, which include the type and frequency of monitoring as well as equipment costs, plugging of the injection well, and site reclamation.

As part of the PISC monitoring and closure plan and in accordance with NDAC 43-05-01-19(5), the MAG 1 injection well will be plugged and abandoned and the injection well pad will be reclaimed. Reclamation of the MAG 1 well and the injection pad includes wellhead removal, sump removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, reclamation of the flowline at the injection pad, and the P&A of SGPS01.

The dedicated Fox Hills monitoring well adjacent to the MAG 1 injection wellsite will remain, at a minimum, until site closure. At the time of site closure, NDIC and Blue Flint will decide if the Fox Hills well adjacent to the MAG 1 wellsite will be plugged and abandoned with the site location reclaimed or if the ownership of the Fox Hills well will transfer to the State.

#### *6.3.2 Site Closure Plan*

To comply with NDAC 43-05-01-19(2), the MAG 2 well will be used for deep subsurface monitoring during the PISC period and will be plugged and abandoned as part of site closure activities. Reclamation of the MAG 2 well and well pad at site closure includes wellhead removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, and the P&A of SGPS02.

As part of the final assessment, Blue Flint will work with NDIC to determine which wells and monitoring equipment will remain and transfer to the State for continued postclosure monitoring. The dedicated Fox Hills monitoring well drilled adjacent to the MAG 1 injection well

## C1.0 QUALITY ASSURANCE AND SURVEILLANCE PLAN

The primary goal of the testing and monitoring plan (Section 5) of this storage facility permit application is to ensure that the geologic storage project is operating as permitted and is not endangering USDWs. In compliance with NDAC § 43-05-01-11.4 (Testing and Monitoring Requirements), this quality assurance and surveillance plan (QASP) was developed and is provided as part of the testing and monitoring plan.

### C1.1 $CO_2$ Stream Analysis

NDAC § 43-05-01-11.4(1)(a) requires analysis of the $CO_2$ stream in compliance with applicable analytical methods and standards generally accepted by industry and with sufficient frequency to yield data representative of its chemical and physical characteristics. Blue Flint will collect samples of the injected $CO_2$ stream quarterly at the liquefaction outlet and analyze the $CO_2$ stream to determine the concentrations of $CO_2$, nitrogen, oxygen, hydrogen, water, hydrogen sulfide, carbon monoxide, and a suite of hydrocarbons (e.g., ethane, propane, n-butane, and methane) via a third party. Selected stable isotopes (i.e., isotopes of carbon dioxide [$^{12}C$ and $^{13}C$], methane [$^{12}C$ and $^{13}C$], and deuterium [$^{2}H$]) will also be sampled in the first year to establish a baseline. The isotopic analyses will be outsourced to commercial laboratories that will employ standard analytical QA/QC protocols used in the industry.

### C1.2 Surface Facilities Leak Detection Plan

The surface leak detection and monitoring plan is outlined in Section 5.2. The SCADA system (described in Attachment A-1) will continuously monitor surface facilities operations in real time and be equipped with automated alarms that will notify the Blue Flint operations center in the event of an anomalous reading. A generalized specification sheet for the $CO_2$ detection stations (see Attachment A-2) will monitor $CO_2$ levels at each wellsite to ensure workspace atmospheres are safe.

### C1.3 Corrosion Monitoring and Prevention Plan

#### *C1.3.1 Corrosion Monitoring*

The flow line will use the corrosion coupon method to monitor for corrosion in the flow line and injection wellbore throughout the operational phase of the project, focusing on loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. The coupon sample port will be located near the liquefaction outlet, and sampling will occur quarterly.

The process that will be used to conduct each coupon test is described below.

##### *C1.3.1.1 Sample Description*

Corrosion coupons that are representative of the construction materials of the flowline and injection well that contact the $CO_2$ stream will be tested. Materials from these process components and/or conventional corrosion coupons of similar composition and specifications will be weighed, measured, and photographed prior to initial exposure.

## 4.2 Corrective Action Evaluation

**Table 4-2. Wells in AOR Evaluated for Corrective Action***

| Well File No. | Operator | Well Name | Spud Date | Surface Casing o.d., inches | Surface Casing Seat, ft | Long-String Casing o.d., inches | Long-String Casing seat, inches | Hole Direction | TD, ft | TVD, ft | Status | Plug Date | TWN | RNG | Section | Qtr/Qtr | County | Corrective Action Needed |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1516** | H. Hanson Oil Syndicate | Ellen Samuelson 1 | 9/14/1957 | 10.75 | 462 | Openhole | | Vertical | 6,600 | 6,600 | P&A | 10/18/1957 | 146N | 82W | 32 | SE/SW | McLean | No |
| **ND-UIC-106**** | Great River Energy | Well #1 | 10/10/2014 | 11.75 | 1,232 | 7 | | Vertical | 4,046 | 4,046 | Active Injector | NA | 145N | 82W | 17 | SE/NE | McLean | No |
| **4810** | W. H. HUNT TRUST ESTATE | Wallace O. Gradin 1 | 12/1/1969 | 8.625 | 233 | Openhole | | Vertical | 4240 | 4240 | P&A | 12/6/1969 | 145N | 82W | 22 | SW/SW | McLean | No |

* TD is total depth, and TVD is true vertical depth.
**ND-UIC-106 is classified as a Class I disposal well.

| Supplement No. | Page Number | Supplemental Requested | Notes/Actions |
|---|---|---|---|
| 1 | 2-8 | Can you provide a supplemental for table 2-2 and 2-3 that shows the temperature and pressure<br>• Give a table that shows all of that information and the source of the data<br>• Include the values used in the model and indicate the source of the info so it's clear in the application. | Supplemental Provided<br><br>Additional information provided as an independent writeup. A folder containing field data provided. |
| 2 | 2-14 | On figure 2-10, provide correct high-def images. | Supplemental Provided |
| 3 | 2-15 | On figure 2-11, provide correct high-def images. | Supplemental Provided |
| 4 | 2-18 | Table 2-5 provide how many side wall cores came from each lithology | Supplemental Provided<br><br>Information provided in footnote of Table 2-5 |
| 5 | 2-30 – 2-36 | Figures 2-21 thru 2-27 give K plane 39 a depth to reference in the geochemical modeling | Supplemental Provided<br><br>Depth of K plane given in caption of Figure 2-21 |
| 6 | 2-51 | On figure 2-38 is the red line showing chlorite?<br>• Hard to differentiate colors<br>• No green calcite line is shown. Provide an updated larger scale version of this image. | Supplemental Provided<br><br>New figures inserted for 2-38 and caption updated accordingly. |
| 7 | 2-52 | Add clarification to Figure 2-39 | Supplemental Provided<br><br>New figures inserted for 2-39 and caption updated accordingly. |
| 8 | 2-53 | Add clarification to Figure 2-40 | Supplemental Provided |

| Supplement No. | Page Number | Supplemental Requested | Notes/Actions |
|---|---|---|---|
| | | | New figures inserted for 2-40 and caption updated accordingly. |
| 9 | 2-55 | Table 2-15 depths do not match the well bore diagram from figure 9-1<br><br>If it needs to be corrected, please provide one of those as a supplement, depending on which is corrected | Supplemental Provided<br><br>Table 2-15 corrected to match Figure 9-1 |
| 10 | 2-67[1]<br>2-68[2] (69)<br>2-83[3] (84)<br>2-86[4] (87)<br>2-92[5] (93) | Request 1:<br>Provide an additional figure 2-52 which demonstrates cell 10 and 11<br><br>Request 2:<br>Add additional clarification to the captions for Figure 2-53 and 2-54<br><br>Request 3:<br>Average Poisson's ratio for the Broom Creek is 0.313 in Table 2-19 and 0.32 in the text.<br><br>Request 4:<br>Can you provide a similar exhibit from the Precambrian to the Broom Creek?<br>• In reference to figure 2-67<br>• Provide in several chunks if necessary<br>• Indicators on the vertical area beyond Precambrian features<br><br>Request 5:<br>In Figure 2-71 expand the figure to include the remainder of the Fort Union Group and the remainder of coal seams | Supplemental Provided<br><br>Request 1: Two additional figures and accompanying captions were added. All page numbers were adjusted for the remainder of Section 2.<br><br>Request 2: New figures inserted for 2-53 and 2-54 and caption updated accordingly.<br><br>Request 3: The value for average Poisson's ratio was updated to of .313 in the text.<br><br>Request 4: Figure 2-67 and 2-68 updated<br><br>Request 5: New figure |

| Supplement No. | Page Number | Supplemental Requested | Notes/Actions |
| --- | --- | --- | --- |
| | | | inserted for Figure 2-71. Caption and reference section updated accordingly. |
| 11 | 2-81[1]<br>2-83[2] | [1]Provide a supplemental table showing the static and dynamic properties that were estimated through the evaluation of the 1D MEM in Spearfish, Broom Creek, and Amsden Formations. Derived from global correlations of dynamic to static parameters their source, inputs and where the source of that data came from to show they were done accordingly.<br>• Equation itself, the literature it was documented, variable that can be identified, and the source of the data where you find the value from<br>Could be include in an appendix<br><br>[2]Show formulas in the geomechanical section can show any of the variables used in the fracture gradient formula calculating the maximum and minimum horizontal and vertical stress.<br>Provide screenshots of Schlumberger calculations. | Supplemental Provided<br><br>Additional information provided as an independent writeup |
| 12 | 3-11 | Provide additional information on how pressure and temperature gradients in Section 3 were calculated. | Supplemental Provided<br><br>Additional text provided on page 3-11, 2nd paragraph. |
| 13 | 3-20 | Asking for the formula to be corrected on page 3-20, $mg/m^3$ should be kg | Supplemental Provided |
| 14 | 3-31 | Explain potential impact of 1 $m^3$ of fluid from the Broom Creek leaking into the Fox Hills Formation. | Supplemental Provided<br><br>Additional information provided as an independent writeup |

| Supplement No. | Page Number | Supplemental Requested | Notes/Actions |
|---|---|---|---|
| 15 | 3-17 – 3-18 | Approximately how many years does it take $CO_2$ to move to the next cell during stabilization. | Supplemental Provided<br><br>Text added to section 3.4.2. |
| 16 | 3-6 | Figure 1-4 should be 3-4 | Supplemental Provided |
| 17 | 3-7 | Paragraph correction<br>• "please note the red ~~and orange~~"<br>Delete "and orange" | Supplemental Provided |
| 18 | 3-23 | table 3-1 should be 3-4 | Supplemental Provided |
| 19 | 3-25 | table 3-2 should be 3-5 | Supplemental Provided |
| 20 | 3-26 | table 3-3 should be 3-6 | Supplemental Provided |
| 21 | 3-30 | table 3-4 should be 3-7 | Supplemental Provided |
| 22 | 4-6 | Provide the "Thickness, ft" in table 4-3<br>• Provide the cement yield to get the estimates for the thickness. | Supplemental Provided<br><br>Table 4-3 updated. |
| 23 | 4-8 | Check the accuracy of table 4-5 it appears to be incorrect | Supplemental Provided<br><br>Cement yield indicated in table by ** in order to provide variable used in |

| Supplement No. | Page Number | Supplemental Requested | Notes/Actions |
|---|---|---|---|
| | | | cement plug calculations. Plugs have been adjusted to reflect correct depths. |
| 24 | 4-18 | Update text, "The Inyan Kara will be monitored for temperature ~~and pressure~~ changes in the injection well (MAG 1) and the monitoring well (MAG 2)." | Supplemental Provided<br><br>4.4.4, 2nd paragraph, 2nd sentence. Sentence updated. |
| 25 | 6-5 | Tables 6-2 and 5-6: PNL logging timescales seem to not match up. | Supplemental Provided<br><br>Table 6-2 adjusted to match Table 5-6<br><br>Paragraph added in section 6.2.2, 2nd paragraph, to detail timing of PNL during postinjection |
| 26 | 9-5 | NDIC number needs to be populated | Supplemental Provided |
| 27 | 12-6 | Paragraph corrections<br>Table 7-3 and 7-4 should be 7-4 and 7-5 | Supplemental Provided |
| 28 | Appendix B | Baseline sampling data | Supplemental Provided<br><br>Additional information provided as an independent writeup |

| Supplement No. | Page Number | Supplemental Requested | Notes/Actions |
|---|---|---|---|
| | Section 1 and Section 5 | GIS Shapefiles for Figure 1-1 and Section 5 figures | GIS Shapefiles provided |
| | 3-18 | Paragraph correction<br>• 0.15 should be 0.25 | No action: Upon further review, EERC agrees that the value of 0.15 is correct and will not be altering the value |
| | Section 9 | There are a handful of wellbore schematics well depth don't match with the completion report with North Star and figure out which one is correct. Needs to be done before the application is approved. | No action: completions report will be updated at a later date. |

To calculate the Pressure and Temperature values in Tables 2-2 and 2-3, the last 30 sample points taken at the end of the first flow period during the flow back test on the MAG 1 were averaged using arithmetic averaging. For Sensor number SH51214 at depth 4,741' this would constitute measurements from timestep '6/6/2022 8:44' through measurements in timestep '6/6/2022 8:49', and for Sensor number SH51215 at depth 4,735'. The following tables below show the data used in the calculations.

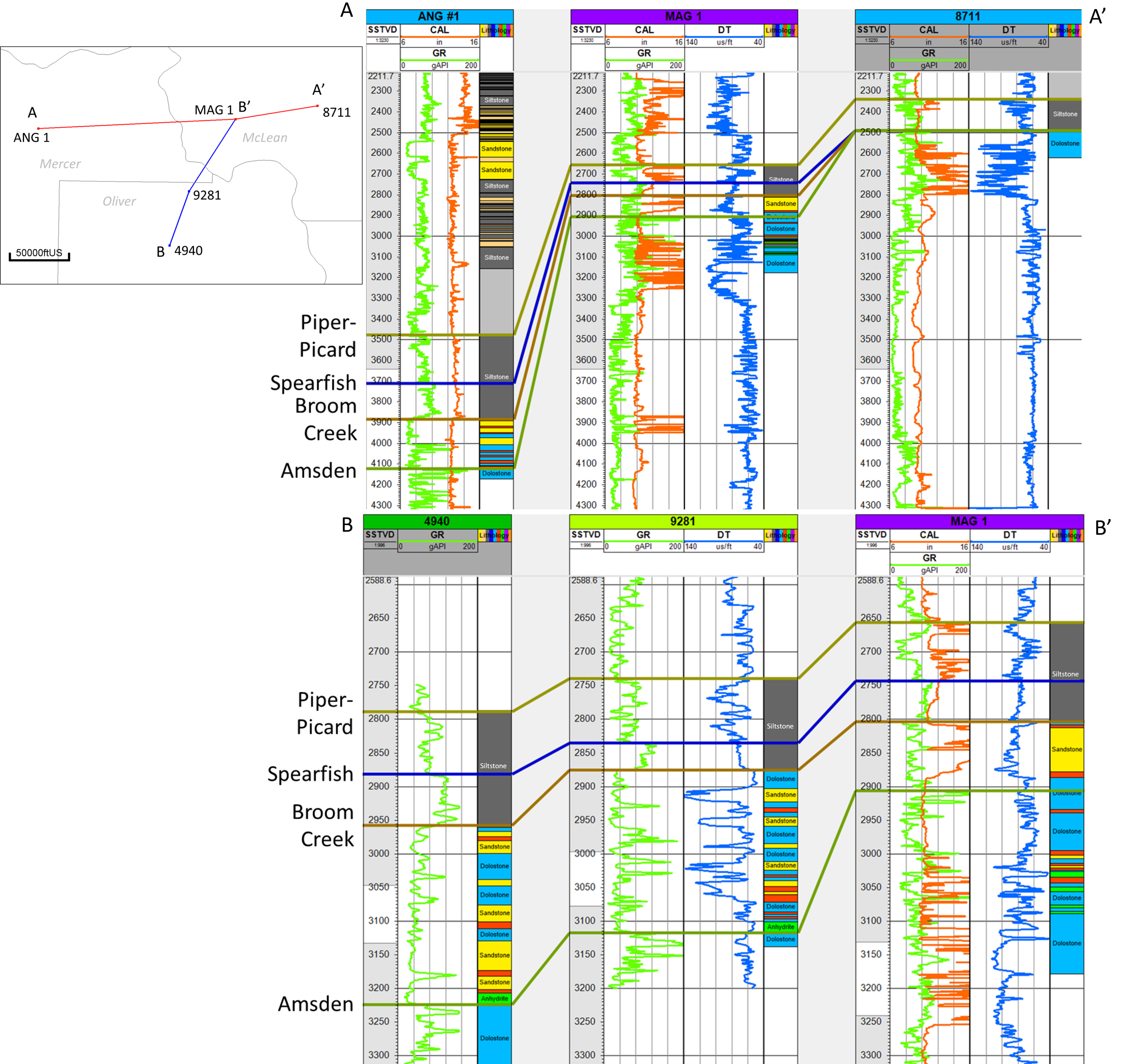
Table 1. Last 30 measurements taken at the end of the First Flow on Sensor SH51214 at 4,741' for the MAG 1 well in the Broom Creek Formation.

| | | |
|---|---|---|
| 6/6/2022 8:44 | 2427.261 | 118.657 |
| 6/6/2022 8:45 | 2427.263 | 118.658 |
| 6/6/2022 8:45 | 2427.24 | 118.657 |
| 6/6/2022 8:45 | 2427.261 | 118.657 |
| 6/6/2022 8:45 | 2427.244 | 118.659 |
| 6/6/2022 8:45 | 2427.229 | 118.657 |
| 6/6/2022 8:45 | 2427.263 | 118.658 |
| 6/6/2022 8:46 | 2427.248 | 118.656 |
| 6/6/2022 8:46 | 2427.243 | 118.654 |
| 6/6/2022 8:46 | 2427.25 | 118.657 |
| 6/6/2022 8:46 | 2427.271 | 118.657 |
| 6/6/2022 8:46 | 2427.261 | 118.657 |
| 6/6/2022 8:46 | 2427.245 | 118.655 |
| 6/6/2022 8:47 | 2427.277 | 118.655 |
| 6/6/2022 8:47 | 2427.269 | 118.656 |
| 6/6/2022 8:47 | 2427.289 | 118.656 |
| 6/6/2022 8:47 | 2427.245 | 118.655 |
| 6/6/2022 8:47 | 2427.279 | 118.656 |
| 6/6/2022 8:47 | 2427.256 | 118.655 |
| 6/6/2022 8:48 | 2427.281 | 118.657 |
| 6/6/2022 8:48 | 2427.237 | 118.656 |
| 6/6/2022 8:48 | 2427.245 | 118.655 |
| 6/6/2022 8:48 | 2427.266 | 118.655 |
| 6/6/2022 8:48 | 2427.281 | 118.657 |
| 6/6/2022 8:48 | 2427.277 | 118.655 |
| 6/6/2022 8:49 | 2427.237 | 118.656 |
| 6/6/2022 8:49 | 2427.253 | 118.654 |
| 6/6/2022 8:49 | 2427.258 | 118.656 |
| 6/6/2022 8:49 | 2427.245 | 118.655 |
| 6/6/2022 8:49 | 2427.89 | 118.654 |

Table 2. Last 30 measurements taken at the end of the First Flow on Sensor SH51215 at 4,735' for the MAG 1 well in the Broom Creek Formation.

| | | |
|---|---|---|
| 6/6/2022 8:44 | 2426.983 | 118.931 |
| 6/6/2022 8:45 | 2426.959 | 118.931 |
| 6/6/2022 8:45 | 2426.981 | 118.931 |
| 6/6/2022 8:45 | 2426.961 | 118.931 |
| 6/6/2022 8:45 | 2427.014 | 118.931 |
| 6/6/2022 8:45 | 2426.959 | 118.931 |
| 6/6/2022 8:45 | 2426.97 | 118.931 |
| 6/6/2022 8:46 | 2426.945 | 118.93 |
| 6/6/2022 8:46 | 2426.97 | 118.931 |
| 6/6/2022 8:46 | 2426.956 | 118.93 |
| 6/6/2022 8:46 | 2427.001 | 118.93 |
| 6/6/2022 8:46 | 2426.979 | 118.93 |
| 6/6/2022 8:46 | 2426.954 | 118.929 |
| 6/6/2022 8:47 | 2426.979 | 118.93 |
| 6/6/2022 8:47 | 2426.959 | 118.931 |
| 6/6/2022 8:47 | 2426.974 | 118.928 |
| 6/6/2022 8:47 | 2426.976 | 118.929 |
| 6/6/2022 8:47 | 2426.988 | 118.929 |
| 6/6/2022 8:47 | 2426.963 | 118.928 |
| 6/6/2022 8:48 | 2426.963 | 118.928 |
| 6/6/2022 8:48 | 2427.034 | 118.93 |
| 6/6/2022 8:48 | 2426.976 | 118.929 |
| 6/6/2022 8:48 | 2426.99 | 118.93 |
| 6/6/2022 8:48 | 2426.979 | 118.93 |
| 6/6/2022 8:48 | 2426.988 | 118.929 |
| 6/6/2022 8:49 | 2427.054 | 118.929 |
| 6/6/2022 8:49 | 2426.988 | 118.929 |
| 6/6/2022 8:49 | 2426.979 | 118.93 |
| 6/6/2022 8:49 | 2426.976 | 118.929 |
| 6/6/2022 8:49 | 2427.754 | 118.928 |

A
A'
ANG #1
MAG 1
8711
SSTVD
CAL
GR
DT
Lithology
Piper-
Picard
Spearfish
Broom
Creek
Amsden
Siltstone
Sandstone
Dolostone
Anhydrite
B
B'
4940
9281
Mercer
Oliver
McLean
ANG 1
MAG 1
50000ftUS



A
A'
B
B'
ANG #1
MAG 1
8711
4940
9281
ANG 1
Mercer
McLean
Oliver
50000ftUS
SSTVD
CAL
GR
DT
Lithology
gAPI
us/ft
Siltstone
Sandstone
Dolostone
Anhydrite
Piper-Picard
Spearfish
Broom Creek
Amsden

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

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

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

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

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

***Laboratory analysis values based on 10 sandstone, 9 dolostone and 4 dolomitic sandstone core samples

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

Sandstone intervals in the Broom Creek Formation are associated with low GR, low density, high porosity (neutron, density, and sonic), low resistivity due to brine salinity, and high sonic slowness measurements. The dolostone intervals in the formation are associated with an increase in GR measurements compared to the sandstone intervals, in addition to high density, low porosity (neutron, density, and sonic), high resistivity, and low sonic slowness measurements. The dolomitic sandstone intervals in the formation are the transitions between sandstone and dolostone,

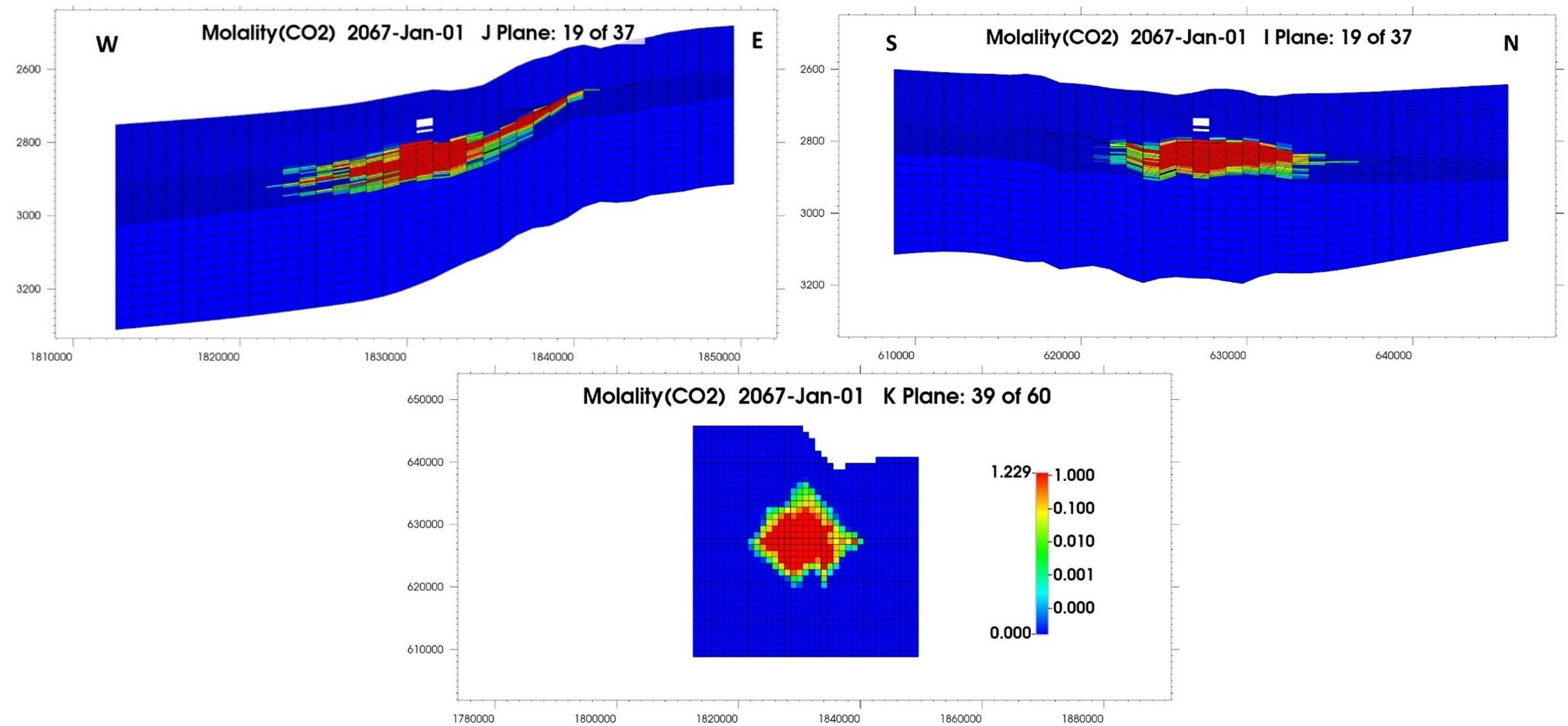



Figure 2-21. $CO_2$ molality for the geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of $CO_2$ molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of simulation in Layer k = 39, which represents the layer that intersections the MAG 1 well at 4787.5 ft. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

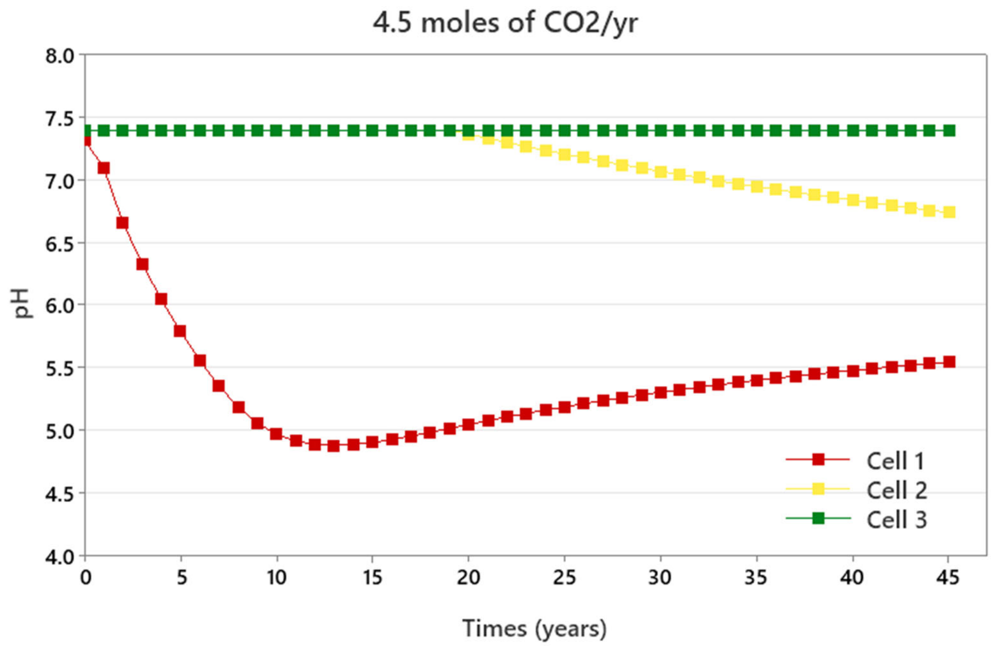



Figure 2-37. Change in fluid pH vs. time. Red line shows pH for the center of Cell C1, 0.5 meters above the Spearfish Formation cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to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

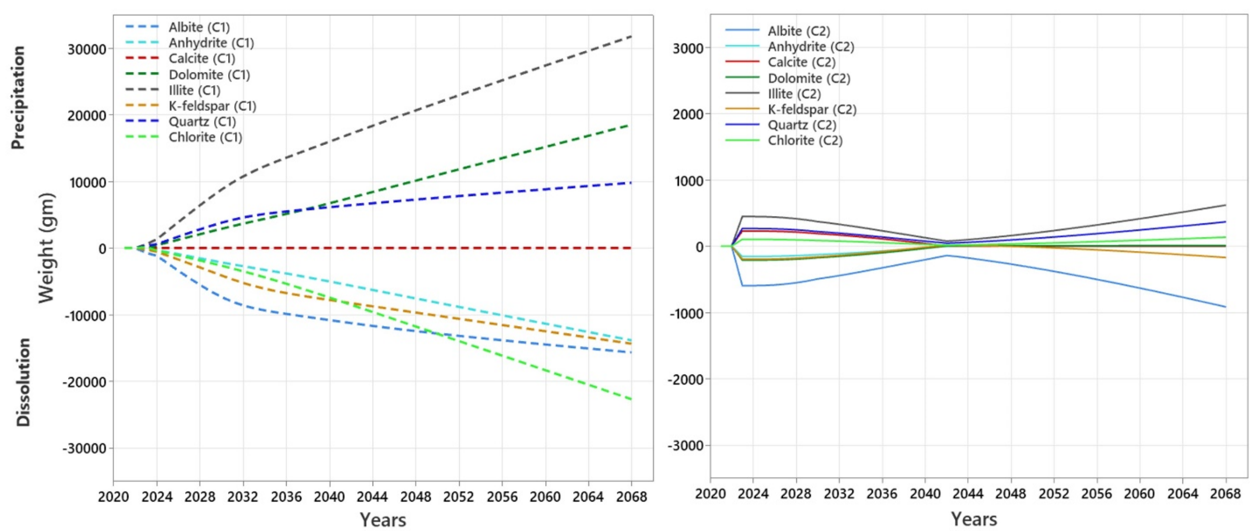



Figure 2-38. Dissolution and precipitation of minerals in the Spearfish Formation cap rock. (Left) Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. (Right) Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible.

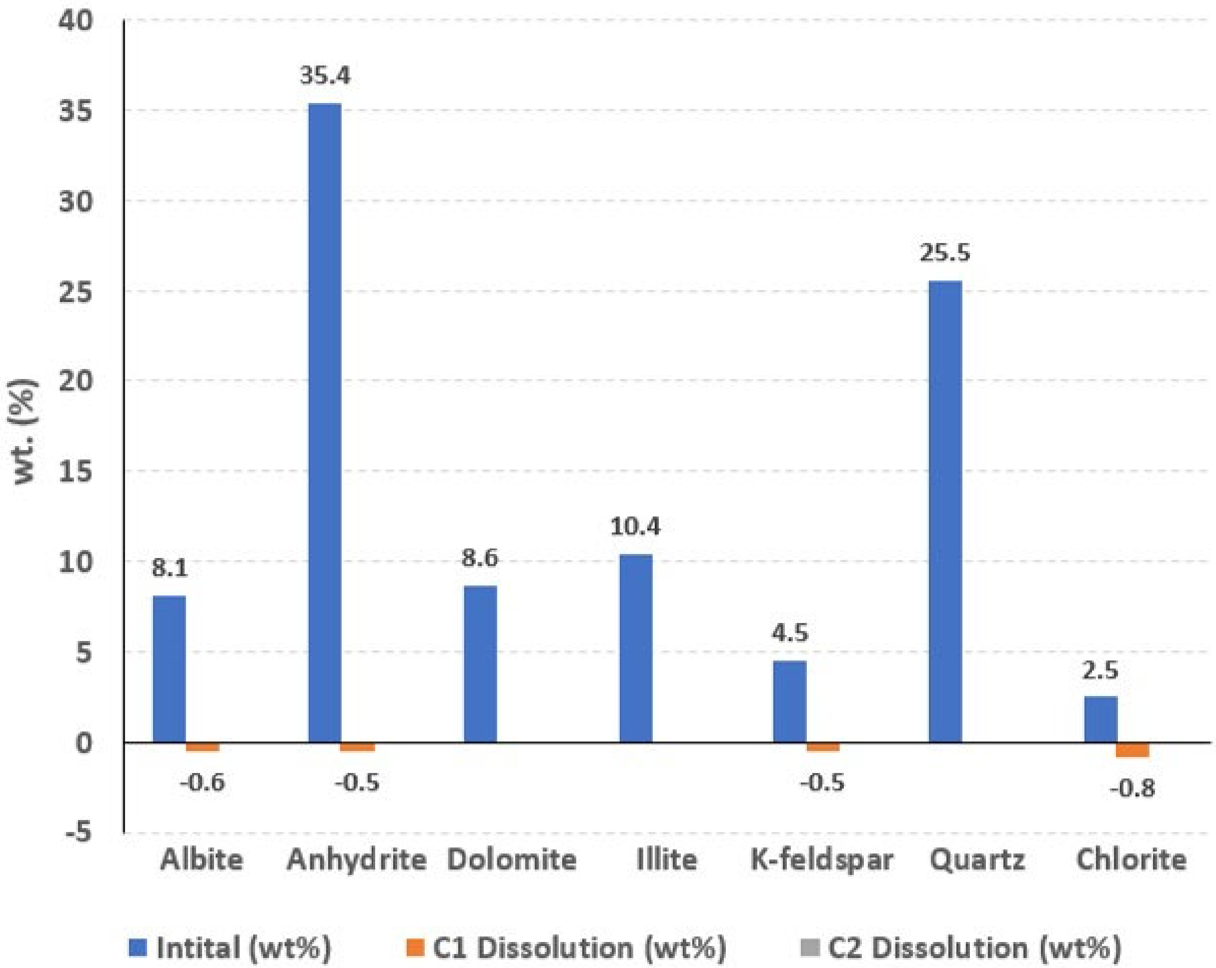



Figure 2-39. Weight percentage (wt%) of potentially reactive minerals present in the Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray, too small to see in the figure) after 20 years of injection plus 25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

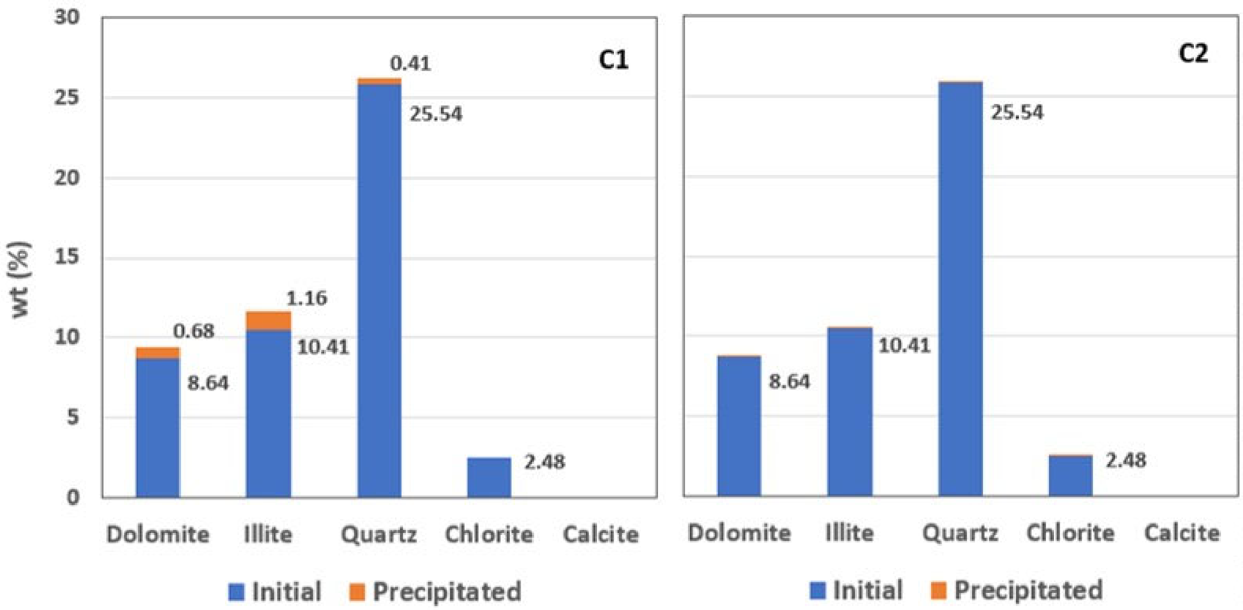



Figure 2-40. Weight percentage (wt.%) of initial (blue) and precipitated (orange) minerals in the C1 (left) and C2 (right) normalized based on total solid (initial – dissolution + precipitation) present in the C1 and C2 after 20 years of injection and 25 years of postinjection. Minerals precipitated in C2 are too small to be seen in the figure.

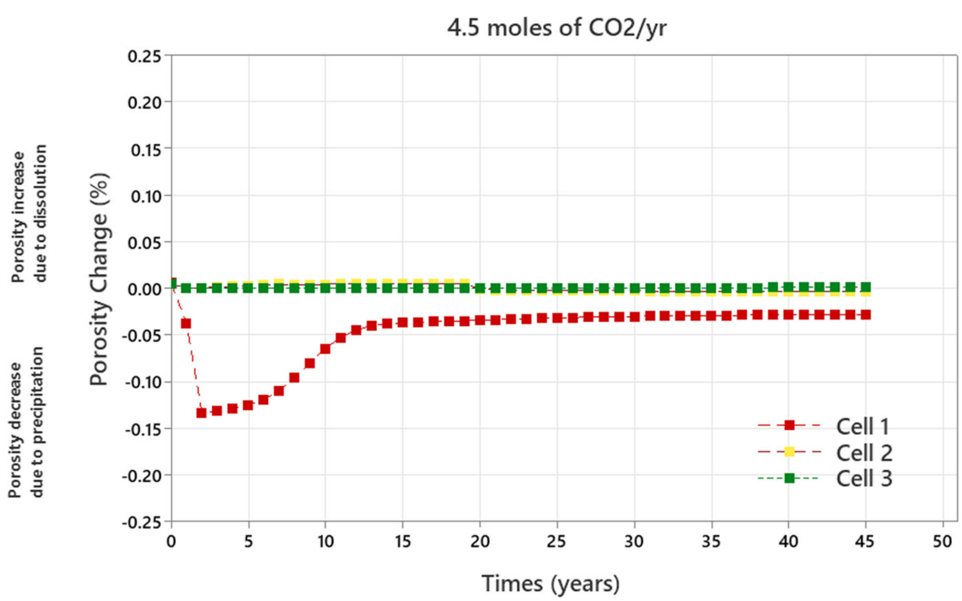



Figure 2-41. Change in percent porosity of the Spearfish cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change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

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

| Name of Formation | Lithology | Formation Top Depth, ft | Thickness, ft | Depth below Lowest Identified USDW, ft |
|---|---|---|---|---|
| Pierre | Shale | 1,092 | 1,316 | 0 |
| Niobrara | Shale | 2,408 | 328 | 1,316 |
| Carlile | Shale | 2,736 | 261 | 1,644 |
| Greenhorn | Shale | 2,997 | 53 | 1,905 |
| Belle Fourche | Shale | 3,050 | 250 | 1,958 |
| Mowry | Shale | 3,300 | 58 | 2,208 |
| Skull Creek | Shale | 3,375 | 229 | 2,282 |
| Swift | Shale | 3,831 | 423 | 2,739 |
| Rierdon | Shale | 4,254 | 178 | 3,3162 |
| Piper (Kline Member) | Limestone | 4,434 | 147 | 3,342 |

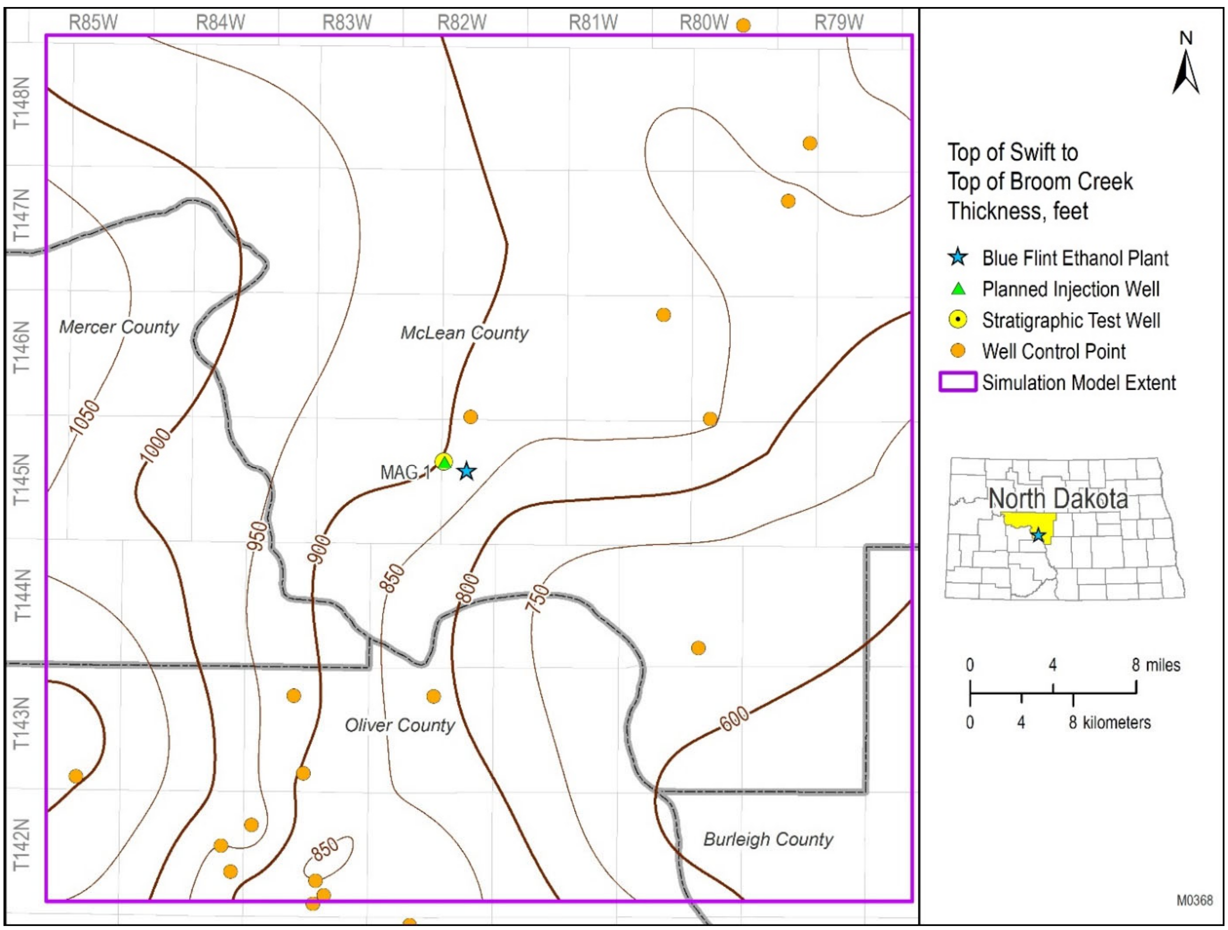



Figure 2-42. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

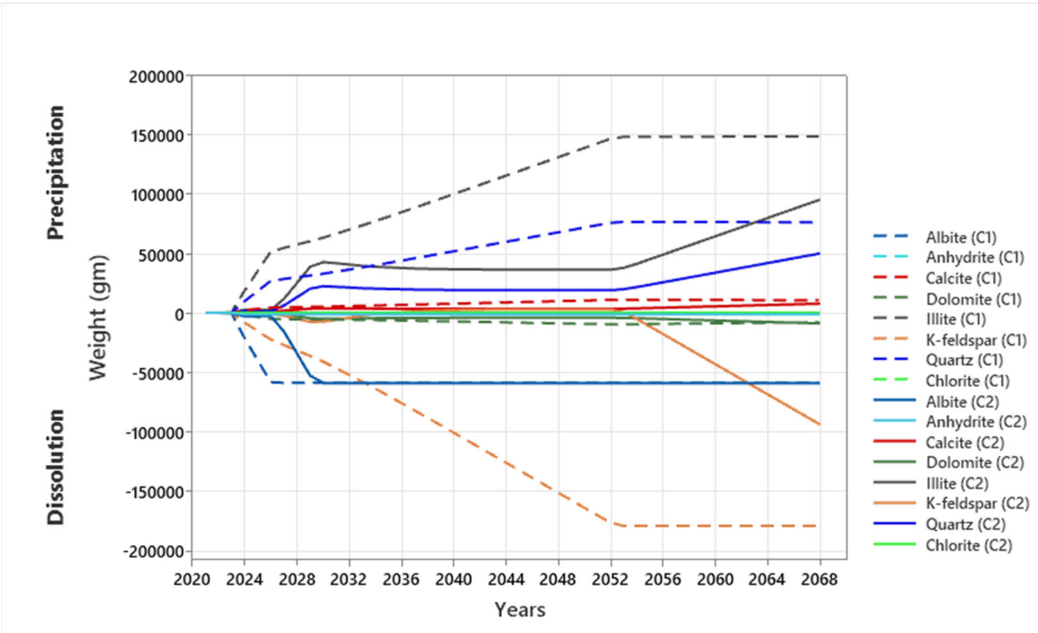



Figure 2-52a. Dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for Cell C1, 0 to 1 meter below the Amsden top. Solid lines show results for Cell C2, 1 to 2 meters below the Amsden top.

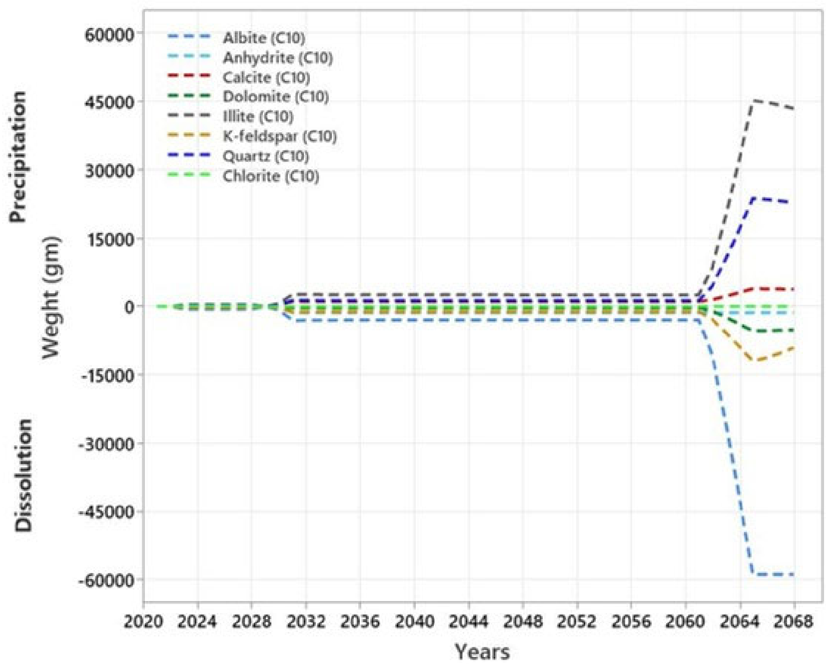



Figure 2-52b. Dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for Cell 10 (C10), 9 to 10 meters below the Amsden top.

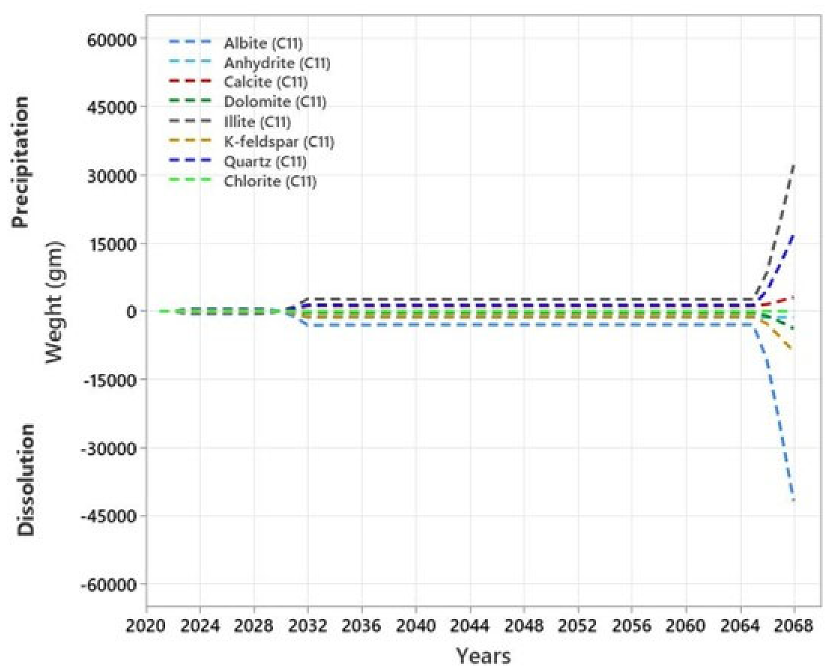



Figure 2-52c. Dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for Cell 11 (C11), 10 to 11 meters below the Amsden top.

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

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

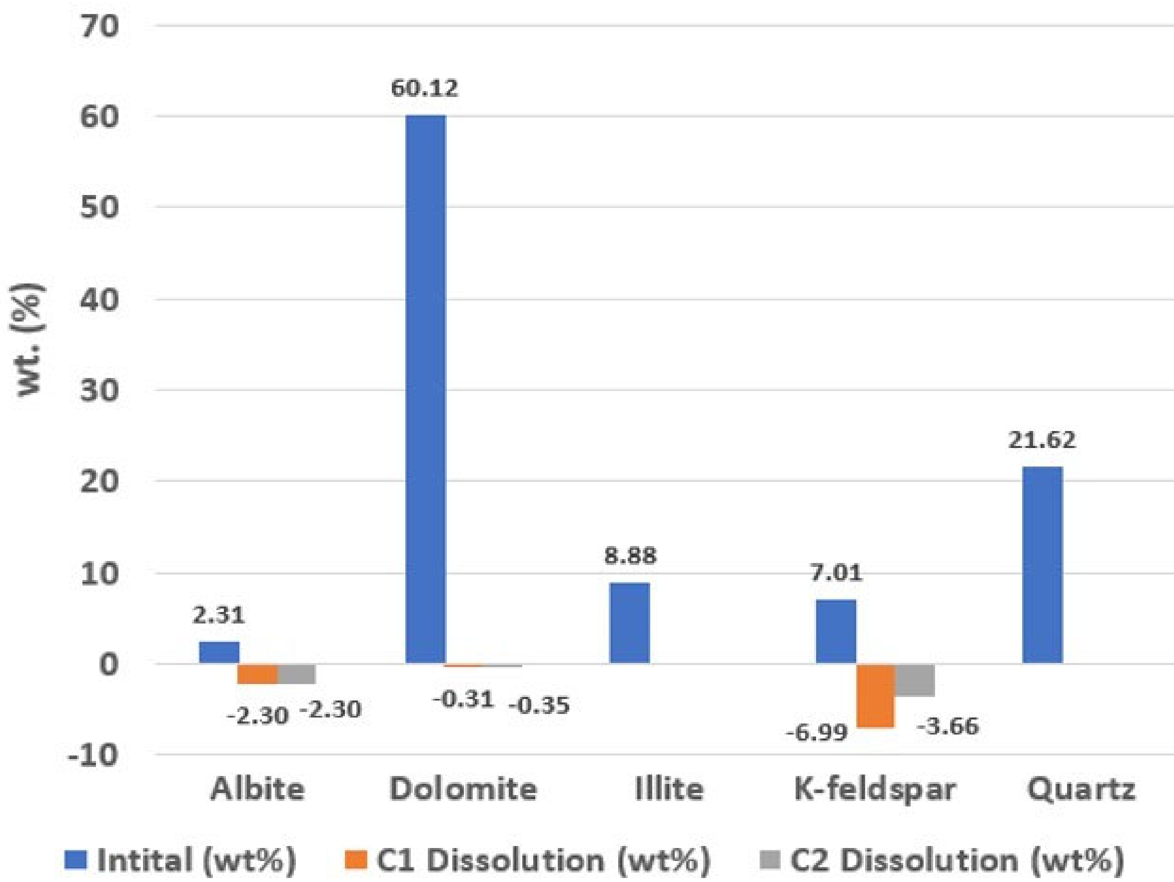



Figure 2-53. Weight percentage (wt%) of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time. Negative values represent total wt%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

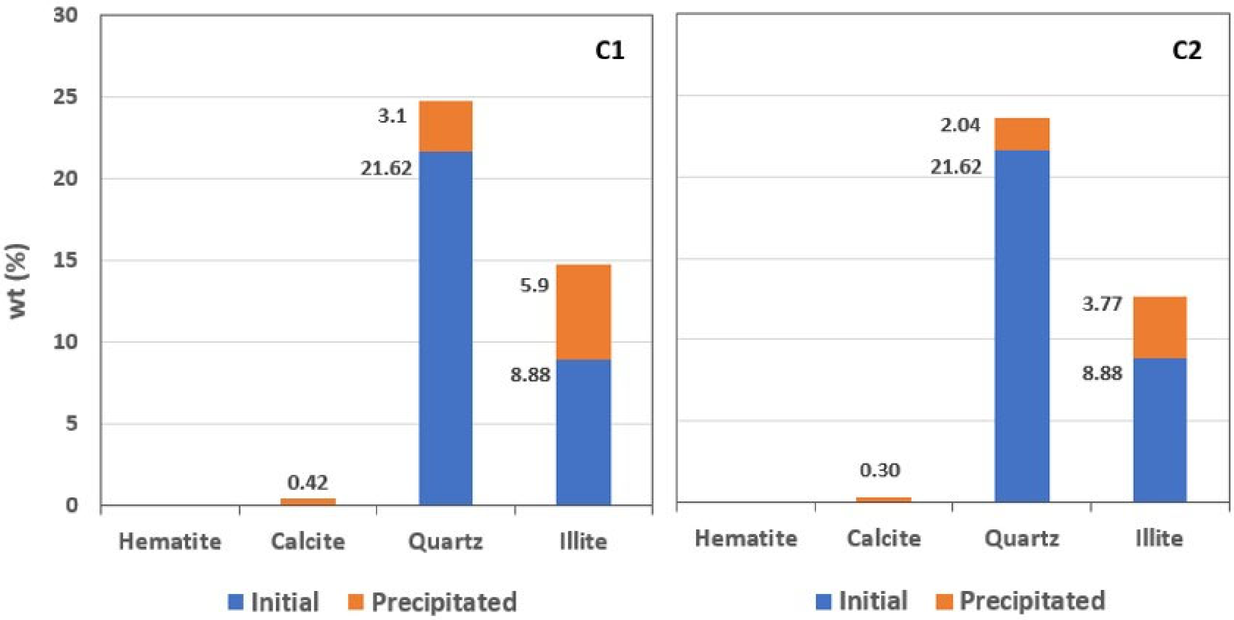



Figure 2-54. Weight percentage (wt.%) of initial (blue) and precipitated (orange) minerals in the C1 (left) and C2 (right) normalized based on total solid (initial – dissolution + precipitation) present in the C1 and C2 after 20 years of injection and 25 years of postinjection. Hematite precipitation in C1 and C2 is too small to see in the figure.

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

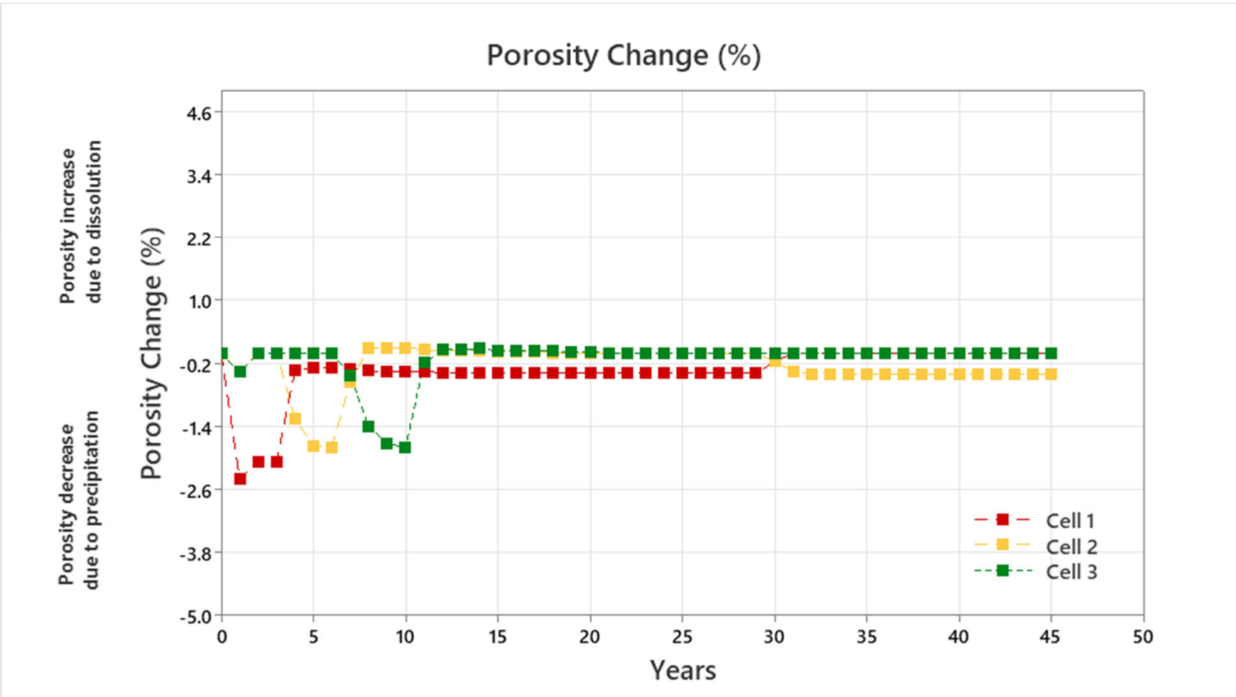



Figure 2-55. Change in percent porosity in the Amsden Formation underlying confining layer. Red line shows porosity change for Cell C1, 0 to 1 meter below the Amsden Formation top. Yellow line shows Cell C2, 1 to 2 meters below the Amsden Formation top. Green line shows Cell C3, 2 to 3 meters below the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

### *2.4.4 Geomechanical Information of Confining Zone*

#### *2.4.4.1 Borehole Image Fracture Analysis*

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

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

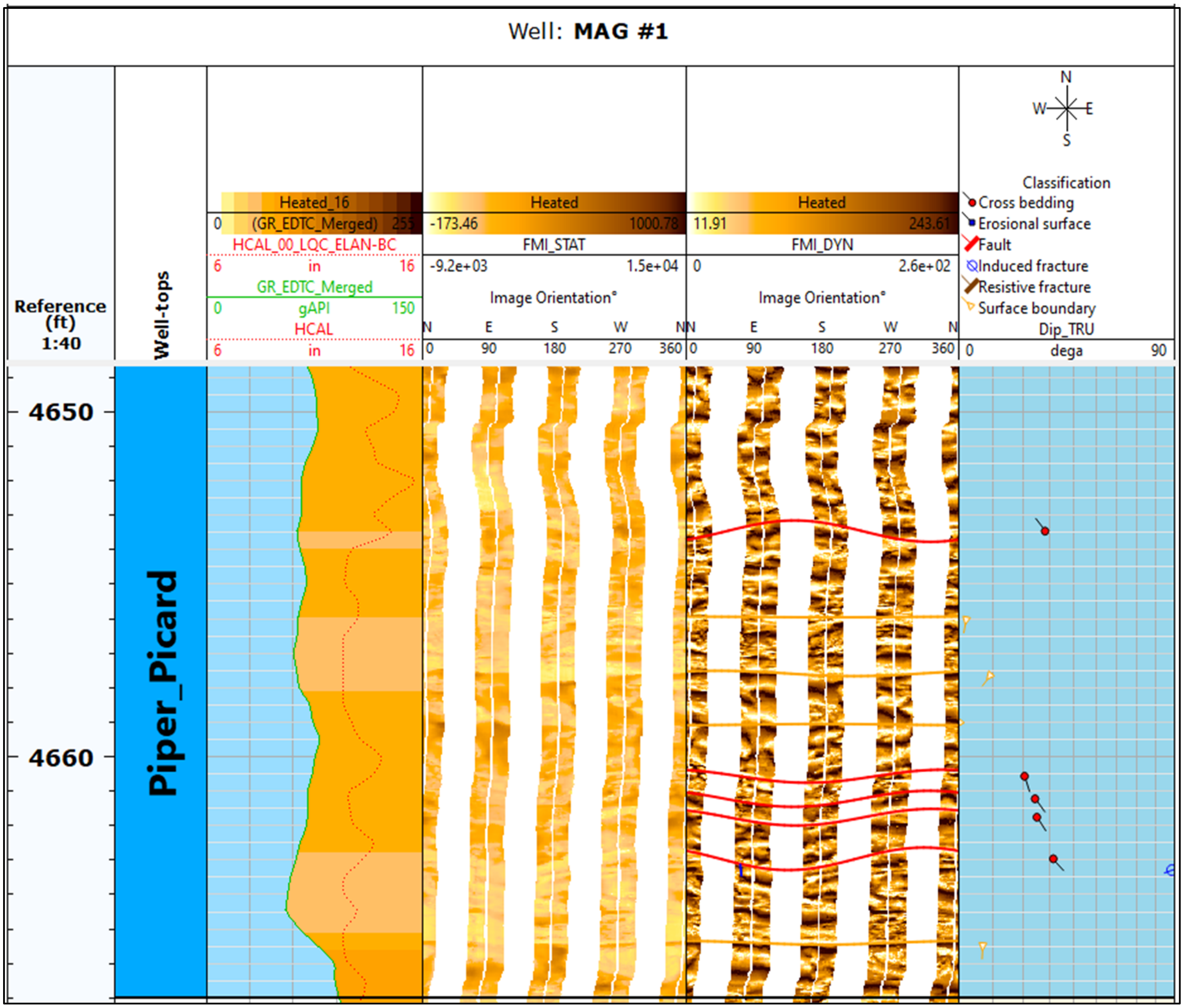



Figure 2-56a. Examples of the interpreted FMI log for the MAG 1 well showing one of the drilling induced fractures observed in the Piper Formation.

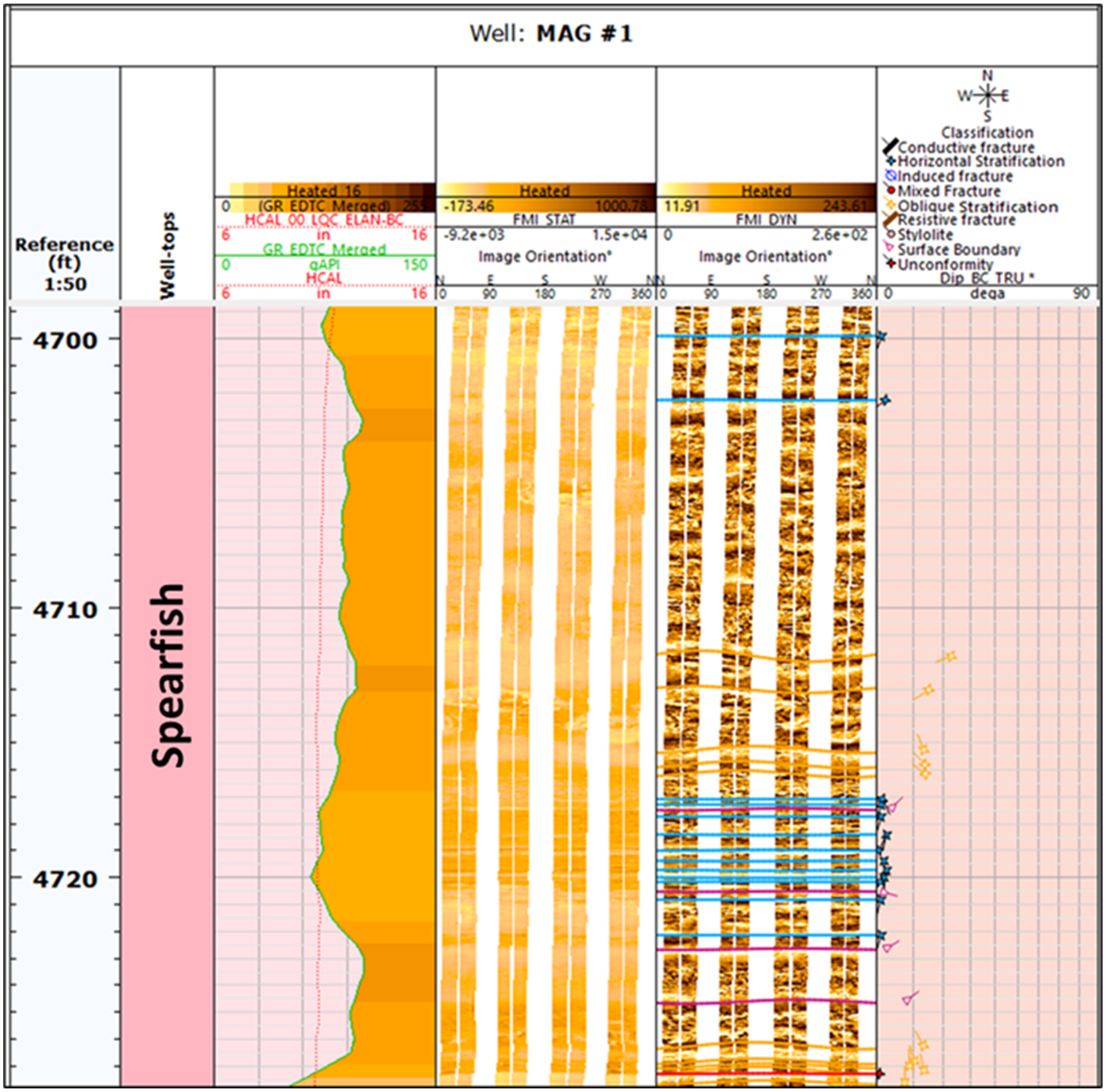



Figure 2-56b. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Spearfish Formation FMI image analysis.

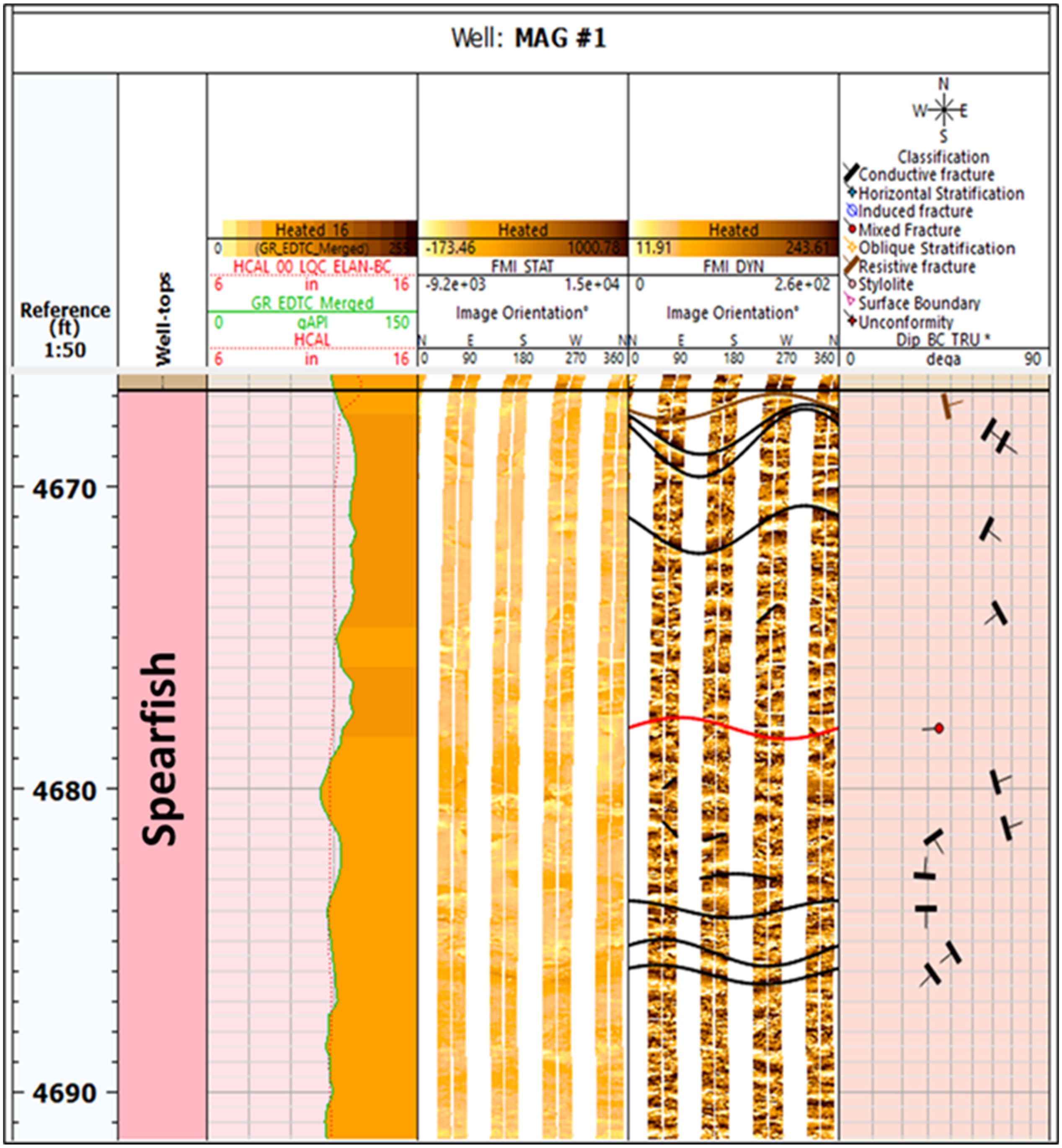



Figure 2-57. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, resistive fracture, mixed fracture, horizontal stratification, and oblique stratification) seen in Spearfish Formation FMI image analysis.

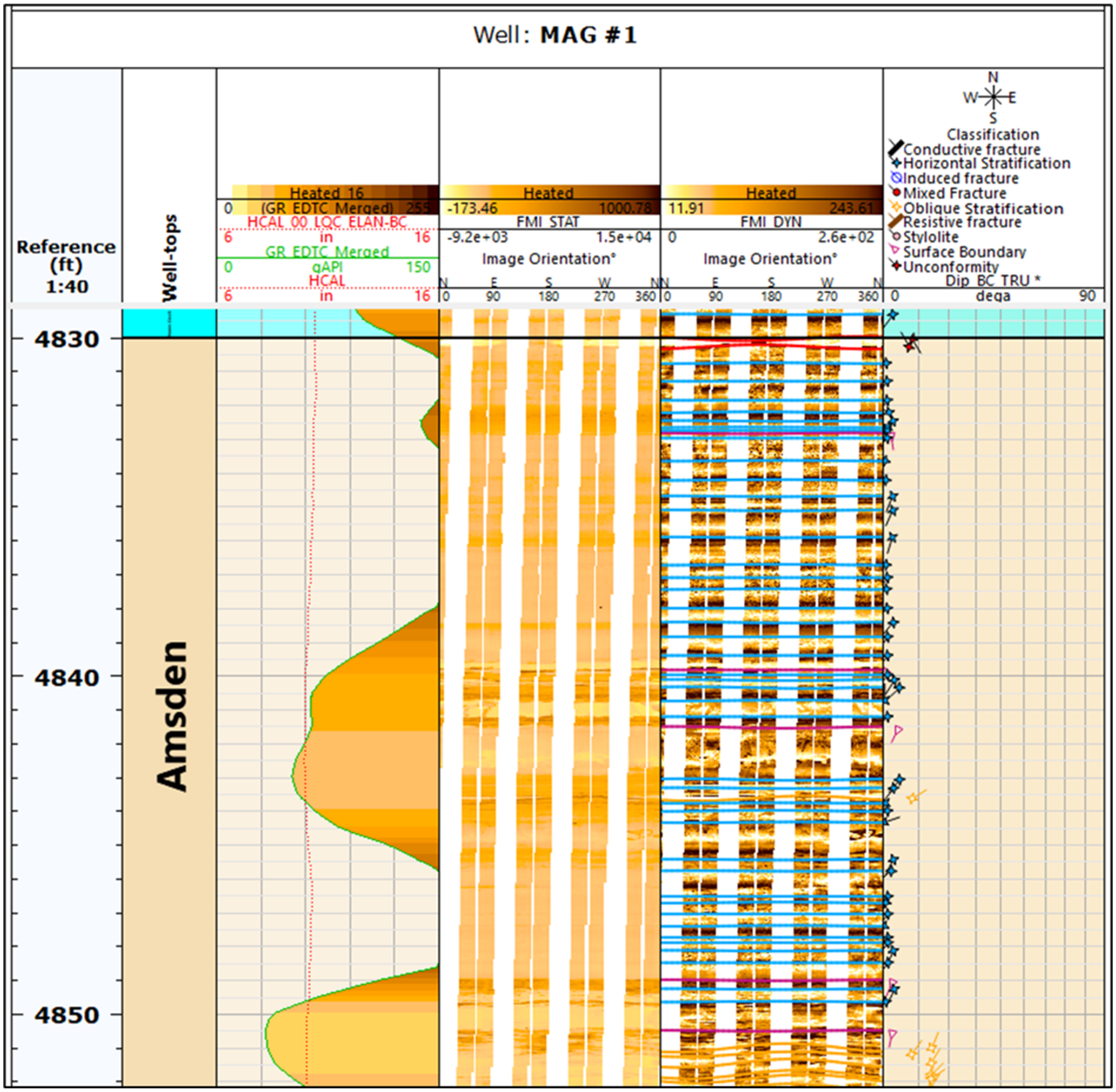



Figure 2-58. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis.

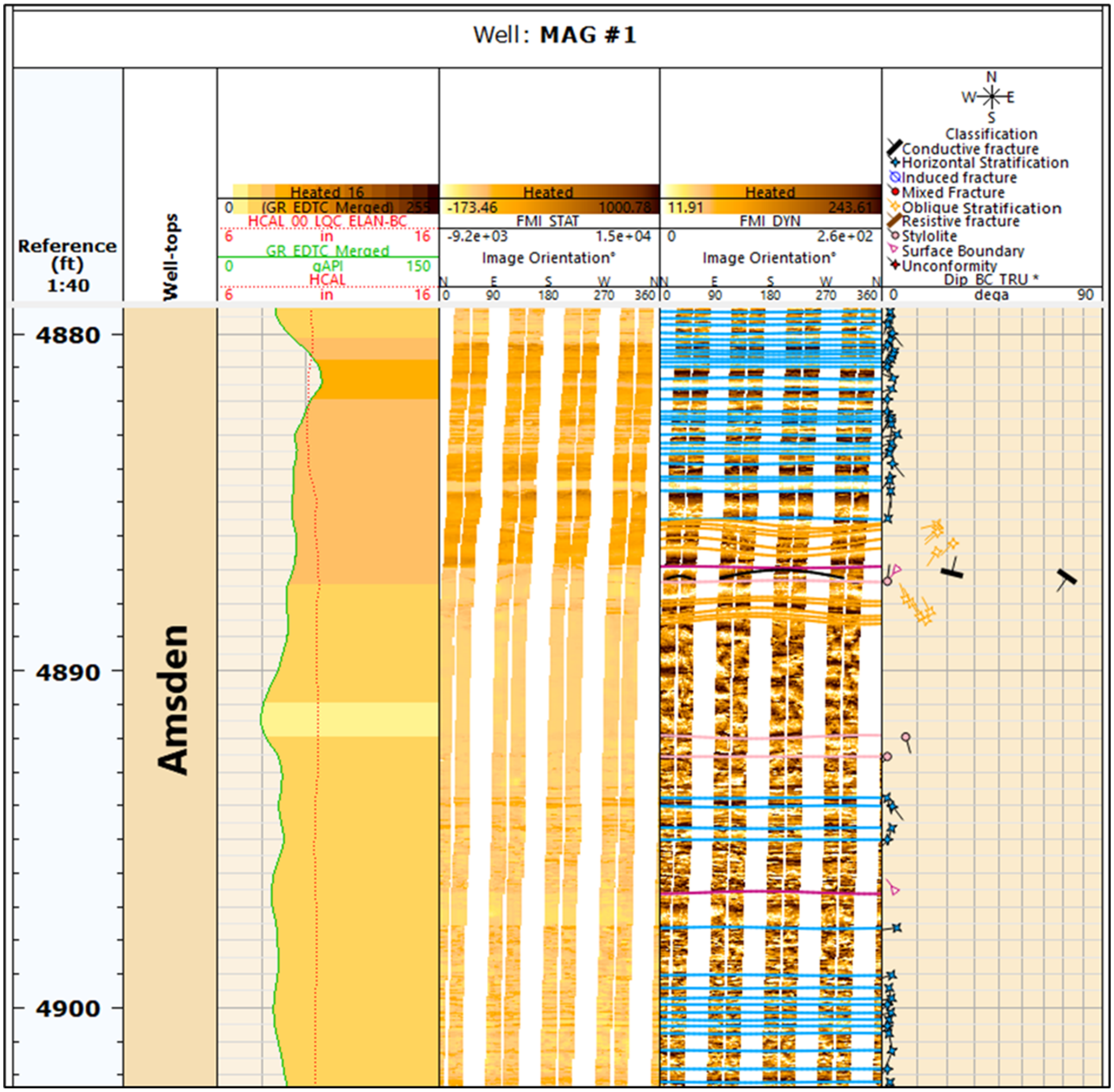



Figure 2-59. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, stylolites, horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis.

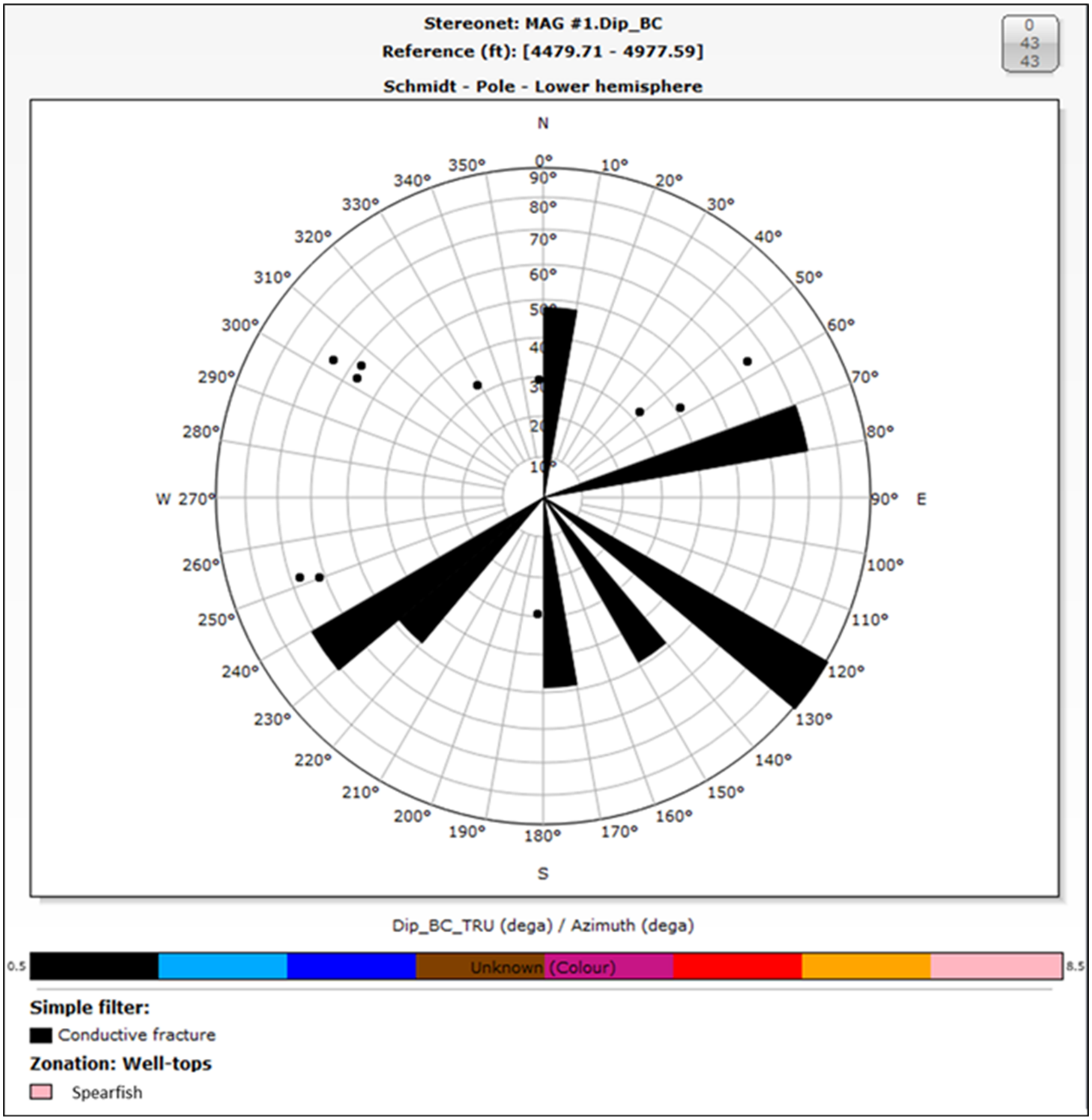



Figure 2-60. This example shows the dip azimuth and dip angle for conductive fractures seen in the Spearfish Formation.

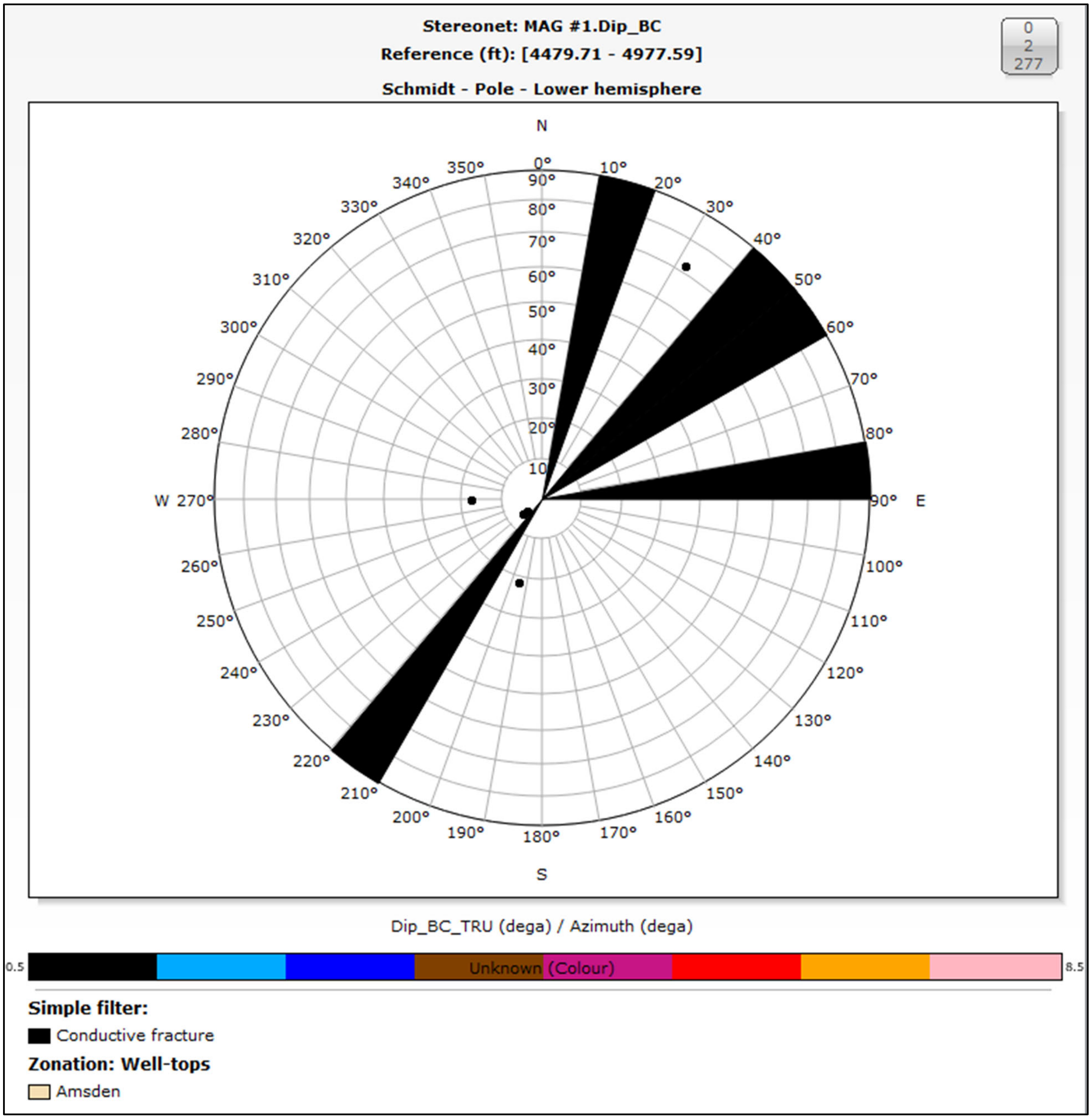



Figure 2-61. This example shows the dip azimuth and dip angle for conductive fractures seen in the Amsden Formation.

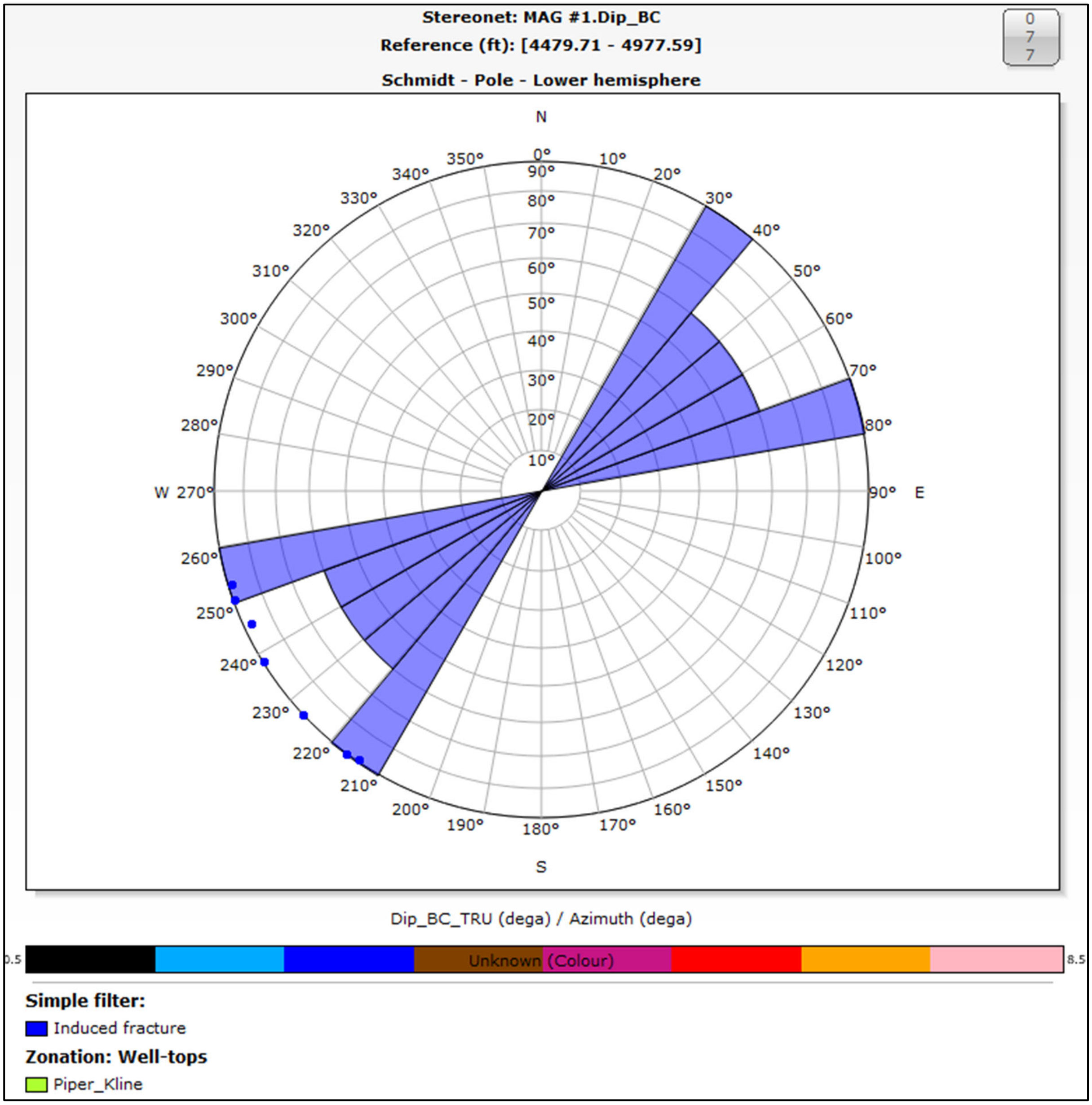



Figure 2-62. This example shows the orientation of drilled-induced fractures in the Piper Formation.

### *2.4.4.2 Stress, Ductility and Rock Strength*

A 1D MEM was derived using the log data from MAG 1 well. Logs were edited to account for washouts in the Broom Creek and Amsden Formation sections using multilinear regressions. Geomechanical parameters in the Spearfish, Broom Creek, and Amsden Formations were estimated using the 1D MEM. The 1D MEM was used to estimate the vertical stress, pore pressure, minimum and maximum horizontal stresses (Shmin, SHmax), Poisson's ratio, Young's modulus,

shear and bulk moduli, tensile, uniaxial compressive strength, and friction angle (Figure 2-63, Figure 2-64, and Figure 2-65). Table 2-19 shows the average and range of elastic and dynamic parameters, and stresses in the Spearfish, Broom Creek, and Amsden Formations.

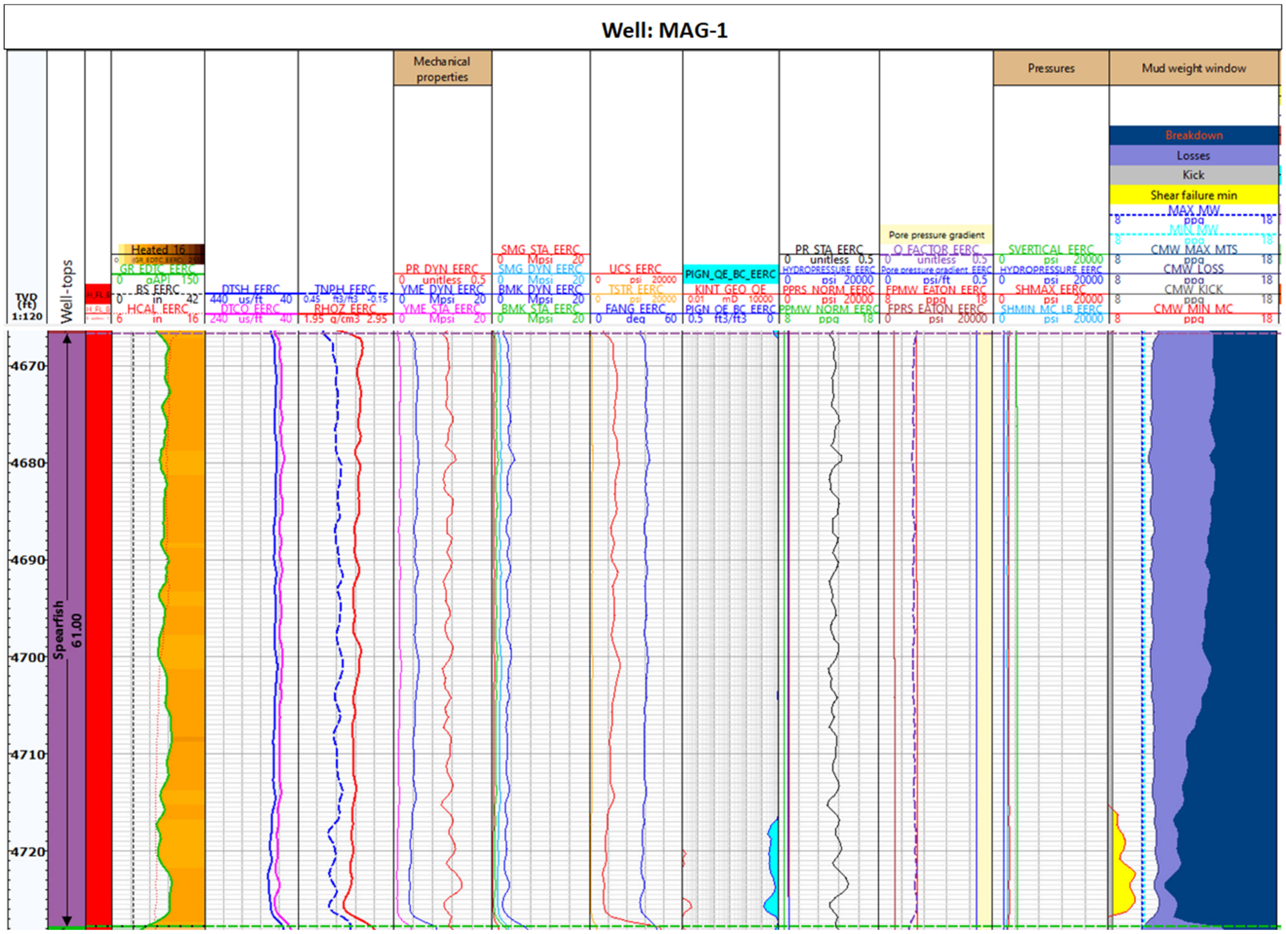



Figure 2-63. Geomechanical parameters in the Spearfish Formation. Track 1, bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, and dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static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

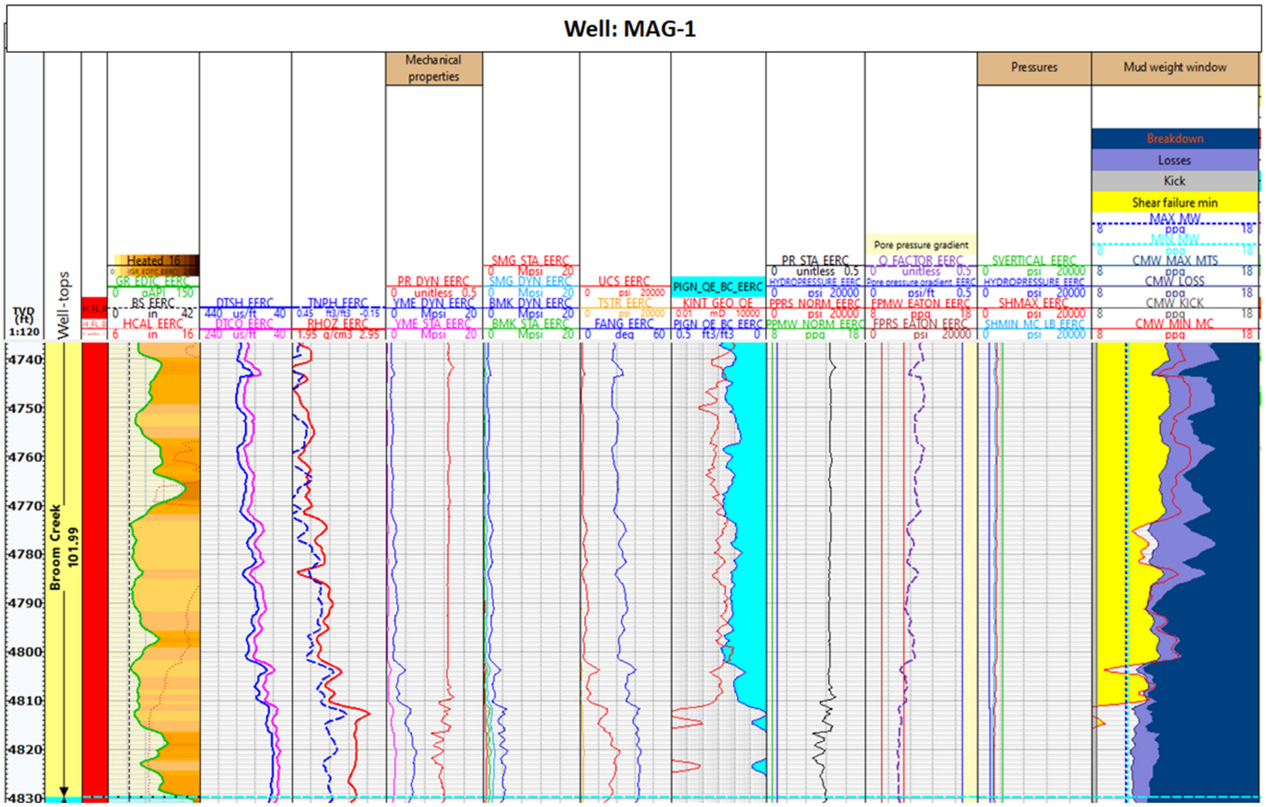



Figure 2-64. Geomechanical parameters in the Broom Creek Formation. Track 1, bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static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

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

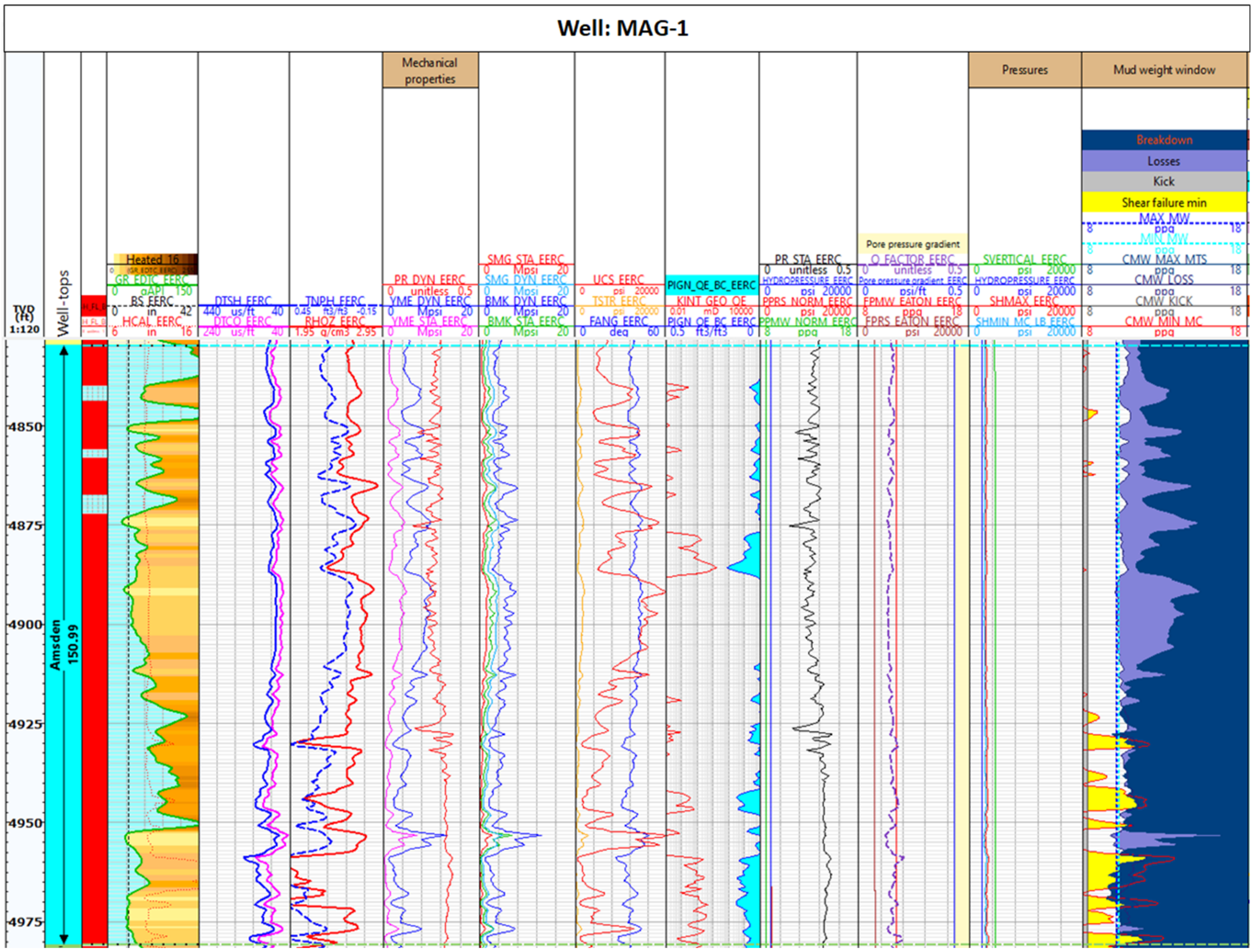



Figure 2-65. Geomechanical parameters in the Amsden Formation. Track 1, Bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static bulk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

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

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

Log data were used to characterize stress in the storage complex to determine the fracture pressure gradient. In the injection zone, the parameters used to calculate stress were determined from the sand intervals in the Broom Creek Formation section. Rock strength defines the limit at which the stress conditions might induce the rock to mechanically fail. The unconfined compressive strength can be determined directly from rock mechanics tests, but in the MAG 1 well case, it was empirically estimated from well log data. Poisson's ratio was estimated using the available well logs, which resulted in an average value for the Broom Creek Formation of 0.313. The Biot factor was calculated using the effective porosity, static bulk modulus, and permeability, resulting in a range of 0.89-1. The pore pressure and hydropressure gradient were estimated using the true vertical depth (TVD), vertical stress (Sv), compressional slowness, and compressional velocity, respectively. The pore pressure and hydropressure gradients are equal to 0.448 and 0.429 psi/ft, respectively. In situ stresses such as Sv, maximum horizontal stress (SHmax), and minimum horizontal stress (Shmin) were calculated using specific parameters and methods (Table 2-20). Sv, which is related to the overburden or lithostatic pressure, is an important parameter in geomechanical modeling. In the Broom Creek Formation, overburden pressure was estimated through the bulk density log to the surface using the extrapolation method, resulting in an overburden gradient of 0.911 psi/ft. The poroelastic horizontal strain model is the most used method for horizontal stress calculation. The poroelastic horizontal strain model can be expressed using static Young's modulus, Poisson ratio, Biot's constant, overburden stress, and pore pressure. The poroelastic horizontal strain model was used to estimate the minimum horizontal stress (Plumb and Hickman, 1985; Aadnoy, 1990; Aadnoy and Bell, 1998; Brudy and Zoback, 1999). The SHmax is estimated from Shmin and process zone stress (as function of porosity). Based on the calculated stresses, the stress regime that can be seen in the Spearfish, Broom Creek, and Amsden Formations is a normal stress regime where Sv > SHmax > Shmin. Shmin magnitude could not be calibrated using the closure pressure measurements obtained from the openhole MDT microfracture in situ stress test because it was not performed in the MAG 1 well because of the large washout in the vicinity of the intervals of interest. The fracture gradient (FG) is calculated from pore pressure and overburden gradient. With the absence of closure pressure measurements

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

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

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

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

Where:

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

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

Where:

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

### 2.5 Faults, Fractures, and Seismic Activity

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

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

### *2.5.1 Stanton Fault*

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

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

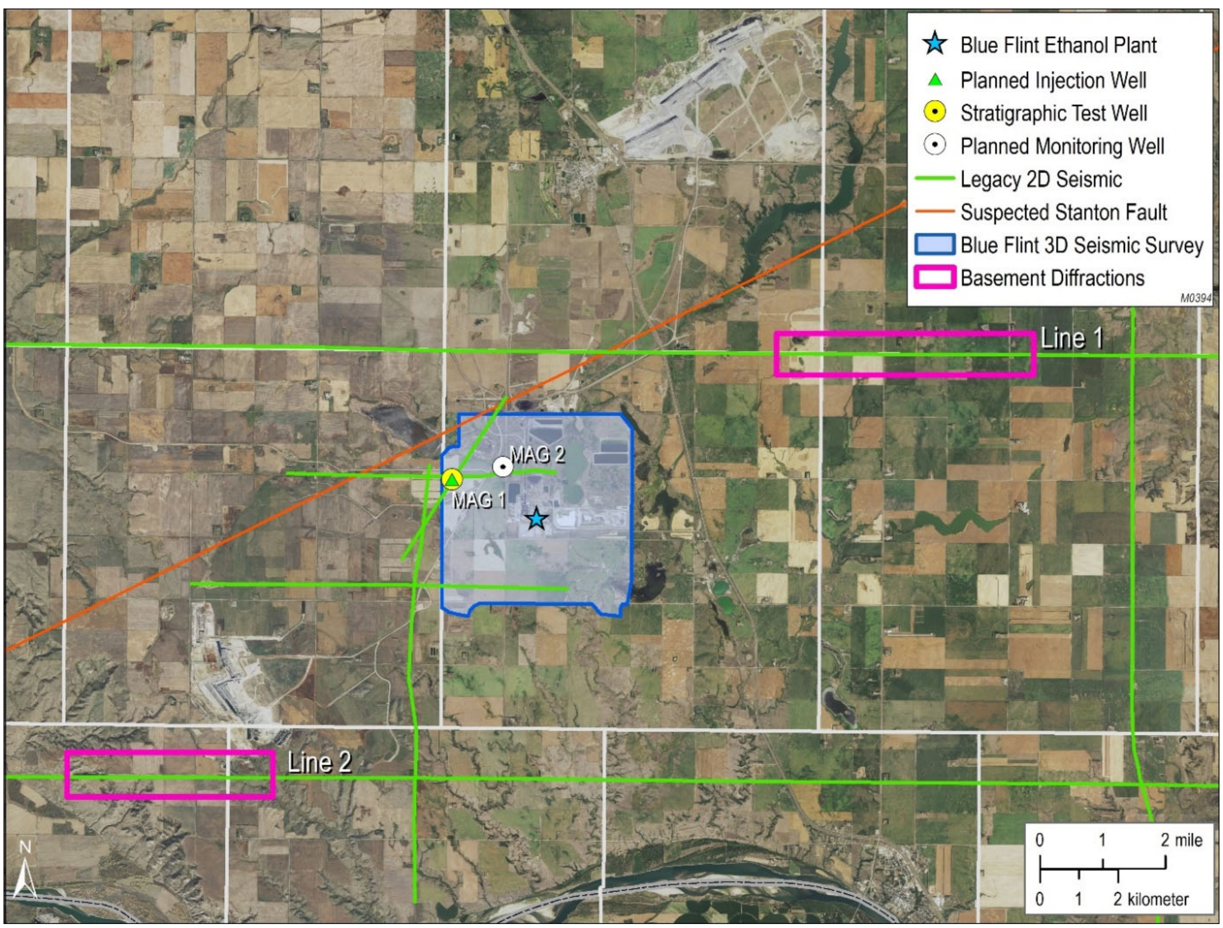



Figure 2-66. Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016).

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

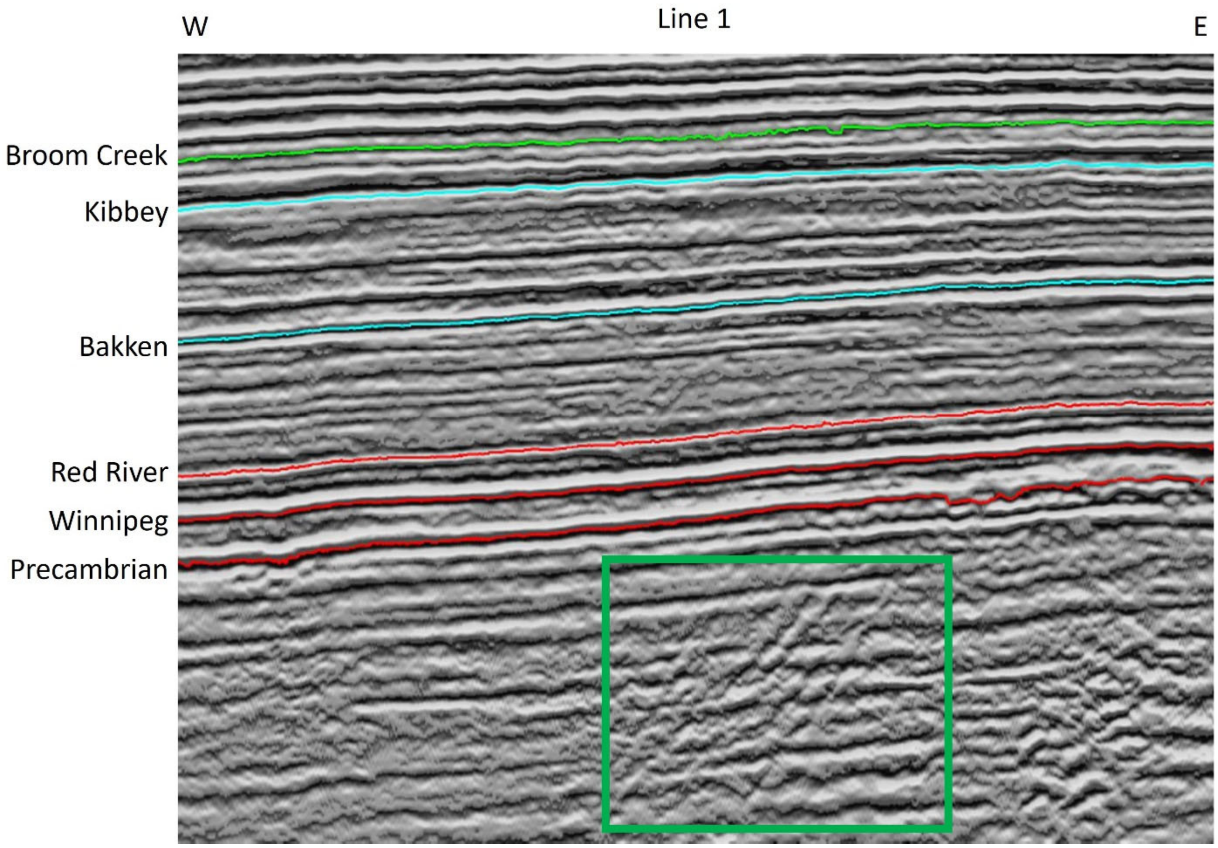



Figure 2-67. Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box).

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

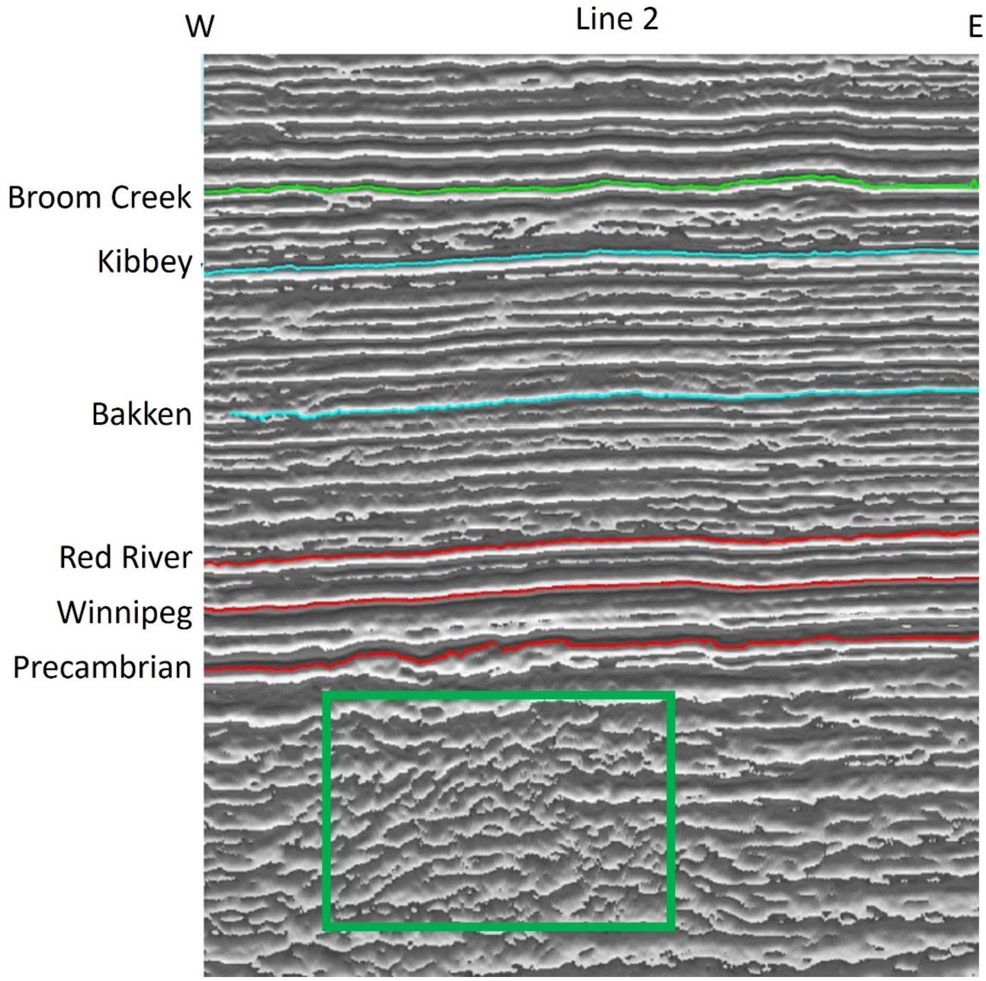



Figure 2-68. Cross section of Line 2 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box).

### *2.5.2 Seismic Activity*

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

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

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

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

* Estimated depth.

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

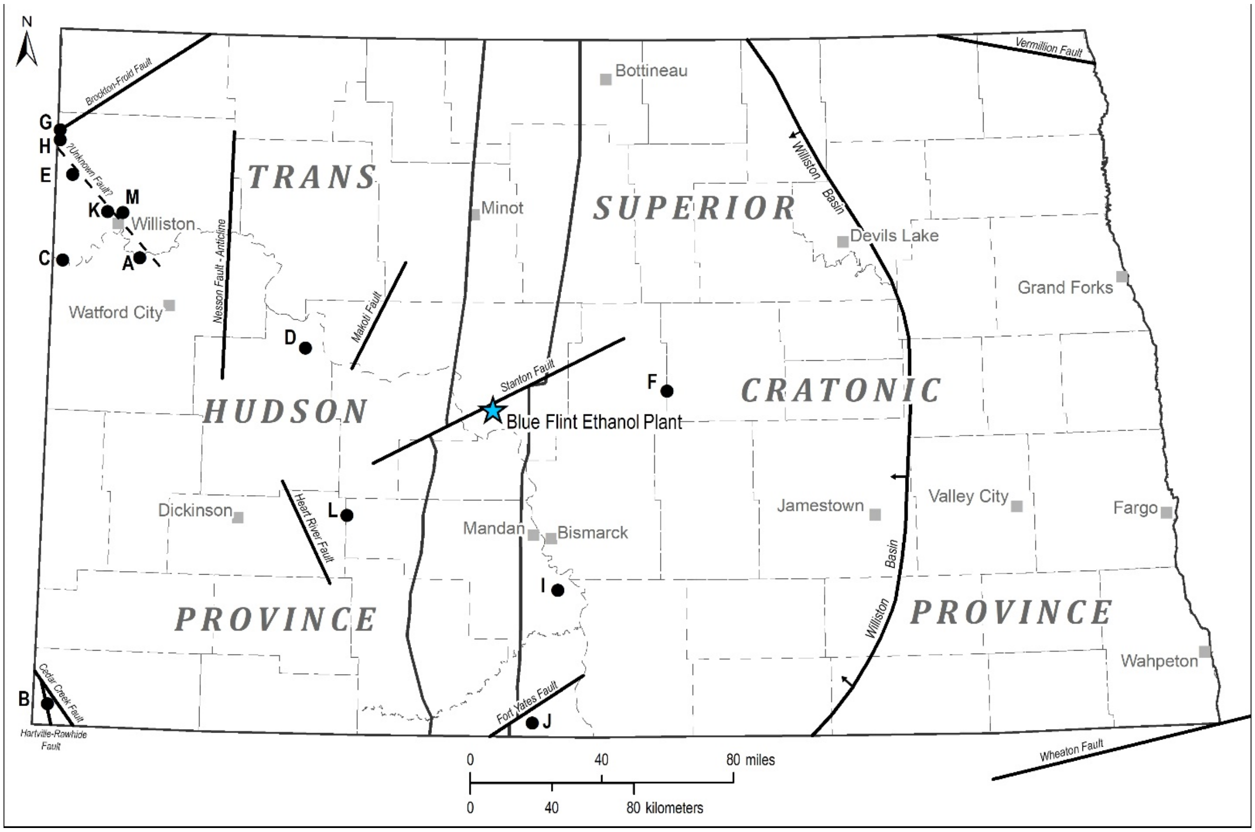



Figure 2-69. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-21.

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

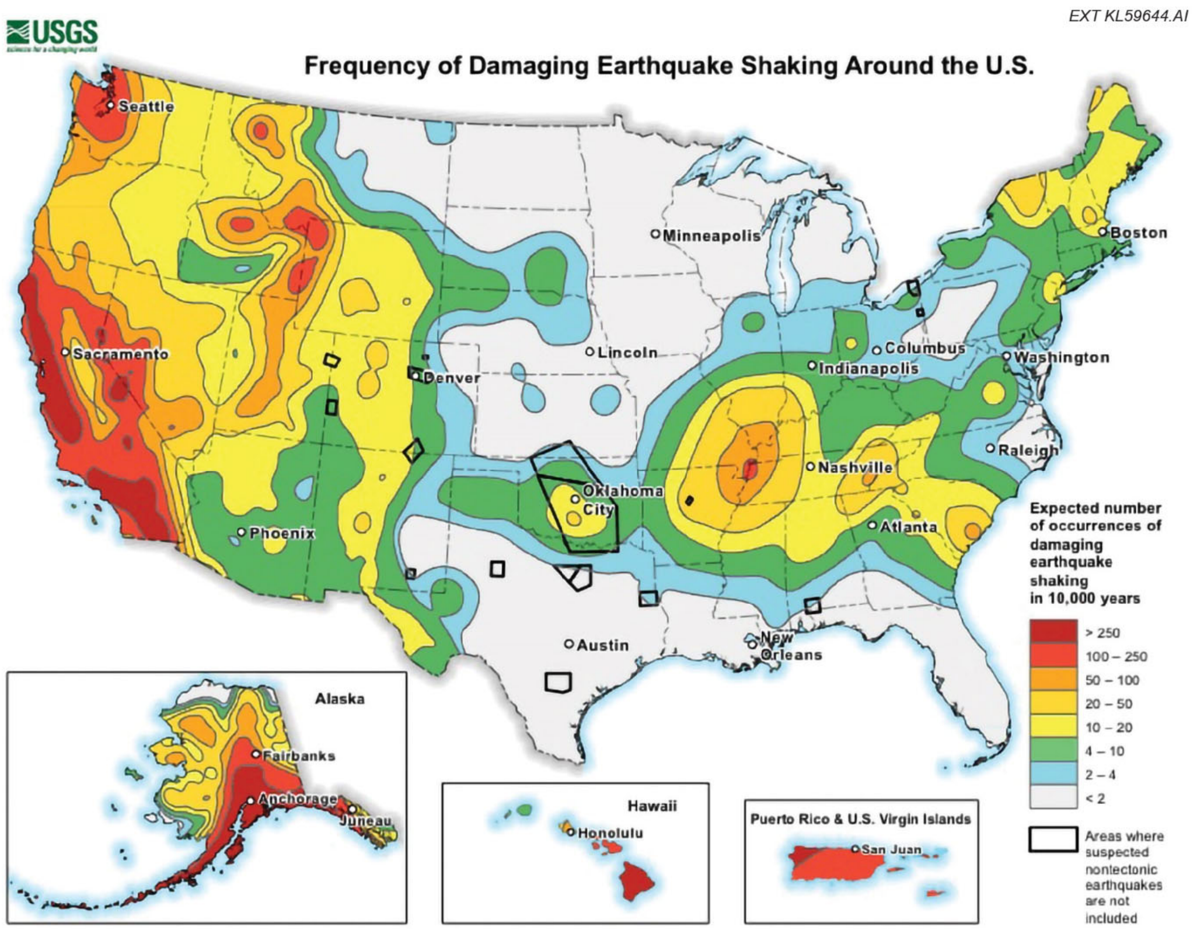



Figure 2-70. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

## 2.6 Potential Mineral Zones

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

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a horizontal well could be used to produce the hydrocarbon while avoiding drilling through the $CO_2$ plume, or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available while the MAG 1 well is in operation, which will allow prospective operators to design an appropriate well control strategy via increased

drilling mud weight. Pressure increase in the Broom Creek caused by injection of $CO_2$ will relax postinjection as the area returns to its preinjection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the $CO_2$ should be designed to include an intermediate casing string placed across the storage reservoir, with $CO_2$-resistant cement used to anchor the casing in place.

Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC § 57-51-01(11)) define a shallow gas zone as gas produced from a zone that consists of "strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation [Jurassic], from which gas may be produced."

Lignite coal is currently mined at the Falkirk Mine, operated by the Falkirk Mining Company, a wholly owned subsidiary of North American Coal Corporation, which is located within the project area. The Falkirk Mine produces from the Hagel coal seam for power generation feedstock at Rainbow Energy's Coal Creek Station. The Hagel coal seam is the lowermost major lignite present in the area in the Sentinel Butte Formation (Figure 2-71).

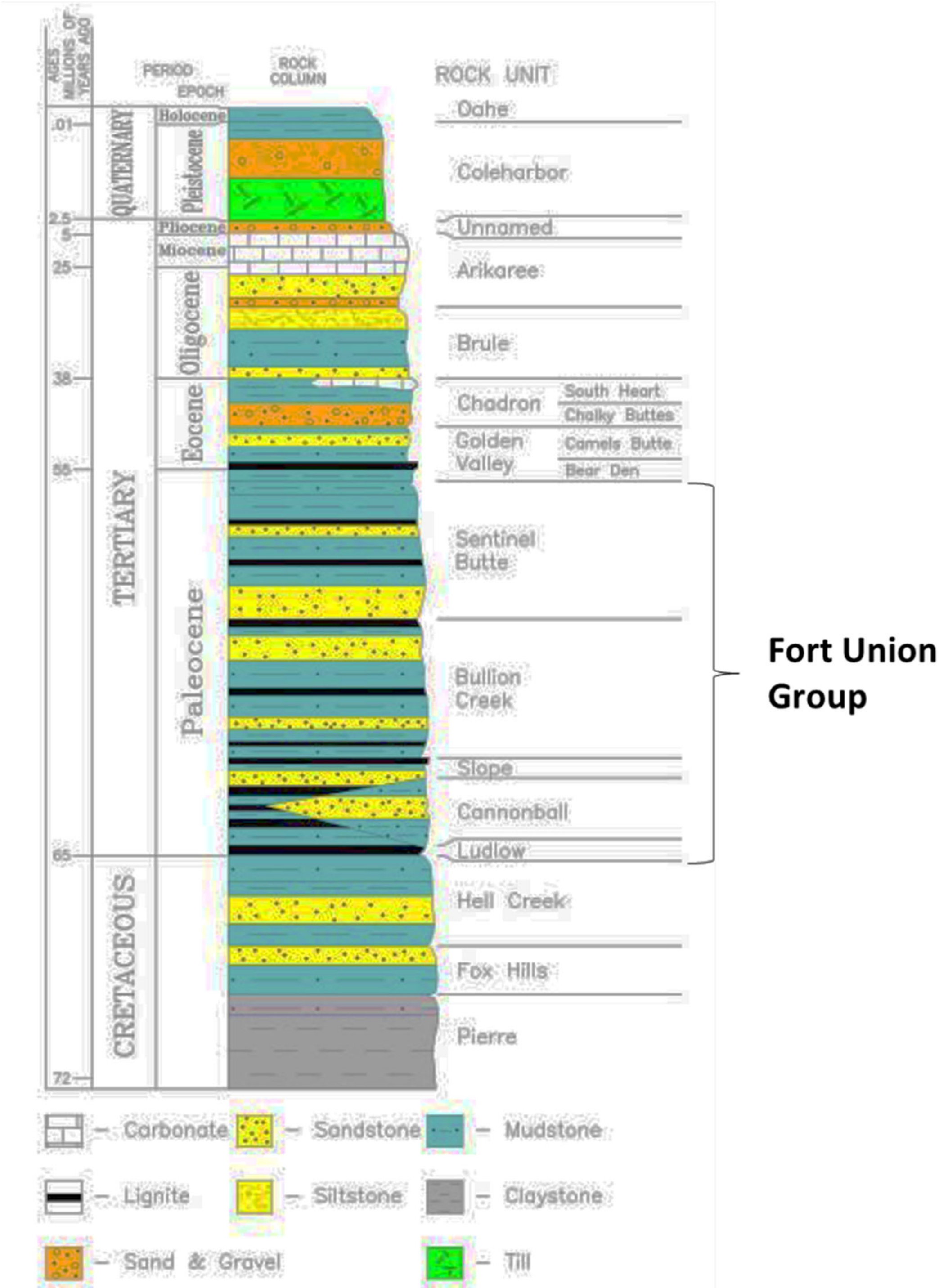



Figure 2-71. Coal beds of the Forth Union Group including the Sentinel Butte and Bullion Creek (Tongue River) Formations showing the lignite coals in western North Dakota (Murphy, 2006).

The Hagel coal seam is divided into two seams: the Hagel A and the Hagel B. The Hagel A lignite bed averages 5.7 ft thick with a range from 0.5 to 11.5 ft. The Hagel B bed has a mean thickness of approximately 1.8 ft, ranging in thickness from 0.5 to 6.3 ft. (Figure 2-72) (Zygarlicke and others, 2019). Coal seams in the Bullion Creek Formation exist in the area below the Hagel seam (Figure 2-71) but are too deep to be economically mined.

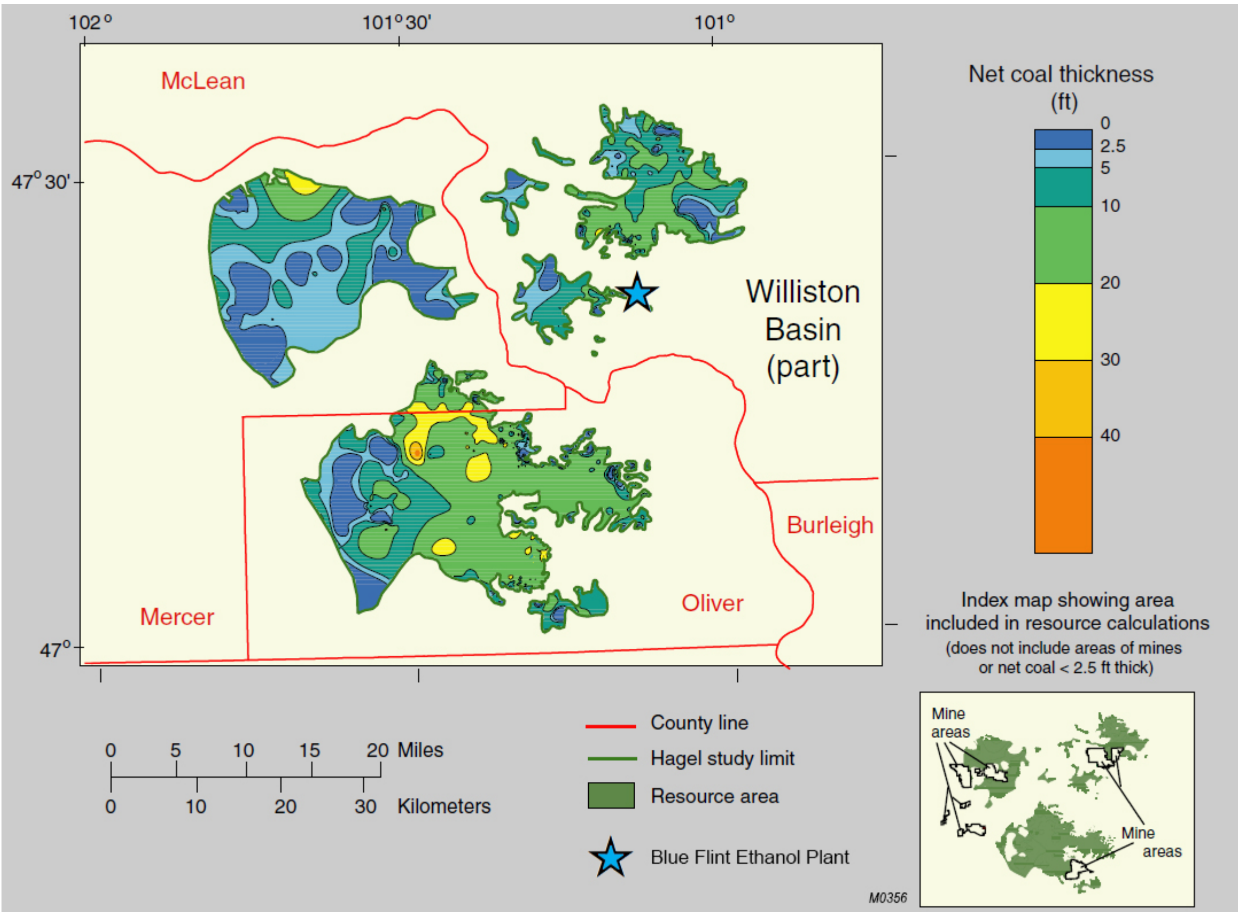



Figure 2-72. Hagel net coal isopach map (modified from Ellis and others, 1999).

## 2.7 References

Aadnoy, B.S., 1990, Inversion technique to determine the in-situ stress field from fracturing data: Journal of Petroleum Science and Engineering, v. 4, no. 2, p. 127–141.

Aadnoy, B.S., and Bell, J.S., 1998, Classification of drilling-induced fractures and their relationship to in-situ stress directions: The Log Analyst, v. 39, no. 6, p. 27–42.

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

Brudy, M., and Zoback, M.D, 1999, Drilling-induced tensile wall-fractures: implications for determination of in-situ stress orientation and magnitude: International Journal of Rock

Mechanics and Mining Sciences, v. 36, no. 2, p. 191–215. doi:10.1016/s0148-062(98)00182 -x.

Carlson, C.G., 1993, Permian to Jurassic redbeds of the Williston Basin: North Dakota Geological Survey Miscellaneous Series 78, 21 p.

Downey, J.S., 1986, Geohydrology of bedrock aquifers in the northern Great Plains in parts of Montana, North Dakota, South Dakota and Wyoming: U.S. Geological Survey Professional Paper 1402-E, 87 p.

Downey, J.S., and Dinwiddie, G.A., 1988, The regional aquifer system underlying the northern Great Plains in parts of Montana, North Dakota, South Dakota, and Wyoming—summary: U.S. Geological Survey Professional Paper 1402-A.

Ellis, M.S., Gunther, G.L., Ochs, A.M., Keighin, C.W., Goven, G.E., Schuenemeyer, J.H., Power, H.C., Stricker, G.D., and Blake, D., 1999, Coal resources, Williston Basin: U.S. Geological Survey Professional Paper 1625-A, Chapter WN.

Espinoza, D.N., and Santamarina, J.C., 2017, $CO_2$ breakthrough—caprock sealing efficiency and integrity for carbon geological storage: International Journal of Greenhouse Gas Control, v. 66, p. 218–229.

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

Glazewski, K.A., Grove, M.M., Peck, W.D., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2015, Characterization of the PCOR Partnership Region: Plains $CO_2$ Reduction (PCOR) Partnership topical report for U.S. Department of Energy and multiclients, Grand Forks, North Dakota, Energy & Environmental Research Center, January.

Murphy, E.C., 2006, The lignite reserves of North Dakota: North Dakota Geological Survey, Report of Investigation No. 104.

Murphy, E.C., Nordeng, S.H., Juenker, B.J., and Hoganson, J.W., 2009, North Dakota stratigraphic column, E.C. Murphy and L.D. Helms, Eds., North Dakota Geological Survey, Bismarck, North Dakota.

North Dakota Industrial Commission, 2022, Overview of petroleum geology of the North Dakota Williston Basin: www.dmr.nd.gov/ndgs/resources/ (accessed July 2022).

North Dakota Industrial Commission, 2021a, NDIC Case No. 29029 – draft permit, fact sheet, and storage facility permit application: Minnkota Power Cooperative supplemental information, Grand Forks, North Dakota, www.dmr.nd.gov/oilgas/C29029.pdf (accessed July 2022).

North Dakota Industrial Commission, 2021b, NDIC Case No. 29032 – draft permit, fact sheet, and storage facility permit application: Minnkota Power Cooperative supplemental information, Grand Forks, North Dakota, www.dmr.nd.gov/oilgas/C29032.pdf (accessed July 2022).

North Dakota Industrial Commission, 2021c, NDIC Case No. 28848 – draft permit, fact sheet, and storage facility permit application: Red Trail Ethanol, LLC, supplemental information, www.dmr.nd.gov/oilgas/C28848.pdf (accessed July 2022).

Nowakowski, A., 2005, The static and dynamic elasticity constants of sandstones and shales from the hard coal mine "Jasmos" determined in the laboratory conditions, *in* Eurock 2005 – impact of human activity on the geologic environment: Konecy, Taylor & Francis Group, London, Eds.

Peck, W.D., Liu, G., Klenner, R.C.L., Grove, M.M., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2014, Storage capacity and regional implications for large-scale storage in the basal Cambrian system: Plains $CO_2$ Reduction (PCOR) Partnership Phase III Task 16 Deliverable D92 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2014-EERC-05-12, Grand Forks, North Dakota, Energy & Environmental Research Center, https://edx.netl.doe.gov/dataset/storage-capacity-and-regional-implications-for-large-scale-storage-in-the-basal-cambrian-system (accessed 2022).

Plumb, R.A., and Hickman, S.H., 1985, Stress-induced borehole elongation—a comparison between the four-arm dipmeter and the borehole televiewer in the Auburn Geothermal Well: Journal of Geophysical Research Atmospheres, v. 90, p. 5513–5521.

Rygh, M.E., 1990, The Broom Creek Formation (Permian), in southwestern North Dakota—depositional environments and nitrogen occurrence [Master's Thesis]: University of North Dakota, Grand Forks, North Dakota.

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

Tutuncu, A.N., and Sharma, M.M., 1992, Relating static and ultrasonic lab measurements to acoustic log measurements in tight gas sands: Presented at 67th SPE ATCE, Washington, D.C., October 1998. SPE-24689.

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

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

Yale, D.P., and Jamieson, W.H. Jr., 1994, Static and dynamic mechanical properties of carbonates, *in* Rock Mechanics – Models and Measurements Challenges from Industry: Nelson and Laubach, Eds., Balkema, Rotterdam.

Yale, D.P., and Walters, D.A., 2016, Integrated, logbased, anisotropic geomechanics analysis in unconventional reservoirs: Presented at SPE Unconventional Reservoir Fracturing Workshop, Muscat, Oman, February 2016.

Yale, D.P., Nieto, J.A., and Austin, S.P., 1995, The effect of cementation on the static and dynamic mechanical properties of the Rotliegendes sandstone, *in* Rock Mechanics – Proceedings of the 35th U.S. Symposium: Daemen and Schultz, Eds., Balkema, Rotterdam.

Zhang, J.J., and Bentley, L.R., 2005, Factors determining Poisson's ratio: CREWES Research Report, v. 17.

Zhang, J., and Yin. S.-X., 2017, Fracture gradient prediction—an overview and an improved method: Petroleum Science, v. 14, no. 4, p. 720–730. DOI 10.1007/s12182-017-0182-1.

Zhou, X.J., Zeng, Z., and Belobraydic, M., 2008, Geomechanical stability assessment of Williston Basin Formations for petroleum production and $CO_2$ sequestration: Presented at the 42nd U.S. Rock Mechanics Symposium and 2nd U.S.–Canada Rock Mechanics Symposium, San Francisco, California, June 29 – July 2, 2008.

Dynamic and static elastic properties were estimated for the Spearfish, Broom Creek and Amsden Formations using a one-dimensional Mechanical Earth Model (1D MEM). The 1D MEM was constructed using Schlumberger's Techlog software and geophysical well log data from the MAG 1 well. Techlog uses the following equations to derive the dynamic and static elastic properties.

1. **Dynamic / Static Young Modulus:**

$$E_{dyn} = \frac{\rho}{DTs^2} * \frac{3 * DTs^2 - 4 * DTp^2}{DTs^2 - DTp^2} * 1.34 * 10^{10}(psi) * 10^{-6} * 6.895\ (Gpa) \tag{1}$$

$$E_{stat} = 0.414 * E_{dyn} - 1.05 \tag{2}$$

where DTp is the compressive slowness and DTs is the shear slowness.

2. **Poisson's Ratio**

$$\upsilon = 0.5 * \frac{DTs^2 - 2 * DTp^2}{DTs^2 - DTp^2} \tag{3}$$

The dynamic and static Poisson's ratios are almost equal.

3. **Shear Modulus**

$$G_{dyn} = \frac{E_{dyn}}{2(1 + \upsilon)} \tag{4}$$

4. **Bulk Modulus**

$$K_{dyn} = \frac{E_{dyn}}{3(1 - 2\upsilon)} \tag{5}$$

5. **Unconfined compressive strength (UCS)** Note: The Uniaxial Strain Modulus (P) label in Table 2-19 in the Blue Flint storage facility permit should be say unconfined compressive strength (UCS).

$$UCS = 4.424 * E_{stat} \tag{6}$$

**6. Friction angle**

$$FANG = 19 + 31.172\,(1 - \phi - V_{clay})^2 \quad (7)$$

where $\phi$ = porosity and $V_{clay}$ is clay volume

The fracture pressure gradient was calculated using Equation 1 and 2 in Section 2.4.4.2 of the Blue Flint storage facility permit. The following includes a list of equations used to derive the values for Biot coefficient, overburden gradient, and pore pressure that were used in the calculation of fracture pressure gradient.

**1. Biot coefficient (**$\alpha$)

For Biot coefficient, Mecpro Alpha model was used. The model estimates α by assuming that the skeleton (dry) bulk modulus is equal to the bulk modulus.

$$\alpha = 1 - \frac{K_{skeleton}}{K_{solid}} = 1 - \frac{K_{bulk}}{K_{solid}} \quad (8)$$

Where:

$K_{Bulk}$= Static bulk modulus.

$K_{solid}$ = Static solid bulk modulus.

$K_{skeleton}$ is used in model only for derivation and not for calculation.

**2. Overburden stress (Sv)**

For Sv, the Extrapolated Density Method shown below was used. Density is extrapolated up to mud line using the following geometric fit.

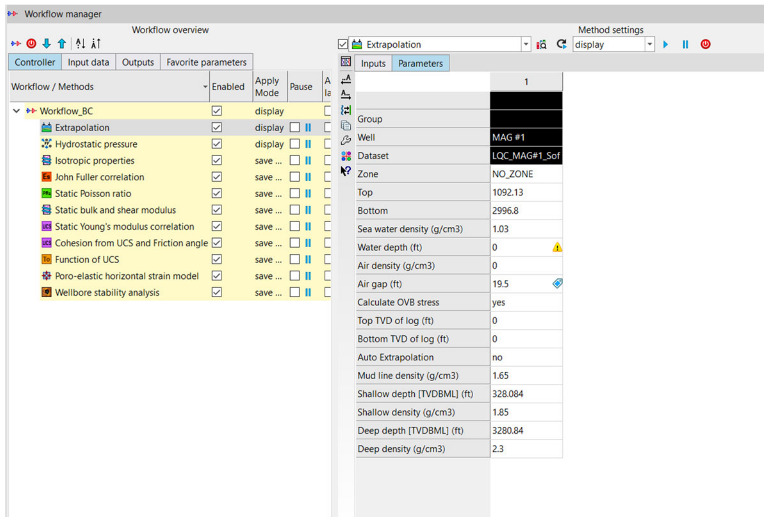
$$\rho_{extrapolated} = \rho_{mudline} + A_0 \times (TVD - \text{AirGap} - \text{WaterDepth})^{\alpha} \quad (9)$$

Where:

$\rho_{mudline}$ is the density at the sea floor or ground level.

$A_0$ and $\alpha$ are the fitting parameters. Techlog internally calculates the parameters based on the given input data.

Alternatively, you can provide the density values at the mud line and two points separated in depth ( $A$ and $B$ ), that is to say a total of 5 parameters since the mud line depth (ML) is known. These values are named Shallow depth ($A$) and Deep depth (B), as shown in the figure below:




Then the overburden can be calculated as follows:

$$S_v = \int_0^Z \rho(z) g dz \approx \rho_{extrapolated} \times gz$$

Where g is gravity and z is depth.

### 3. Minimum horizontal stress (Shmin)

For Shmin, the poro-elastic strain equation was used. To use this equation for Shmin, the two strain values are necessary: εH(maximum principal horizontal strain) and εh(minimum principal horizontal strain). εH = 0.001 and εh= 0.001 are used.

In the equation, α is Biot coefficient, σv is overburden and Pp is pore pressure.

Poro-Elastic Horizontal Strain Model is the most generally used method for horizontal stresses calculation.

Assuming flat-layered poro-elasticity deformation in the formation rock, a pair of particular constant strains, $\varepsilon_{SHMIN}$ and $\varepsilon_{SHMAX}$ are applied to the formation in the directions of minimum and maximum stress respectively. The Poro-Elastic Horizontal Strain Model can be expressed using Static Young's modulus Poisson ratio, Biot's constant, overburden stress, and pore pressure. You cannot directly measure $\varepsilon_{SHMIN}$ and $\varepsilon_{SHMAX}$ By adjusting these strains, you can calibrate the calculated stresses with the measured horizontal stresses at depth.

For a fluid saturated porous material that is assumed to be linear elastic and isotropic, considering anisotropic tectonic strain, the horizontal stresses ( $\sigma_h$ and $\sigma_H$ ) are equal to:

$$\sigma_h = \frac{v}{1-v}\sigma_v - \frac{v}{1-v}\alpha P_p + \alpha P_p + \frac{E}{1-v^2}\varepsilon_h + \frac{vE}{1-v^2}\varepsilon_H \tag{10}$$

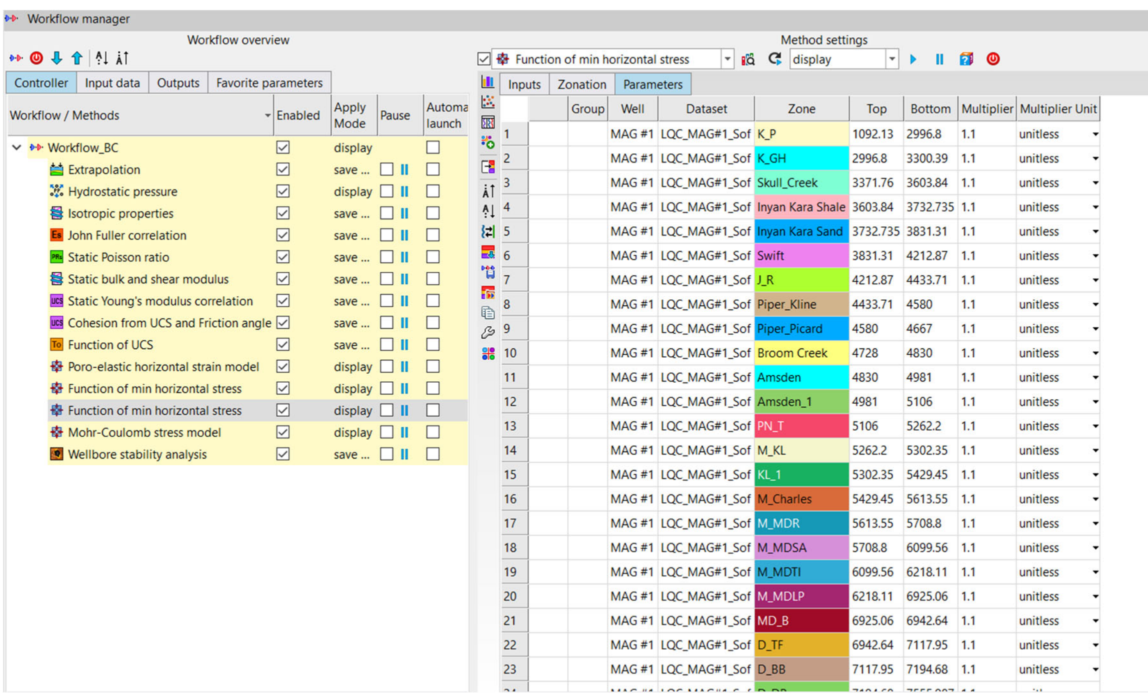
$$\sigma_H = \frac{v}{1-v}\sigma_V - \frac{v}{1-v}\alpha P_p + \alpha P_p + \frac{E}{1-v^2}\varepsilon_H + \frac{vE}{1-v^2}\varepsilon_h \tag{11}$$

Where:

$\varepsilon_h$ is the minimum principal horizontal strain.
$\varepsilon_H$ is the maximum principal horizontal strain.
$v$ is poison ratio
$\sigma_v$ is the overburden gradient.
$\alpha$ is Biot coefficient.
$P_p$ is pore pressure.
$E$ is young's modulus

## 4. Maximum horizontal stress (Shmax)

Shmax was calculated by using a multiplier of Shmin. The multiplier used is shown below.



## 5. Pore pressure

Pore pressure is calculated by using the normal pressure gradient:

$$P_p = TVD \times gradient = TVD \times 0.448\ (psi/ft) \tag{12}$$

Capillary pressure curves calculated from MICP data were modified to the model scale based on the permeability and porosity values of the simulation model and used in the numerical simulations. These modified capillary pressure curves are also shown in Figures 3-6–3-8. The capillary entry pressure values applied in the model were determined by deriving a ratio between the reservoir quality index of core samples and modeled properties to scale the capillary entry pressure value derived from core testing (Table 3-2).

Temperature and pressure data recorded in the MAG 1 wellbore were used to derive a temperature and pressure gradient to initialize the numerical simulation model for the proposed injection site. In combination with depth, a temperature gradient of 0.025°F/ft was used to calculate subsurface temperatures throughout the study area. The temperature gradient was calculated using the temperature measurements listed in Table 2-2 with an assumption of the average annual surface temperature of 0°F. A pressure gradient of 0.512 psi/ft was used to calculate initial pressure in the model. The pressure gradient was calculated using the pressure measurements listed in Table 2-3. Standard atmospheric pressure of 14.7 psi was not used to calculate the pressure gradient as CMG uses PSIC instead of PSIA. The calculated pressure and temperature gradients were not used as direct inputs for simulation but rather used to calculate the pressure and temperature of a reference point at the corresponding reference depth which are the direct inputs for simulation. For a reference point at a depth of 4782.7 ft in the simulation model, the temperature and pressure values input were 119.6°F (4782.8 ft*0.025°F/ft+0°F) and 2448.8 psi (4782.8 ft*0.0512 psi/ft), respectively to correctly distribute the temperature and pressure data, that are in line with the measured temperature and pressure values reported in Section 2. The fracture gradient was obtained from a geomechanical analysis, resulting in an average of 0.69 psi/ft. The maximum allowable BHP of 2,970 psi was estimated to be 90% of the fracture gradient multiplied by the depth of the top perforation in the injection zone, the Broom Creek Formation, and used as the injection constraint in the numerical simulation of the expected injection scenario.

### *3.3.2 Sensitivity Analysis*

Because the availability of data for this study included well logs, core sample data, and rock–fluid properties, the need for typical sensitivity studies of influential reservoir parameters has been reduced. A preliminary sensitivity analysis made to the wellbore model parameters suggested, at the given injection volume rates and BHP conditions, the wellhead temperature played a prominent role in determining WHP response. Sensitivity simulations of different wellhead temperatures indicated that injection at a higher wellhead temperature would require a higher WHP. For evaluating the expected injection design, a wellhead temperature value of 60°F was chosen that most closely represents the expected operational temperature.

## 3.4 Simulation Results

The target injection rate of 200,000 tonnes per year (tpy) (548 tonnes per day) was consistently achievable over 20 years (Figure 3-9), translating to a cumulative 4 MMt of $CO_2$ injection (Figure 3-10). Simulations of $CO_2$ injection with the given well constraints, listed in Table 3-3, predicted the BHP would not reach the maximum BHP constraint of 2,970 psi (90% of the formation fracture pressure) as a result of injecting the target $CO_2$ volume of 200,000 tpy. The predicted maximum BHP and the average BHP during the 20 year injection period were 2,661 and 2,570 psi (Figure 3-11), respectively.

Under Method 1, the maximum pressure increase that may be sustained in the injection zone (critical threshold pressure increase) is given by Equation 1:

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_I \qquad \text{[Eq. 1]}$$

Where:

$P_u$ is the initial fluid pressure in the USDW (Pa).
$\rho_i$ is the storage reservoir fluid density (kg/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 ($\Delta P_c$), which is the fluid pressure increase sufficient to drive formation fluids into the lowermost USDW. This $\Delta P_c$ is determined using Equations 2 and 3, assuming 1) hydrostatic conditions, 2) initially linear densities in the borehole, and 3) constant density once the injection zone fluid Is lifted to the top of the borehole (i.e., uniform density approach):

$$\Delta P_C = \frac{1}{2}\, g\, \xi\, (Z_u - Z_i)^2 \qquad \text{[Eq. 2]}$$

Where $\xi$ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{Z_u - Z_i} \qquad \text{[Eq. 3]}$$

Where:

$\Delta P_c$ is the critical threshold pressure increase (Pa).
$g$ is the acceleration of gravity (m/s$^2$).
$z_u$ is the elevation of the base of the lowermost USDW (m amsl).
$z_i$ is the elevation of the top of the injections zone (m amsl).
$P_i$ is the fluid density in the injection zone (kg/m$^3$).
$P_u$ is the fluid density in the USDW (kg/m$^3$).

### *3.5.2 Risk-Based AOR Delineation*

The methods described by EPA (2013) for estimating the AOR under the Class VI rule (40 U.S. Code of Federal Regulations [CFR] 146.81 et seq.) were developed assuming that the storage

## Possible Geochemical Influence: Binary Mixing of Two Fluids

While no leakage pathways have been identified in the AOR, for the hypothetical leaky wellbore scenario detailed in the risked based AOR calculation, less than 1 $m^3$ of incremental flow from the Broom Creek (BC) into the Fox Hills USDW (FH) is expected. The following write-up discusses the potential impact of fluid flow from the BC into the FH in this hypothetical leaky wellbore scenario.

In the region of North Dakota that includes the storage facility area, the present TDS concentrations of the BC formation and FH formation are approximately 28,600 mg/L and an estimated 1,800 mg/L, respectively.[1] The geochemical effects of mixing BC formation fluid with FH formation fluid would be the increase in salinity (TDS concentration) of the FH formation fluid. As with many other natural processes, the mixing process is controlled by mass-balance or conservation of mass. When two components of different chemical composition mix in varying proportions, the chemical compositions of the resulting mixtures vary systematically depending on the relative abundances of the endmembers. The two-endmember mixing model for a single chemical compound (denoted here as "TDS") is given by a simple algebraic expression based on the fraction of each endmember in the mixture, as follows:[2]

$$TDS_{mixutre} = TDS_{BC} f_{BC} + TDS_{FH} f_{FH} \qquad [1]$$

Where:

$TDS_{mixture}$ is the TDS concentration of the mixture;

$TDS_{BC}$ is the TDS concentration in BC formation fluid (endmember 1);

$TDS_{FS}$ is the TDS concentration in FH formation fluid (endmember 2);

$f_{BC}$ is the fraction of BC formation fluid in the mixture;

$f_{FH}$ is the fraction of FH formation fluid in the mixture; and

$f_{BC} + f_{FH} = 1$.

Equation 1 describes a linear relationship between the two endmembers, such that the values for $TDS_{mixture}$ fall on a straight line when plotting the TDS concentration of the mixture against the fraction of one of the endmembers in the mixture (Figure 1).

However, in a situation where BC formation fluid is leaking into the FH formation via a conduit like a legacy wellbore, the volumetric fraction of BC formation fluid ($f_{BC}$) would be very small since the FH formation thickness is approximately 82 m (270 ft). For example, in a cylindrical

---

[1] Refer to Table 2-4 in the Storage Facility Permit.

[2] Langmuir, C.H.; Vocke, R.D., Jr.; Hanson, G.N. (1978) A general mixing equation with applications to Icelandic basalts. Earth and Planetary Science Letters, 37:380-392.

volume of 10 m in diameter, the FH formation bulk volume would be $\pi r^2 h = \pi (5\ m)^2 (82\ m) = 6{,}440\ m^3$ and the pore volume assuming 34.4% porosity would be $6{,}440\ m^3 \times 0.344 = 2{,}215\ m^3$. Therefore, a cumulative leakage volume of 1 $m^3$ would only represent 0.04% of the pore volume within that cylindrical volume. Using Eq. 1, the TDS concentration for the mixture with $f_{BC}$ = 0.04% would be 1,810 mg/L, which would not be detectable from a baseline FH formation fluid concentration of 1,800 mg/L (if the true FH formation fluid TDS concentration could reasonably fall within the interval from 1,800 ± 200 mg/L, i.e., from 1,600 to 2,000 mg/L).

Within a smaller cylindrical volume, for example 1 m in diameter, the pore volume would be smaller (22 $m^3$), $f_{BC}$ would be larger (4.5%), and the TDS concentration would be greater (3,006 mg/L) and potentially detectable from a baseline FH formation fluid concentration of 1,800 ± 200 mg/L, i.e., from 1,600 to 2,000 mg/L.

These calculations show that for small cumulative leakage volumes (e.g., 1 $m^3$) of BC formation fluid into the FH formation, there would be no measurable impact to the FH formation fluid TDS concentration except perhaps if the monitoring measurement was acquired right at the leakage point (essentially from within the leaking wellbore). Furthermore, these calculations assume a static FH formation where groundwater is not flowing. The FH formation would more accurately be described as a hydrodynamic system, with fresh water continually recharging and moving through the system. The additional of new fresh water to the system would further reduce the TDS concentration of the mixture.

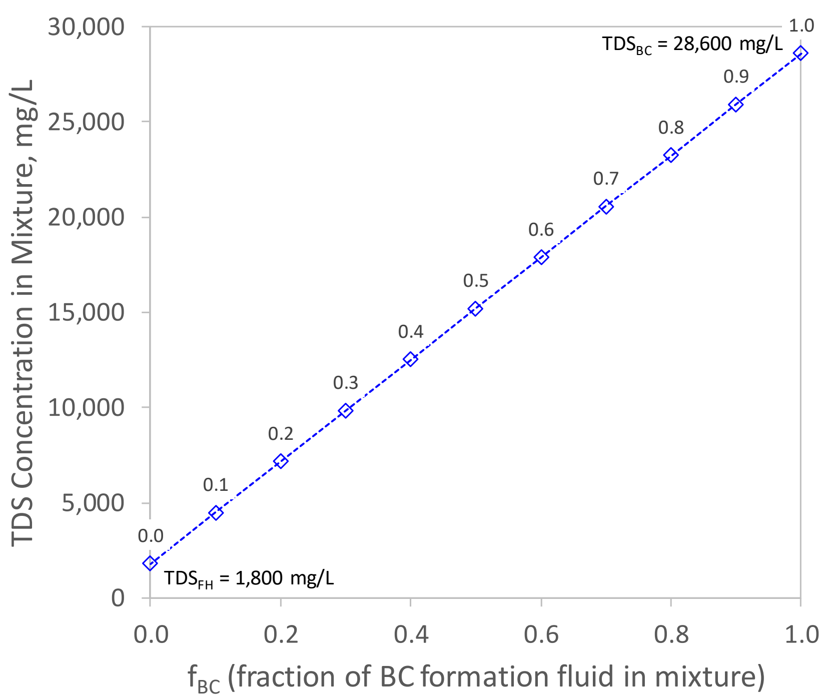



**Figure 1.** Hypothetical example of linear mixing using Eq. 1 to solve for $TDS_{mixture}$ using increasing fractions of Broom Creek formation fluid from 0 to 1 ($f_{BC}$ = 0, 0.1, 0.2, …, 0.8, 0.9, 1.0). In this example, the TDS concentration in the Broom Creek formation fluid is 28,600 mg/L (upper right-hand corner) and the TDS concentration in the Fox Hills formation fluid is 1,800

mg/L (lower left-hand corner). The fraction above each diamond symbol is the $f_{BC}$ value used to derive that $TDS_{mixture}$ value.

### *3.4.1 Maximum Injection Pressures and Rates*

An additional case was run to determine the maximum storage potential if the well was only limited by the maximum calculated downhole pressure of 2,970 psi (90% of the formation fracture pressure). In this scenario, the MAG 1 well was able to inject at a daily average rate of 2,729 tonnes/day of $CO_2$ with a 2.875-in. diameter tubing, achieving a total injection volume of 19.9 MMt of $CO_2$. The predicted average WHP, using the designed injection tubing of 2.875 inches, was 4,300 psi (Figure 3-15).

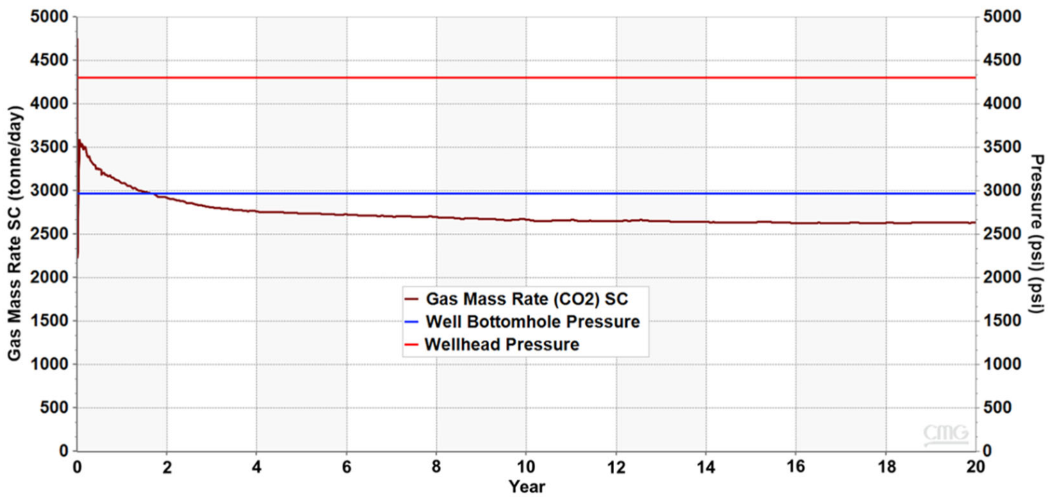



Figure 3-15. Maximum pressures and rate response when the well was operated without any injection rate limits.

### *3.4.2 Stabilized Plume and Storage Facility Area*

Movement of the injected $CO_2$ plume is driven by the potential energy found in the buoyant force of the injected $CO_2$. As the plume spreads out within the reservoir and $CO_2$ is trapped residually through the effects of relative permeability and dissolution, the potential energy of the buoyant $CO_2$ is gradually lost. Eventually, the buoyant force of the $CO_2$ is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the $CO_2$ plume ceases to move within the subsurface and becomes stabilized. The extent of the stabilized plume is important for determining the project's AOR and the corresponding scale and scope of the project's monitoring plans.

Plume stabilization can be visualized at the microscale as $CO_2$ being unable to exit its current pore space and enter the neighboring pore space, but at the macroscale, these interactions cannot be measured. Instead, plume stabilization may be estimated using the tools available to predict the $CO_2$ plume's extent.

For the Blue Flint project the $CO_2$ plume was simulated in 5-year time steps until the rate of total areal extent change slowed to less than 0.15 square miles per 5-year time step to define the stabilized plume extent boundary (Figure 3-13) and the associated buffers and boundaries. The $CO_2$ plume stabilization is expected to occur at 10 years of postinjection. Afterwards, it would take the stabilized plume five years to move one cell (1000ft). This estimate is anticipated to be regularly updated during the $CO_2$ storage operation as data collected from the site are used to update predictions made about the behavior of the injected $CO_2$.

## 3.5 Delineation of the Area of Review

The North Dakota Administrative Code (NDAC) defines AOR as the region surrounding the geologic storage project where underground sources of drinking water (USDWs) may be endangered by $CO_2$ injection activity (NDAC § 43-05-01-05). The primary endangerment risk is the potential for vertical migration of $CO_2$ and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the $CO_2$ plume within the storage reservoir.

However, the $CO_2$ plume has an associated pressure front where $CO_2$ injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the $CO_2$ plume. Therefore, the AOR encompasses both the areal extent of the $CO_2$ plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the $CO_2$ plume, AOR delineation focuses on the pressure front.

The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the underground injection control (UIC) program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure.

In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), "potential thief zone" refers to the Inyan Kara Formation, and "lowest USDW" refers to the Fox Hills Formation.

### *3.5.1 EPA Methods 1 and 2: AOR Delineation for Class VI Wells*

EPA guidance for AOR evaluation includes several computational methods for estimating the pressure buildup in the storage reservoir in response to $CO_2$ injection and the resultant areal extent of pressure buildup above a "critical threshold pressure" that could potentially drive higher-salinity formation fluids from the storage reservoir up an open conduit to the lowest USDW (U.S. Environmental Protection Agency, 2013). The following equations and analytical approach define the EPA methods used to delineate AOR. Each method can be applied both at a single location (e.g., the MAG 1 stratigraphic well) using site-specific data or for each vertical stack of grid cells in a geocellular model, considering the varying stratigraphic thickness between storage reservoir and lowest USDW.

EPA Method 1 (*pressure front based on bringing the injection zone and USDW to equivalent hydraulic heads*) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW (U.S. Environmental Protection Agency, 2013).

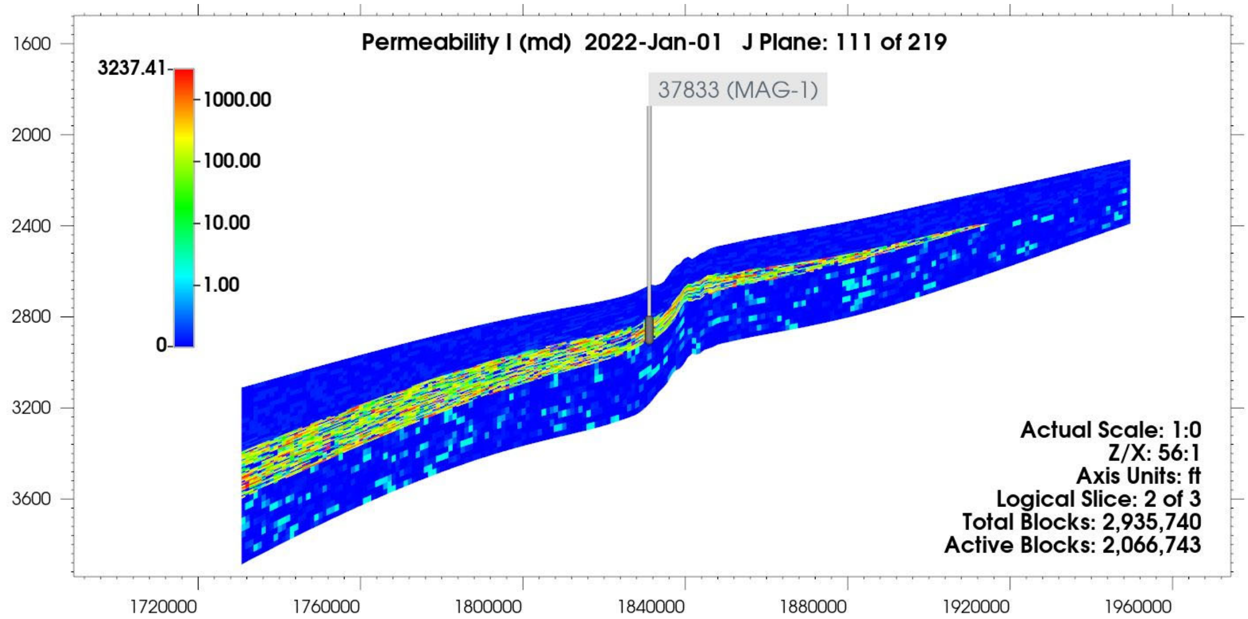



Figure 3-4. Cross-sectional view of the simulation model with the permeability property and injection well displayed. The low-permeability layers (blue) at the top and bottom of the figure should be noted. These layers represent the lower Piper and Spearfish Formations (upper confining zone) and the Amsden Formation (lower confining zone). The varied permeability of the Broom Creek Formation is shown between these layers.

**Table 3-1. Summary of Reservoir Properties in the Simulation Model**

| Formation | Average Permeability, mD | Average Porosity, % | Initial Pressure, $P_i$, psi | Salinity, mg/L | Boundary Condition |
|---|---|---|---|---|---|
| Spearfish | 0.068 | 5.1 | 2,448.8 (at 4,782.7 ft MD[1]) | 28,600 | Partially infinite |
| Broom Creek | 629.5 | 22.6 | | | |
| Amsden | 18.4 | 7.8 | | | |

[1] Measured depth.

Numerical simulations of $CO_2$ injection performed allowed $CO_2$ to dissolve into the native formation brine. Mercury injection capillary pressure (MICP) data for the Spearfish, Broom Creek, and Amsden Formations were used to generate relative permeability and the capillary curves for the five representative lithofacies in the simulation model (sandstone, siltstone, dolomite, dolomitic sands, and anhydrite) (Figures 3-6–3-8). Samples tested within the Spearfish, Broom Creek, and Amsden Formations included siltstone, sandstone, and dolomite lithologies. The siltstone (Spearfish) and dolomite (Amsden) values were assigned to anhydrite and dolomitic sandstone lithofacies, respectively, for both capillary entry pressure and relative permeability, as there were no available samples of these rock types from the MICP calculations. The main reason is both siltstone and anhydrite represent low perm facies. As for the dolomitic sandstone, the

dolomite relative permeability data was used because the dolomitic sandstones within the Broom Creek Formation are expected to be more similar to dolomite rather than to sandstone. Anhydrite and dolomitic sandstone facies intervals in the reservoir are sparse and very thin; therefore, these relative permeability assumptions are not expected to impact injectivity or $CO_2$ plume extent (Figure 3-5). Figure 3-5 shows the facies distribution in the simulation model. Please note the red and yellow colors represent the anhydrite (red) and dolomitic sandstone (yellow), respectively and these facies barely exist around the injection point.

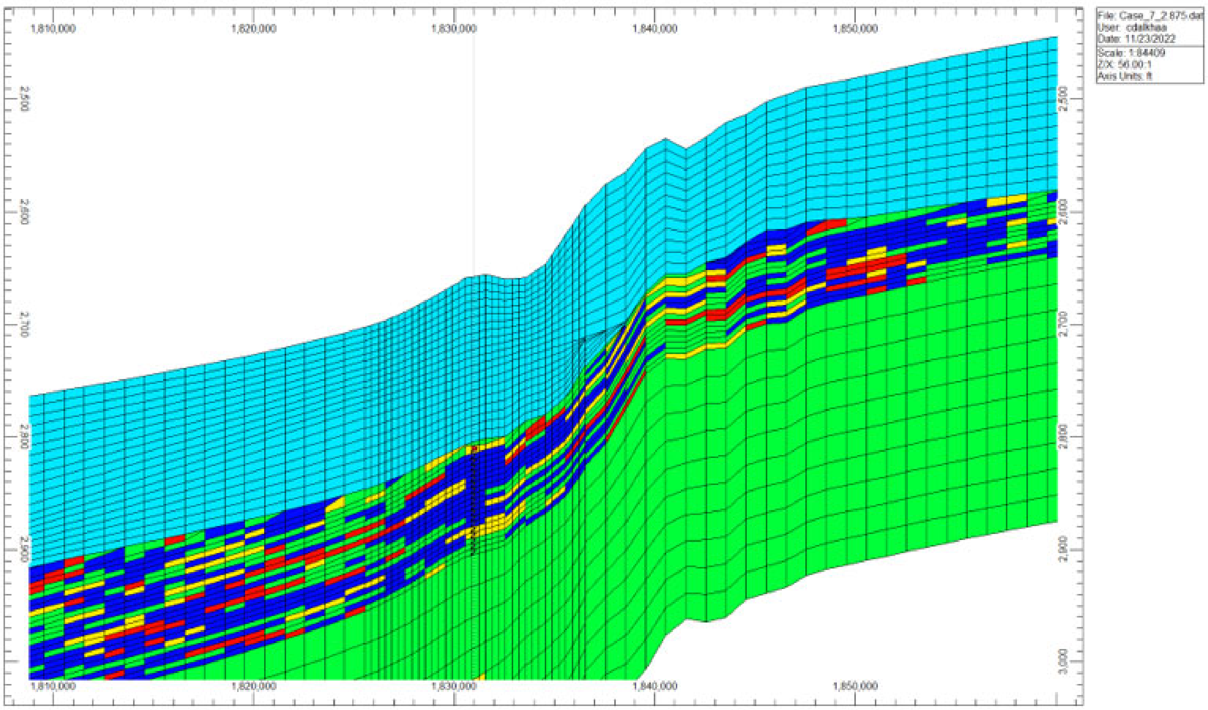



Figure 3-5. Facies distributions in the simulation model. Low permeability indicated by the color teal is siltstone. Other facies representations in the model are red representing anhydrite, yellow representing dolomitic sandstone, blue representing sandstone, and green representing dolomite.

formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR.

### *3.5.3 Critical Threshold Pressure Increase Estimation*

For the purposes of delineating AOR for the project study area, constant fluid densities for the lowermost USDW (Fox Hills Formation) and injection zone (Broom Creek Formation) were used in the calculations. Respective fluid densities were used to represent the injection zone fluids ($\rho_i$), which are estimated based on the in situ estimated brine salinity, temperature, and pressure at the MAG 1 stratigraphic test well.

Application of EPA Method 1 (Equation 1) using site-specific data from the MAG 1 well shows that the injection zone in the project area is overpressurized with respect to the lowest USDW (i.e., Method 1 $\Delta P_{i,f} < 0$). An example of the EPA Method 1 application showing negative $\Delta P_{i,f}$ (relative overpressure) is given in Table 3-4, with similar results when applied to each column of the grid cells in the Broom Creek Formation simulation model.

**Table 3-4. EPA Method 1 Critical Threshold Pressure Increase Calculated at the MAG 1 Wellbore Location Using Measured and Calculated Data Shown in Table 3-2**

| Depth,* ft | Depth,* m | $P_i$ Injection Zone Pressure, MPa | $P_u$ USDW Base Pressure, MPa | $\rho_i$ Injection Zone Density, kg/m$^3$ | $Z_u$ USDW Base Elevation, m amsl | $Z_i$ Reservoir Elevation, m amsl | $\Delta P_{i,f}$ Threshold Pressure Increase, MPa | $\Delta P_{i,f}$ Threshold Pressure Increase, psi |
|---|---|---|---|---|---|---|---|---|
| 4,731 | 1,442 | 16.41 | 3.15 | 1,006 | 276 | −855 | −2.11 | −306 |

* Ground surface elevation is 581 m above mean sea level. Depth provided is the reference depth used for the CMG simulation.

In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value across the project area and b) lack of evidence for hydrostatic equilibrium between the reservoir and the USDW (i.e., Method 2 does not apply) indicates that a risk-based approach to AOR delineation may be pursued.

### *3.5.4 Risk-Based AOR Calculations*

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). The inputs, assumptions, and results discussed here provide the necessary details for reproducing and verifying the results. A macro-enabled Microsoft Excel file was used to define the inputs and calculations that were employed in the method (hereafter “ASLMA Workbook”).

#### *3.5.4.1 Initial Hydraulic Heads*

The original ASLMA Model (Cihan and others, 2011) initially assumed hydrostatic pressure distributions in the entire system. The current work uses a modified version of the ASLMA Model to simulate pressure perturbations and leakage rates when there are initial head differences in the aquifers (Oldenburg and others, 2014). The initial hydraulic heads are calculated assuming a total

**Table 3-5. Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex**

| Hydrostratigraphic Unit | Depth to Top,* m | Thickness, m | Pressure, MPa | Temperature, °C | Salinity, ppm | Brine Density, $kg/m^3$ | Porosity, % | Permeability, mD | Permeability, $m^2$ | HCON, m/d | Specific Storage, $m^{-1}$ | Total Head, m |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Overlying Units to Ground Surface (not directly modeled) | 0 | 215 | | | | | | | | | | |
| Aquifer 3 (USDW – Fox Hills Fm) | 215 | 90 | 2.6 | 12.5 | 1,800 | 1,002 | 34.4 | 280 | 2.76E-13 | 1.92-01 | 5.56E-06 | 591 |
| Aquitard 2 (Pierre Fm–Inyan Kara Fm) | 305 | 788 | 7.0 | 25.3 | 16,300 | | 10 | 0.1 | 9.87E-17 | 9.30E-05 | 9.26E-06 | 585 |
| Aquifer 2 (Thief Zone – Inyan Kara Fm) | 1,093 | 69 | 11.3 | 37.8 | 16,300 | 1,008 | 22.4 | 42.1 | 4.16E-14 | 5.06E-02 | 5.25E-06 | 593 |
| Aquitard 1 (Swift–Broom Creek Fm) (primary upper seal) | 1,161 | 273 | 13.0 | 42.7 | 28,600 | | 10 | 0.1 | 9.87E-17 | 1.30E-04 | 9.31E-06 | 583 |
| Aquifer 1 (Storage Reservoir – Broom Creek Fm) | 1,435 | 32 | 16.5 | 68.3 | 28,600 | 1,003 | 18.2 | 121.3 | 1.20E-13 | 2.31E-01 | 5.15E-06 | 808 |

* Ground surface elevation 614 m amsl.

*3.5.4.2 $CO_2$ Injection Parameters*

The ASLMA Model for the project used a Broom Creek $CO_2$ injection rate that matched the simulation scenario. A single injector is placed at the center of the ASLMA Model grid at an x,y-location of (0,0) in the coordinate reference system. The ASLMA Model requires the $CO_2$ injection rate to be converted into an equivalent-volume injection of formation fluid in units of cubic meters per day. Microsoft Excel Visual Basic for Applications (VBA) functions were used to estimate the $CO_2$ density from the storage reservoir pressure and temperature, which resulted in an estimated density, shown in Table 3-6. The $CO_2$ mass injection rate and $CO_2$ density are then used to derive the daily equivalent-volume injection rate, shown in Table 3-6.

**Table 3-6. $CO_2$ Density and Injection Parameters Used for the ASLMA Model**

| $CO_2$ Density, Reservoir Conditions, kg/m$^3$ | Injection Period | Injection Rate, m$^3$ per day | Injection Period, years |
|---|---|---|---|
| 580 | 1 | 944 | 20 |

*3.5.4.3 Hypothetical Leaky Wellbore*

In the project area, few wellbores are known to exist that penetrate the primary seal of the Broom Creek storage reservoir. However, for heuristic, "what-if" scenario modeling, which is needed to generate the data for delineating a risk-based AOR, a single hypothetical leaky wellbore is inserted into the ASLMA Model at 1, 2, …, 100 km from the $CO_2$ injection well. The pressure buildup in the storage reservoir at each distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 12-year injection period, provides the data set needed to derive the risk-based AOR.

Published ranges for the effective permeability of a leaky wellbore (Figure 3-17) have included an "open wellbore" with an effective permeability as high as $10^{-5}$ m$^2$ ($10^{10}$ mD) to values more representative of leakage through a wellbore annulus of $10^{-12}$ to $10^{-10}$ m$^2$ ($10^3$ to $10^5$ mD) (Watson and Bachu, 2008, 2009; Celia and others, 2011). Carey (2017) provides probability distributions for the effective permeability of potentially leaking wells at $CO_2$ storage sites and estimated a wide range from $10^{-20}$ to $10^{-10}$ m$^2$ ($10^{-5}$ to $10^5$ mD). For the project Broom Creek ASLMA Model, the effective permeability of the leaky wellbore is set to $10^{-16}$ m$^2$ (0.1 mD), which is a conservative (highly permeable) value near the top of the published range for the effective permeability of potentially leaking wells at $CO_2$ storage sites (Figure 3-17).

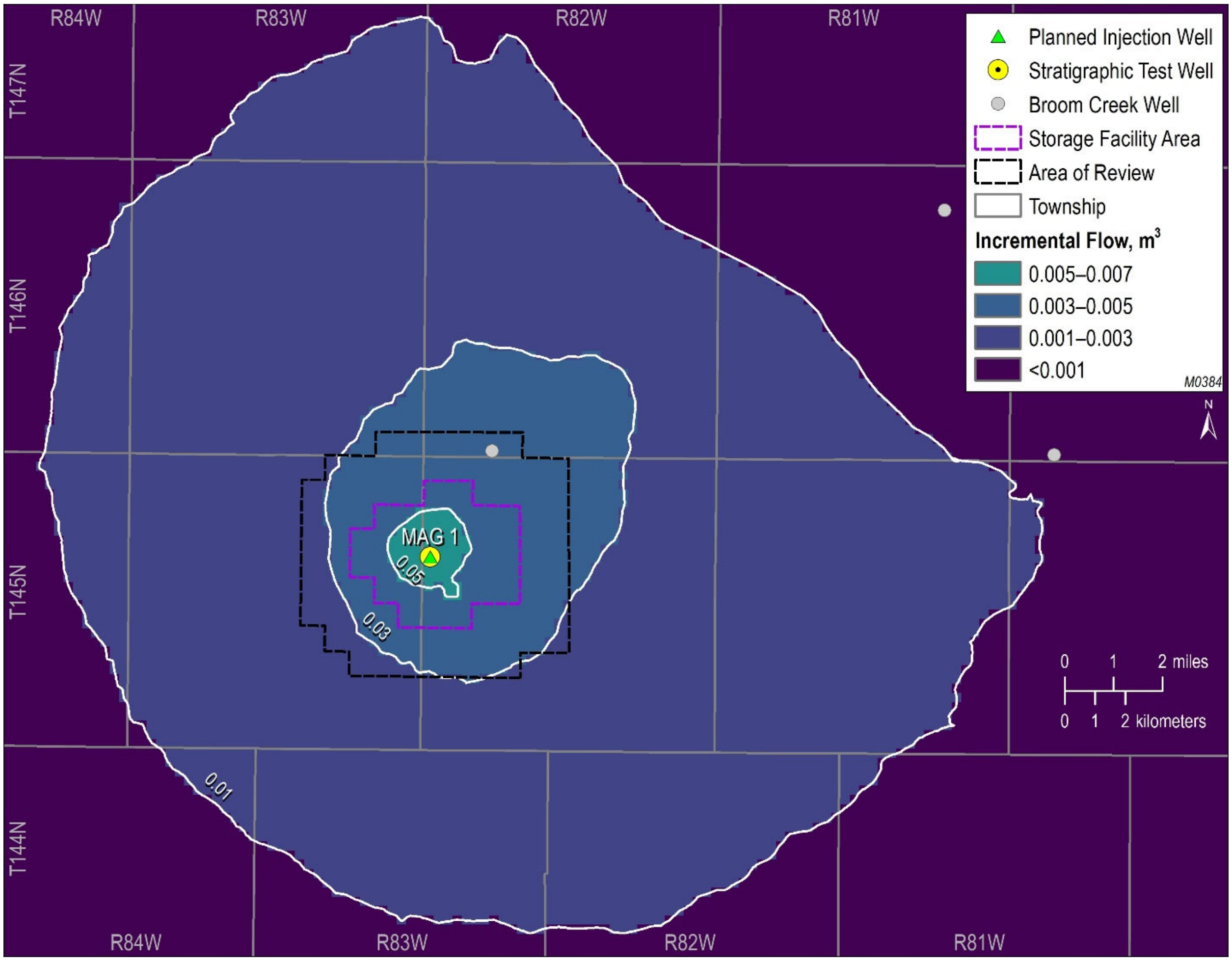



Figure 3-19. Map of potential incremental leakage into the USDW at the end of 20 years of $CO_2$ injection for the scenario where the hypothetical leaky wellbore is closed to Aquifer 2 (thief zone).

**Table 3-7. Summary Results from the Risk-Based AOR Method of Estimated Potential Cumulative Leakage after 20 years of Injection and No Thief Zone**

| | |
|---|---|
| Maximum Vertically Averaged Change in Reservoir Pressure, psi | 113.2 |
| Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Without* Injection, $m^3$ | 0.019 |
| Maximum Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Attributable to* Injection, $m^3$ | 0.005 |

**Table 4-3. Ellen Samuelson 1 (NDIC File No. 1516) Well Evaluation**

Well Name: Ellen Samuelson 1 (NDIC File No. 1516)

| Cement Plugs | | | | |
|---|---|---|---|---|
| Number | Interval, ft | | Thickness**, ft | Volume, sacks |
| 1 | 5,885 | 5,940 | 55 | 20 |
| 2 | 5,425 | 5,480 | 55 | 20 |
| 3 | 4,675 | 4,730 | 55 | 20 |
| 4 | 3,615 | 3,670 | 55 | 20 |
| 5 | 432 | 492 | 60 | 25 |
| 6 | 0 | 10 | 10 | 5 |

* Data and information are provided from well-plugging report found in NDIC database.
** Cement yield assumed at 1.15 cu ft per sack in thickness calculation.

| Formation | | Cement Plug Class G* |
|---|---|---|
| Name | Estimated Top, ft | |
| 10¾" Casing Shoe | 462 | Cement Plug 5 isolates the 10¾" casing shoe. |
| Pierre | 1,055 | |
| Mowry | 3,355 | Top of Inyan Kara Formation is not covered by cement. However, Cement Plug 4 isolates Dakota Group. |
| Inyan Kara | 3,655 | |
| Swift | 3,912 | |
| Broom Creek | 4,860 | Cement Plug 3 isolates the formations above the Broom Creek Formation. |
| Kibby Lime | 5,272 | Cement Plugs 2 and 1 isolate the formations below the Broom Creek Formation. |

Spud Date: 9/14/1957
Total Depth: 6,600 (Mission Canyon Formation)

Surface Casing: 10¾" casing set at 462, cement to surface with 200 sacks Class G cement.

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Ellen Samuelson 1 well (NDIC File No. 1516) will not be in contact with the $CO_2$ plume, and pressure increase in the Broom Creek Formation at this well location is predicted to be approximately 76 psi. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled and plugged.

* Cement Type is assumed to be Class G as no cement type was on file.

**Table 4-5. Wallace O. Gradin 1 (NDIC File No. 4810) Well Evaluation**

Well Name: Wallace O. Gradin 1 (NDIC File No. 4810)

| Cement Plugs | | | | |
|---|---|---|---|---|
| Number | Interval, ft | | Thickness**, ft | Volume, sacks |
| 1 | 3181 | 3249 | 68 | 20 |
| 2 | 1152 | 1220 | 68 | 20 |
| 3 | 204 | 270 | 66 | 20 |
| 4 | 0 | 16 | 16 | 5 |

*Data and information are provided from well-plugging report found in NDIC database.
** Cement yield assumed at 1.15 cu ft per sack in thickness calculation.

| Formation | | Cement Plug Remarks |
|---|---|---|
| Name | Estimated Top, ft | |
| 8.625" Casing Shoe | 233 | 8-5/8" J-55, 20# casing. Set at 233'. Cemented w/ 135 sks 8-5/8", 20# casing capacity is 2.7328 lin ft per ft^3. Plug 4 at surface and plug 3 at surface casing shoe. |
| Pierre | 915 | Plug 2 is 200' into the Pierre Fm. Fox Hills Formation isolated by plug 2 and 3. |
| Mowry | 3195 | Cement Plug 1 isolates the uppermost Inyan Kara porosity. |
| Newcastle | 3249 | |
| Swift | 3745 | |
| Rierdon | 4083 | Well file reports TD in Piper Formation. |

Spud Date: 12/01/1969
Total Depth: 4240 ft

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Wallace O. Gradin 1 (NDIC File No. 4810) well will not be in contact with the $CO_2$ plume, and the well does not penetrate the Broom Creek Formation. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled above the Broom Creek Formation.

The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. The upper Sentinel Butte is approximately 150 ft thick in the area of investigation (Hemish, 1975). TDS concentrations in the Sentinel Butte Formation are approximately 1,000 ppm (Klausing, 1974). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers.

#### *4.4.4 Protection for USDWs*

The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AOR. The injection zone (Broom Creek Formation) and the lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and siltstone formations (Figure 4-6). The primary seal of the injection zone is the Permian-aged Spearfish and the Jurassic-aged Piper, Rierdon, and Swift Formations, all of which overlie the Broom Creek Formation. These formations will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation.

Above the Swift is the confined saltwater aquifer system of the Inyan Kara Formation, which extends across much of the Williston Basin. The Inyan Kara will be monitored for temperature changes in the injection well (MAG 1) and the monitoring well (MAG 2). The Pierre Formation is the thickest shale formation in the area of investigation and the primary geologic barrier between the USDWs and the Inyan Kara. The geologic strata overlying the injection zone consist of multiple impermeable rock layers that are free of transmissive faults or fractures and provide adequate isolation of the USDWs from $CO_2$ injection activities in the area of investigation.

### 4.5 References


Bluemle, John P., 1971, Geology of McLean County, North Dakota: Theses and Dissertations.

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 No. 54.

Hemish, L., 1975, Stratigraphy of the upper part of the Fort Union Group in Southwestern Mclean County, North Dakota.

Honeyman, R.P., 2007, Pressure head fluctuations of the Fox Hills-Hell Creek Aquifer in the Knife River Basin, North Dakota.

Klausing, R., 1974, Ground-water resources of McLean County, North Dakota: U.S. Geological Survey, www.swc.nd.gov/info_edu/reports_and_publications/county_groundwater_studies/pdfs/Mclean_Part_III.pdf (accessed July 2022).

Thamke, J.N., LeCain, G.D., Ryter, D.W., Sando, R., and Long, A.J., 2014, Hydrogeologic framework of the uppermost principal aquifer systems in the Williston and Powder River structural basins, United States and Canada: U.S. Geological Survey Groundwater Resources Program Scientific Investigations Report 2014–5047.

**Table 6-2. Overview of Blue Flint's PISC Monitoring Plan**

| Activity | Postinjection Frequency (10-year period) |
| --- | --- |
| **Soil Gas** | |
| SGPSs (SGPS01 and SGPS02) (Figure 6-3) | Sample SGPS01 prior to MAG 1 reclamation. Sample SGPS02 annually until site closure. |
| Soil Gas Probe Locations (SG01 to SG04) (Figure 6-3) | Sample soil gas probe locations at the start of the PISC period and prior to site closure. |
| **Shallow Groundwater** | |
| Shallow Groundwater Wells | Sampling may be performed on active and accessible shallow groundwater wells in the AOR prior to site closure. |
| **Lowest USDW** | |
| Dedicated Fox Hills Monitoring Well near the MAG 1 (Figure 6-3) | Sample the dedicated Fox Hills monitoring well annually until site closure. |
| **Above-Zone Monitoring Interval (AZMI) Monitoring** | |
| DTS | Continuous monitoring |
| PNL | Perform PNL in the MAG 2 well in Year 21 from the Spearfish up through the Inyan Kara and repeat annually until the near-wellbore environment reaches full $CO_2$ saturation. Reduce frequency to every 4 years thereafter. |
| **Storage Reservoir (direct)** | |
| DTS | Continuous monitoring |
| PNL | Perform PNL in the MAG 2 well in Year 21 and repeat annually until the near-wellbore environment reaches full $CO_2$ saturation. Reduce frequency to every 4 years thereafter. |
| **Storage Reservoir (indirect)** | |
| 2D Time-Lapse Seismic (Figure 6-4) | Actual design and frequency to be determined based on reevaluations of the testing and monitoring plan (Section 5.0) and migration of the $CO_2$ plume over time. |
| Passive Seismicity | USGS seismic network, supplemented with additional stations as needed. |

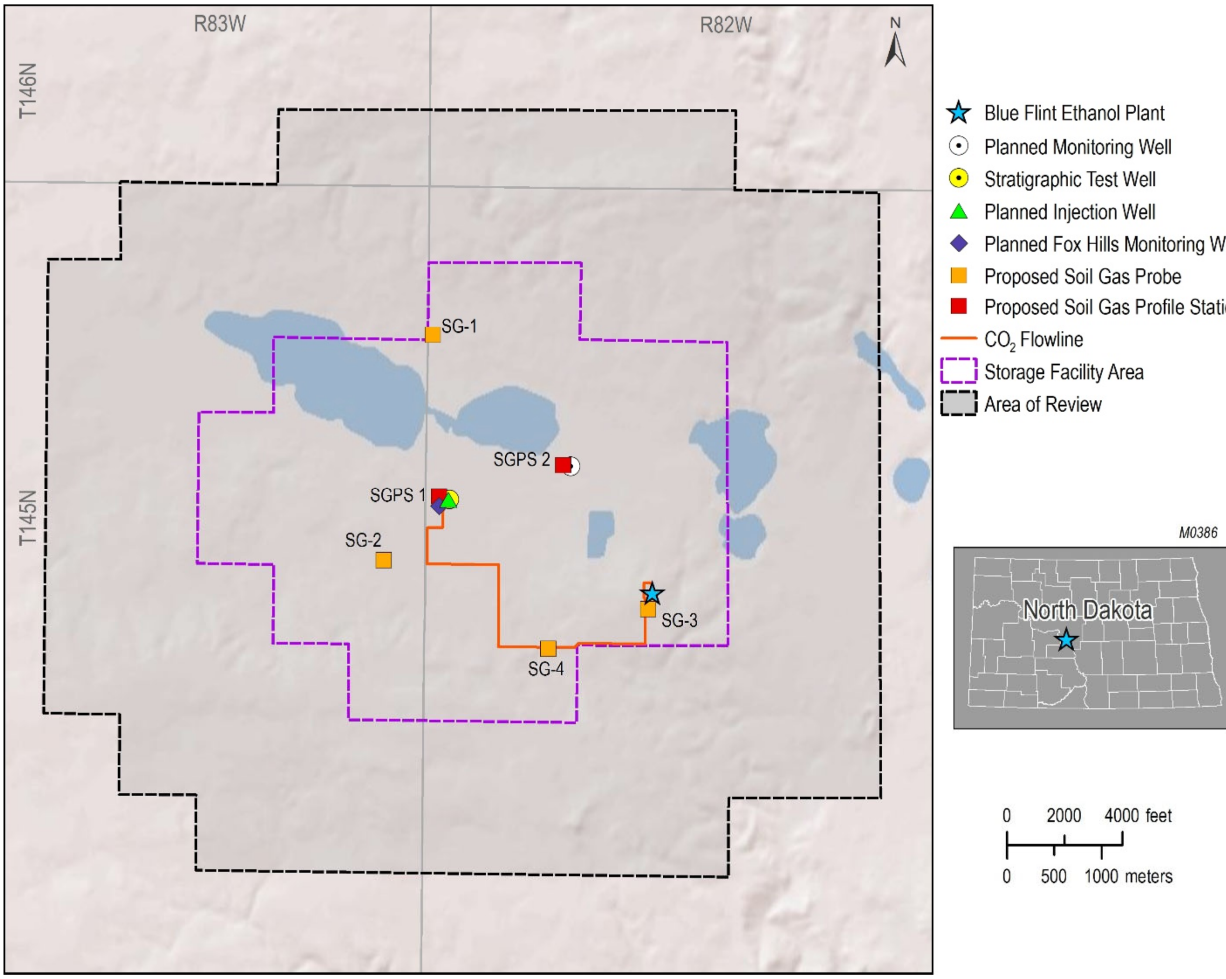



Figure 6-3. Soil gas- and groundwater well-sampling locations included in the PISC monitoring program.

### *6.2.2 $CO_2$ Plume Monitoring*

The design and frequency of the 2D time-lapse seismic survey will depend on how the $CO_2$ plume is migrating and the results of the adaptive management approach (Section 5.6.3). As stated in Table 5-6 and Section 5.6.3.3 of the testing and monitoring plan, the 2D seismic survey design and frequency will be repeatedly reevaluated and updated as necessary starting in Year 4 of injection.

$CO_2$ is anticipated to reach the MAG 2 wellbore in year 14 of injection. During the first year of postinjection, PNL will be acquired in the MAG 2 and annually thereafter until full $CO_2$ saturation can be demonstrated in the reservoir. Once demonstrated, the frequency will be reduced to once every 4 years thereafter.

Existing seismicity stations and the network maintained by the USGS (Figure 5-7) will be used to monitor for any seismic events that may occur during the postinjection period of the Blue Flint $CO_2$ storage project.

**Table 9-1. $CO_2$ Injection Well MAG 1 – Well Information**

| **Well Name:** | **MAG 1** | **NDIC No.:** | **37833** | **API No.:** | **3305500196** |
|---|---|---|---|---|---|
| **County:** | McLean | **State:** | ND | **Operator:** | Midwest AgEnergy Group, LLC |
| **Location:** | Sect. 18, T145N R82W | **Footages:** | 295 FNL 740 FWL | **Total Depth:** | 9,213 ft |

FNL: From the north line.
FWL: From the west line.

**Table 9-2. $CO_2$ Injection Well MAG 1 – Casing Program**

| Section | Hole Size, in. | Casing o.d., in. | Weight, lb/ft | Grade | Connection* | Top Depth, ft | Bottom Depth, ft | Objective |
|---|---|---|---|---|---|---|---|---|
| Surface | 17½ | 13⅜ | 54.5 | J55 | BTC | 0 | 1,330 | Isolate Fox Hills |
| Intermediate | 12¼ | 10¾ | 45.5 | L80 | BTC | 0 | 3,433 | Isolate Inyan Kara |
| Intermediate | 12¼ | 10¾ | 60.7 | VM-80 13CR | VAM TOP | 3,433 | 3,907 | Isolate Inyan Kara |
| Intermediate | 12¼ | 10¾ | 45.5 | L80 | BTC | 3,907 | 4,163 | Isolate Inyan Kara |
| Long String | 9½ | 7 | 29 | L80 | Premium | 0 | 4,200 | |
| Long String | 9½ | 7 | 29 | L80 CR13 | Premium | 4,200 | 5,150 | Injection target |

BTC: Buttress.

### *12.3.4 Implementation of Emergency and Remedial Response Actions*

*12.3.4.1 Emergency Response Actions*

A review of the technical risk categories for Blue Flint identified a list of events that could potentially result in the movement of injected $CO_2$ or formation fluids in a manner that may endanger a USDW and require an emergency response. These events are as follows:

- Injectivity
- Storage capacity
- Containment – lateral migration of $CO_2$
- Containment – pressure propagation
- Containment – vertical migration of $CO_2$ or formation water brine via injection wells, other wells, or inadequate confining zones
- Natural disasters (induced seismicity)

If it is determined that one or more of these events have occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7). These response actions are summarized in Tables 7-3 and 7-4.

*12.3.4.2 Estimation of Costs of Emergency Response Actions*

Estimating the costs of implementing the emergency response actions in Tables 7-4 and 7-5 is challenging since remediation measures specifically dedicated to $CO_2$ storage impacts are poorly documented, with one of the more important data gaps being the lack of precise knowledge of the leakage mechanisms and associated impacts (Manceau and others, 2014). Without this knowledge, it is not possible to design appropriate remedial measures. Furthermore, to date, no remediation action following $CO_2$ leakage after geologic storage has ever been implemented mainly because of the absence of established impacts (Manceau and others, 2014). Consequently, the degree of maturity of remediation measures in the carbon capture and storage (CCS) field is low, making it necessary to rely on literature that is primarily based on modeling or analogies with other pollutants, e.g., the analogy between $CO_2$ and volatile organic compounds, the latter having been addressed extensively in the literature. Additionally, for the remedial measures, costs and time for adequate removal are generally site-dependent, and no information is specifically available in this area in the CCS field.

Based on this current situation, two key technical manuscripts were relied upon to identify and estimate the costs of mitigation/remediation technologies to address undesired migration of $CO_2$ from a geological storage unit (Manceau and others, 2014; Bielicki and others, 2014).

<u>12.3.4.2.1 Identification of Remediation Technologies</u>

Manceau and others (2014) identified several remediation technologies/strategies that are available to address the potential impacted media that may result from an emergency event. These impacted media and remediation measures are listed in Table 12-3. The impacted media in Table 12-3 include surface and groundwater/USDWs, vadose zone, indoor settings, and atmosphere; the

# Results from Blue Flint's Initiated Baseline Near-Surface Sampling Program

## Baseline Soil Gas and Atmospheric Sampling Results

Blue Flint has initiated a baseline soil gas and ambient air sampling program for the Blue Flint $CO_2$ storage project. Tables 1 and 2 provide baseline soil gas and ambient air sampling results for three sample events (September 2022, December 2022, and March 2023), respectively. Table 3 provides the location, install date, and screened interval for each soil gas probe location sampled.

**Table 1. Results for Blue Flint's Initiated Baseline Soil Gas Sampling Program**

| Probe ID | Laboratory Measurement | | | |
|---|---|---|---|---|
| | $CO_2$ (vol %) | $O_2$ + Ar (vol %) | $N_2$ (vol %) | $\delta^{13}CO_2$ (‰ VPDB[1]) |
| **September 2022** | | | | |
| SG-1 (PRT-1a[2]) | 0.5 | 21.0 | 77.2 | -20.4 |
| SG-2 | 1.5 | 20.9 | 77.4 | -21.3 |
| SG-3 | 1.6 | 20.8 | 77.1 | -20.0 |
| SG-4 | 1.5 | 20.4 | 77.4 | -21.5 |
| SG-5 (PRT-5[2]) | 1.8 | 20.5 | 77.1 | -21.0 |
| **December 2022** | | | | |
| SG-1 (PRT-1b[2]) | 1.3 | 21.0 | 77.1 | -21.5 |
| SG-2 | 0.6 | 21.3 | 77.4 | -21.2 |
| SG-3 | 0.8 | 20.3 | 78.3 | -21.8 |
| SG-4 (PRT-4a[2]) | 0.4 | 21.5 | 77.7 | -21.2 |
| SG-5 | 0.6 | 21.7 | 77.6 | -22.2 |
| **March 2023** | | | | |
| SG-1 (PRT-1c[2]) | 0.07 | 21.7 | 77.7 | No result[3] |
| SG-2 (PRT-2[2]) | 0.4[4] | 21.2 | 78.4 | -22.2 |
| SG-3 | 1.3 | 14.9 | 83.0 | -24.0 |
| SG-4 (PRT-4b[2]) | 0.5 | 20.8 | 77.7 | -22.6[4] |
| SG-5 | 0.3 | 21.3 | 77.4 | -22.9[4] |

[1] Vienna Pee Dee Belemnite $\delta^{13}C$ Standard
[2] Alternate sampling location
[3] Insufficient $CO_2$ for analysis
[4] Low signal

**Table 2. Results for Blue Flint's Initiated Baseline Atmospheric Sampling Program. All samples had insufficient concentrations of $CO_2$ for performing stable isotope analysis.**

| Sampling Location | Laboratory Measurement | | |
|---|---|---|---|
| | $CO_2$ (vol %) | $O_2$ + Ar (vol %) | $N_2$ (vol %) |
| **September 2022** | | | |
| SG-1 (PRT-1a[1]) | 0.05 | 21.7 | 77.8 |
| SG-2 | 0.05 | 21.8 | 78.1 |
| SG-3 | 0.05 | 21.6 | 77.7 |
| SG-4 | 0.05 | 21.6 | 77.7 |
| SG-5 (PRT-5[1]) | 0.05 | 21.9 | 77.8 |
| **December 2022** | | | |
| SG-1 (PRT-1b[1]) | 0.08 | 21.7 | 77.7 |
| SG-2 | 0.08 | 21.7 | 77.5 |
| SG-3 | 0.08 | 21.7 | 77.6 |
| SG-4 (PRT-4a[1]) | 0.08 | 21.7 | 77.5 |
| SG-5 | 0.08 | 21.7 | 77.6 |
| **March 2023** | | | |
| SG-1 (PRT-1c[1]) | 0.04 | 21.8 | 77.2 |
| SG-2 (PRT-2[1]) | 0.04 | 21.9 | 77.4 |
| SG-3 | 0.04 | 21.9 | 77.4 |
| SG-4 (PRT-4b[1]) | 0.04 | 21.8 | 77.3 |
| SG-5 | 0.04 | 21.8 | 77.2 |

[1] Alternate sampling location

**Table 3. Soil Gas Probe Location, Install Date, and Screened Interval**

| Probe ID | Latitude[1] | Longitude[1] | Install Date | Screened Interval (feet below ground surface) |
|---|---|---|---|---|
| **SG-1** | 47.4005500 | -101.1836200 | 9/16/2022 | 4–5 |
| **SG-2** | 47.3793500 | -101.1714056 | 9/18/2022 | 4–5 |
| **SG-3** | 47.3749700 | -101.1537100 | 9/18/2022 | 2.3–3.3 |
| **SG-4** | 47.3749700 | -101.1681000 | 9/18/2022 | 4–5 |
| **SG-5** | 47.3888900 | -101.1640200 | 9/16/2022 | 4–5 |
| **PRT-1a** | 47.4005500 | -101.1836200 | 9/16/2022 | 4–5 |
| **PRT-1b** | 47.4004355 | -101.1714056 | 12/1/2022 | 2–2.5 |
| **PRT-1c** | 47.4003990 | -101.1632560 | 3/8/2023 | 1.1–1.4 |
| **PRT-2** | 47.3857710 | -101.1851053 | 3/8/2023 | 3–3.5 |
| **PRT-4a** | 47.3714766 | -101.1636807 | 12/3/2022 | 2–2.5 |
| **PRT-4b** | 47.3713500 | -101.1638330 | 3/8/2023 | 1.1–1.4 |
| **PRT-5** | 47.3888900 | -101.1640200 | 9/16/2022 | 4–5 |

[1] Coordinates are in North American Datum (NAD) 1983

All soil gas and ambient air samples were collected by Vista Geoscience, and all compositional and stable isotopic analyses were performed by Dolan Integration Group (DIG). The sampling locations for both soil gas and ambient air are the same. Due to site accessibility issues (e.g., snow cover during the winter months) associated with select soil gas probe locations, alternate sites (designated with PRT-#) were selected for acquiring the baseline soil gas and ambient air data. The alternate sites were nested together with the previously installed probe locations (SG-1–SG-5) where possible. The locations of all soil gas and ambient air sample sites are shown in Figure 1.

,.

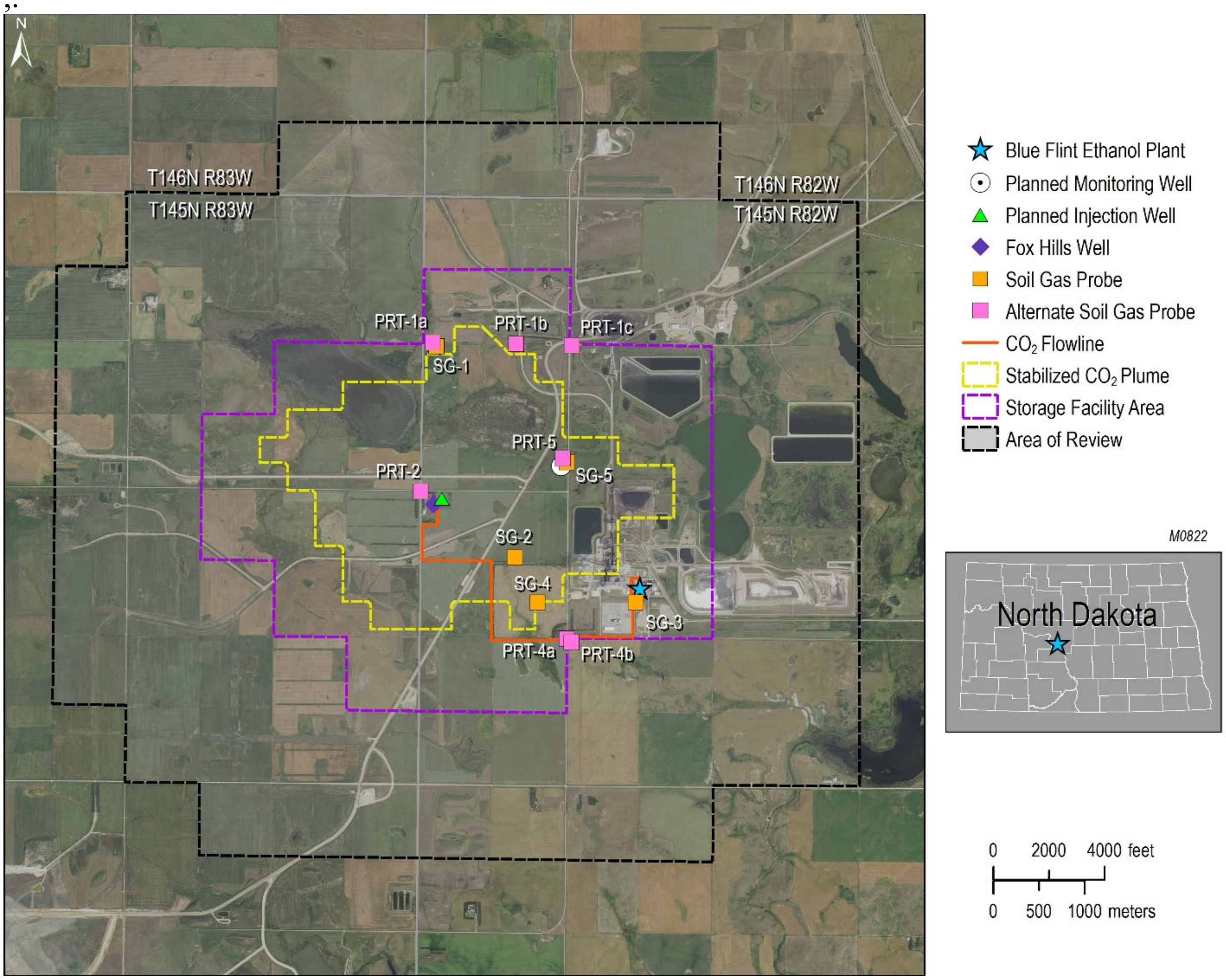



Figure 1. Map illustrating the locations of the previously installed soil gas probes (SG-1–SG-5) and alternate probe locations (PRT-# series) for establishing baseline conditions at the project site.

**Baseline Groundwater Sampling Results**

Blue Flint has initiated a baseline groundwater sampling program for the Blue Flint $CO_2$ storage project. The results of groundwater sampling in September 2022 and December 2022 are provided in laboratory reports appended to this short report. Minnesota Valley Testing Laboratories (MVTL) was the state-certified laboratory selected to collect and analyze all water samples. Results for the Fox Hills (lowest USDW) monitoring well near the planned $CO_2$ injection well (MAG 1) and shallow groundwater wells FA-Sec25, FA-Sec5, and Landenberger are included in the reports. As shown in Figure 2, the Landenberger was selected as an alternative sampling site for wells 121-1, 122-1, and FA-Sec26, all of which could not be accessed for baseline groundwater sampling. Blue Flint has collected a third round of water samples from the project area and is awaiting the laboratory results from MVTL.

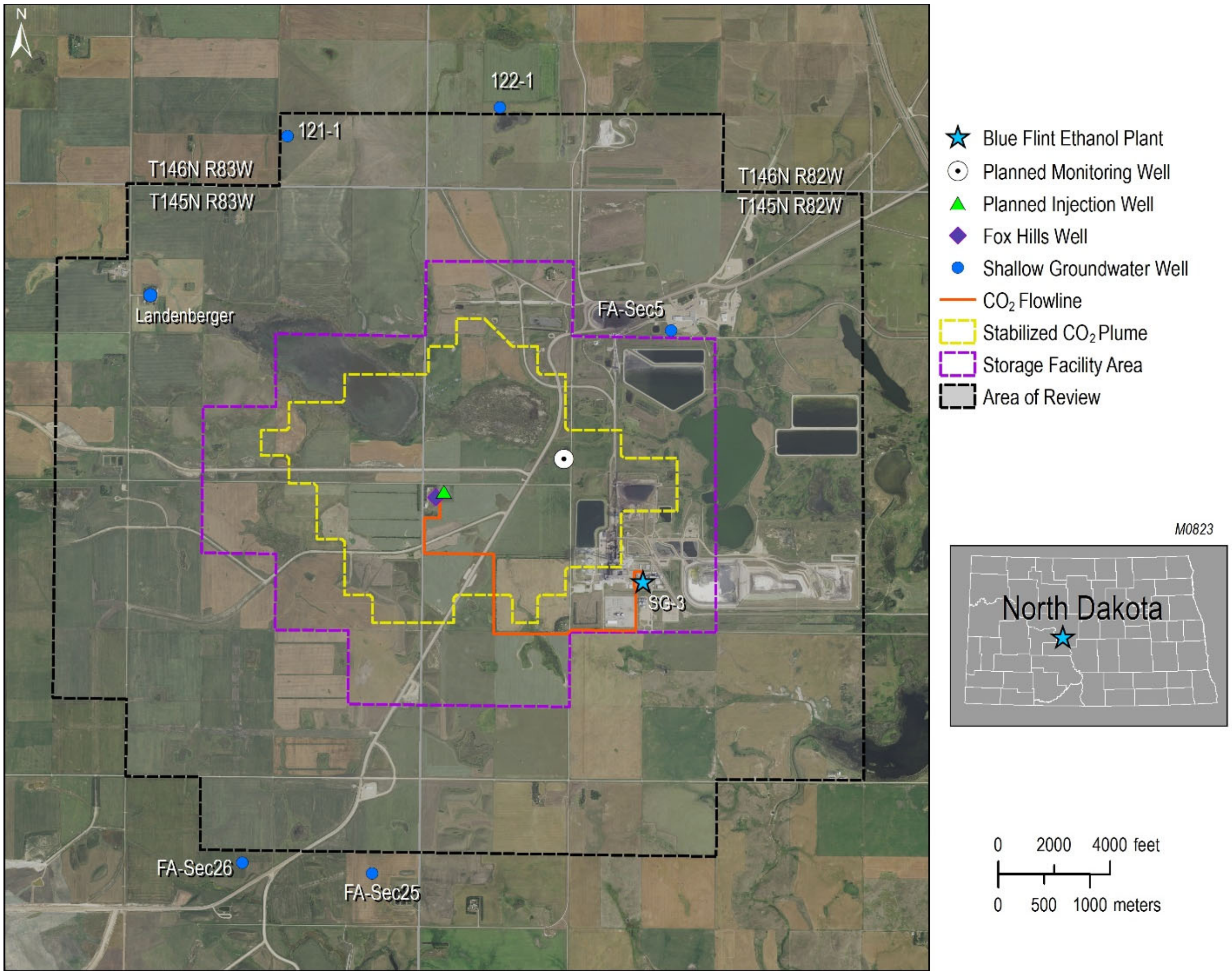



Figure 2. Map illustrating the locations of the shallow groundwater well locations either planned for sampling or sampled as part of its baseline data acquisition activities. The Fox Hills well near the planned $CO_2$ injection well (MAG 1) and wells FA-Sec5, FA-Sec25, and Landenberger have all been sampled as part of Blue Flint's baseline groundwater sampling activities.

**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

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint
**Workorder:** Midwest Ag Energy (6782)

Adam Dunlop
Blue Flint Ethanol
2841 3rd ST SW
Underwood, ND 58576

**Certificate of Analysis**

## Approval

**All data reported has been reviewed and approved by:**

C. Carroll

Claudette Carroll, Lab Manager Bismarck, ND

Dave Smahel, Inorganic Chemistry/Feed Lab Manager New Ulm, MN

Analyses performed under Minnesota Department of Health Accreditation conforms to the current TNI standards.

NEW ULM LAB CERTIFICATIONS:
MN LAB # 027-015-125 ND WW/DW # R-040

BISMARCK LAB CERTIFICATIONS:
MN LAB # 038-999-267 ND W/DW # ND-016 SD SDWA



Report Date: Wednesday, January 25, 2023 1:23:25 PM

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Workorder Summary

### Workorder Comments

All analytes with dilution factors greater than 1 (displayed in DF column) required dilution due to matrix or high concentration of target analyte unless otherwise noted and reporting limits (RDL column) have been adjusted accordingly.

### Analysis Results Comments

***6782001 (USDW)***

Matrix spike and/or matrix spike duplicate recoveries were low. Low recoveries were due to the amount of spike added and the use of HCl in the metals digestion process. Data was accepted based on the acceptable recoveries of the post digestion spikes and/or LCS. (Silver)

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 6782001 | **Date Collected:** | 12/28/2022 14:35 | **Matrix:** | Groundwater |
| **Sample ID:** | USDW | **Date Received:** | 12/28/2022 16:08 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 8.1 **Received on Ice:** Yes

### Calculated

**Method: SM1030F**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Cation Summation | **24.8** | meq/L | | 1 | 01/24/2023 14:26 | 01/24/2023 14:26 | CW | | |
| Anion Summation | **26.0** | meq/L | | 1 | 01/24/2023 14:26 | 01/24/2023 14:26 | CW | | |
| Percent Difference | **-2.28** | % | | 1 | 01/24/2023 14:26 | 01/24/2023 14:26 | CW | | |

### Inorganic Chemistry

**Method: ASTM D516-16**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfate | <5 | mg/L | 5 | 1 | 01/04/2023 09:16 | 01/04/2023 09:16 | AMC | MA,NDA | |

**Method: EPA 300.0**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Bromide | **2.58** | mg/L | 0.100 | 1 | 01/11/2023 15:14 | 01/11/2023 15:14 | MDH | MA,NDA | |

**Method: EPA 353.2**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Nitrate + Nitrite as N | <0.2 | mg/L | 0.2 | 1 | 01/19/2023 09:14 | 01/19/2023 09:14 | AMC | MA,NDA | |

**Method: EPA 365.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Phosphorus as P | **0.15** | mg/L | 0.1 | 1 | 12/29/2022 08:17 | 12/30/2022 09:16 | AMC | MA,NDA | |
| Phosphorus as P, Dissolved | **0.13** | mg/L | 0.1 | 1 | 12/29/2022 09:53 | 12/30/2022 09:55 | AMC | | |

**Method: SM 5310C-2014**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Dissolved Organic Carbon | **1.2** | mg/L | 1 | 1 | 01/06/2023 11:31 | 01/06/2023 11:31 | NS | MA,NDA | |
| Total Organic Carbon | **1.1** | mg/L | 0.5 | 1 | 01/06/2023 11:31 | 01/06/2023 11:31 | NS | MA,NDA | |

**Method: SM2320 B-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Alkalinity, Total | **894** | mg/L as CaCO3 | 20.5 | 1 | 12/30/2022 13:51 | 12/30/2022 13:51 | RAA | MA,NDA | |
| Alkalinity, Phenolphthalein | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 12/30/2022 13:51 | 12/30/2022 13:51 | RAA | | |



Report Date: Wednesday, January 25, 2023 1:23:25 PM

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 6782001 | **Date Collected:** | 12/28/2022 14:35 | **Matrix:** | Groundwater |
| **Sample ID:** | USDW | **Date Received:** | 12/28/2022 16:08 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 8.1 | **Received on Ice:** | Yes | | |

### Inorganic Chemistry

**Method: SM2320 B-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Carbonate | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 12/30/2022 13:51 | 12/30/2022 13:51 | RAA | | |
| Bicarbonate | **894** | mg/L as CaCO3 | 20.5 | 1 | 12/30/2022 13:51 | 12/30/2022 13:51 | RAA | | |
| Hydroxide | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 12/30/2022 13:51 | 12/30/2022 13:51 | RAA | | |

**Method: SM4500-Cl-E 2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Chloride | **286** | mg/L | 2.0 | 1 | 12/29/2022 15:11 | 12/29/2022 15:11 | AMC | MA,NDA | |

**Method: SM4500-F-C-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Fluoride | **4.50** | mg/L | 1 | 10 | 12/30/2022 13:51 | 12/30/2022 13:51 | RAA | | |

**Method: SM4500S2 D-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfide | <50 | ug/L | 50 | 1 | 12/30/2022 12:00 | 12/30/2022 12:00 | CMG | MA,NDA | |

**Method: USGS I-1750-85**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Total Dissolved Solids | **1490** | mg/L | 10 | 1 | 12/30/2022 08:51 | 12/30/2022 08:51 | RAA | MA,NDA | |

### Metals

**Method: EPA 200.7/SW6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Silicates as SiO2 | **12.6** | mg/L | 0.214 | 1 | 01/24/2023 14:26 | 01/24/2023 14:26 | CW | | |

**Method: EPA 245.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Mercury | **0.0002** | mg/L | 0.0002 | 1 | 01/06/2023 14:45 | 01/06/2023 15:24 | MDE | MA,NDA, SDA | |
| Mercury, Dissolved | <0.0002 | mg/L | 0.0002 | 1 | 01/06/2023 14:46 | 01/06/2023 15:24 | MDE | MA,NDA | |

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Aluminum | <0.1 | mg/L | 0.1 | 1 | 12/29/2022 16:24 | 01/04/2023 10:19 | SLZ | MA,NDA | |



Report Date: Wednesday, January 25, 2023 1:23:25 PM

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 6782001 | **Date Collected:** | 12/28/2022 14:35 | **Matrix:** | Groundwater |
| **Sample ID:** | USDW | **Date Received:** | 12/28/2022 16:08 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 8.1 **Received on Ice:** Yes

### Metals

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Boron | **2.13** | mg/L | 1 | 10 | 12/29/2022 16:24 | 01/05/2023 10:57 | SLZ | MA,NDA | |
| Barium | <0.1 | mg/L | 0.1 | 1 | 12/29/2022 16:24 | 01/04/2023 10:19 | SLZ | MA,NDA | |
| Calcium | **4.81** | mg/L | 1 | 1 | 12/29/2022 16:24 | 12/30/2022 11:45 | MDE | MA,NDA | |
| Iron | <0.1 | mg/L | 0.1 | 1 | 12/29/2022 16:24 | 01/04/2023 10:19 | SLZ | MA,NDA | |
| Potassium | **3.07** | mg/L | 1 | 1 | 12/29/2022 16:24 | 12/30/2022 11:45 | MDE | MA,NDA | |
| Magnesium | <1 | mg/L | 1 | 1 | 12/29/2022 16:24 | 12/30/2022 11:45 | MDE | MA,NDA | |
| Sodium | **597** | mg/L | 5 | 5 | 12/29/2022 16:24 | 12/30/2022 14:50 | MDE | MA,NDA | |
| Strontium | **0.10** | mg/L | 0.1 | 1 | 12/29/2022 16:24 | 01/04/2023 10:19 | SLZ | MA,NDA | |
| Zinc | <0.05 | mg/L | 0.05 | 1 | 12/29/2022 16:24 | 01/04/2023 10:19 | SLZ | MA,NDA | |
| Lithium | **0.0728** | mg/L | 0.02 | 1 | 12/29/2022 16:24 | 01/06/2023 09:25 | SLZ | NDA | |
| Silicon | **5.90** | mg/L | 0.1 | 1 | 12/29/2022 16:24 | 01/06/2023 10:56 | SLZ | MA,NDA | |
| Aluminum, Dissolved | <0.1 | mg/L | 0.1 | 1 | 12/29/2022 10:31 | 01/04/2023 10:41 | SLZ | MA,NDA | |
| Boron, Dissolved | **2.05** | mg/L | 1 | 10 | 12/29/2022 10:31 | 01/05/2023 11:17 | SLZ | MA,NDA | |
| Barium, Dissolved | <0.1 | mg/L | 0.1 | 1 | 12/29/2022 10:31 | 01/04/2023 10:41 | SLZ | MA,NDA | |
| Calcium, Dissolved | **4.80** | mg/L | 1 | 1 | 12/29/2022 10:31 | 12/30/2022 12:02 | MDE | MA,NDA | |
| Iron, Dissolved | <0.1 | mg/L | 0.1 | 1 | 12/29/2022 10:31 | 01/04/2023 10:41 | SLZ | MA,NDA | |
| Potassium, Dissolved | **3.43** | mg/L | 1 | 1 | 12/29/2022 10:31 | 12/30/2022 12:02 | MDE | MA,NDA | |
| Magnesium, Dissolved | <1 | mg/L | 1 | 1 | 12/29/2022 10:31 | 12/30/2022 12:02 | MDE | MA,NDA | |
| Sodium, Dissolved | **562** | mg/L | 1 | 1 | 12/29/2022 10:31 | 12/30/2022 12:02 | MDE | MA,NDA | |
| Strontium, Dissolved | **0.10** | mg/L | 0.1 | 1 | 12/29/2022 10:31 | 01/04/2023 10:41 | SLZ | MA,NDA | |
| Zinc, Dissolved | <0.05 | mg/L | 0.05 | 1 | 12/29/2022 10:31 | 01/04/2023 10:41 | SLZ | MA,NDA | |
| Lithium, Dissolved | **0.0771** | mg/L | 0.02 | 1 | 12/29/2022 10:31 | 01/06/2023 09:27 | SLZ | NDA | |
| Silicon, Dissolved | **5.90** | mg/L | 0.1 | 1 | 12/29/2022 10:31 | 01/06/2023 10:58 | SLZ | MA,NDA | |



Report Date: Wednesday, January 25, 2023 1:23:25 PM

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

**Lab ID:** 6782001 **Date Collected:** 12/28/2022 14:35 **Matrix:** Groundwater
**Sample ID:** USDW **Date Received:** 12/28/2022 16:08 **Collector:** MVTL Field Service

**Temp @ Receipt (C):** 8.1 **Received on Ice:** Yes

### Metals

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Beryllium | <0.0005 | mg/L | 0.0005 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Beryllium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Vanadium | <0.002 | mg/L | 0.002 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Vanadium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Chromium | <0.002 | mg/L | 0.002 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Chromium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Manganese | **0.0083** | mg/L | 0.002 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Manganese, Dissolved | **0.0076** | mg/L | 0.002 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Cobalt | <0.002 | mg/L | 0.002 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Cobalt, Dissolved | <0.002 | mg/L | 0.002 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Nickel | <0.005 | mg/L | 0.005 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Nickel, Dissolved | <0.005 | mg/L | 0.005 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Copper | <0.005 | mg/L | 0.005 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Copper, Dissolved | <0.005 | mg/L | 0.005 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Arsenic | <0.002 | mg/L | 0.002 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Arsenic, Dissolved | <0.002 | mg/L | 0.002 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Selenium | <0.005 | mg/L | 0.005 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Selenium, Dissolved | <0.005 | mg/L | 0.005 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Molybdenum | **0.0063** | mg/L | 0.002 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Molybdenum, Dissolved | **0.0066** | mg/L | 0.002 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Silver | <0.0005 | mg/L | 0.0005 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | * |
| Silver, Dissolved | <0.001 | mg/L | 0.001 | 10 | 12/29/2022 10:31 | 01/06/2023 15:11 | MDE | MA,NDA | |
| Cadmium | <0.0005 | mg/L | 0.0005 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Cadmium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |



Report Date: Wednesday, January 25, 2023 1:23:25 PM

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 6782001 | **Date Collected:** | 12/28/2022 14:35 | **Matrix:** | Groundwater |
| **Sample ID:** | USDW | **Date Received:** | 12/28/2022 16:08 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 8.1 **Received on Ice:** Yes

### Metals

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Antimony | <0.001 | mg/L | 0.001 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Antimony, Dissolved | <0.001 | mg/L | 0.001 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Thallium | <0.0005 | mg/L | 0.0005 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Thallium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Lead | <0.0005 | mg/L | 0.0005 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | MA,NDA | |
| Lead, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 12/29/2022 10:31 | 01/05/2023 17:57 | MDE | MA,NDA | |
| Uranium | <0.002 | mg/L | 0.002 | 5 | 12/29/2022 16:24 | 01/05/2023 16:52 | MDE | | |
| Uranium, Dissolved | <0.004 | mg/L | 0.004 | 10 | 12/29/2022 10:31 | 01/06/2023 15:11 | MDE | MA,NDA | |

### Sampling Information

**Method: 120.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Specific Conductance - Field | **2522** | umhos/cm | 1 | 1 | 12/28/2022 14:35 | 12/28/2022 14:35 | DJN | | |

**Method: 150.2**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| pH - Field | **8.36** | units | 0.01 | 1 | 12/28/2022 14:35 | 12/28/2022 14:35 | DJN | | |

**Method: 170.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Temperature - Field C | **11.5** | degrees C | | 1 | 12/28/2022 14:35 | 12/28/2022 14:35 | DJN | | |

**Method: EPA 180.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Turbidity - Field | **12.67** | NTU | 0.1 | 1 | 12/28/2022 14:35 | 12/28/2022 14:35 | DJN | | |

**Method: Field Method**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Pumping Rate - Field | **8** | gpm | | 1 | 12/28/2022 14:35 | 12/28/2022 14:35 | DJN | | |

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 6782001 | **Date Collected:** | 12/28/2022 14:35 | **Matrix:** | Groundwater |
| **Sample ID:** | USDW | **Date Received:** | 12/28/2022 16:08 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 8.1 | **Received on Ice:** | Yes | | |

### Sampling Information

**Method: SM2110**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Appearance - Field | Clear | | | 1 | 12/28/2022 14:35 | 12/28/2022 14:35 | DJN | | |

**Method: SM2580B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| EH - Field | **-194.1** | mV | | 1 | 12/28/2022 14:35 | 12/28/2022 14:35 | DJN | | |

**Method: SM4500 O G-93**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Dissolved Oxygen - Field | <0.1 | mg/L | 0.1 | 1 | 12/28/2022 14:35 | 12/28/2022 14:35 | DJN | | |

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**

1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com


Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

Minnesota Valley Testing Laboratories
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Midwest Ag Energy Blue Fl
WO: 6782

## Chain of Custody Record

| | |
|---|---|
| Report To: | Midwest AgEnergy |
| Attn: | Adam Dunlop |
| Address: | 2841 3rd St SW<br>Underwood, ND 58576 |
| Phone: | 701-442-7500 |
| Email: | adunlop@midwestagenergy.com |
| CC: | |
| Project Name: | Midwest AgEnergy |
| Event: | |
| Sampled By: | Darren Niewaas |

| Lab Number | Sample ID | Date | Time | Sample Type | 1 Liter Raw | 500 mL HNO3 | 500 mL HNO3 (filtered) | 250 mL H2SO4 | 250mL H2SO4 (filtered) | DOC (set of 3) (filtered) | TOC (set of 3) | 1 Liter NaOH/Zinc | 125mL Raw | | Temp (°C) | Spec. Cond. | pH | | Analysis Required |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 001 | USDW | 28Dec22 | 1435 | GW | X | X | X | X | X | X | X | X | X | | 11.50 | 2522 | 8.36 | | AgEnergy List |

Comments:

| Relinquished By Name | Date/Time | Sample Condition Location | Temp (°C) | Received By Name | Date/Time |
|---|---|---|---|---|---|
| 1 [signature] | 28Dec22 1608 | Log In<br>Walk In #2 | TM920 8.1<br>TM562 / TM805 | [signature] | 28Dec22 1608 |
| 2 | | | | | |



Report Date: Wednesday, January 25, 2023 1:23:25 PM

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

**Minnesota Valley Testing Laboratories**
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

## Chain of Custody Record

| | | | |
|---|---|---|---|
| Report To: | Midwest AgEnergy | CC: | Project Name: Midwest AgEnergy |
| Attn: | Adam Dunlop | | Event: |
| Address: | 2841 3rd St SW<br>Underwood, ND 58576 | | Sampled By: Darren Nieswaag |
| Phone: | 701-442-7500 | | |
| Email: | adunlop@midwestagenergy.com | | |

| Lab Number | Sample ID | Date | Time | Sample Type | 1 Liter Raw | 1 Liter Raw (filtered) | Analysis Required |
|---|---|---|---|---|---|---|---|
| | USDW | 28Dec22 | 1435 | GW | X | | dD &18O, TEE |
| | USDW | 28Dec22 | 1435 | GW | | X | RAG |

Comments:

| | Relinquished By Name | Date/Time | Sample Condition Location | Temp (°C) | Received By Name | Date/Time |
|---|---|---|---|---|---|---|
| 1 | [signature] | 28Dec22 1608 | Log In / Walk In #2 | TM420 8.1 TM562 / TM805 | [signature] | 28Dec22 1608 |
| 2 | | | | | | |

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

**Minnesota Valley Testing Laboratories**
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

## Chain of Custody Record

Report To: **Midwest AgEnergy**
Attn: Adam Dunlop
Address: 2841 3rd St SW
Underwood, ND 58576
Phone: 701-442-7500
Email: adunlop@midwestagenergy.com

CC:

Project Name: **Midwest AgEnergy**
Event:
Sampled By: Darren Niesmaag

| Lab Number | Sample ID | Date | Time | Sample Type | 500mL Amber Raw | 500mL Amber (filtered) | Analysis Required |
|---|---|---|---|---|---|---|---|
| | USDW | 28Dec22 | 1435 | GW | X | | Total Inorganic Carbon |
| | USDW | 28Dec22 | 1435 | GW | | X | Dissolved Inorganic Carbon |

Comments:

| | Relinquished By Name | Date/Time | Sample Condition Location | Temp (°C) | Received By Name | Date/Time |
|---|---|---|---|---|---|---|
| 1 | [signature] | 28Dec22 1608 | ~~Log In~~ Walk In #2 | TM920 8.1 TM562 / TM805 | [signature] | 28Dec22 1608 |
| 2 | | | | | | |

MVTL

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

MVTL
2616 E. Broadway Ave, Bismarck, ND
Phone: (701) 258-9720

# Field Datasheet
Monitoring Well

Company: Midwest AgEnergy
Event:
Sample ID: USDW
Sampling Personal: Darren Nieswang

**Weather Conditions:** Temp: 25 °F Wind: Light @ Precip: Sunny / Partly Cloudy / Cloudy

**SITE INFORMATION**

| Source: | Well |
|---|---|

| | Date | Time | GPM |
|---|---|---|---|
| Purge Start: | 28Dec22 | 0935 | 8.0 |

**SAMPLING INFORMATION**

| Sampling Method: | Grab |
|---|---|

| Bottle List: | |
|---|---|
| 1 Liter Raw | 3 DOC |
| 500mL Nitric | 3 TOC |
| 500mL Nitric (filtered) | 1 L NaOH/Zinc |
| 250mL Sulfuric | 125mL Raw |

| Sample Date | Time | Temp. (°C) | Spec. Cond. | pH | DO (mg/L | ORP (mV) | Turbidity (NTU) | | | | Appearance or Comment Clarity, Color, Odor, Ect. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 28Dec22 | 1435 | 11.50 | 2522 | 8.36 | 0.04 | -194.1 | 12.67 | | | | clear |

| Comments: | |
|---|---|



Report Date: Wednesday, January 25, 2023 1:23:25 PM

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

EERC Energy & Environmental Research Center

UNIVERSITY OF NORTH DAKOTA

15 North 23rd Street -- Stop 9018 / Grand Forks, ND 58202-9018 / Phone: (701) 777-5000 Fax: 777-5181
Web Site: www.undeerc.org

## ANALYTICAL RESEARCH LAB - Final Results

*January 6, 2023*

**Set Number:** 55062
**Fund#:** 8032
**PI:** Jacob Loing
**Contact Person:** C. Nyberg

**Request Date:** Friday, January 6, 2023
**Due Date:** Friday, January 20, 2023
**Set Description:** USDW Sample for DIC/TIC

| Sample | Parameter | Result |
|---|---|---|
| **55062-01** | **MVTL #6782001** | |
| | Dissolved Inorganic Carbon | 234 mg/L |
| | Total Inorganic Carbon | 233 mg/L |

Distribution Carolyn Nyberg Date 1/6/23

1 of 1

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint
**Workorder:** Carbon Capture (3344)

Adam Dunlop
Blue Flint Ethanol
2841 3rd ST SW
Underwood, ND 58576

**Certificate of Analysis**

## Approval

**All data reported has been reviewed and approved by:**

C. Carroll

Claudette Carroll, Lab Manager Bismarck, ND

Dave Smahel, Inorganic Chemistry/Feed Lab Manager New Ulm, MN

Analyses performed under Minnesota Department of Health Accreditation conforms to the current TNI standards.

NEW ULM LAB CERTIFICATIONS:
MN LAB # 027-015-125 ND WW/DW # R-040

BISMARCK LAB CERTIFICATIONS:
MN LAB # 038-999-267 ND W/DW # ND-016 SD SDWA

**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

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Workorder Summary

### Workorder Comments

All analytes with dilution factors greater than 1 (displayed in DF column) required dilution due to matrix or high concentration of target analyte unless otherwise noted and reporting limits (RDL column) have been adjusted accordingly.

### Batch Comments

***METb/635 - 200.7/6010 DP Dis MinAnaly Bis***

Sodium detected in method blanks above one half the reporting limit. The reporting limit has been raised.

### Analysis Results Comments

***3344001 (USDW)***

Target analyte detected in method blank at one half or greater of reporting limit. Reporting limit has been elevated.(Alkalinity, Total)

***3344001 (USDW)***

Sample required dilution due to high concentration of target analyte(s). Reporting limit has been raised.
(Bromide)

***3344001 (USDW)***

Matrix spike and/or matrix spike duplicate recoveries were low. Low recoveries were due to the amount of spike added and the use of HCl in the metals digestion process. Data was accepted based on the acceptable recoveries of the post digestion spikes and/or LCS. (Silver)

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 3344001 | **Date Collected:** | 09/16/2022 13:30 | **Matrix:** | Groundwater |
| **Sample ID:** | USDW | **Date Received:** | 09/16/2022 15:30 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 9.0 **Received on Ice:** Yes

### Calculated

**Method: SM1030F**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Cation Summation | **27.8** | meq/L | | 1 | 10/04/2022 14:00 | 10/04/2022 14:00 | CW | | |
| Anion Summation | **26.1** | meq/L | | 1 | 10/04/2022 14:00 | 10/04/2022 14:00 | CW | | |
| Percent Difference | **3.14** | % | | 1 | 10/04/2022 14:00 | 10/04/2022 14:00 | CW | | |

### Inorganic Chemistry

**Method: ASTM D516-16**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfate | <5 | mg/L | 5 | 1 | 09/21/2022 11:45 | 09/21/2022 11:45 | EJV | MA,NDA | |

**Method: EPA 300.0**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Bromide | **2.56** | mg/L | 0.500 | 5 | 09/22/2022 13:23 | 09/22/2022 13:23 | RMV | MA,NDA | * |

**Method: EPA 353.2**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Nitrate + Nitrite as N | <0.2 | mg/L | 0.2 | 1 | 09/22/2022 11:20 | 09/22/2022 11:20 | EJV | MA,NDA | |

**Method: EPA 365.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Phosphorus as P | <0.4 | mg/L | 0.1 | 1 | 09/22/2022 16:09 | 09/23/2022 08:54 | EJV | MA,NDA | |
| Phosphorus as P, Dissolved | **0.28** | mg/L | 0.1 | 1 | 09/22/2022 16:07 | 09/23/2022 11:23 | EJV | | |

**Method: SM 5310C-2014**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Dissolved Organic Carbon | **1.1** | mg/L | 1 | 1 | 09/23/2022 23:39 | 09/23/2022 23:39 | NS | MA,NDA | |
| Total Organic Carbon | **0.9** | mg/L | 0.5 | 1 | 09/23/2022 23:26 | 09/23/2022 23:26 | NS | MA,NDA | |

**Method: SM2320 B-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Alkalinity, Total | **909** | mg/L as CaCO3 | 20.5 | 1 | 09/17/2022 00:07 | 09/17/2022 00:07 | RAA | MA,NDA | * |
| Alkalinity, Phenolphthalein | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 09/17/2022 00:07 | 09/17/2022 00:07 | RAA | | |



Report Date: Thursday, November 3, 2022 3:53:11 PM

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 3344001 | **Date Collected:** | 09/16/2022 13:30 | **Matrix:** | Groundwater |
| **Sample ID:** | USDW | **Date Received:** | 09/16/2022 15:30 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 9.0 **Received on Ice:** Yes

### Inorganic Chemistry

**Method: SM2320 B-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Carbonate | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 09/17/2022 00:07 | 09/17/2022 00:07 | RAA | | |
| Bicarbonate | **909** | mg/L as CaCO3 | 20.5 | 1 | 09/17/2022 00:07 | 09/17/2022 00:07 | RAA | | |
| Hydroxide | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 09/17/2022 00:07 | 09/17/2022 00:07 | RAA | | |

**Method: SM4500-Cl-E 2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Chloride | **281** | mg/L | 2.0 | 1 | 09/26/2022 09:52 | 09/26/2022 09:52 | EJV | MA,NDA | |

**Method: SM4500-F-C-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Fluoride | **4.40** | mg/L | 1 | 10 | 09/19/2022 12:18 | 09/19/2022 12:18 | RAA | | |

**Method: SM4500S2 D-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfide | <50 | ug/L | 50 | 1 | 09/19/2022 09:00 | 09/19/2022 09:00 | CMG | MA,NDA | |

**Method: USGS I-1750-85**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Total Dissolved Solids | **1500** | mg/L | 10 | 1 | 09/20/2022 14:00 | 09/20/2022 14:00 | RAA | MA,NDA | |

### Metals

**Method: EPA 200.7/SW6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Silicates as SiO2 | **22.4** | mg/L | 0.214 | 1 | 10/04/2022 14:00 | 10/04/2022 14:00 | CW | | |

**Method: EPA 245.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Mercury | <0.001 | mg/L | 0.001 | 5 | 09/20/2022 14:35 | 09/20/2022 14:55 | MDE | MA,NDA, SDA | |
| Mercury, Dissolved | <0.001 | mg/L | 0.001 | 5 | 09/20/2022 14:37 | 09/20/2022 15:24 | MDE | MA,NDA | |

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Aluminum | **2.07** | mg/L | 1 | 10 | 09/16/2022 17:12 | 09/21/2022 16:18 | SLZ | MA,NDA | |



Report Date: Thursday, November 3, 2022 3:53:11 PM

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 3344001 | **Date Collected:** | 09/16/2022 13:30 | **Matrix:** | Groundwater |
| **Sample ID:** | USDW | **Date Received:** | 09/16/2022 15:30 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 9.0 | **Received on Ice:** | Yes | | |

### Metals

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Boron | **2.68** | mg/L | 0.1 | 1 | 09/16/2022 17:12 | 09/23/2022 15:17 | SLZ | MA,NDA | |
| Barium | <0.1 | mg/L | 0.1 | 1 | 09/16/2022 17:12 | 09/21/2022 11:49 | SLZ | MA,NDA | |
| Calcium | **4.76** | mg/L | 1 | 1 | 09/16/2022 17:12 | 09/28/2022 10:21 | MDE | MA,NDA | |
| Iron | **3.70** | mg/L | 1 | 10 | 09/16/2022 17:12 | 09/21/2022 16:18 | SLZ | MA,NDA | |
| Potassium | **3.20** | mg/L | 1 | 1 | 09/16/2022 17:12 | 09/28/2022 10:21 | MDE | MA,NDA | |
| Magnesium | **1.04** | mg/L | 1 | 1 | 09/16/2022 17:12 | 09/28/2022 10:21 | MDE | MA,NDA | |
| Sodium | **635** | mg/L | 5 | 5 | 09/16/2022 17:12 | 09/28/2022 14:01 | MDE | MA,NDA | |
| Strontium | **0.11** | mg/L | 0.1 | 1 | 09/16/2022 17:12 | 09/21/2022 11:49 | SLZ | MA,NDA | |
| Zinc | <0.05 | mg/L | 0.05 | 1 | 09/16/2022 17:12 | 09/21/2022 11:49 | SLZ | MA,NDA | |
| Lithium | **0.0781** | mg/L | 0.02 | 1 | 09/16/2022 17:12 | 09/22/2022 16:33 | SLZ | NDA | |
| Silicon | **10.5** | mg/L | 0.1 | 1 | 09/16/2022 17:12 | 09/22/2022 10:04 | SLZ | MA,NDA | |
| Aluminum, Dissolved | <0.1 | mg/L | 0.1 | 1 | 09/19/2022 08:49 | 09/19/2022 12:15 | SLZ | MA,NDA | |
| Boron, Dissolved | **2.67** | mg/L | 0.1 | 1 | 09/19/2022 08:49 | 09/23/2022 14:50 | SLZ | MA,NDA | |
| Barium, Dissolved | <0.1 | mg/L | 0.1 | 1 | 09/19/2022 08:49 | 09/19/2022 12:15 | SLZ | MA,NDA | |
| Calcium, Dissolved | **4.80** | mg/L | 1 | 1 | 09/19/2022 08:49 | 10/03/2022 13:17 | SLZ | MA,NDA | |
| Iron, Dissolved | <0.1 | mg/L | 0.1 | 1 | 09/19/2022 08:49 | 09/19/2022 12:15 | SLZ | MA,NDA | |
| Potassium, Dissolved | **2.86** | mg/L | 1 | 1 | 09/19/2022 08:49 | 10/03/2022 13:17 | SLZ | MA,NDA | |
| Magnesium, Dissolved | **1.05** | mg/L | 1 | 1 | 09/19/2022 08:49 | 10/03/2022 13:17 | SLZ | MA,NDA | |
| Sodium, Dissolved | **630** | mg/L | 2 | 1 | 09/19/2022 08:49 | 10/03/2022 13:17 | SLZ | MA,NDA | |
| Strontium, Dissolved | **0.10** | mg/L | 0.1 | 1 | 09/19/2022 08:49 | 09/19/2022 12:15 | SLZ | MA,NDA | |
| Zinc, Dissolved | <0.05 | mg/L | 0.05 | 1 | 09/19/2022 08:49 | 09/19/2022 12:15 | SLZ | MA,NDA | |
| Lithium, Dissolved | **0.0753** | mg/L | 0.02 | 1 | 09/19/2022 08:49 | 09/22/2022 16:46 | SLZ | NDA | |
| Silicon, Dissolved | **5.74** | mg/L | 0.1 | 1 | 09/19/2022 08:49 | 09/22/2022 10:07 | SLZ | MA,NDA | |



Report Date: Thursday, November 3, 2022 3:53:11 PM

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 3344001 | **Date Collected:** | 09/16/2022 13:30 | **Matrix:** | Groundwater |
| **Sample ID:** | USDW | **Date Received:** | 09/16/2022 15:30 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 9.0 **Received on Ice:** Yes

### Metals

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Beryllium | <0.0005 | mg/L | 0.0005 | 5 | 09/16/2022 17:12 | 09/27/2022 11:59 | MDE | MA,NDA | |
| Beryllium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Vanadium | **0.0047** | mg/L | 0.002 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Vanadium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Chromium | **0.0084** | mg/L | 0.002 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Chromium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Manganese | **0.0865** | mg/L | 0.002 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Manganese, Dissolved | **0.0043** | mg/L | 0.002 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Cobalt | <0.002 | mg/L | 0.002 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Cobalt, Dissolved | <0.002 | mg/L | 0.002 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Nickel | **0.0049** | mg/L | 0.002 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Nickel, Dissolved | <0.002 | mg/L | 0.002 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Copper | **0.0028** | mg/L | 0.002 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Copper, Dissolved | <0.002 | mg/L | 0.002 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Arsenic | **0.0037** | mg/L | 0.002 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Arsenic, Dissolved | <0.002 | mg/L | 0.002 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Selenium | <0.005 | mg/L | 0.005 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Selenium, Dissolved | <0.005 | mg/L | 0.005 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Molybdenum | **0.0082** | mg/L | 0.002 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Molybdenum, Dissolved | **0.0065** | mg/L | 0.002 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Silver | <0.0005 | mg/L | 0.0005 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | * |
| Silver, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Cadmium | <0.0005 | mg/L | 0.0005 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Cadmium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |



Report Date: Thursday, November 3, 2022 3:53:11 PM

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 3344001 | **Date Collected:** | 09/16/2022 13:30 | **Matrix:** | Groundwater |
| **Sample ID:** | USDW | **Date Received:** | 09/16/2022 15:30 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 9.0 **Received on Ice:** Yes

### Metals

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Antimony | <0.001 | mg/L | 0.001 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Antimony, Dissolved | <0.001 | mg/L | 0.001 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Thallium | <0.0005 | mg/L | 0.0005 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Thallium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Lead | **0.0016** | mg/L | 0.0005 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | MA,NDA | |
| Lead, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |
| Uranium | <0.002 | mg/L | 0.002 | 5 | 09/16/2022 17:12 | 09/26/2022 17:30 | MDE | | |
| Uranium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 09/19/2022 08:49 | 10/04/2022 10:03 | MDE | MA,NDA | |

### Sampling Information

**Method: 120.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Specific Conductance - Field | **2431** | umhos/cm | 1 | 1 | 09/16/2022 13:30 | 09/16/2022 13:30 | JSM | | |

**Method: 150.2**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| pH - Field | **8.34** | units | 0.01 | 1 | 09/16/2022 13:30 | 09/16/2022 13:30 | JSM | | |

**Method: 170.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Temperature - Field C | **14.88** | degrees C | | 1 | 09/16/2022 13:30 | 09/16/2022 13:30 | JSM | | |

**Method: EPA 180.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Turbidity - Field | **10.84** | NTU | 0.1 | 1 | 09/16/2022 13:30 | 09/16/2022 13:30 | JSM | | |

**Method: Field Method**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Pumping Rate - Field | **6** | gpm | | 1 | 09/16/2022 13:30 | 09/16/2022 13:30 | JSM | | |

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 3344001 | **Date Collected:** | 09/16/2022 13:30 | **Matrix:** | Groundwater |
| **Sample ID:** | USDW | **Date Received:** | 09/16/2022 15:30 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 9.0 **Received on Ice:** Yes

### Sampling Information

**Method: SM2110**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Appearance - Field | Clear | | | 1 | 09/16/2022 13:30 | 09/16/2022 13:30 | JSM | | |

**Method: SM2580B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| EH - Field | **-11.8** | mV | | 1 | 09/16/2022 13:30 | 09/16/2022 13:30 | JSM | | |

**Method: SM4500 O G-93**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Dissolved Oxygen - Field | **2.41** | mg/L | 0.1 | 1 | 09/16/2022 13:30 | 09/16/2022 13:30 | JSM | | |

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

**Minnesota Valley Testing Laboratories**
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Midwest Ag Energy Blue Flint
WO: 3344

## Chain of Custody Record

| | | | |
|---|---|---|---|
| Report To: | Midwest AgEnergy | CC: | |
| Attn: | Adam Dunlop | Project Name: | Midwest AgEnergy |
| Address: | 2841 3rd St SW<br>Underwood, ND 58576 | Event: | |
| Phone: | 701-442-7500 | Sampled By: | Jeremy [illegible] |
| Email: | adunlop@midwestagenergy.com | | |

| Lab Number | Sample ID | Date | Time | Sample Type | 1 Liter Raw | 500 mL HNO3 | 500 mL HNO3 (filtered) | 250 mL H2SO4 | 250mL H2SO4 (filtered) | DOC (set of 3) (filtered) | TOC (set of 3) | 1 Liter NaOH/Zinc | 125mL Raw | | Temp (°C) | Spec. Cond. | pH | | Analysis Required |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 001 | USDW | 16 Sept 22 | 1330 | GW | X | X | X | X | X | X | X | X | X | | 14.88 | 2431 | 8.34 | | AgEnergy List |

Comments:

| Relinquished By Name | Date/Time | Sample Condition Location | Temp (°C) | Received By Name | Date/Time |
|---|---|---|---|---|---|
| 1 [signature] | 16 Sept 22 1530 | ~~Log In~~ Walk In #2 | R01 9.0 TM562 / TM805 | C. Cantel | 16 Sep 22 1530 |
| 2 | | | | | |

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

**Minnesota Valley Testing Laboratories**
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

## Chain of Custody Record

Report To: **Midwest AgEnergy**
Attn: Adam Dunlop
Address: 2841 3rd St SW
Underwood, ND 58576
Phone: 701-442-7500
Email: adunlop@midwestagenergy.com

CC:

Project Name: **Midwest AgEnergy**
Event:
Sampled By: Jerry [signature]

| | Sample Information | | | | Sample Containers | | | | | | | | | | Field Readings | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Lab Number | Sample ID | Date | Time | Sample Type | 1 Liter Raw | 1 Liter Raw (filtered) | | | | | | | | | | | | | Analysis Required |
| | USDW | 16Sept22 | 1330 | GW | X | | | | | | | | | | | | | | dD &18O, TEE |
| | USDW | 16Sept22 | 1330 | GW | | X | | | | | | | | | | | | | RAG |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |

Comments:

| | Relinquished By | | Sample Condition | | Received By | |
|---|---|---|---|---|---|---|
| | Name | Date/Time | Location | Temp (°C) | Name | Date/Time |
| 1 | [signature] | 16Sept22 1530 | ~~Log In~~ Walk In #2 | ROI 9.0 TM562 / ~~TM805~~ | [signature] | 16Sept22 1530 |
| 2 | | | | | | |

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

Minnesota Valley Testing Laboratories
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

## Chain of Custody Record

| | | | |
|---|---|---|---|
| Report To: | Midwest AgEnergy | CC: | Project Name: Midwest AgEnergy |
| Attn: | Adam Dunlop | | Event: |
| Address: | 2841 3rd St SW Underwood, ND 58576 | | Sampled By: Jeremy [signature] |
| Phone: | 701-442-7500 | | |
| Email: | adunlop@midwestagenergy.com | | |

| Lab Number | Sample ID | Date | Time | Sample Type | 500mL Amber Raw | 500mL Amber (filtered) | Analysis Required |
|---|---|---|---|---|---|---|---|
| | USDW | 16Sept22 | 1330 | GW | X | | Total Inorganic Carbon |
| | USDW | 16Sept22 | 1330 | GW | | X | Dissolved Inorganic Carbon |

Comments:

| | Relinquished By Name | Date/Time | Sample Condition Location | Temp (°C) | Received By Name | Date/Time |
|---|---|---|---|---|---|---|
| 1 | [signature] | 20Sept22 ~~1005~~ | ~~Log In~~ Walk In #2 | 2.9 TM562 / ~~TM805~~ | [signature] | 16Sept22 1530 |
| 2 | | 16 Sept22 1530 | | | | |

20Sept22

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

ISOTECH
a Stratum Reservoir brand
www.isotechlabs.com

| | | | | | |
|---|---|---|---|---|---|
| Lab #: | 842980 | Job #: 52257 | IS-76159 | Co. Job#: | |
| Sample Name: | USDW | | | Co. Lab#: | 3344001 |
| Company: | MVTL Laboratories | | | | |
| API/Well: | | | | | |
| Container: | 1 Liter Plastic Bottle | | | | |
| Field/Site Name: | WO# 3344 | | | | |
| Location: | | | | | |
| Formation/Depth: | | | | | |
| Sampling Point: | | | | | |
| Date Sampled: | 9/16/2022 13:30 | Date Received: | 9/22/2022 | Date Reported: | 11/03/2022 |

| | | |
|---|---|---|
| δD of water | --------------- | -124.8 ‰ relative to VSMOW |
| $\delta^{18}O$ of water | --------------- | -15.77 ‰ relative to VSMOW |
| Tritium content of water | --------------- | < 0.60 TU |
| $\delta^{13}C$ of DIC | --------------- | -9.3 ‰ relative to VPDB |
| $^{14}C$ content of DIC | --------------- | 0.8 ± 0.1 percent modern carbon |
| $\delta^{15}N$ of nitrate | --------------- | na |
| $\delta^{18}O$ of nitrate | --------------- | na |
| $\delta^{34}S$ of sulfate | --------------- | na |
| $\delta^{18}O$ of sulfate | --------------- | na |
| Vacuum Distilled? * | --------------- | No |

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

**LABORATORIES, Inc.**
2616 E Broadway Ave
Bismarck, ND 58501
Phone: (701) 258-9720
Toll Free: (800) 279-6885 Fax: (701) 258-9724

## Chain of Custody Record

Page 1 of 1.

WO# 3344

| | | |
|---|---|---|
| Company Name and Address: MVTL, 2616 E Broadway, Bismarck, ND 58501 | Account #: | Phone #: 701-258-9720 |
| | Contact: Claudette | Fax #: For faxed report check box ☐ |
| Billing Address (indicate if different from above): PO Box 249, New Ulm, MN 56073 | Name of Sampler: | E-mail: ccarroll@mvtl.com For e-mail report check box ☐ |
| | Quote Number | Date Submitted: 21-Sep-22 |
| | Project Name/Number: | Purchase Order #: BL6599 |

| Lab Number | MVTL Lab Number | Client Sample ID | Sample Type | Date Sampled | Time Sampled | Untreated | Filtered | VOC Vials Umpreserved | Glass Jar | Other | | Analysis Required |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 3344001 | USDW | GW | 16-Sep-22 | 13:30 | 1 | 1 | | | | | δD of water, $\delta^{18}O$ of water, $\delta^{13}C$ of DIC, $^{14}C$ content of DIC, 3H Tritium (detection limit 1TU) |

| Transferred by: | Date: | Time: | Sample Condition: | Received by: | Date: | | Temp: |
|---|---|---|---|---|---|---|---|
| T. Olson | 21-Sep-22 | 1700 | | Abby Skube/SR Isotech | SEP 22 2022 | 9:00 | |

EERC Energy & Environmental Research Center
UNIVERSITY OF NORTH DAKOTA
15 North 23rd Street -- Stop 9018 / Grand Forks, ND 58202-9018 / Phone: (701) 777-5000 Fax: 777-5181
Web Site: www.undeerc.org

## ANALYTICAL RESEARCH LAB - Final Results

*October 17, 2022*

**Set Number:** 55051
**Fund#:** 8032
**PI:** Jacob Loing
**Contact Person:** C. Nyberg

**Request Date:** Monday, October 10, 2022
**Due Date:** Monday, October 24, 2022
**Set Description:** USDW Sample for DIC/TIC

| Sample | Parameter | Result |
|---|---|---|
| **55051-01** | **MVTL #3344001** | |
| | Dissolved Inorganic Carbon | 227 mg/L |
| | Total Inorganic Carbon | 228 mg/L |

Distribution Carolyn Nyberg Date 10/17/22

1 of 1

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint
**Workorder:** Carbon Capture (4283)

Adam Dunlop
Blue Flint Ethanol
2841 3rd ST SW
Underwood, ND 58576

**Certificate of Analysis**

## Approval

**All data reported has been reviewed and approved by:**

C. Carroll

Claudette Carroll, Lab Manager Bismarck, ND

Dave Smahel, Inorganic Chemistry/Feed Lab Manager New Ulm, MN

Analyses performed under Minnesota Department of Health Accreditation conforms to the current TNI standards.

NEW ULM LAB CERTIFICATIONS:
MN LAB # 027-015-125 ND WW/DW # R-040

BISMARCK LAB CERTIFICATIONS:
MN LAB # 038-999-267 ND W/DW # ND-016 SD SDWA

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Workorder Summary

### Workorder Comments

All analytes with dilution factors greater than 1 (displayed in DF column) required dilution due to matrix or high concentration of target analyte unless otherwise noted and reporting limits (RDL column) have been adjusted accordingly.

For all samples, mercury (total and dissolved) analysis exceeded hold time

### Analysis Results Comments

***4283001 (Section 5)***

Sample required dilution due to matrix. Reporting limit has been raised.
(Bromide)

***4283001 (Section 5)***

Matrix spike and/or matrix spike duplicate recoveries were low. Low recoveries were due to the amount of spike added and the use of HCl in the metals digestion process. Data was accepted based on the acceptable recoveries of the post digestion spikes and/or LCS. (Silver)

***4283002 (Section 25)***

Sample required dilution due to matrix. Reporting limit has been raised.
(Bromide)

***4283003 (Brad Landenberger)***

Sample required dilution due to matrix. Reporting limit has been raised.
(Bromide)

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

**Lab ID:** 4283001 **Date Collected:** 10/13/2022 09:14 **Matrix:** Groundwater
**Sample ID:** Section 5 **Date Received:** 10/14/2022 08:00 **Collector:** MVTL Field Service

**Temp @ Receipt (C):** 1.0 **Received on Ice:** Yes

### Calculated

**Method: SM1030F**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Cation Summation | **7.92** | meq/L | | 1 | 11/07/2022 14:10 | 11/07/2022 14:10 | CW | | |
| Anion Summation | **7.41** | meq/L | | 1 | 11/07/2022 14:10 | 11/07/2022 14:10 | CW | | |
| Percent Difference | **3.34** | % | | 1 | 11/07/2022 14:10 | 11/07/2022 14:10 | CW | | |

### Inorganic Chemistry

**Method: ASTM D516-16**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfate | **152** | mg/L | 5 | 1 | 10/19/2022 11:37 | 10/19/2022 11:37 | EJV | MA,NDA | |

**Method: EPA 300.0**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Bromide | <0.500 | mg/L | 0.500 | 5 | 10/19/2022 14:02 | 10/19/2022 14:02 | RMV | MA,NDA | * |

**Method: EPA 365.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Phosphorus as P | **0.10** | mg/L | 0.1 | 1 | 10/20/2022 11:31 | 10/24/2022 08:49 | EJV | MA,NDA | |
| Phosphorus as P, Dissolved | **0.10** | mg/L | 0.1 | 1 | 10/20/2022 11:33 | 10/24/2022 11:42 | EJV | | |

**Method: SM 5310C-2014**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Dissolved Organic Carbon | **5.9** | mg/L | 2 | 2 | 10/28/2022 09:50 | 10/28/2022 09:50 | NS | MA,NDA | |
| Total Organic Carbon | **6.0** | mg/L | 1 | 2 | 10/28/2022 09:50 | 10/28/2022 09:50 | NS | MA,NDA | |

**Method: SM2320 B-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Alkalinity, Total | **192** | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 17:47 | 10/14/2022 17:47 | RAA | MA,NDA | |
| Alkalinity, Phenolphthalein | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 17:47 | 10/14/2022 17:47 | RAA | | |
| Carbonate | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 17:47 | 10/14/2022 17:47 | RAA | | |
| Bicarbonate | **192** | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 17:47 | 10/14/2022 17:47 | RAA | | |
| Hydroxide | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 17:47 | 10/14/2022 17:47 | RAA | | |

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283001 | **Date Collected:** | 10/13/2022 09:14 | **Matrix:** | Groundwater |
| **Sample ID:** | Section 5 | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 1.0 | **Received on Ice:** | Yes | | |

### Inorganic Chemistry

**Method: SM4500-Cl-E 2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Chloride | **14.5** | mg/L | 2.0 | 1 | 10/25/2022 15:00 | 10/25/2022 15:00 | EJV | MA,NDA | |

**Method: SM4500-F-C-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Fluoride | **0.46** | mg/L | 0.1 | 1 | 10/14/2022 17:47 | 10/14/2022 17:47 | RAA | | |

**Method: SM4500S2 D-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfide | **971** | ug/L | 150 | 3 | 10/17/2022 10:00 | 10/17/2022 10:00 | CMG | MA,NDA | |

**Method: USGS I-1750-85**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Total Dissolved Solids | **416** | mg/L | 10 | 1 | 10/14/2022 09:00 | 10/14/2022 09:00 | RAA | MA,NDA | |

### Metals

**Method: EPA 200.7/SW6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Silicates as SiO2 | **3.53** | mg/L | 0.214 | 1 | 11/07/2022 14:11 | 11/07/2022 14:11 | CW | | |

**Method: EPA 245.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Mercury | <0.0002 | mg/L | 0.0002 | 1 | 11/14/2022 10:30 | 11/15/2022 10:45 | AMC | MA,NDA, SDA | |
| Mercury, Dissolved | <0.0002 | mg/L | 0.0002 | 1 | 10/28/2022 11:15 | 10/28/2022 13:46 | AMC | MA,NDA | |

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Aluminum | <0.1 | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:52 | SLZ | MA,NDA | |
| Boron | **0.24** | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/17/2022 11:54 | SLZ | MA,NDA | |
| Barium | <0.1 | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:52 | SLZ | MA,NDA | |
| Calcium | **41.8** | mg/L | 1 | 1 | 10/14/2022 16:39 | 10/25/2022 12:47 | SLZ | MA,NDA | |
| Iron | **0.10** | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:52 | SLZ | MA,NDA | |



Report Date: Friday, January 13, 2023 9:54:52 AM

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

**Lab ID:** 4283001 **Date Collected:** 10/13/2022 09:14 **Matrix:** Groundwater
**Sample ID:** Section 5 **Date Received:** 10/14/2022 08:00 **Collector:** MVTL Field Service

**Temp @ Receipt (C):** 1.0 **Received on Ice:** Yes

### Metals

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Potassium | **5.29** | mg/L | 1 | 1 | 10/14/2022 16:39 | 10/25/2022 12:47 | SLZ | MA,NDA | |
| Magnesium | **24.4** | mg/L | 1 | 1 | 10/14/2022 16:39 | 10/25/2022 12:47 | SLZ | MA,NDA | |
| Sodium | **91.5** | mg/L | 1 | 1 | 10/14/2022 16:39 | 10/25/2022 12:47 | SLZ | MA,NDA | |
| Strontium | **0.57** | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:52 | SLZ | MA,NDA | |
| Zinc | <0.05 | mg/L | 0.05 | 1 | 10/14/2022 16:39 | 10/20/2022 11:52 | SLZ | MA,NDA | |
| Lithium | **0.0361** | mg/L | 0.02 | 1 | 10/14/2022 16:39 | 10/26/2022 09:03 | SLZ | NDA | |
| Silicon | **1.65** | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/26/2022 10:57 | SLZ | MA,NDA | |
| Aluminum, Dissolved | <0.1 | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:32 | SLZ | MA,NDA | |
| Boron, Dissolved | **0.24** | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/17/2022 12:20 | SLZ | MA,NDA | |
| Barium, Dissolved | <0.1 | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:32 | SLZ | MA,NDA | |
| Calcium, Dissolved | **40.8** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:42 | SLZ | MA,NDA | |
| Iron, Dissolved | <0.1 | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:32 | SLZ | MA,NDA | |
| Potassium, Dissolved | **5.25** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:42 | SLZ | MA,NDA | |
| Magnesium, Dissolved | **23.7** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:42 | SLZ | MA,NDA | |
| Sodium, Dissolved | **87.2** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:42 | SLZ | MA,NDA | |
| Strontium, Dissolved | **0.56** | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:32 | SLZ | MA,NDA | |
| Zinc, Dissolved | <0.05 | mg/L | 0.05 | 1 | 10/17/2022 07:54 | 10/19/2022 15:32 | SLZ | MA,NDA | |
| Lithium, Dissolved | **0.0362** | mg/L | 0.02 | 1 | 10/17/2022 07:54 | 10/26/2022 09:14 | SLZ | NDA | |
| Silicon, Dissolved | **1.63** | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/26/2022 11:02 | SLZ | MA,NDA | |

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Beryllium | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Beryllium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Vanadium | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Vanadium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283001 | **Date Collected:** | 10/13/2022 09:14 | **Matrix:** | Groundwater |
| **Sample ID:** | Section 5 | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 1.0 **Received on Ice:** Yes

### Metals

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Chromium | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Chromium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Manganese | **0.2082** | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Manganese, Dissolved | **0.2130** | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Cobalt | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Cobalt, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Nickel | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Nickel, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Copper | <0.005 | mg/L | 0.005 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Copper, Dissolved | <0.005 | mg/L | 0.005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Arsenic | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Arsenic, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Selenium | <0.005 | mg/L | 0.005 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Selenium, Dissolved | <0.005 | mg/L | 0.005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Molybdenum | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Molybdenum, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Silver | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | * |
| Silver, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Cadmium | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Cadmium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Antimony | <0.001 | mg/L | 0.001 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Antimony, Dissolved | <0.001 | mg/L | 0.001 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Thallium | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Thallium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283001 | **Date Collected:** | 10/13/2022 09:14 | **Matrix:** | Groundwater |
| **Sample ID:** | Section 5 | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 1.0 | **Received on Ice:** | Yes | | |

### Metals

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Lead | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | MA,NDA | |
| Lead, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |
| Uranium | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 10:47 | MDE | | |
| Uranium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:39 | MDE | MA,NDA | |

### Sampling Information

**Method: 120.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Specific Conductance - Field | **724** | umhos/cm | 1 | 1 | 10/13/2022 09:14 | 10/13/2022 09:14 | DJN | | |

**Method: 150.2**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| pH - Field | **8.07** | units | 0.01 | 1 | 10/13/2022 09:14 | 10/13/2022 09:14 | DJN | | |

**Method: 170.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Temperature - Field C | **10.98** | degrees C | | 1 | 10/13/2022 09:14 | 10/13/2022 09:14 | DJN | | |

**Method: EPA 180.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Turbidity - Field | **0.7** | NTU | 0.1 | 1 | 10/13/2022 09:14 | 10/13/2022 09:14 | DJN | | |

**Method: Field Method**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Pumping Rate - Field | **75** | gpm | | 1 | 10/13/2022 09:14 | 10/13/2022 09:14 | DJN | | |

**Method: SM2580B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| EH - Field | **-210.8** | mV | | 1 | 10/13/2022 09:14 | 10/13/2022 09:14 | DJN | | |

**Method: SM4500 O G-93**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Dissolved Oxygen - Field | **1.97** | mg/L | 0.1 | 1 | 10/13/2022 09:14 | 10/13/2022 09:14 | DJN | | |



Report Date: Friday, January 13, 2023 9:54:52 AM

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283001 | **Date Collected:** | 10/13/2022 09:14 | **Matrix:** | Groundwater |
| **Sample ID:** | Section 5 | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 1.0 **Received on Ice:** Yes

### Sampling Information

**Method: SM4500 O G-93**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283002 | **Date Collected:** | 10/13/2022 09:50 | **Matrix:** | Groundwater |
| **Sample ID:** | Section 25 | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 1.0 **Received on Ice:** Yes

### Calculated

**Method: SM1030F**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Cation Summation | **29.8** | meq/L | | 1 | 11/07/2022 14:14 | 11/07/2022 14:14 | CW | | |
| Anion Summation | **28.9** | meq/L | | 1 | 11/07/2022 14:14 | 11/07/2022 14:14 | CW | | |
| Percent Difference | **1.51** | % | | 1 | 11/07/2022 14:14 | 11/07/2022 14:14 | CW | | |

### Inorganic Chemistry

**Method: ASTM D516-16**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfate | **483** | mg/L | 25 | 5 | 10/19/2022 11:39 | 10/19/2022 11:39 | EJV | MA,NDA | |

**Method: EPA 300.0**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Bromide | <0.500 | mg/L | 0.500 | 5 | 10/19/2022 14:23 | 10/19/2022 14:23 | RMV | MA,NDA | * |

**Method: EPA 365.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Phosphorus as P | **0.27** | mg/L | 0.1 | 1 | 10/20/2022 11:31 | 10/24/2022 08:50 | EJV | MA,NDA | |
| Phosphorus as P, Dissolved | **0.26** | mg/L | 0.1 | 1 | 10/20/2022 11:33 | 10/24/2022 11:42 | EJV | | |

**Method: SM 5310C-2014**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Dissolved Organic Carbon | **13.0** | mg/L | 2 | 2 | 10/28/2022 09:50 | 10/28/2022 09:50 | NS | MA,NDA | |
| Total Organic Carbon | **12.8** | mg/L | 1 | 2 | 10/28/2022 09:50 | 10/28/2022 09:50 | NS | MA,NDA | |

**Method: SM2320 B-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Alkalinity, Total | **926** | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 19:06 | 10/14/2022 19:06 | RAA | MA,NDA | |
| Alkalinity, Phenolphthalein | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 19:06 | 10/14/2022 19:06 | RAA | | |
| Carbonate | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 19:06 | 10/14/2022 19:06 | RAA | | |
| Bicarbonate | **926** | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 19:06 | 10/14/2022 19:06 | RAA | | |
| Hydroxide | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 19:06 | 10/14/2022 19:06 | RAA | | |

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283002 | **Date Collected:** | 10/13/2022 09:50 | **Matrix:** | Groundwater |
| **Sample ID:** | Section 25 | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 1.0 | **Received on Ice:** | Yes | | |

### Inorganic Chemistry

**Method: SM4500-Cl-E 2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Chloride | **12.6** | mg/L | 2.0 | 1 | 10/25/2022 15:01 | 10/25/2022 15:01 | EJV | MA,NDA | |

**Method: SM4500-F-C-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Fluoride | **0.81** | mg/L | 0.1 | 1 | 10/14/2022 19:06 | 10/14/2022 19:06 | RAA | | |

**Method: SM4500S2 D-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfide | <50 | ug/L | 50 | 1 | 10/17/2022 10:00 | 10/17/2022 10:00 | CMG | MA,NDA | |

**Method: USGS I-1750-85**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Total Dissolved Solids | **1780** | mg/L | 10 | 1 | 10/14/2022 09:00 | 10/14/2022 09:00 | RAA | MA,NDA | |

### Metals

**Method: EPA 200.7/SW6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Silicates as SiO2 | **14.5** | mg/L | 0.214 | 1 | 11/07/2022 14:14 | 11/07/2022 14:14 | CW | | |

**Method: EPA 245.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Mercury | <0.0002 | mg/L | 0.0002 | 1 | 11/14/2022 10:30 | 11/15/2022 10:45 | AMC | MA,NDA, SDA | |
| Mercury, Dissolved | <0.0002 | mg/L | 0.0002 | 1 | 10/28/2022 11:15 | 10/28/2022 13:46 | AMC | MA,NDA | |

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Aluminum | <0.1 | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:54 | SLZ | MA,NDA | |
| Boron | **0.66** | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/17/2022 11:56 | SLZ | MA,NDA | |
| Barium | <0.1 | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:54 | SLZ | MA,NDA | |
| Calcium | **5.95** | mg/L | 1 | 1 | 10/14/2022 16:39 | 10/25/2022 12:50 | SLZ | MA,NDA | |
| Iron | <0.1 | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:54 | SLZ | MA,NDA | |



Report Date: Friday, January 13, 2023 9:54:52 AM

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283002 | **Date Collected:** | 10/13/2022 09:50 | **Matrix:** | Groundwater |
| **Sample ID:** | Section 25 | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 1.0 **Received on Ice:** Yes

### Metals

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Potassium | **3.07** | mg/L | 1 | 1 | 10/14/2022 16:39 | 10/25/2022 12:50 | SLZ | MA,NDA | |
| Magnesium | **2.75** | mg/L | 1 | 1 | 10/14/2022 16:39 | 10/25/2022 12:50 | SLZ | MA,NDA | |
| Sodium | **731** | mg/L | 5 | 5 | 10/14/2022 16:39 | 10/25/2022 14:31 | SLZ | MA,NDA | |
| Strontium | **0.18** | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:54 | SLZ | MA,NDA | |
| Zinc | <0.05 | mg/L | 0.05 | 1 | 10/14/2022 16:39 | 10/20/2022 11:54 | SLZ | MA,NDA | |
| Lithium | **0.0699** | mg/L | 0.02 | 1 | 10/14/2022 16:39 | 10/26/2022 09:05 | SLZ | NDA | |
| Silicon | **6.80** | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/26/2022 10:59 | SLZ | MA,NDA | |
| Aluminum, Dissolved | <0.1 | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:35 | SLZ | MA,NDA | |
| Boron, Dissolved | **0.64** | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/17/2022 12:22 | SLZ | MA,NDA | |
| Barium, Dissolved | <0.1 | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:35 | SLZ | MA,NDA | |
| Calcium, Dissolved | **5.79** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:44 | SLZ | MA,NDA | |
| Iron, Dissolved | <0.1 | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:35 | SLZ | MA,NDA | |
| Potassium, Dissolved | **3.13** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:44 | SLZ | MA,NDA | |
| Magnesium, Dissolved | **2.71** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:44 | SLZ | MA,NDA | |
| Sodium, Dissolved | **672** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:44 | SLZ | MA,NDA | |
| Strontium, Dissolved | **0.18** | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:35 | SLZ | MA,NDA | |
| Zinc, Dissolved | <0.05 | mg/L | 0.05 | 1 | 10/17/2022 07:54 | 10/19/2022 15:35 | SLZ | MA,NDA | |
| Lithium, Dissolved | **0.0689** | mg/L | 0.02 | 1 | 10/17/2022 07:54 | 10/26/2022 09:16 | SLZ | NDA | |
| Silicon, Dissolved | **6.48** | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/26/2022 11:05 | SLZ | MA,NDA | |

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Beryllium | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Beryllium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Vanadium | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Vanadium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283002 | **Date Collected:** | 10/13/2022 09:50 | **Matrix:** | Groundwater |
| **Sample ID:** | Section 25 | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 1.0 | **Received on Ice:** | Yes | | |

**Metals**

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Chromium | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Chromium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Manganese | **0.0051** | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Manganese, Dissolved | **0.0048** | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Cobalt | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Cobalt, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Nickel | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Nickel, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Copper | <0.005 | mg/L | 0.005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Copper, Dissolved | <0.005 | mg/L | 0.005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Arsenic | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Arsenic, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Selenium | <0.005 | mg/L | 0.005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Selenium, Dissolved | <0.005 | mg/L | 0.005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Molybdenum | **0.0023** | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Molybdenum, Dissolved | **0.0022** | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Silver | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Silver, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Cadmium | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Cadmium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Antimony | <0.001 | mg/L | 0.001 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Antimony, Dissolved | <0.001 | mg/L | 0.001 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Thallium | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Thallium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283002 | **Date Collected:** | 10/13/2022 09:50 | **Matrix:** | Groundwater |
| **Sample ID:** | Section 25 | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 1.0 | **Received on Ice:** | Yes | | |

### Metals

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Lead | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | MA,NDA | |
| Lead, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |
| Uranium | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:08 | MDE | | |
| Uranium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:44 | MDE | MA,NDA | |

### Sampling Information

**Method: 120.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Specific Conductance - Field | **2634** | umhos/cm | 1 | 1 | 10/13/2022 09:50 | 10/13/2022 09:50 | DJN | | |

**Method: 150.2**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| pH - Field | **8.22** | units | 0.01 | 1 | 10/13/2022 09:50 | 10/13/2022 09:50 | DJN | | |

**Method: 170.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Temperature - Field C | **8.15** | degrees C | | 1 | 10/13/2022 09:50 | 10/13/2022 09:50 | DJN | | |

**Method: EPA 180.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Turbidity - Field | **1.82** | NTU | 0.1 | 1 | 10/13/2022 09:50 | 10/13/2022 09:50 | DJN | | |

**Method: Field Method**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Pumping Rate - Field | **40** | gpm | | 1 | 10/13/2022 09:50 | 10/13/2022 09:50 | DJN | | |

**Method: SM2580B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| EH - Field | **50.3** | mV | | 1 | 10/13/2022 09:50 | 10/13/2022 09:50 | DJN | | |

**Method: SM4500 O G-93**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Dissolved Oxygen - Field | **9.63** | mg/L | 0.1 | 1 | 10/13/2022 09:50 | 10/13/2022 09:50 | DJN | | |



Report Date: Friday, January 13, 2023 9:54:52 AM

**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

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

**Lab ID:** 4283002 **Date Collected:** 10/13/2022 09:50 **Matrix:** Groundwater
**Sample ID:** Section 25 **Date Received:** 10/14/2022 08:00 **Collector:** MVTL Field Service

**Temp @ Receipt (C):** 1.0 **Received on Ice:** Yes

**Sampling Information**

**Method: SM4500 O G-93**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|



Report Date: Friday, January 13, 2023 9:54:52 AM

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283003 | **Date Collected:** | 10/13/2022 10:28 | **Matrix:** | Groundwater |
| **Sample ID:** | Brad Landenberger | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 1.0 **Received on Ice:** Yes

### Calculated

**Method: SM1030F**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Cation Summation | **20.2** | meq/L | | 1 | 11/07/2022 14:18 | 11/07/2022 14:18 | CW | | |
| Anion Summation | **18.6** | meq/L | | 1 | 11/07/2022 14:18 | 11/07/2022 14:18 | CW | | |
| Percent Difference | **4.13** | % | | 1 | 11/07/2022 14:18 | 11/07/2022 14:18 | CW | | |

### Inorganic Chemistry

**Method: ASTM D516-16**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfate | **388** | mg/L | 10 | 2 | 10/19/2022 11:40 | 10/19/2022 11:40 | EJV | MA,NDA | |

**Method: EPA 300.0**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Bromide | <0.500 | mg/L | 0.500 | 5 | 10/19/2022 14:44 | 10/19/2022 14:44 | RMV | MA,NDA | * |

**Method: EPA 365.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Phosphorus as P | <0.1 | mg/L | 0.1 | 1 | 10/20/2022 11:31 | 10/24/2022 08:51 | EJV | MA,NDA | |
| Phosphorus as P, Dissolved | <0.1 | mg/L | 0.1 | 1 | 10/20/2022 11:33 | 10/24/2022 11:42 | EJV | | |

**Method: SM 5310C-2014**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Dissolved Organic Carbon | **5.9** | mg/L | 2 | 2 | 10/28/2022 09:50 | 10/28/2022 09:50 | NS | MA,NDA | |
| Total Organic Carbon | **6.0** | mg/L | 1 | 2 | 10/28/2022 09:50 | 10/28/2022 09:50 | NS | MA,NDA | |

**Method: SM2320 B-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Alkalinity, Total | **519** | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 17:24 | 10/14/2022 17:24 | RAA | MA,NDA | |
| Alkalinity, Phenolphthalein | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 17:24 | 10/14/2022 17:24 | RAA | | |
| Carbonate | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 17:24 | 10/14/2022 17:24 | RAA | | |
| Bicarbonate | **519** | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 17:24 | 10/14/2022 17:24 | RAA | | |
| Hydroxide | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 10/14/2022 17:24 | 10/14/2022 17:24 | RAA | | |



Report Date: Friday, January 13, 2023 9:54:52 AM

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283003 | **Date Collected:** | 10/13/2022 10:28 | **Matrix:** | Groundwater |
| **Sample ID:** | Brad Landenberger | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 1.0 **Received on Ice:** Yes

### Inorganic Chemistry

**Method: SM4500-Cl-E 2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Chloride | **6.3** | mg/L | 2.0 | 1 | 10/25/2022 15:07 | 10/25/2022 15:07 | EJV | MA,NDA | |

**Method: SM4500-F-C-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Fluoride | **0.29** | mg/L | 0.1 | 1 | 10/14/2022 17:24 | 10/14/2022 17:24 | RAA | | |

**Method: SM4500S2 D-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfide | <50 | ug/L | 50 | 1 | 10/17/2022 10:00 | 10/17/2022 10:00 | CMG | MA,NDA | |

**Method: USGS I-1750-85**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Total Dissolved Solids | **1080** | mg/L | 10 | 1 | 10/14/2022 09:00 | 10/14/2022 09:00 | RAA | MA,NDA | |

### Metals

**Method: EPA 200.7/SW6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Silicates as SiO2 | **29.4** | mg/L | 0.214 | 1 | 11/07/2022 14:19 | 11/07/2022 14:19 | CW | | |

**Method: EPA 245.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Mercury | <0.0002 | mg/L | 0.0002 | 1 | 11/14/2022 10:30 | 11/15/2022 10:45 | AMC | MA,NDA, SDA | |
| Mercury, Dissolved | <0.0002 | mg/L | 0.0002 | 1 | 10/28/2022 11:15 | 10/28/2022 13:46 | AMC | MA,NDA | |

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Aluminum | <0.1 | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:56 | SLZ | MA,NDA | |
| Boron | **0.55** | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/17/2022 11:58 | SLZ | MA,NDA | |
| Barium | <0.1 | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:56 | SLZ | MA,NDA | |
| Calcium | **167** | mg/L | 1 | 1 | 10/14/2022 16:39 | 10/25/2022 12:53 | SLZ | MA,NDA | |
| Iron | **2.93** | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:56 | SLZ | MA,NDA | |



Report Date: Friday, January 13, 2023 9:54:52 AM

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

**Lab ID:** 4283003 **Date Collected:** 10/13/2022 10:28 **Matrix:** Groundwater
**Sample ID:** Brad Landenberger **Date Received:** 10/14/2022 08:00 **Collector:** MVTL Field Service

**Temp @ Receipt (C):** 1.0 **Received on Ice:** Yes

### Metals

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Potassium | **7.54** | mg/L | 1 | 1 | 10/14/2022 16:39 | 10/25/2022 12:53 | SLZ | MA,NDA | |
| Magnesium | **123** | mg/L | 1 | 1 | 10/14/2022 16:39 | 10/25/2022 12:53 | SLZ | MA,NDA | |
| Sodium | **69.1** | mg/L | 1 | 1 | 10/14/2022 16:39 | 10/25/2022 12:53 | SLZ | MA,NDA | |
| Strontium | **2.27** | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/20/2022 11:56 | SLZ | MA,NDA | |
| Zinc | **0.05** | mg/L | 0.05 | 1 | 10/14/2022 16:39 | 10/20/2022 11:56 | SLZ | MA,NDA | |
| Lithium | **0.163** | mg/L | 0.02 | 1 | 10/14/2022 16:39 | 10/26/2022 09:05 | SLZ | NDA | |
| Silicon | **13.7** | mg/L | 0.1 | 1 | 10/14/2022 16:39 | 10/26/2022 11:00 | SLZ | MA,NDA | |
| Aluminum, Dissolved | <0.1 | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:36 | SLZ | MA,NDA | |
| Boron, Dissolved | **0.51** | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/17/2022 12:22 | SLZ | MA,NDA | |
| Barium, Dissolved | <0.1 | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:36 | SLZ | MA,NDA | |
| Calcium, Dissolved | **156** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:45 | SLZ | MA,NDA | |
| Iron, Dissolved | **2.36** | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:36 | SLZ | MA,NDA | |
| Potassium, Dissolved | **6.94** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:45 | SLZ | MA,NDA | |
| Magnesium, Dissolved | **114** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:45 | SLZ | MA,NDA | |
| Sodium, Dissolved | **64.4** | mg/L | 1 | 1 | 10/17/2022 07:54 | 10/28/2022 11:45 | SLZ | MA,NDA | |
| Strontium, Dissolved | **2.18** | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/19/2022 15:36 | SLZ | MA,NDA | |
| Zinc, Dissolved | <0.05 | mg/L | 0.05 | 1 | 10/17/2022 07:54 | 10/19/2022 15:36 | SLZ | MA,NDA | |
| Lithium, Dissolved | **0.151** | mg/L | 0.02 | 1 | 10/17/2022 07:54 | 10/26/2022 09:16 | SLZ | NDA | |
| Silicon, Dissolved | **13.1** | mg/L | 0.1 | 1 | 10/17/2022 07:54 | 10/26/2022 11:05 | SLZ | MA,NDA | |

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Beryllium | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Beryllium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Vanadium | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Vanadium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283003 | **Date Collected:** | 10/13/2022 10:28 | **Matrix:** | Groundwater |
| **Sample ID:** | Brad Landenberger | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 1.0 | **Received on Ice:** | Yes | | |

### Metals

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Chromium | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Chromium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Manganese | **0.8366** | mg/L | 0.008 | 20 | 10/14/2022 16:39 | 11/03/2022 15:03 | MDE | MA,NDA | |
| Manganese, Dissolved | **0.7953** | mg/L | 0.008 | 20 | 10/17/2022 07:54 | 11/03/2022 15:35 | MDE | MA,NDA | |
| Cobalt | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Cobalt, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Nickel | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Nickel, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Copper | **0.0457** | mg/L | 0.005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Copper, Dissolved | **0.0051** | mg/L | 0.005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Arsenic | **0.0036** | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Arsenic, Dissolved | **0.0029** | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Selenium | <0.005 | mg/L | 0.005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Selenium, Dissolved | <0.005 | mg/L | 0.005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Molybdenum | **0.0027** | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Molybdenum, Dissolved | **0.0020** | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Silver | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Silver, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Cadmium | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Cadmium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Antimony | <0.001 | mg/L | 0.001 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Antimony, Dissolved | <0.001 | mg/L | 0.001 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Thallium | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Thallium, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |



Report Date: Friday, January 13, 2023 9:54:52 AM

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283003 | **Date Collected:** | 10/13/2022 10:28 | **Matrix:** | Groundwater |
| **Sample ID:** | Brad Landenberger | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 1.0 | **Received on Ice:** | Yes | | |

### Metals

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Lead | <0.0005 | mg/L | 0.0005 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | MA,NDA | |
| Lead, Dissolved | <0.0005 | mg/L | 0.0005 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |
| Uranium | <0.002 | mg/L | 0.002 | 5 | 10/14/2022 16:39 | 11/03/2022 11:12 | MDE | | |
| Uranium, Dissolved | <0.002 | mg/L | 0.002 | 5 | 10/17/2022 07:54 | 11/03/2022 15:48 | MDE | MA,NDA | |

### Sampling Information

**Method: 120.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Specific Conductance - Field | **1508** | umhos/cm | 1 | 1 | 10/13/2022 10:28 | 10/13/2022 10:28 | DJN | | |

**Method: 150.2**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| pH - Field | **6.79** | units | 0.01 | 1 | 10/13/2022 10:28 | 10/13/2022 10:28 | DJN | | |

**Method: 170.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Temperature - Field C | **9.22** | degrees C | | 1 | 10/13/2022 10:28 | 10/13/2022 10:28 | DJN | | |

**Method: EPA 180.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Turbidity - Field | **1.24** | NTU | 0.1 | 1 | 10/13/2022 10:28 | 10/13/2022 10:28 | DJN | | |

**Method: Field Method**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Pumping Rate - Field | **20** | gpm | | 1 | 10/13/2022 10:28 | 10/13/2022 10:28 | DJN | | |

**Method: SM2580B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| EH - Field | **-11.4** | mV | | 1 | 10/13/2022 10:28 | 10/13/2022 10:28 | DJN | | |

**Method: SM4500 O G-93**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Dissolved Oxygen - Field | **2.25** | mg/L | 0.1 | 1 | 10/13/2022 10:28 | 10/13/2022 10:28 | DJN | | |



Report Date: Friday, January 13, 2023 9:54:52 AM

**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

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 4283003 | **Date Collected:** | 10/13/2022 10:28 | **Matrix:** | Groundwater |
| **Sample ID:** | Brad Landenberger | **Date Received:** | 10/14/2022 08:00 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 1.0 **Received on Ice:** Yes

**Sampling Information**

**Method: SM4500 O G-93**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**

1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

**Minnesota Valley Testing Laboratories**
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Midwest Ag Energy Blue Flint
WO: 4283

## Chain of Custody Record

| | |
|---|---|
| Report To: | **Midwest AgEnergy** |
| Attn: | Adam Dunlop |
| Address: | 2841 3rd St SW<br>Underwood, ND 58576 |
| Phone: | 701-442-7500 |
| Email: | adunlop@midwestagenergy.com |
| CC: | |
| Project Name: | **Midwest AgEnergy** |
| Event: | |
| Sampled By: | Darren Niewalis |

| Lab Number | Sample ID | Date | Time | Sample Type | 1 Liter Raw | 500 mL HNO3 | 500 mL HNO3 (filtered) | 250 mL H2SO4 | 250mL H2SO4 (filtered) | DOC (set of 3) (filtered) | TOC (set of 3) | 1 Liter NaOH/Zinc | 125mL Raw | | Temp (°C) | Spec. Cond. | pH | | Analysis Required |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 001 | Section 5 | 13oct22 | 0914 | GW | X | X | X | X | X | X | X | X | X | | 10.98 | 724 | 8.07 | | |
| 002 | Section 25 | 13oct22 | 0950 | GW | X | X | X | X | X | X | X | X | X | | 8.15 | 2634 | 8.22 | | AgEnergy List |
| 003 | Brad Landenberger | 13oct22 | 1028 | GW | X | X | X | X | X | X | X | X | X | | 9.22 | 1508 | 6.79 | | |

Comments:

| Relinquished By Name | Date/Time | Sample Condition Location | Temp (°C) | Received By Name | Date/Time |
|---|---|---|---|---|---|
| 1 [signature] | 13oct22 1634 | Log In / Walk In #2 | ROI 1.0 TM562 / TM805 | C. Carroll | 14OCT22 0800 |
| 2 | | | | | |



Report Date: Friday, January 13, 2023 9:54:52 AM

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

Minnesota Valley Testing Laboratories
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

## Chain of Custody Record

Report To: Midwest AgEnergy
Attn: Adam Dunlop
Address: 2841 3rd St SW
Underwood, ND 58576
Phone: 701-442-7500
Email: adunlop@midwestagenergy.com

CC:

Project Name: Midwest AgEnergy
Event:
Sampled By: Darren Niesen

| Lab Number | Sample ID | Date | Time | Sample Type | 500mL Amber Raw | 500mL Amber (filtered) | Analysis Required |
|---|---|---|---|---|---|---|---|
| | Section 5 | 14oct22 | 0837 | GW | X | X | TIC and DIC |
| | Section 25 | 14oct22 | 0856 | GW | X | X | |
| | Brad Landenberger | 14oct22 | 0917 | GW | X | X | |

Comments:

TIC = Total Inorganic Carbon
DIC = Disolved Inorganic Carbon

| | Relinquished By Name | Date/Time | Sample Condition Location | Temp (°C) | Received By Name | Date/Time |
|---|---|---|---|---|---|---|
| 1 | [signature] | 14oct22 1027 | Log In / Walk In #2 | ROI 6.8 TM562 / TM805 | [signature] | 14oct22 1027 |
| 2 | | | | | | |

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

# Field Datasheet

**Monitoring Well**

2616 E. Broadway Ave, Bismarck, ND
Phone: (701) 258-9720

Company: **Midwest Ag Energy**
Event:
Sample ID: Section 5
Sampling Personal: Darren Niegmay

**Weather Conditions:** Temp: 36 °F Wind: NW @ 40 Precip: **Sunny / Partly Cloudy / Cloudy**

**SITE INFORMATION**

| Source: | Well |
|---|---|

Purge Start:

| Date | Time | GPM |
|---|---|---|
| 13 Oct 22 | 0630 | 75 |

**SAMPLING INFORMATION**

| Sampling Method: | Grab |
|---|---|

Bottle List:

| | | |
|---|---|---|
| 1 Liter Raw | 3 DOC (filtered) | 500mL Amber Raw |
| 500mL Nitric | 3 TOC | 500mL Amber (filtered) |
| 500mL Nitric (filtered) | 1 L NaOH/Zinc | |
| 250mL Sulfuric | 125mL Raw | |
| 250mL Sulfuric (filtered) | | |

| Sample Date | Time | Temp. (°C) | Spec. Cond. | pH | DO (mg/L | ORP (mV) | Turbidity (NTU) | | | | Appearance or Comment Clarity, Color, Odor, Ect. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 Oct 22 | 0914 | 10.98 | 724 | 8.07 | 1.97 | -210.8 | 0.70 | | | | clear |

| Comments: | Falkirk section 5 well |
|---|---|

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

# Field Datasheet

**Monitoring Well**

2616 E. Broadway Ave, Bismarck, ND
Phone: (701) 258-9720

| | |
|---|---|
| Company: | Midwest Ag Energy |
| Event: | |
| Sample ID: | Section 25 |
| Sampling Personal: | Darian Nieswag |

**Weather Conditions:** Temp: 37°F Wind: NW @ 40 Precip: Sunny / Partly Cloudy / Cloudy

## SITE INFORMATION

| Source: | Well |
|---|---|

Purge Start:

| Date | Time | GPM |
|---|---|---|
| 13Oct22 | 0630 | 40 |

## SAMPLING INFORMATION

| Sampling Method: | Grab |
|---|---|

| Bottle List: | | |
|---|---|---|
| 1 Liter Raw | 3 DOC (filtered) | 500mL Amber Raw |
| 500mL Nitric | 3 TOC | 500mL Amber (filtered) |
| 500mL Nitric (filtered) | 1 L NaOH/Zinc | |
| 250mL Sulfuric | 125mL Raw | |
| 250mL Sulfuric (filtered) | | |

| Sample Date | Time | Temp. (°C) | Spec. Cond. | pH | DO (mg/L | ORP (mV) | Turbidity (NTU) | | | | Appearance or Comment Clarity, Color, Odor, Ect. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 13Oct22 | 0950 | 8.15 | 2634 | 8.22 | 9.63 | 50.3 | 1.82 | | | | Clear |

| Comments: | |
|---|---|

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

# Field Datasheet

Monitoring Well

2616 E. Broadway Ave, Bismarck, ND
Phone: (701) 258-9720

Company: Midwest Ag Energy
Event:
Sample ID: Brady Landenberger
Sampling Personal: Dayten Nissvaag

**Weather Conditions:** Temp: 37°F Wind: NW @ 40 Precip: Sunny / Partly Cloudy / Cloudy

## SITE INFORMATION

| Source: | Well |
|---|---|

Purge Start:

| Date | Time | GPM |
|---|---|---|
| 13Oct22 | 1015 | 20 |

## SAMPLING INFORMATION

| Sampling Method: | Grab |
|---|---|

| Bottle List: | | |
|---|---|---|
| 1 Liter Raw | 3 DOC (filtered) | 500mL Amber Raw |
| 500mL Nitric | 3 TOC | 500mL Amber (filtered) |
| 500mL Nitric (filtered) | 1 L NaOH/Zinc | |
| 250mL Sulfuric | 125mL Raw | |
| 250mL Sulfuric (filtered) | | |

| Sample Date | Time | Temp. (°C) | Spec. Cond. | pH | DO (mg/L | ORP (mV) | Turbidity (NTU) | | | | Appearance or Comment Clarity, Color, Odor, Ect. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 13Oct22 | 1028 | 9.22 | 1508 | 6.79 | 2.25 | -11.4 | 1.24 | | | | clear |

Comments: Hydrant next to fuel barrels is where I collected the sample.

Brad said he let the well run for awhile this morning to clean the water in the well.

**Account #:** 21017 **Client:** Midwest Ag Energy Blue Flint

EERC Energy & Environmental Research Center

UNIVERSITY OF NORTH DAKOTA

15 North 23rd Street -- Stop 9018 / Grand Forks, ND 58202-9018 / Phone: (701) 777-5000 Fax: 777-5181
Web Site: www.undeerc.org

## ANALYTICAL RESEARCH LAB - Final Results

*November 1, 2022*

**Set Number:** 55053
**Fund#:** 8032
**PI:** Jacob Loing
**Contact Person:** C. Nyberg
**Request Date:** Tuesday, November 1, 2022
**Due Date:** Tuesday, November 15, 2022
**Set Description:** GW Samples for DIC/TIC

| Sample | Parameter | Result |
|---|---|---|
| **55053-01** | **MVTL #4283001** | |
| | Dissolved Inorganic Carbon | 45.4 mg/L |
| | Total Inorganic Carbon | 45.6 mg/L |
| **55053-02** | **MVTL #4283002** | |
| | Dissolved Inorganic Carbon | 249 mg/L |
| | Total Inorganic Carbon | 251 mg/L |
| **55053-03** | **MVTL #4283003** | |
| | Dissolved Inorganic Carbon | 147 mg/L |
| | Total Inorganic Carbon | 151 mg/L |

EERC Invoice No. FY23 - 8032 - 04

Distribution Carolyn Nyberg Date 11/1/22

1 of 1

# Kadrmas, Bethany R.

**From:** Nelson, Steve
**Sent:** Monday, April 10, 2023 3:55 PM
**To:** Entzi-Odden, Lyn; Kadrmas, Bethany R.; Bender, Lawrence
**Subject:** RE: Letter from Lawrence RE extension for affidavit

Thank you, Bethany. The record shall remain open until Friday April 14th, 2023.

**Steven B. Nelson**
Assistant Attorney General
500 North 9th Street
Bismarck, ND 58501-4509
Office: (701) 328-3640
stnelson@nd.gov

---

**From:** Entzi-Odden, Lyn <lodden@fredlaw.com>
**Sent:** Monday, April 10, 2023 2:49 PM
**To:** Kadrmas, Bethany R. <brkadrmas@nd.gov>; Bender, Lawrence <LBender@fredlaw.com>; Nelson, Steve <stnelson@nd.gov>
**Subject:** RE: Letter from Lawrence RE extension for affidavit



Yes. Friday the 14th.
Thanks Bethany.

*Lyn*
***Fredrikson & Byron, P.A.***
***701-221-8700***

---

**From:** Kadrmas, Bethany R. <brkadrmas@nd.gov>
**Sent:** Monday, April 10, 2023 2:47 PM
**To:** Bender, Lawrence <LBender@fredlaw.com>; Nelson, Steve <stnelson@nd.gov>
**Cc:** Entzi-Odden, Lyn <lodden@fredlaw.com>
**Subject:** RE: Letter from Lawrence RE extension for affidavit



---

It looks like the 15th is a Saturday.  Did you intend to reference Friday, April 14th?

Bethany

---

**From:** Bender, Lawrence <LBender@fredlaw.com>
**Sent:** Monday, April 10, 2023 2:40 PM

**Kadrmas, Bethany R.**

---

**From:** Entzi-Odden, Lyn <lodden@fredlaw.com>
**Sent:** Monday, April 10, 2023 2:49 PM
**To:** Kadrmas, Bethany R.; Bender, Lawrence; Nelson, Steve
**Subject:** RE: Letter from Lawrence RE extension for affidavit

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Yes. Friday the 14th.
Thanks Bethany.

*Lyn*
*Fredrikson & Byron, P.A.*
*701-221-8700*

---

**From:** Kadrmas, Bethany R. <brkadrmas@nd.gov>
**Sent:** Monday, April 10, 2023 2:47 PM
**To:** Bender, Lawrence <LBender@fredlaw.com>; Nelson, Steve <stnelson@nd.gov>
**Cc:** Entzi-Odden, Lyn <lodden@fredlaw.com>
**Subject:** RE: Letter from Lawrence RE extension for affidavit

**CAUTION: EXTERNAL E-MAIL**

---

It looks like the 15th is a Saturday. Did you intend to reference Friday, April 14th?

Bethany

---

**From:** Bender, Lawrence <LBender@fredlaw.com>
**Sent:** Monday, April 10, 2023 2:40 PM
**To:** Nelson, Steve <stnelson@nd.gov>
**Cc:** Entzi-Odden, Lyn <lodden@fredlaw.com>; Kadrmas, Bethany R. <brkadrmas@nd.gov>
**Subject:** Re: Letter from Lawrence RE extension for affidavit

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Thank you Mr. Nelson.

221-8700. **The name and biographical data provided above are for informational purposes only and are not intended to be a signature or other indication of an intent by the sender to authenticate the contents of this electronic message.****

On Apr 10, 2023, at 2:38 PM, Nelson, Steve <stnelson@nd.gov> wrote:

**CAUTION: EXTERNAL E-MAIL**

---

The request for an extension of time in Case Nos. 29888, 29889 and 29890 to submit supplemental information is granted. Blue Flint Sequester Company, LLC and its counsel will have until Friday, April 15, 2023 to submit the affidavit addressing the issue of notice sent to Bradley Schafer.

**Steven B. Nelson**
Assistant Attorney General
500 North 9th Street
Bismarck, ND 58501-4509
Office: (701) 328-3640
stnelson@nd.gov

---

**From:** Entzi-Odden, Lyn <lodden@fredlaw.com>
**Sent:** Monday, April 10, 2023 1:26 PM
**To:** Nelson, Steve <stnelson@nd.gov>
**Cc:** Kadrmas, Bethany R. <brkadrmas@nd.gov>; Bender, Lawrence <LBender@fredlaw.com>
**Subject:** Letter from Lawrence RE extension for affidavit

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Assistant Attorney General Nelson,

Please see the attached letter from Lawrence.

<image001.png>

**Lyn Entzi-Odden**
**Executive Legal Assistant**
1133 College Drive | Suite 1000 | Bismarck, ND 58501
Ph: 701.221.8700|lodden@fredlaw.com

**Fredrikson**

**Fredrikson & Byron, P.A.**
Attorneys and Advisors

1133 College Drive, Suite 1000
Bismarck, ND 58501-1215
Main: 701.221.8700
fredlaw.com

April 10, 2023

***VIA EMAIL***

Mr. Steven Nelson
Assistant Attorney General
Office of the Attorney General
500 N. Ninth St.
Bismarck, ND 58501-4509

**RE: Case Nos. 29888, 29889 and 29890**
**Blue Flint Sequester Company, LLC**

Dear Assistant Attorney General Nelson:

At the hearing held for the captioned matter on March 21, 2023, Blue Flint Sequester Company, LLC was granted until Tuesday, April 11, 2023, to submit supplemental information. Blue Flint will not have a problem meeting the deadline to supplement the record by April 11, however, I also need to submit an affidavit addressing the issue of notice sent to Bradley Schafer. In that regard, I am requesting an extension of time until Friday, April 15, 2023, to submit the affidavit.

I look forward to hearing from you.

Should you have any questions, please advise.

Sincerely,

/s/ Lawrence Bender
LAWRENCE BENDER

LB/leo
cc: Mr. Adam Dunlop – (w/enc.) *Via Email*
78836469 v1

# Blue Flint Sequester Company, LLC

## Case Nos. 29888, 29889 and 29890

**Case No. 29888: Application of Blue Flint Sequester Company, LLC requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Blue Flint Sequester Company, LLC intends to capture carbon dioxide from the Blue Flint Ethanol Facility and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT March 20, 2023. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Tammy Madche, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Blue Flint Sequester Company, LLC, 2841 3rd St. SW, Underwood, North Dakota 58576.**

**Case No. 29889: A motion of the Commission to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Blue Flint Sequester Company, LLC storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West,.**

**Case No. 29890: A motion of the Commission to determine the amount of financial responsibility for the geologic storage of carbon dioxide from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.**

## March 21, 2023

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
DATE 3/21/23 CASE NO. 29888-90
Introduced By Blue Flint
Exhibit 3
Identified By Bender

**EXHIBIT 1**

Case No.: 29888
Date Established: January 30, 2023

# DRAFT STORAGE FACILITY PERMIT

## STORAGE FACILITY FOR CARBON SEQUESTRATION UNDER THE NORTH DAKOTA UNDERGROUND INJECTION CONTROL PROGRAM

In compliance with North Dakota Century Code Chapter (NDCC) 38-22 (Carbon Dioxide Underground Storage) and North Dakota Administrative Code (NDAC) Chapter 43-05-01 (Geologic Storage of Carbon Dioxide), Blue Flint Sequester Company, LLC has applied for a carbon dioxide storage facility permit. A draft permit does not grant the authorization to inject. This is a document prepared under NDAC 43-05-01-07.2 indicating the Commission's tentative decision to issue a storage facility permit. Before preparing the draft permit, the Commission has consulted with the Department of Environmental Quality and determined the storage facility permit application to be complete. The draft permit contains permit conditions required under NDAC 43-05-01-07.3 and 43-05-01-07.4. A fact sheet is included and contains the following information:

1. A brief description of the type of facility or activity which is the subject of the draft permit.
2. The quantity and quality of the carbon dioxide which is proposed to be injected and stored.
3. A brief summary of the basis for the draft permit conditions, including references to applicable statutory or regulatory provisions.
4. The reasons why any requested variances or alternatives to required standards do or do not appear justified.
5. A description of the procedures for reaching a final decision on the draft permit, including:
    a. The beginning and ending dates of the comment period.
    b. The address where comments will be received.
    c. The date, time, and location of the storage facility permit hearing.
    d. Any other procedures by which the public may participate in the final decision.
6. The name and telephone number of a person to contact for additional information.

This draft permit has been established on January 30, 2023 and shall remain in effect until a storage facility permit is granted under NDAC 43-05-01-05, unless amended or terminated by the Department of Mineral Resources (commission).

Tamara Madche, Geologist
Department of Mineral Resources
Date: January 30, 2023

## I. APPLICANT

Blue Flint Sequester Company, LLC
2841 3rd St SW
Underwood, ND 58576

## II. PERMIT CONDITIONS (NDAC 43-05-01-07.3)

1. The storage operator shall comply with all conditions of the permit. Any noncompliance with the permit constitutes a violation and is grounds for enforcement action, including permit termination, revocation, or modification pursuant to NDAC 43-05-01-12.

2. In an administrative action, it shall not be a defense that it would have been necessary for the storage operator to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

3. The storage operator shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with the storage facility permit.

4. The storage operator shall develop and implement an emergency and remedial response plan pursuant to section 43-05-01-13.

5. The storage operator shall at all times properly operate and maintain all storage facilities which are installed or used by the storage operator to achieve compliance with the conditions of the storage facility permit. Proper operation and maintenance include effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the storage facility permit.

6. The permit may be modified, revoked and reissued, or terminated pursuant to section 43-05-01-12. The filing of a request by the storage operator for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. The injection well permit or the permit to operate an injection well does not convey any property rights of any sort or any exclusive privilege.

8. The storage operator shall furnish to the commission, within a time specified by the commission, any information which the commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The storage operator shall also

furnish to the commission, upon request, copies of records required to be kept by the storage facility permit.

9. The storage operator shall allow the commission, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

    a. Enter upon the storage facility premises where records must be kept under the conditions of the permit;
    b. At reasonable times, have access to and copy any records that must be kept under the conditions of the permit;
    c. At reasonable times, inspect any facilities, equipment, including monitoring and control equipment, practices, or operations regulated or required under the permit; and
    d. At reasonable times, sample or monitor for the purposes of assuring permit compliance, any substances or parameters at any location.

10. The storage operator shall prepare, maintain, and comply with a testing and monitoring plan pursuant to section 43-05-01-11.4.

11. The storage operator shall comply with the reporting requirements provided in section 43-05-01-18.

12. The storage operator must obtain an injection well permit under section 43-05-01-10 and injection wells must meet the construction and completion requirements in section 43-05-01-11.

13. The storage operator shall prepare, maintain, and comply with a plugging plan pursuant to section 43-05-01-11.5.

14. The storage operator shall establish mechanical integrity prior to commencing injection and maintain mechanical integrity pursuant to section 43-05-01-11.1.

15. The storage operator shall implement the worker safety plan pursuant to section 43-05-01.13.

16. The storage operator shall comply with leak detection and reporting requirements pursuant to section 43-05-01-14.

17. The storage operator shall conduct a corrosion monitoring and prevention program pursuant to section 43-05-01-15.

18. The storage operator shall prepare, maintain, and comply with the area of review and corrective action plan pursuant to section 43-05-01-05.1.

19. The storage operator shall maintain financial responsibility pursuant to section 43-05-01-09.1

20. The storage operator shall maintain and comply with the postinjection site care and facility closure plan pursuant to section 43-05-01-19.

## III. CASE SPECIFIC PERMIT CONDITIONS

1. NDAC 43-05-01-11.4, subsection 1, subdivision b; The operator shall notify the commission within 24 hours of failure or malfunction of any surface or bottom hole gauge in the MAG 1 (WF# 37833 – LOT 1 18-145N-82W) injector and the proposed MAG 2 monitor well.

2. NDAC 43-05-01-11.4, subsection 1, subdivision c and NDAC 43-05-01-11, subsection 14; The operator shall run an ultrasonic or another log capable of evaluating internal and external pipe condition to establish a baseline for corrosion monitoring for the MAG 1 and proposed MAG 2. The operator shall run logs with the same capabilities for the MAG 1 on a 5 year schedule unless analysis of corrosion coupons or subsequent logging necessitates a more frequent schedule.

3. NDAC 43-05-01-11.4, subsection 1, subdivision d and NDAC 43-05-01-13, subsection 2; The operator shall cease injection immediately, take all steps reasonably necessary to identify and characterize any release, implement the emergency and remedial response plan approved by the commission, and notify the commission within 24 hours of carbon dioxide detected above the confining zone.

4. NDAC 43-05-01-11.4, subsection 1, subdivision e and NDAC 43-05-01-11.1 subsections 3 and 5; External mechanical integrity shall be continuously monitored with the proposed fiber optic lines for the MAG 1 and MAG 2. The MAG 1 fiber optic line shall be run in the intermediate-long string casing annulus. The commission must be notified within 24 hours should a fiber optic line fail. The commission must be notified prior to severing the line above the confining zone if such an action becomes necessary for remedial work or monitoring activities.

5. NDAC 43-05-01-11.4, subsection 1, subdivision h, paragraph 1; Surface air and soil gas monitoring is required and is planned by the operator in Section 5.7 (Environmental Monitoring Plan), Section 5.7.1 (Atmospheric Monitoring), and Section 5.7.2 (Soil Gas and Groundwater Monitoring) of its permit.

6. NDAC 43-05-01-10, subsection 9, subdivision c, NDAC 43-05-01-11, subsection 15, and NDAC 43-05-01-11.1, subsection 2; The operator shall notify the commission at least 48 hours in advance to witness a mechanical integrity test of the tubing-casing annulus. The packer must be set within 100' of the upper most

perforation and in the 13CR-80 casing. Dependent on evaluation, the operator shall run the same test on a 5 year schedule for the MAG 1 injection well.

7. NDAC 43-05-01-11, subsections 3 and 5; The operator shall continuously monitor surface-intermediate casing annulus with a gauge not to exceed 300psi. The operator shall continuously monitor the intermediate-long string casing annulus with the proposed fiber optic line, and a gauge not to exceed 300psi. The commission must be notified in advance if there is pressure that needs to be bled off.

# Fact Sheet

## 1. Description of Facility

The Blue Flint Sequester Company, LLC (Blue Flint), is a subsidiary of Midwest AgEnergy Group, LLC (MAG). The Blue Flint Ethanol (BFE) facility, owned and operated by MAG, is a 70 million gallon dry mill ethanol production plant located in McLean County, North Dakota, near the city of Underwood. BFE emits carbon dioxide from the fermentation process during ethanol production.

## 2. Quantity and Quality of Carbon Dioxide Stream

The BFE emits an annual average of 200,000 metric tons of carbon dioxide that is expected to be captured, dehydrated, compressed, and then injected. The projected composition of the carbon dioxide stream is greater than 99.98% carbon dioxide with trace quantities of water, oxygen, nitrogen, methane, acetaldehyde, hydrogen sulfide, dimethyl sulfide, ethyl acetate, isopentyl acetate, methanol, ethanol, acetone, n-Propanol, and n-Butanol, equaling less than 0.02% combined.

## 3. Summary of Basis of Draft Permit Conditions

The case specific permit conditions are unique to this storage facility, and not indicative of conditions for other storage facility permits. The conditions take into consideration the equipment proposed for this storage facility. Regulatory provisions for these conditions are all cited from NDAC Chapter 43-05-01 (Geologic Storage of Carbon Dioxide).

## 4. Reasons for Variances or Alternatives

<u>Draft Permit Section III. Case Specific Conditions are referenced below by number from aforementioned section</u>

4. NDAC 43-05-01-11.4, subsection 1, subdivision e, requires a demonstration of external mechanical integrity at least once per year until the injection well is

plugged. NDAC 43-05-01-11.1, subsection 3 requires the storage operator to, at least annually, determine the absence of significant fluid movement by running an approved tracer survey or temperature log or noise log. The installed fiber optic line shall provide a continuous temperature log for the length of the wellbore.

## 5. Procedures Required for Final Decision

**The beginning and ending dates of the comment period:**
January 30, 2023 to 5:00 P.M. CDT March 20, 2023

**The address where comments will be received:**
Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov

**Date, time, and location of the storage facility permit hearing:**
March 21, 2023 9:00 A.M. CDT at 1000 East Calgary Avenue, Bismarck, North Dakota 58503

**Any other procedures by which the public may participate in the final decision:**
At the hearing, the Commission will receive testimony and exhibits of interested parties.

## 6. Contact for Additional Information

Draft Permit Information: Tamara Madche – tjmadche@nd.gov – 701-328-8020
Hearing Information: Bethany Kadrmas – brkadrmas@nd.gov – 701-328-8020#

MIDWEST
AgEnergy

2841 3rd St SW
Underwood, ND 58576
(701) 442-7500

September 30, 2022



Mr. Lynn Helms
North Dakota Industrial Commission
State Capitol, Department 405
600 East Boulevard Avenue
Bismarck, ND 58505-0840

Dear Mr. Helms:

Subject: Development of CCS Facility Permit Application and CCS Incentive Program Compliance – Storage Facility Permit Application

Midwest AgEnergy Group, LLC, together with its partners and affiliates, respectfully submits a storage facility permit application for the dedicated geologic storage of carbon dioxide at Blue Flint Ethanol facility in McLean County, North Dakota.

Following is a link to the application: SFP Application

Please find attached the permit application certification for filing.

If you have any questions, please contact Adam Dunlop of my staff by phone at (701) 442-7500 or by e-mail at adunlop@midwestagenergy.com.

Sincerely,

Jeff Zueger
Chief Executive Officer
Midwest AgEnergy Group, LLC

# STORAGE FACILITY PERMIT APPLICATION CERTIFICATION

BEFORE ME, the undersigned authority, personally appeared Jeff Zueger of Midwest AgEnergy Group, LLC, who being duly sworn upon oath stated and certifies that:

1. I, Jeff Zueger, am over 18 years of age. I have personal knowledge of the information and facts stated by me in this Certification, and they are true and correct. I have never been convicted of any felony or of any crime involving moral turpitude and am fully competent to make these representations.

2. I hold the position of Chief Executive Officer for Midwest AgEnergy Group, LLC. As required in accordance with North Dakota Administrative Code 43-05-01-07.1 and by virtue of my position with Midwest AgEnergy Group, LLC, I am authorized to make the representations on behalf of Midwest AgEnergy Group, LLC.

3. Attached is the storage facility permit application requesting a permit under Chapter 38-22 of the North Dakota Century Code and in accordance with Article 43-05 of the North Dakota Administrative Code for the establishment of a carbon dioxide storage facility located in McLean County, North Dakota.

4. Based upon information and reports provided by individuals immediately responsible for compiling and preparing the enclosed permit applications and supporting information, I have personal knowledge and am familiar with the information being submitted in the attached documents to the permit application. Based upon information and belief, the information contained herein is true, accurate, and complete.

5. I affirm under penalty of perjury that the representations contained in this affidavit are true to the best of my knowledge, information, and belief. I understand that there are significant penalties for submitting false information, including the possibility of a fine and imprisonment.

6. By my signature below, I hereby submit the attached application and supporting documentation and information on behalf of Midwest AgEnergy Group, LLC.

Executed this 30th day of September 2022.

Jeff Zueger

STATE OF NORTH DAKOTA )
)
COUNTY OF MCLEAN )

Subscribed and sworn to before me this 30th day of September 2022.

KYLIE L LANDEIS
Notary Public
State of North Dakota
My Commission Expires Sept. 15, 2026

Notary Public

| | |
|---|---|
| **From:** | Regorrah, Josh |
| **To:** | Madche, Tamara J.; Suggs, Richard A. |
| **Cc:** | Adam Dunlop; Livers-Douglas, Amanda; Connors, Kevin; Riter, Charlotte |
| **Subject:** | Midwest AgEnergy Storage Facility Permit Submission |
| **Date:** | Tuesday, December 13, 2022 10:00:50 AM |
| **Attachments:** | image002.png<br>MAG Supplements and Changes 2022-12-13.docx |



Tammy and Richard,

Midwest AgEnergy respectfully resubmits for the review and consideration of the North Dakota Industrial Commission, the application for a carbon dioxide storage facility permit. A link to the application is provided below. The application is submitted pursuant to and in accordance with Chapter 38-22 of the North Dakota Century Code and Chapter 43-05-01 of the North Dakota Administrative Code. Simulation files, high-resolution figures, and supplemental well logs are included with the link. A list of changes that were made to the SFP have been attached.

SFP Folder: SFP Application

Please let me and the team know if there are any questions or concerns.

Josh Regorrah
EERC | UND UNIVERSITY OF NORTH DAKOTA
Permitting and Regulatory Specialist
**Energy & Environmental Research Center**
**University of North Dakota**
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018
| Cell: (218) 779-2781
jregorrah@undeerc.org|www.undeerc.org

# BLUE FLINT SEQUESTER COMPANY, LLC

Carbon Dioxide Geologic Storage Facility Permit Application

*Prepared for*:

Tamara Madche

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

*Prepared by*:

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

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

December 2022

## TABLE OF CONTENTS



Continued . . .

**TABLE OF CONTENTS (continued)**



Continued . . .

**TABLE OF CONTENTS (continued)**

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

### PERMIT APPLICATION SUMMARY

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

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

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

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

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

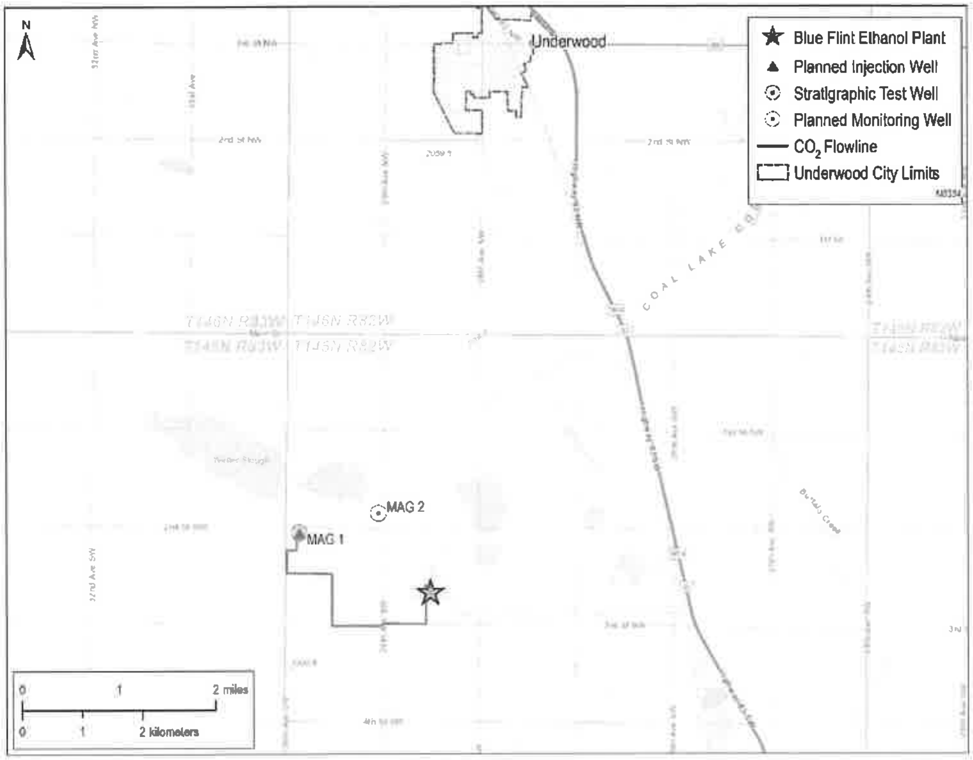



Figure PS-1. Location of the Blue Flint $CO_2$ storage project in relation to the city of Underwood, North Dakota.

# 1.0 PORE SPACE ACCESS

## 1.0 PORE SPACE ACCESS

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

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

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

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

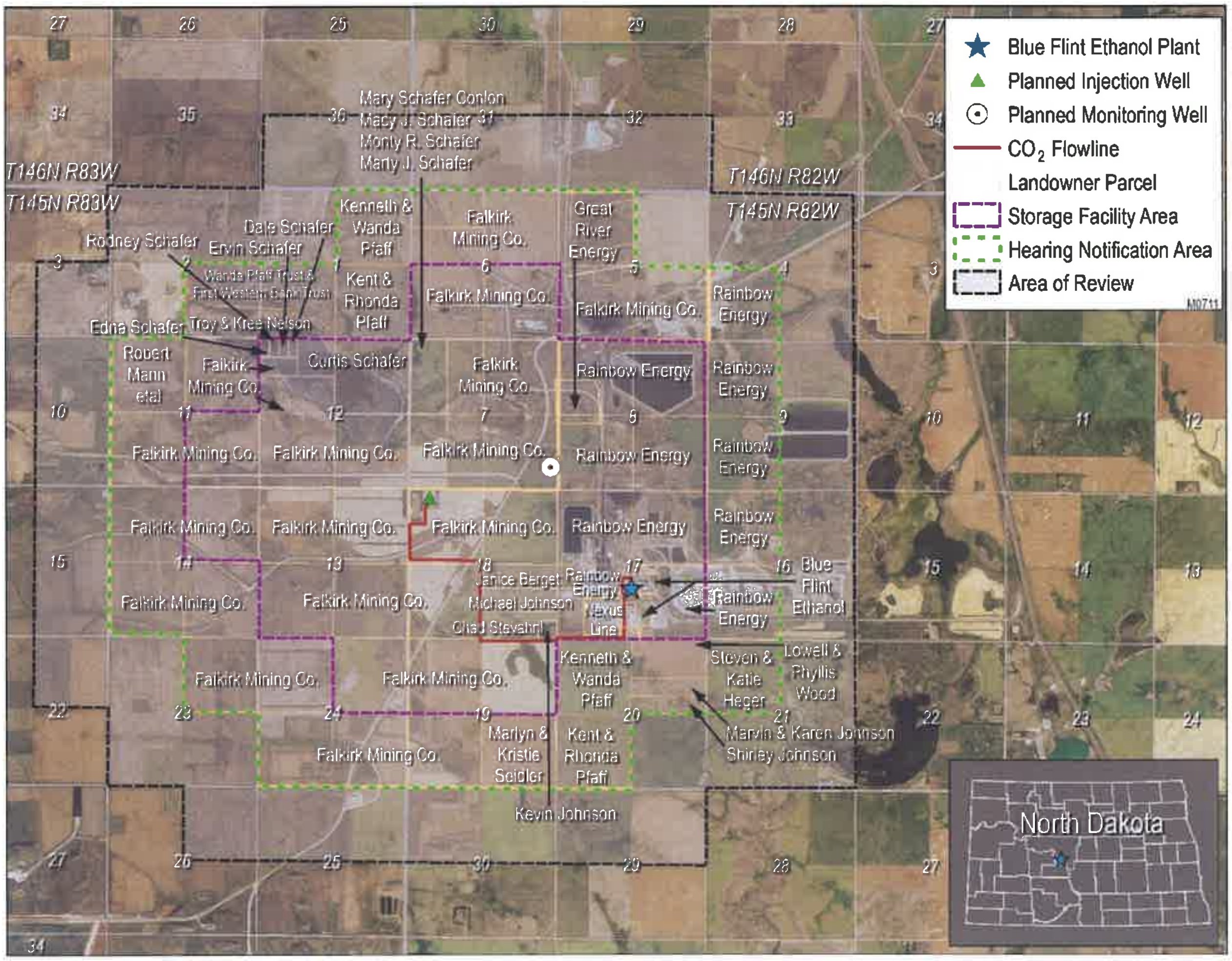



Figure 1-1. Storage facility area map showing pore space ownership.

Fredrikson

Fredrikson & Byron, P.A.
Attorneys and Advisors

1133 College Drive, Suite 1000
Bismarck, ND 58501-1215
Main: 701.221.8700
fredlaw.com



December 6, 2022

***HAND DELIVERED***

Mr. Bruce Hicks
Assistant Director
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

**RE: NDIC CASE NO. ____________**
**CARBON DIOXIDE STORAGE FACILITY PERMIT APPLICATION OF BLUE FLINT SEQUESTER COMPANY, LLC**

Dear Mr. Hicks:

Enclosed herewith for filing in the above-captioned matter, please find the *Storage Agreement – Blue Flint Broom Creek – Secure Geologic Storage, McLean County North Dakota.*

Should you have any questions, please advise.

Sincerely,

LAWRENCE BENDER

LB/tjg
Enclosure(s)

cc: Blue Flint Sequester Company, LLC

RECEIVED
DEC - 6 2022
N.D. INDUSTRIAL COMMISSION

# STORAGE AGREEMENT
# BLUE FLINT BROOM CREEK – SECURE GEOLOGIC STORAGE
# MCLEAN COUNTY, NORTH DAKOTA

**STORAGE AGREEMENT**
**BLUE FLINT BROOM CREEK – SECURE GEOLOGIC STORAGE**
**MCLEAN COUNTY, NORTH DAKOTA**

**THIS AGREEMENT** ("Agreement") is entered into as of the ___ day of ________, 20__, by the parties who have signed the original of this instrument, a counterpart thereof, ratification and joinder or other instrument agreeing to become a Party hereto.

## RECITALS:

A. It is in the public interest to promote the geologic storage of carbon dioxide in a manner which will benefit the state and the global environment by reducing greenhouse gas emissions and in a manner which will help ensure the viability of the state's coal and power industries, to the economic benefit of North Dakota and its citizens;

B. To further geologic storage of carbon dioxide, a potentially valuable commodity, may allow for its ready availability if needed for commercial, industrial, or other uses, including enhanced recovery of oil, gas, and other minerals; and

C. For geologic storage, however, to be practical and effective requires cooperative use of surface and subsurface property interests and the collaboration of property owners, which may require procedures that promote, in a manner fair to all interests, cooperative management, thereby ensuring the maximum use of natural resources.

## AGREEMENT:

It is agreed as follows:

## ARTICLE 1
## DEFINITIONS

As used in this Agreement:

1.1 **Carbon Dioxide** means carbon dioxide in gaseous, liquid, or supercritical fluid state together with incidental associated substances derived from the source materials, capture process and any substances added or used to enable or improve the injection process.

1.2 **Commission** means the North Dakota Industrial Commission.

1.3 **Effective Date** is the time and date this Agreement becomes effective as provided in Article 14.

1.4 **Facility Area** is the land described by Tracts in Exhibit "B" and shown on Exhibit "A" containing 4953.71 acres, more or less.

1.5 **Party** is any individual, corporation, limited liability company, partnership, association, receiver, trustee, curator, executor, administrator, guardian, tutor, fiduciary, or other representative of any kind, any department, agency, or instrumentality of the state, or any governmental subdivision thereof, or any other entity capable of holding an interest in the Storage Reservoir.

1.6 **Pore Space** means a cavity or void, whether natural or artificially created, in any subsurface stratum.

1.7 **Pore Space Interest** is a right to or interest in the Pore Space in any Tract within the boundaries of the Facility Area.

1.8 **Pore Space Owner** is a Party hereto who owns Pore Space Interest.

1.9 **Storage Equipment** is any personal property, lease and well equipment, plants and other facilities and equipment for use in Storage Operations.

1.10 **Storage Expense** is all costs, expense or indebtedness incurred by the Storage Operator pursuant to this Agreement for or on account of Storage Operations.

1.11 **Storage Facility** is the unitized or amalgamated Storage Reservoir created pursuant to an order of the Commission.

1.12 **Storage Facility Participation** is the percentage shown on Exhibit "C" for allocating payments for use of the Pore Space under each Tract identified in Exhibit "B".

1.13 **Storage Operations** are all operations conducted by the Storage Operator pursuant to this Agreement or otherwise authorized by any lease covering any Pore Space Interest.

1.14 **Storage Operator** is the person or entity named in Section 4.1 of this Agreement.

1.15 **Storage Reservoir** consists of the Pore Space and confining subsurface strata underlying the Facility Area described as the lower Piper Picard and Spearfish(Upper Confining Zone), Broom Creek (Storage Reservoir/Injection Zone), and Amsden (Lower Confining Zone) Formation(s) and which are defined as identified by the well logging suite performed at the stratigraphic well, the MAG 1 well (File No. 37833). The log suites included caliper, spontaneous potential (SP), gamma ray (GR), density, porosity (neutron, density), dipole sonic, resistivity, and a full-bore formation microimager (FMI) log. Further, the logs were used to pick formation top depths and interpret lithology, petrophysical properties, and time-to-depth shifting of seismic data obtained from a 3D seismic survey covering an area totaling 9-mi$^2$ in and around the MAG 1 (located in Section 18, Township 145 North, Range 82 West) stratigraphic well located in Mclean County, North Dakota. Formation top depths were picked from the top of the lower Piper Picard Formation to the top of the Tyler Formation. These logs and data which encompass the stratigraphic interval from an average depth of 4,553 feet to an average depth of 5,053 feet within the limits of the Facility Area.

1.16 **Storage Rights** are the rights to explore, develop, and operate lands within the Facility Area for the storage of Storage Substances.

1.17 **Storage Substances** are Carbon Dioxide and incidental associated substances, fluids, and minerals.

1.18 **Tract** is the land described as such and given a Tract number in Exhibit "B."

## ARTICLE 2
## EXHIBITS

2.1 **Exhibits.** The following exhibits, which are attached hereto, are incorporated herein by reference:

2.1.1 Exhibit "A" is a map that shows the boundary lines of the Blue Flint Broom Creek Facility Area and the tracts therein;

2.1.2 Exhibit "B" is a schedule that describes the acres of each Tract in the Blue Flint Broom Creek Facility Area;

2.1.3 Exhibit "C" is a schedule that shows the Storage Facility Participation of each Tract; and

2.1.4 Exhibit "D" is a form of Pore Space Lease.

2.2 **Reference to Exhibits.** When reference is made to an exhibit, it is to the exhibit as originally attached or, if revised, to the last revision.

2.3 **Exhibits Considered Correct.** Exhibits "A," "B," "C" and "D" shall be considered to be correct until revised as herein provided.

2.4 **Correcting Errors.** The shapes and descriptions of the respective Tracts have been established by using the best information available. If it subsequently appears that any Tract, mechanical miscalculation or clerical error has been made, Storage Operator, with the approval of Pore Space Owners whose interest is affected, shall correct the mistake by revising the exhibits to conform to the facts. The revision shall not include any re-evaluation of engineering or geological interpretations used in determining Storage Facility Participation. Each such revision of an exhibit made prior to thirty (30) days after the Effective Date shall be effective as of the Effective Date. Each such revision thereafter made shall be effective at 7:00 a.m. on the first day of the calendar month next following the filing for record of the revised exhibit or on such other date as may be determined by Storage Operator and set forth in the revised exhibit.

2.5 **Filing Revised Exhibits.** If an exhibit is revised, Storage Operator shall execute an appropriate instrument with the revised exhibit attached and file the same for record in the county or counties in which this Agreement or memorandum of the same is recorded and shall also file the amended changes with the Commission.

## ARTICLE 3
## CREATION AND EFFECT OF STORAGE FACILITY

3.1 **Unleased Pore Space Interests.** Any Pore Space Owner in the Storage Facility who owns a Pore Space Interest in the Storage Reservoir that is not leased for the purposes of this Agreement and during the term hereof, shall be treated as if it were subject to the Pore Space Lease attached hereto as Exhibit "D".

3.2 **Amalgamation of Pore Space.** All Pore Space Interests in and to the Tracts are hereby amalgamated and combined insofar as the respective Pore Space Interests pertain to the Storage Reservoir, so that Storage Operations may be conducted with respect to said Storage Reservoir as if all of the Pore Space Interests in the Facility Area had been included in a single lease executed by all Pore Space Owners, as lessors, in favor of Storage Operator, as lessee and as if the lease contained all of the provisions of this Agreement.

3.3 **Amendment of Leases and Other Agreements.** The provisions of the various leases, agreements, or other instruments pertaining to the respective Tracts or the storage of the Storage Substances therein, including the Pore Space Lease attached hereto as Exhibit "D", are amended to the extent necessary to make them conform to the provisions of this Agreement, but otherwise shall remain in effect.

3.4 **Continuation of Leases and Term Interests.** Injection in to any part of the Storage Reservoir, or other Storage Operations, shall be considered as injection in to or upon each Tract within said Storage Reservoir, and such injection or operations shall continue in effect as to each lease as to all lands and formations covered thereby just as if such operations were conducted on and as if a well were injecting in each Tract within said Storage Reservoir.

3.5 **Titles Unaffected by Storage.** Nothing herein shall be construed to result in the transfer of title of the Pore Space Interest of any Party hereto to any other Party or to Storage Operator.

3.6 **Injection Rights.** Storage Operator is hereby granted the right to inject into the Storage Reservoir any Storage Substances in whatever amounts Storage Operator may deem expedient for Storage Operations, together with the right to drill, use, and maintain injection wells in the Facility Area, and to use for injection purposes.

3.7 **Transfer of Storage Substances from Storage Facility.** Storage Operator may transfer from the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, to any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North Dakota Century Code. The transfer of such Storage Substances out of the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.8 **Receipt of Storage Substances.** Storage Operator may accept and receive into the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, being stored in any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North Dakota Century Code. The receipt of such Storage Substances into the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.9 **Cooperative Agreements.** Storage Operator may enter into cooperative agreements with respect to lands adjacent to the Facility Area for the purpose of coordinating Storage Operations. Such cooperative agreements may include, but shall not be limited to, agreements regarding the transfer and receipt of Storage Substances pursuant to Sections 3.7 and 3.8 of this Agreement.

3.10 **Border Agreements.** Storage Operator may enter into an agreement or agreements with owners of adjacent lands with respect to operations which may enhance the injection of the Storage Substances in the Storage Reservoir in the Facility Area or which may otherwise be necessary for the conduct of Storage Operations.

## ARTICLE 4
## STORAGE OPERATIONS

4.1 **Storage Operator.** Blue Flint Sequester Company, LLC is hereby designated as the initial Storage Operator. Storage Operator shall have the exclusive right to conduct Storage Operations, which shall conform to the provisions of this Agreement and any lease covering a Pore Space Interest. If there is any conflict between such agreements, this Agreement shall govern.

4.2 **Successor Operators.** The initial Storage Operator and any subsequent operator may, at any time, transfer operatorship of the Storage Facility with and upon the approval of the Commission.

4.3 **Method of Operation.** Storage Operator shall engage in Storage Operations with diligence and in accordance with good engineering and injection practices.

4.4 **Change of Method of Operation.** As permitted by the Commission nothing herein shall prevent Storage Operator from discontinuing or changing in whole or in part any method of operation which, in its opinion, is no longer in accord with good engineering or injection practices. Other methods of operation may be conducted or changes may be made by Storage Operator from time to time if determined by it to be feasible, necessary or desirable to increase the injection or storage of Storage Substances.

## ARTICLE 5
## TRACT PARTICIPATIONS

5.1 **Tract Participations.** The Storage Facility Participation of each Tract is shown in Exhibit "C." The Storage Facility Participation of each Tract shall be based 100% upon the ratio of surface acres in each Tract to the total surface acres for all Tracts within the Facility Area.

5.2 **Relative Storage Facility Participations.** If the Facility Area is enlarged or reduced, the revised Storage Facility Participation of the Tracts remaining in the Facility Area and which were within the Facility Area prior to the enlargement or reduction shall remain in the same ratio to one another.

## ARTICLE 6
## ALLOCATION OF STORAGE SUBSTANCES

6.1 **Allocation of Tracts.** All Storage Substances injected shall be allocated to the several Tracts in accordance with the respective Storage Facility Participation effective during the period that the Storage Substances are injected. The amount of Storage Substances allocated to each tract, regardless of whether the amount is more or less than the actual injection of Storage Substances from the well or wells, if any, on such Tract, shall be deemed for all purposes to have been injected into such Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.1.

6.2 **Distribution within Tracts.** The Storage Substances injected and allocated to each Tract shall be distributed among, or accounted for to, the Pore Space Owners who own a Pore Space Interest in such Tract in accordance with each Pore Space Owner's Storage Facility Participation effective during the period that the Storage Substances were injected. If any Pore Space Interest in a Tract hereafter becomes divided and owned in severalty as to different parts of the Tract, the owners of the divided interests, in the absence of an agreement providing for a different division, shall be compensated for the storage of the Storage Substances in proportion to the surface acreage of their respective parts of the Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.2.

## ARTICLE 7
## TITLES

7.1 **Warranty and Indemnity.** Each Pore Space Owner who, by acceptance of revenue for the injection of Storage Substances into the Storage Reservoir, shall be deemed to have warranted title to its Pore Space Interest, and, upon receipt of the proceeds thereof to the credit of such interest, shall indemnify and hold harmless the Storage Operator and other Parties from any loss due to failure, in whole or in part, of its title to any such interest.

7.2 **Injection When Title Is in Dispute.** If the title or right of any Pore Space Owner claiming the right to receive all or any portion of the proceeds for the storage of any Storage Substances allocated to a Tract is in dispute, Storage Operator shall require that the Pore Space Owner to whom the proceeds thereof are paid furnish security for the proper accounting thereof to the rightful Pore Space Owner if the title or right of such Pore Space Owner fails in whole or in part.

7.3 **Payments of Taxes to Protect Title.** The owner of surface rights to lands within the Facility Area is responsible for the payment of any *ad valorem* taxes on all such rights, interests or property, unless such owner and the Storage Operator otherwise agree. If any *ad valorem* taxes are not paid by or for such owner when due, Storage Operator may at any time prior to tax sale or expiration of period of redemption after tax sale, pay the tax, redeem such rights, interests or property, and discharge the tax lien. Storage Operator shall, if possible, withhold from any proceeds derived from the storage of Storage Substances otherwise due any Pore Space Owner who is a delinquent taxpayer an amount sufficient to defray the costs of such payment or redemption, such withholding to be credited to the Storage Operator. Such withholding shall be without prejudice to any other remedy available to Storage Operator.

7.4 **Pore Space Interest Titles.** If title to a Pore Space Interest fails, but the tract to which it relates is not removed from the Facility Area, the Party whose title failed shall not be entitled to share under this Agreement with respect to that interest.

## ARTICLE 8
## EASEMENTS OR USE OF SURFACE

8.1 **Grant of Easement.** Storage Operator shall have the right to use as much of the surface of the land within the Facility Area as may be reasonably necessary for Storage Operations and the injection of Storage Substances.

8.2 **Use of Water.** Storage Operator shall have and is hereby granted free use of water from the Facility Area for Storage Operations, except water from any well, lake, pond or irrigation ditch of a Pore Space Owner; notwithstanding the foregoing, Storage Operator may access any well, lake, or pond as provided in Exhibit "D".

8.3 **Surface Damages.** Storage Operator shall pay surface owners for damage to growing crops, timber, fences, improvements and structures located on the Facility Area that result from Storage Operations.

8.4 **Surface and Sub-Surface Operating Rights.** Except to the extent modified in this Agreement, Storage Operator shall have the same rights to use the surface and sub-surface and use of water and any other rights granted to Storage Operator in any lease covering Pore Space Interests. Except to the extent expanded by this Agreement or the extent that such rights are common to the effected leases, the rights granted by a lease may be exercised only on the land covered by that lease. Storage Operator will to the extent possible minimize surface impacts.

## ARTICLE 9
## ENLARGEMENT OF STORAGE FACILITY

9.1 **Enlargement of Storage Facility.** The Storage Facility may be enlarged from time to time to include acreage and formations reasonably proven to be geologically capable of storing Storage Substances. Any expansion must be approved in accordance with the rules and regulations of the Commission.

9.2 **Determination of Tract Participation.** Storage Operator, subject to Section 5.2, shall determine the Storage Facility Participation of each Tract within the Storage Facility as enlarged, and shall revise Exhibits "A", "B" and "C" accordingly and in accordance with the rules, regulations and orders of the Commission.

9.3 **Effective Date.** The effective date of any enlargement of the Storage Facility shall be effective as determined by the Commission.

## ARTICLE 10
## TRANSFER OF TITLE PARTITION

10.1 **Transfer of Title.** Any conveyance of all or part of any interest owned by any Party hereto with respect to any Tract shall be made expressly subject to this Agreement. No change of title shall be binding upon Storage Operator, or any Party hereto other than the Party so transferring, until 7:00 a.m. on the first day of the calendar month following thirty (30) days from the date of receipt by Storage Operator of a photocopy, or a certified copy, of the recorded or filed instrument evidencing such a change in ownership.

10.2 **Waiver of Rights to Partition.** Each Party hereto agrees that, during the existence of this Agreement, it will not resort to any action to partition any Tract or parcel within the Facility Area or the facilities used in the development or operation thereof, and to that extent waives the benefits or laws authorizing such partition.

## ARTICLE 11
## RELATIONSHIP OF PARTIES

11.1 **No Partnership.** The duties, obligations and liabilities arising hereunder shall be several and not joint or collective. This Agreement is not intended to create, and shall not be construed to create, an association or trust, or to impose a partnership duty, obligation or liability with regard to any one or more of the Parties hereto. Each Party hereto shall be individually responsible for its own obligations as herein provided.

11.2 **No Joint Marketing.** This Agreement is not intended to provide, and shall not be construed to provide, directly or indirectly, for any joint marketing of Storage Substances.

11.3 **Pore Space Owners Free of Costs.** This Agreement is not intended to impose, and shall not be construed to impose, upon any Pore Space Owner any obligation to pay any Storage Expense unless such Pore Space Owner is otherwise so obligated.

11.4 **Information to Pore Space Owners.** Each Pore Space Owner shall be entitled to all information in possession of Storage Operator to which such Pore Space Owner is entitled by an existing lease or a lease imposed by this Agreement.

## ARTICLE 12
## LAWS AND REGULATIONS

12.1 **Laws and Regulations.** This Agreement shall be subject to all applicable federal, state and municipal laws, rules, regulations and orders.

## ARTICLE 13
## FORCE MAJEURE

13.1 **Force Majeure.** All obligations imposed by this Agreement on each Party, except for the payment of money, shall be suspended while compliance is prevented, in whole or in part, by a labor dispute, fire, war, civil disturbance, or act of God; by federal, state or municipal laws; by any rule, regulation or order of a governmental agency; by inability to secure materials; or by any other cause or causes, whether similar or dissimilar, beyond reasonable control of the Party. No Party shall be required against his will to adjust or settle any labor dispute. Neither this Agreement nor any lease or other instrument subject hereto shall be terminated by reason of suspension of Storage Operations due to any one or more of the causes set forth in this Article.

## ARTICLE 14
## EFFECTIVE DATE

14.1 **Effective Date.** This Agreement shall become effective as determined by the Commission.

14.2 **Ipso Facto Termination.** If the requirements of Section 14.1 are not accomplished on or before __________, 20__ this Agreement shall *ipso facto* terminate on that date (hereinafter called "termination date") and thereafter be of no further effect, unless prior thereto Pore Space Owners owning a combined Storage Facility Participation of at least thirty percent (30%) of the Facility Area have become Parties to this Agreement and have decided to extend the termination date for a period not to exceed six (6) months. If the termination date is so extended and the requirements of Section 14.1 are not accomplished on or before the extended termination date this Agreement shall *ipso facto* terminate on the extended termination date and thereafter be of no further effect.

14.3 **Certificate of Effectiveness.** Storage Operator shall file for record in the county or counties in which the land affected is located a certificate stating the Effective Date of this Agreement.

## ARTICLE 15
## TERM

15.1 **Term.** Unless sooner terminated in the manner hereinafter provided or by order of the Commission, this Agreement shall remain in full force and effect until the Commission has issued a certificate of project completion with respect to the Storage Facility in accordance with § 38-22-17 of the North Dakota Century Code.

15.2 **Termination by Storage Operator.** This Agreement may be terminated at any time by the Storage Operator with the approval of the Commission.

15.3 **Effect of Termination.** Upon termination of this Agreement all Storage Operations shall cease. Each lease and other agreement covering Pore Space within the Facility Area shall remain in force for ninety (90) days after the date on which this Agreement terminates, and for such further period as is provided by Exhibit "D" or other agreement.

15.4 **Salvaging Equipment Upon Termination.** If not otherwise granted by Exhibit "D" or other instruments affecting each Tract, Pore Space Owners hereby grant Storage Operator a period of six (6) months after the date of termination of this Agreement within which to salvage and remove Storage Equipment.

15.5 **Certificate of Termination.** Upon termination of this Agreement, Storage Operator shall file for record in the county or counties in which the land affected is located a certificate that this Agreement has terminated, stating its termination date.

## ARTICLE 16
## APPROVAL

16.1 **Original, Counterpart or Other Instrument.** A Pore Space Owner may approve this Agreement by signing the original of this instrument, a counterpart thereof, ratification or joinder or other instrument approving this instrument hereto. The signing of any such instrument shall have the same effect as if all Parties had signed the same instrument.

16.2 **Joinder in Dual Capacity.** Execution as herein provided by any Party as either a Pore Space Owner or the Storage Operator shall commit all interests owned or controlled by such Party and any additional interest thereafter acquired in the Facility Area.

16.3 **Approval by the North Dakota Industrial Commission.**
Notwithstanding anything in this Article to the contrary, all Tracts within the Facility Area shall be deemed to be qualified for participation if this Agreement is duly approved by order of the Commission.

## ARTICLE 17
## GENERAL

17.1 **Amendments Affecting Pore Space Owners.** Amendments hereto relating wholly to Pore Space Owners may be made with approval by the Commission.

17.4 **Construction.** This agreement shall be construed according to the laws of the State of North Dakota.

## ARTICLE 18
## SUCCESSORS AND ASSIGNS

18.1 **<u>Successors and Assigns.</u>** This Agreement shall extend to, be binding upon, and inure to the benefit of the Parties hereto and their respective heirs, devisees, legal representatives, successors and assigns and shall constitute a covenant running with the lands, leases and interests covered hereby.

[*Remainder of page intentionally left blank. Signature page follows.*]

Executed the date set opposite each name below but effective for all purposes as provided by Article 14.

Dated: ____________, 20__

**STORAGE OPERATOR**

BLUE FLINT SEQUESTER COMPANY, LLC

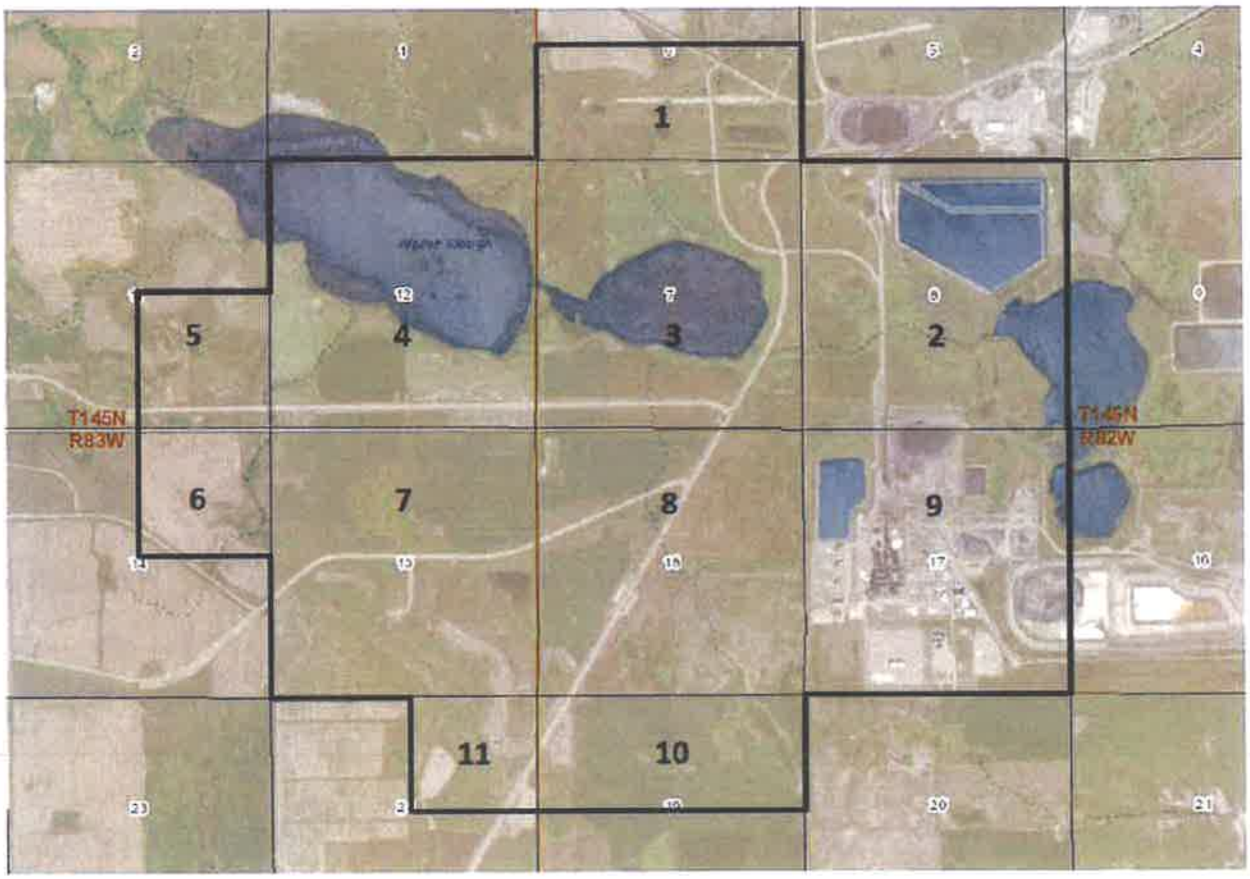
By:_________________________________
[Name]
Its: [Title]

**77739768 v1**

**Exhibit A**

Tract Map

Attached to and made part of the Storage Agreement
Blue Flint Broom Creek – Secure Geological Storage
McLean County, North Dakota



# Exhibit B

Tract Summary

Attached to and made part of the Storage Agreement
Blue Flint Broom Creek – Secure Geological Storage
McLean County, North Dakota

| Tract No. | Land Description | Owner Name | Tract Net Acres | Tract Participation | Storage Facility Participation |
|---|---|---|---|---|---|
| | | | | | |
| 1 | Section 6-T145N-R82W | The Falkirk Mining Company | 318.770 | 100.00000000% | 6.43497500% |
| | | **Tract Total:** | **318.770** | **100.00000000%** | |
| | | | | | |
| 2 | Section 8-T145N-R82W | Rainbow Energy Center, LLC | 590.730 | 92.30156250% | 11.92500167% |
| | | Great River Energy | 49.270 | 7.69843750% | 0.99460808% |
| | | **Tract Total:** | **640.000** | **100.00000000%** | |
| | | | | | |
| 3 | Section 7-T145N-R82W | The Falkirk Mining Company | 558.760 | 87.56895687% | 11.27962678% |
| | | Mary Schafer Conlon | 19.830 | 3.10776078% | 0.40030603% |
| | | Macy J. Schafer | 19.830 | 3.10776078% | 0.40030603% |
| | | Monty R. Schafer | 19.830 | 3.10776078% | 0.40030603% |
| | | Marty J. Schafer | 19.830 | 3.10776078% | 0.40030603% |
| | | **Tract Total:** | **638.080** | **100.00000000%** | |

| Tract No. | Land Description | Owner Name | Tract Net Acres | Tract Participation | Storage Facility Participation |
|---|---|---|---|---|---|
| | | | | | |
| 4 | Section 12-T145N-R83W | The Falkirk Mining Company | 420.000 | 65.62500000% | 8.47849390% |
| | | Curtis Schafer | 200.000 | 31.25000000% | 4.03737805% |
| | | Estate of Edna B. Schafer | 5.000 | 0.78125000% | 0.10093445% |
| | | Rodney C. Schafer | 5.000 | 0.78125000% | 0.10093445% |
| | | Ervin R. Schafer Revocable Trust | 5.000 | 0.78125000% | 0.10093445% |
| | | Dale J. Schafer | 5.000 | 0.78125000% | 0.10093445% |
| | | **Tract Total:** | **640.000** | **100.00000000%** | |
| | | | | | |
| 5 | Section 11-T145N-R83W | The Falkirk Mining Company | 160.000 | 100.00000000% | 3.22990244% |
| | | **Tract Total:** | **160.000** | **100.00000000%** | |
| | | | | | |
| 6 | Section 14-T145N-R83W | The Falkirk Mining Company | 160.000 | 100.00000000% | 3.22990244% |
| | | **Tract Total:** | **160.000** | **100.00000000%** | |
| | | | | | |
| 7 | Section 13-T145N-R83W | The Falkirk Mining Company | 640.000 | 100.00000000% | 12.91960975% |
| | | **Tract Total:** | **640.000** | **100.00000000%** | |
| | | | | | |
| 8 | Section 18-T145N-R82W | The Falkirk Mining Company | 477.600 | 74.90589711% | 9.64125877% |
| | | Janice Berget | 40.000 | 6.27352572% | 0.80747561% |
| | | Michael Johnson | 60.000 | 9.41028858% | 1.21121341% |
| | | Chad Stevahn | 16.667 | 2.61396905% | 0.33644817% |
| | | Tammy Stevahn | 16.667 | 2.61396905% | 0.33644817% |
| | | Michelle Albrecht | 16.667 | 2.61396905% | 0.33644817% |
| | | Brandy Schmidt | 3.333 | 0.52279381% | 0.06728963% |
| | | Kevin L. Johnson | 3.333 | 0.52279381% | 0.06728963% |
| | | Keith Johnson | 3.333 | 0.52279381% | 0.06728963% |
| | | **Tract Total:** | **637.600** | **100.00000000%** | |

| Tract No. | Land Description | Owner Name | Tract Net Acres | Tract Participation | Storage Facility Participation |
|---|---|---|---|---|---|
| | | | | | |
| 9 | Section 17-T145N-R82W | Rainbow Energy Center, LLC | 552.000 | 86.25000000% | 11.14316341% |
| | | Blue Flint Ethanol LLC | 49.460 | 7.72812500% | 0.99844359% |
| | | Nexus Line, LLC | 38.540 | 6.02187500% | 0.77800275% |
| | | **Tract Total:** | **640.000** | **100.00000000%** | |
| | | | | | |
| 10 | Section 19-T145N-R82W | The Falkirk Mining Company | 319.260 | 100.00000000% | 6.44486657% |
| | | **Tract Total:** | **319.260** | **100.00000000%** | |
| | | | | | |
| 11 | Section 24-T145N-R83W | The Falkirk Mining Company | 160.000 | 100.00000000% | 3.22990244% |
| | | **Tract Total:** | **160.000** | **100.00000000%** | |
| | | | | | |
| | | **Total Acres:** | **4953.710** | **Total Participation:** | **100.00000000%** |

## Exhibit C

Tract Participation Factors

Attached to and made part of the Storage Agreement
Blue Flint Broom Creek – Secure Geological Storage
McLean County, North Dakota

| Tract No. | Acres | Tract Participation Factor |
|---|---|---|
| | | |
| 1 | 318.770 | 6.43497500% |
| 2 | 640.000 | 12.91960975% |
| 3 | 638.080 | 12.88085092% |
| 4 | 640.000 | 12.91960975% |
| 5 | 160.000 | 3.22990244% |
| 6 | 160.000 | 3.22990244% |
| 7 | 640.000 | 12.91960975% |
| 8 | 637.600 | 12.87116121% |
| 9 | 640.000 | 12.91960975% |
| 10 | 319.260 | 6.44486657% |
| 11 | 160.000 | 3.22990244% |
| | | |
| **Total:** | **4953.710** | **100.00000000%** |

## Exhibit D

Form of Pore Space Lease

Attached to and made part of the Storage Agreement
Blue Flint Broom Creek – Secure Geological Storage
McLean County, North Dakota

## PORE SPACE LEASE

THIS PORE SPACE LEASE (this "Lease") is made effective as of the Effective Date (as defined below) by and between [______________________________], [husband and wife/a single person/a widow/a _________], whose address is [__________________________] (whether one or more, "Lessor"), and Blue Flint Sequester Company, LLC, a Delaware limited liability company, whose address is 2841 3rd Street SW, Underwood, ND 58576 ("Lessee"). Lessor and Lessee may be individually referred to herein as a "Party" and collectively as the "Parties".

1. Leased Premises. Lessor, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, does hereby grant, demise, lease and let unto Lessee for Lessee's geologic storage operations and other purposes set forth herein, the lands described in Exhibit A attached hereto and incorporated herein by reference (the "Leased Premises").

2. Term.

(a) Initial and Primary Term. This Lease shall commence on the date Lessee executes this Lease ("Effective Date") and continue for an initial term of twenty (20) years ("Initial Term") unless sooner terminated in accordance with the terms of this Lease. As consideration for the Initial Term, Lessee shall pay to Lessor [_____ AND __/100 DOLLARS ($__.__)] per acre as a single one-time bonus payment. Lessee may, at any time prior to the expiration of the Initial Term, elect to extend the Initial Term for up to an additional twenty (20) years by providing written notice to Lessor and payment of [_____ AND __/100 DOLLARS ($__.__)] per acre (the Initial Term, together with all extensions shall be referred to herein as the "Primary Term"). For the avoidance of doubt, Lessor's consent to any such extension will not be required provided that the foregoing payment is tendered to Lessor prior to the expiration of the Initial Term.

(b) Operational Term. This Lease shall continue beyond the Primary Term for so long as any portion of the Leased Premises or Lessee's storage facilities located in, on or under the Leased Premises (including without limitation, any Reservoirs) are subject to a permit issued by the North Dakota Industrial Commission (the "Commission") (a "Permit") or under the ownership or control of the State of North Dakota; *provided, however,* that all of Lessee's obligations under this Lease shall terminate upon issuance of a certificate of project completion pursuant to Chapter 38-22 of the North Dakota Century Code (the "Operational Term"). If the Primary Term expires and no portion of the Leased Premises or Lessee's storage facilities located in, on or under the Leased Premises is subject to a Permit, this Lease shall terminate, and Lessee shall execute a document evidencing termination of this Lease in recordable form and shall record it in the official records of the county in which the

Leased Premises is located. As consideration for the Operational Term, Lessee shall pay to Lessor the royalty set forth in Section 3, below.

3. Royalty. Lessee shall pay to Lessor its proportionate share of [_______ ($_.__)] per metric ton of carbon dioxide ($CO_2$) injected into the reservoirs and subsurface pore spaces (as used herein, such terms shall have the meanings set forth in Chapter 38-22 and Chapter 47-31 of the North Dakota Century Code), stratum or strata underlying the Leased Premises (collectively, "Reservoirs"), or reservoirs and subsurface pore spaces, stratum or strata unitized or amalgamated therewith. The quantity of $CO_2$ so injected shall be measured by meters installed by Lessee. Lessor's "proportionate share" shall be determined on a net acre basis and the Parties hereby stipulate that the acreage set forth in Exhibit A shall be used to calculate Lessor's proportionate share. The quantity of carbon dioxide injected into the Reservoirs or any reservoirs or subsurface pore spaces, stratum or strata unitized or amalgamated therewith shall be determined through the use of metering equipment installed and operated by Lessee at the injection site. All royalties due hereunder for carbon dioxide injected into the Reservoirs or any reservoirs or subsurface pore spaces, stratum or strata unitized or amalgamated therewith during any calendar month shall be paid to Lessor annually on or before March 1 for the prior year's injection volumes. Lessor and Lessee agree that this Lease shall continue as specified herein even in the absence of injection operations and the payment of royalties.

4. Right to Pore Space/Storage of Carbon Dioxide. Lessor grants to Lessee the exclusive right to inject and store carbon dioxide ($CO_2$) and other incidental gaseous substances into the Reservoirs, together with the right to construct, replace, inspect, repair, monitor, maintain, relocate, change the size of such surface or subsurface facilities on the Leased Premises that Lessee determines necessary or desirable for Lessee's storage operations, including, but not limited to fences, pipelines, tanks, reservoirs, electric and communication lines, roadways, underground facilities and equipment, surface facilities and equipment, buildings, structures and other such facilities and appurtenances. Lessor shall not grant any other person the right to inject or store $CO_2$ or any other incidental substances.

5. Facility Right of Ways/Compensation. Lessor grants Lessee the right of reasonable use of the surface of the Leased Premises, including without limitation, the rights of ingress and egress over the Leased Premises together with the right of way over, under and across the Leased Premises and the right from time to time to construct, replace, inspect, repair, monitor, maintain, relocate, change the size of such surface or subsurface facilities on the Leased Premises that Lessee determines necessary or desirable for Lessee's storage operations, including, but not limited to fences, pipelines, tanks, reservoirs, electric and communication lines, roadways, underground facilities and equipment, surface facilities and equipment, buildings, structures and other such facilities and appurtenances, (each a "Facility" and collectively the "Facilities"); *provided, however*, that (i) Lessee shall provide Lessor with notice of operations and an offer of damage, disruption and loss of production payments, as each may be applicable, prior to the installation of any such Facilities on the Leased Premises, and (ii) the agreed up terms, including the amount of damage payments to be paid to Lessor, shall be memorialized in an agreement separate from this Lease, such agreement to be consistent with the grant contained herein. Lessee shall be entitled to proceed with the installation of the Facilities while the separate agreement and amount of damage, disruption or loss is being agreed or determined. Lessee shall have the further right to fence the perimeter of any Facility on the Leased Premises and sufficiently illuminate the site for the safety and security of operations.

6. Amalgamation. Lessee, in its sole discretion, shall have the right and power, at any time and from time to time during the term of this Lease to pool, unitize, or amalgamate any reservoirs or subsurface pore spaces, stratum or strata underlying the Leased Premises with any other lands or interests into which such reservoirs or subsurface pore spaces extend and document such unit in accordance with applicable law or agency order. Amalgamated units shall be of such shape and dimensions as Lessee may elect and as are approved by the Commission. Amalgamated areas may include, but are not required to include, land upon which injection or extraction wells have been completed or upon which the injection and/or withdrawal of carbon dioxide and/or related gaseous substances has commenced prior to the effective date of amalgamation. In exercising its amalgamation rights under this Lease and if required by law, Lessee shall record or cause to be recorded a copy of the Commission's amalgamation order or other notice thereof in the county in which the amalgamated unit is located. Amalgamating in one or more instances shall, if approved by the Commission, not exhaust the rights of Lessee to amalgamate Reservoirs or portions of Reservoirs into other amalgamation areas, and Lessee shall have the recurring right to revise any amalgamated area formed under this Lease by expansion or contraction or both. Lessee may dissolve any amalgamated area at any time and document such dissolution by recording an instrument in accordance with applicable law or agency order. Lessee shall have the right to negotiate, on behalf of and as agent for Lessor, any unit, amalgamation, storage or operating agreements with respect to amalgamation of reservoir or pore space interests underlying the Leased Premises or the operation of any amalgamated areas formed under such agreements. To the extent any of the terms of such agreements conflict with the terms of this Lease, the terms of such agreements shall control, and the provisions of this Lease shall be deemed modified to conform to the terms, conditions, and provisions of any such agreements which are approved by the Commission.

7. Lessee Obligations. Lessee shall have no obligation, express or implied, to begin, prosecute or continue storage operations in, upon or under the Leased Premises, or store and/or sell or use all or any portion of the gaseous substances stored thereon. The timing, nature, manner and extent of Lessee's operations, if any, under this Lease shall be at the sole discretion of Lessee. All obligations of Lessee are expressed herein, and there shall be no covenants implied under this Lease, it being agreed that all amounts paid hereunder constitute full and adequate consideration for this Lease.

8. Ownership. Lessee shall at all times be the owner of (i) the carbon dioxide and other gaseous substances stored in the Reservoirs or any reservoirs or subsurface pore spaces, stratum or strata unitized or amalgamated therewith, and (ii) all equipment, buildings, structures, facilities and other property constructed or installed by Lessee on the Leased Premises. Lessee shall have the right, but not the obligation, at any time during this Lease to remove all or any portion of the property or fixtures placed by Lessee on the Lease Premises. Notwithstanding the foregoing, title to the storage facility and to the stored carbon dioxide or other gaseous substances shall be transferred to the State of North Dakota upon issuance of a certificate of project completion by the Commission in accordance with Chapter 38-22 of the North Dakota Century Code.

9. Minerals, Oil and Gas. This Lease is not intended to grant or convey, nor does it grant or convey, any right to or obligation for Lessee to explore for or produce minerals, including oil and gas, that may exist on or under the Leased Premises.

10. Surrender of Leased Premises. Lessee shall have the right, but not the obligation, at any time from time to time to execute and deliver to Lessor a surrender and/or release covering all or any part of the Leased Premises for which the Reservoirs are not being utilized for storage as set forth herein, and upon delivery of such surrender and/or release to Lessor this Lease shall terminate as to such lands, and Lessee shall be released from all further obligations and duties as to the lands so surrendered and/or released, including, without limitation, any obligation to make payments provided for herein, except obligations accrued as of the date of the surrender and/or release. Lessee shall be able to surrender the any and or all of the Leased Premises if not utilizing the Reservoirs located thereunder.

11. Hold Harmless and Indemnification. The Lessee agrees to defend, indemnify, and hold harmless Lessor from any claims by any person that are a direct result of the Lessee's use of the Leased Premises or Reservoirs. Notwithstanding the foregoing, such indemnity/hold harmless obligation excludes (i) any claim or cause of action, or alleged or threatened claim or cause of action, damage, judgment, interest, penalty or other loss arising or resulting from the negligence or intentional acts of Lessor or Lessor's agents, invitees, or licensees; or third parties, and (ii) any claim for exemplary, punitive, special or consequential damages claimed by Lessor. Lessee further accepts liability and indemnifies Lessor for reasonable costs, expenses and attorneys' fees incurred in establishing and litigating the indemnification coverage provided above. The legal defense provided by Lessee to the Lessor under this paragraph must be free of any conflicts of interest even if this requires Lessee to retain separate legal counsel for Lessor.

12. Hazardous Substances. Lessee shall have no liability for any regulated hazardous substances located on the Leased Premises prior to the Effective Date or placed in, on or about the Leased Premises by Lessor or any third-party on or after the Effective Date, and nothing in this Lease shall be construed to impose upon Lessee any obligation for the removal of such regulated hazardous substances. As used herein, "hazardous substances" shall have the meaning set forth in the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) and any amendments thereto, or any other local, state or federal statutes.

13. Termination. A material violation or default of any terms of this Lease by Lessee shall be grounds for termination of the Lease. Lessor shall give Lessee written notice of violation or default and Lessee shall have sixty (60) days after receipt of said notice to substantially cure such violations or defaults. If Lessee fails to substantially cure such violations or defaults within the 60-day cure period, Lessor may terminate the Lease; provided that if it is not possible to cure such violations or defaults within the 60-day cure period, Lessee shall have a reasonable longer period of time to cure such violations or defaults provided it commences cure within the initial 60-day cure period and thereafter diligently pursues such cure. Lessee may terminate the lease with thirty (30) days written notice to Lessor. Upon termination of this Lease, Lessee shall have one hundred eighty (180) days to remove all facilities and property of Lessee located on the Leased Premises. For the avoidance of doubt, Lessee shall not be required to remove any $CO_2$ or other incidental gaseous substances injected into the Reservoirs.

14. Taxes. Lessee shall pay all taxes, if any, levied against its personal property or on its improvements to the Leased Premises. Lessor shall pay for all real estate taxes and other assessments levied upon the Leased Premises. Lessee shall have the right to pay all taxes,

assessments and other fees on behalf of Lessor and to deduct the amount so paid from other payments due to Lessor hereunder.

15. Conduct of Operations. In conducting its operations hereunder, Lessee shall use its best efforts to comply with all applicable laws, rules and regulations and ordinances pertaining thereto. Lessee reserves and shall have the right to challenge and/or appeal any law, ruling, regulation, order or other determination and to carry on its operations in accordance with Lessee's interpretation of the same, pending final determination.

16. Force Majeure. Should Lessee be prevented from complying with any express or implied covenant of this Lease or from utilizing the Lease Premises for underground storage purposes by reason of scarcity of or an inability to obtain or to use equipment or material or failure or breakdown of equipment, or by operation of force majeure, any federal or state law or any order, rule or regulation of governmental authority, then while so prevented, Lessee's obligation to comply with such covenant shall be suspended and the primary term of this Lease shall be extended while and so long as Lessee is prevented by any such cause from utilizing the property for underground storage purposes and the time while Lessee is so prevented shall not be counted against Lessee, anything in this Lease to the contrary notwithstanding.

17. Surface Damage Compensation. The bonus and royalty amounts contemplated and paid to Lessor hereunder is compensation for, among other things, damages sustained by Lessor for lost land value, lost use of and access to Lessor's land and lost value of improvements, if any and to the extent applicable. Subject to Lessee's obligation to compensate Lessor for the installation of any Facilities on the Leased Premises pursuant to Section 5 of this Agreement, Lessor agrees that such compensation is just and adequate for any and all such damages and all other damages which Lessor may sustain as a result of Lessee's use of the property for its storage operations.

18. Warranty of Title and Quiet Enjoyment.

(a) Lessor represents and warrants to Lessee that Lessor is the owner of the surface of the Leased Premises and the pore space located thereunder. Lessor hereby warrants and agrees to defend title to the Leased Premises and the pore space located thereunder and Lessor hereby agrees that Lessee, at its option, shall have the right to discharge any tax, mortgage, or other lien upon the Leased Premises, and in the event Lessee does so, Lessee shall be subrogated to such lien with the right to enforce the same and apply royalty payments or any other payments due to Lessor toward satisfying the same.

(b) Lessor warrants that, except as disclosed to Lessee in writing, there are no liens, encumbrances, leases, mortgages, deeds of trust, options, or other exceptions to Lessor's fee title ownership of the Leased Premises (collectively, "Liens") which are not recorded in the public records of the County in which the Leased Premises is located. Lienholders (including tenants), whether or not their Liens are recorded, shall be Lessor's responsibility, and Lessor shall cooperate with Lessee to obtain a non-disturbance agreement from each party that holds a Lien (recorded or unrecorded) that might interfere with Lessee's rights under this Lease. A non-disturbance agreement is an agreement between Lessee and a lienholder which provides that the lienholder shall not disturb Lessee's possession or rights under the Lease or terminate this Lease so long as Lessor is not entitled to terminate this Lease under the provisions hereof.

(c) Lessor shall have the quiet use and enjoyment of the Leased Premises in accordance with the terms of this Lease. Lessor's activities and any grant of rights Lessor makes to any person or entity, whether located on the Leased Premises or elsewhere, shall not, currently or prospectively, materially interfere with activities permitted hereunder. If Lessor has any right to select, determine, prohibit or control the location of sites for drilling, exploitation, production and/or exploration of minerals, hydrocarbons, water, gravel, or any other similar resource in, to or under the Lease Premises, then Lessor shall exercise such right so as to minimize interference with any of the foregoing.

19. Environmental Incentives and Tax Credits. Lessee shall be the owner of (i) any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to Lessee's geologic storage operations, including any avoided emissions and the reporting rights related to these avoided emissions, such as 26 U.S.C. §45Q Tax Credits, and any other attributes of Lessee's ownership of the Facilities and Lessee's geologic storage operations ("Environmental Attributes"), and (ii) any and all credits, rebates, subsidies, payments or other incentives that relate to the use of technology incorporated into Lessee's geologic storage operations, environmental benefits of such operations, or other similar programs available from any regulated entity or any governmental authority ("Environmental Incentives"). Lessee is further entitled to the benefit of any and all (a) investment tax credits, (b) production tax credits, (c) credits under 26 U.S.C. §45Q credits, and (d) similar tax credits or grants under federal, state or local law relating to Lessee's geologic storage operations ("Tax Credits"). Lessor shall (i) cooperate with Lessee in obtaining, securing and transferring all Environmental Attributes and Environmental Incentives and the benefit of all Tax Credits, and (ii) shall allow Lessee to take any actions necessary to install additional equipment on the Facilities to comply with all monitoring and reporting obligations, and allow Lessee's personnel to enter the premises and collect any data Lessee requires to satisfy its obligations required in connection with obtaining Tax Credits and Environmental Attributes. Lessor shall not be obligated to incur any out-of-pocket costs or expenses in connection with such actions unless reimbursed by Lessee. If any Environmental Incentives are paid directly to Lessor, Lessor shall immediately pay such amounts over to Lessee.

20. Assignment. The rights of either Party hereto may be assigned in whole or part. The assigning party shall provide written notice of any assignment within sixty (60) days after such assignment has become effective; *provided, however,* that an assigning party's failure to deliver written notice of assignment within such 60-day period shall not be deemed a breach of this Lease unless such failure is willful and intentional. The Lessor's consent shall not be required for an assignment by the Lessee of this Lease, whether by way of a collateral assignment to its financiers or otherwise.

21. Change of Ownership. No change of ownership in the Leased Premises shall be binding on the Lessee for purpose of making payments to Lessor hereunder until the date Lessor, or Lessor's successors or assigns, furnishes Lessee the recorded original or a certified copy of the instrument evidencing the change in ownership. The Lessor's consent shall not be required for a change in the direct or indirect control of the Lessee.

22. Notices. All notices required to be given under this Lease shall be in writing and addressed to the respective Party at the addresses set forth at the beginning of this Lease unless otherwise directed by either Party.

23. No Waiver. The failure of either Party to insist in any one or more instances upon strict performance of any of the provisions of this Lease or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provision or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

24. Notice of Lease. This Lease shall not be recorded in the real property records. Lessee shall cause a memorandum of this Lease to be recorded in the real property records of the county in which the Leased Premises are situated.

25. Confidentiality. Lessor shall maintain in the strictest confidence, for the benefit of Lessee, all information pertaining to the compensation paid under this Lease, any information regarding Lessee and its business or operations on the Leased Premises or on any other lands, the capacity and suitability of any Reservoir or reservoirs and subsurface pore spaces, stratum or strata unitized or amalgamated therewith, and any other information that is deemed proprietary or that Lessee requests or identifies to be held confidential, in each such case whether disclosed by Lessee or discovered by Lessor.

26. Counterparts. This Lease may be executed in any number of counterparts, each of which, when executed and delivered, shall be an original, but all of which shall collectively constitute one and the same instrument.

27. Severability. If any provision of this Lease is found to be invalid, illegal or unenforceable in any respect, such provision shall be deemed to be severed from this Agreement, and the validity, legality and enforceability of the remaining provisions contained herein shall not in any way be affected or impaired thereby.

28. Governing Law. This Lease shall be governed by, construed and enforced in accordance with the laws of the State of North Dakota and the Parties hereby submit to the jurisdiction of the state or federal courts located in the State of North Dakota.

29. Further Assurances. Each Party will execute and deliver all documents, provide all information, and take or forbear from all actions as may be necessary or appropriate to achieve the purposes of this Lease, including without limitation executing a memorandum of this Lease and all documents required to obtain any necessary government approvals.

30. Entire Agreement. This Lease constitutes the entire agreement between the Parties and supersedes all prior negotiations, undertakings, notices, memoranda and agreement between the Parties, whether oral or written, with respect to the subject matter hereof. This Lease may only be amended or modified by a written agreement duly executed by Lessor and Lessee.

31. Cooperation with Financiers. The Lessor hereby acknowledges and consents that Lessee may grant a collateral assignment or leasehold mortgage of Lessee's rights under this Lease to Lessee's debt financiers, it being understood that such collateral assignment or leasehold mortgage would only encumber the leasehold interest created hereunder.

32. Electronic Signatures. This Lease, and any amendments hereto, to the extent signed and delivered by means of electronic transmission in portable document format (pdf) or by DocuSign or similar electronic signature process, shall be treated in all manner and respects as an original contract and shall be considered to have the same binding legal effect as if it were the original signed version thereof delivered in person.

IN WITNESS WHEREOF, the Parties have executed this Lease effective for all purposes as of the Effective Date.

**LESSOR:**

[______________________]

By: ______________________

Print: ______________________

Its: ______________________

**Effective Date:**______________

**LESSEE:**

BLUE FLINT SEQUESTER COMPANY, LLC

By: ______________________

Print: ______________________

Its: ______________________

# <u>EXHIBIT A</u>

**Leased Premises**

[Insert Legal Description and Net Surface Acres]

# 2.0 GEOLOGIC EXHIBITS

## 2.0 GEOLOGIC EXHIBITS

### 2.1 Overview of Project Area Geology

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

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

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

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

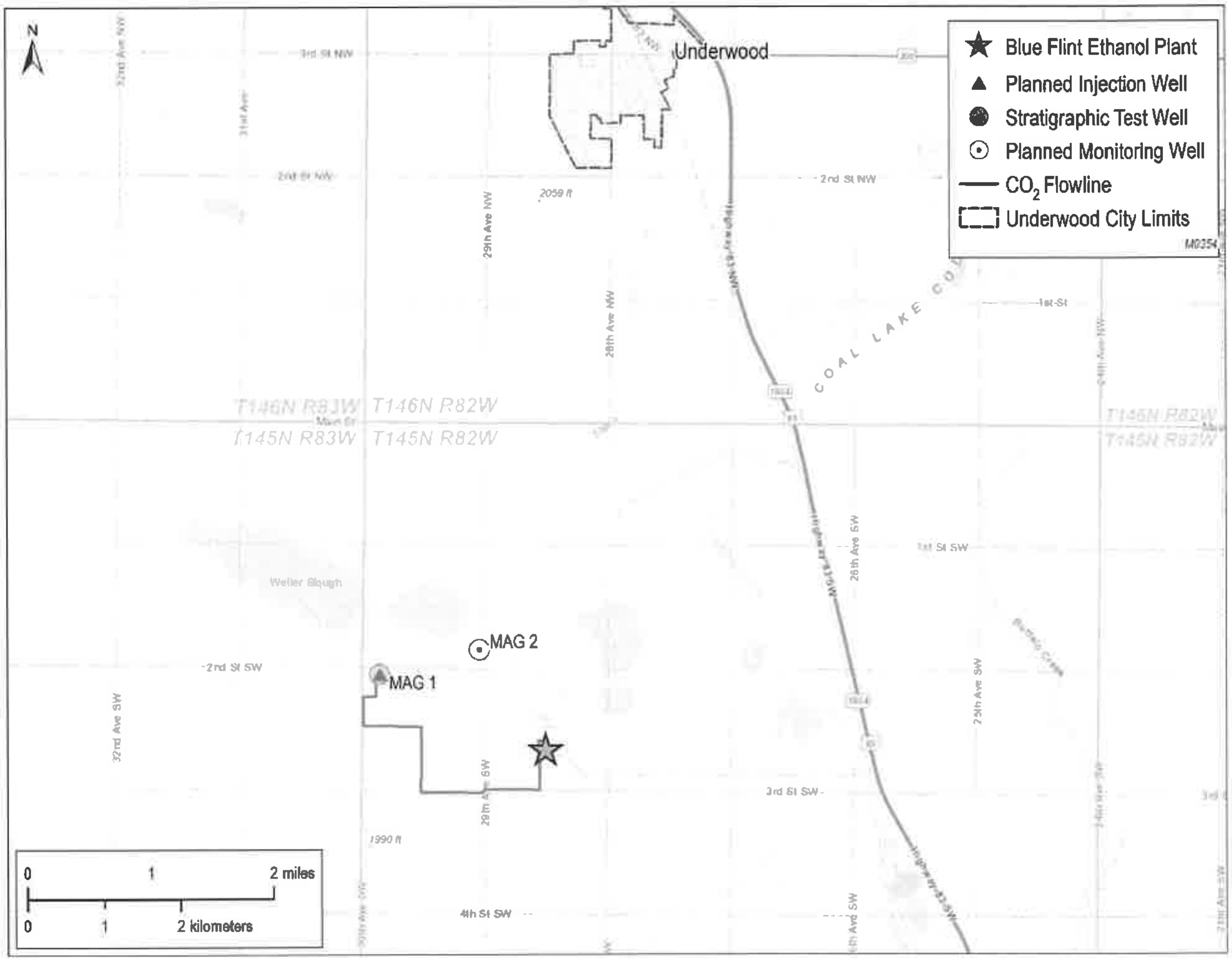



Figure 2-1. Topographic map of the project area showing the planned injection well, the planned monitoring well, and the BFE plant (blue star).

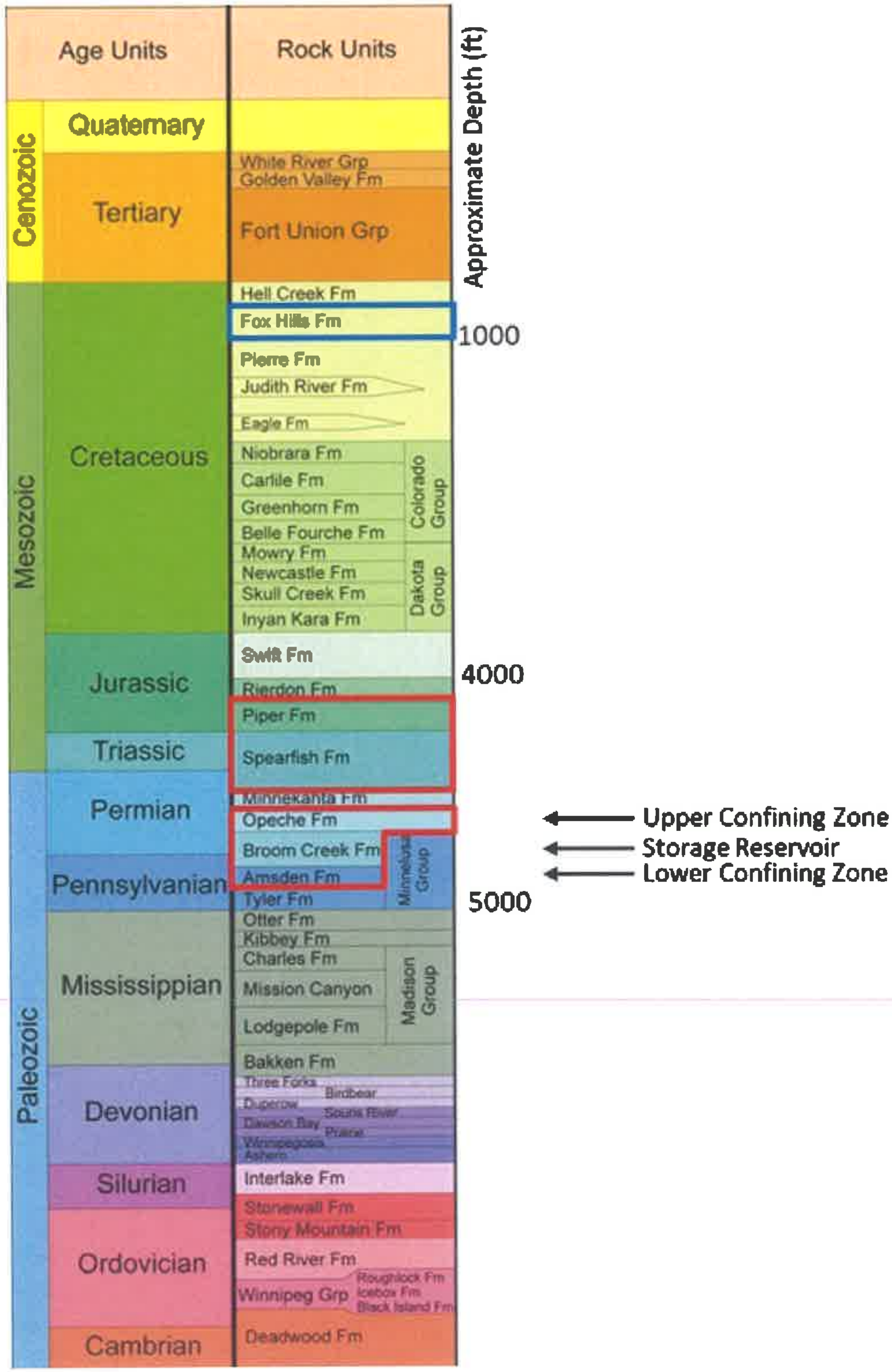



Figure 2-2. Stratigraphic column identifying the potential storage reservoirs and confining zones (outlined in red) and the lowest USDW (outlined in blue). The Minnekahta Formation is not present at this site.

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

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

* Measured depth.

## 2.2 Data and Information Sources

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

### *2.2.1 Existing Data*

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

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

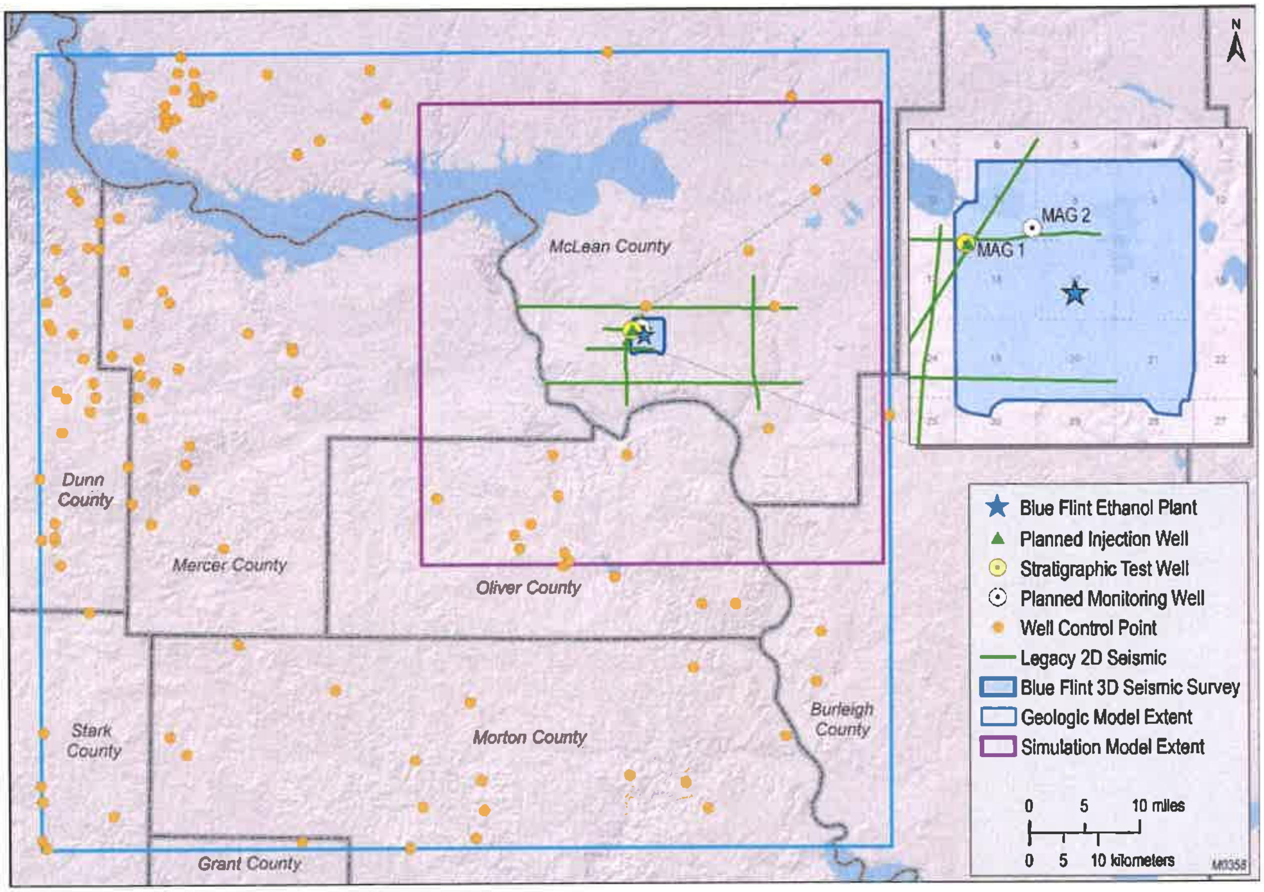



Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

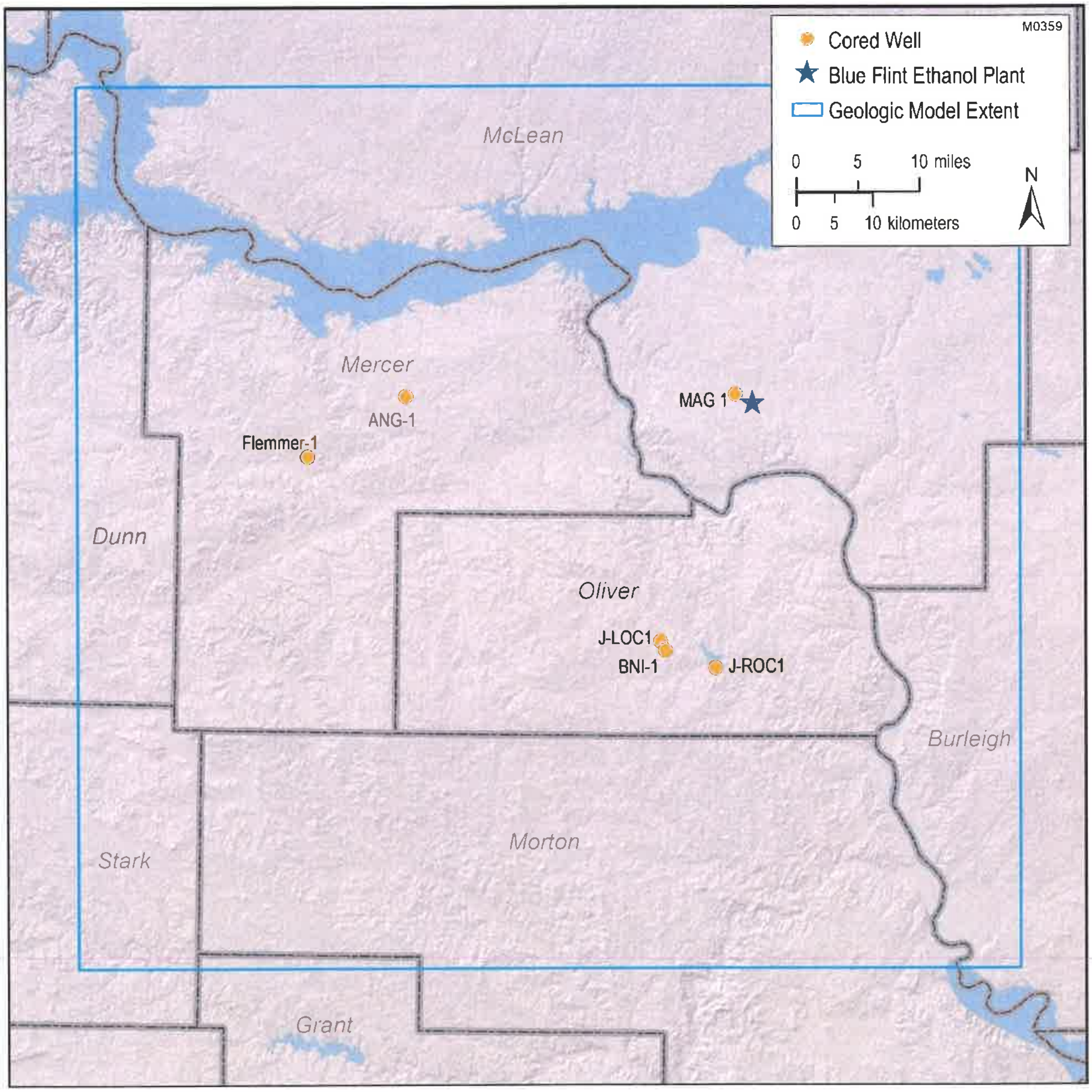



Figure 2-4. Map showing the spatial relationship between the Blue Flint project area and wells where the Broom Creek Formation core samples were collected. Wells with core data include the Flemmer-1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), ANG 1 (Well No. ND-UIC-101), J-LOC1(NDIC File No.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

### *2.2.2 Site-Specific Data*

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

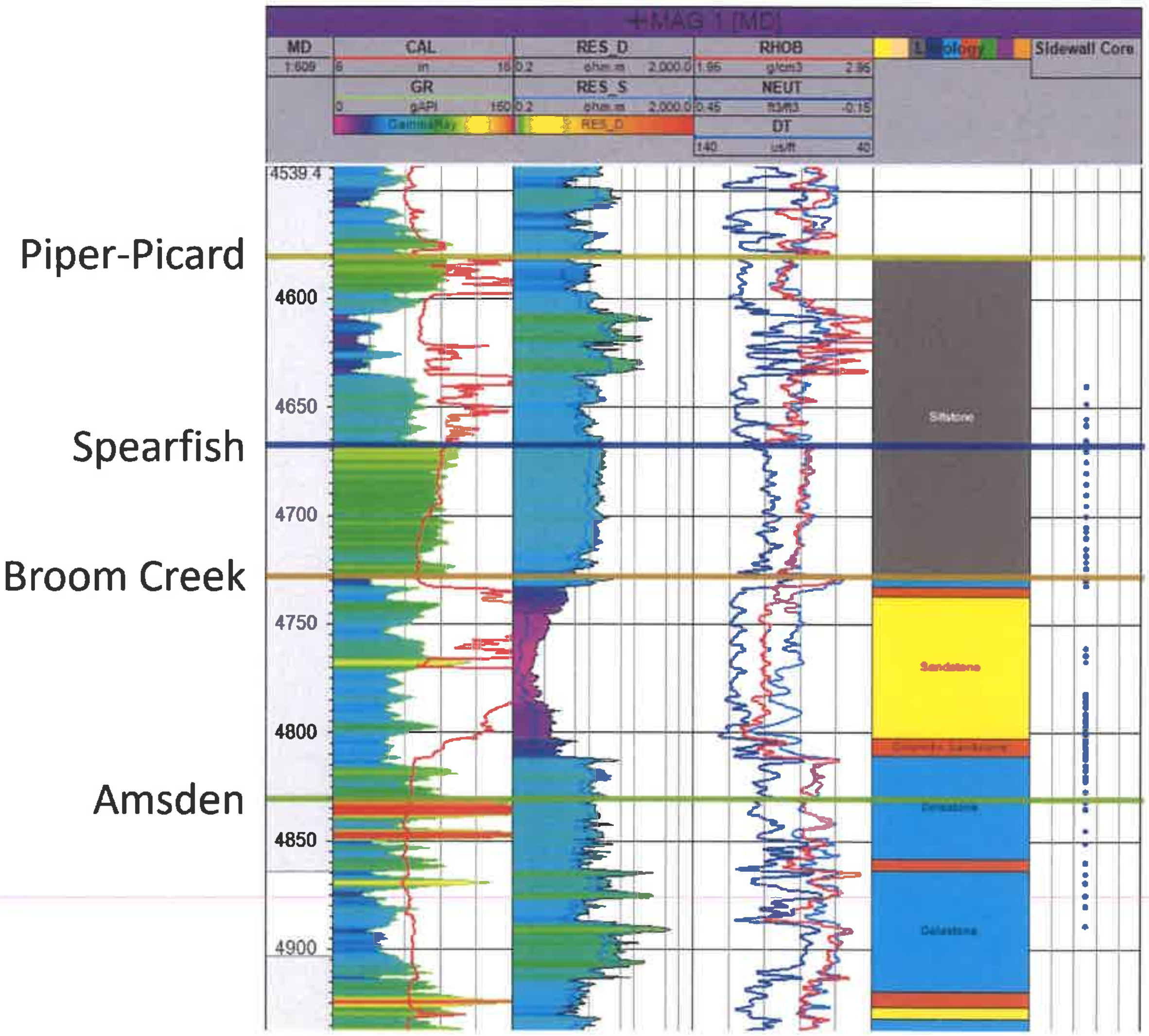



Figure 2-5. Well log display showing the vertical relationship of SW Core plugs taken from the Broom Creek Formation and confining zones. The 50 SW Core plugs are noted as blue circles on the far-right track. The Piper-Picard top denotes the top of the lower Piper Formation.

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

#### *2.2.2.1 Geophysical Well Logs*

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

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

#### *2.2.2.2 Core Sample Analyses*

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

#### *2.2.2.3 Formation Temperature and Pressure*

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

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

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

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

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

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

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

#### 2.2.2.4 *Fluid Samples*

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

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

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

#### 2.2.2.5 *Seismic Survey*

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

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

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

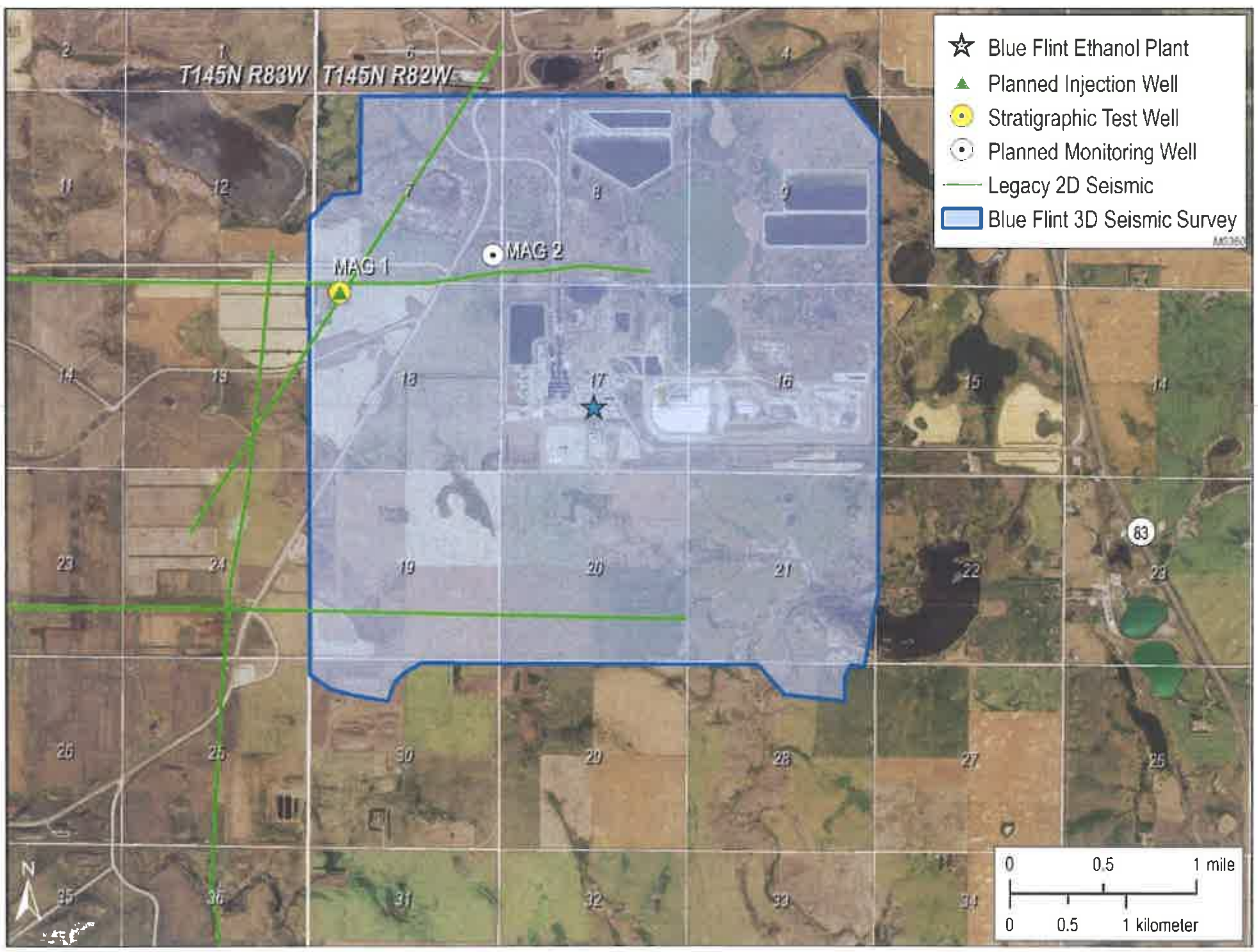



Figure 2-6. Map showing the 2D and 3D seismic surveys in the Blue Flint project area.

## 2.3 Storage Reservoir (injection zone)

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

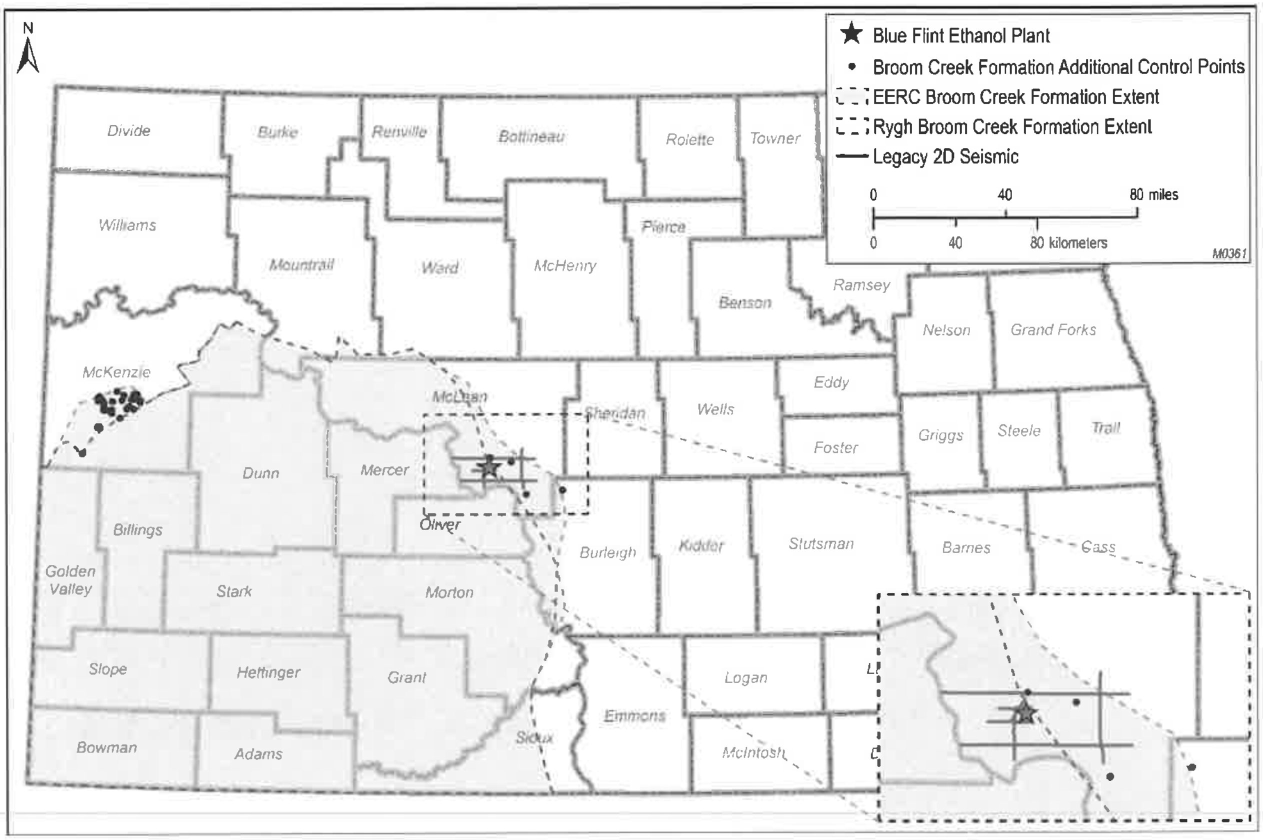



Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (red dashed line). This extent was modified from Rygh (1990) (green dashed line) based on new well control points shown outside of the green-dashed line. Legacy 2D seismic lines are depicted by green lines.

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

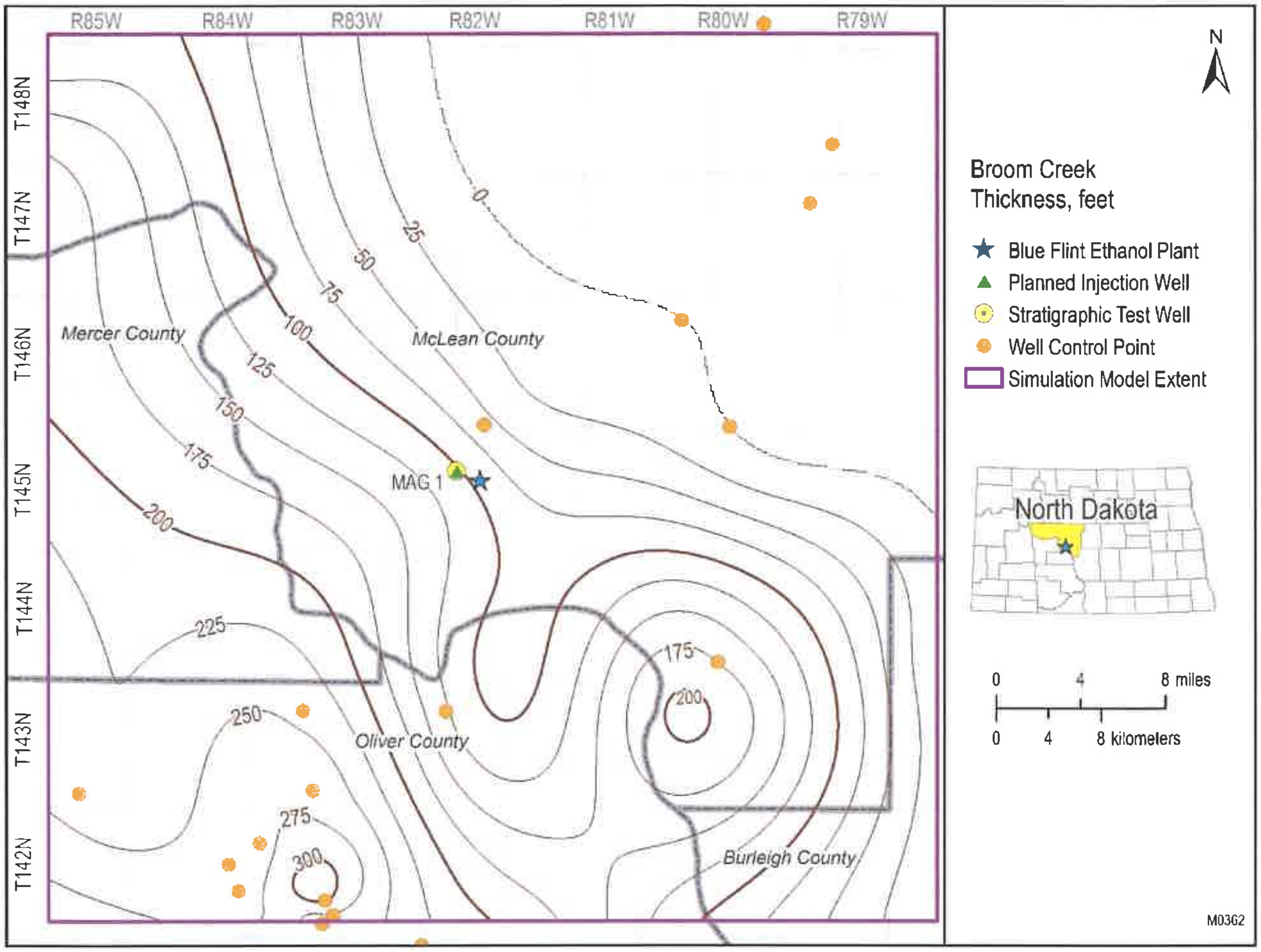



Figure 2-8. Isopach map of the Broom Creek Formation in the greater Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

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

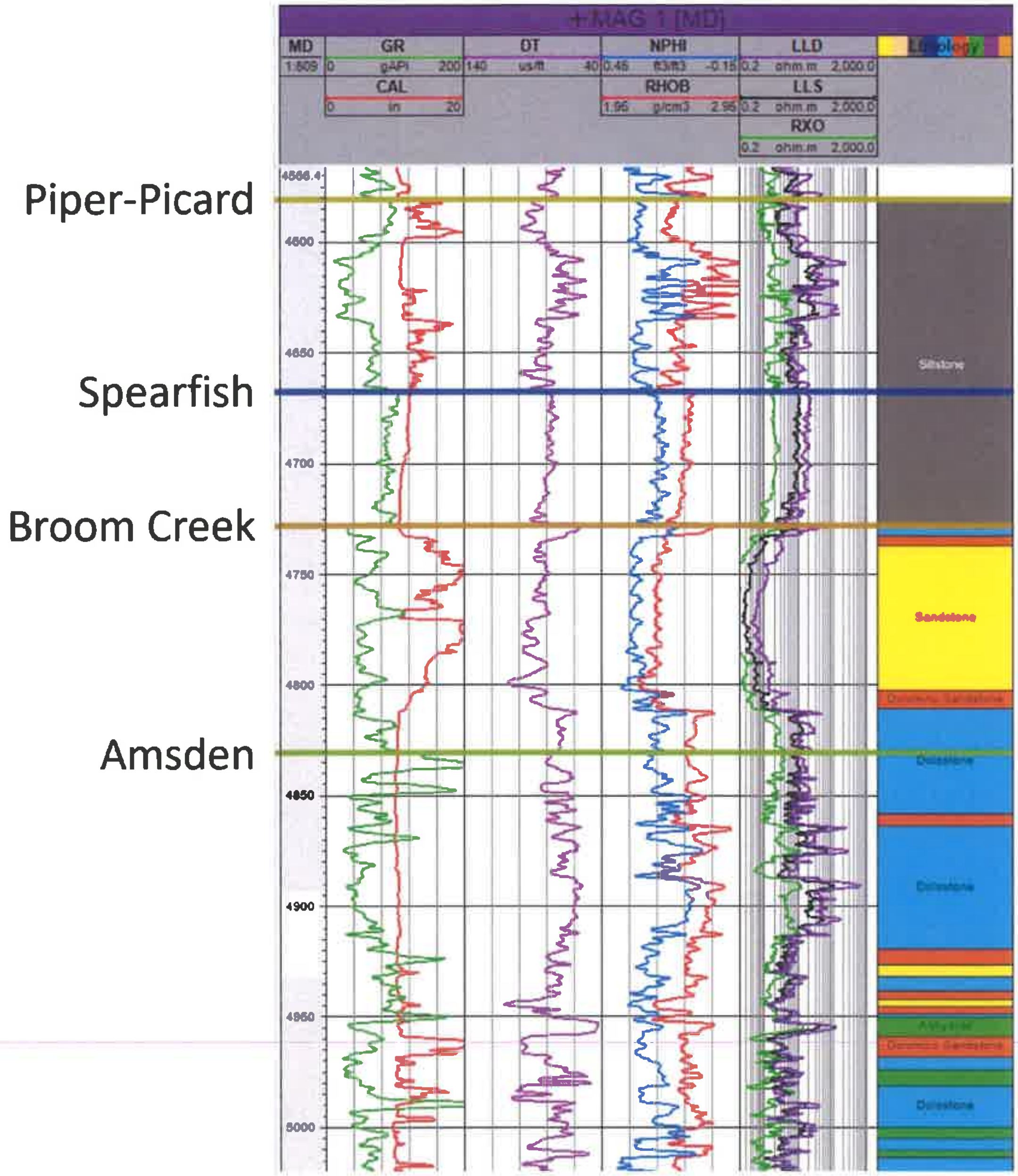



Figure 2-9. Well log display of the interpreted lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations in MAG 1.

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

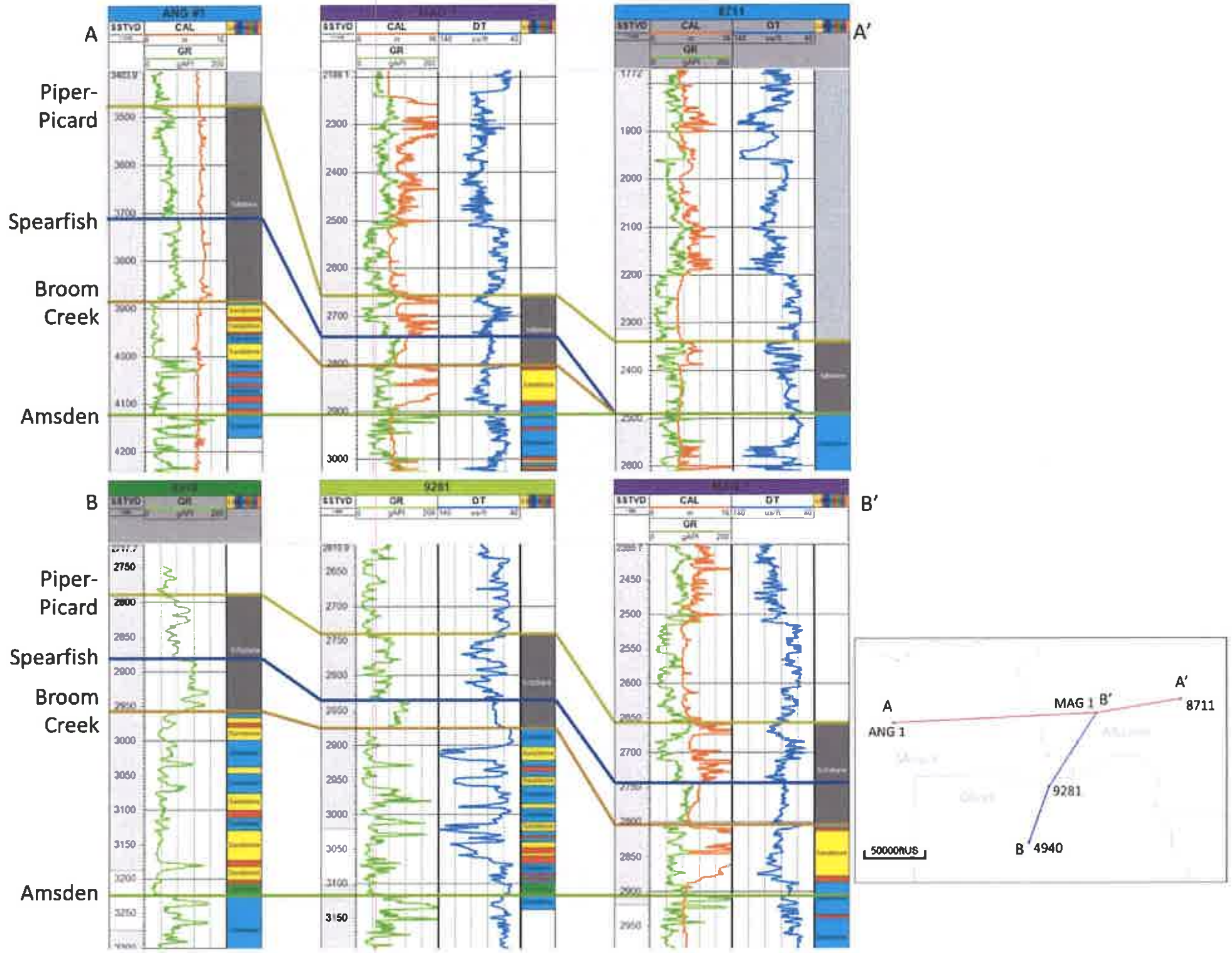



Figure 2-10. Regional well log stratigraphic cross sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) interpreted lithology log.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

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

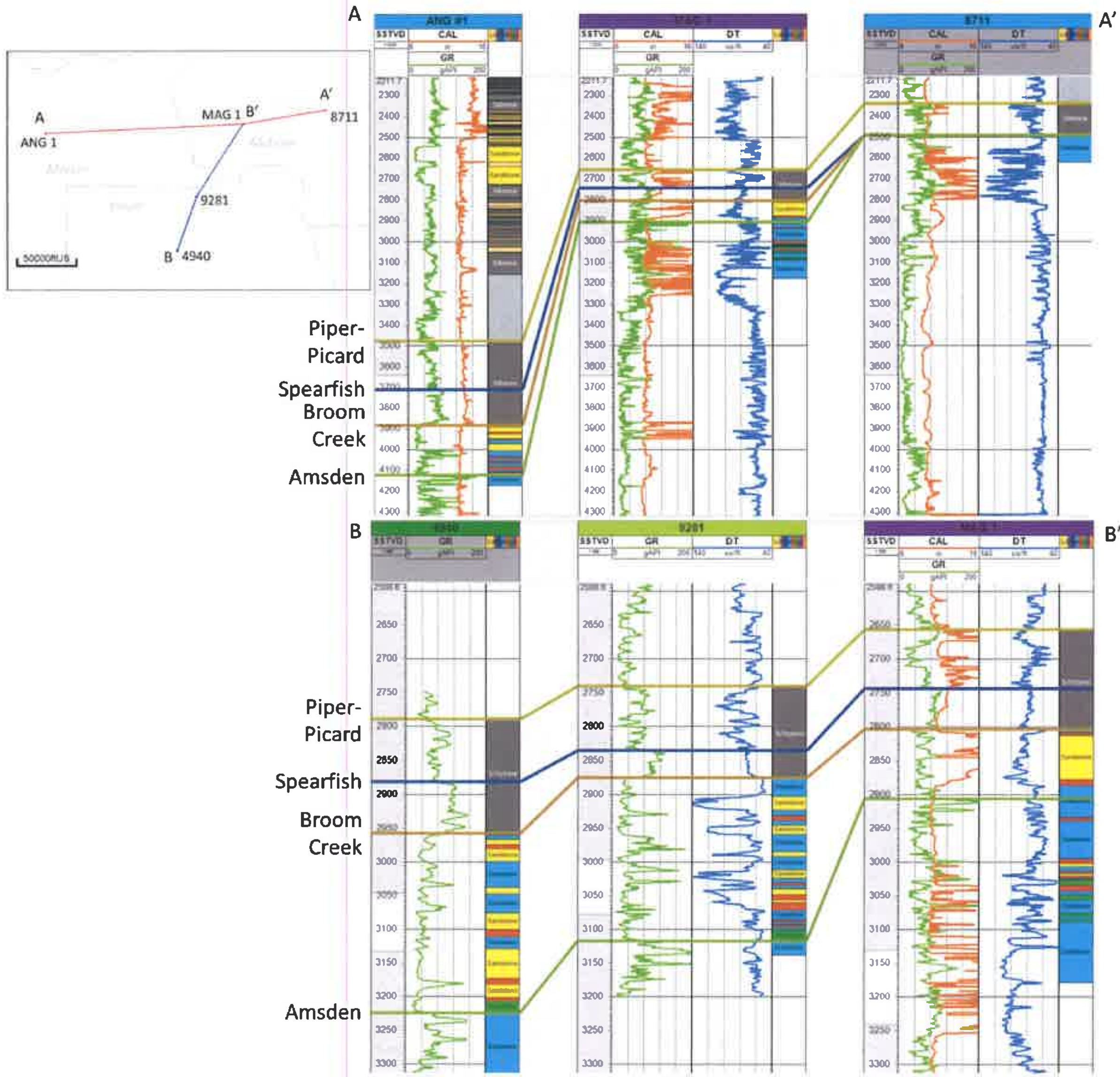



Figure 2-11. Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. Displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) interpreted lithology log. The different depth scales are used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

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

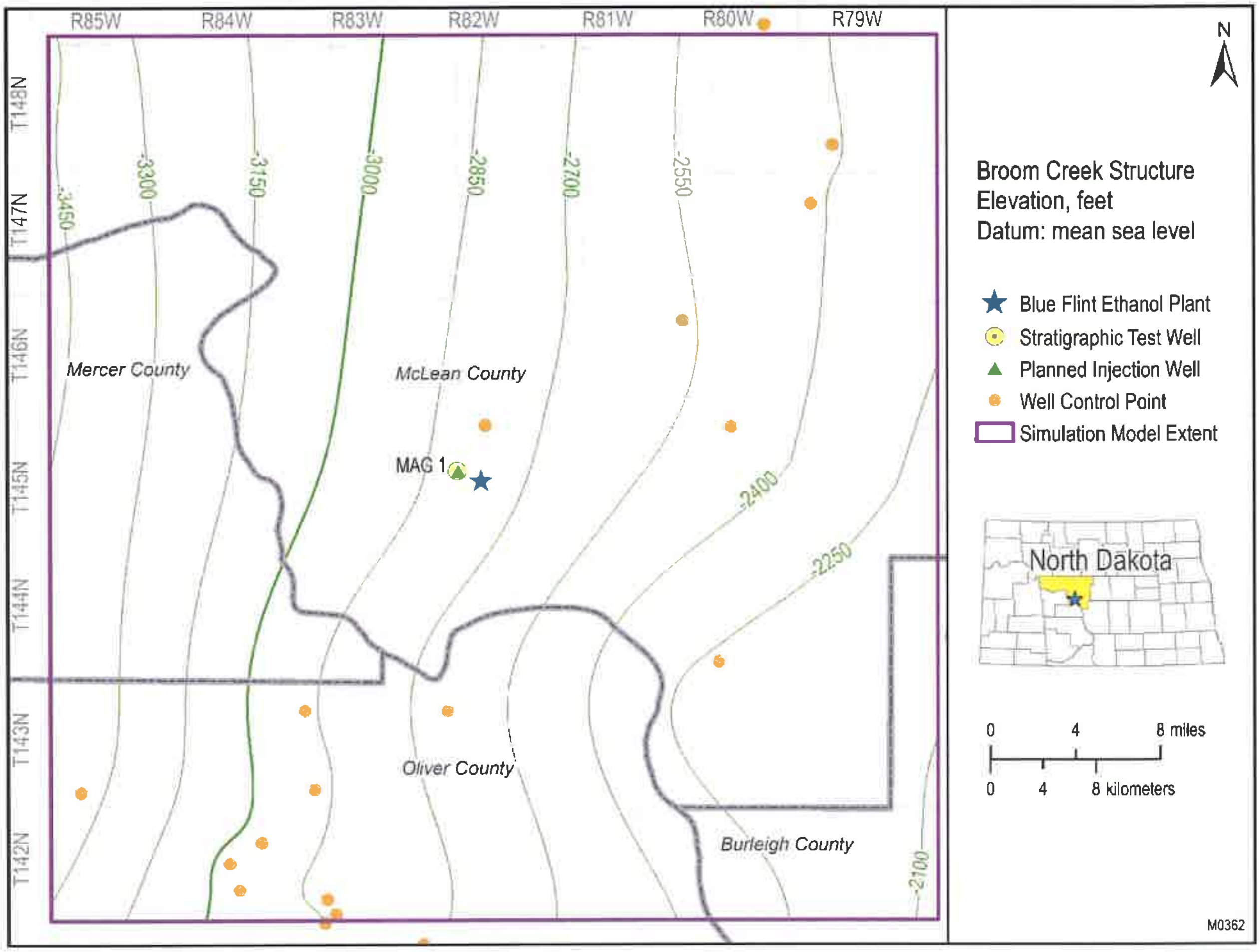



Figure 2-12. Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

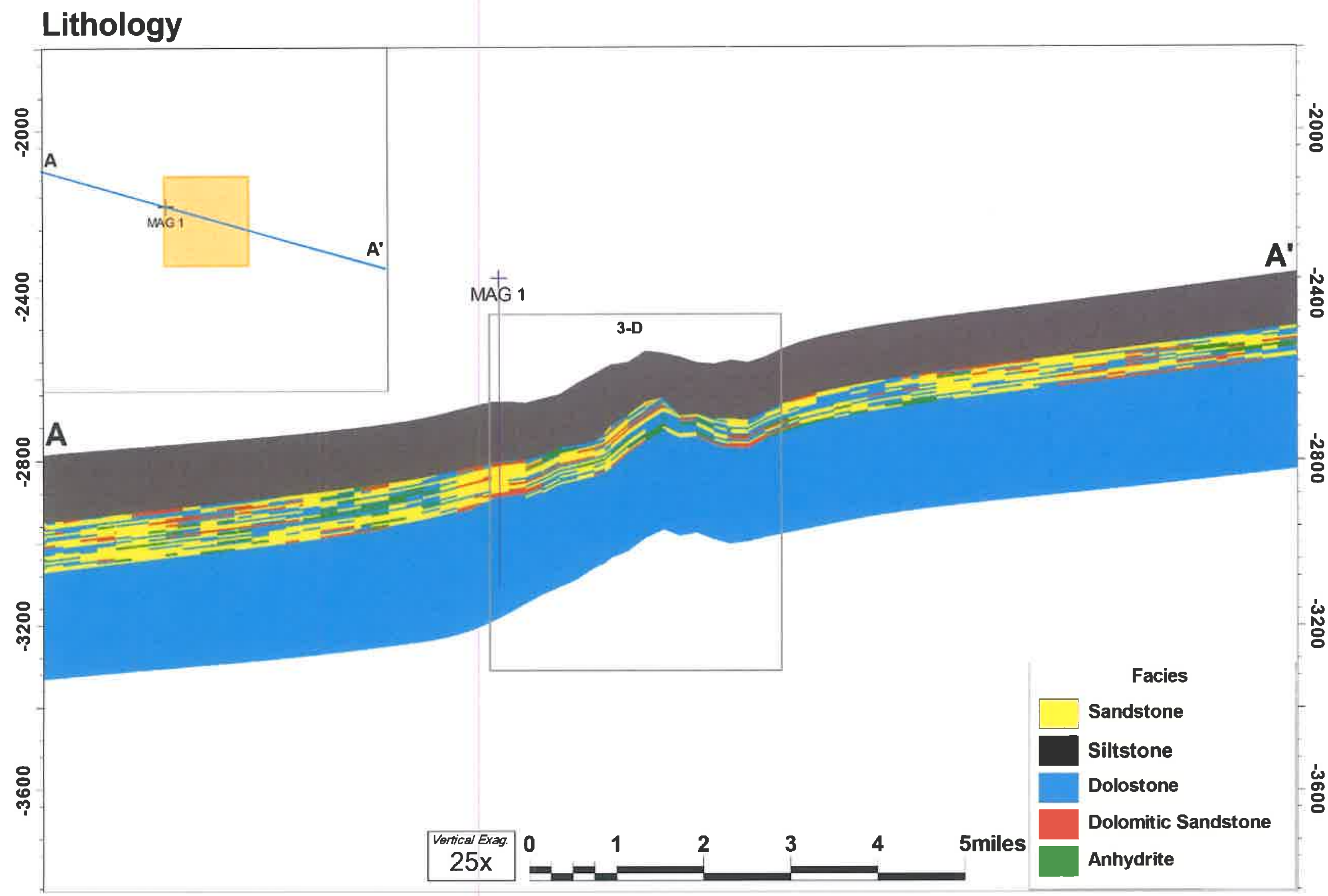



Figure 2-13. Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level.

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

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

**Geologic Properties**

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

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

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

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

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

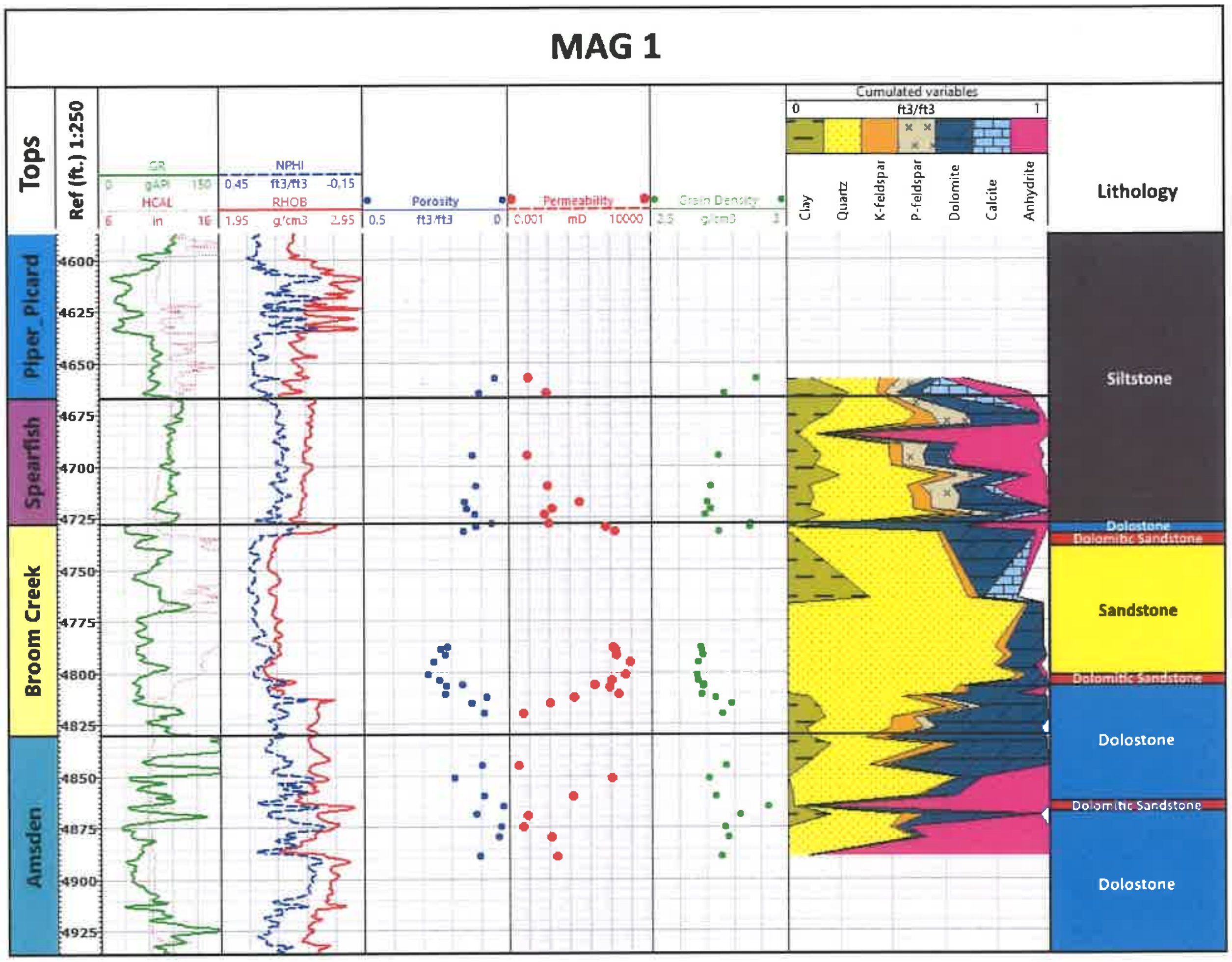



Figure 2-14. Vertical distribution of core-derived porosity and permeability values and the laboratory-derived mineralogic characteristics in the Blue Flint storage complex from MAG 1. Logs displayed in tracks from left to right are 1) formation designation, 2) measured depth track, 3) GR and caliper,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

### *2.3.1 Mineralogy*

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

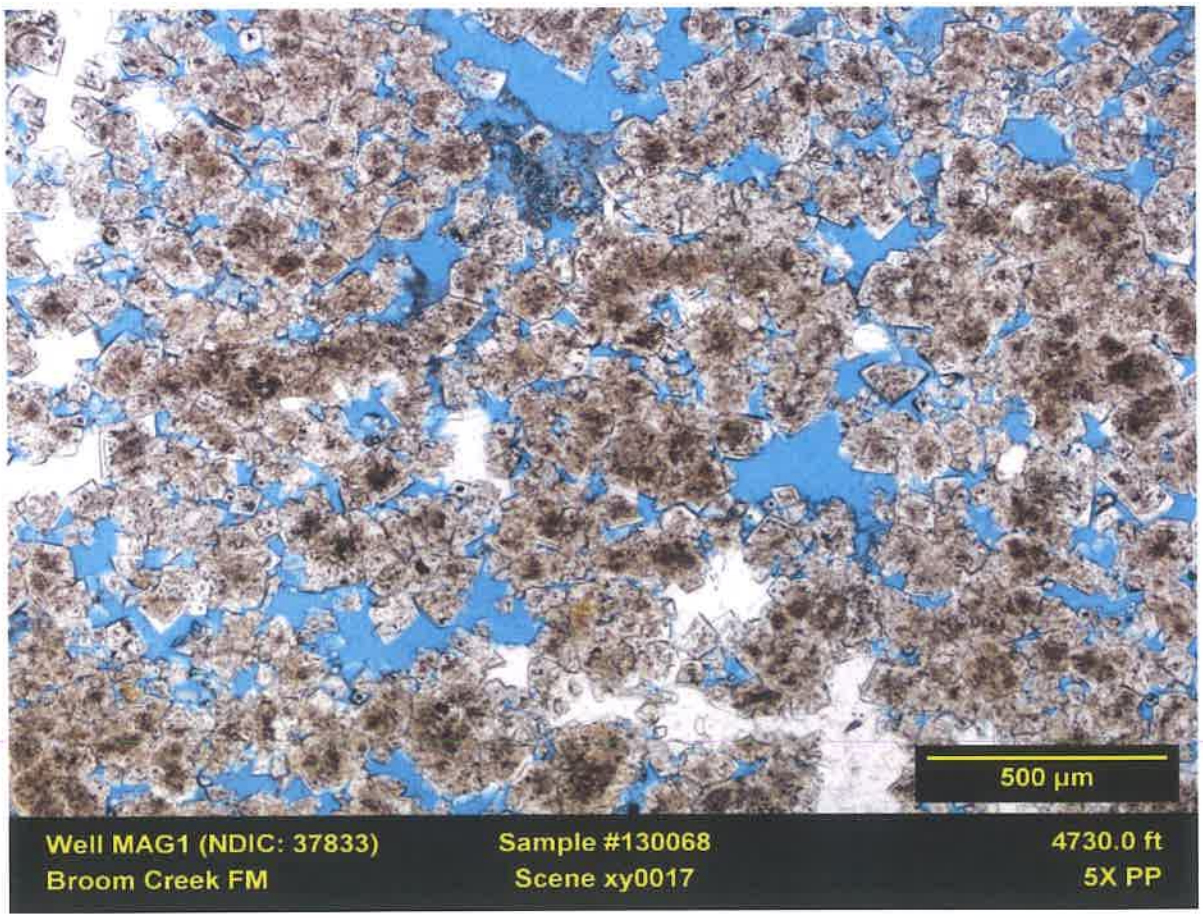



Figure 2-15. Thin section in upper Broom Creek Formation. This interval is primarily dolomite (gray) with anhydritic cement.

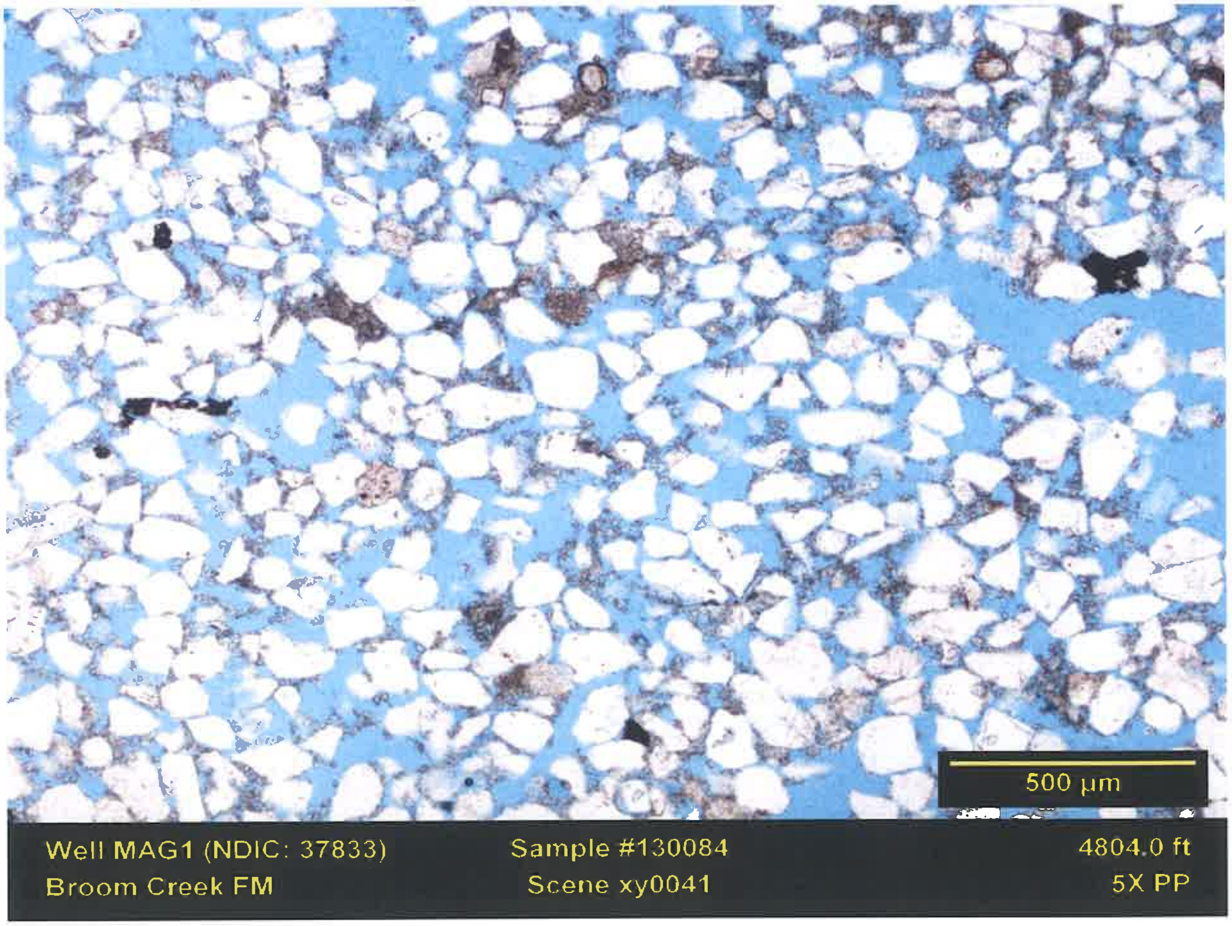



Figure 2-16. Thin section in middle Broom Creek Formation. This interval is dominated by fine-grained quartz and minor dolomite. Porosity is high in this interval.

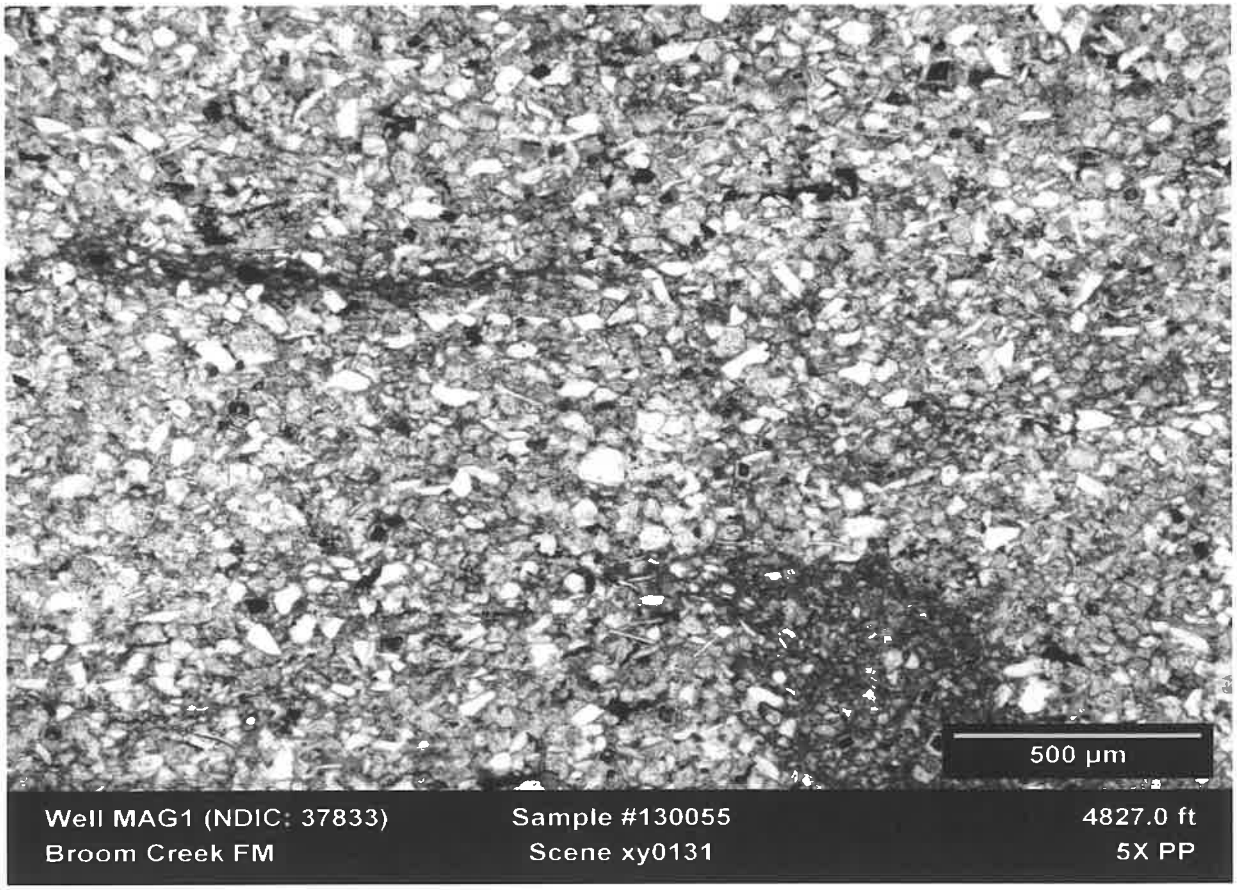



Figure 2-17. Thin section in lower Broom Creek Formation. This interval is a laminated silty mudstone. The matrix is dominated by clay and quartz.

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

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

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

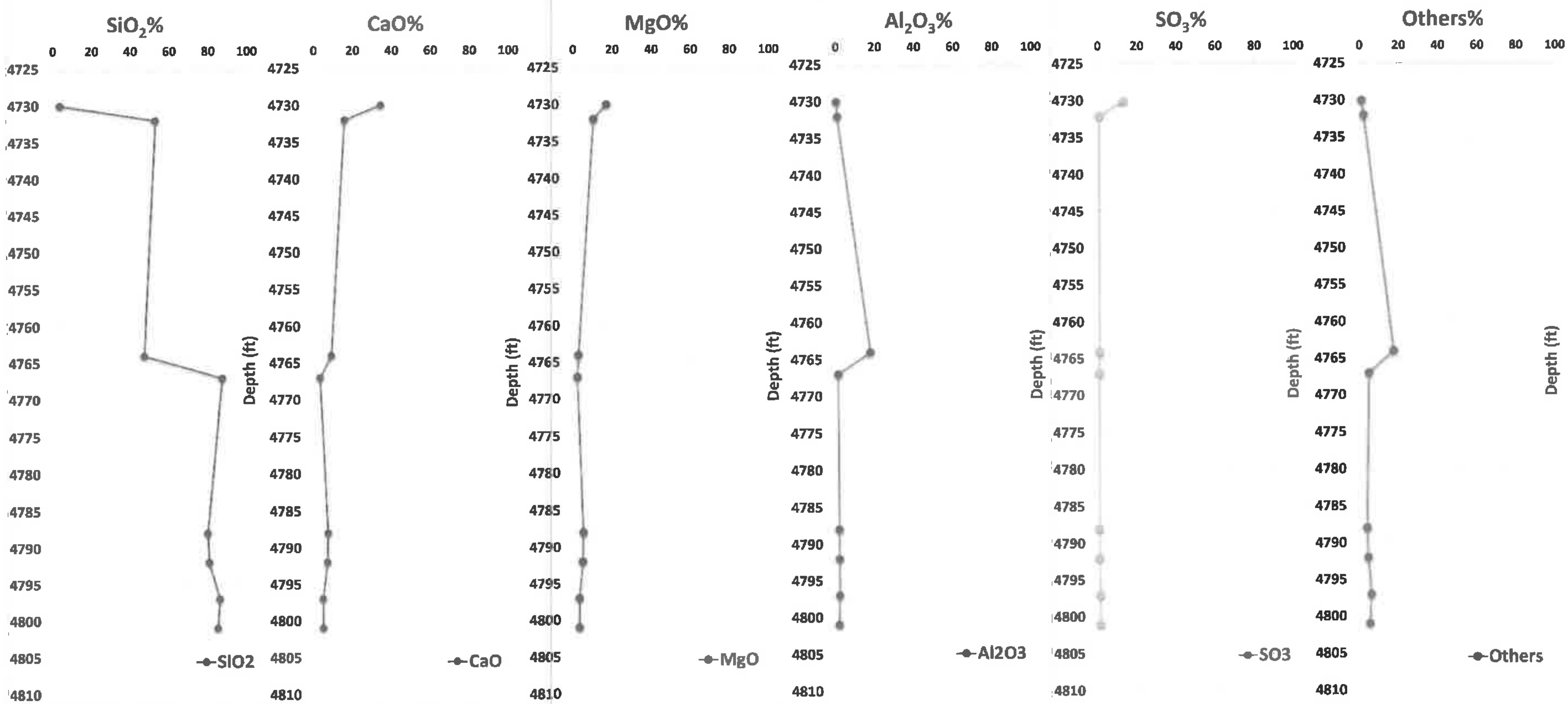



Figure 2-18. XRF analysis in Broom Creek Formation from MAG 1.

### *2.3.2 Mechanism of Geologic Confinement*

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

### *2.3.3 Geochemical Information of Injection Zone*

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

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

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

**Table 2-7. Injection Stream Composition**

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

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

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

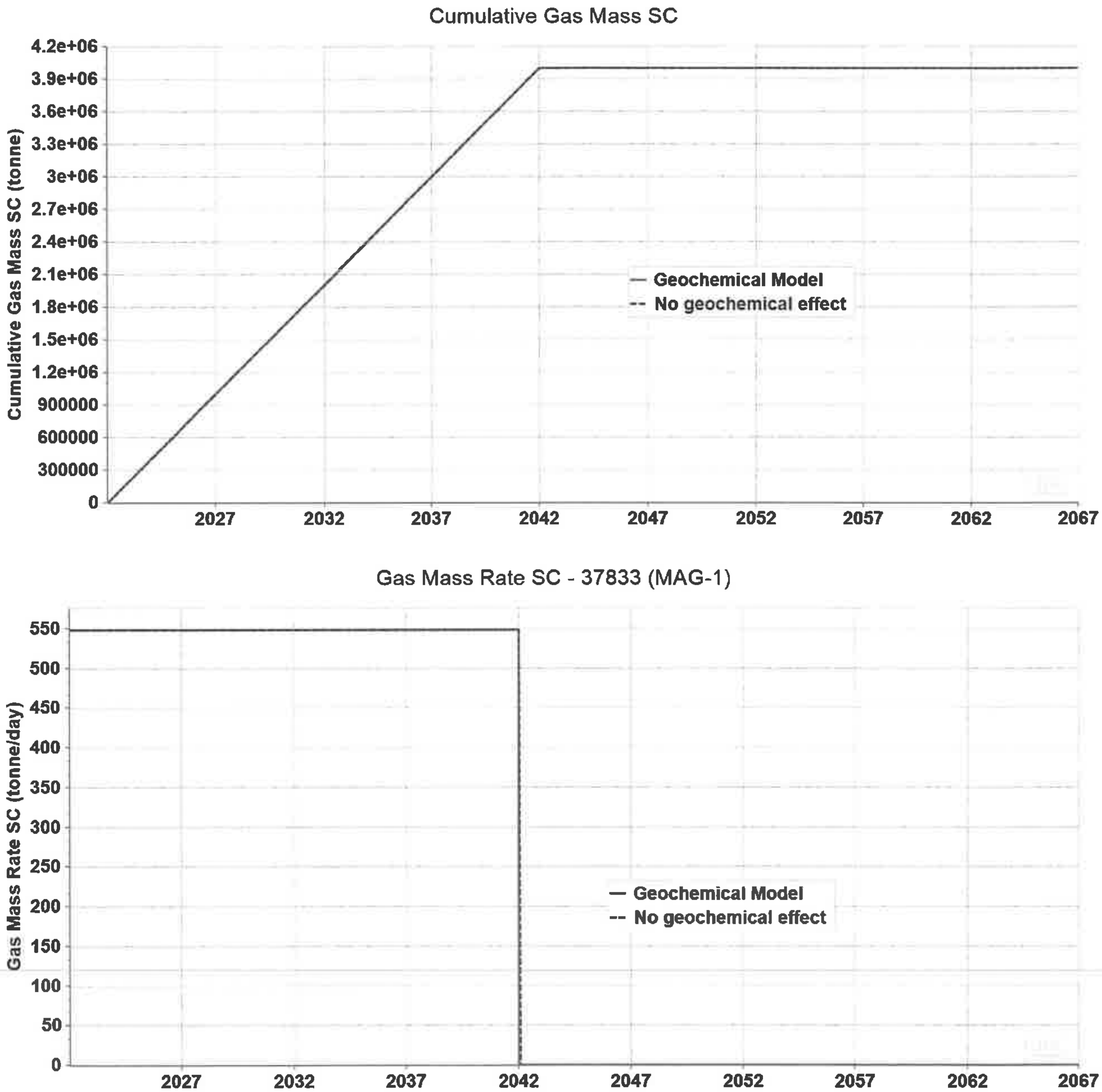



Figure 2-19. Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions.

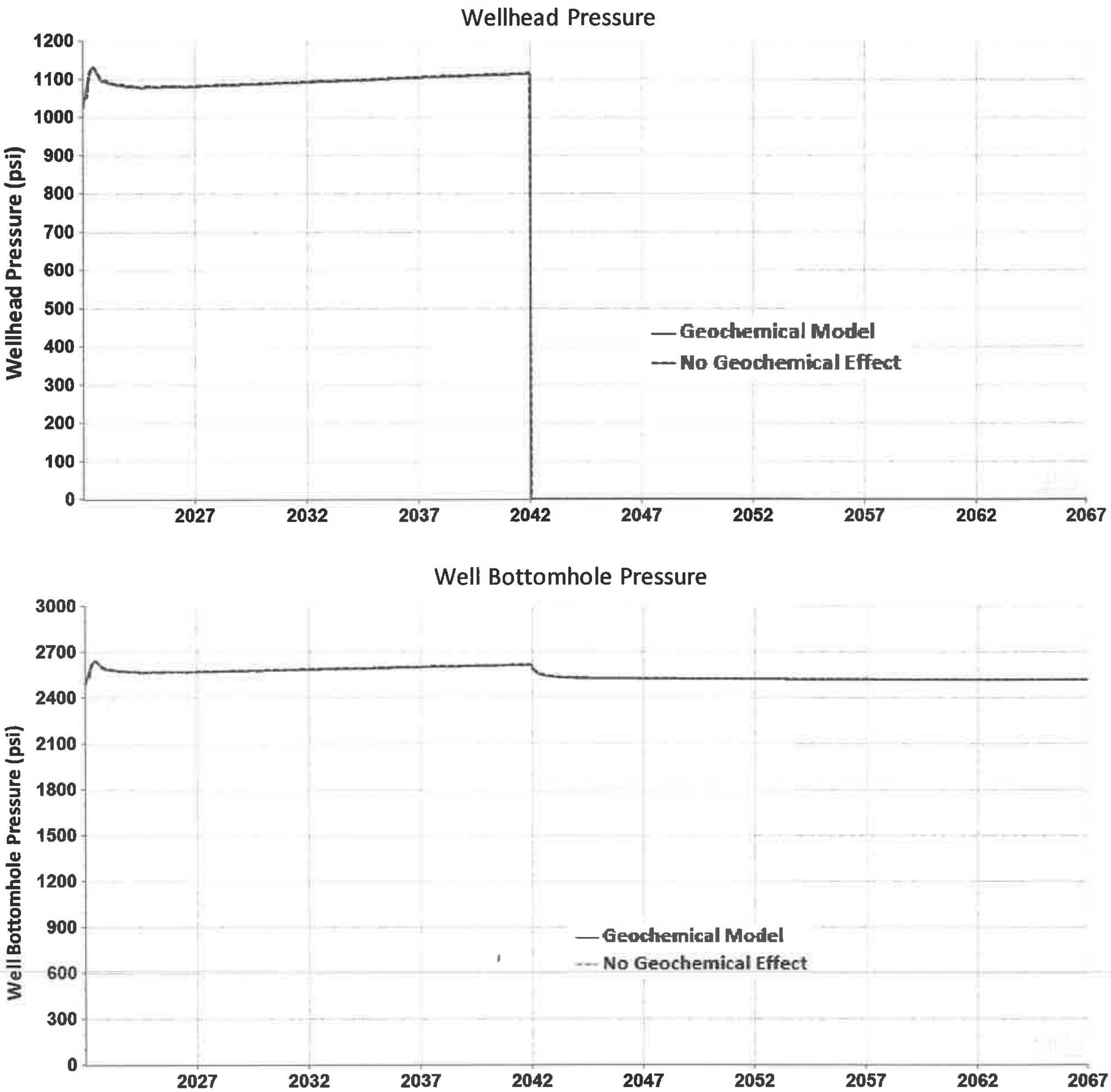



Figure 2-20. Upper graph shows wellhead pressure vs. time; the bottom figure shows the bottomhole pressure vs. time. There is no observable difference in pressures due to geochemical reactions.

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

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

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

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

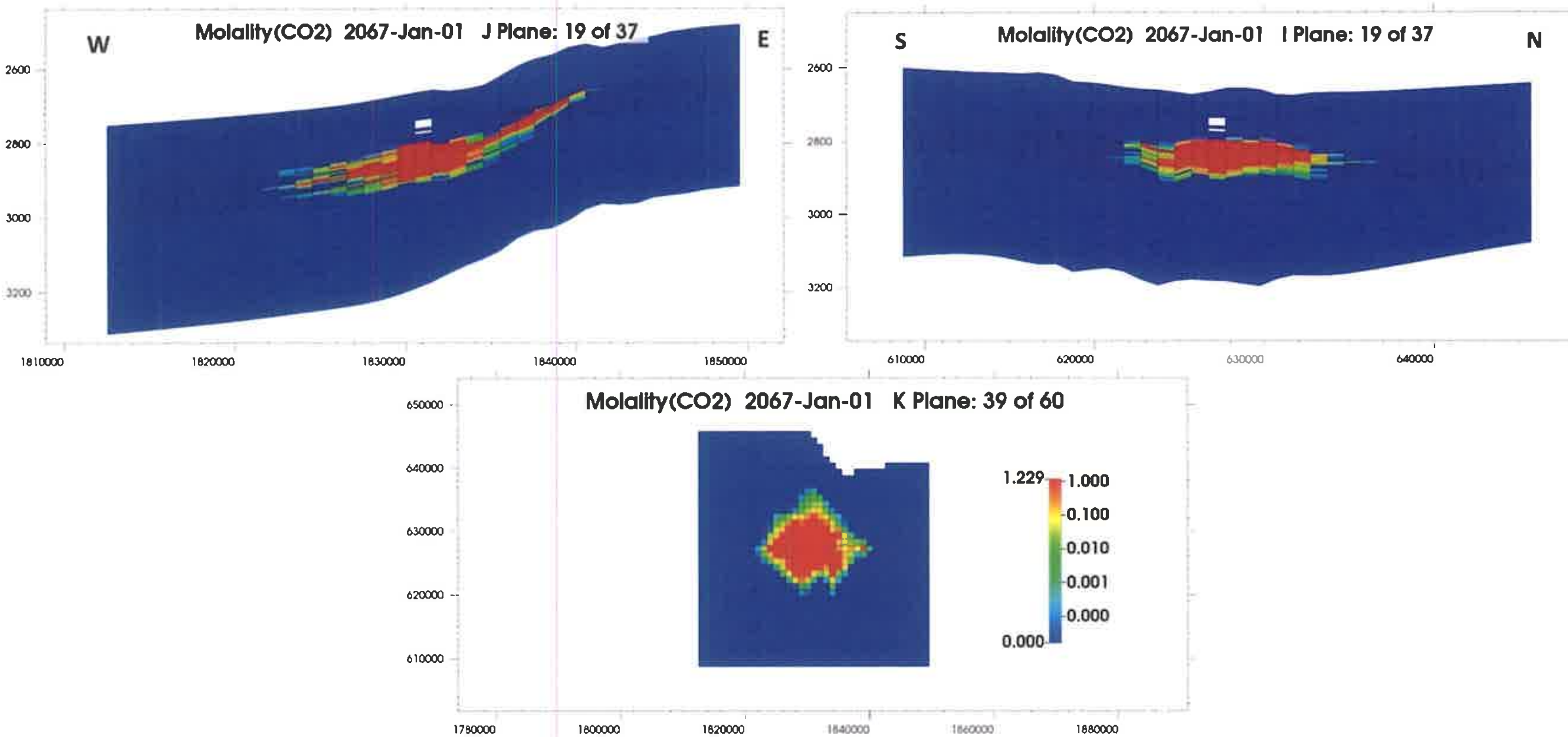



Figure 2-21. $CO_2$ molality for the geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of $CO_2$ molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of simulation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

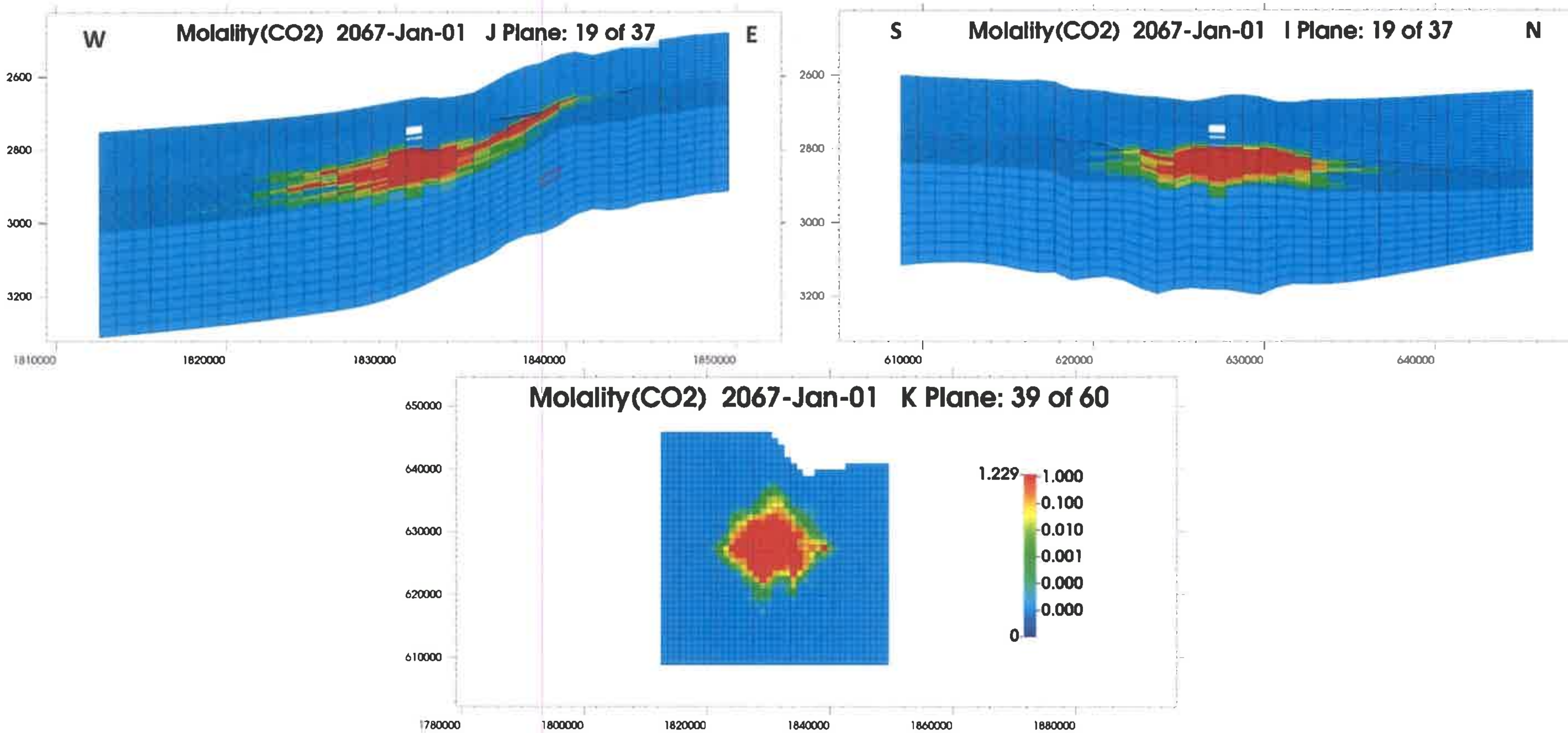



Figure 2-22. $CO_2$ molality for the non-geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of $CO_2$ molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of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

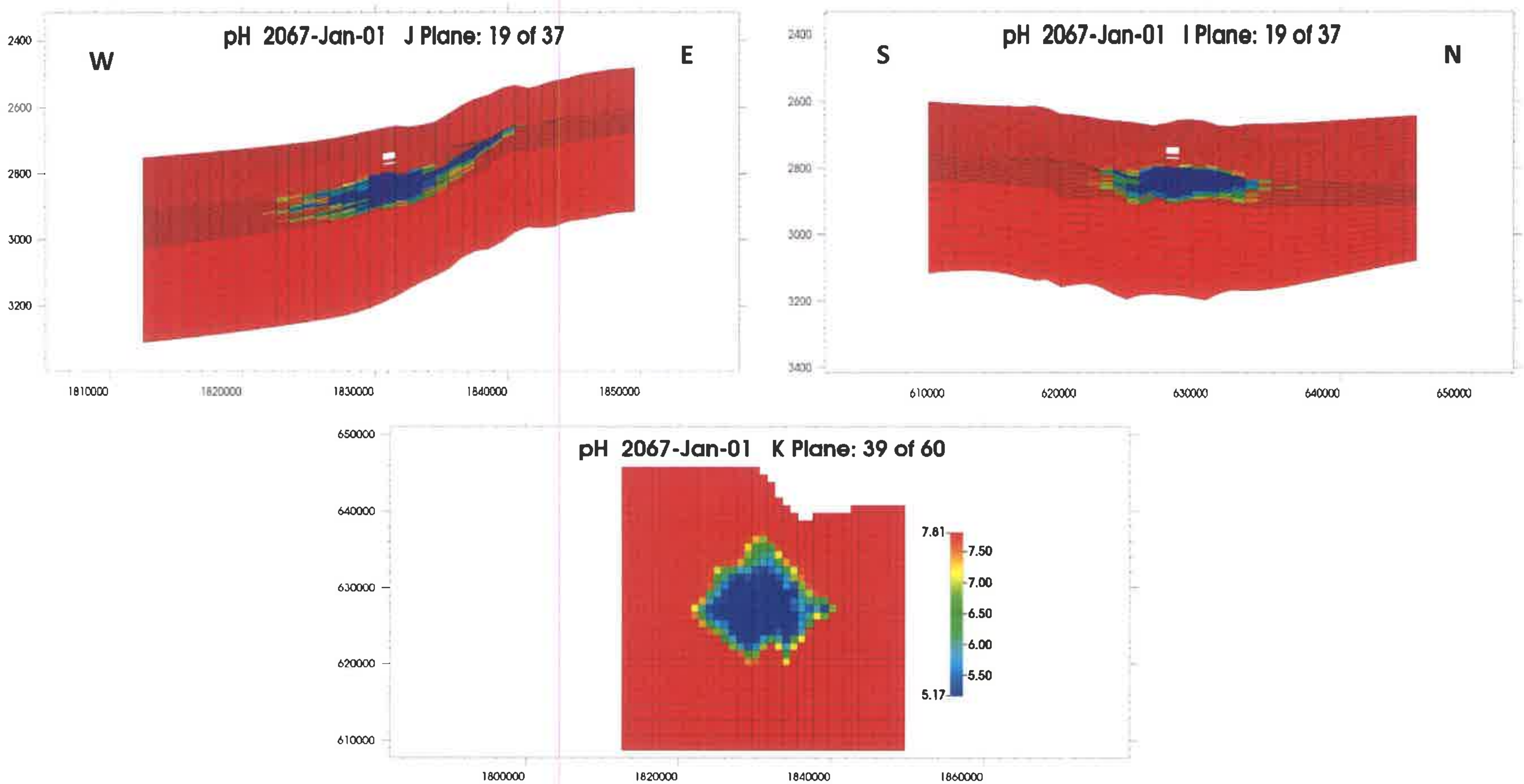



Figure 2-23. Geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

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

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

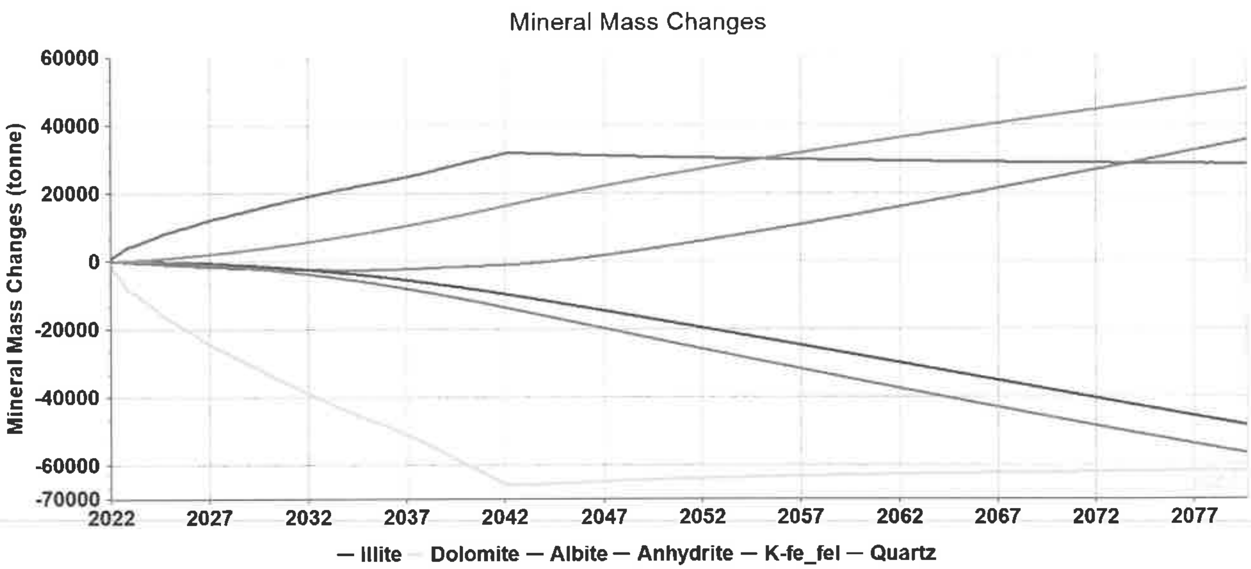



Figure 2-24. Dissolution and precipitation quantities of reservoir minerals because of $CO_2$ injection. Dissolution of albite, K-feldspar (K-fe_fel), and dolomite with precipitation of illite, quartz, and anhydrite was observed.

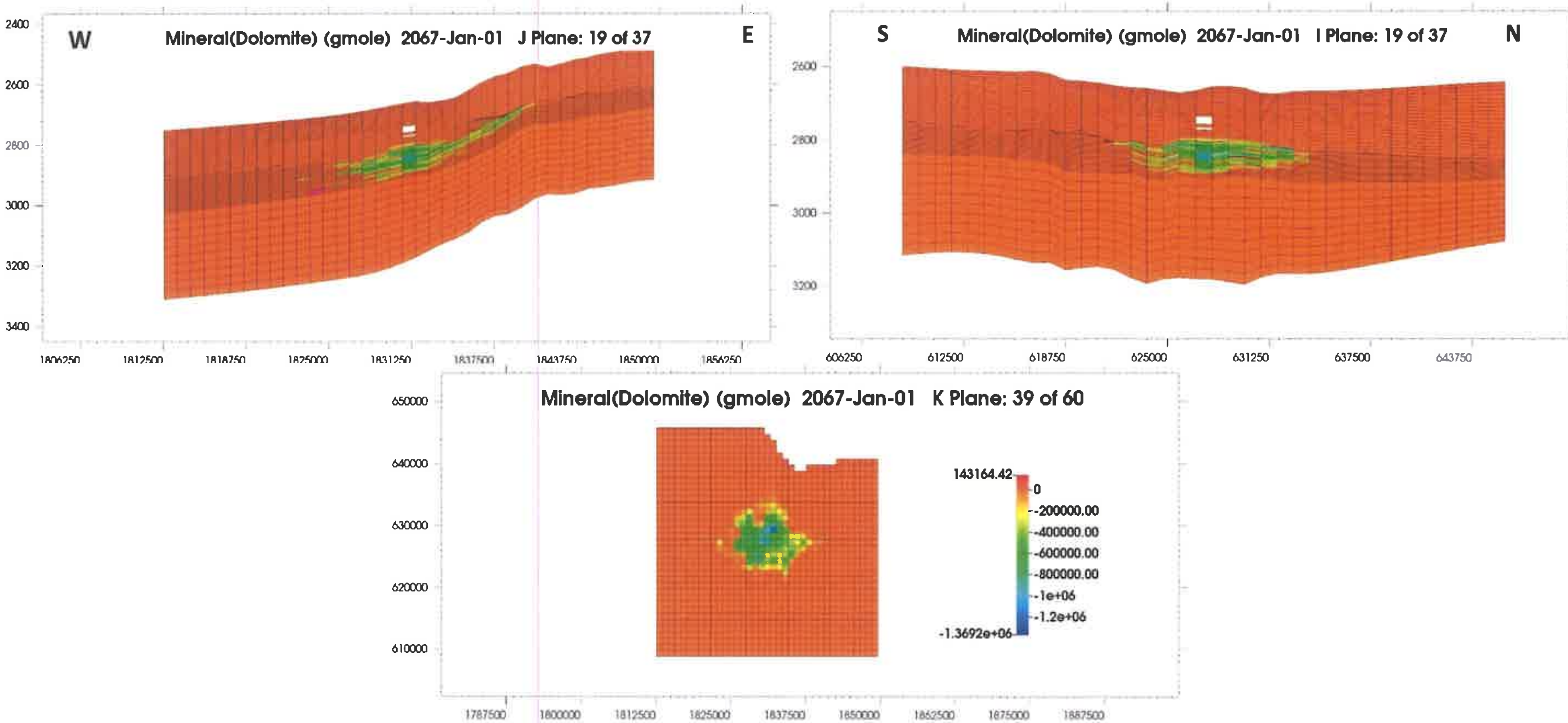



Figure 2-25. Change in molar distribution of dolomite, the most prominent dissolved mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

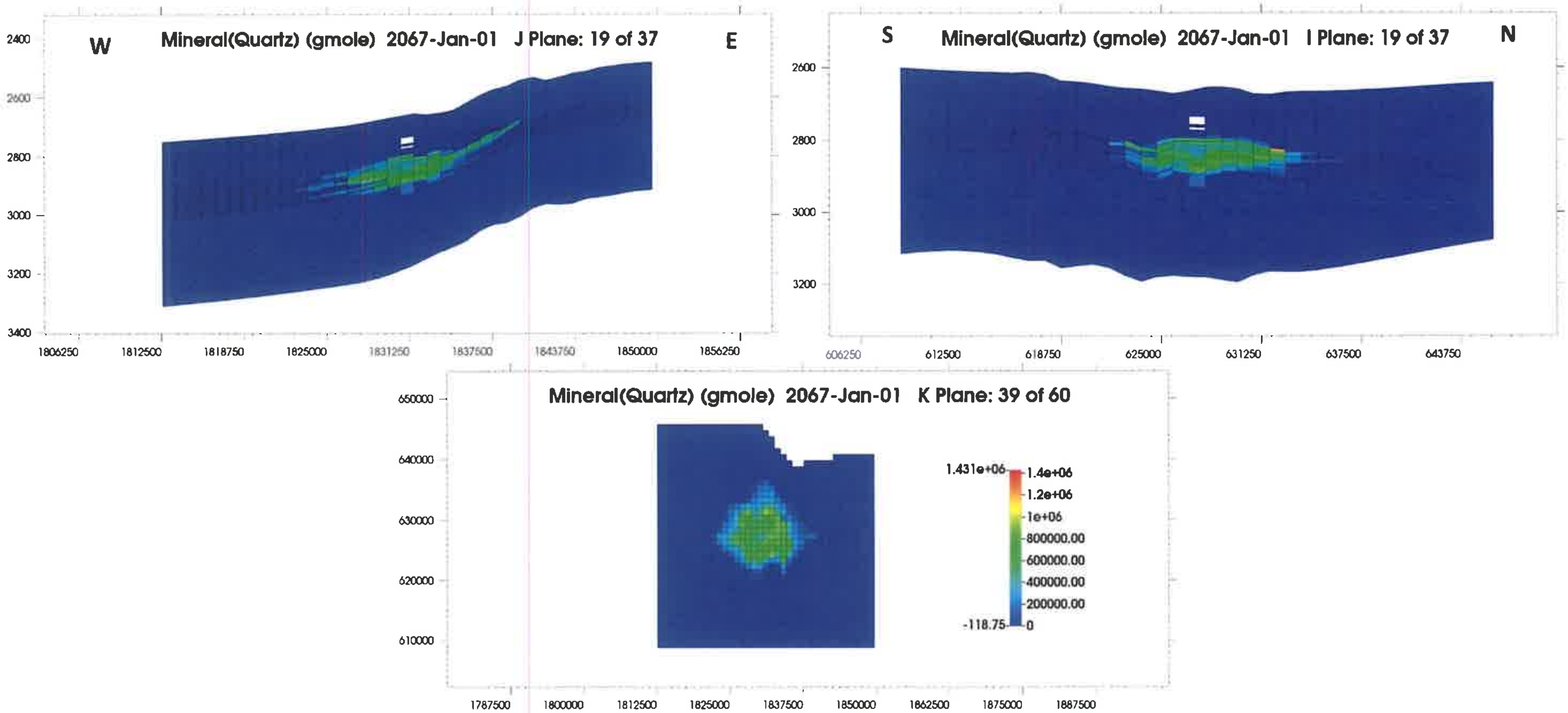



Figure 2-26. Change in molar distribution of quartz, the most prominent precipitated mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

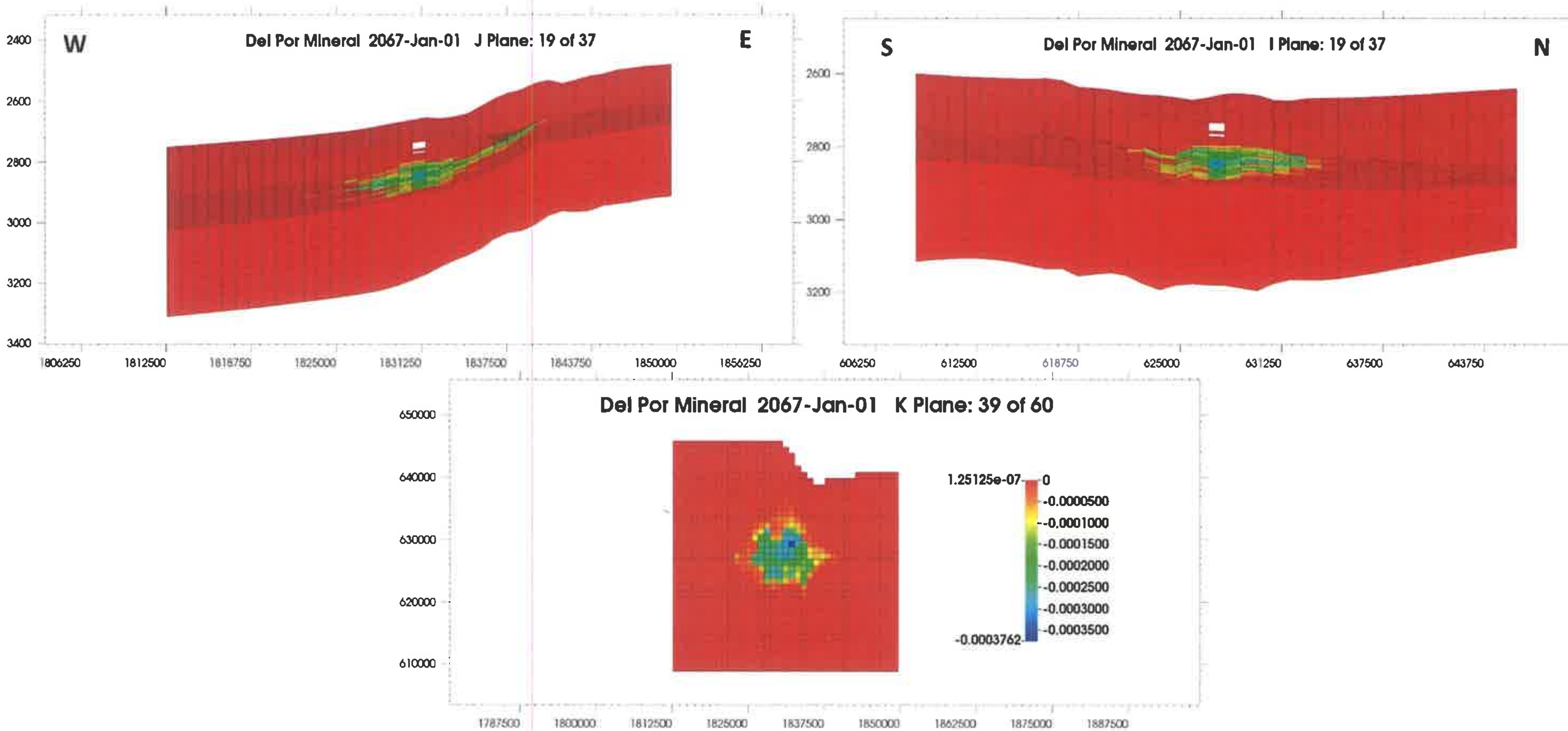



Figure 2-27. Change in porosity due to net geochemical dissolution at the end of the 20-year injection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

## 2.4 Confining Zones

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

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

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

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

* Porosity values recorded at 2,400-psi confining pressure are reported as the arithmetic mean followed by the range of values in parenthesis.

** Permeability values recorded at 2,400-psi confining pressure are reported as the geometric mean followed by the range of values in parenthesis.

*** Average not available for two samples.

### *2.4.1 Upper Confining Zone*

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

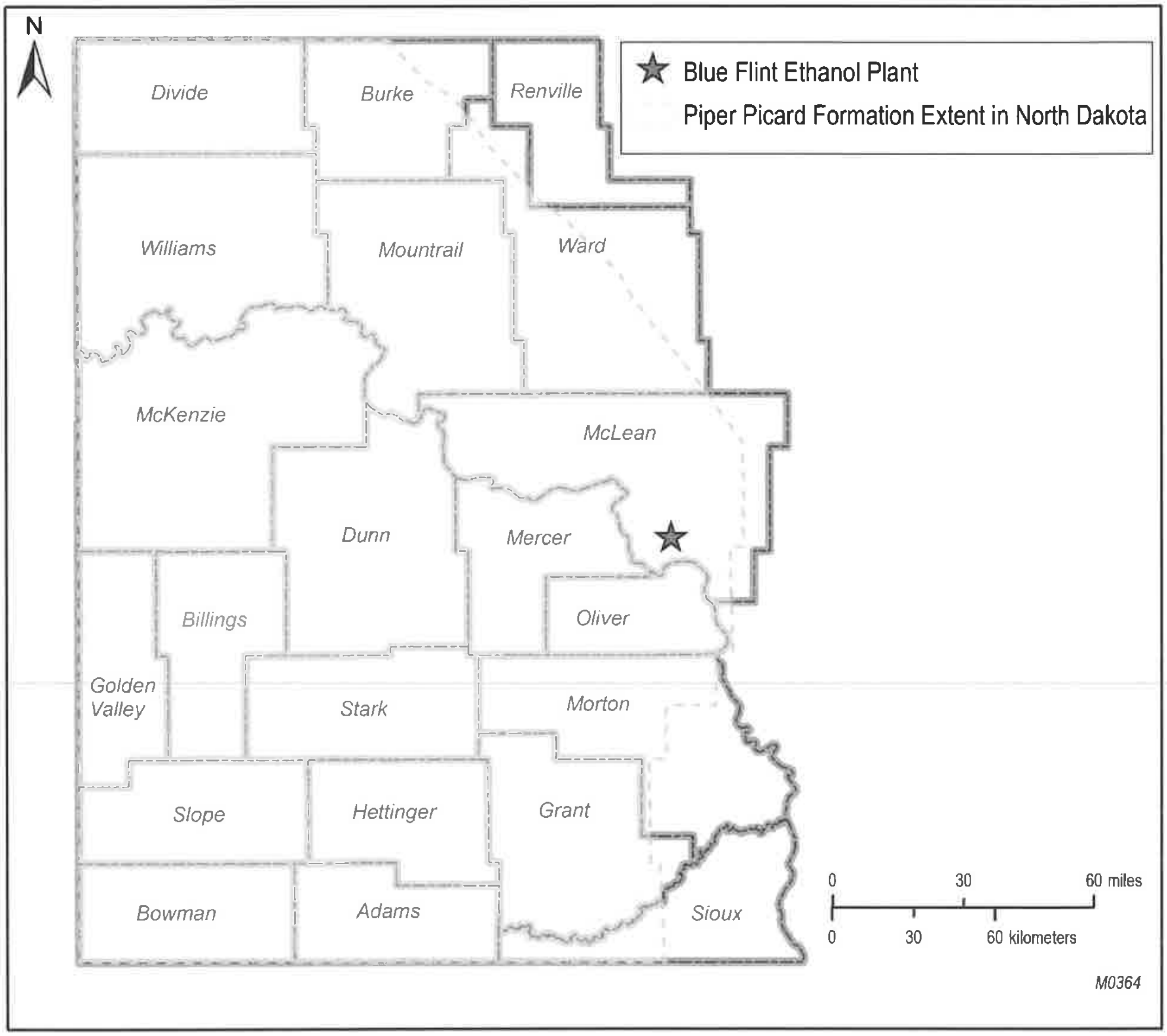



Figure 2-28. Areal extent of the lower Piper Formation in western North Dakota (modified from Carlson, 1993).

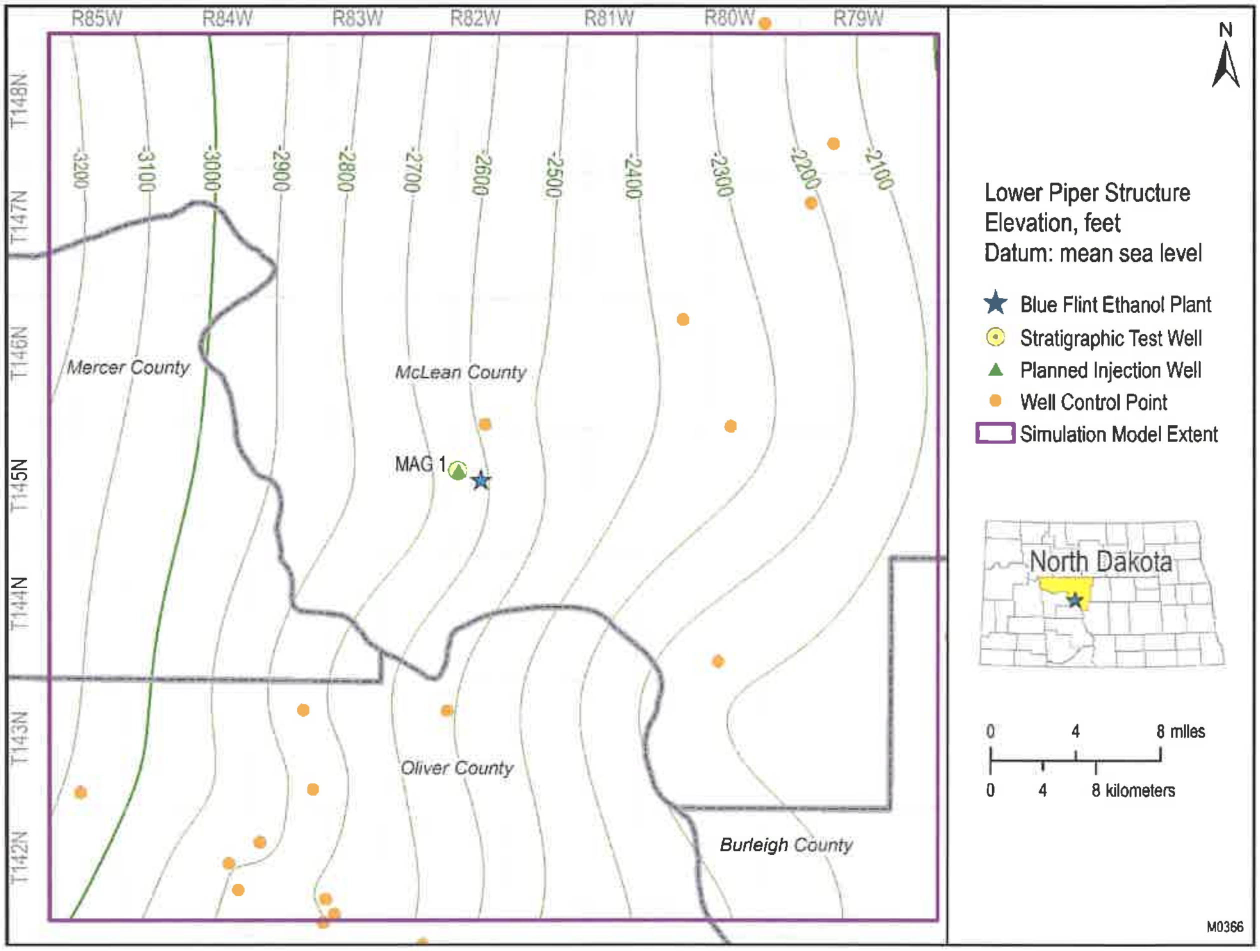



Figure 2-29. Structure map of the lower Piper Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

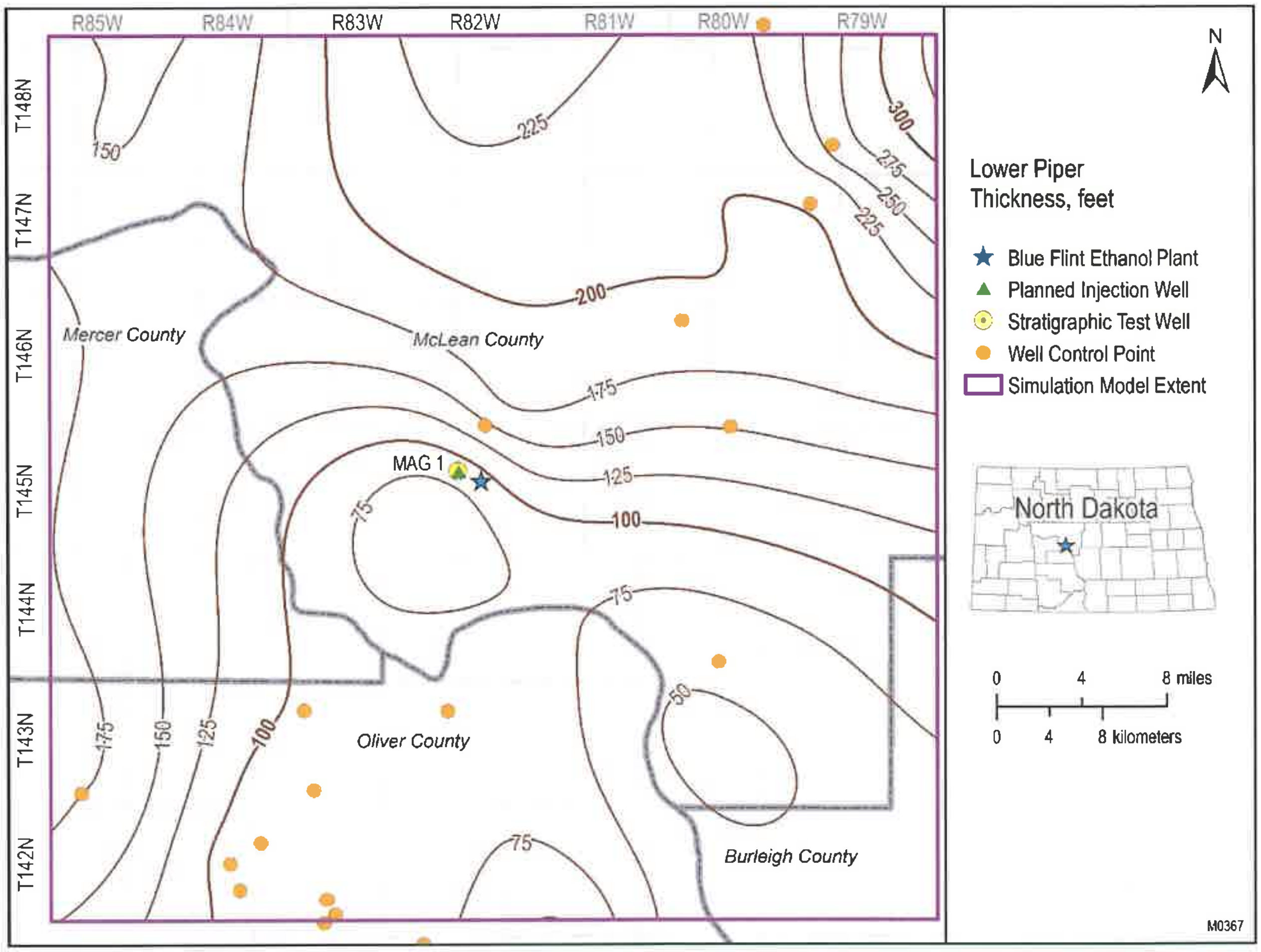



Figure 2-30. Isopach map of the lower Piper Formation in the greater Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

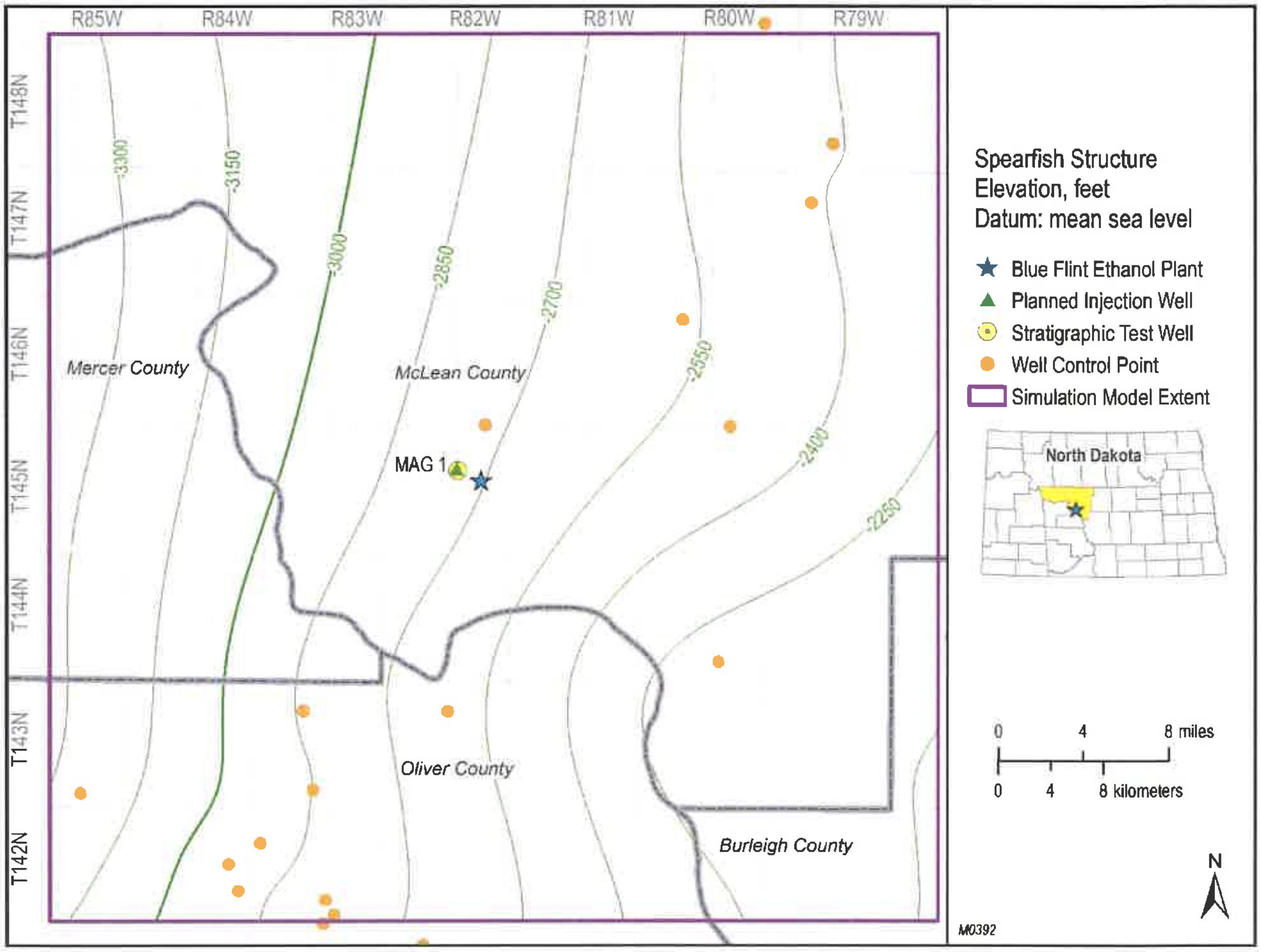



Figure 2-31. Structure map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

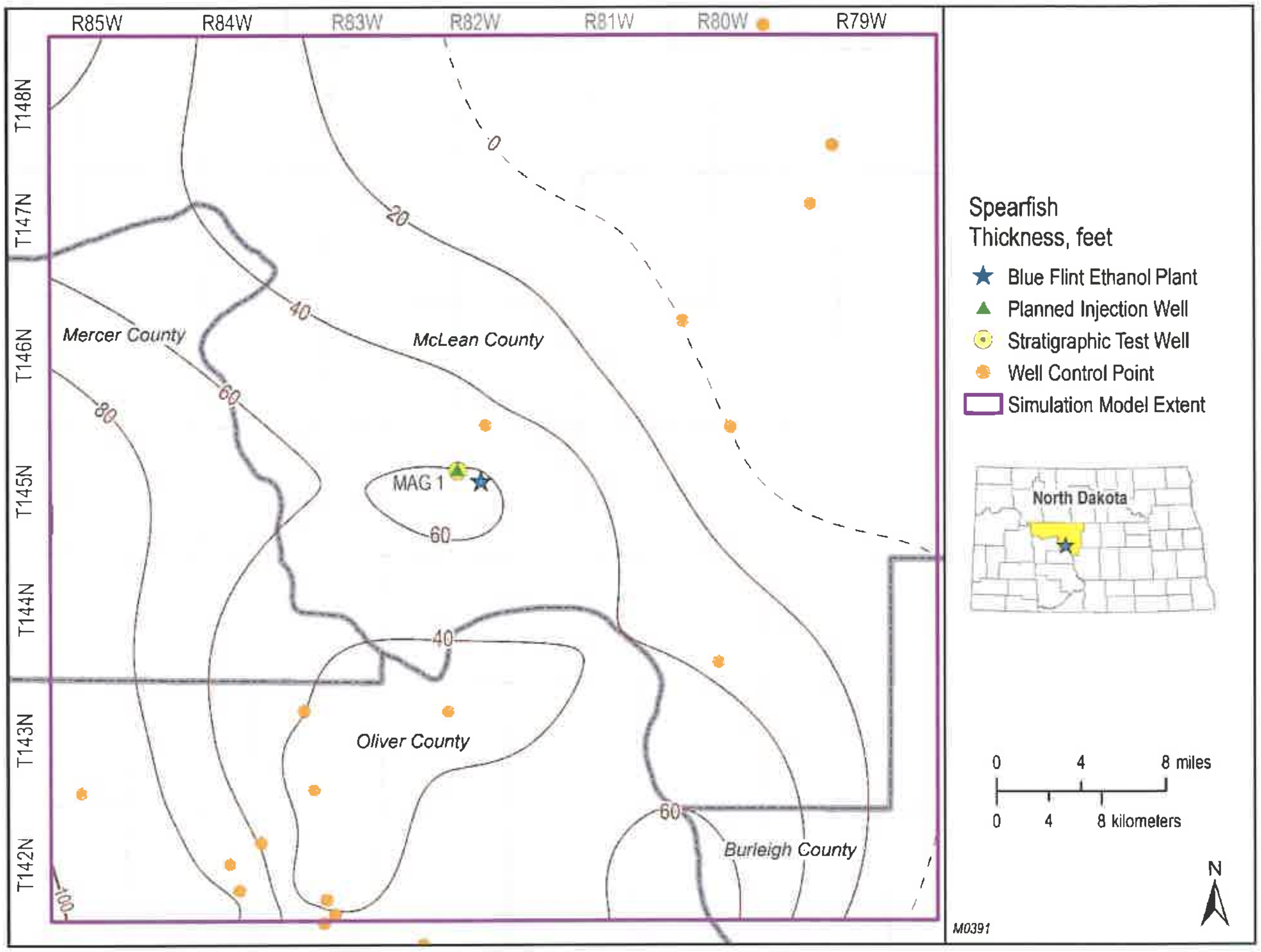



Figure 2-32. Isopach map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

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

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

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

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

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

#### *2.4.1.1 Mineralogy*

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

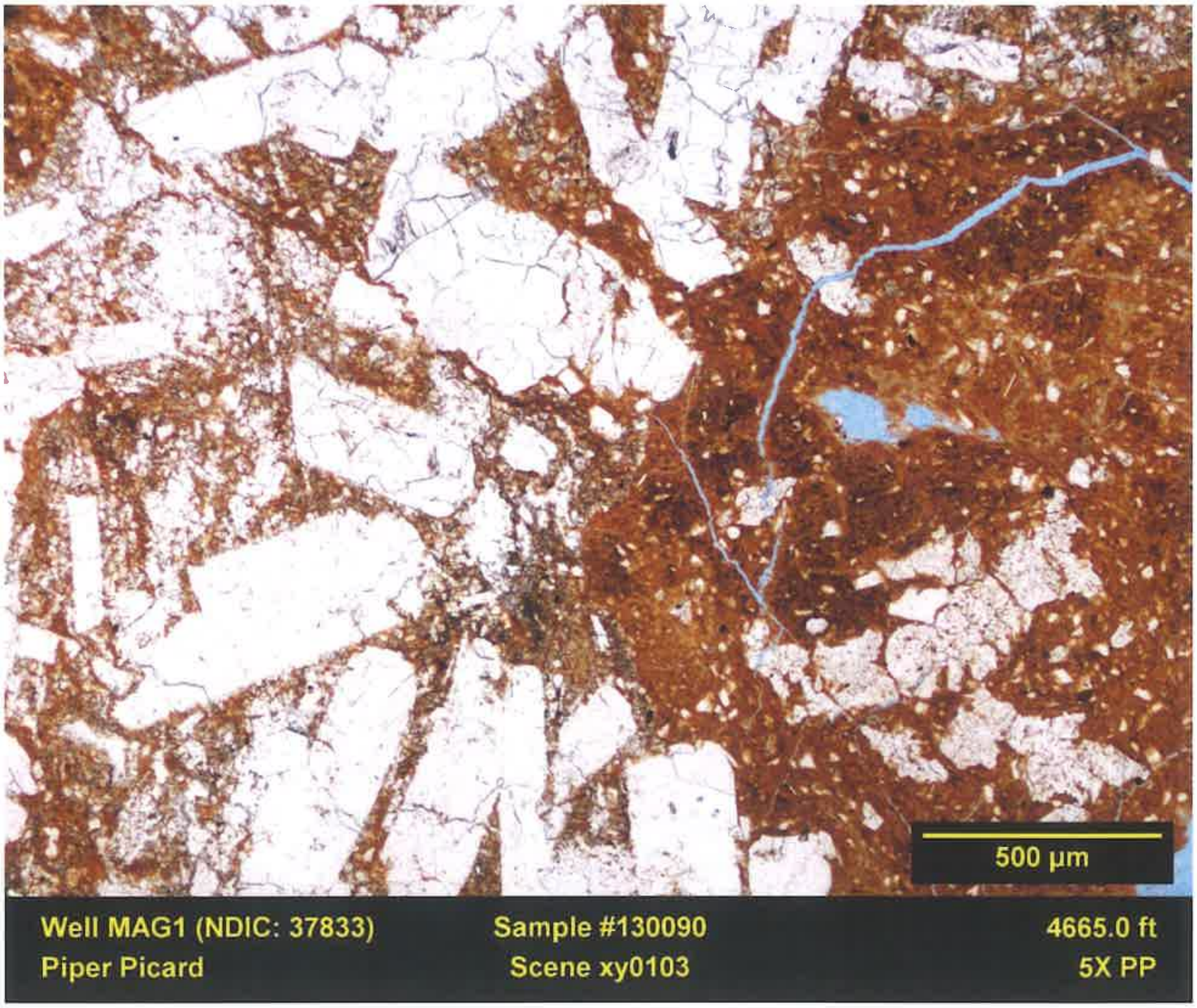



Figure 2-33. Thin section of Piper Formation. In this example, clay (brown) and anhydrite (white) dominate the depth interval. Minor porosity is observed (blue).

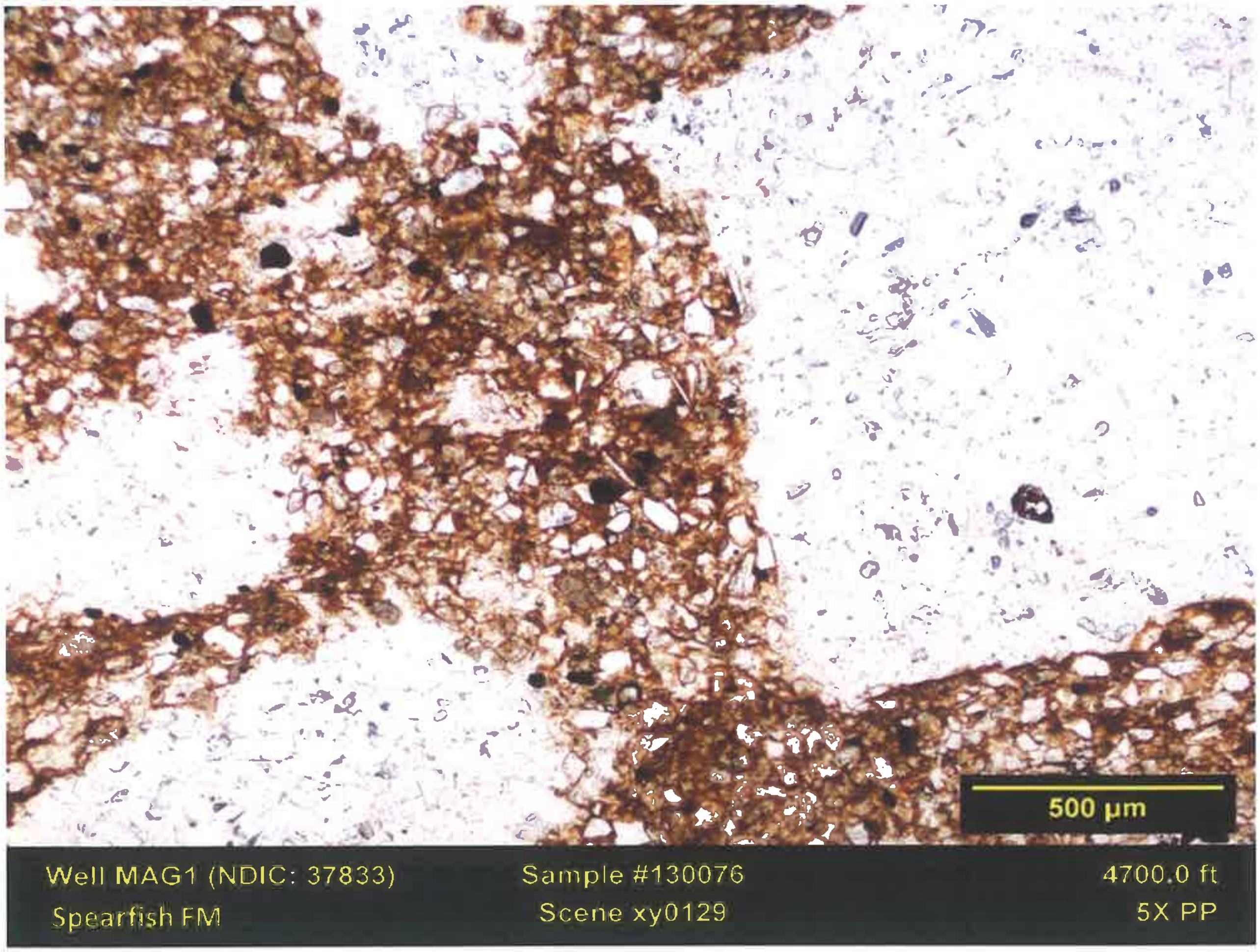



Figure 2-34. Thin section of Spearfish Formation. In this example, clay (brown), quartz (small white grains), anhydrite (large white grains), and iron oxides (black grains) dominate the depth interval. No porosity is observed.

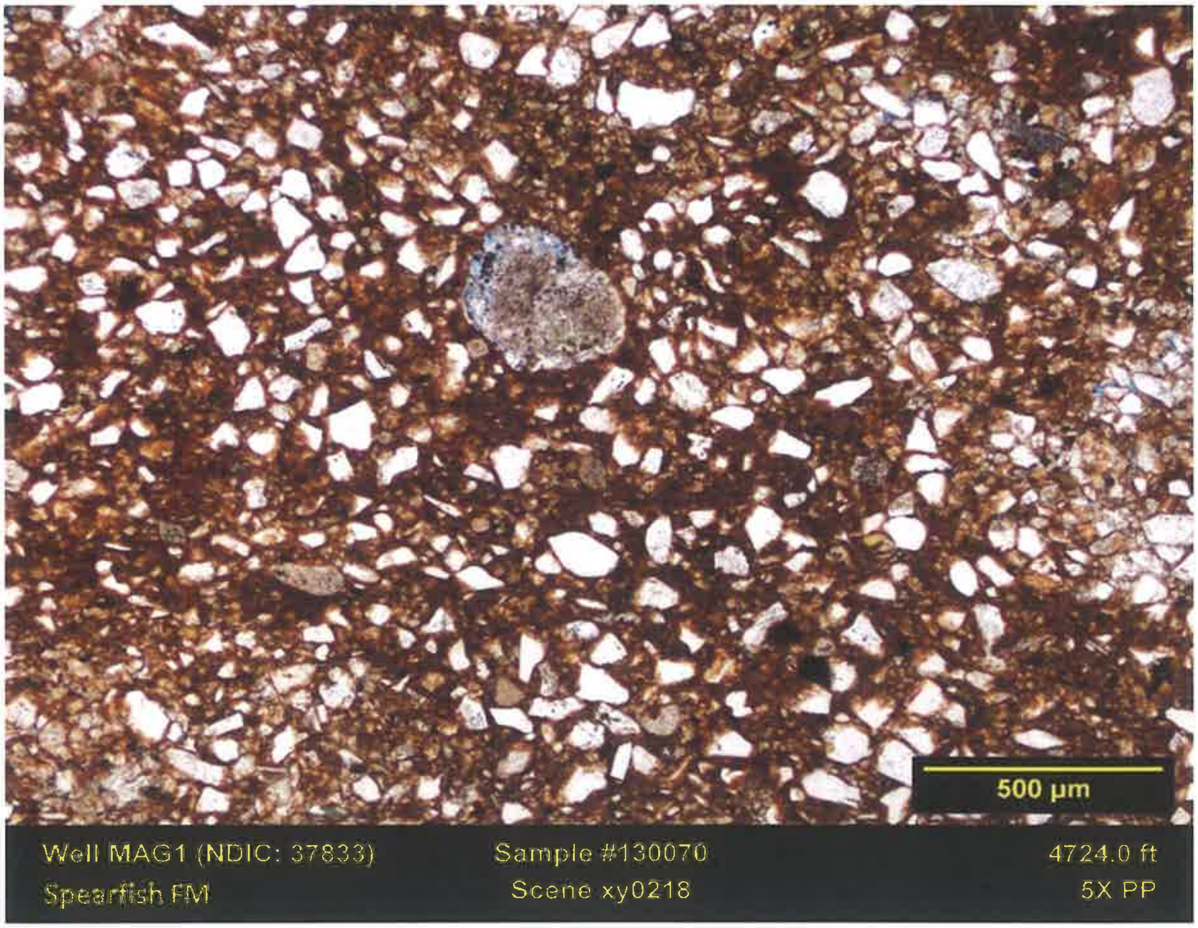



Figure 2-35. Thin section of Spearfish Formation. In this example, clay (brown) and quartz (white) dominate the depth interval. Minor intergranular and intragranular porosity are observed (blue).

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

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

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

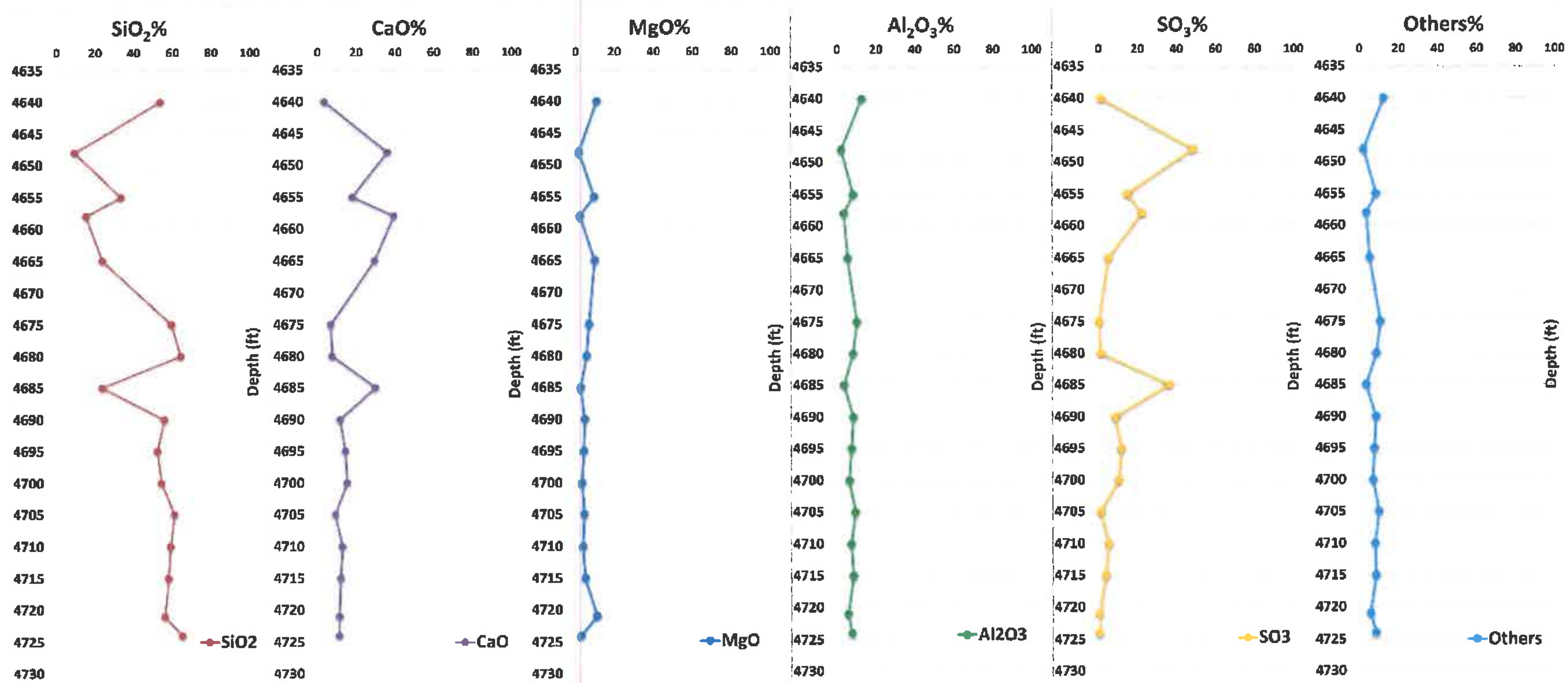



Figure 2-36. XRF analysis in the upper confining zone (Spearfish and lower Piper Formations) from MAG 1.

### 2.4.1.2 *Geochemical Interaction*

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

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

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

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

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

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

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

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

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

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

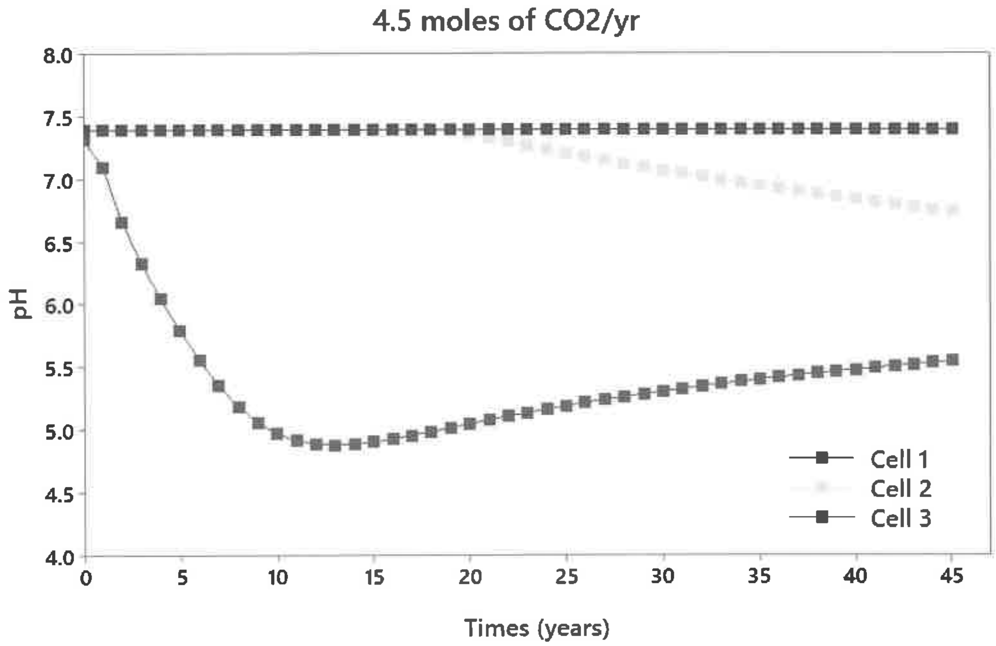



Figure 2-37. Change in fluid pH vs. time. Red line shows pH for the center of Cell C1, 0.5 meters above the Spearfish Formation cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to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

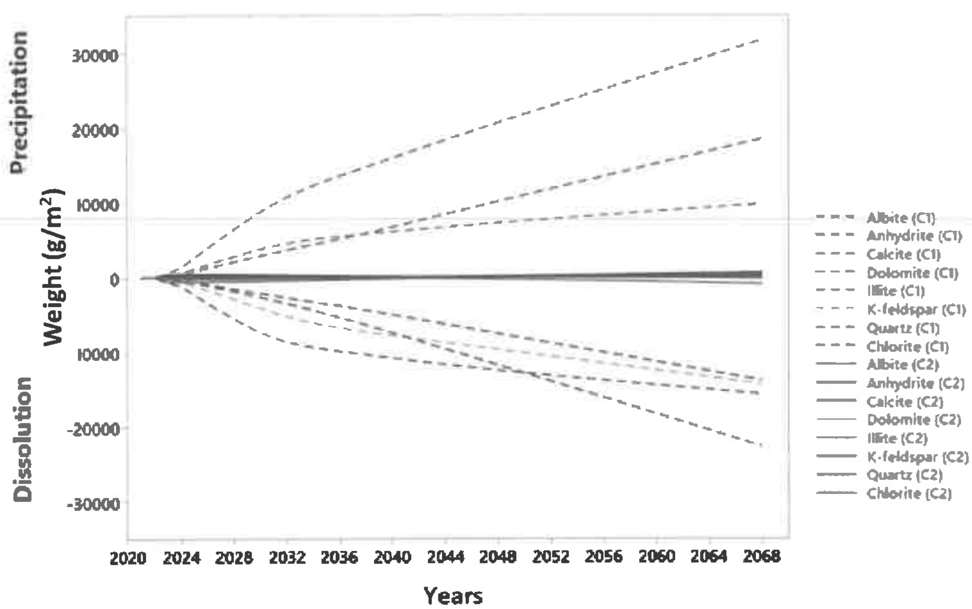



Figure 2-38. Dissolution and precipitation of minerals in the Spearfish Formation cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible. Results from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

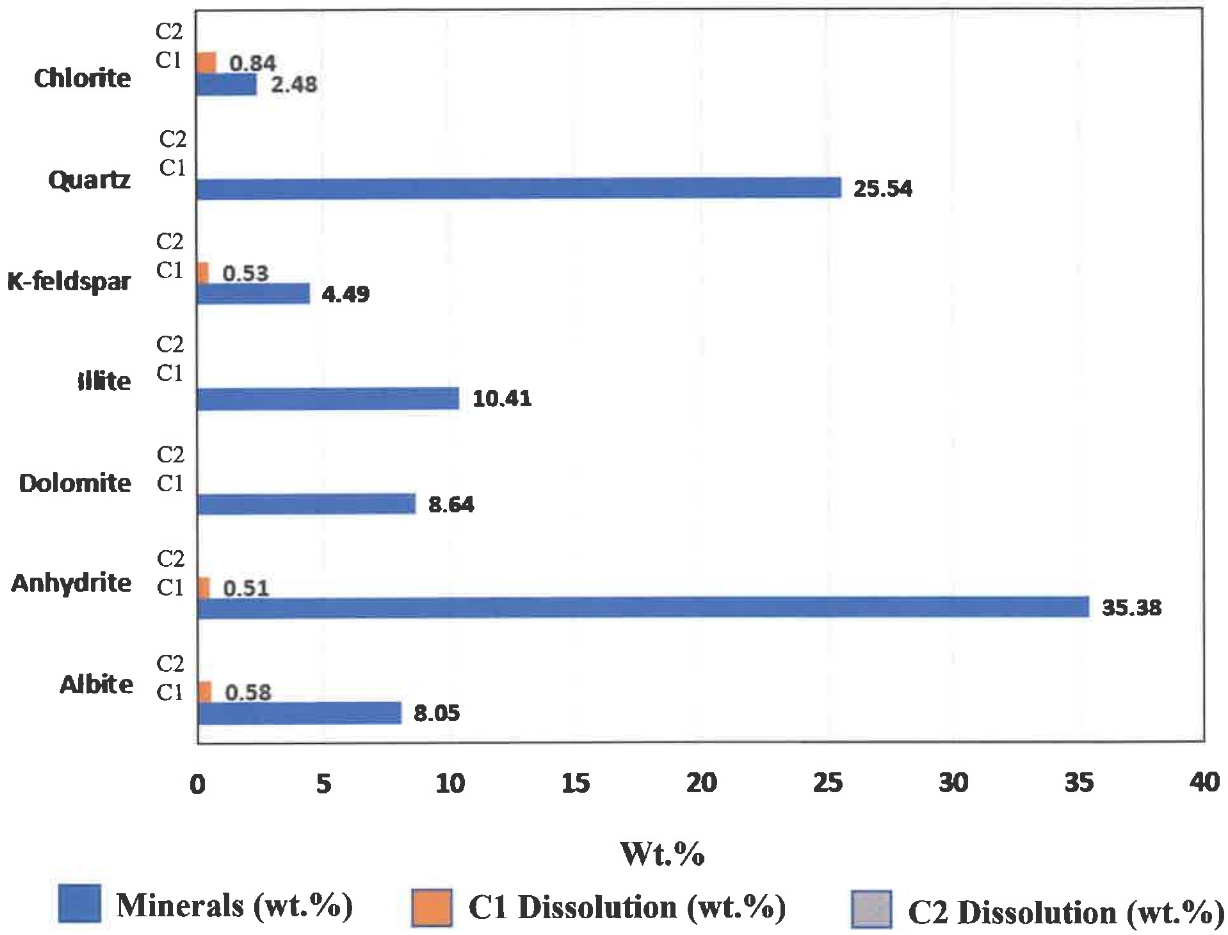



Figure 2-39. Weight percentage (wt%) of potentially reactive minerals present in the Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray, too small to see in the figure) after 20 years of injection plus 25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

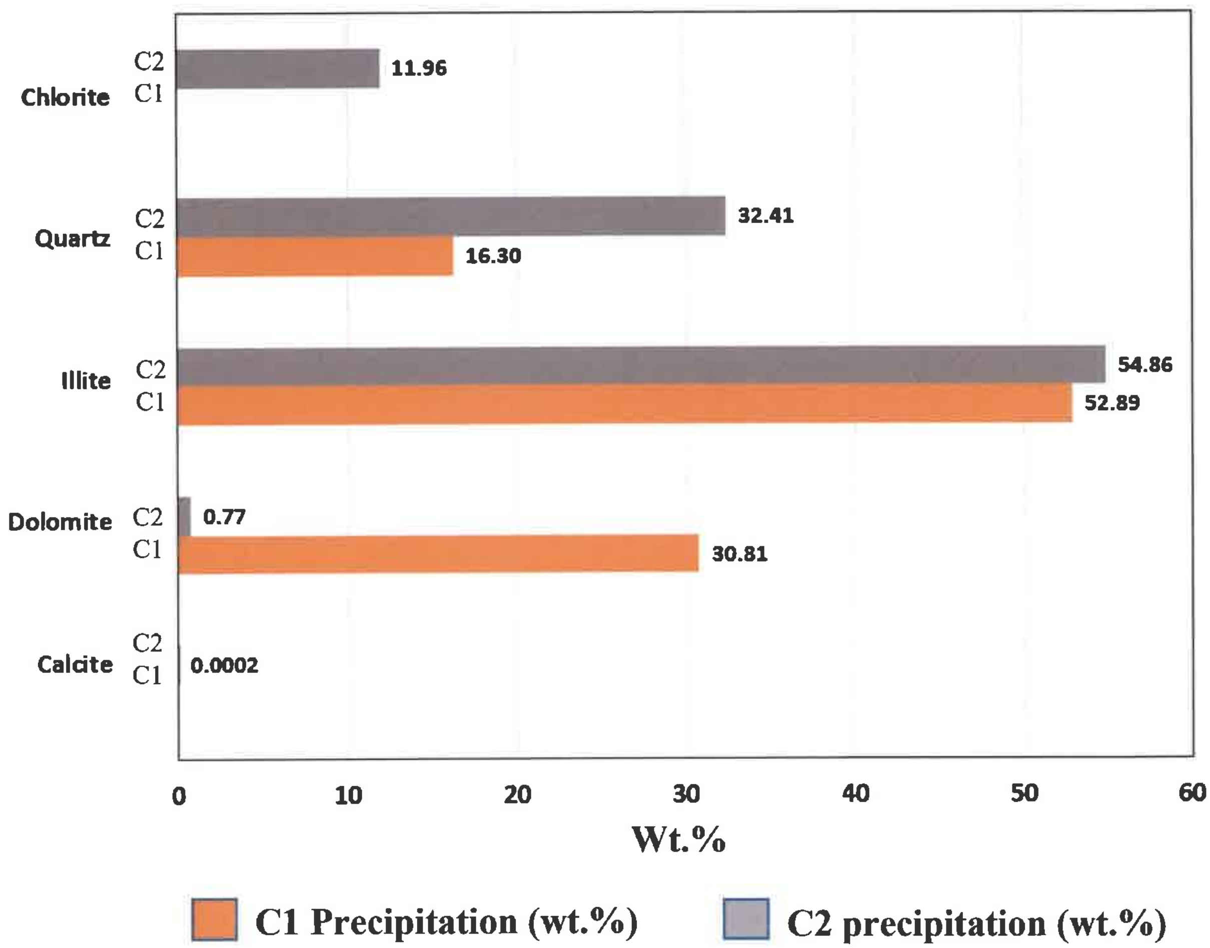



Figure 2-40. Weight percentage (wt%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time.

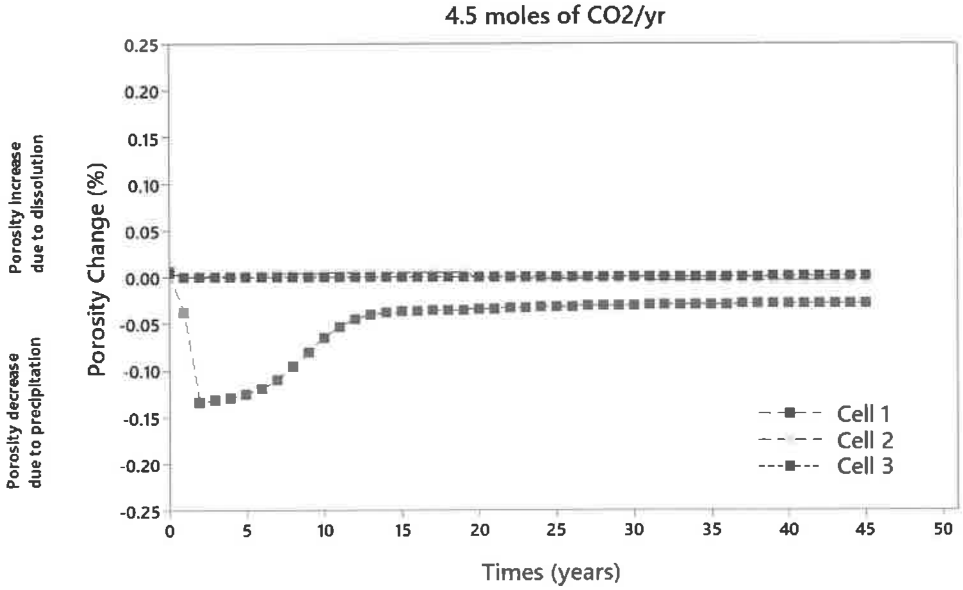



Figure 2-41. Change in percent porosity of the Spearfish cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change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

### *2.4.2 Additional Overlying Confining Zones*

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

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

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

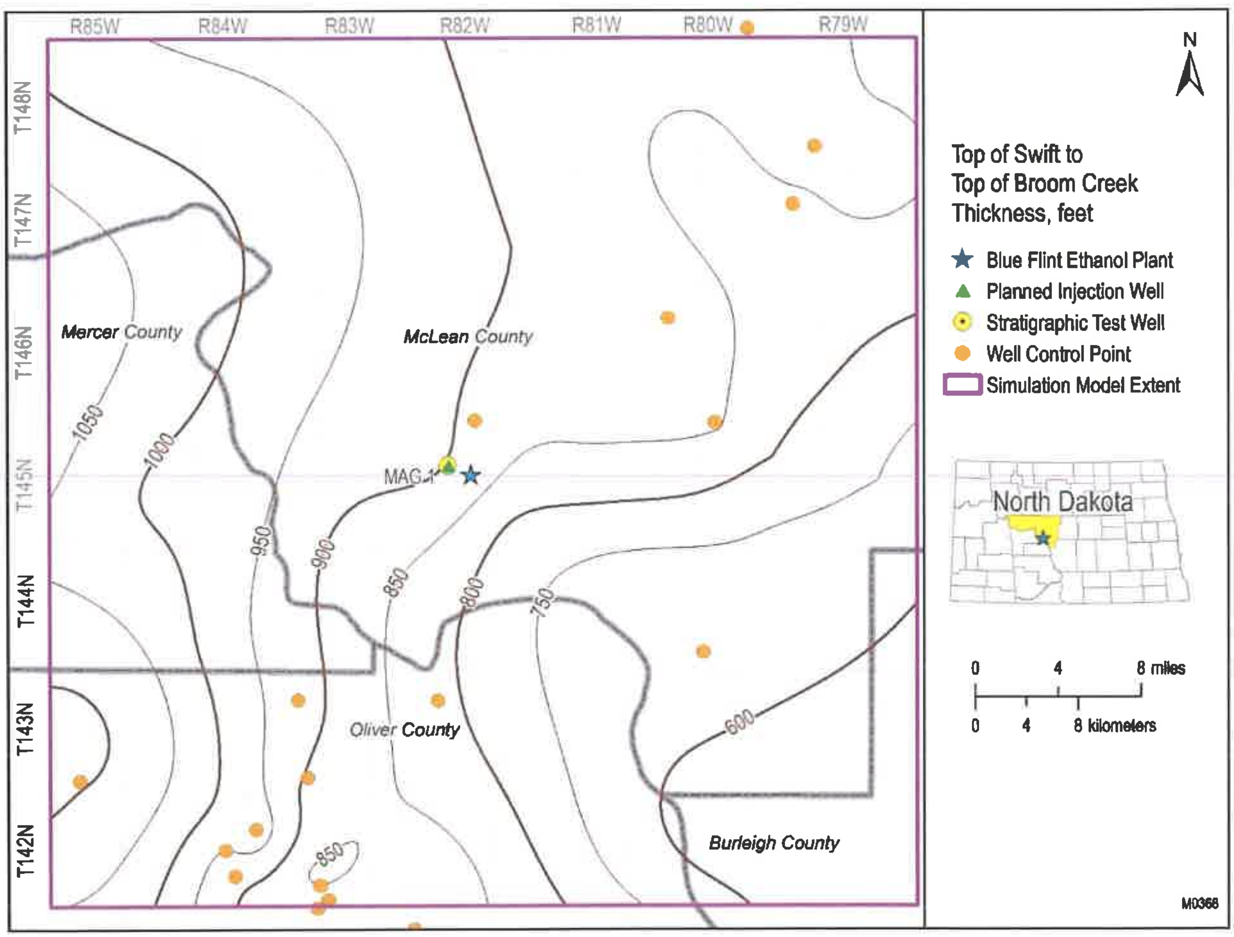



Figure 2-42. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

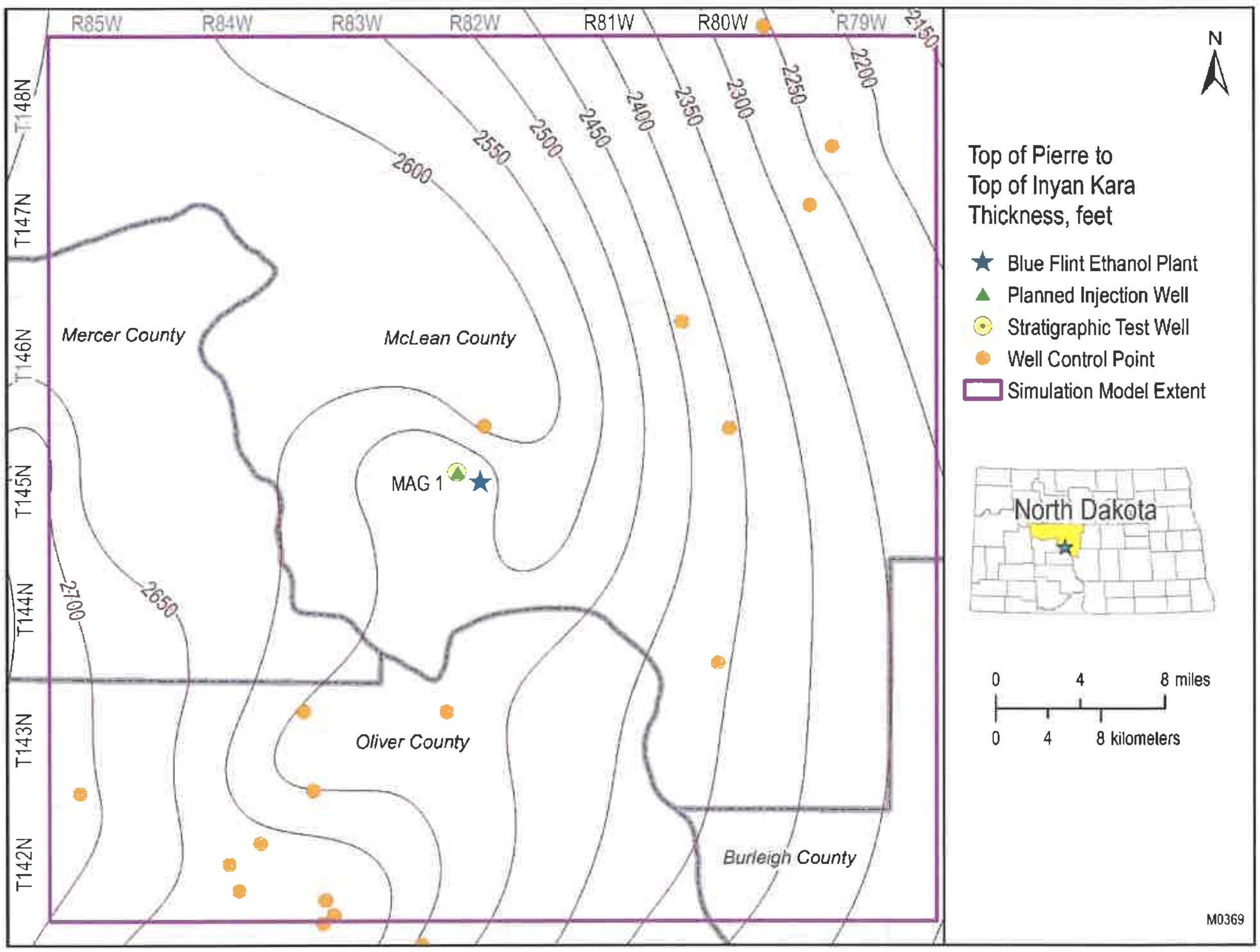



Figure 2-43. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

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

### 2.4.3 *Lower Confining Zone*

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

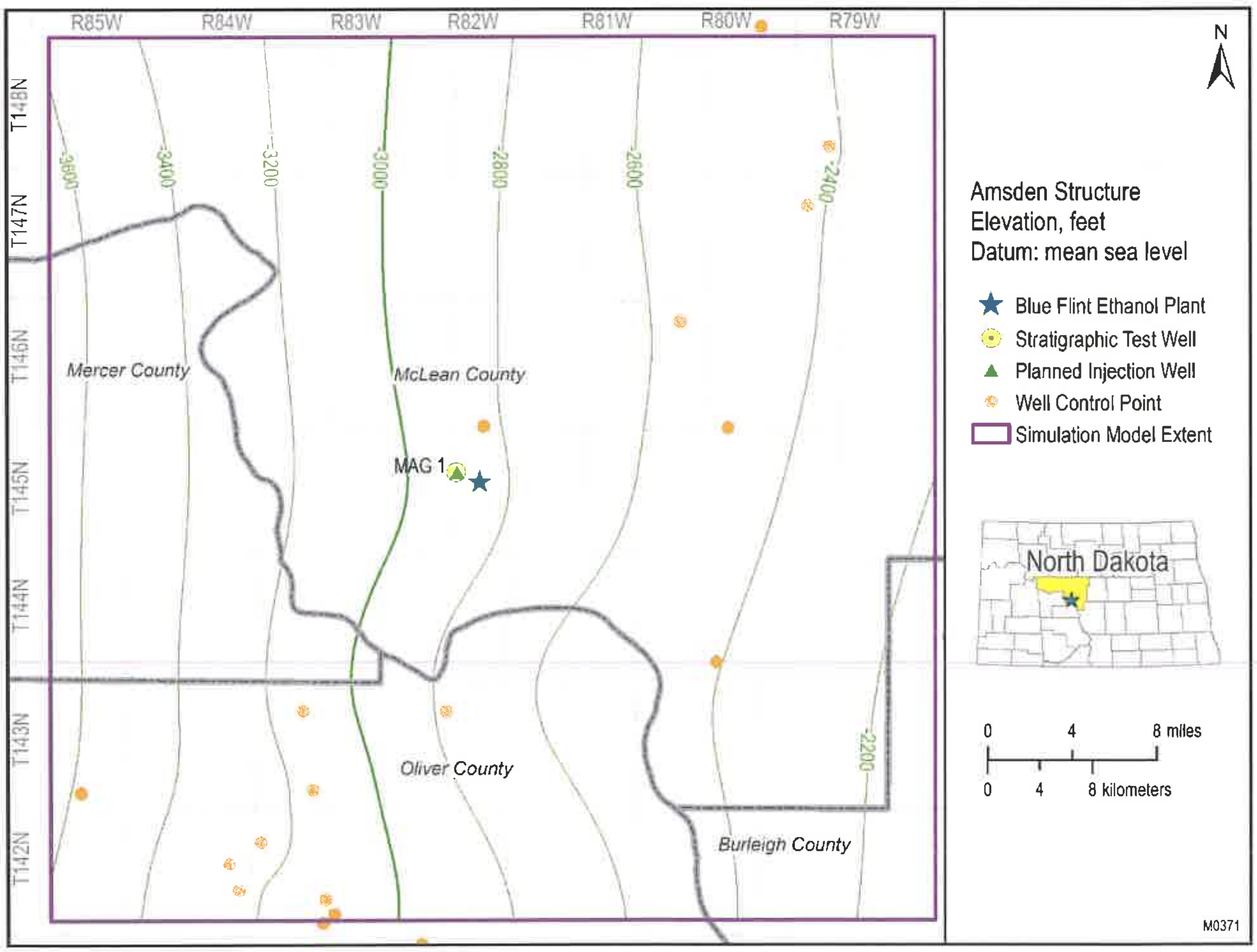



Figure 2-44. Structure map of the Amsden Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

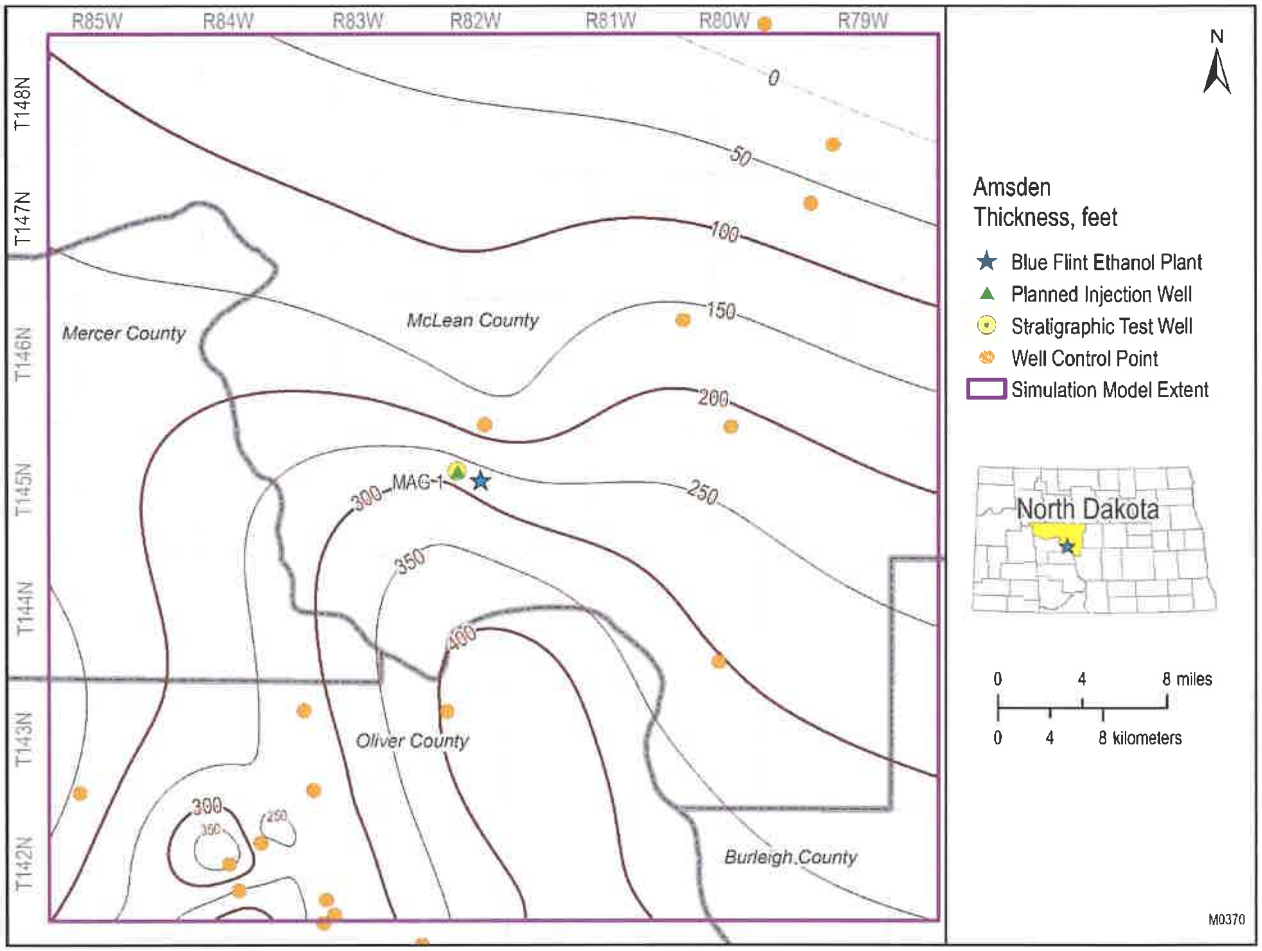



Figure 2-45. Isopach map of the Amsden Formation across the greater Blue Flint project area. The convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

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

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

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

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

### *2.4.3.1 Mineralogy*

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

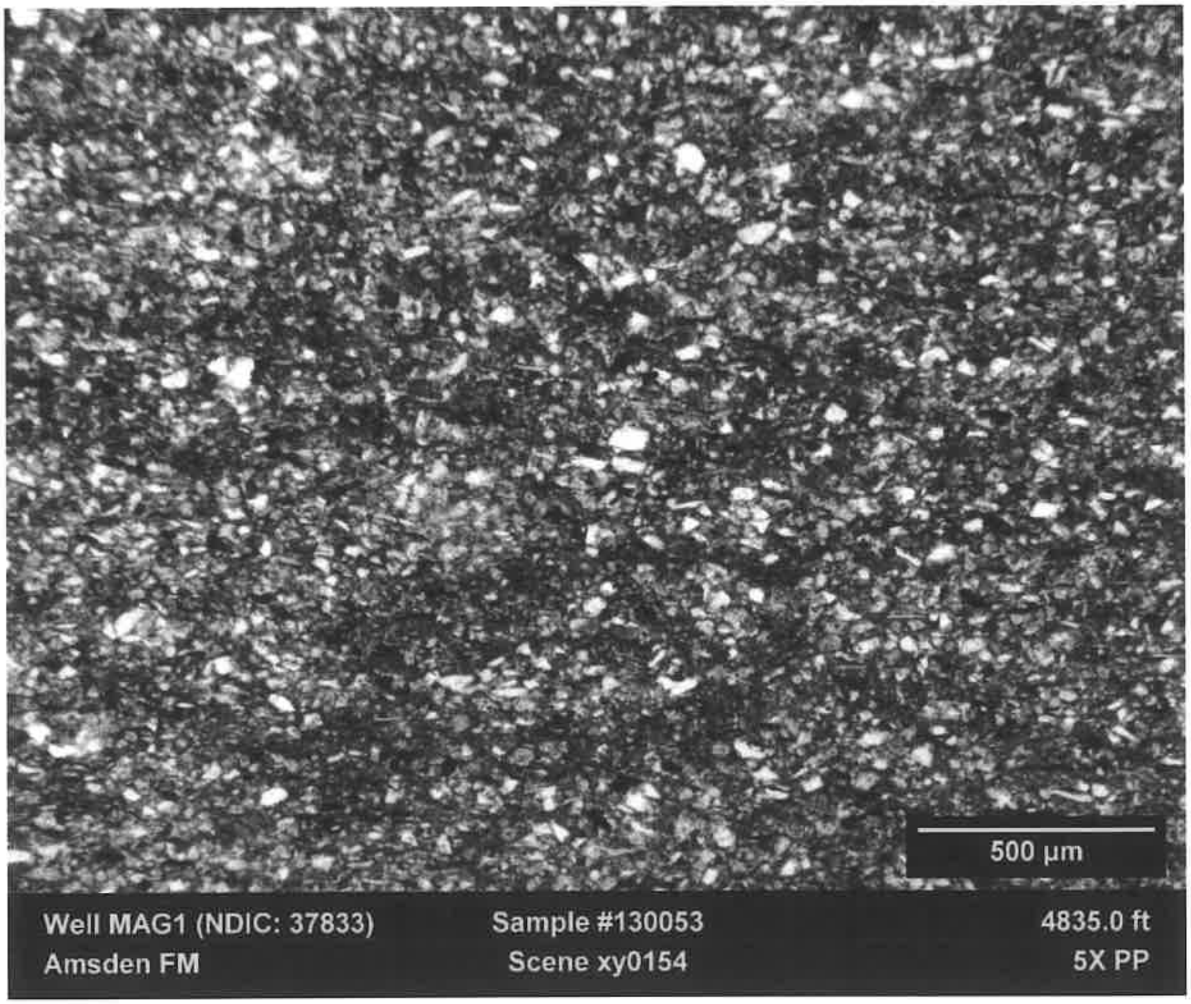



Figure 2-46. Thin section in the Amsden Formation. This example shows a dolomite matrix (gray/brown) with quartz grains distributed throughout. Minor porosity is observed.

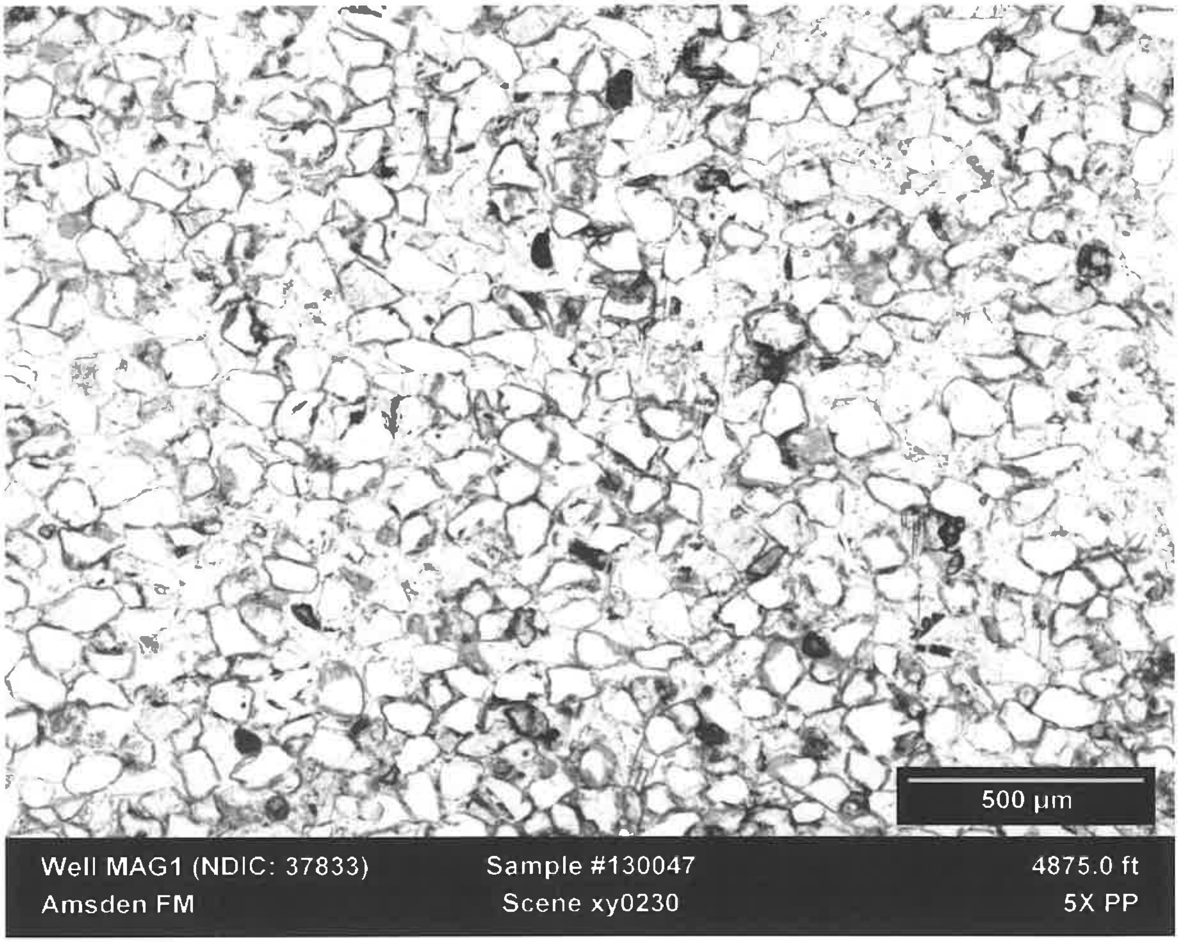



Figure 2-47. Thin section in the Amsden Formation. This interval is dominated by anhydrite and quartz. In this example, quartz grains are tightly cemented, and almost no porosity is observed.


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

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

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

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

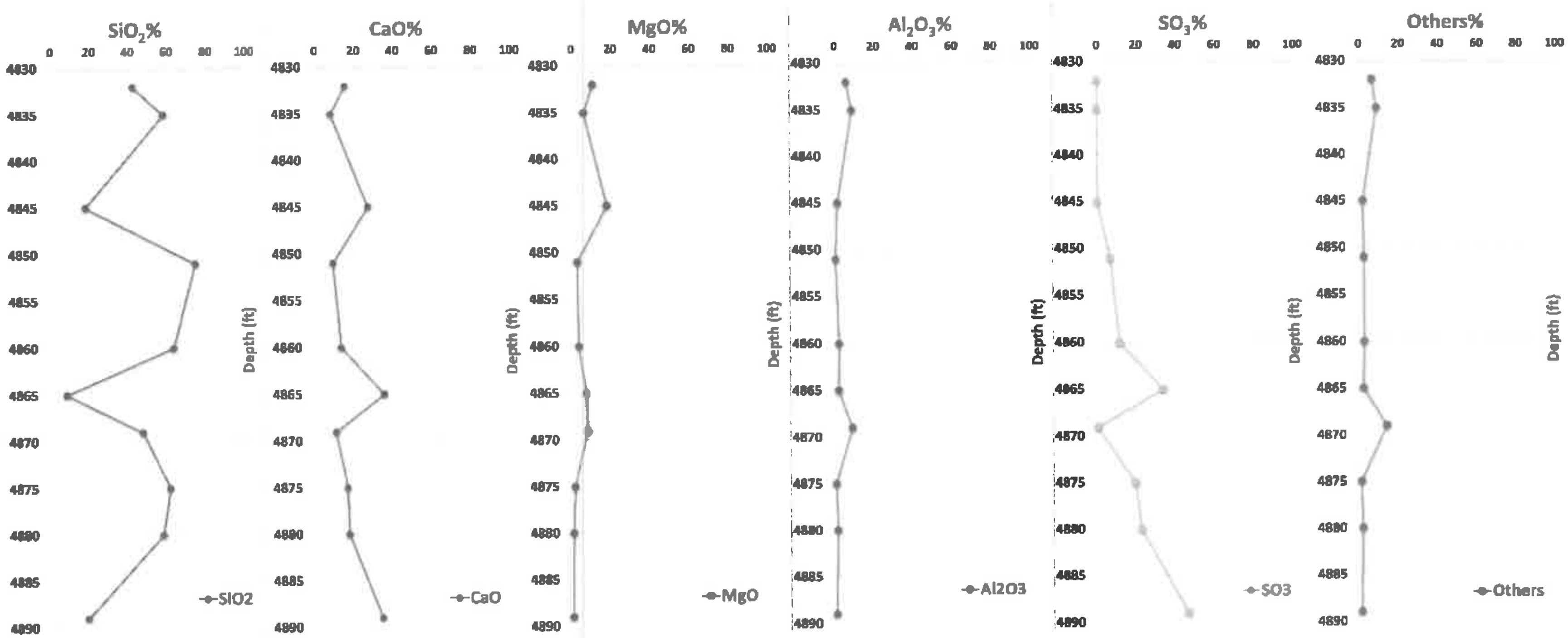



Figure 2-49. XRF analysis in the lower confining zone (Amsden Formation) from MAG 1.

### *2.4.3.2 Geochemical Interaction*

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

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

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

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

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

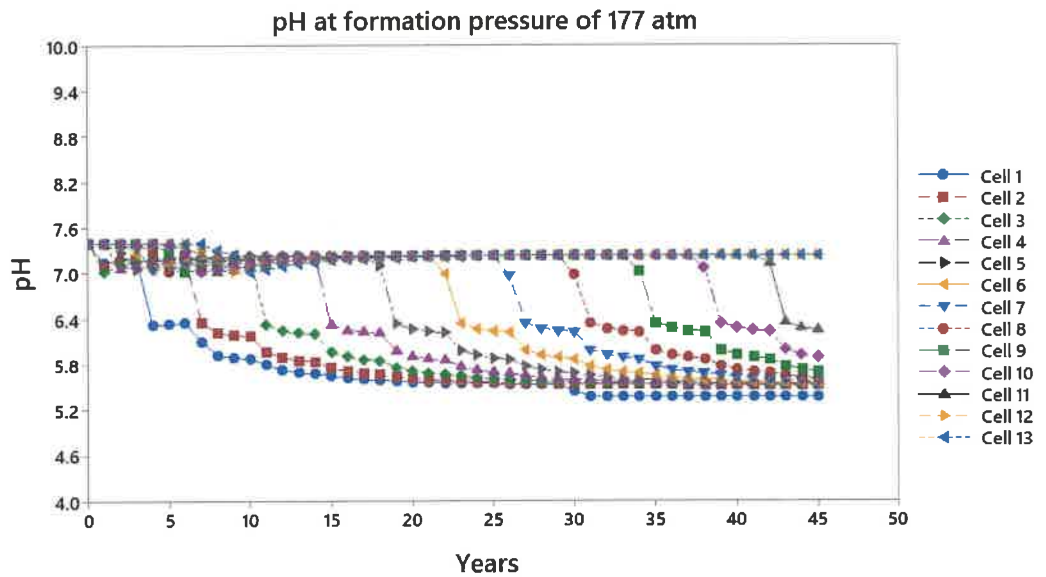



Figure 2-50. Change in fluid pH in the Amsden Formation underlying confining layer for Cells C1–C13.

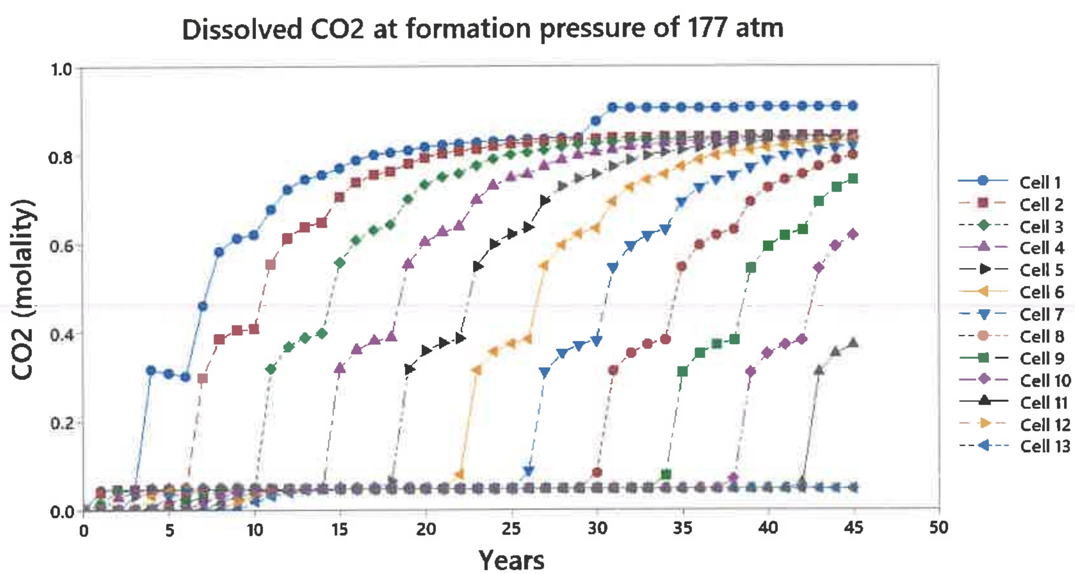



Figure 2-51. $CO_2$ concentration (molality) in the Amsden Formation underlying confining layer for Cells C1–C13.

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

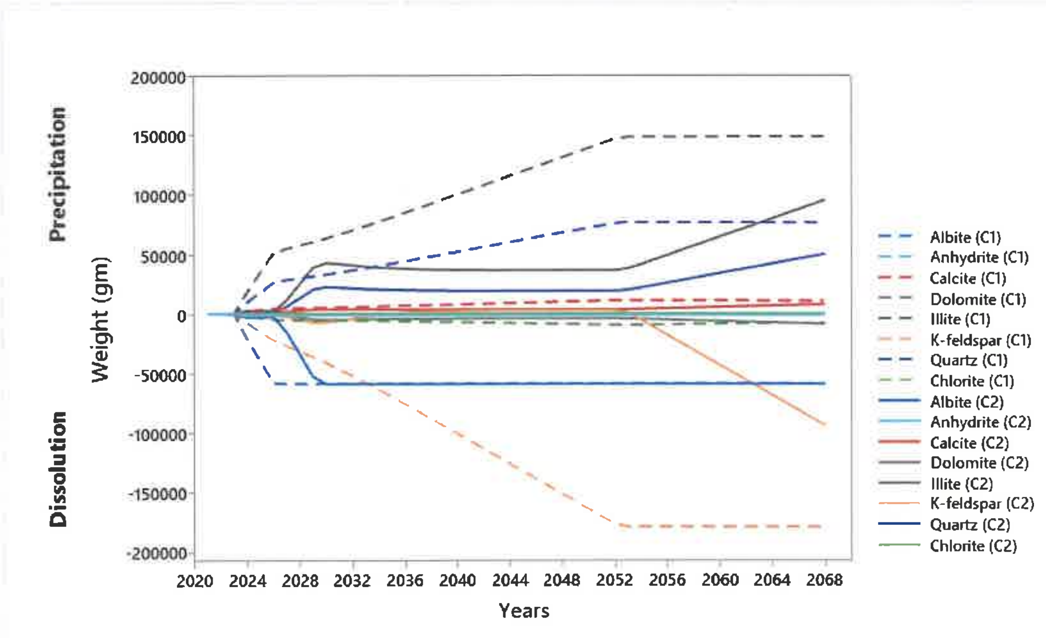



Figure 2-52. Dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for Cell C1, 0 to 1 meter below the Amsden top. Solid lines show results for Cell C2, 1 to 2 meters below the Amsden top.

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

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

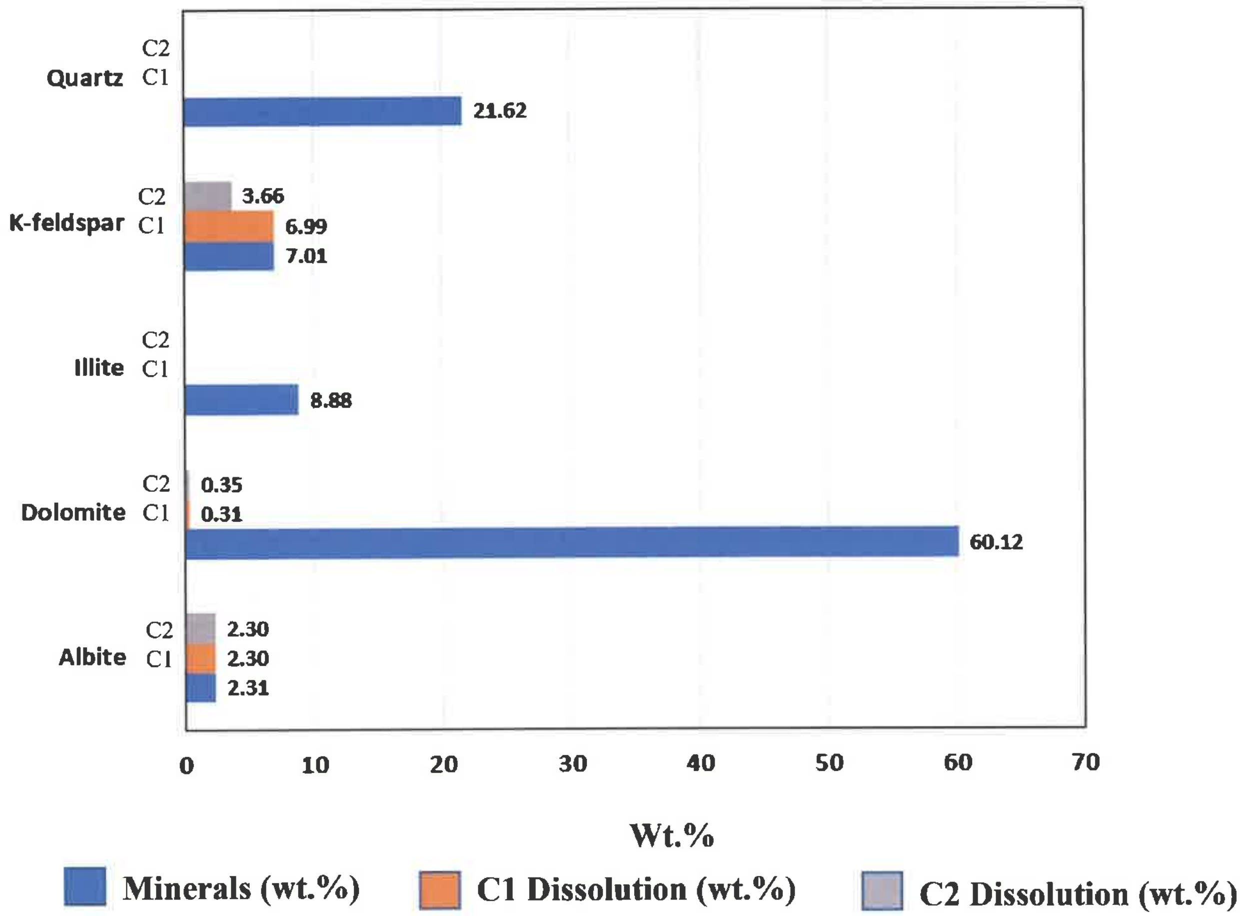



Figure 2-53. Weight percentage (wt%) of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time.

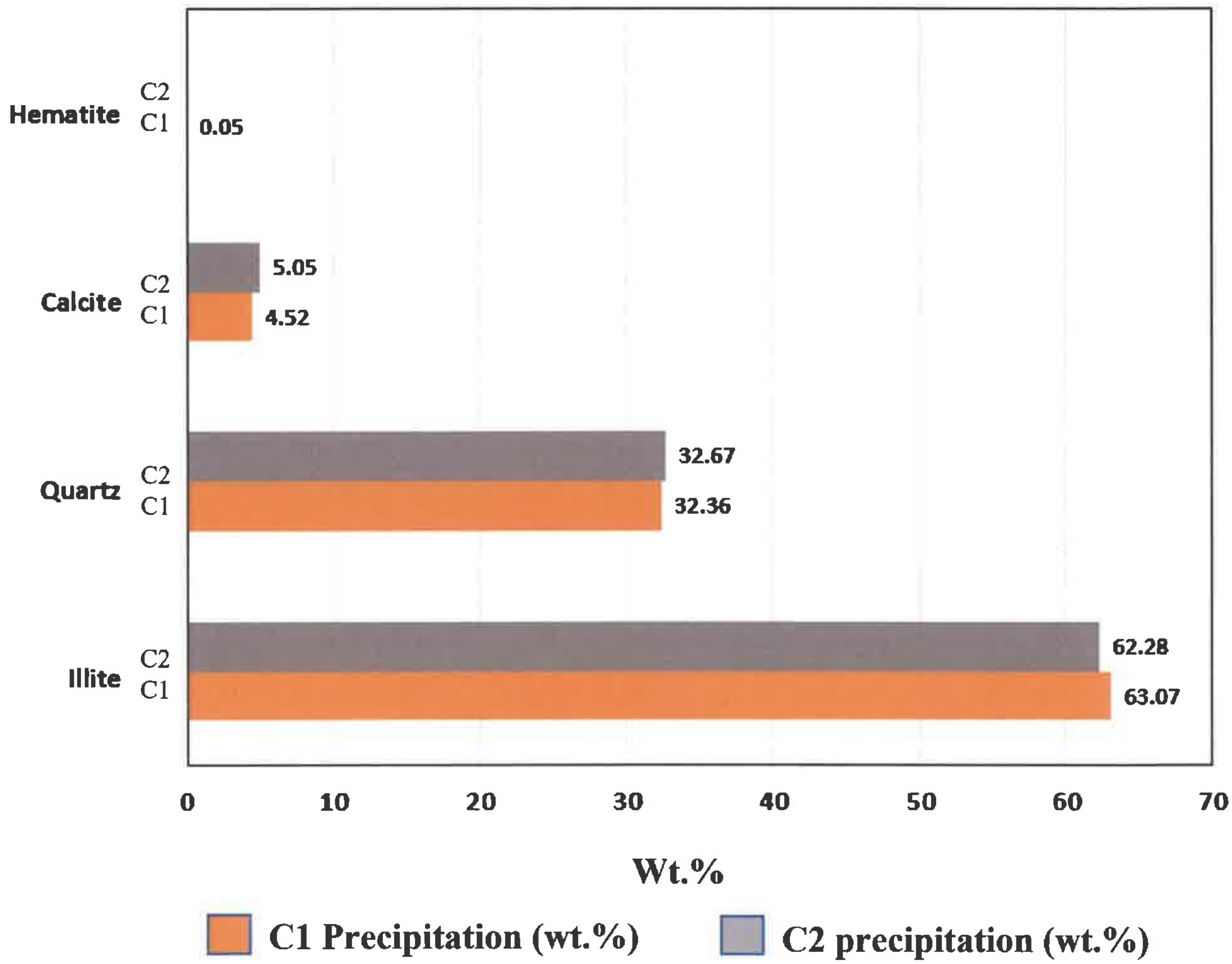



Figure 2-54. Weight percentage (wt%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time.

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

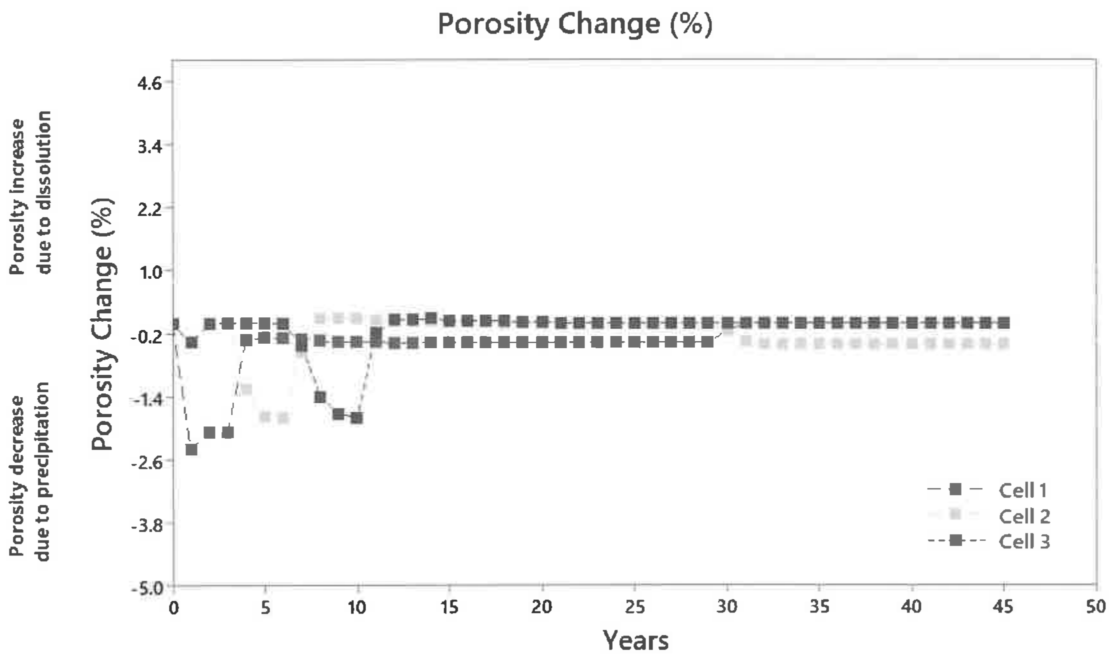



Figure 2-55. Change in percent porosity in the Amsden Formation underlying confining layer. Red line shows porosity change for Cell C1, 0 to 1 meter below the Amsden Formation top. Yellow line shows Cell C2, 1 to 2 meters below the Amsden Formation top. Green line shows Cell C3, 2 to 3 meters below the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

### *2.4.4 Geomechanical Information of Confining Zone*

#### *2.4.4.1 Borehole Image Fracture Analysis*

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

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

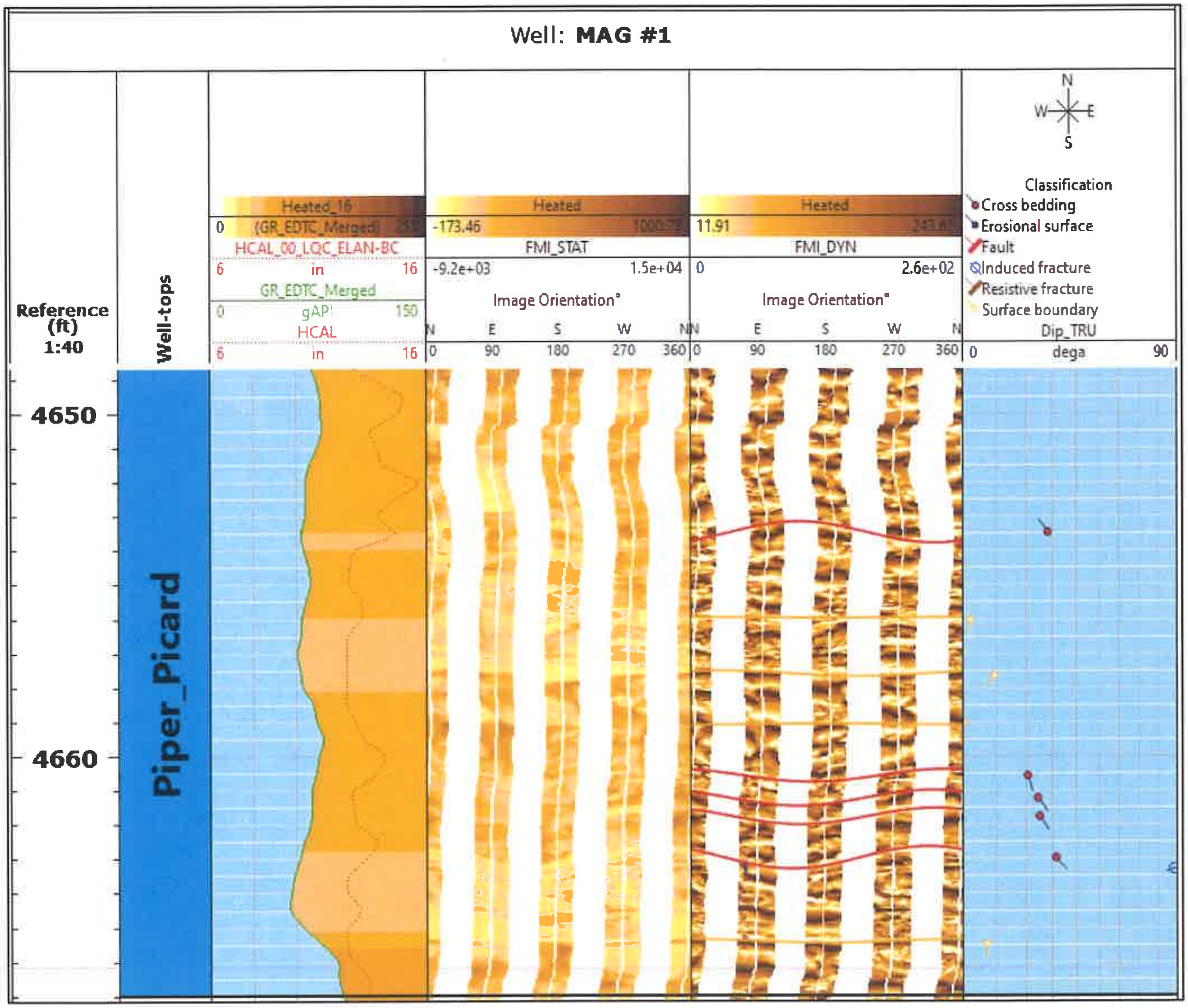



Figure 2-56a. Examples of the interpreted FMI log for the MAG 1 well showing one of the drilling induced fractures observed in the Piper Formation.

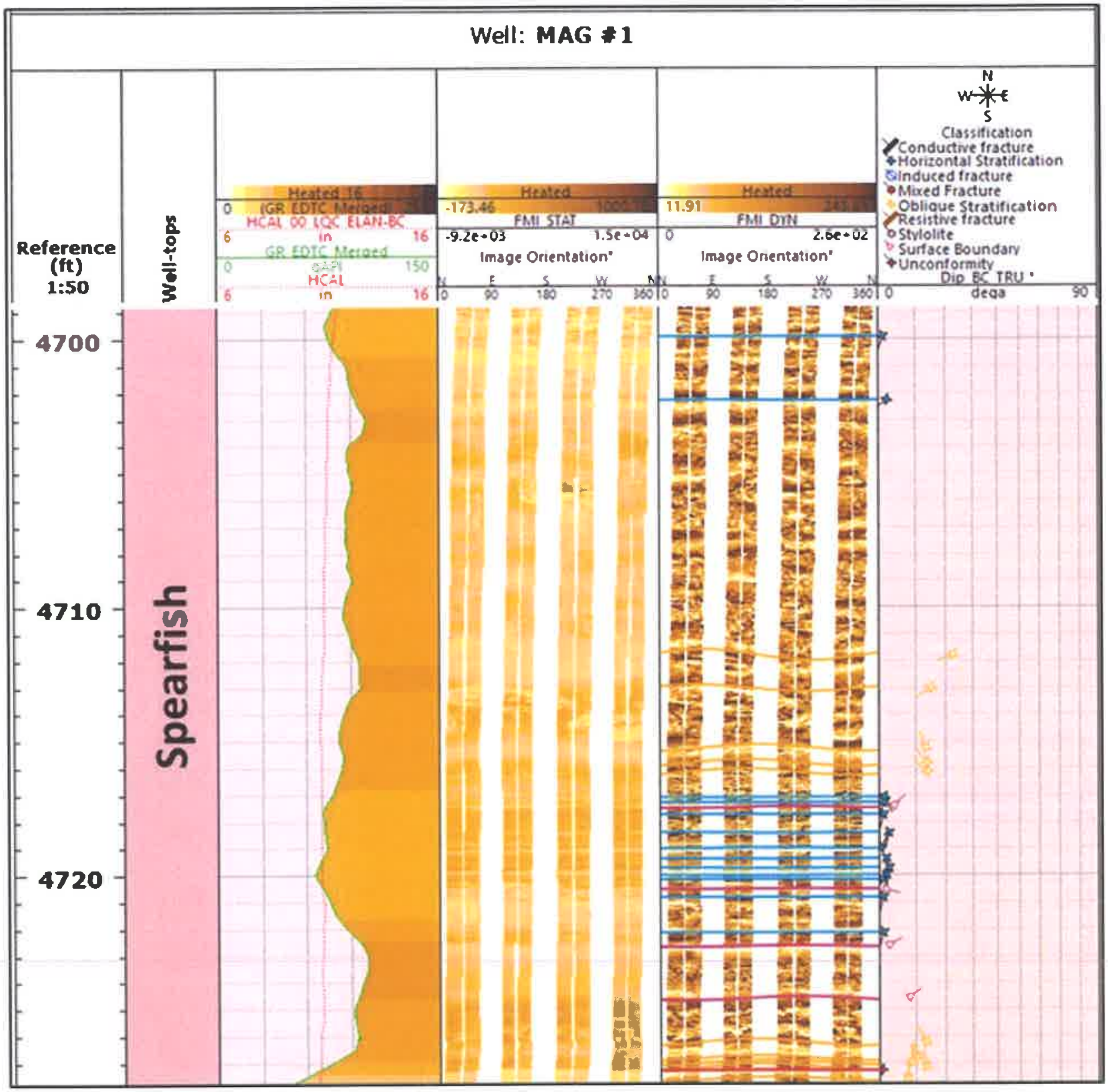



Figure 2-56b. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Spearfish Formation FMI image analysis.

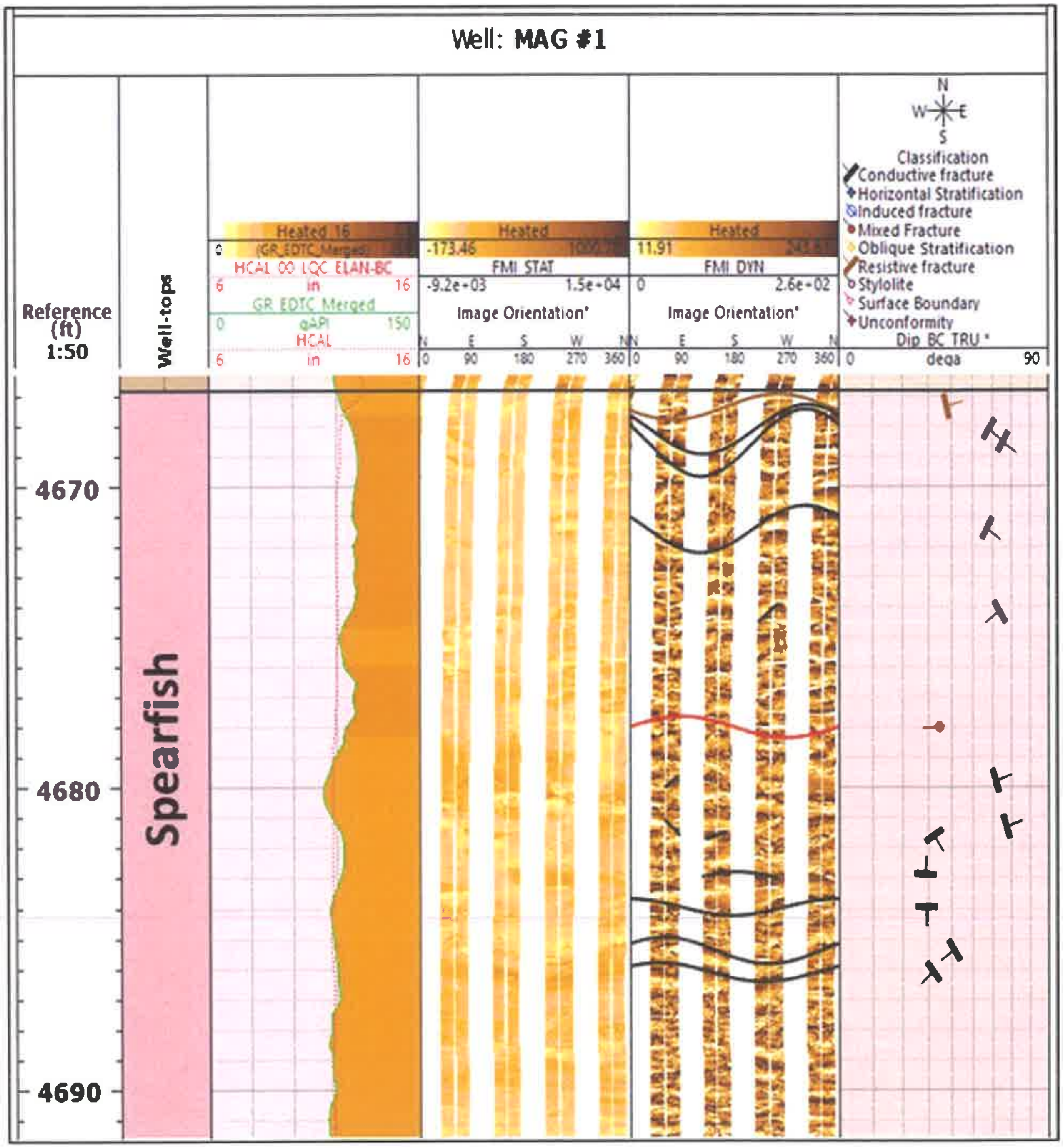



Figure 2-57. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, resistive fracture, mixed fracture, horizontal stratification, and oblique stratification) seen in Spearfish Formation FMI image analysis.

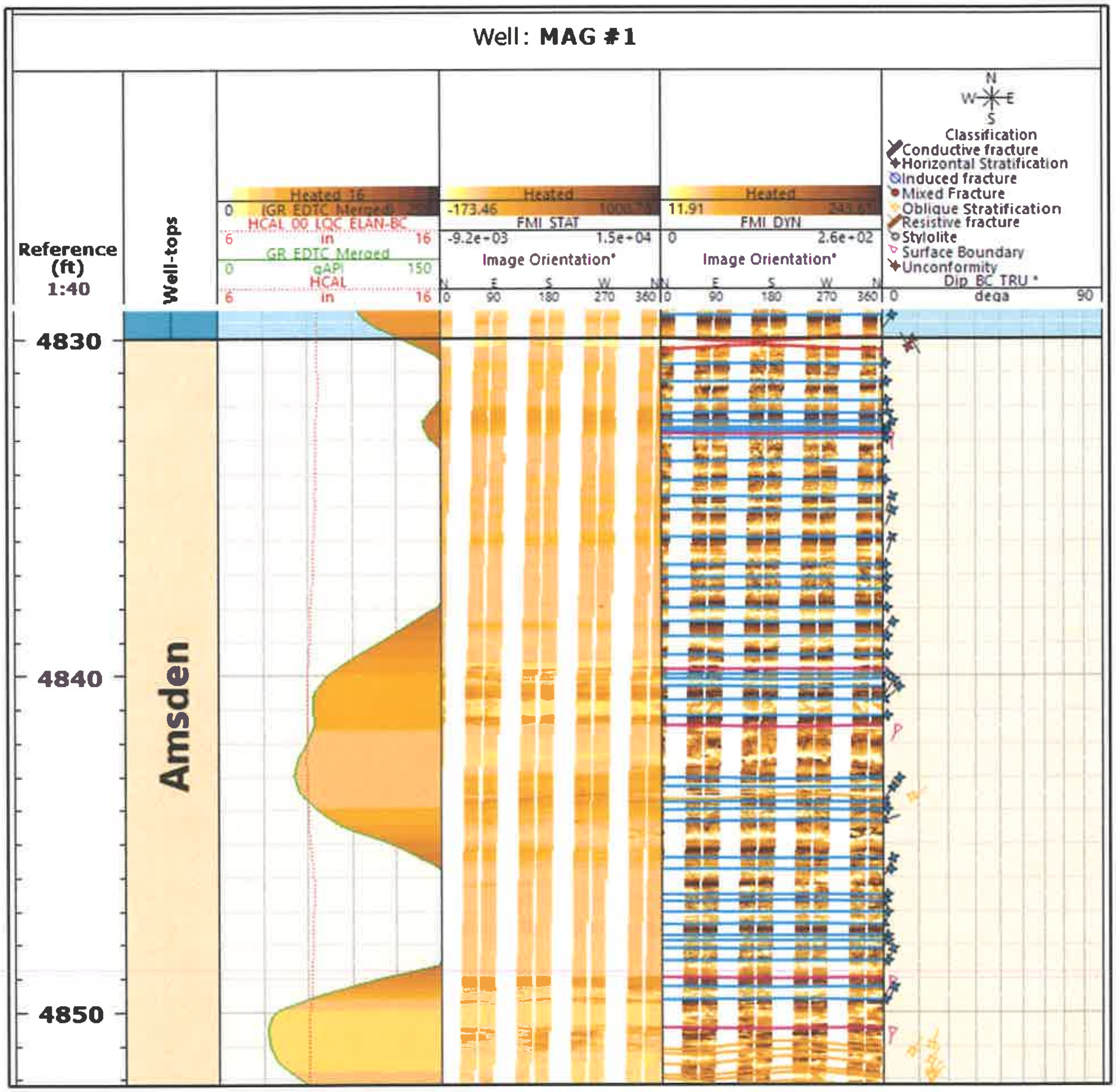



Figure 2-58. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis.

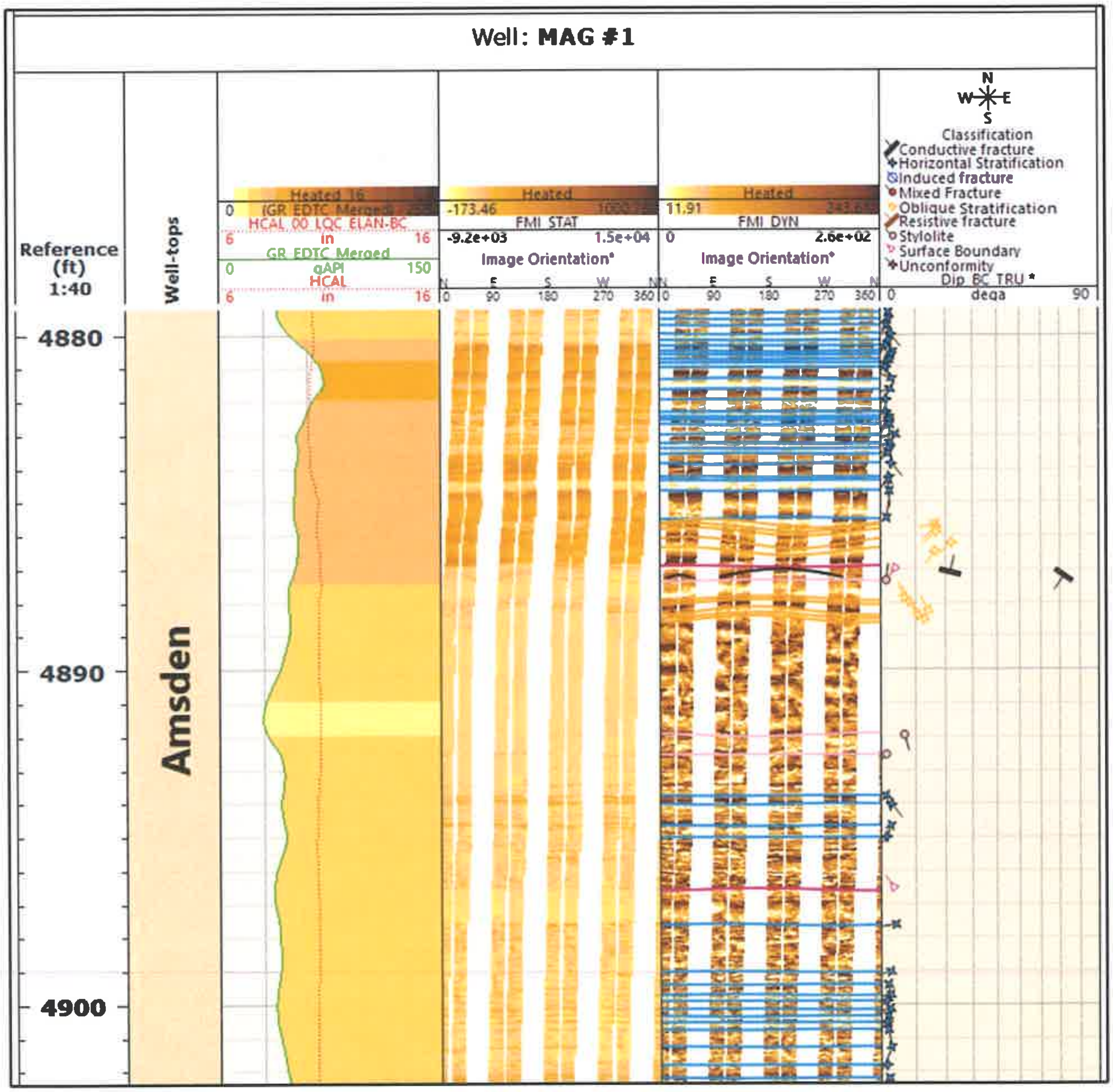



Figure 2-59. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, stylolites, horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis.

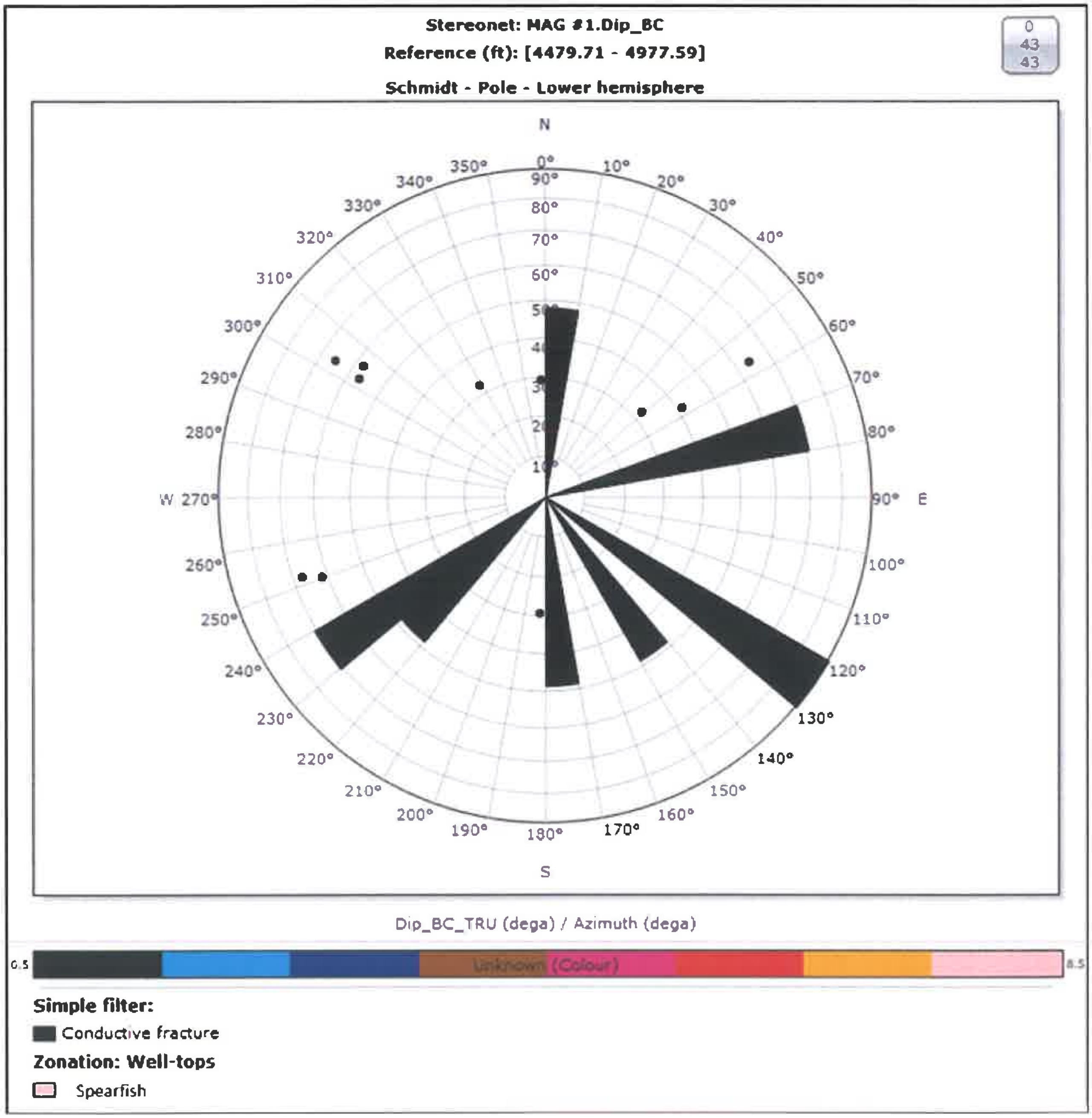



Figure 2-60. This example shows the dip azimuth and dip angle for conductive fractures seen in the Spearfish Formation.

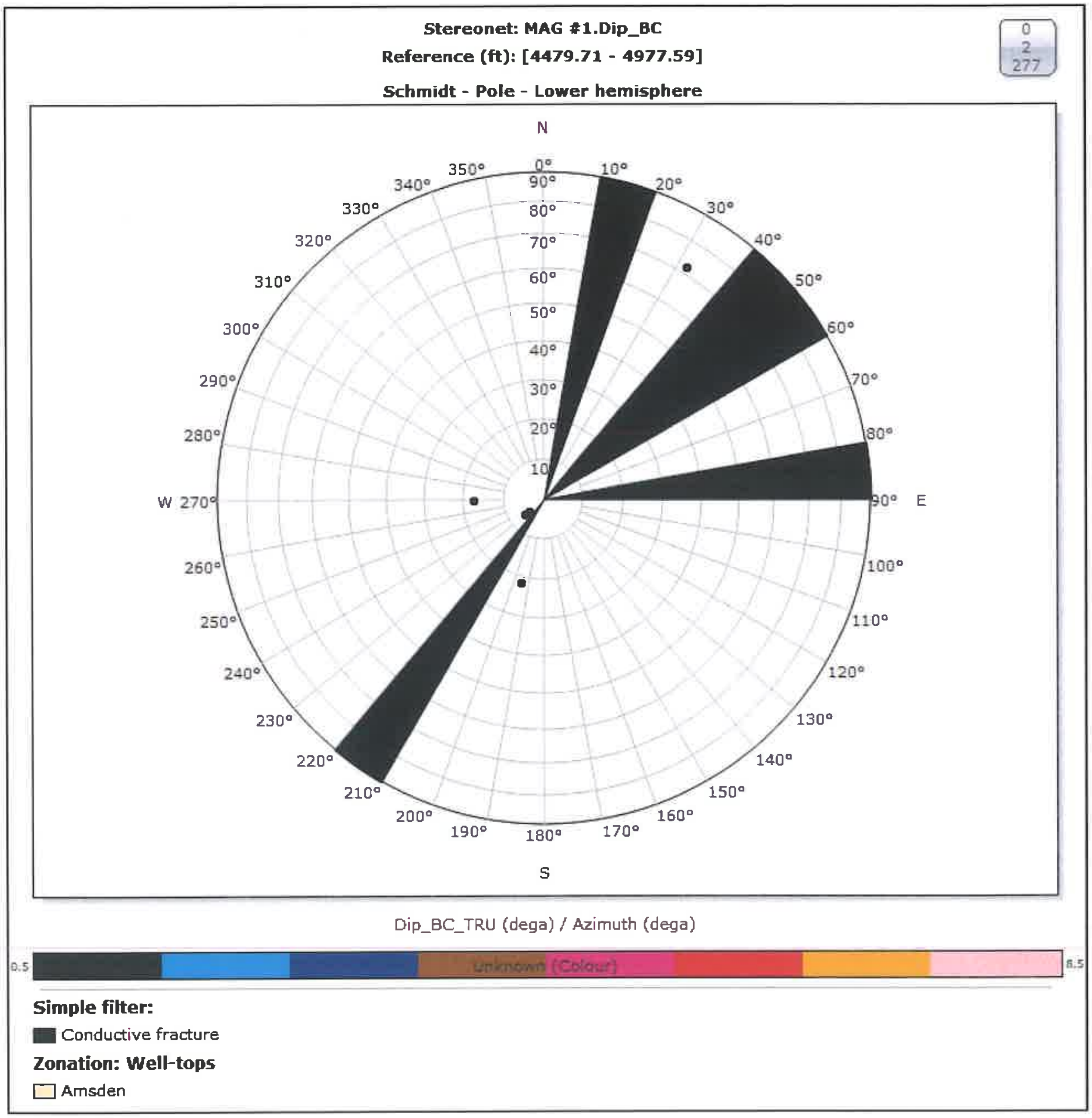



Figure 2-61. This example shows the dip azimuth and dip angle for conductive fractures seen in the Amsden Formation.

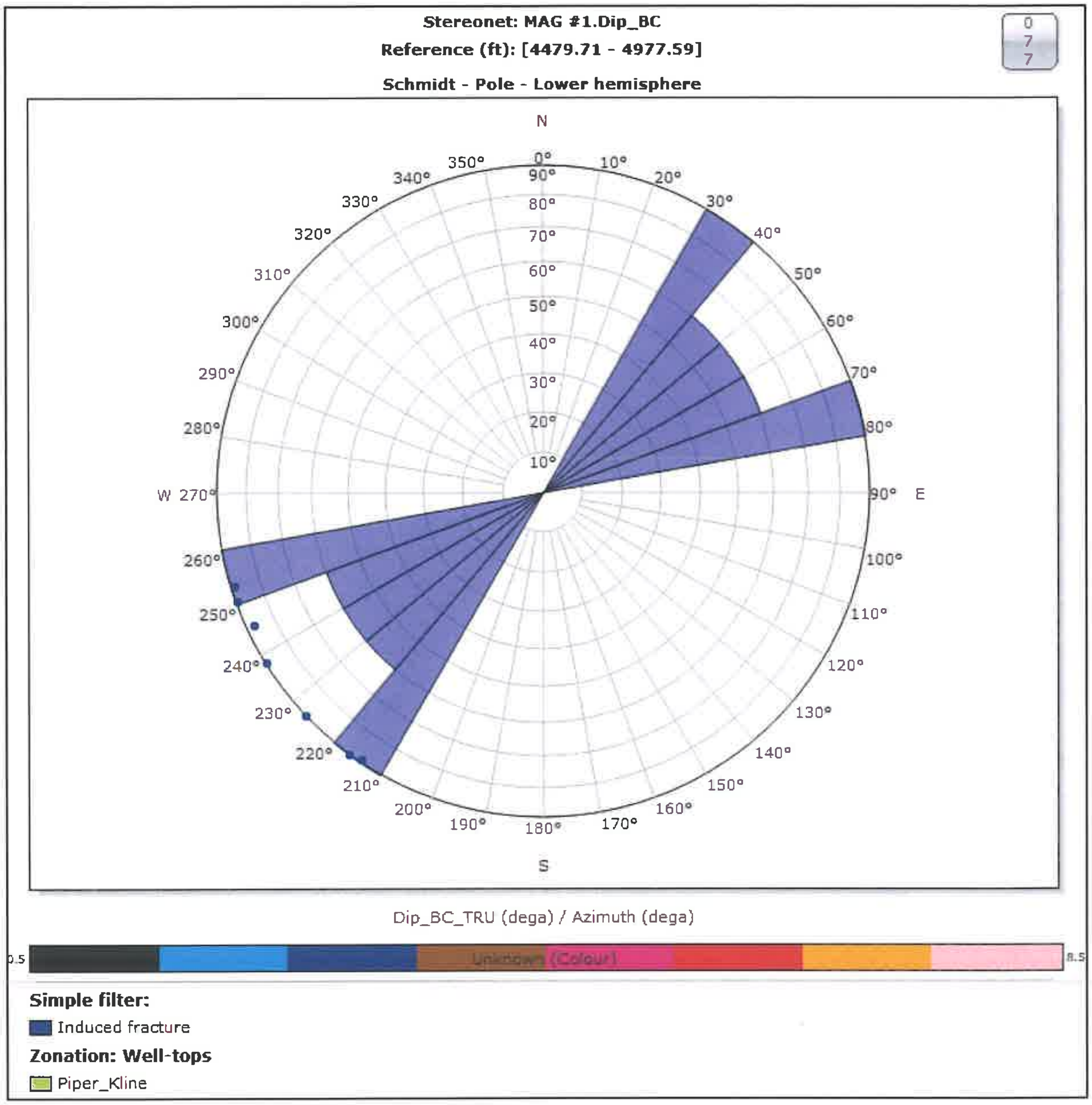



Figure 2-62. This example shows the orientation of drilled-induced fractures in the Piper Formation.

### 2.4.4.2 *Stress, Ductility and Rock Strength*

A 1D MEM was derived using the log data from MAG 1 well. Logs were edited to account for washouts in the Broom Creek and Amsden Formation sections using multilinear regressions. Geomechanical parameters in the Spearfish, Broom Creek, and Amsden Formations were estimated using the 1D MEM. The 1D MEM was used to estimate the vertical stress, pore pressure, minimum and maximum horizontal stresses (Shmin, SHmax), Poisson's ratio, Young's modulus,

shear and bulk moduli, tensile, uniaxial compressive strength, and friction angle (Figure 2-63, Figure 2-64, and Figure 2-65). Table 2-19 shows the average and range of elastic and dynamic parameters, and stresses in the Spearfish, Broom Creek, and Amsden Formations.

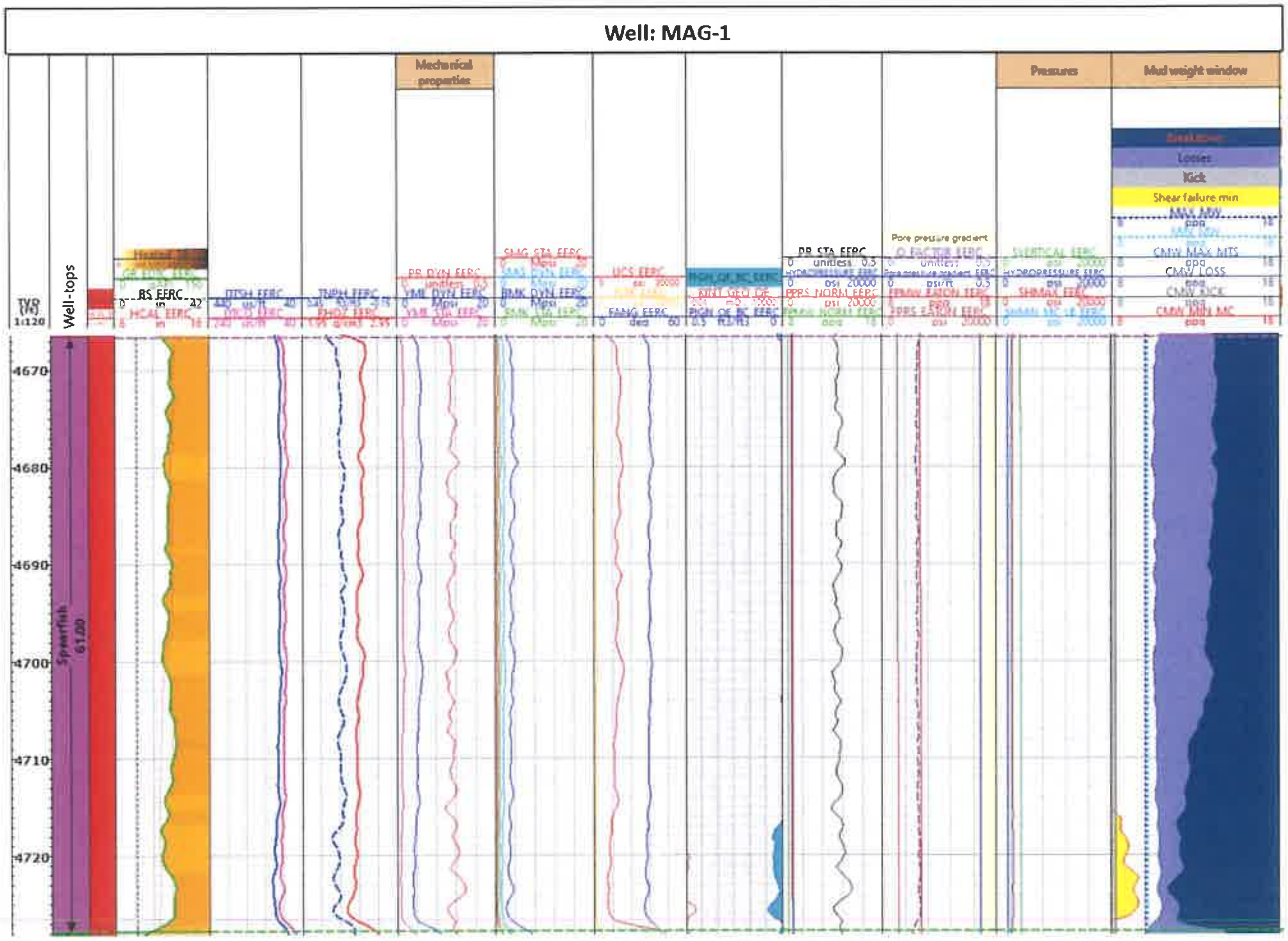



Figure 2-63. Geomechanical parameters in the Spearfish Formation. Track 1, bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, and dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static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

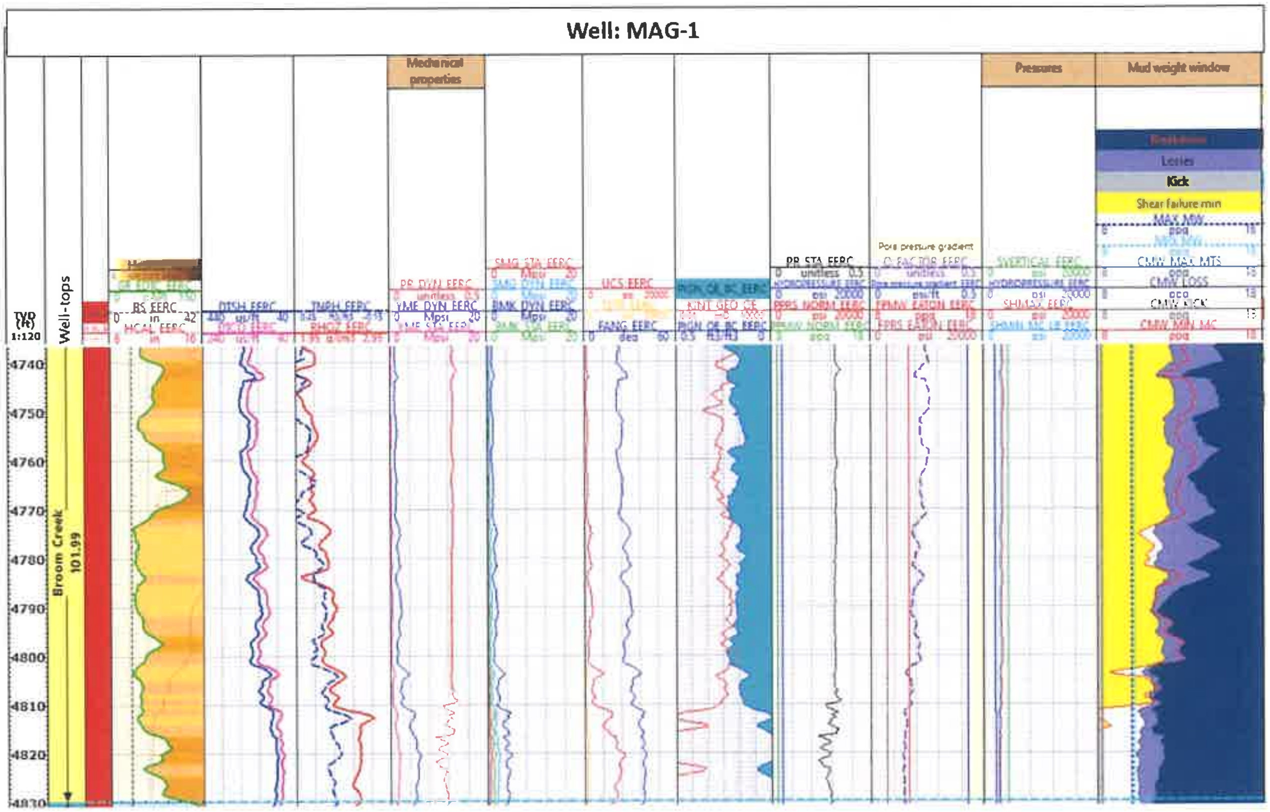



Figure 2-64. Geomechanical parameters in the Broom Creek Formation. Track 1, bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static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

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

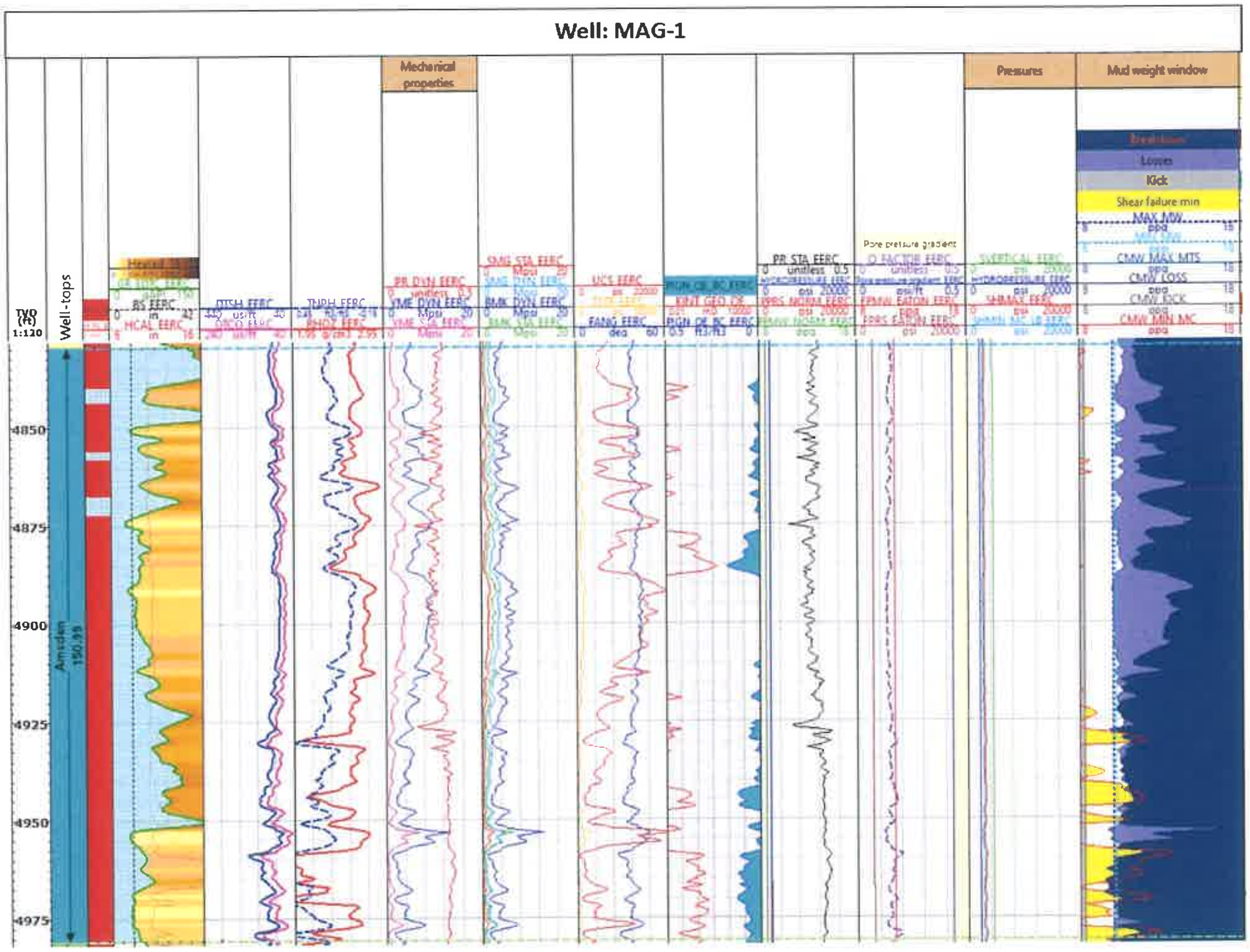



Figure 2-65. Geomechanical parameters in the Amsden Formation. Track 1, Bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static bulk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

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

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

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

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

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

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

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

Where:

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

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

Where:

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

## 2.5 Faults, Fractures, and Seismic Activity

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

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

### *2.5.1 Stanton Fault*

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

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

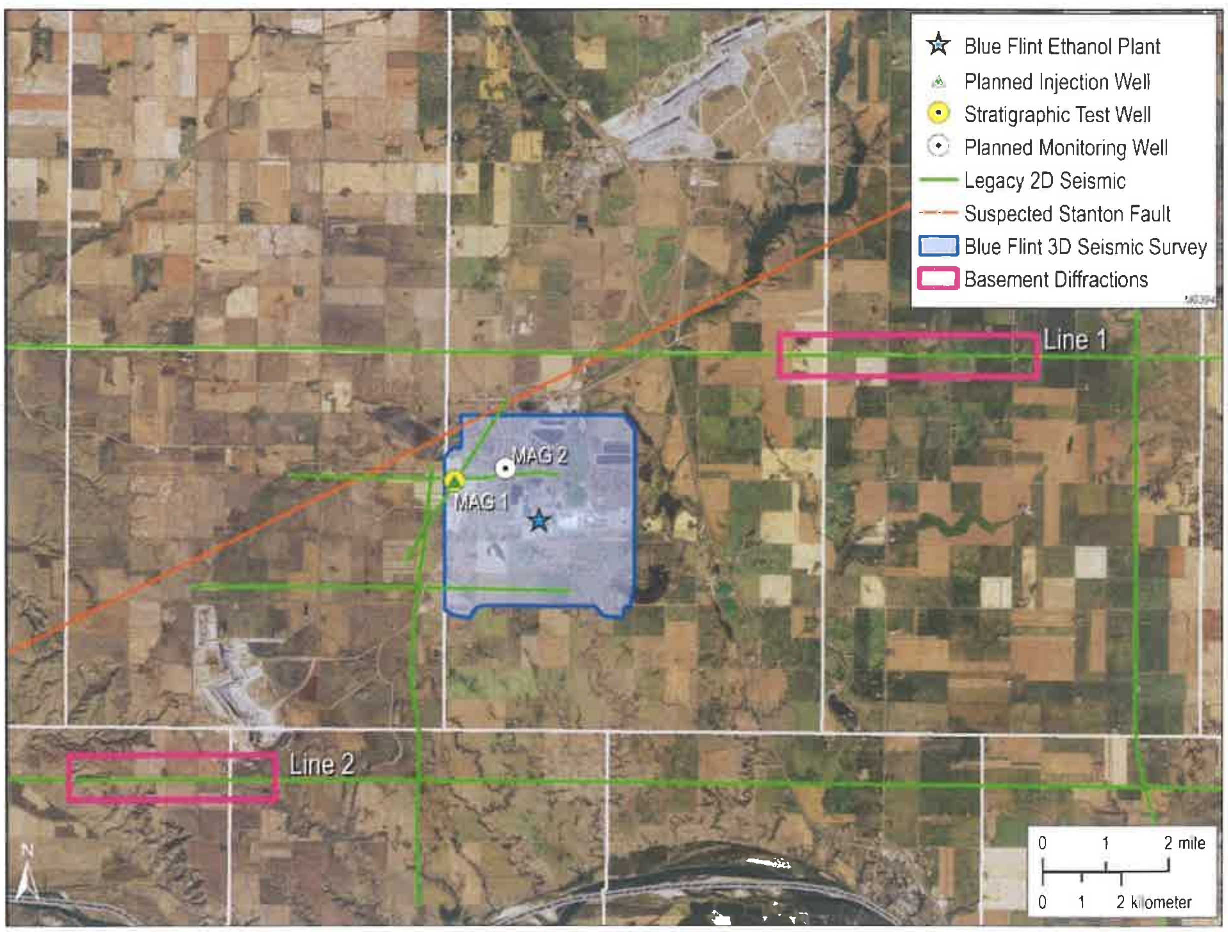



Figure 2-66. Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016).

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

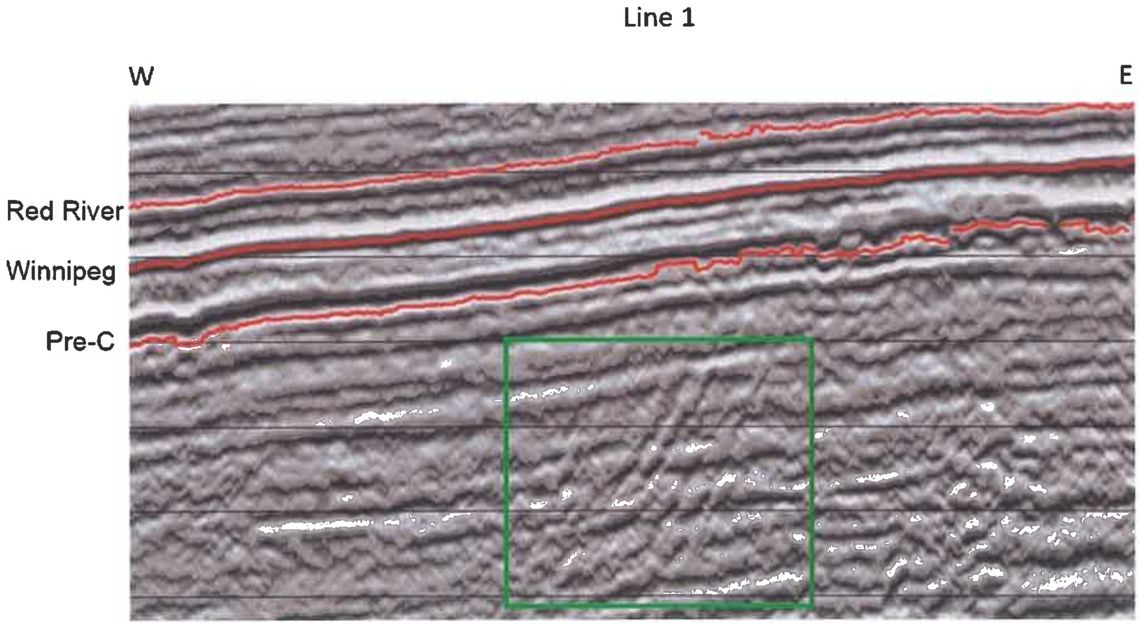



Figure 2-67. Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box).

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

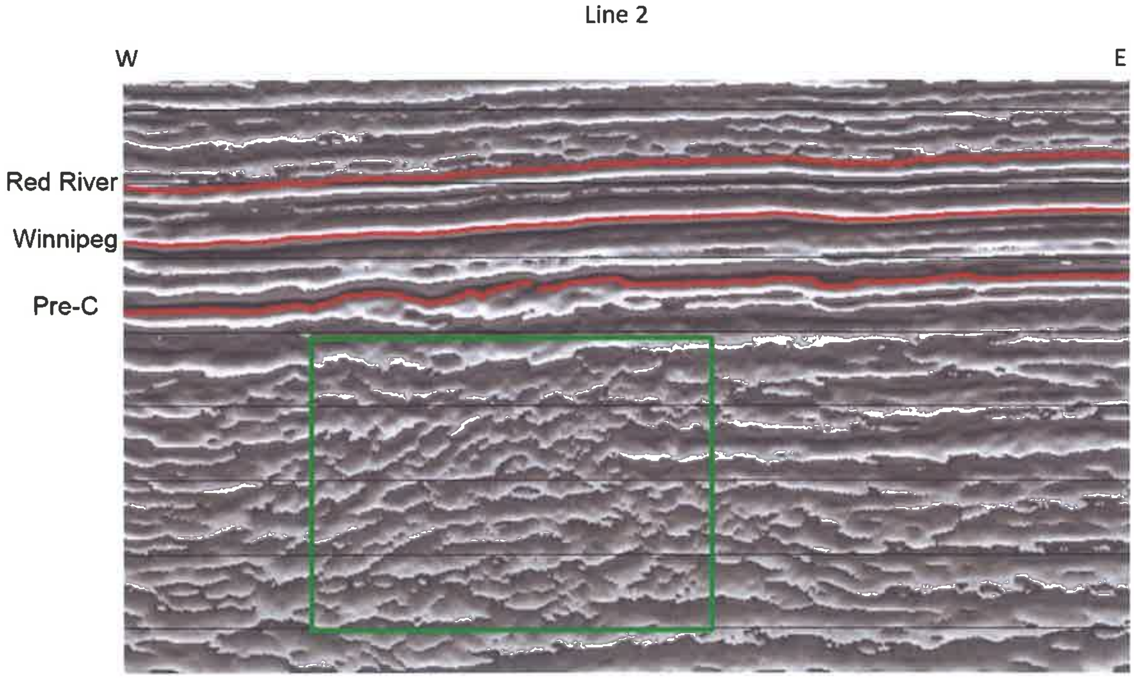



Figure 2-68. Cross section of Line 2 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box).

### *2.5.2 Seismic Activity*

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

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

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

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

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

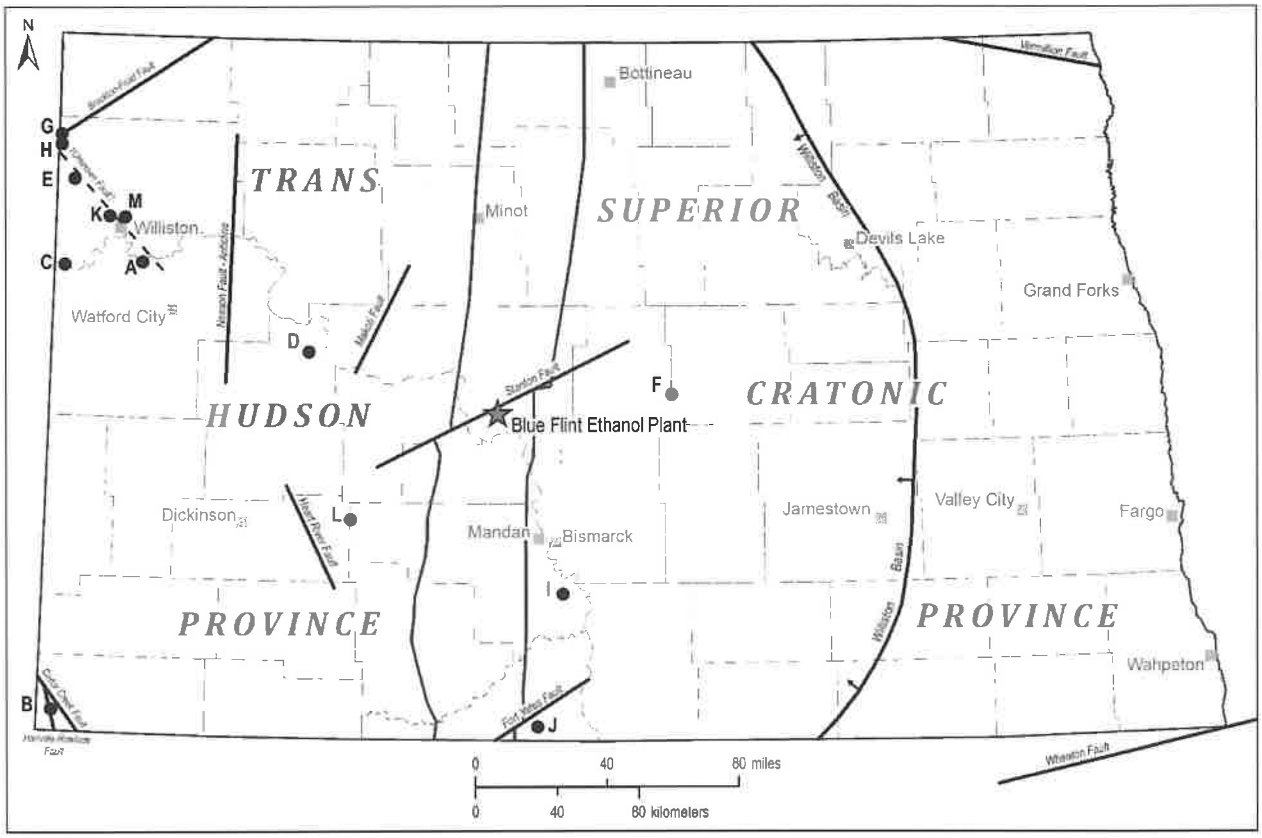



Figure 2-69. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-21.

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

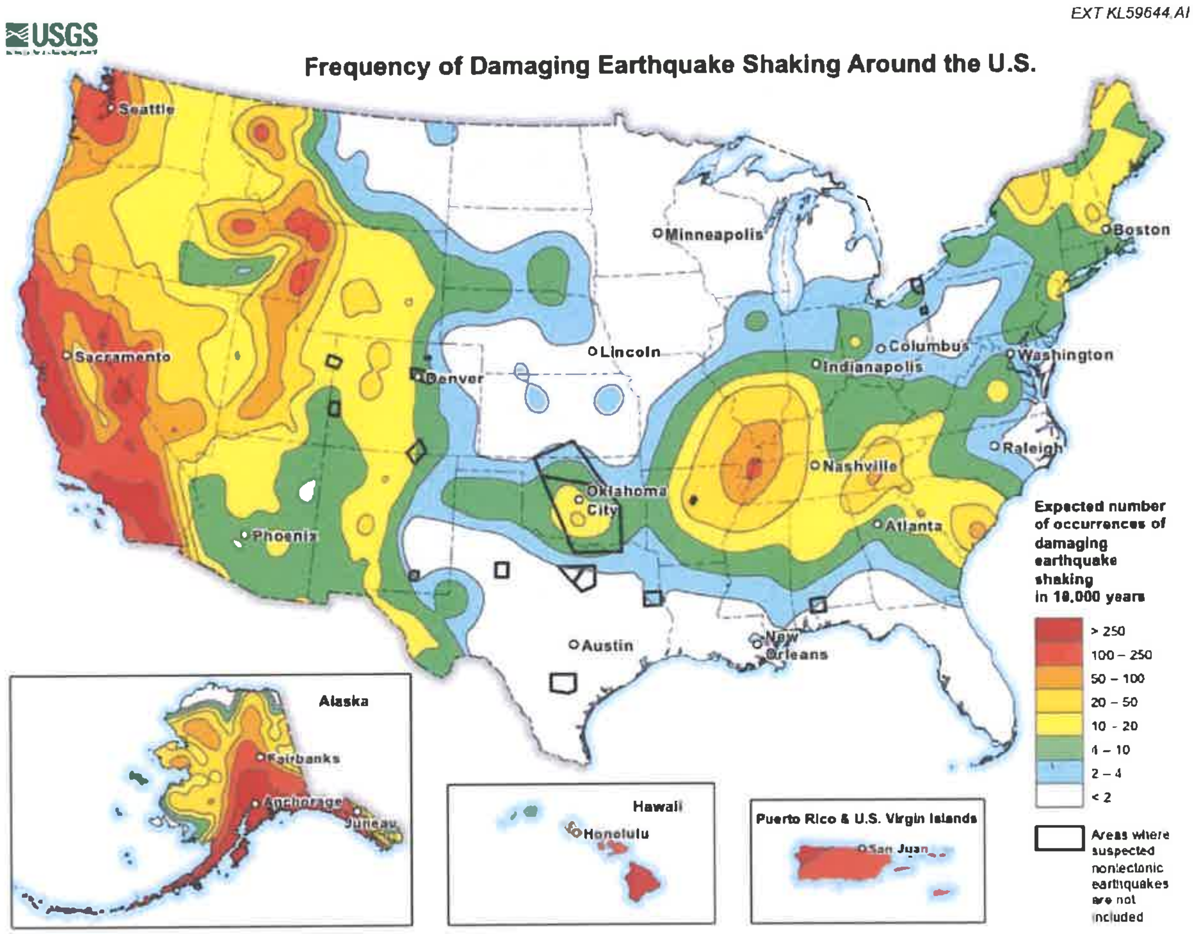



Figure 2-70. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

## 2.6 Potential Mineral Zones

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

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a horizontal well could be used to produce the hydrocarbon while avoiding drilling through the $CO_2$ plume, or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available while the MAG 1 well is in operation, which will allow prospective operators to design an appropriate well control strategy via increased

drilling mud weight. Pressure increase in the Broom Creek caused by injection of $CO_2$ will relax postinjection as the area returns to its preinjection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the $CO_2$ should be designed to include an intermediate casing string placed across the storage reservoir, with $CO_2$-resistant cement used to anchor the casing in place.

Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC § 57-51-01(11)) define a shallow gas zone as gas produced from a zone that consists of "strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation [Jurassic], from which gas may be produced."

Lignite coal is currently mined at the Falkirk Mine, operated by the Falkirk Mining Company, a wholly owned subsidiary of North American Coal Corporation, which is located within the project area. The Falkirk Mine produces from the Hagel coal seam for power generation feedstock at Rainbow Energy's Coal Creek Station. The Hagel coal seam is the lowermost major lignite present in the area in the Sentinel Butte Formation (Figure 2-71).

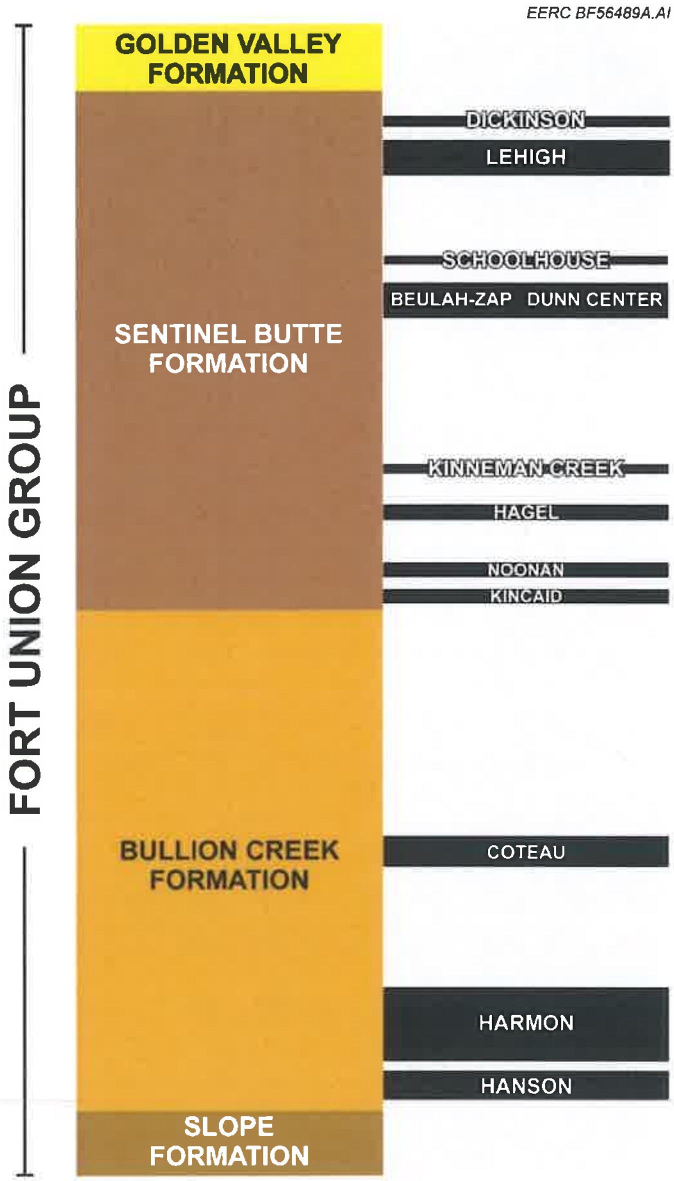



Figure 2-71. Coal beds of the Sentinel Butte and Bullion Creek (Tongue River) Formations showing the lignite coals in western North Dakota (Zygarlicke and others, 2019).

The Hagel coal seam is divided into two seams: the Hagel A and the Hagel B. The Hagel A lignite bed averages 5.7 ft thick with a range from 0.5 to 11.5 ft. The Hagel B bed has a mean thickness of approximately 1.8 ft, ranging in thickness from 0.5 to 6.3 ft. (Figure 2-72) (Zygarlicke and others, 2019). Coal seams in the Bullion Creek Formation exist in the area below the Hagel seam (Figure 2-71) but are too deep to be economically mined.

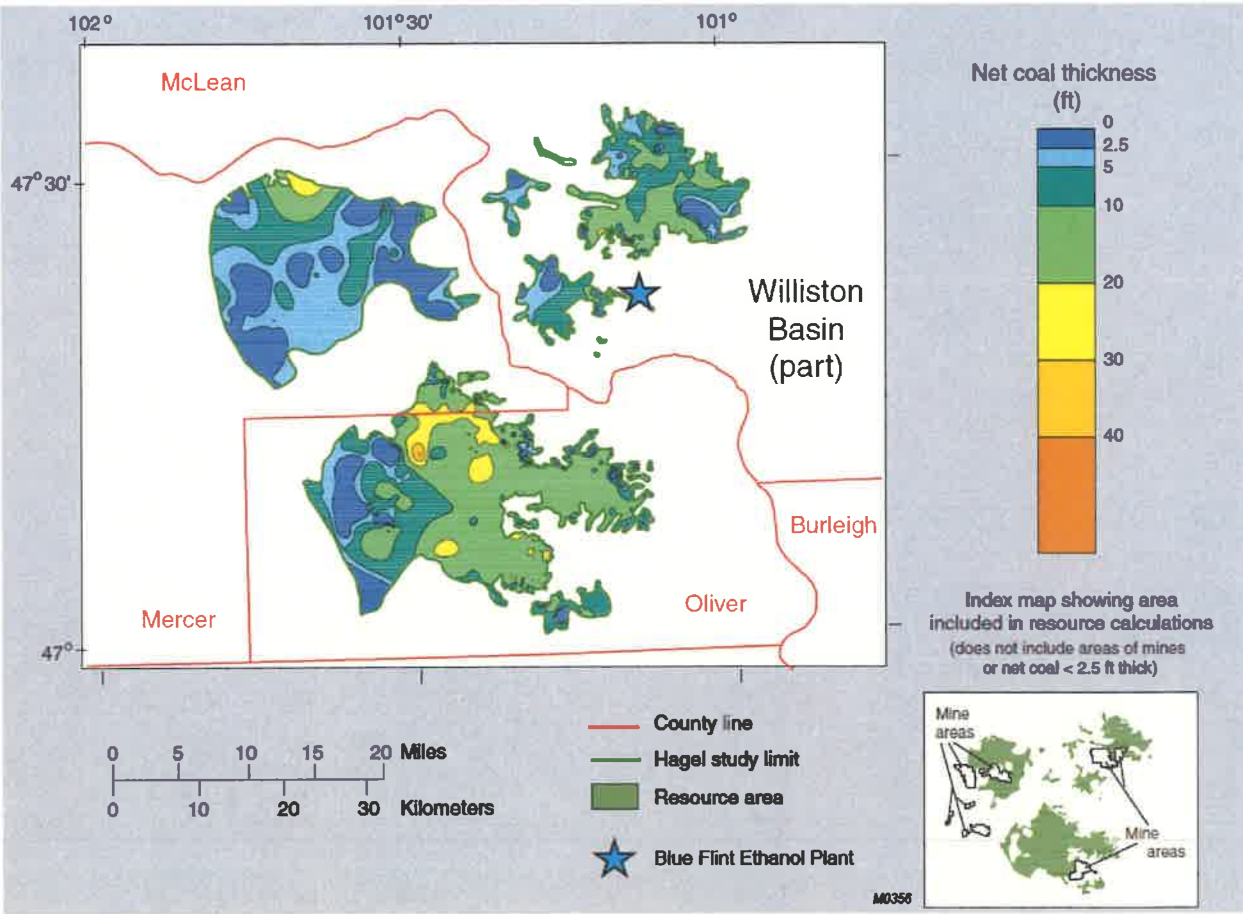



Figure 2-72. Hagel net coal isopach map (modified from Ellis and others, 1999).

## 2.7 References


Aadnoy, B.S., 1990, Inversion technique to determine the in-situ stress field from fracturing data: Journal of Petroleum Science and Engineering, v. 4, no. 2, p. 127–141.

Aadnoy, B.S., and Bell, J.S., 1998, Classification of drilling-induced fractures and their relationship to in-situ stress directions: The Log Analyst, v. 39, no. 6, p. 27–42.

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

Brudy, M., and Zoback, M.D, 1999, Drilling-induced tensile wall-fractures: implications for determination of in-situ stress orientation and magnitude: International Journal of Rock

Mechanics and Mining Sciences, v. 36, no. 2, p. 191–215. doi:10.1016/s0148-062(98)00182 -x.

Carlson, C.G., 1993, Permian to Jurassic redbeds of the Williston Basin: North Dakota Geological Survey Miscellaneous Series 78, 21 p.

Downey, J.S., 1986, Geohydrology of bedrock aquifers in the northern Great Plains in parts of Montana, North Dakota, South Dakota and Wyoming: U.S. Geological Survey Professional Paper 1402-E, 87 p.

Downey, J.S., and Dinwiddie, G.A., 1988, The regional aquifer system underlying the northern Great Plains in parts of Montana, North Dakota, South Dakota, and Wyoming—summary: U.S. Geological Survey Professional Paper 1402-A.

Ellis, M.S., Gunther, G.L., Ochs, A.M., Keighin, C.W., Goven, G.E., Schuenemeyer, J.H., Power, H.C., Stricker, G.D., and Blake, D., 1999, Coal resources, Williston Basin: U.S. Geological Survey Professional Paper 1625-A, Chapter WN.

Espinoza, D.N., and Santamarina, J.C., 2017, $CO_2$ breakthrough—caprock sealing efficiency and integrity for carbon geological storage: International Journal of Greenhouse Gas Control, v. 66, p. 218–229.

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

Glazewski, K.A., Grove, M.M., Peck, W.D., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2015, Characterization of the PCOR Partnership Region: Plains $CO_2$ Reduction (PCOR) Partnership topical report for U.S. Department of Energy and multiclients, Grand Forks, North Dakota, Energy & Environmental Research Center, January.

Murphy, E.C., Nordeng, S.H., Juenker, B.J., and Hoganson, J.W., 2009, North Dakota stratigraphic column, E.C. Murphy and L.D. Helms, Eds., North Dakota Geological Survey, Bismarck, North Dakota.

North Dakota Industrial Commission, 2022, Overview of petroleum geology of the North Dakota Williston Basin: www.dmr.nd.gov/ndgs/resources/ (accessed July 2022).

North Dakota Industrial Commission, 2021a, NDIC Case No. 29029 – draft permit, fact sheet, and storage facility permit application: Minnkota Power Cooperative supplemental information, Grand Forks, North Dakota, www.dmr.nd.gov/oilgas/C29029.pdf (accessed July 2022).

North Dakota Industrial Commission, 2021b, NDIC Case No. 29032 – draft permit, fact sheet, and storage facility permit application: Minnkota Power Cooperative supplemental information, Grand Forks, North Dakota, www.dmr.nd.gov/oilgas/C29032.pdf (accessed July 2022).

North Dakota Industrial Commission, 2021c, NDIC Case No. 28848 – draft permit, fact sheet, and storage facility permit application: Red Trail Ethanol, LLC, supplemental information, www.dmr.nd.gov/oilgas/C28848.pdf (accessed July 2022).

Nowakowski, A., 2005, The static and dynamic elasticity constants of sandstones and shales from the hard coal mine "Jasmos" determined in the laboratory conditions, *in* Eurock 2005 – impact of human activity on the geologic environment: Konecy, Taylor & Francis Group, London, Eds.

Peck, W.D., Liu, G., Klenner, R.C.L., Grove, M.M., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2014, Storage capacity and regional implications for large-scale storage in the basal Cambrian system: Plains $CO_2$ Reduction (PCOR) Partnership Phase III Task 16 Deliverable D92 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2014-EERC-05-12, Grand Forks, North Dakota, Energy & Environmental Research Center, https://edx.netl.doe.gov/dataset/storage-capacity-and-regional-implications-for-large-scale-storage-in-the-basal-cambrian-system (accessed 2022).

Plumb, R.A., and Hickman, S.H., 1985, Stress-induced borehole elongation—a comparison between the four-arm dipmeter and the borehole televiewer in the Auburn Geothermal Well: Journal of Geophysical Research Atmospheres, v. 90, p. 5513–5521.

Rygh, M.E., 1990, The Broom Creek Formation (Permian), in southwestern North Dakota—depositional environments and nitrogen occurrence [Master's Thesis]: University of North Dakota, Grand Forks, North Dakota.

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

Tutuncu, A.N., and Sharma, M.M., 1992, Relating static and ultrasonic lab measurements to acoustic log measurements in tight gas sands: Presented at 67th SPE ATCE, Washington, D.C., October 1998. SPE-24689.

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

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

Yale, D.P., and Jamieson, W.H. Jr., 1994, Static and dynamic mechanical properties of carbonates, *in* Rock Mechanics – Models and Measurements Challenges from Industry: Nelson and Laubach, Eds., Balkema, Rotterdam.

Yale, D.P., and Walters, D.A., 2016, Integrated, logbased, anisotropic geomechanics analysis in unconventional reservoirs: Presented at SPE Unconventional Reservoir Fracturing Workshop, Muscat, Oman, February 2016.

Yale, D.P., Nieto, J.A., and Austin, S.P., 1995, The effect of cementation on the static and dynamic mechanical properties of the Rotliegendes sandstone, *in* Rock Mechanics – Proceedings of the 35th U.S. Symposium: Daemen and Schultz, Eds., Balkema, Rotterdam.

Zhang, J.J., and Bentley, L.R., 2005, Factors determining Poisson's ratio: CREWES Research Report, v. 17.

Zhang, J., and Yin. S.-X., 2017, Fracture gradient prediction—an overview and an improved method: Petroleum Science, v. 14, no. 4, p. 720–730. DOI 10.1007/s12182-017-0182-1.

Zhou, X.J., Zeng, Z., and Belobraydic, M., 2008, Geomechanical stability assessment of Williston Basin Formations for petroleum production and $CO_2$ sequestration: Presented at the 42nd U.S. Rock Mechanics Symposium and 2nd U.S.–Canada Rock Mechanics Symposium, San Francisco, California, June 29 – July 2, 2008.

Zygarlicke, C.J., Folkedahl, B.C., Nyberg, C.M., Feole, I.K., Kurz, B.A., Theakar, N.L., Benson, S.A., Hower, J., and Eble, C., 2019, Rare-earth elements (REEs) in U.S. coal-based resources—20 sampling, characterization, and round-robin interlaboratory study: Final Report for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0029007, EERC Publication 2019-EERC-09-08, Grand Forks, North Dakota, Energy & Environmental Research Center, September.

# 3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF $CO_2$ INJECTION

# 3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF $CO_2$ INJECTION

## 3.1 Introduction

Multiple sets of publicly available and newly acquired site-specific subsurface data were analyzed and interpreted (Section 2.2). The data and interpretations were used as inputs to Schlumberger's Petrel software (Schlumberger, 2020) to construct a geologic model of the injection zone: the Broom Creek Formation, the upper confining zone: the lower Piper and Spearfish Formations, and the lower confining zone: the Amsden Formation. The geologic model encompasses a 76-mile × 72-mile area around the proposed storage site to characterize the geologic extent, depth, and thickness of the subsurface geologic strata (Figure 2-3). Geologic properties were distributed within the 3D model, including lithofacies, porosity, and permeability.

The geologic model and properties served as inputs for numerical simulations of $CO_2$ injection using Computer Modelling Group Ltd.'s (CMG's) GEM software (Computer Modelling Group Ltd., 2019). Numerical simulations of $CO_2$ injection were conducted to assess potential $CO_2$ injection rate, disposition of injected $CO_2$, wellhead pressure (WHP), bottomhole pressure (BHP), and pressure changes in the storage reservoir throughout the expected injection time frame and postinjection period. Results of the numerical simulations were then used to determine the project's area of review (AOR) pursuant to North Dakota's geologic $CO_2$ storage regulations.

## 3.2 Overview of Simulation Activities

### *3.2.1 Modeling of the Injection Zone and Overlying and Underlying Seals*

A geologic model was constructed to characterize the injection zone and upper and lower confining zones. Activities included data aggregation, structural framework creation, data analysis, and property distribution. Major inputs for the geologic model included geophysical logs from nearby wells and core sample measurements, which acted as control points during the distribution of the geologic properties throughout the modeled area, and seismic survey data. The geologic properties distributed throughout the model include the effective porosity, permeability, and lithofacies.

Because of the uncertainty in sonic log values related to washouts in the Broom Creek Formation in the MAG 1 well, inversion results of the site-specific 3D seismic data were not used to inform property distribution in the geologic model. Instead, publicly available variograms reported in the Tundra SGS (secure geologic storage) facility permit were used to inform the distribution of the lithofacies and petrophysical properties in the geologic model. The variograms reported in the Tundra SGS (secure geologic storage) facility permit were selected as they provide a generalized representation of the property distributions expected within the Broom Creek Formation (North Dakota Industrial Commission, 2021).

### *3.2.2 Structural Framework Construction*

Schlumberger's Petrel software was used to interpolate structural surfaces for the lower Piper (Picard Member), Spearfish, Broom Creek, and Amsden Formations. Input data included formation top depths from the online North Dakota Industrial Commission (NDIC) database; core data collected from the MAG 1, Flemmer 1, ANG 1, J-LOC 1, and BNI-1 wells (Figure 2-4); and two 3D seismic surveys (Figure 2-3) conducted at the Flemmer 1 and MAG 1 wellsites. The interpolated data were used to constrain the model extent in 3D space.

### *3.2.3 Data Analysis and Property Distribution*

#### *3.2.3.1 Confining Zones (lower Piper, Spearfish, and Amsden Formations)*

The upper confining zone (lower Piper and Spearfish Formations), and the lower confining zone (Amsden Formation) were each assigned a single lithology, based on their primary lithology determined by well log analysis to be siltstone and dolostone, respectively. Porosity and permeability logs were upscaled from a well log scale to the scale of the geologic model grid to serve as control points for property distributions. The control points were used in combination with the publicly available variograms and Gaussian random function simulation algorithms to distribute the properties. A 3,000-ft-major and minor axis length variogram model in the lateral direction and a 6-ft vertical variogram length were used within the lower Piper Formation. The variogram used within the Spearfish Formation was the same as the one used for the lower Piper Formation, except the lateral variogram is a 4,000-ft-diameter circle. A major axis length of 6,000 ft and a minor axis length of 3,000 ft were used for the Amsden Formation along an azimuth of 155° with a vertical variogram of 5 ft.

#### *3.2.3.2 Injection Zone (Broom Creek Formation)*

Prior variogram assessments completed for use in a similar storage facility permit application, the Tundra SGS $CO_2$ storage project, were used to assign variogram ranges within the injection zone. Variogram mapping investigations, as noted in the Tundra SGS application, investigated the size and shape of variograms in several different azimuthal directions, which indicated that geobody structures with the following dimensions were present in the Broom Creek Formation: major axis range of 5,000 ft, minor axis range of 4,500 ft, and an azimuth of 155° (NDIC, 2021). Well logs recorded from the MAG 1 wellbore served as the basis for deriving a vertical variogram length of 7 ft. The variogram ranges were used to distribute lithofacies and petrophysical properties.

Lithofacies classifications were interpreted from well log data and correlated with descriptions of core taken from the MAG 1, BNI-1, J-LOC 1, Flemmer 1, and ANG 1 wells. Four lithofacies were identified within the Broom Creek Formation: 1) sandstone, 2) dolostone, 3) dolomitic sandstone, and 4) anhydrite. Lithofacies logs were generated from gamma ray, density, neutron porosity, and resistivity logs. The lithofacies logs were upscaled to the resolution of the 3D model to serve as control points for geostatistical distribution using sequential indicator simulation (Figure 2-13 and Figure 3-1).

Prior to distributing the porosity and permeability properties, total porosity (PHIT), effective porosity (PHIE), and permeability (KNIT) well logs were estimated and compared with core porosity and permeability measurements to ensure good agreement with the five wells: MAG 1, Flemmer 1, J-LOC 1, BNI-1and ANG 1.

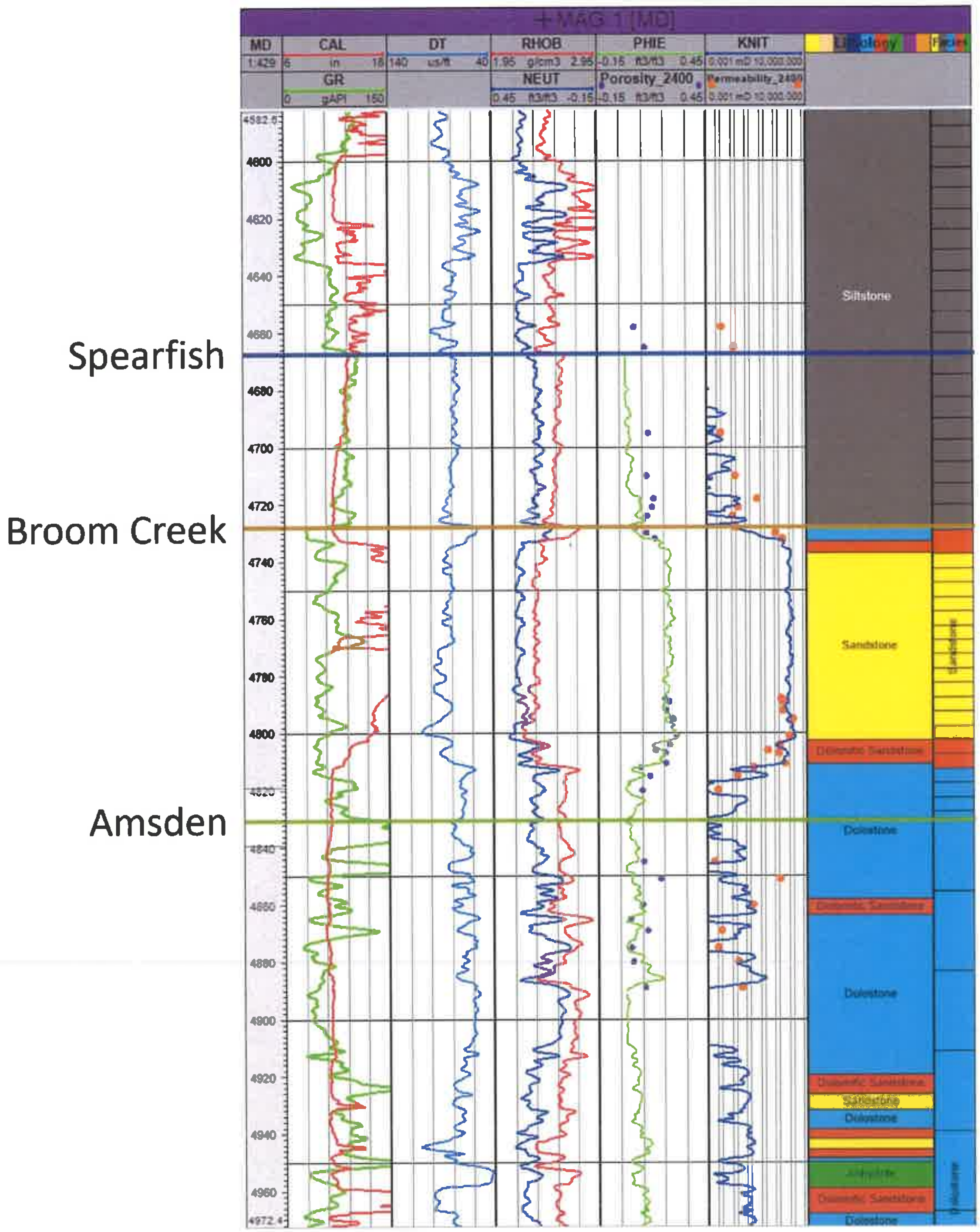



Figure 3-1. Lithofacies classification in MAG 1 well. Well logs displayed in tracks from left to right are 1) gamma ray (green) and caliper (red), 2) delta time (light blue), 3) neutron porosity (blue) and density (red), 4) effective porosity (green) and core sample porosity (purple dots), 5) predicted intrinsic permeability (blue) and core sample permeability (orange dots), 6) interpreted lithology, and 7) upscaled lithology.

A PHIE property (effective porosity; total porosity less occupied or isolated pore space) was distributed using calculated PHIE well logs, upscaled to the resolution of the 3D model as control points and variogram structures described previously with Gaussian random function simulation and conditioned to the distributed lithofacies. A permeability property was distributed using the same variables and algorithm but cokriged to the PHIE volume (Figures 3-2 and 3-3).

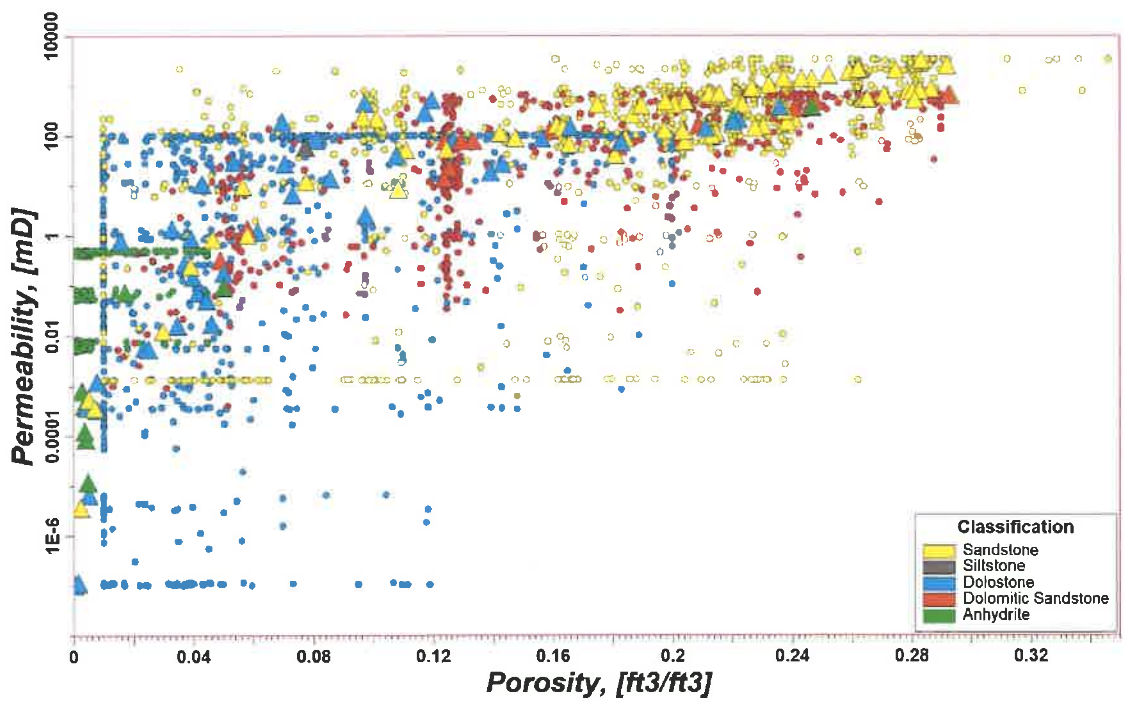



Figure 3-2. Illustration of the relationship between the modeled porosity and permeability. Upscaled well log values are represented by triangles, while circles represent distributed values. Values are colored according to lithofacies classification, as seen in Figure 3-3.

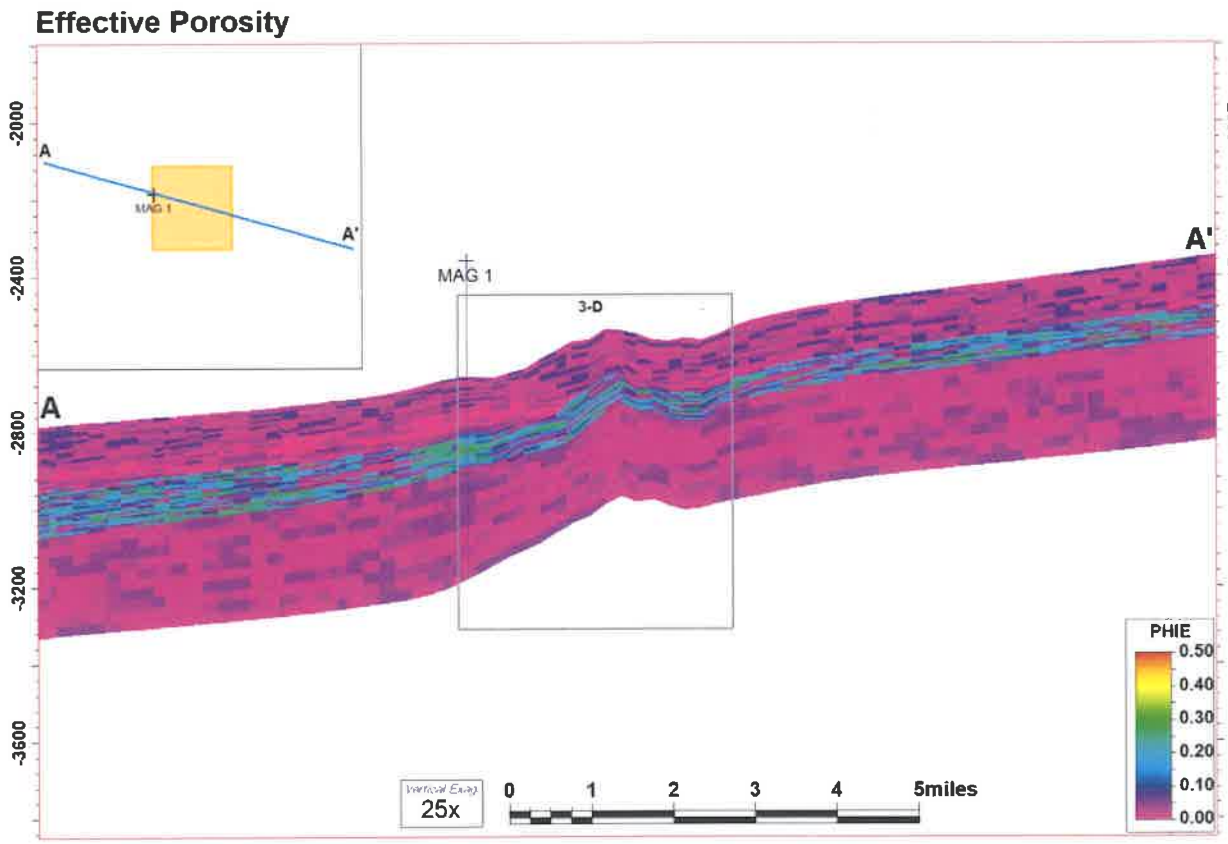



Figure 3-3. Distributed PHIE property along a northwest–southeast cross section. The distributed PHIE property was used to distribute permeability throughout the model. Units on the y-axis represent feet below mean sea level (25× vertical exaggeration shown).

## 3.3 Numerical Simulation of $CO_2$ Injection

### *3.3.1 Simulation Model Development*

Numerical simulations of $CO_2$ injection into the Broom Creek Formation were conducted using the geologic model described above. Simulations were carried out using CMG GEM, a compositional reservoir simulation module. Both measured temperature and pressure, along with the reference datum depth, were used to initialize the reservoir equilibrium conditions for performing numerical simulation. Figure 3-4 displays a 2D view of the simulation model with the permeability property and MAG 1 injection well.

The simulation model boundaries were assigned infinite-acting conditions along the western and southern boundaries and partially closed along the northern and eastern boundaries, as the Broom Creek Formation partially pinches out in the northern and eastern parts of the modeled area. The reservoir was assumed to be 100% brine-saturated with a measured initial formation salinity of 28,600 mg/L total dissolved solids (TDS) (Table 3-1).

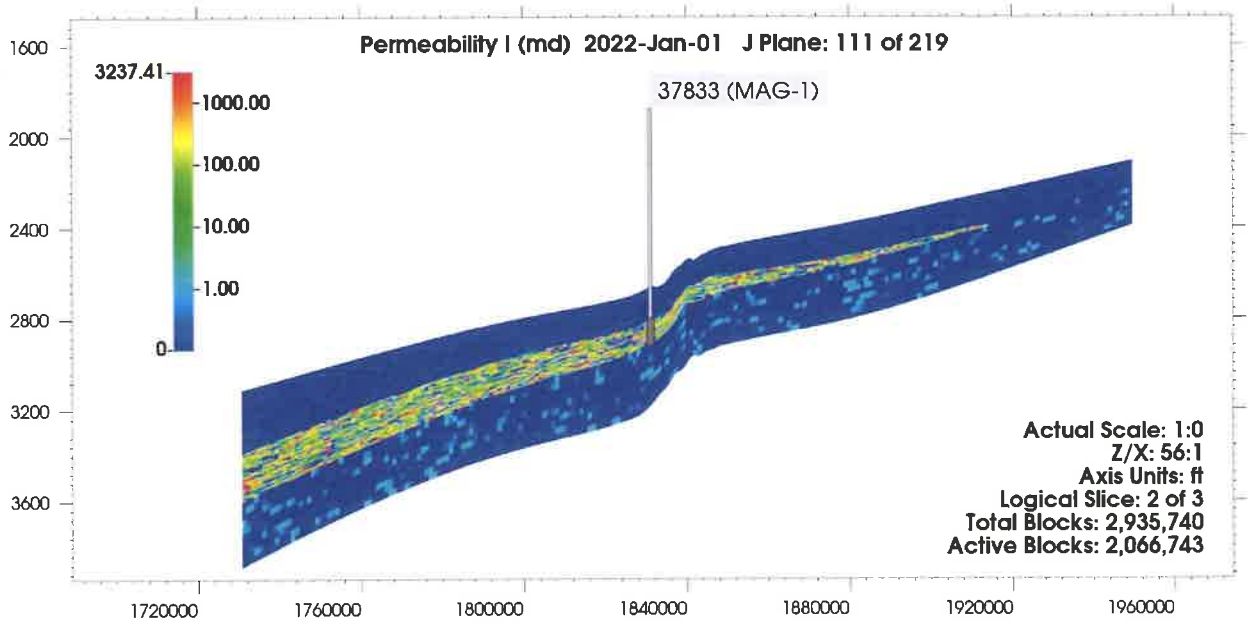



Figure 1-4. Cross-sectional view of the simulation model with the permeability property and injection well displayed. The low-permeability layers (blue) at the top and bottom of the figure should be noted. These layers represent the lower Piper and Spearfish Formations (upper confining zone) and the Amsden Formation (lower confining zone). The varied permeability of the Broom Creek Formation is shown between these layers.

**Table 3-1. Summary of Reservoir Properties in the Simulation Model**

| Formation | Average Permeability, mD | Average Porosity, % | Initial Pressure, $P_i$, psi | Salinity, mg/L | Boundary Condition |
|---|---|---|---|---|---|
| Spearfish | 0.068 | 5.1 | 2,448.8 (at 4,782.7 ft MD[1]) | 28,600 | Partially infinite |
| Broom Creek | 629.5 | 22.6 | | | |
| Amsden | 18.4 | 7.8 | | | |

[1] Measured depth.

Numerical simulations of $CO_2$ injection performed allowed $CO_2$ to dissolve into the native formation brine. Mercury injection capillary pressure (MICP) data for the Spearfish, Broom Creek, and Amsden Formations were used to generate relative permeability and the capillary curves for the five representative lithofacies in the simulation model (sandstone, siltstone, dolomite, dolomitic sands, and anhydrite) (Figures 3-6–3-8). Samples tested within the Spearfish, Broom Creek, and Amsden Formations included siltstone, sandstone, and dolomite lithologies. The siltstone (Spearfish) and dolomite (Amsden) values were assigned to anhydrite and dolomitic sandstone lithofacies, respectively, for both capillary entry pressure and relative permeability, as there were no available samples of these rock types from the MICP calculations. The main reason is both siltstone and anhydrite represent low perm facies. As for the dolomitic sandstone, the

dolomite relative permeability data was used because the dolomitic sandstones within the Broom Creek Formation are expected to be more similar to dolomite rather than to sandstone. Anhydrite and dolomitic sandstone facies intervals in the reservoir are sparse and very thin; therefore, these relative permeability assumptions are not expected to impact injectivity or $CO_2$ plume extent (Figure 3-5). Figure 3-5 shows the facies distribution in the simulation model. Please note the red and yellow colors represent the anhydrite (red) and dolomitic sandstone (yellow), respectively and these facies barely exist around the injection point.

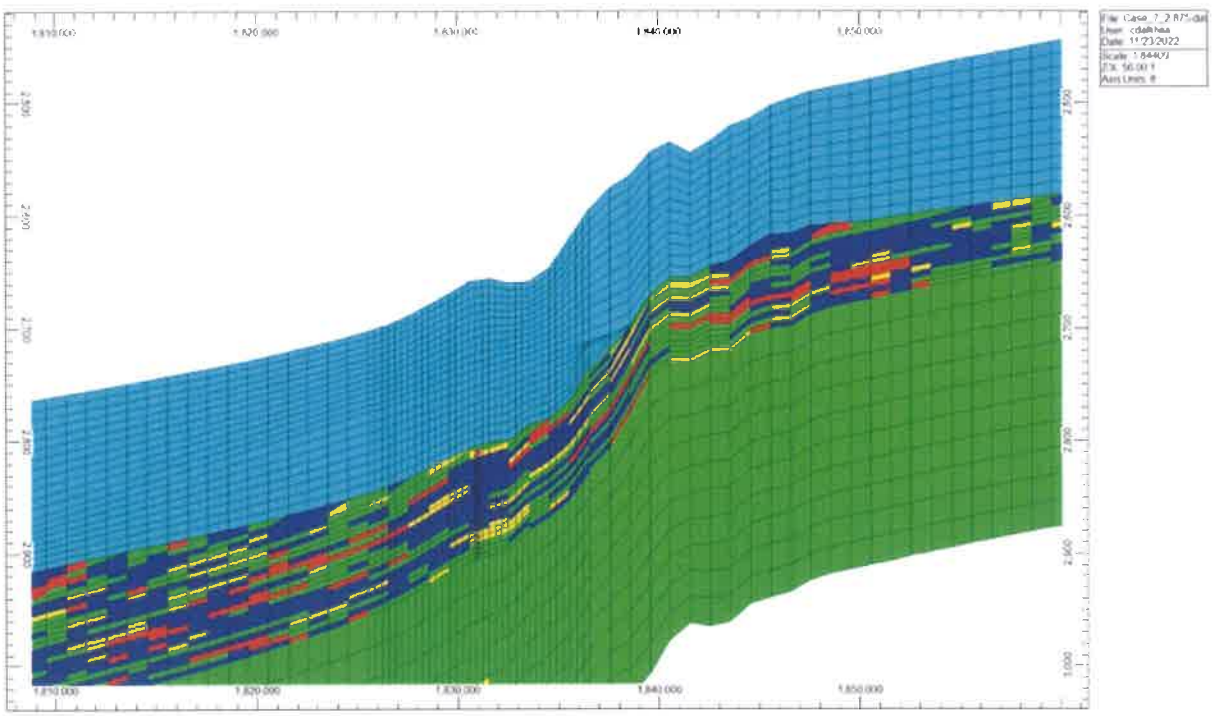
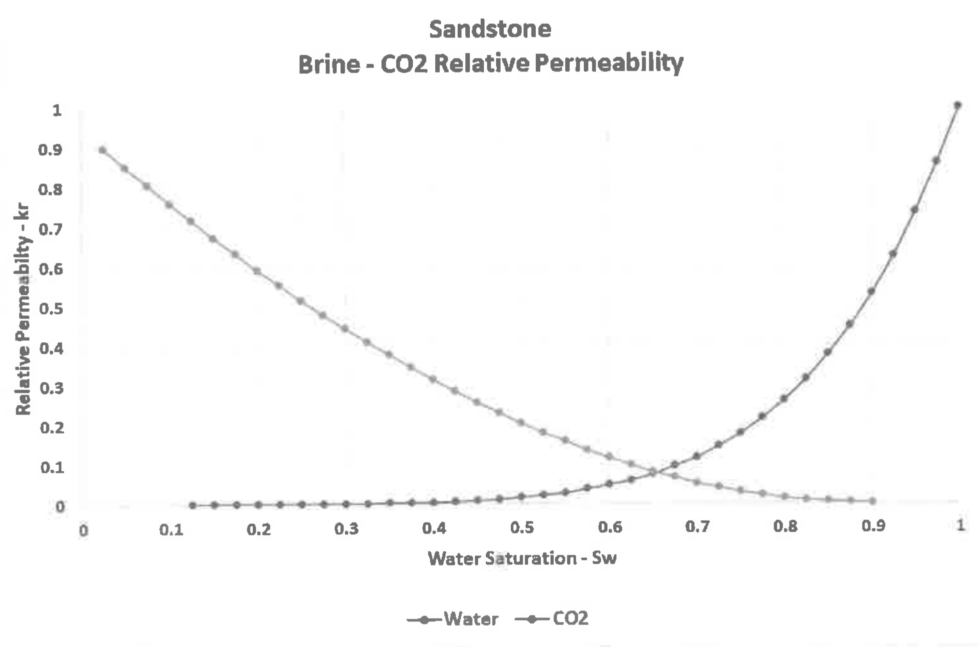


Figure 3-5. Facies distributions in the simulation model. Low permeability indicated by the color teal is siltstone. Other facies representations in the model are red representing anhydrite, yellow representing dolomitic sandstone, blue representing sandstone, and green representing dolomite.



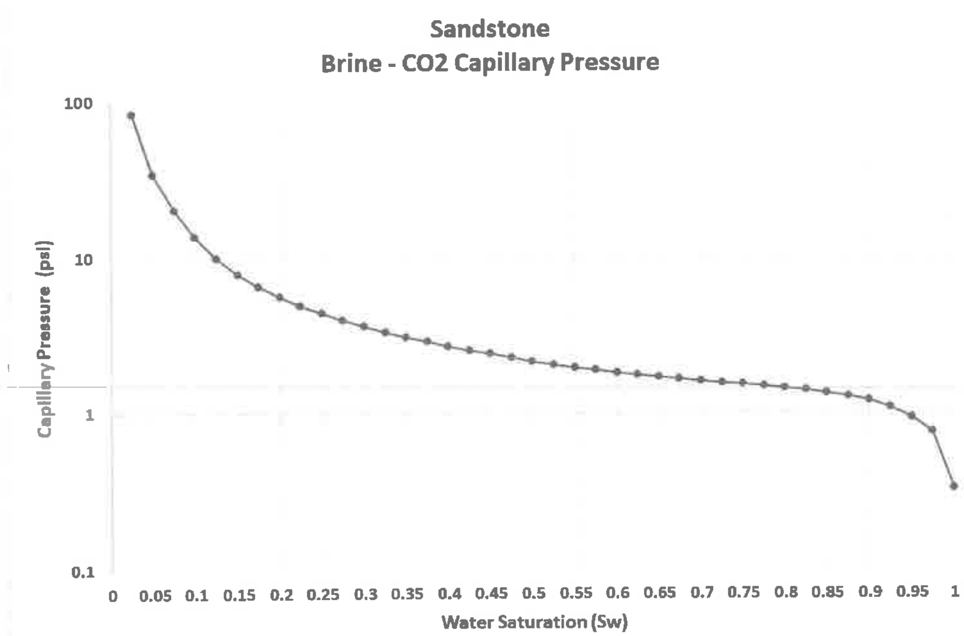




Figure 3-6. Relative permeability (top) and capillary pressure curves (bottom) for the sandstone rock type in the Broom Creek Formation.

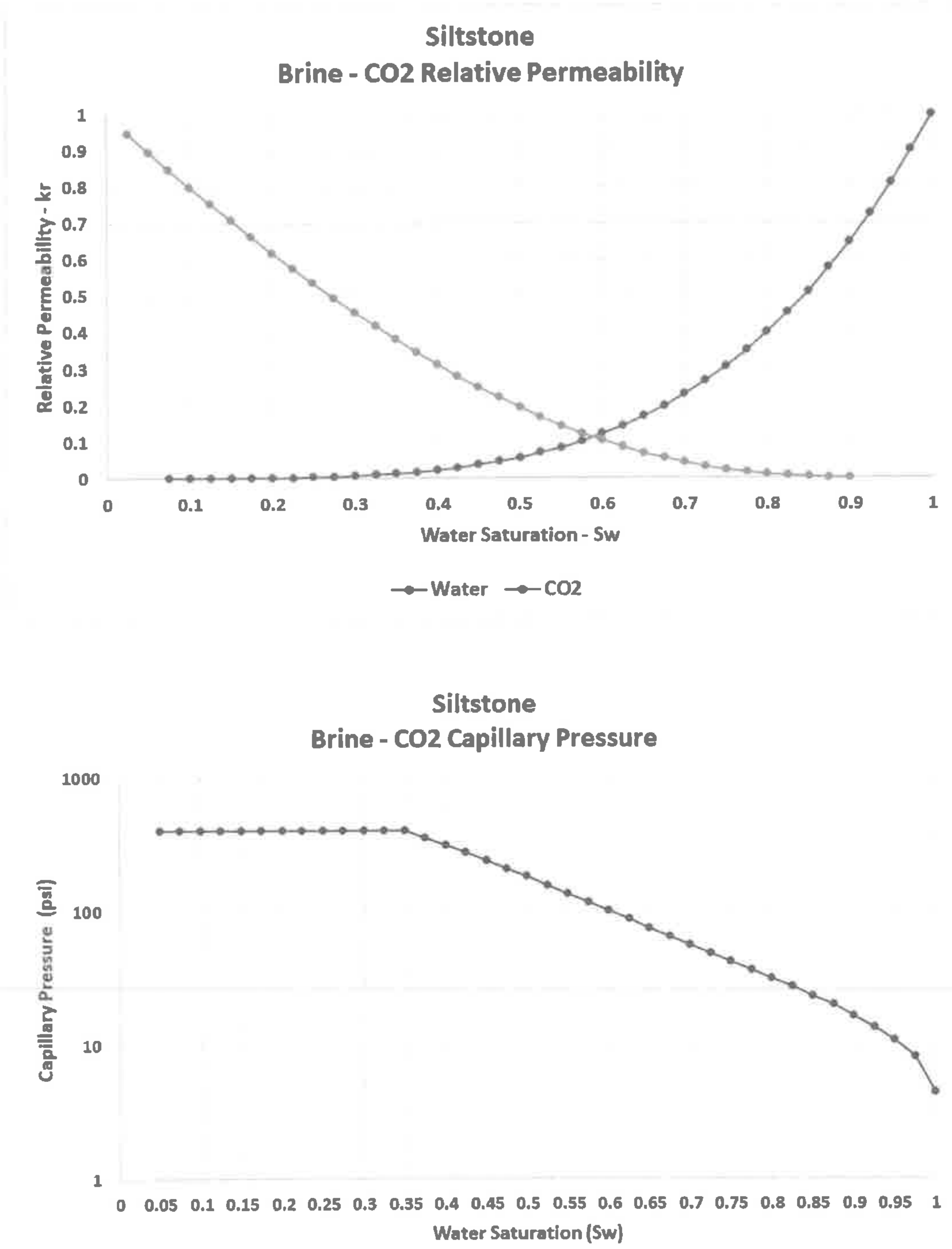



Figure 3-7. Relative permeability (top) and capillary pressure curves (bottom) for the siltstone rock type in the Spearfish Formation.

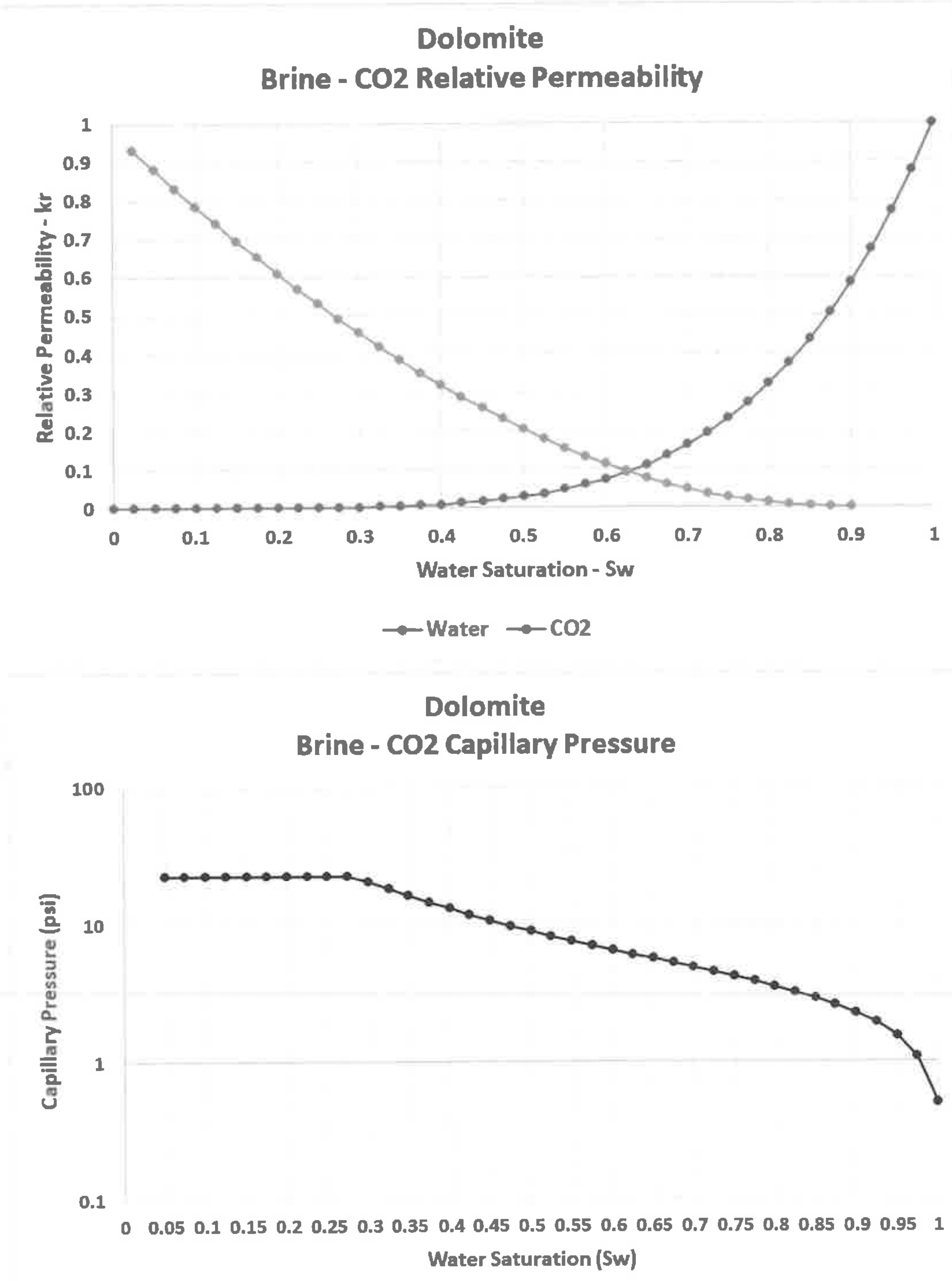



Figure 3-8. Relative permeability (top) and capillary pressure curves (bottom) for the dolomite rock type in the Amsden Formation.

Capillary pressure curves calculated from MICP data were modified to the model scale based on the permeability and porosity values of the simulation model and used in the numerical simulations. These modified capillary pressure curves are also shown in Figures 3-6–3-8. The capillary entry pressure values applied in the model were determined by deriving a ratio between the reservoir quality index of core samples and modeled properties to scale the capillary entry pressure value derived from core testing (Table 3-2).

Temperature and pressure data recorded in the MAG 1 wellbore were used to derive a temperature and pressure gradient to initialize the numerical simulation model for the proposed injection site. In combination with depth, a temperature gradient of 0.025°F/ft was used to calculate subsurface temperatures throughout the study area. A pressure reading recorded from the Broom Creek Formation was used to derive a pore pressure gradient of 0.512 psi/ft. The fracture gradient was obtained from a geomechanical analysis, resulting in an average of 0.69 psi/ft. The maximum allowable BHP of 2,970 psi was estimated to be 90% of the fracture gradient multiplied by the depth of the top perforation in the injection zone, the Broom Creek Formation, and used as the injection constraint in the numerical simulation of the expected injection scenario.

### *3.3.2 Sensitivity Analysis*

Because the availability of data for this study included well logs, core sample data, and rock–fluid properties, the need for typical sensitivity studies of influential reservoir parameters has been reduced. A preliminary sensitivity analysis made to the wellbore model parameters suggested, at the given injection volume rates and BHP conditions, the wellhead temperature played a prominent role in determining WHP response. Sensitivity simulations of different wellhead temperatures indicated that injection at a higher wellhead temperature would require a higher WHP. For evaluating the expected injection design, a wellhead temperature value of 60°F was chosen that most closely represents the expected operational temperature.

## 3.4 Simulation Results

The target injection rate of 200,000 tonnes per year (tpy) (548 tonnes per day) was consistently achievable over 20 years (Figure 3-9), translating to a cumulative 4 MMt of $CO_2$ injection (Figure 3-10). Simulations of $CO_2$ injection with the given well constraints, listed in Table 3-3, predicted the BHP would not reach the maximum BHP constraint of 2,970 psi (90% of the formation fracture pressure) as a result of injecting the target $CO_2$ volume of 200,000 tpy. The predicted maximum BHP and the average BHP during the 20 year injection period were 2,661 and 2,570 psi (Figure 3-11), respectively.

**Table 3-2. Core and Model Properties Showing the Multiplication Factor Used to Calculate Capillary Entry Pressure Used in the Simulation Model**

| | Core | | | | | Model | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Porosity (fraction) | Permeability, mD | Capillary Entry Pressure, A/Hg, psi | Capillary Entry Pressure B/$CO_2$, psi | Reservoir Quality Index | Porosity (fraction) | Permeability*, mD | Capillary Entry Pressure B/$CO_2$, psi | Reservoir Quality Index | Multiplication Factor |
| **Spearfish** | 0.125 | 0.028 | 58.3 | 12.245 | 0.015 | 0.051 | 0.068 | 5.018 | 0.036 | 0.410 |
| **Broom Creek** | 0.238 | 129 | 4.16 | 0.867 | 0.731 | 0.226 | 629.500 | 0.382 | 1.657 | 0.441 |
| **Amsden** | 0.096 | 0.011 | 126 | 26.134 | 0.011 | 0.078 | 18.400 | 0.576 | 0.482 | 0.022 |

* Pore volume weighted average

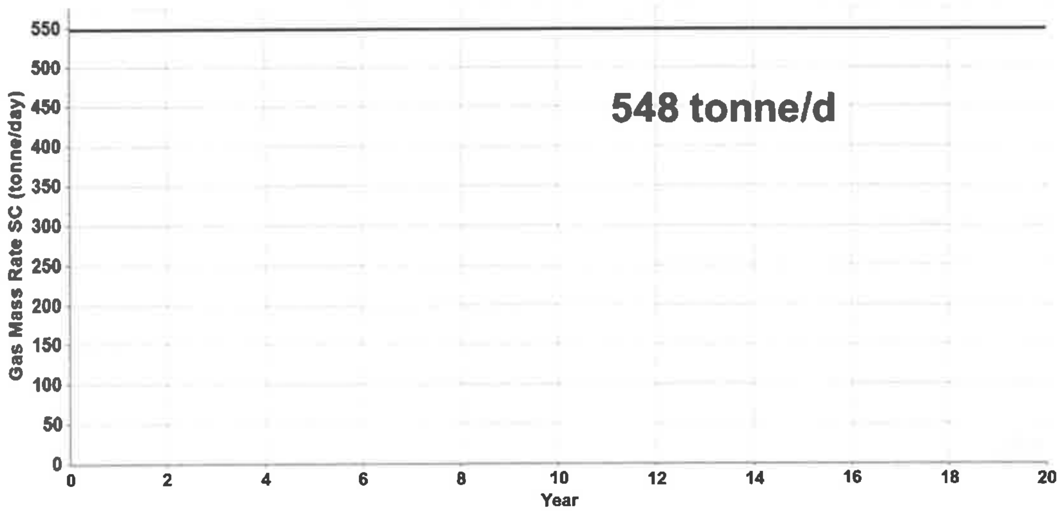



Figure 3-9. Mass injection rate over 20 years of injection with the expected injection rate.

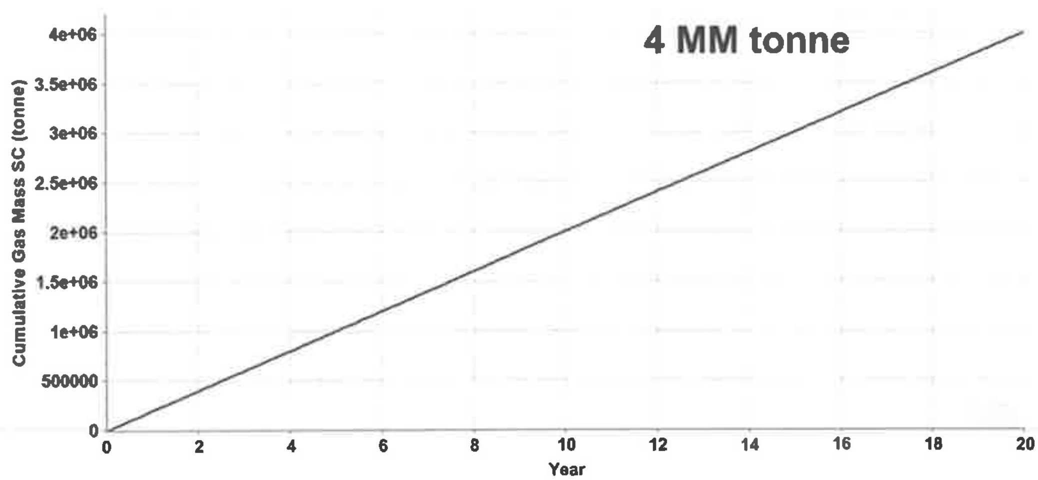



Figure 3-10. Cumulative injected gas mass over 20 years of injection with the expected injection rate.

**Table 3-3. Well Constraints and Wellbore Model in the Simulation Model**

| Injection rate | Well Constraint, maximum BHP | Tubing Size | Wellhead Temperature | Downhole Temperature |
|---|---|---|---|---|
| 200,000 tonnes/year for 20 years | 2,970 psi | 2.875 in. | 60°F | 119.6°F |

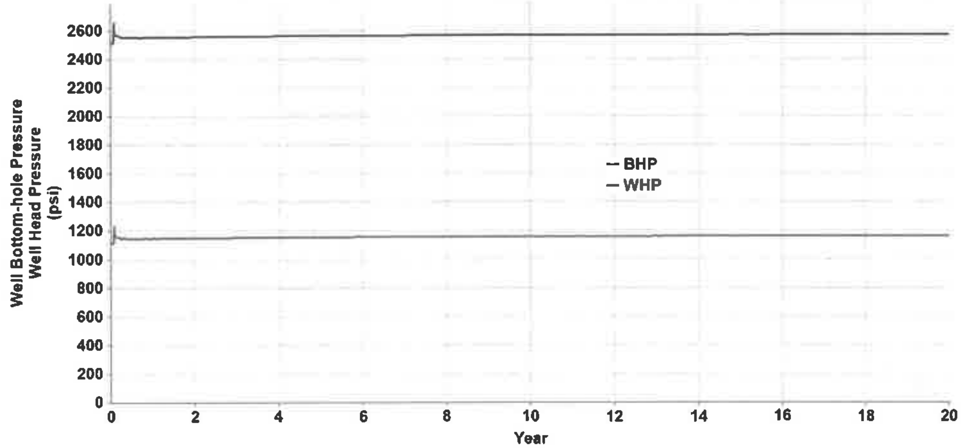



Figure 3-11. WHP and BHP response with the expected injection rate.

WHP depends on several factors, including injection rate, injection tubing parameters (tubing size and relative toughness), and surface injection temperature. For the designed injection rate and tubing size of 2.875 in., the predicted maximum WHP and average WHP during the 20 year injection period were 1,236 and 1,158 psi (Figure 3-11), respectively.

During and after injection, supercritical $CO_2$ (free-phase $CO_2$) accounts for the majority of $CO_2$ observed in the modeled pore space. Throughout the injection operation, a portion of the free-phase $CO_2$ is trapped in the pore space through a process known as residual trapping. Residual trapping can occur as a function of low $CO_2$ saturation and inability to flow under the effects of relative permeability. $CO_2$ also dissolves into the formation brine throughout injection operations (and continues afterward), although the rate of dissolution slows over time. The free-phase $CO_2$ transitions to either residually trapped or dissolved $CO_2$ during the postinjection period, resulting in a decline in the mass of free-phase $CO_2$. The relative portions of supercritical, trapped, and dissolved $CO_2$ can be tracked throughout the duration of the simulation (Figure 3-12).

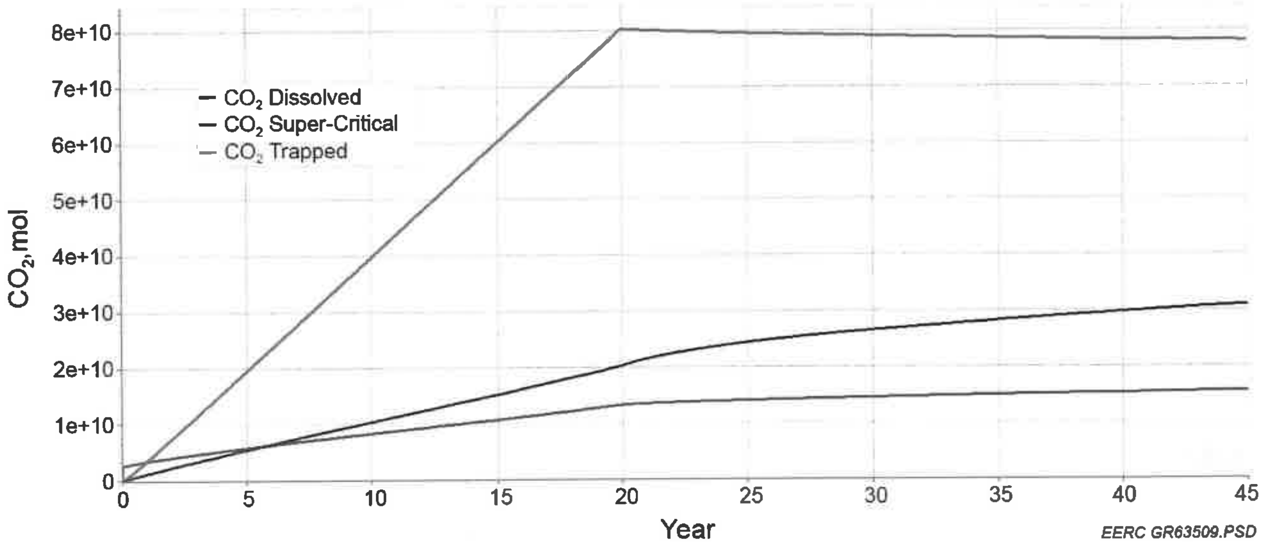



Figure 3-12. Simulated total super-critical free-phase $CO_2$, trapped $CO_2$, and dissolved $CO_2$ in brine.

The pressure front (Figure 3-13) shows the distribution of average pressure increase throughout the Broom Creek Formation after 1, 10, and 20 years of injection as well as 10 years postinjection (stabilization year). A maximum increase of 113.2 psi was estimated in the near-wellbore area at the end of the 20-year injection period.

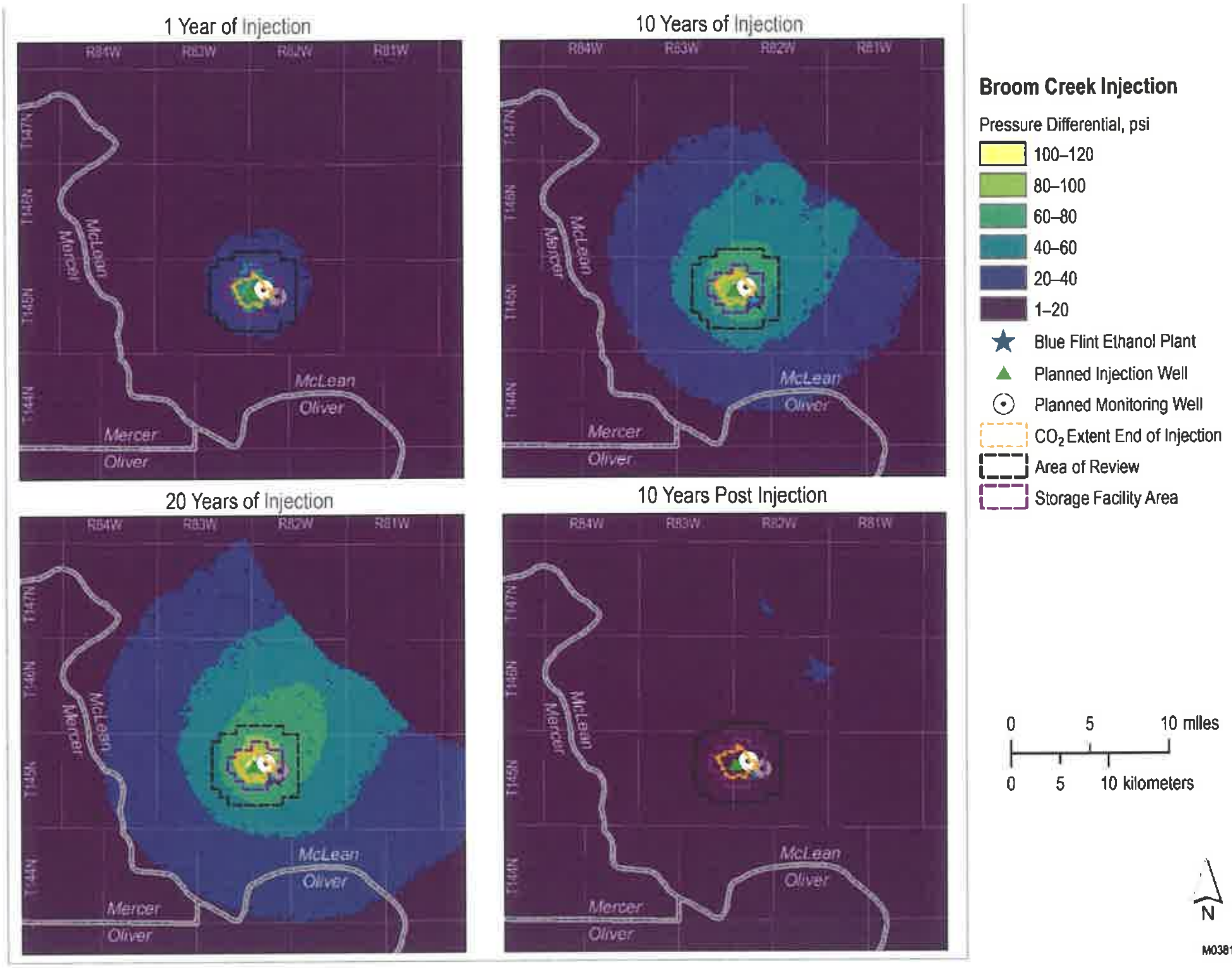



Figure 3-13. Top left, top right, and bottom left display average pressure increase within the Broom Creek Formation after 1, 10, and 20 years of simulated $CO_2$ injection operation. Bottom right displays pressure differential during 10 years of postinjection (plume stabilization year).

Long-term $CO_2$ migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase $CO_2$ injected into the formation rises to the bottom of the upper confining zone or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of $CO_2$ at the center which gradually spreads out toward the model edges where the $CO_2$ saturation is lower. Trapped $CO_2$ saturations, employed in the model to represent fractions of $CO_2$ trapped in small pores as immobile, tiny bubbles, ultimately immobilize the $CO_2$ plume and limit the plume's lateral migration and spreading. Figure 3-14 shows the $CO_2$ saturation at the injection well at the end of injection in north-to-south and east-to-west cross-sectional views.

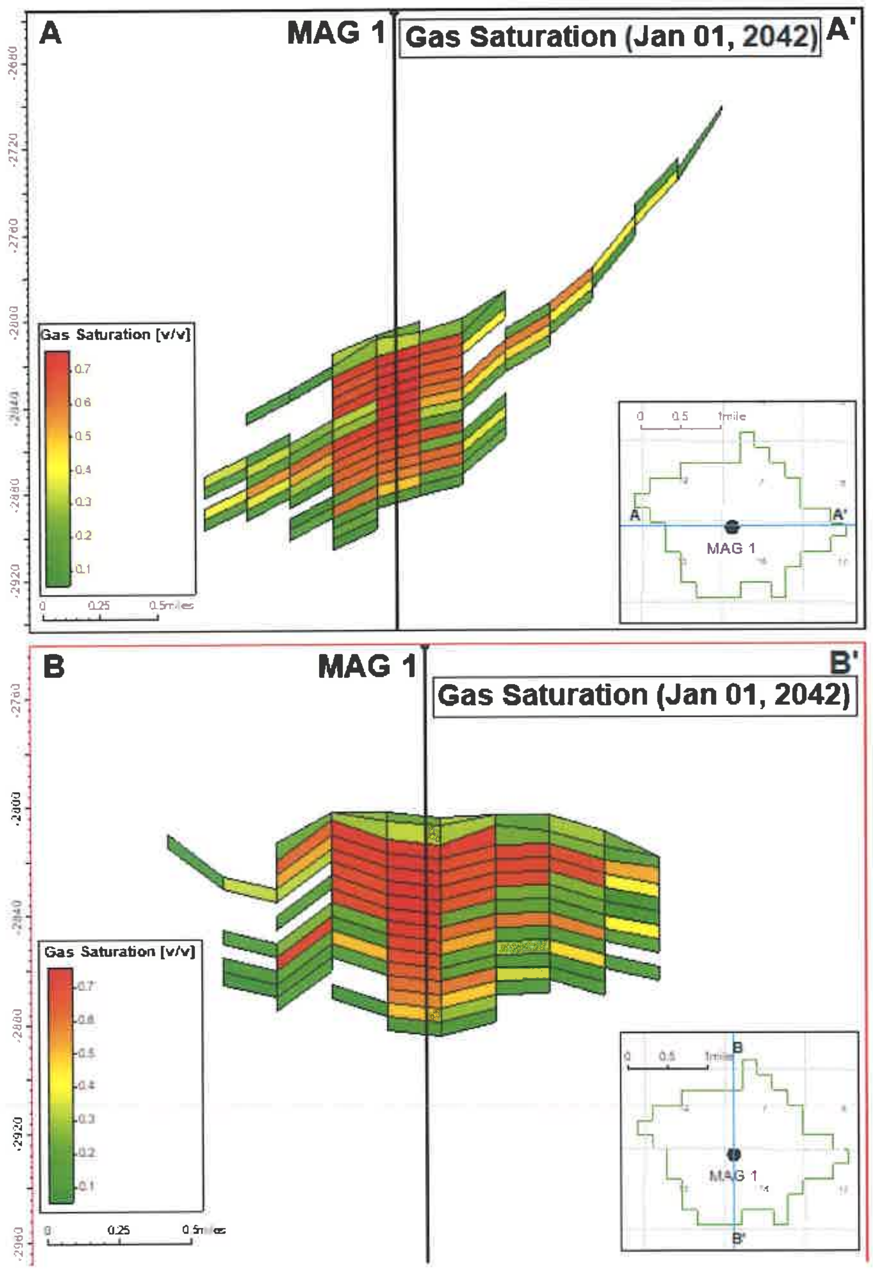



Figure 3-14. $CO_2$ plume cross section of MAG 1 at the end of injection displayed by a) west to east and b) north to south (50× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

### 3.4.1 *Maximum Injection Pressures and Rates*

An additional case was run to determine the maximum storage potential if the well was only limited by the maximum calculated downhole pressure of 2,970 psi (90% of the formation fracture pressure). In this scenario, the MAG 1 well was able to inject at a daily average rate of 2,729 tonnes/day of $CO_2$ with a 2.875-in. diameter tubing, achieving a total injection volume of 19.9 MMt of $CO_2$. The predicted average WHP, using the designed injection tubing of 2.875 inches, was 4,300 psi (Figure 3-15).

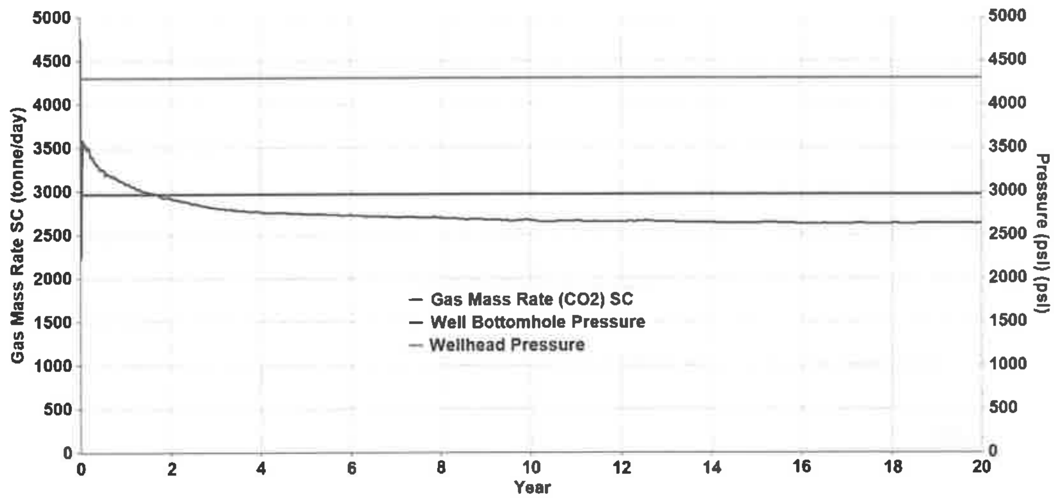



Figure 3-15. Maximum pressures and rate response when the well was operated without any injection rate limits.

### 3.4.2 *Stabilized Plume and Storage Facility Area*

Movement of the injected $CO_2$ plume is driven by the potential energy found in the buoyant force of the injected $CO_2$. As the plume spreads out within the reservoir and $CO_2$ is trapped residually through the effects of relative permeability and dissolution, the potential energy of the buoyant $CO_2$ is gradually lost. Eventually, the buoyant force of the $CO_2$ is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the $CO_2$ plume ceases to move within the subsurface and becomes stabilized. The extent of the stabilized plume is important for determining the project's AOR and the corresponding scale and scope of the project's monitoring plans.

Plume stabilization can be visualized at the microscale as $CO_2$ being unable to exit its current pore space and enter the neighboring pore space, but at the macroscale, these interactions cannot be measured. Instead, plume stabilization may be estimated using the tools available to predict the $CO_2$ plume's extent.

For the Blue Flint project the $CO_2$ plume was simulated in 5-year time steps until the rate of total areal extent change slowed to less than 0.15 square miles per 5-year time step to define the stabilized plume extent boundary (Figure 3-13) and the associated buffers and boundaries. This estimate is anticipated to be regularly updated during the $CO_2$ storage operation as data collected from the site are used to update predictions made about the behavior of the injected $CO_2$.

## 3.5 Delineation of the Area of Review

The North Dakota Administrative Code (NDAC) defines AOR as the region surrounding the geologic storage project where underground sources of drinking water (USDWs) may be endangered by $CO_2$ injection activity (NDAC § 43-05-01-05). The primary endangerment risk is the potential for vertical migration of $CO_2$ and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the $CO_2$ plume within the storage reservoir.

However, the $CO_2$ plume has an associated pressure front where $CO_2$ injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the $CO_2$ plume. Therefore, the AOR encompasses both the areal extent of the $CO_2$ plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the $CO_2$ plume, AOR delineation focuses on the pressure front.

The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the underground injection control (UIC) program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure.

In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), "potential thief zone" refers to the Inyan Kara Formation, and "lowest USDW" refers to the Fox Hills Formation.

### *3.5.1 EPA Methods 1 and 2: AOR Delineation for Class VI Wells*

EPA guidance for AOR evaluation includes several computational methods for estimating the pressure buildup in the storage reservoir in response to $CO_2$ injection and the resultant areal extent of pressure buildup above a "critical threshold pressure" that could potentially drive higher-salinity formation fluids from the storage reservoir up an open conduit to the lowest USDW (U.S. Environmental Protection Agency, 2013). The following equations and analytical approach define the EPA methods used to delineate AOR. Each method can be applied both at a single location (e.g., the MAG 1 stratigraphic well) using site-specific data or for each vertical stack of grid cells in a geocellular model, considering the varying stratigraphic thickness between storage reservoir and lowest USDW.

EPA Method 1 (*pressure front based on bringing the injection zone and USDW to equivalent hydraulic heads*) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW (U.S. Environmental Protection Agency, 2013).

Under Method 1, the maximum pressure increase that may be sustained in the injection zone (critical threshold pressure increase) is given by Equation 1:

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_I \qquad \text{[Eq. 1]}$$

Where:

$P_u$ is the initial fluid pressure in the USDW (Pa).
$\rho_i$ 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 ($\Delta P_c$), which is the fluid pressure increase sufficient to drive formation fluids into the lowermost USDW. This $\Delta P_c$ is determined using Equations 2 and 3, assuming 1) hydrostatic conditions, 2) initially linear densities in the borehole, and 3) constant density once the injection zone fluid Is lifted to the top of the borehole (i.e., uniform density approach):

$$\Delta P_C = \frac{1}{2} g \, \xi \, (Z_u - Z_i)^2 \qquad \text{[Eq. 2]}$$

Where $\xi$ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{Z_u - Z_i} \qquad \text{[Eq. 3]}$$

Where:

$\Delta P_c$ is the critical threshold pressure increase (Pa).
$g$ is the acceleration of gravity (m/s$^2$).
$z_u$ is the elevation of the base of the lowermost USDW (m amsl).
$z_i$ is the elevation of the top of the injections zone (m amsl).
$P_i$ is the fluid density in the injection zone (kg/m$^3$).
$P_u$ is the fluid density in the USDW (kg/m$^3$).

### *3.5.2 Risk-Based AOR Delineation*

The methods described by EPA (2013) for estimating the AOR under the Class VI rule (40 U.S. Code of Federal Regulations [CFR] 146.81 et seq.) were developed assuming that the storage

reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and potentially elsewhere around the United States, candidate storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW, even prior to the planned storage project. Consequently, applying EPA (2013) methods to these geologic situations essentially results in an infinite AOR, which makes regulatory compliance infeasible.

Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer and others (2014) described the unnecessary conservatism in EPA's definition of critical pressure, which could lead to a heavy burden on storage facility permit (SFP) applicants. As an alternative, Burton-Kelly and others (2021) proposed a risk-based reinterpretation of this framework that would allow for a reduction in the AOR while ensuring protection of drinking water resources.

A computational framework for estimating a risk-based AOR was proposed by Oldenburg and others (2014, 2016), who compared formation fluid leakage through a hypothetical open flow path in the baseline scenario (no $CO_2$ injection) to the incrementally larger leakage that would occur in the $CO_2$ injection case. The modeling for the risk-based AOR used semianalytical solutions to single-phase flow equations to model reservoir pressurization and vertical migration through leaky wells. These semianalytical solutions were extensions of earlier work for formation fluid leakage through abandoned wellbores by Raven and others (1990) and Avci (1994), which were creatively solved, coded, and compiled in FORTRAN under the name ASLMA (Analytical Solution for Leakage in Multilayered Aquifers) and extensively described by Cihan and others (2011, 2012) (hereafter "ASLMA Model").

Recently, White and others (2020) outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, NRAP-IAM-CS and the subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers.

Building a geologic model in a commercial-grade software platform (like Petrel; Schlumberger, 2020) and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform (like CMG's compositional simulator, GEM) provide the "gold standard" for estimating pressure buildup in response to $CO_2$ injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that are unwarranted given the amount of uncertainty that may be present if only a few nearby wells can be used for characterization activities. Earlier studies (e.g., Nicot and others, 2008; Birkholzer and others, 2009; Bandilla and others, 2012; Cihan and others, 2011, 2012) have shown that far-field fluid pressure changes outside of the $CO_2$ plume domain can be reasonably described by a single-phase flow calculation by representing $CO_2$ injection as an equivalent-volume injection of brine (Oldenburg and others, 2014).

The semianalytical solutions embedded within the ASLMA Model have been shown to compare with the numerical model, TOUGH2-ECO2-N, and provided accurate results for pressures beyond the $CO_2$ plume zone (Birkholzer and others, 2009; Cihan and others, 2011, 2012). Therefore, the proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and resultant effects of this buildup on the vertical migration of formation fluid via (single) hypothetical leaky wellbores located at progressively greater distances from the injection well (Figure 3-16).

An important distinction between EPA Methods 1 and 2, which both calculate a critical pressure threshold (either $\Delta P_{i,f}$ for Method 1 or $\Delta P_c$ for Method 2) and the risk-based AOR approach is that the risk-based approach 1) calculates and maps the potential incremental flow of

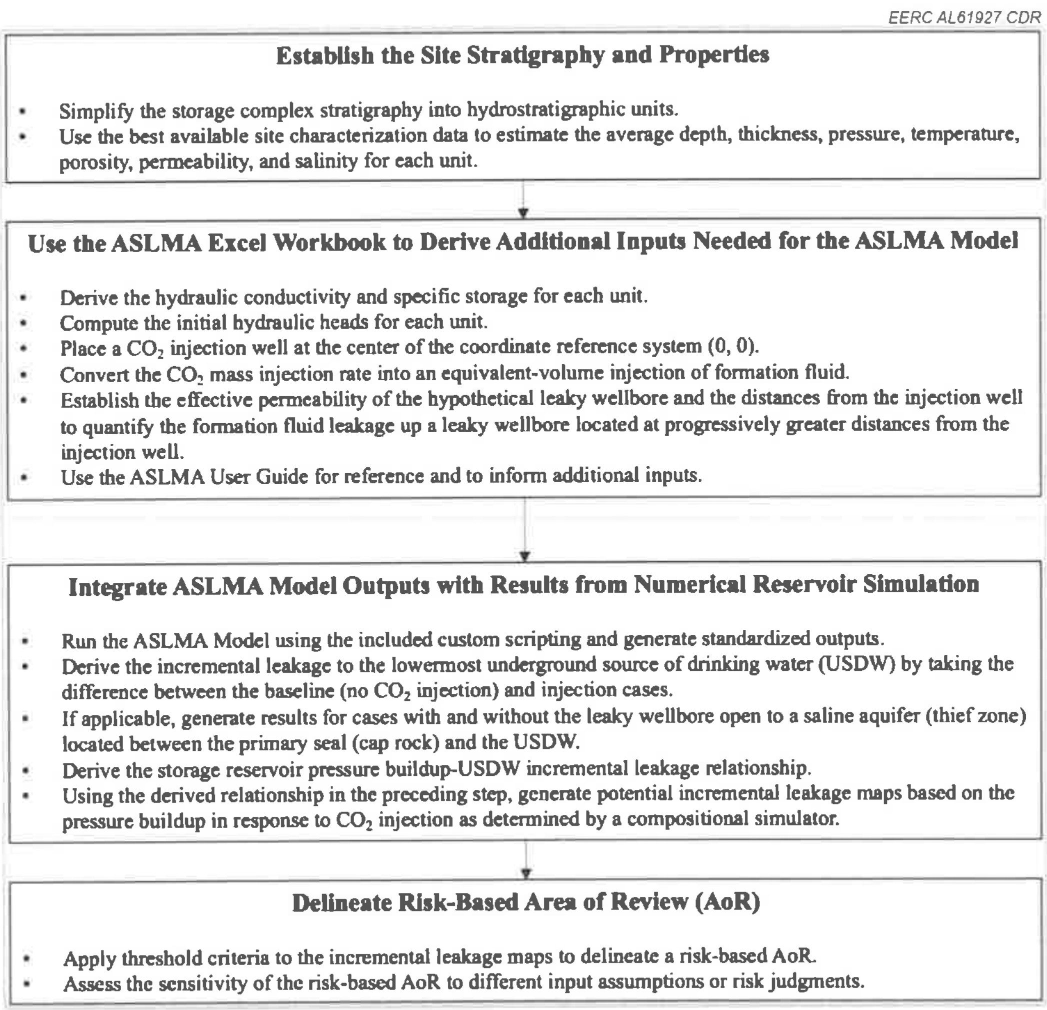



Figure 3-16. Workflow for delineating a risk-based AOR for a SFP (modified from Burton-Kelly and others, 2021).

formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR.

### *3.5.3 Critical Threshold Pressure Increase Estimation*

For the purposes of delineating AOR for the project study area, constant fluid densities for the lowermost USDW (Fox Hills Formation) and injection zone (Broom Creek Formation) were used in the calculations. Respective fluid densities were used to represent the injection zone fluids ($\rho_i$), which are estimated based on the in situ estimated brine salinity, temperature, and pressure at the MAG 1 stratigraphic test well.

Application of EPA Method 1 (Equation 1) using site-specific data from the MAG 1 well shows that the injection zone in the project area is overpressurized with respect to the lowest USDW (i.e., Method 1 $\Delta P_{i,f} < 0$). An example of the EPA Method 1 application showing negative $\Delta P_{i,f}$ (relative overpressure) is given in Table 3-4, with similar results when applied to each column of the grid cells in the Broom Creek Formation simulation model.

**Table 3-1. EPA Method 1 Critical Threshold Pressure Increase Calculated at the MAG 1 Wellbore Location Using Measured and Calculated Data Shown in Table 3-2**

| Depth,* ft | Depth,* m | $P_i$ Injection Zone Pressure, MPa | $P_u$ USDW Base Pressure, MPa | $\rho_i$ Injection Zone Density, kg/m³ | $Z_u$ USDW Base Elevation, m amsl | $Z_i$ Reservoir Elevation, m amsl | $\Delta P_{i,f}$ Threshold Pressure Increase, MPa | $\Delta P_{i,f}$ Threshold Pressure Increase, psi |
|---|---|---|---|---|---|---|---|---|
| 4,731 | 1,442 | 16.41 | 3.15 | 1,006 | 276 | −855 | −2.11 | −306 |

* Ground surface elevation is 581 m above mean sea level. Depth provided is the reference depth used for the CMG simulation.

In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value across the project area and b) lack of evidence for hydrostatic equilibrium between the reservoir and the USDW (i.e., Method 2 does not apply) indicates that a risk-based approach to AOR delineation may be pursued.

### *3.5.4 Risk-Based AOR Calculations*

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). The inputs, assumptions, and results discussed here provide the necessary details for reproducing and verifying the results. A macro-enabled Microsoft Excel file was used to define the inputs and calculations that were employed in the method (hereafter "ASLMA Workbook").

#### *3.5.4.1 Initial Hydraulic Heads*

The original ASLMA Model (Cihan and others, 2011) initially assumed hydrostatic pressure distributions in the entire system. The current work uses a modified version of the ASLMA Model to simulate pressure perturbations and leakage rates when there are initial head differences in the aquifers (Oldenburg and others, 2014). The initial hydraulic heads are calculated assuming a total

head based on the unit-specific elevations and pressures. The total heads are entered into the ASLMA Model and establish the initial pressure conditions for the storage complex prior to $CO_2$ injection.

For example, the initial reference case total heads for the storage reservoir (Aquifer 1), potential thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-5 and illustrate the state of overpressure in the storage complex, as Aquifer 1 has a greater initial hydraulic head than Aquifers 2 and 3. Therefore, the storage complex requires different treatment than the default AOR calculations described by EPA (2013). Details on the calculations of initial hydraulic head are provided in Burton-Kelly and others (2021).

## Table 3-2. Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex

| Hydrostratigraphic Unit | Depth to Top,* m | Thickness, m | Pressure, MPa | Temperature, °C | Salinity, ppm | Brine Density, kg/m³ | Porosity, % | Permeability, mD | Permeability, m² | HCON, m/d | Specific Storage, m⁻¹ | Total Head, m |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Overlying Units to Ground Surface (not directly modeled) | 0 | 215 | | | | | | | | | | |
| Aquifer 3 (USDW – Fox Hills Fm) | 215 | 90 | 2.6 | 12.5 | 1,800 | 1,002 | 34.4 | 280 | 2.76E-13 | 1.92-01 | 5.56E-06 | 591 |
| Aquitard 2 (Pierre Fm–Inyan Kara Fm) | 305 | 788 | 7.0 | 25.3 | 16,300 | | 10 | 0.1 | 9.87E-17 | 9.30E-05 | 9.26E-06 | 585 |
| Aquifer 2 (Thief Zone – Inyan Kara Fm) | 1,093 | 69 | 11.3 | 37.8 | 16,300 | 1,008 | 22.4 | 42.1 | 4.16E-14 | 5.06E-02 | 5.25E-06 | 593 |
| Aquitard 1 (Swift–Broom Creek Fm) (primary upper seal) | 1,161 | 273 | 13.0 | 42.7 | 28,600 | | 10 | 0.1 | 9.87E-17 | 1.30E-04 | 9.31E-06 | 583 |
| Aquifer 1 (Storage Reservoir – Broom Creek Fm) | 1,435 | 32 | 16.5 | 68.3 | 28,600 | 1,003 | 18.2 | 121.3 | 1.20E-13 | 2.31E-01 | 5.15E-06 | 808 |

* Ground surface elevation 614 m amsl.

*3.5.4.2 $CO_2$ Injection Parameters*

The ASLMA Model for the project used a Broom Creek $CO_2$ injection rate that matched the simulation scenario. A single injector is placed at the center of the ASLMA Model grid at an x,y-location of (0,0) in the coordinate reference system. The ASLMA Model requires the $CO_2$ injection rate to be converted into an equivalent-volume injection of formation fluid in units of cubic meters per day. Microsoft Excel Visual Basic for Applications (VBA) functions were used to estimate the $CO_2$ density from the storage reservoir pressure and temperature, which resulted in an estimated density, shown in Table 3-6. The $CO_2$ mass injection rate and $CO_2$ density are then used to derive the daily equivalent-volume injection rate, shown in Table 3-6.

**Table 3-3. $CO_2$ Density and Injection Parameters Used for the ASLMA Model**

| $CO_2$ Density, Reservoir Conditions, kg/m$^3$ | Injection Period | Injection Rate, m$^3$ per day | Injection Period, years |
|---|---|---|---|
| 580 | 1 | 944 | 20 |

*3.5.4.3 Hypothetical Leaky Wellbore*

In the project area, few wellbores are known to exist that penetrate the primary seal of the Broom Creek storage reservoir. However, for heuristic, "what-if" scenario modeling, which is needed to generate the data for delineating a risk-based AOR, a single hypothetical leaky wellbore is inserted into the ASLMA Model at 1, 2, …, 100 km from the $CO_2$ injection well. The pressure buildup in the storage reservoir at each distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 12-year injection period, provides the data set needed to derive the risk-based AOR.

Published ranges for the effective permeability of a leaky wellbore (Figure 3-17) have included an "open wellbore" with an effective permeability as high as $10^{-5}$ m$^2$ ($10^{10}$ mD) to values more representative of leakage through a wellbore annulus of $10^{-12}$ to $10^{-10}$ m$^2$ ($10^3$ to $10^5$ mD) (Watson and Bachu, 2008, 2009; Celia and others, 2011). Carey (2017) provides probability distributions for the effective permeability of potentially leaking wells at $CO_2$ storage sites and estimated a wide range from $10^{-20}$ to $10^{-10}$ m$^2$ ($10^{-5}$ to $10^5$ mD). For the project Broom Creek ASLMA Model, the effective permeability of the leaky wellbore is set to $10^{-16}$ m$^2$ (0.1 mD), which is a conservative (highly permeable) value near the top of the published range for the effective permeability of potentially leaking wells at $CO_2$ storage sites (Figure 3-17).

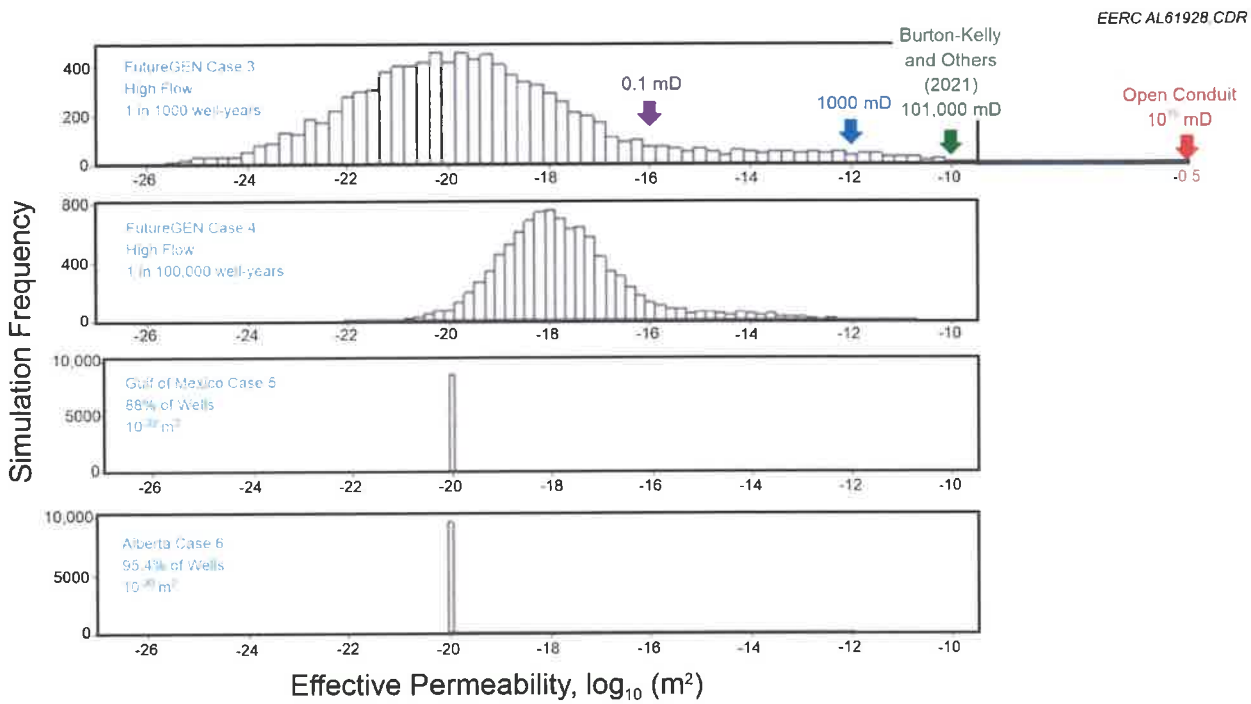



Figure 3-17. Histograms describing the expected frequency of leaky wellbore effective permeabilities under different scenarios. The ASLMA Model used for AOR delineation used a value of approximately 0.1 mD (constructed from data presented by Carey [2017]).

The current work uses the ASLMA Model Type 1 feature (focused leakage only) for the nominal model response, which makes the conservative assumption that the aquitards are impermeable. This assumption prevents the pressure from diffusing into the overlying aquitards, resulting in a greater pressure buildup in the storage reservoir and a commensurately greater amount of formation fluid vertically migrating from the storage reservoir through the leaky wellbore. The conservative assumption of Model Type 1 rather than Model Type 3 (coupled focused and diffuse leakage) provides an added level of protection to the delineation of a risk-based AOR by projecting a larger pressure buildup in the storage reservoir than a scenario in which pressure is allowed to dissipate through the upper seal and, therefore, a greater leakage of formation fluid up the leaky wellbore.

#### *3.5.4.4 Saline Aquifer Thief Zone*

As shown in Table 3-5, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the primary seal above the storage reservoir and USDW (Aquifer 3, Fox Hills Formation). Formation fluid migrating up a leaky wellbore that is open to Aquifer 2 will preferentially flow into Aquifer 2, and the continued flow up the wellbore and into the USDW will be reduced. Therefore, the presence of Aquifer 2 may act as a thief zone and reduces the potential for formation fluid impacts to the groundwater.

The thief zone phenomenon was described by Nordbotten and others (2004) as an "elevator model" by analogy with an elevator full of people on the main floor, who then get off at various floors as the elevator moves up, such that only very few people ride all the way to the top floor. The term "thief zone" is also used in the oil and gas industry to describe a formation encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 (Inyan Kara Formation) were run and evaluated to quantify the effect of a thief zone on the risk-based AOR.

#### *3.5.4.5 Aquifer- and Aquitard-Derived Properties*

The ASLMA Model assumes homogeneous properties within each hydrostratigraphic unit (Table 3-5). For each unit shown in Table 3-5, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: hydraulic conductivity (HCON) and specific storage (SS). Average porosity and permeability values were derived as follows: Broom Creek, from distributed properties in the geologic model; Inyan Kara, from MAG 1 core data and regional well logs; and Fox Hills, from regional well log data. Porosity is represented as an arithmetic mean and permeability as a geometric mean value within each hydrostratigraphic unit (excluding nonsandstone rock types).

VBA functions included in the ASLMA Workbook are used to estimate the formation fluid density and viscosity from the aquifer or aquitard pressure, temperature, and salinity inputs, which are then used to estimate the HCON and SS. The estimated reference case HCON for the storage reservoir (Aquifer 1), thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-5. Details about the HCON and SS derivations are provided in supporting information for Burton-Kelly and others (2021).

### ***3.5.5 Risk-Based AOR Results***

#### *3.5.5.1 Relating Pressure Buildup to Incremental Leakage with ASLMA Model and Compositional Simulation*

Figure 3-18 shows the relationship between the maximum pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 (USDW) for scenarios with and without the leaky wellbore open to Aquifer 2 (thief zone). In the case where the leaky wellbore is closed to Aquifer 2, there is no incremental leakage to Aquifer 2. The curvilinear relationship between pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 is used to predict the incremental leakage from the pressure buildup map produced by the compositional simulation of the geocellular model. The average simulated pressure buildup in the reservoir is represented by a raster (grid) map of pressure buildup values. For each raster value (grid cell map location), the relationship between pressure buildup and incremental leakage (Figure 3-18) is used to predict incremental leakage using a linear interpolation between the points making up the curve. The estimated cumulative leakage potential from Aquifer 1 to Aquifer 3 along a hypothetical leaky wellbore without injection occurring (i.e., leakage due to natural overpressure) and no thief zone is shown in Table 3-7.

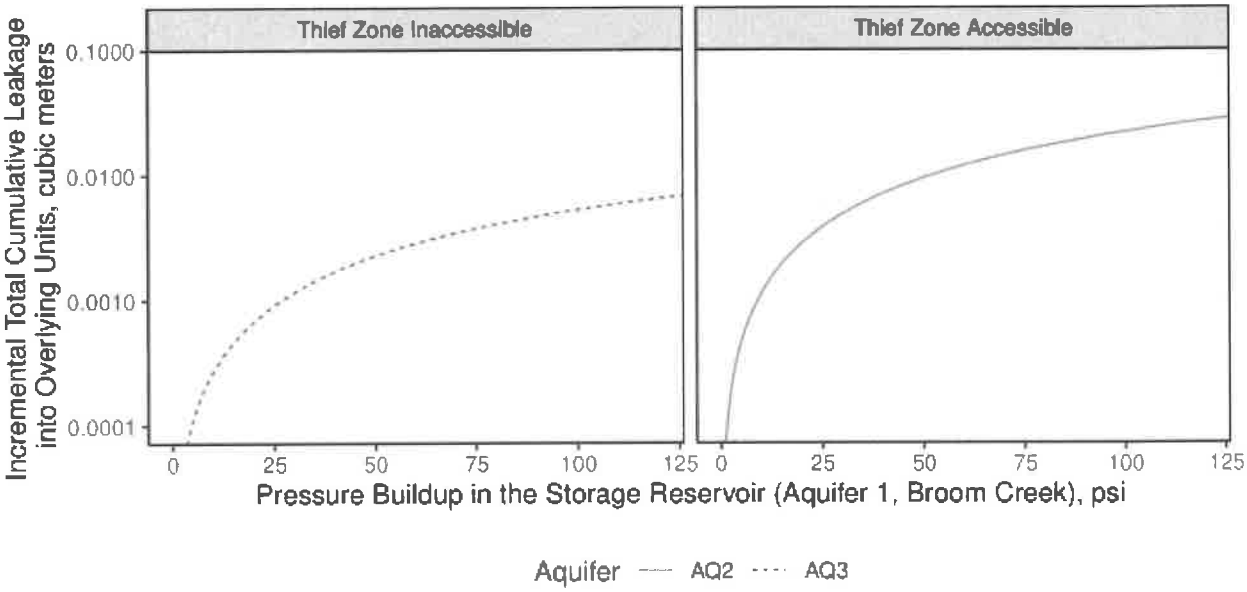



Figure 3-18. Relationship between pressure buildup (x-axis, psi) in the storage reservoir (Aquifer 1, Broom Creek) and incremental total cumulative leakage (y-axis, m$^3$) into Aquifer 2 (thief zone, Inyan Kara, red solid line) and Aquifer 3 (USDW, Fox Hills, dashed blue line). In the left-hand scenario, the leaky wellbore is closed to Aquifer 2 (Inyan Kara), so all flow is from the storage reservoir to the USDW. In the right-hand scenario, the leaky wellbore is open to Aquifer 2 (Inyan Kara), so the vast majority of flow is from the storage reservoir to the thief zone, and the curve showing flow into the USDW is not visible on this plot.

#### *3.5.5.2 Incremental Leakage Maps and AOR Delineation*

The pressure buildup–incremental leakage relationship, shown in Figure 3-18, results in the incremental leakage map, shown in Figure 3-19, which show the estimated total cumulative incremental leakage potential from a hypothetical leaky well into Aquifer 3 (USDW) over the entire injection period if the hypothetical leaky wellbore is not open to the thief zone.

The final step of the risk-based AOR workflow is to apply a threshold criterion to the incremental leakage maps to delineate a risk-based AOR. For the Broom Creek Formation injection at the project site, a threshold of 1 m$^3$ of potential incremental flow into the Fox Hills Formation USDW along a hypothetical leaky wellbore over the injection period is established. A value of 1 m$^3$ is the lowest meaningful value that can be produced by the ASLMA Model; although the model can return smaller values, they likely represent statistical noise. This potential incremental flow threshold is greater than all calculated potential incremental flow values described by the curve in Figure 3-18. The maximum vertically averaged change in pressure in the storage reservoir at the end of the simulated injection period and the corresponding flow over the injection period are shown in Table 3-7. This pressure is below the potential incremental flow threshold of 1 m$^3$. Therefore, the storage reservoir pressure buildup is not a deciding factor in determining the AOR extent.

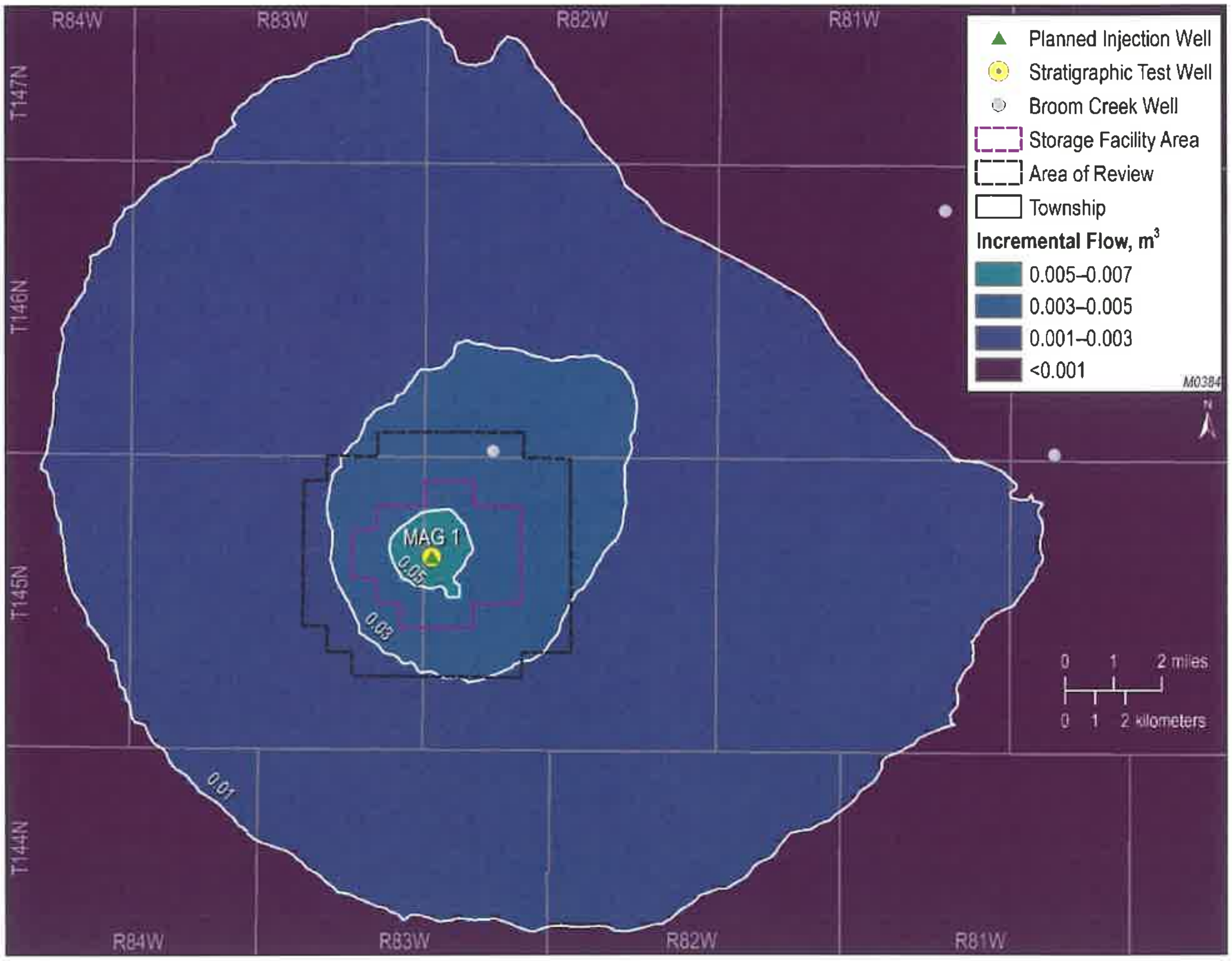



Figure 3-19. Map of potential incremental leakage into the USDW at the end of 20 years of $CO_2$ injection for the scenario where the hypothetical leaky wellbore is closed to Aquifer 2 (thief zone).

**Table 3-4. Summary Results from the Risk-Based AOR Method of Estimated Potential Cumulative Leakage after 20 years of Injection and No Thief Zone**

| | |
|---|---|
| Maximum Vertically Averaged Change in Reservoir Pressure, psi | 113.2 |
| Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Without* Injection, $m^3$ | 0.019 |
| Maximum Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Attributable to* Injection, $m^3$ | 0.005 |

The assumptions and calculations used to determine the risk-based AOR at the project site incorporate at least four safety factors for the protection of groundwater resources. If the ASLMA Model has resulted in an underestimation of the amount of potential leakage over the injection period, such underestimation is likely to be mitigated by:

- The statistical overestimation of hypothetical leaky wellbore permeability compared to known and estimated values in the literature—A more statistically likely hypothetical leaky wellbore permeability would be lower and allow less flow into the USDW.

- The lack of communication between the hypothetical leaky wellbore and Inyan Kara Formation, which would act as a thief zone—A real leaky wellbore would likely communicate with the Inyan Kara Formation, which would receive much, if not all, of the brine leaked from the storage reservoir.

- The low density of known legacy wellbores in the Blue Flint project area—$CO_2$ injection is proposed to occur in an area with few available leakage pathways.

- The continued overpressurized nature of the Broom Creek Formation with respect to overlying saline aquifers, over relatively short (e.g., 50-year) timescales, overpressurized aquifers with leakage pathways would demonstrate a change in upward flow rate and corresponding pressure (Oldenburg and others, 2016).

The risk-based method detailed above shows that storage reservoir pressure buildup is not necessary for determining AOR because the potential incremental flow into the USDW is below the identified threshold of 1 $m^3$. Therefore, the AOR is delineated as the storage facility area plus a 1-mile buffer (Figure 3-20). Figure 3-21 illustrates the land use within the AOR.

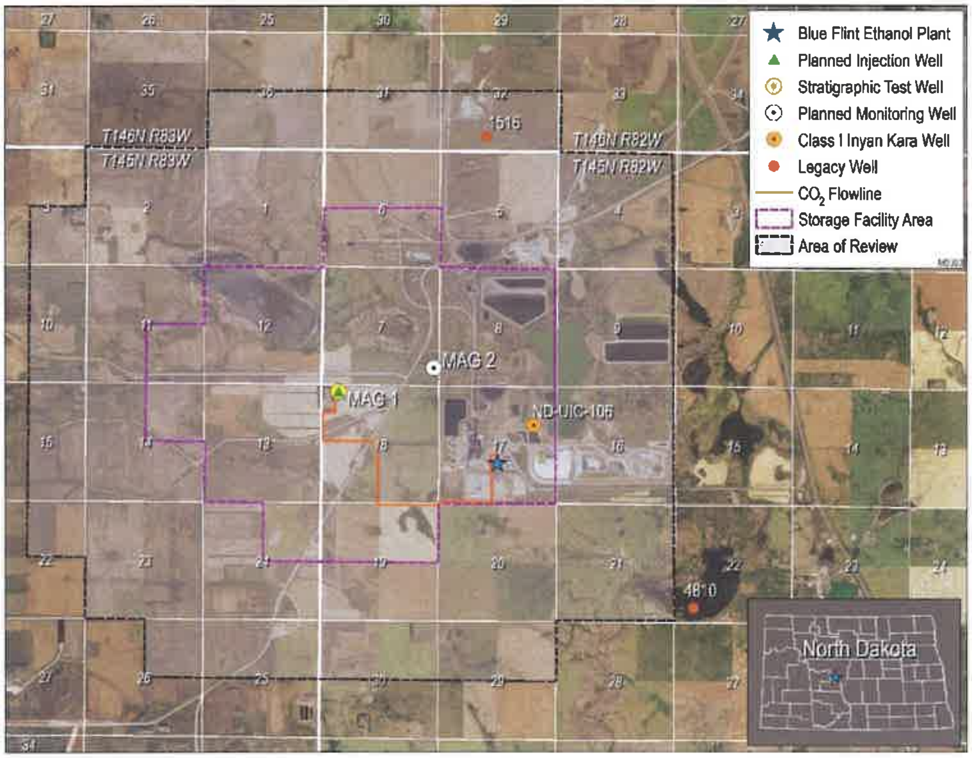



Figure 3-20. Final AOR estimations of the project storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple polygon) and AOR (black polygon). Orange circles represent legacy oil and gas wells near the storage facility area.

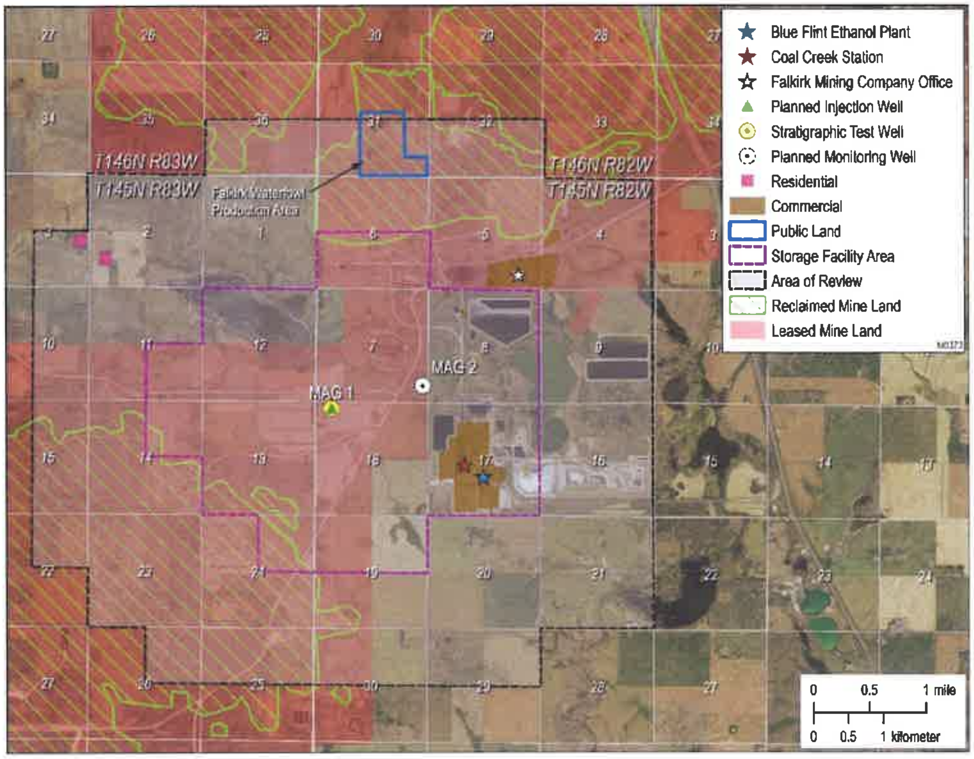



Figure 3-21. Land use in and around the AOR of the project storage facility.

## 3.6 References

Avci, C.B., 1994, Evaluation of flow leakage through abandoned wells and boreholes: Water Resour. Res., v. 9, p. 2565–2578.

Bandilla, K.W., Kraemer, S.R., and Birkholzer, J.T., 2012, Using semi-analytical solutions to approximate the area of potential impact for carbon dioxide injection: Int. J. Greenhouse Gas Control, v. 8, p. 196–204.

Birkholzer, J., Cihan, A., and Bandilla, K., 2014, A tiered area-of-review framework for geologic carbon sequestration (2013): Greenhouse Gases Sci. Technol. v. 4, no. 1, p. 20–35. https://doi.org/10.1002/ghg.1393.

Birkholzer, J.T., Zhou, Q., and Tsang, C.F., 2009, Large-scale impact of $CO_2$ storage in deep saline aquifers: a sensitivity study on pressure response in stratified systems: Int. J. Greenhouse Gas Control, v. 3, p. 181–194.

Bosshart, N.W., Pekot, L.J., Wildgust, N., Gorecki, C.D., Torres, J.A., Jin, L., Ge, J., Jiang, T., Heebink, L.V., Kurz, M.D., Dalkhaa, C., Peck, W.D., and Burnison, S.A., 2018, Best practices for modeling and simulation of $CO_2$ storage: Plains $CO_2$ Reduction (PCOR) Partnership Phase III, Task 9, Deliverable D69 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592.

Burton-Kelly, M.E., Azzolina, N.A., Connors, K.C., Peck, W.D., Nakles, D.V. and Jiang, T., 2021, Risk-based area of review estimation in overpressured reservoirs to support injection well storage facility permit requirements for $CO_2$ storage projects: Greenhouse Gas Sci Technol, v. 11, p. 887–906. https://doi.org/10.1002/ghg.2098.

Carey, J.W., 2017, Probability distributions for effective permeability of potentially leaking wells at $CO_2$ sequestration sites: NRAPTRS-III-021-2017, NRAP Technical Report Series, Morgantown, West Virginia, U.S. Department of Energy National Energy Technology Laboratory, p. 28.

Celia, M.A., Nordbotten, J.M., Court, B., Dobossy, M., and Bachu, S., 2011, Field-scale application of a semi-analytical model for estimation of $CO_2$ and brine leakage along old wells: Int. J. Greenhouse Gas Control, v. 5, no. 2, p. 257–269.

Cihan, A., Zhou, Q., and Birkholzer, J.T., 2011, Analytical solutions for pressure perturbation and fluid leakage through aquitards and wells in multilayered aquifer systems: Water Resour. Res., v. 47, p. W10504. doi:10.1029/2011WR010721.

Cihan, A., Birkholzer, J.T., and Zhou, Q., 2012, Pressure buildup and brine migration during $CO_2$ storage in multilayered aquifers: Ground Water. doi:10.1111/j.1745–6584.2012.00972.x.

Computer Modelling Group, 2019, GEM user guide.

Nicot, J.P., Oldenburg, C.M., Bryant, S.L., and Hovorka, S.D., 2008, Pressure perturbations from geologic carbon sequestration—area-of-review boundaries and borehole leakage driving forces: Proceedings of the 9th International Conference of Greenhouse Gas Control Technologies, Washington, USA, November.

Nordbotten, J., Celia, M., and Bachu, S., 2004, Analytical solutions for leakage rates through abandoned wells: Water Resour. Res., v. 40, p. W04204. doi:10.1029/2003WR002997.

North Dakota Industrial Commission, 2021, NDIC Case No. 29029 – draft permit, fact sheet, and storage facility permit application: Minnkota Power Cooperative supplemental information, Grand Forks, North Dakota, www.dmr.nd.gov/oilgas/GeoStorageofCO2.asp (accessed 2021).

Oldenburg, C.M., Cihan, A., Zhou, Q., Fairweather, S., and Spangler, L.J., 2014, Delineating area of review in a system with pre-injection relative overpressure: Energy Procedia, v. 63, p. 3715–3722.

Oldenburg, C.M., Cihan, A., and Zhou, Q., 2016, Geologic carbon sequestration injection wells in overpressured storage reservoirs—estimating area of review: Greenhouse Gases Sci. Technol., v. 6, no. 6. Raven, K.G., Lafleur, D.W., and Sweezey, R.A., 1990, Monitoring well into abandoned deep-well disposal formations at Sarnia, Ontario: Canadian Geotechnical J., v. 27, no. 1, p. 105–118. https://doi.org/10.1139/t90-010.

Schlumberger, 2020, Petrel 2019.5: Petrel E&P Software Platform.

U.S. Environmental Protection Agency, 2013, Geologic sequestration of carbon dioxide underground injection control (UIC) program Class VI well area of review evaluation and corrective action guidance: EPA 816-R-13-005, May.

Watson, T.L., and Bachu, S., 2008, Identification of wells with high $CO_2$-leakage potential in mature oil fields developed for $CO_2$-enhanced oil recovery, *in* SPE Improved Oil Recovery Symposium: Tulsa, Oklahoma, USA, 19–23 April, SPE 11294.

Watson, T.L., and Bachu, S., 2009, Evaluation of the potential for gas and $CO_2$ leakage along wellbores: SPE Drilling & Completion, v. 24, no. 1, p. 115–126.

White, S., Carroll, S., Chu, S., Bacon, D., Pawar, R., Cumming, L., Hawkins, J., Kelley, M., Demirkanli, I., Middletone, R., Sminchak, J., and Pasumarti, A., 2020, A risk-based approach to evaluating the area of review and leakage risks at $CO_2$ storage sites: Int. J. Greenhouse Gas Control, v. 93, p. 102884.

Wyllie, M.R.J., and Rose, W.D., 1950, Some theoretical considerations related to the quantitative evaluation of the physical characteristics of reservoir rock from electrical log data: J. Pet. Tech., v. 189.

# 4.0 AREA OF REVIEW

# 4.0 AREA OF REVIEW

## 4.1 Area of Review (AOR) Delineation

### *4.1.1 Written Description*

North Dakota geologic storage of $CO_2$ regulations require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water [USDW] may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of $CO_2$ and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase $CO_2$ plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the MAG 1 well (NDIC File No. 37833) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-5]).

NDAC § 43-05-01-05(1)(b)(3) requires "[a] review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate $CO_2$ injection activities and associated pressure front (Figure 4-1), the resulting AOR for the geologic storage project is delineated as being 1 mile from the SFP boundary. This extent ensures compliance with existing state regulations.

All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-20 and 4-2) by a professional engineer pursuant to NDAC § 43-05-01-05(1)(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected $CO_2$ from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 through 4-4, and Figure 4-3 through Figure 4-5).

An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC uncovered no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.

This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05(1)(a) and (b) and § 43-05-01-05.1(2), such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05(1)(a) and (b)(3) and § 43-05-01-05.1(2). Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1.

### 4.1.2 Supporting Maps

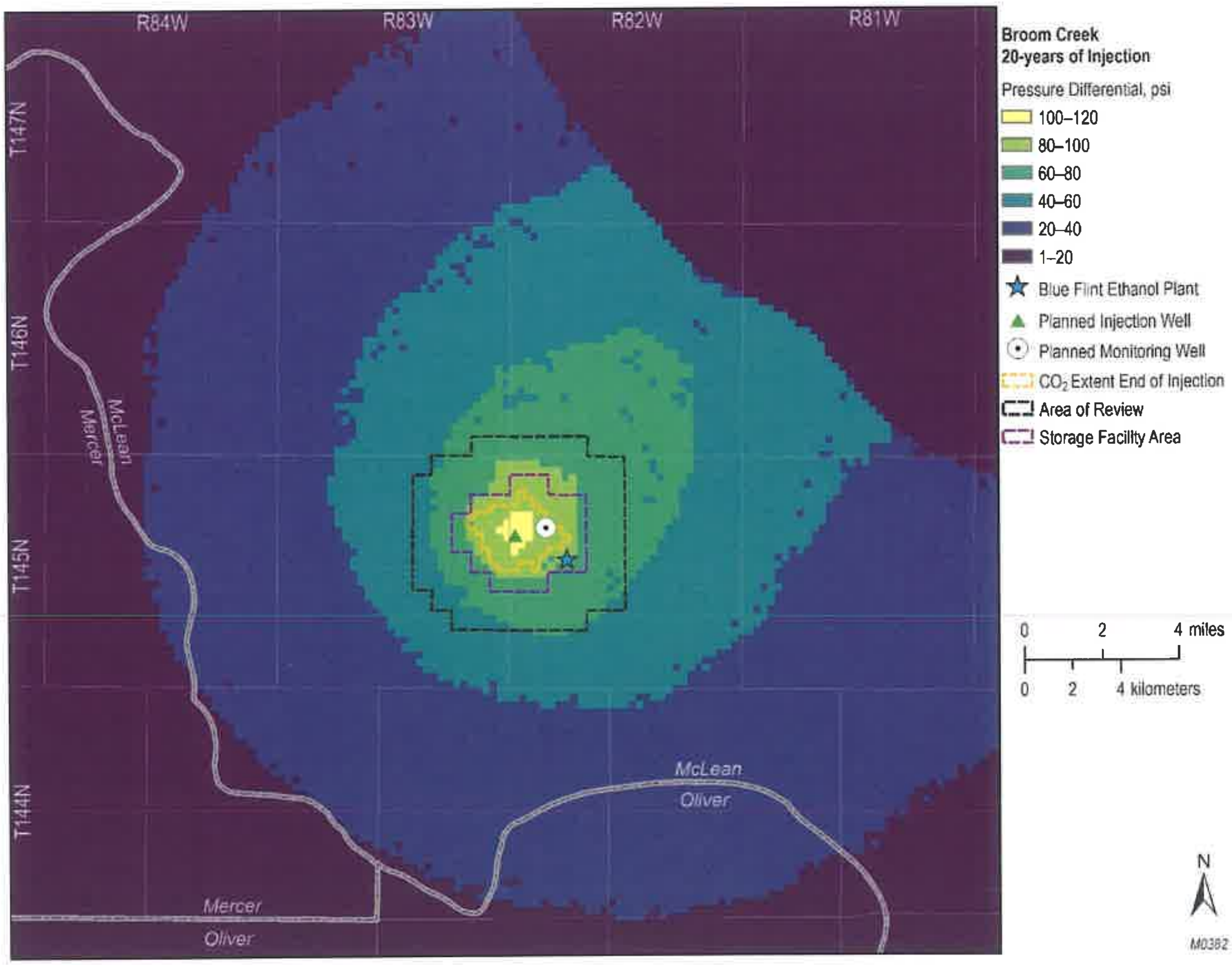



Figure 4-1. Pressure map showing the maximum subsurface pressure influence associated with $CO_2$ injection in the Broom Creek Formation. Shown is the $CO_2$ plume extent after end of injection, the storage facility area, and the 1-mile AOR boundary in relation to the maximum subsurface pressure influence.

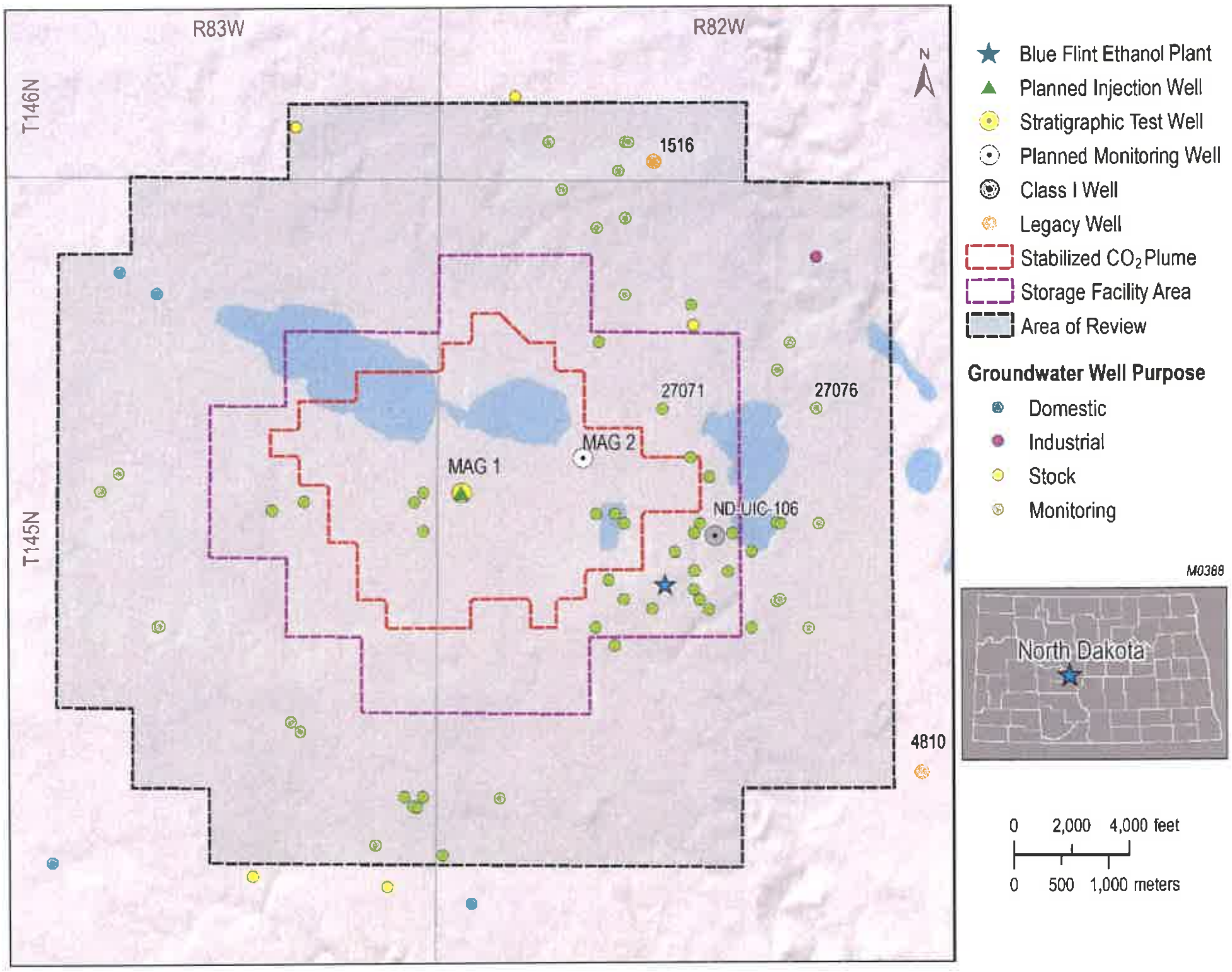



Figure 4-2. AOR map in relation to nearby groundwater wells. Shown are the stabilized $CO_2$ plume extent postinjection (dashed red boundary), storage facility area (dashed purple boundary), and 1-mile AOR (dashed black boundary). All groundwater wells in the AOR are identified above. All observation/monitoring wells shown are shallow groundwater wells associated with the mine activities. No springs are present in the AOR.

**Table 4-1. Investigated and Identified Surface and Subsurface Features (Figures 3-20, 4-1 and 4-2)**

| Surface and Subsurface Features | Investigated and Identified (Figures 4-1–4-5) | Investigated But Not Found in AOR |
|---|---|---|
| Producing (active) Wells | | X |
| Abandoned Wells | X | |
| Plugged Wells or Dry Holes | X | |
| Deep Stratigraphic Boreholes | X | |
| Subsurface Cleanup Sites | | X |
| Surface Bodies of Water | X | |
| Springs | | X |
| Water Wells | X | |
| Mines (surface and subsurface) | X | |
| Quarries | | X |
| Subsurface Structures (e.g., coal mines) | | X |
| Location of Proposed Wells | X | |
| *Location of Proposed Cathodic Protection Boreholes | | X |
| Any Existing Aboveground Facilities | X | |
| Roads | X | |
| State Boundary Lines | | X |
| County Boundary Lines | | X |
| Indian Boundary Lines | | X |
| Other Pertinent Surface Features | X | |

* There are no plans for cathodic protection for the injection well (MAG 1).

### 4.2 Corrective Action Evaluation

**Table 4-2. Wells in AOR Evaluated for Corrective Action***

| Well File No. | Operator | Well Name | Spud Date | Surface Casing o.d., inches | Surface Casing Seat, ft | Long-String Casing o.d., inches | Long-String Casing seat, inches | Hole Direction | TD, ft | TVD, ft | Status | Plug Date | TWN | RNG | Section | Qtr/Qtr | County | Corrective Action Needed |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1516** | H. Hanson Oil Syndicate | Ellen Samuelson 1 | 9/14/1957 | 10.75 | 462 | Openhole | | Vertical | 6,600 | 6,600 | P&A | 10/18/1957 | 146N | 82W | 32 | SE/SW | McLean | No |
| **ND-UIC-106**** | Great River Energy | Well #1 | 10/10/2014 | 11.75 | 1,232 | 7 | | 3531 | Vertical | 4,046 | 4,046 | NA | 145N | 82W | 17 | SE/NE | McLean | No |
| **4810** | W. H. HUNT TRUST ESTATE | Wallace O. Gradin 1 | 12/1/1969 | 8.625 | 233 | Openhole | | Vertical | 4240 | 4240 | P&A | 12/6/1969 | 145N | 82W | 22 | SW/SW | McLean | No |

* TD is total depth, and TVD is true vertical depth.
**ND-UIC-106 is classified as a Class I disposal well.

**Table 4-3. Ellen Samuelson 1 (NDIC File No. 1516) Well Evaluation**

Well Name: Ellen Samuelson 1 (NDIC File No. 1516)

| Cement Plugs | | | | |
|---|---|---|---|---|
| Number | Interval, ft | | Thickness, ft | Volume, sacks |
| 1 | 5,940 | | | 20 |
| 2 | 5,480 | | | 20 |
| 3 | 4,730 | | | 20 |
| 4 | 3,670 | | | 20 |
| 5 | Base of Surface | | | 25 |
| 6 | Top of Surface | | | 5 |

* Data and information are provided from well-plugging report found in NDIC database.

| Formation | | Cement Plug Class G* |
|---|---|---|
| Name | Estimated Top, ft | |
| 10¾" Casing Shoe | 462 | Cement Plug 5 isolates the 10¾" casing shoe. |
| Pierre | 1,055 | Top of Inyan Kara Formation is not covered by cement. However, Cement Plug 4 isolates Dakota Group. |
| Mowry | 3,355 | |
| Inyan Kara | 3,655 | |
| Swift | 3,912 | |
| Kibby Lime | 5,272 | Cement Plugs 3, 2, and 1 isolate the formations below the Broom Creek Formation. |
| | | |

Spud Date: 9/14/1957
Total Depth: 6,600 (Mission Canyon Formation)

Surface Casing: 10¾" casing set at 462, cement to surface with 200 sacks Class G cement.

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Ellen Samuelson 1 well (NDIC File No. 1516) will not be in contact with the $CO_2$ plume, and pressure increase in the Broom Creek Formation at this well location is predicted to be approximately 76 psi. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled and plugged.

* Cement Type is assumed to be Class G as no cement type was on file.

**Table 4-4. Well #1 (ND-UIC-106) Well Evaluation**

Well Name: Well #1 (ND-UIC-106)

| Formation | | Cement Plug Remarks |
|---|---|---|
| Name | Estimated Top, ft | |
| 11¾" Casing Shoe | 1,232 | Production Casing Cement isolates the 11¾" casing shoe. |
| Pierre | 1,110 | |
| Mowry | 3,190 | |
| Inyan Kara | 3,531 | |
| Production Casing | 3,531 | |

Spud Date: 10/10/2014
Total Depth: 4,046 (Inyan Kara Formation)

Surface Casing: 11¾" casing set at 1,232, cement to surface

Production Casing: 7" casing set at 3,531, cement to surface

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Well #1 well (ND-UIC-106) will not be in contact with the $CO_2$ plume, and the well does not penetrate the Broom Creek Formation. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled above the Broom Creek Formation.

Additional information: Well #1 is classified as a Class I disposal well for nonhazardous waste injection into the Inyan Kara.

**Table 4-5. Wallace O. Gradin 1 (NDIC File No. 4810) Well Evaluation**

Well Name: Wallace O. Gradin 1 (NDIC File No. 4810)

| Cement Plugs | | | | |
|---|---|---|---|---|
| Number | Interval, ft | | Thickness, ft | Volume, sacks |
| 1 | 3181 | 3249 | 68 | 20 |
| 2 | 1152 | 1220 | 68 | 20 |
| 3 | 204 | 270 | 66 | 20 |
| 4 | 0 | 16 | 16 | 5 |

*Data and information are provided from well-plugging report found in NDIC database.

| Formation | | Cement Plug Remarks |
|---|---|---|
| Name | Estimated Top, ft | |
| 8.625" Casing Shoe | 233 | 8-5/8" J-55, 20# casing. Set at 233'. Cemented w/ 135 sks 8-5/8", 20# casing capacity is 2.7328 lin ft per ft^3. Plug 1 at surface and plug 2 at surface casing shoe. |
| Pierre | 915 | Plug 3 is 200' into the Pierre Fm. Fox Hills Formation isolated by plug 2 and 3. |
| Mowry | 3195 | Cement Plug 3 isolates the uppermost Inyan Kara porosity. |
| Newcastle | 3249 | |
| Swift | 3745 | |
| Rierdon | 4083 | Well file reports TD in Piper Formation. |

Spud Date: 12/01/1969
Total Depth: 4083 ft

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Wallace O. Gradin 1 (NDIC File No. 4810) well will not be in contact with the $CO_2$ plume, and the well does not penetrate the Broom Creek Formation. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled above the Broom Creek Formation.

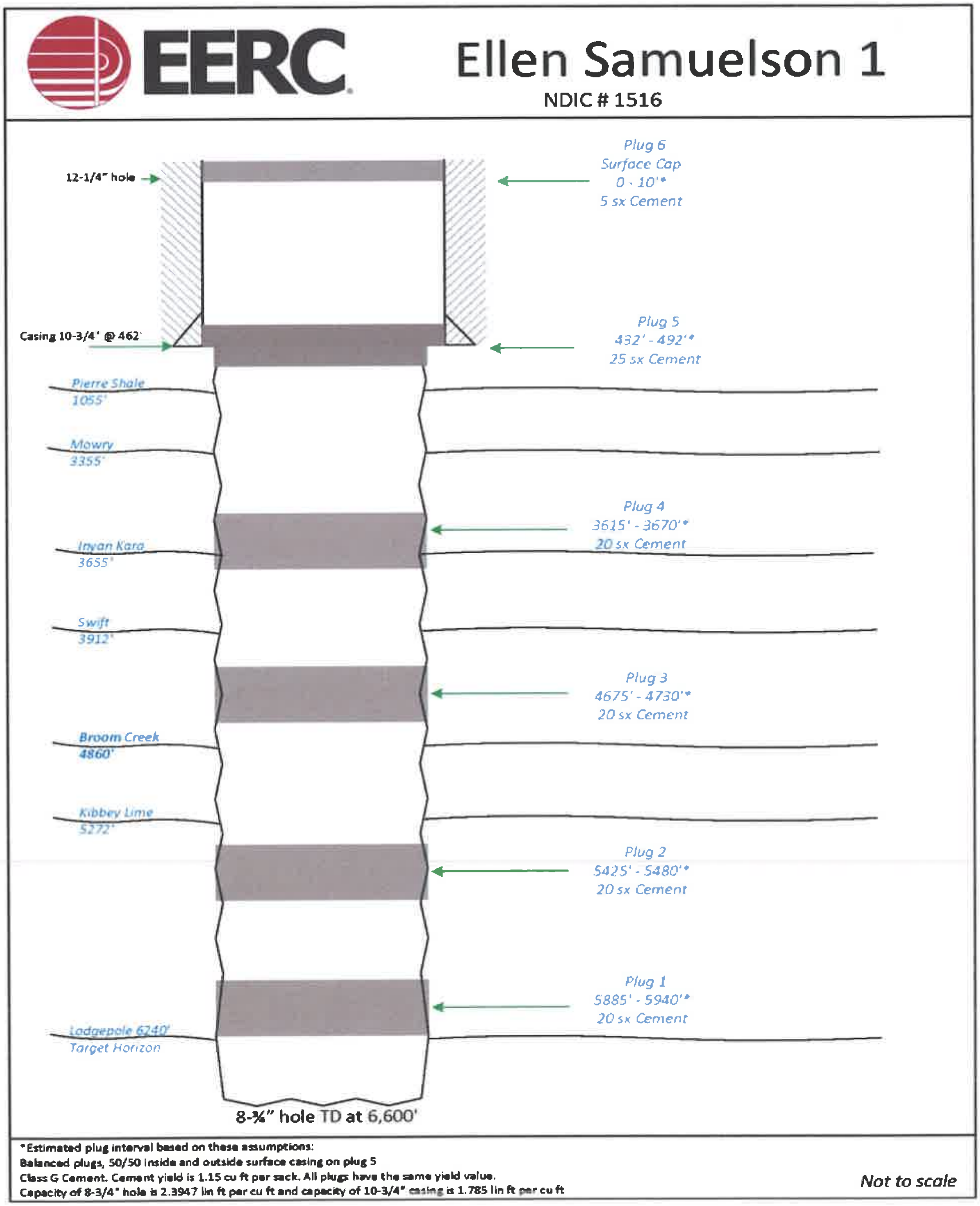



Figure 4-3. Ellen Samuelson 1 (NDIC File No. 1516) well schematic showing the location of cement plugs.

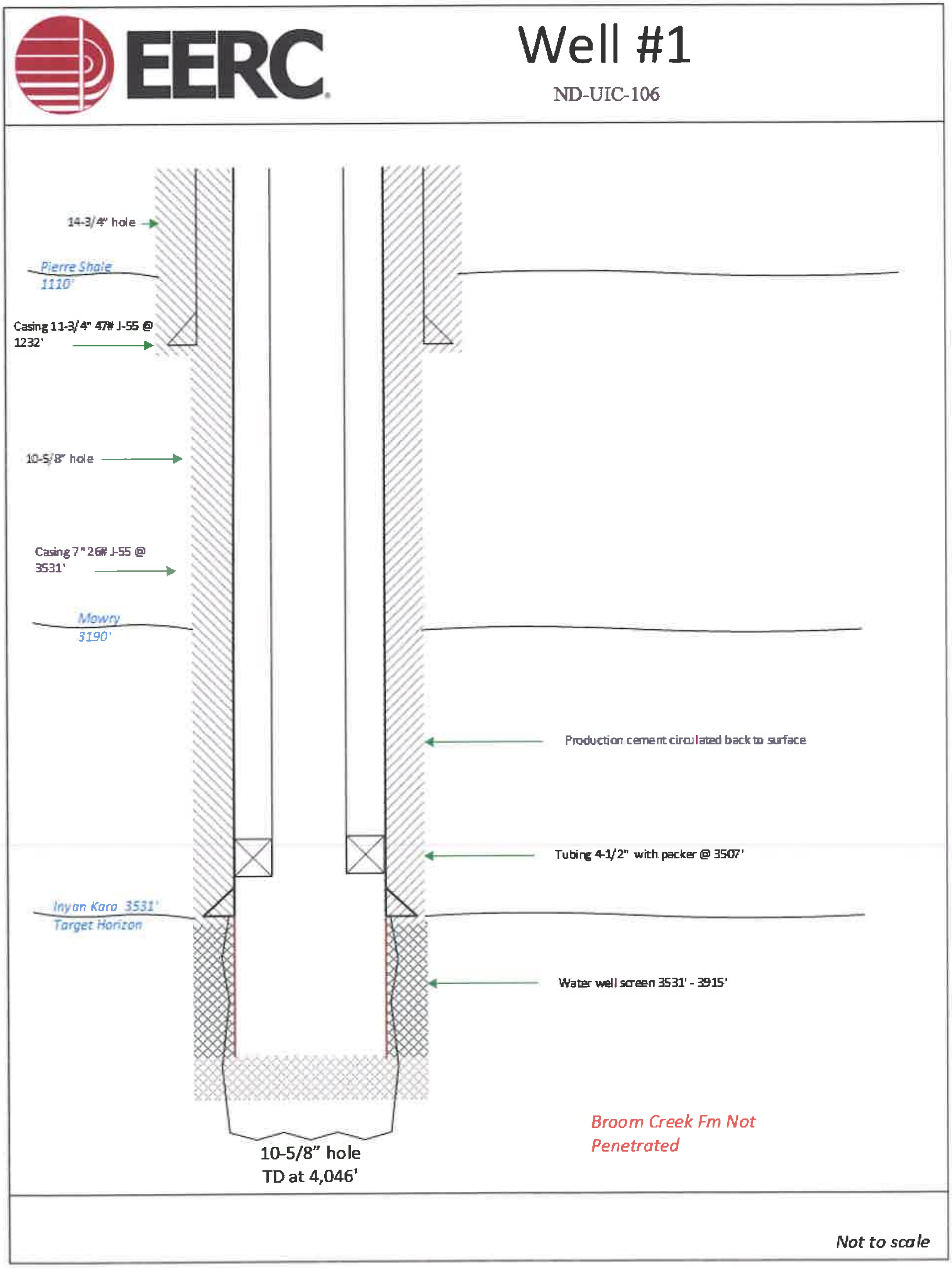



Figure 4-4. Well #1 (ND-UIC-106) well schematic.

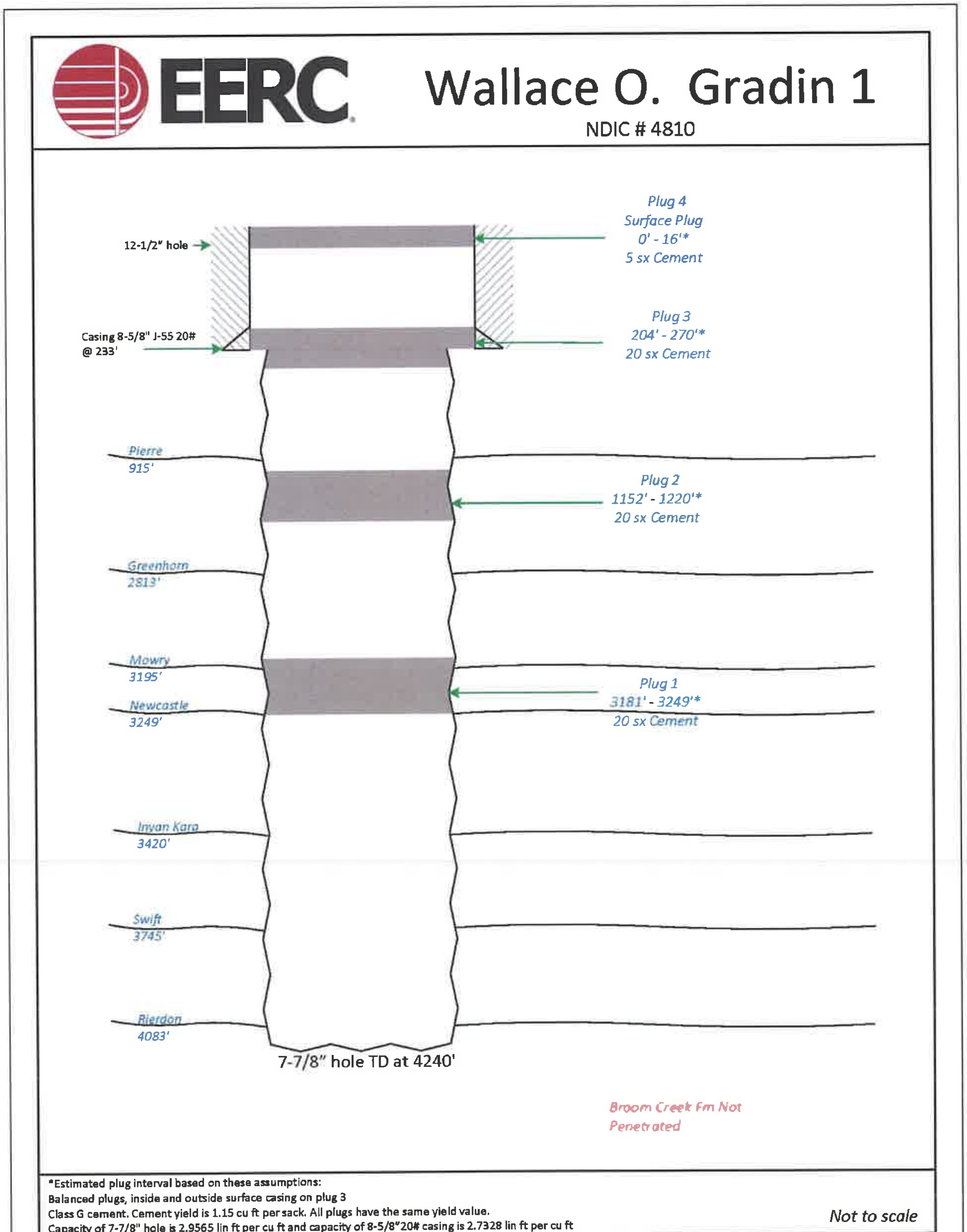



Figure 4-5. Wallace O. Gradin 1 (NDIC File No. 4810) well schematic showing the location of cement plugs.

## 4.3 Reevaluation of AOR and Corrective Action Plan

BFE will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place no later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following:

- Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date will be identified.
- Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and the computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and the operational data to be utilized as the basis for that update will be identified.
- The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.

## 4.4 Protection of USDWs (Broom Creek Formation)

### *4.4.1 Introduction of USDW Protection*

The primary confining zone and additional overlying confining zones geologically isolate the Fox Hills and Hell Creek Formations, the lowest USDW in the area of investigation from the underlying injection zone. The Spearfish Formation is the primary confining zone for the injection zone with additional confining layers above, geologically isolating all USDWs from the injection zone. The uppermost confining layer is the Pierre Formation, an impermeable shale in excess of 1,000 ft thick, providing an additional seal for all USDWs in the region.

### *4.4.2 Geology of USDW Formations*

The hydrogeology of western North Dakota is composed of several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 4-6). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1,000 and 1,500 ft thick (Thamke and others, 2014).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formation; the overlying Cannonball, Tongue River, and Sentinel Butte Formation of the Tertiary Fort Union Group; and the Tertiary Golden Valley Formation (Figure 4-7). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the area of investigation (Bluemle, 1971).

The lowest USDW in the area of investigation is the Fox Hills Formation, which together with the overlying Hell Creek Formation, is a confined aquifer system. The Hell Creek Formation is a poorly consolidated unit composed of interbedded sandstone, siltstone, and claystones with occasional carbonaceous beds, all fluvial origin. The underlying Fox Hills Formation is interpreted

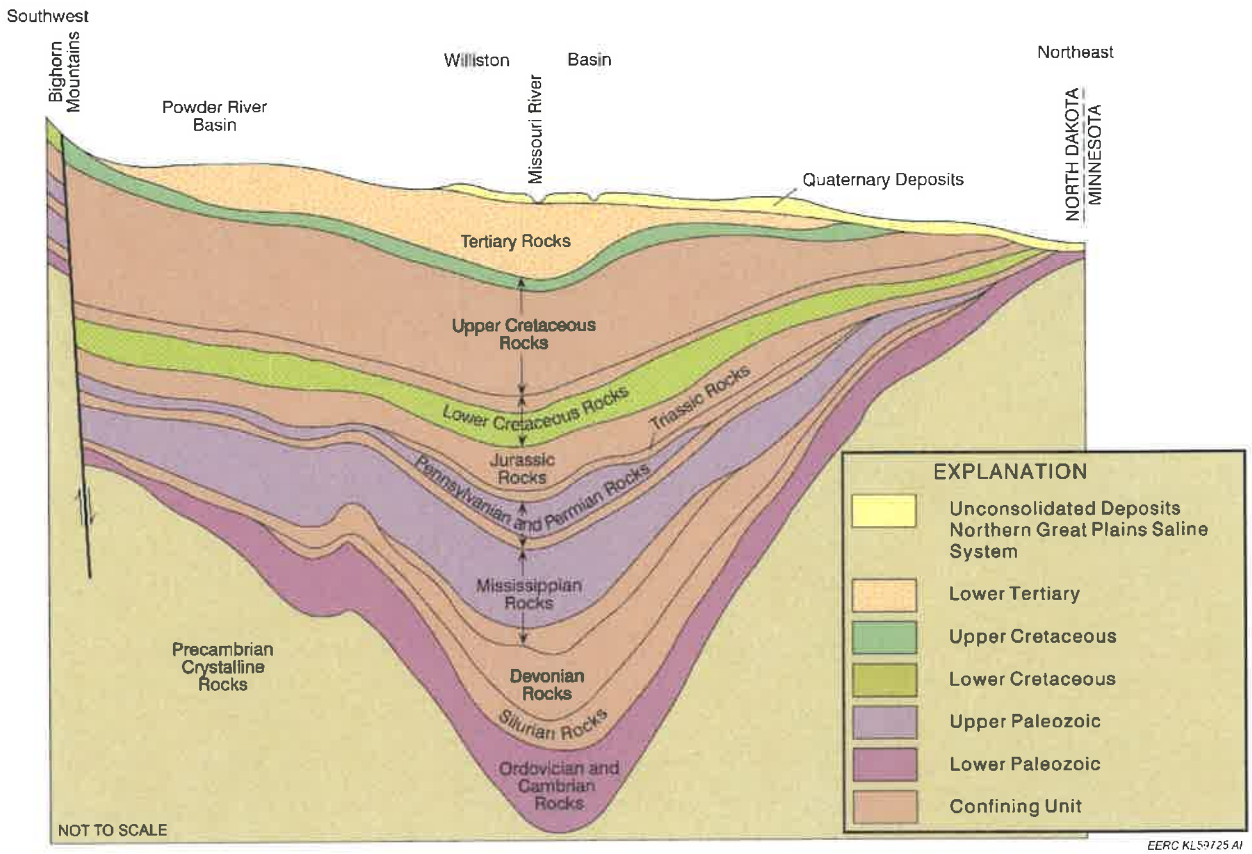



Figure 4-6. Major aquifer systems of the Williston Basin.

as interbedded nearshore marine deposits of sand, silt, and shale deposited as part of the final Western Interior Seaway retreat (Fischer, 2013). The Fox Hills Formation in the area of investigation is approximately 700 to 900 ft deep and 350–450 ft thick (Bluemle, 1971). The structure of the Fox Hills and Hell Creek Formations follows that of the Williston Basin, dipping gently toward the center of the basin to the northwest of the area of investigation (Figure 4-8).

The Pierre Shale is a thick, regionally extensive shale unit which forms the lower boundary of the Fox Hills–Hell Creek system, also isolating all overlying freshwater aquifers from the deeper saline aquifer systems. The Pierre Shale is a dark gray to black marine shale and is typically over 1,000 ft thick in the area of investigation (Thamke and others, 2014).

| Era | Period | Group | Formation | Freshwater Aquifer(s) Present |
|---|---|---|---|---|
| Cenozoic | Quaternary | | Glacial Drift | Yes |
| | Tertiary | | Golden Valley | Yes |
| | | Fort Union | Sentinel Butte | Yes |
| | | | Tongue River | Yes |
| | | | Cannonball | Yes |
| Mesozoic | Cretaceous | | Hell Creek | Yes |
| | | | Fox Hills | Yes |
| | | | Pierre | No |
| | | Colorado | Niobrara | No |
| | | | Carlile | No |
| | | | Greenhorn | No |
| | | | Belle Fourche | No |

Figure 4-7. Upper stratigraphy of McLean County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Bluemle, 1971).

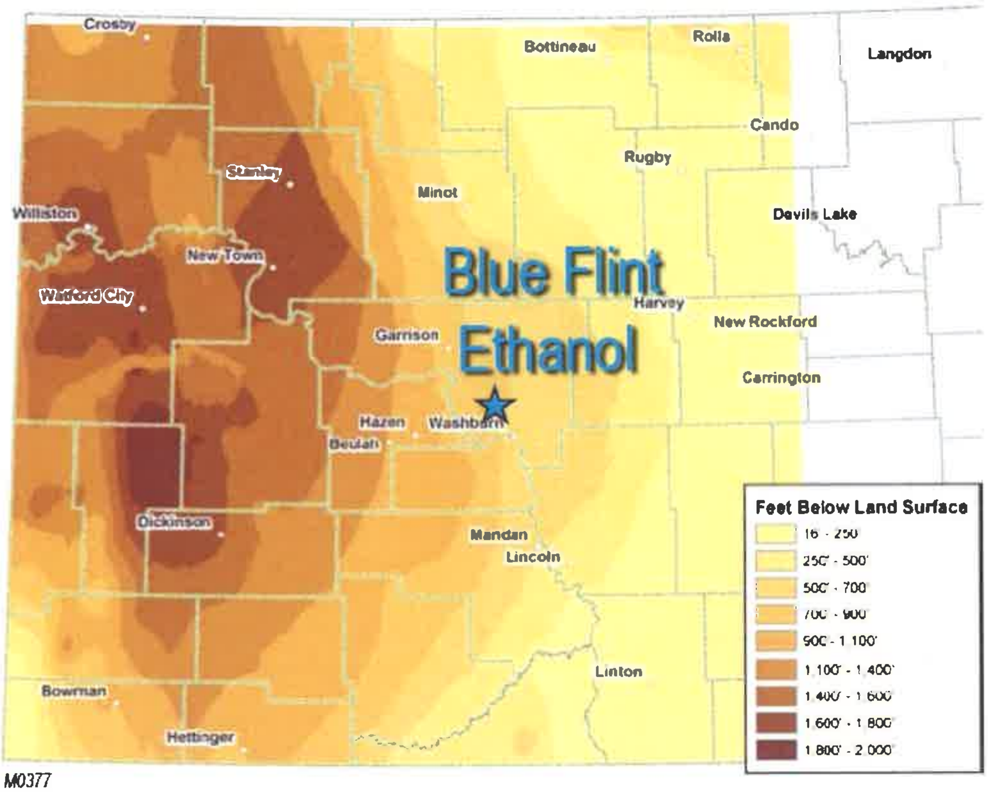



Figure 4-8. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

### *4.4.3 Hydrology of USDW Formations*

The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the northeast (Figure 4-9). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,500 ppm (Klausing, 1974). Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Honeyman, 2007). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering.

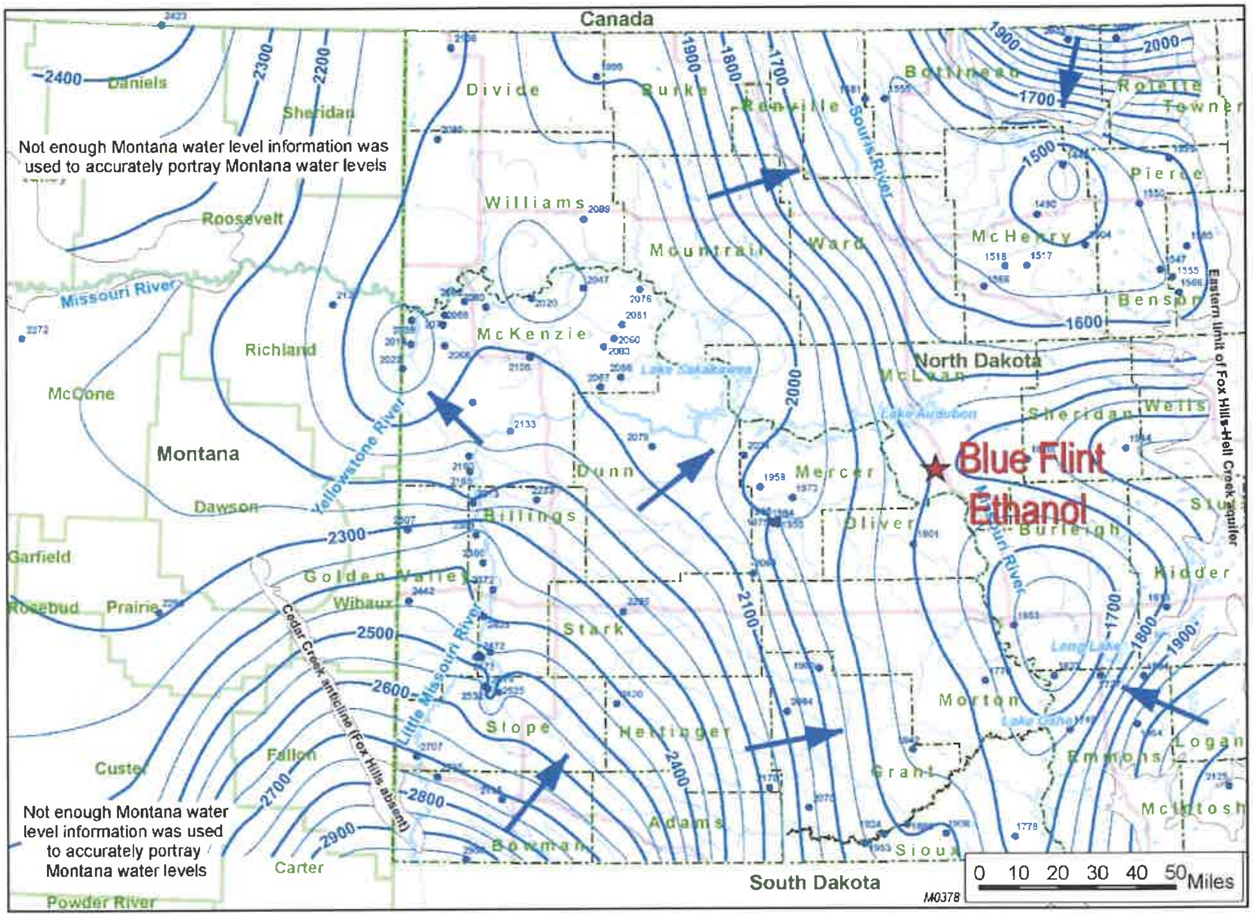



Figure 4-9. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central McLean County (modified from Fischer, 2013).

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the area of investigation. A cross section of these formations is presented in Figure 4-10. The upper formations are generally used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. The basal sandstone member of the Tongue River is persistent and a reliable source of groundwater in the region. The thickness of this basal sand ranges from approximately 50 to 200 ft and can be found at a depth of approximately 550 ft. Tongue River groundwaters are generally sodium bicarbonate with a TDS of approximately 1,000 ppm (Klausing, 1974).

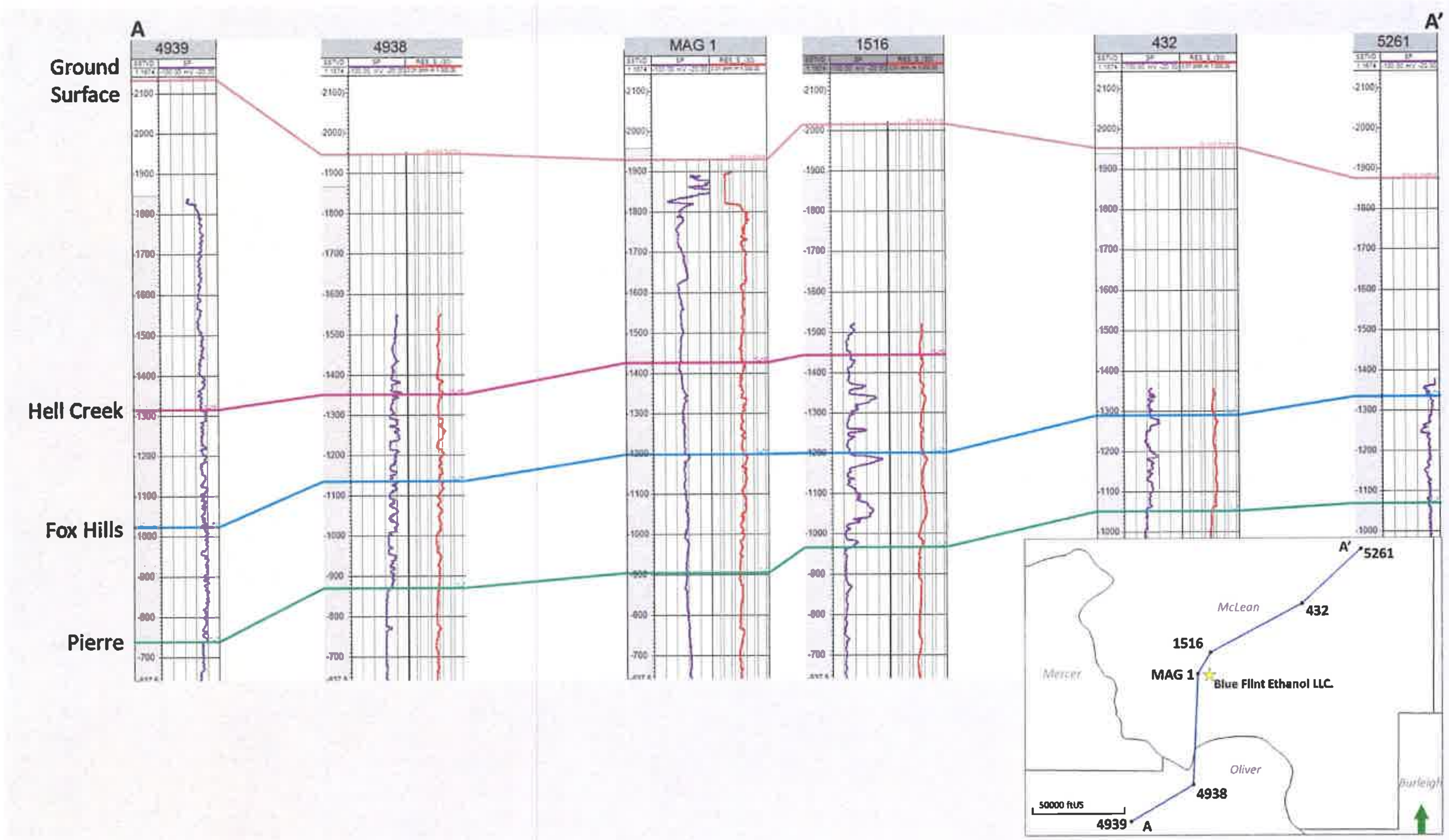



Figure 4-10. Southwest to northeast cross section of the major aquifer layers in McLean County. The black dots on the inset map represent the locations of the six wells used to create the cross section. The wells are labeled with their designation at the top of the cross section.

The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. The upper Sentinel Butte is approximately 150 ft thick in the area of investigation (Hemish, 1975). TDS concentrations in the Sentinel Butte Formation are approximately 1,000 ppm (Klausing, 1974). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers.

#### *4.4.4 Protection for USDWs*

The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AOR. The injection zone (Broom Creek Formation) and the lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and siltstone formations (Figure 4-6). The primary seal of the injection zone is the Permian-aged Spearfish and the Jurassic-aged Piper, Rierdon, and Swift Formations, all of which overlie the Broom Creek Formation. These formations will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation.

Above the Swift is the confined saltwater aquifer system of the Inyan Kara Formation, which extends across much of the Williston Basin. The Inyan Kara will be monitored for temperature and pressure changes in the injection well (MAG 1) and the monitoring well (MAG 2). The Pierre Formation is the thickest shale formation in the area of investigation and the primary geologic barrier between the USDWs and the Inyan Kara. The geologic strata overlying the injection zone consist of multiple impermeable rock layers that are free of transmissive faults or fractures and provide adequate isolation of the USDWs from $CO_2$ injection activities in the area of investigation.

### 4.5 References

Bluemle, John P., 1971, Geology of McLean County, North Dakota: Theses and Dissertations.

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 No. 54.

Hemish, L., 1975, Stratigraphy of the upper part of the Fort Union Group in Southwestern Mclean County, North Dakota.

Honeyman, R.P., 2007, Pressure head fluctuations of the Fox Hills-Hell Creek Aquifer in the Knife River Basin, North Dakota.

Klausing, R., 1974, Ground-water resources of McLean County, North Dakota: U.S. Geological Survey, www.swc.nd.gov/info_edu/reports_and_publications/county_groundwater_studies/pdfs/Mclean_Part_III.pdf (accessed July 2022).

Thamke, J.N., LeCain, G.D., Ryter, D.W., Sando, R., and Long, A.J., 2014, Hydrogeologic framework of the uppermost principal aquifer systems in the Williston and Powder River structural basins, United States and Canada: U.S. Geological Survey Groundwater Resources Program Scientific Investigations Report 2014–5047.

# 5.0 TESTING AND MONITORING PLAN

## 5.0 TESTING AND MONITORING PLAN

This testing and monitoring plan includes 1) a plan for analyzing the injected $CO_2$ stream, 2) leak detection and corrosion-monitoring plans for surface facilities and well components of the $CO_2$ injection system, 3) a well-testing and logging plan, and 4) an environmental monitoring and verification plan to ensure $CO_2$ is stored safely and permanently in the storage reservoir. The combination of the foregoing monitoring efforts is used to verify that the geologic storage project is operating as permitted and is protecting all USDWs. Another goal of this testing and monitoring plan is to establish baseline conditions at the Blue Flint $CO_2$ storage project site, including but not limited to the injection and monitoring wellbores, soil gas, groundwaters from surface to lowest USDW (Fox Hills Aquifer[1]), and the storage reservoir complex. An overview of the testing and monitoring efforts is provided in Table 5-1.

Blue Flint will review this testing and monitoring plan at a minimum of every 5 years to ensure the monitoring and verification strategies remain appropriate for demonstrating containment of $CO_2$ in the storage reservoir and conformance with predictive modeling and simulations. If needed, amendments to this testing and monitoring plan (e.g., technologies applied, frequency of testing, etc.) will be submitted to the NDIC for approval. Results of pertinent analyses and data evaluations conducted as part of this testing and monitoring plan will be compiled and reported as required.

Details of the individual efforts for this testing and monitoring plan are provided in the remainder of this section and in Section 6 (Postinjection Site Care and Facility Closure Plan).

---

[1] The Fox Hills Aquifer underlying the Blue Flint $CO_2$ storage project site and western North Dakota is a confined aquifer system that does not receive measurable flow from overlying aquifers or the underlying Pierre Shale. The overlying confining layer in the Hell Creek Formation comprises impermeable clays, and the underlying Pierre Shale serves as the lower confining layer (Trapp and Croft, 1975). Recharge occurs hundreds of miles to the southwest in the Black Hills of South Dakota, where the corresponding geologic layers are exposed at the surface. Flow within the aquifer is to the east with a rate on the order of single feet per year. Groundwater in the Fox Hills Aquifer at the Blue Flint $CO_2$ storage project site is geochemically stable, as it is isolated from its source of recharge and does not receive other sources of recharge (Fischer, 2013). The aquifer itself is a quartz-rich sand and is not known to contain reactive mineralogy. Minimal geochemical variation can be expected to occur across the site, attributable to minor variations in the geologic composition of the aquifer sediments.

**Table 5-1. Overview of Blue Flint's Testing and Monitoring Plan**

| | Monitoring Type | Equipment/Testing | Target Area |
|---|---|---|---|
| Surface Monitoring | $CO_2$ Stream Analysis | Compositional and isotopic testing | $CO_2$ liquefaction outlet at the capture facility |
| Surface Monitoring | Surface Facilities Leak Detection | $CO_2$ detection stations on flowline risers and wellheads, pressure gauges, dual flowmeters, and SCADA* system | Flowline from capture facility to injection wellhead |
| Surface Monitoring | Flowline Corrosion Detection | Flow-through corrosion coupon system | Flowline from capture facility to injection wellhead |
| Surface Monitoring | Continuous Recording of Injection Pressure, Rate, and Volume | Surface pressure-temperature gauges and flowmeters installed at the capture facility and injection wellhead with shutoff alarms | Surface-to-reservoir ($CO_2$ injection well) |
| Wellbore Monitoring | External Mechanical Integrity Testing | Ultrasonic imaging tool (USIT) or electromagnetic casing inspection log and distributed temperature sensing (DTS) | Well infrastructure |
| Wellbore Monitoring | Internal Mechanical Integrity Testing | Tubing-conveyed pressure–temperature gauges, surface digital gauges, and annulus pressure testing | Well infrastructure |
| Wellbore Monitoring | Downhole Corrosion Detection | Flow-through corrosion coupon system | Well materials |
| Environmental Monitoring | Atmosphere | $CO_2$ detection stations outside injection wellhead enclosure and gas analyzer sample blanks at soil gas profile stations | Well pads |
| Environmental Monitoring | Near Surface | Compositional and isotopic analysis of soil gas and shallow groundwater down to the Fox Hills | Vadose zone and lowest USDW |
| Environmental Monitoring | Above-Zone Monitoring Interval | DTS and pulsed-neutron logs (PNLs) over the Inyan Kara and Spearfish intervals | Downhole tubing and casing strings |
| Environmental Monitoring | Direct Reservoir | DTS, PNLs, tubing-conveyed bottomhole pressure-temperature-(BHP/T) gauges, and pressure falloff testing | Storage reservoir |
| Environmental Monitoring | Indirect Reservoir | Time-lapse 2D seismic and surface seismometer stations | Entire storage complex |

* Supervisory control and data acquisition.

## 5.1 $CO_2$ Stream Analysis

Prior to injection, Blue Flint determined the chemical content of the captured $CO_2$ stream via laboratory testing performed by Salof, Ltd. The chemical content is 99.98% dry $CO_2$ (by volume) and 0.02% other chemical components, as specified in Table 5-2. The $CO_2$ stream will be sampled at the liquefaction outlet quarterly and analyzed using methods and standards generally accepted by industry to determine its chemical and physical characteristics, including composition, corrosiveness, temperature, and density.

| Table 5-2. Chemical Content of the captured $CO_2$ | |
|---|---|
| **Chemical Content** | **Volume %** |
| Carbon Dioxide | 99.98 |
| Water, Oxygen, Nitrogen, Hydrogen Sulfide, $C_2^+$, and Hydrocarbons | Trace amounts of each (0.02 total) |
| Total | 100.00 |

## 5.2 Surface Facilities Leak Detection Plan

The purpose of this leak detection plan is to monitor the surface facilities from the liquefaction outlet to the injection wellsite during the operational phase of the Blue Flint $CO_2$ storage project. Figure 5-1 is a map showing the surface facilities layout. Figure 5-2 illustrates a generalized flow diagram of surface connections from the liquefaction outlet to the MAG 1 injection wellsite.

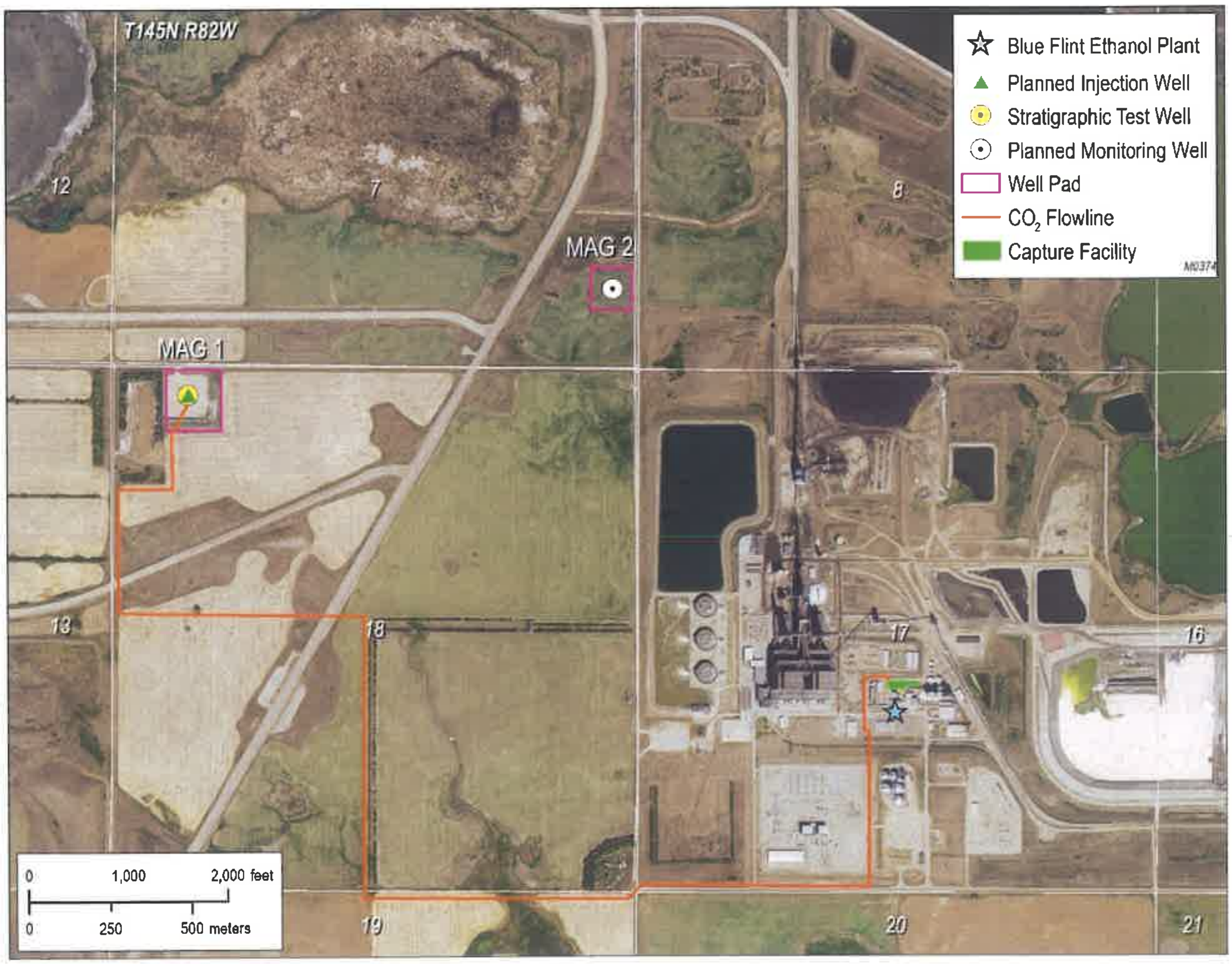



Figure 5-1. Site map showing the surface facilities layout for the Blue Flint $CO_2$ storage project.

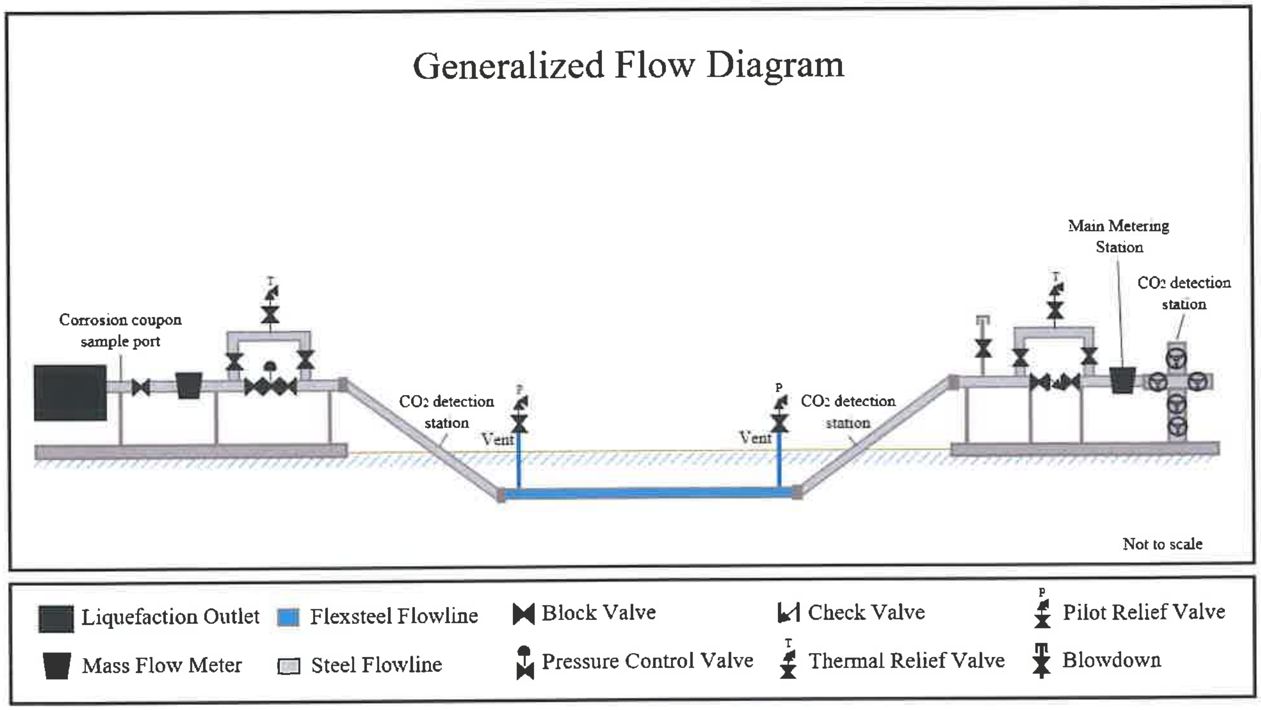



Figure 5-2. Diagram of surface connections and major components of the CCS system from the liquefaction outlet to the MAG 1 wellsite.

Surface components of the injection system, including the flowline and $CO_2$ injection wellhead, will be monitored with leak detection equipment. The flowline will be monitored continuously via dual flowmeters located at the liquefaction outlet and near the wellhead for performing mass balance calculations. The flowline will also be regularly inspected for any visual or auditory signs of equipment failure and monitored continuously with one pressure gauge at the capture facility outlet and one at the wellhead. $CO_2$ detection stations will be located on the flowline risers and the $CO_2$ injection wellhead. The leak detection equipment will be integrated with automated warning systems that notify Blue Flint's operations center, giving the operator the ability to remotely close the valves in the event of an anomalous reading.

Performance targets designed for the Blue Flint $CO_2$ storage project to detect potential leaks in the flowline are provided in Table 5-3. The performance targets are dependent upon the actual performance of instrumentation (e.g., pressure gauges) and the SCADA system (described further in Attachment A-1 of Appendix C), which uses software to track the status of the flowline in real time by comparing live pressure and flow rate data to a comprehensive predictive model. The performance targets assume a flow rate of approximately 550 metric tons of $CO_2$ per day. An alarm will trigger on the SCADA system if a volume deviation of more than 1% is registered.

**Table 5-3. Performance Targets for Detecting Leaks in Surface Equipment with SCADA**

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

* Thousand standard cubic feet per day.

$CO_2$ detection stations will be mounted on the inside of the wellhead enclosures to detect any potential indoor leaks. An additional $CO_2$ detection station will be mounted outside the injection wellhead enclosure to detect any potential atmospheric leaks at the wellsite. The stations can detect $CO_2$ concentrations as low as 2% by volume and have an integrated alarm system for increases of from 0% to 0.4% and 0.4% to 0.8% by volume. The stations are further described in Appendix C (Attachment A-2).

Field personnel will have multigas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multigas detectors will primarily monitor $CO_2$ levels in workspace atmospheres.

Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be made available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

## 5.3 Flowline Corrosion Prevention and Detection Plan

The purpose of this corrosion prevention and detection plan is to monitor the flowline and well materials during the operational phase of the project to ensure that all materials meet the minimum standards for material strength and performance.

### *5.3.1 Corrosion Prevention*

The chemical composition of the $CO_2$ stream is highly pure and dry (Table 5-2), and the target moisture level for the $CO_2$ stream is estimated to be up to 12 ppm by volume. These factors help to prevent corrosion of the surface facilities. In addition, the flowline construction materials will be $CO_2$-resistant in accordance with API 17J (2017) requirements. The flowline will be constructed using FlexSteel, a 3-layer flexible steel pipe product. The inner and outer layers contain a $CO_2$-resistant polyethylene liner, and the middle layer comprises reinforcing steel. FlexSteel product specifications can be found in Appendix C (Attachment A-3).

### *5.3.2 Corrosion Detection*

The flowline will use the corrosion coupon method to monitor for corrosion throughout the operational phase of the project, focusing on the loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. A coupon sample port will be located near the liquefaction outlet, and sampling will occur quarterly during the first year of injection and once a year thereafter. The process that will be used to conduct each coupon test is described in Appendix C under Section 1.3.

## 5.4 Wellbore Mechanical Integrity Testing

External mechanical integrity in the $CO_2$ injection well (MAG 1) and deep monitoring well (MAG 2) will be demonstrated with the following:

1) A USIT (described in Attachment A-4 of Appendix C), in combination with variable-density and cement bond logs will be used to establish the baseline external mechanical integrity behind the injection casing. The USIT log or another casing inspection logging (CIL) method will be run during well workovers but no less than once every 5 years.

2) DTS installed in the long-string casing will continuously monitor the temperature profile of the wellbore from the storage reservoir to surface.

3) A baseline temperature log will be run in case DTS fails and temperature log data are needed in the future.

Internal mechanical integrity in the MAG 1 and MAG 2 will be demonstrated with the following:

1) A tubing-casing annulus pressure test prior to injection and during well workovers but no less than once every 5 years. The tubing-casing annulus pressure will be continuously monitored with a surface digital pressure gauge at each wellhead.

2) The tubing pressure will be continuously monitored with tubing-conveyed BHP/T gauges and a digital surface pressure gauge.

3) USIT or another method may be used during well workovers but no less than once every 5 years.

Table 5-4 summarizes the foregoing mechanical integrity testing plan. Blue Flint will conduct an initial annulus pressure test to confirm the mechanical integrity of the tubing-casing annulus and confer with NDIC to confirm the annulus pressure test procedure satisfies all regulatory requirements prior to conducting the test.

**Table 5-4. Overview of Blue Flint's Mechanical Integrity Testing Plan**

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

* The baseline monitoring effort has been initiated as of the writing of this permit application.

## 5.5 Well Testing and Logging Plan

Table 5-5 describes the testing and logging plan developed for the MAG 1 wellbore (exclusive of any coring) to establish baseline conditions. Included in the table is a description of fluid sampling and pressure testing performed. The logging and testing plan for the MAG 2 wellbore will be the same as what is presented in Table 5-5, with the addition of a PNL but excluding dipole, elemental capture spectroscopy (ECS), fluid swab, and FMI. Table 5-4 and Table 5-6 (see Section 5.7) detail the frequency with which logging data will be acquired and in which wellbores throughout the operational period of the project.

Wellbore data collected from MAG 1 have been integrated with the geologic model and to inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations (Section 3). The simulated $CO_2$ plume extents informed the timing and frequency of the application of the direct and indirect monitoring methods of the testing and monitoring plan.

**Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore**

| OH/CH* Depth, ft | Logging/Testing | Justification | NDAC § 43-05-01 |
|---|---|---|---|
| **Surface Section** | | | |
| OH 1340-0 | Triple combo (resistivity, bulk density, density and neutron porosity, GR, caliper, and spontaneous potential [SP]) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. | 11.2(1)(b)(1) |
| CH 1260-0 | Ultrasonic, casing collar locator (CCL), variable-density log (VDL), GR, and temperature log | Identified cement bond quality radially. Interpreted minor cement channeling throughout several isolated intervals and determined good azimuthal cement coverage and zonal isolation. | 11.2(1)(b)(2) |
| **Intermediate Section** | | | |
| OH 4170-1334 | Triple Combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for enhanced geomodeling and predictive simulation of $CO_2$ injection into the interest zones to improve test design and interpretations. Generated core-log correlations. | 11.2(1)(c)(1) |
| OH 4170-1334 | Dipole sonic | Identified mechanical properties in intermediate section. | 11.2(1)(c)(1) |
| OH 4170-3070 | Dielectric scanner | Quantified petrophysical properties and salinity calculations within the intermediate zones (Inyan Kara Formation). Provided information on rock properties and fluid distribution as inputs for reservoir evaluation and management. | 11.2(4) |
| CH 4070-30 | Ultrasonic, CCL, VDL, GR, and temperature log | Identified cement bond quality radially. Interpreted good azimuthal cement coverage and casing condition. Evaluated the cement top and zonal isolation. | 11.2(1)(c)(2) |
| **Long-string Section** | | | |
| OH 7068-4163 | Triple combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. | 11.2(1)(c)(1) |
| OH 7556-4163 | Dipole sonic | Identified mechanical properties of the rock including stress anisotropy. Provided compression and shear waves for seismic tie in and quantitative analysis of seismic data. | 11.2(1)(c)(1) |
| OH 5250-4250 | Fullbore FMI | Verified no fracture networks exist in the Broom Creek Formation or confining layers to ensure safe storage of $CO_2$. | 11.2(1)(c)(1) |
| OH 4741 and 4735 | BHP/T survey | Measured Broom Creek Formation pressure and temperature in the wellbore. | 11.2(2) |
| OH 4740-4733 | Fluid swab | Collected fluid sample from the Broom Creek Formation for analysis. | 11.2(2) |
| CH** TBD | Ultrasonic, CCL, VDL, and GR | Will identify cement bond quality radially and determine azimuthal cement coverage. Will evaluate the cement top and zonal isolation. | 11.2(1)(b)(2) |

* OH/CH – openhole/cased-hole
** Planned activity at the time of writing this permit to be completed prior to injection.

## 5.6 Wellbore Corrosion Prevention and Detection Plan

To prevent corrosion of the well materials, the following preemptive measures will be implemented in the MAG 1 and MAG 2 wellbores: 1) cement in the injection well opposite the injection interval and extending 1850 feet uphole will be $CO_2$-resistant; 2) the well casing will also be $CO_2$-resistant from the bottomhole to a depth just above the Spearfish Formation (upper confining zone); 3) the well tubing (poly-lined) will be $CO_2$-resistant from the injection interval to surface; 4) the packer (Ni-Plated) will be $CO_2$-resistant; and 5) the packer fluid will be an industry standard corrosion inhibitor.

To detect possible signs of corrosion in the MAG 1 and MAG 2, corrosion coupon samples will be used which will be constructed from the well materials. The corrosion coupon method is described in Section 5.3.2 of this testing and monitoring plan. In addition, the USIT or an equivalent wall thickness or imaging tool (e.g., EM CIL) may also be considered for detecting corrosion in the MAG 1 and MAG 2 wellbores. The USIT (or equivalent tool) may be used during workovers but no less than every 5 years.

## 5.7 Environmental Monitoring Plan

To verify the injected $CO_2$ is contained in the storage reservoir and to protect all USDWs, multiple environments will be monitored.

The surface atmosphere environment will be monitored via air sampling at soil gas profile stations installed near the MAG 1 and MAG 2 and a $CO_2$ detection station installed outside the injection wellhead enclosure.

The near-surface environment will be monitored via soil gas profile stations, shallow groundwater wells, and one dedicated Fox Hills Formation (lowest USDW) monitoring well.

The deep subsurface environment, defined as the region from below the lowest USDW to the base of the storage reservoir, will be monitored with multiple methods, starting with the above-zone monitoring interval (AZMI) or the geologic interval from the Spearfish Formation to the Inyan Kara Formation. The AZMI will be monitored with DTS in the MAG 1 and MAG 2 as well as PNLs in the MAG 2 (further described in Attachment A-5 of Appendix C).

The storage reservoir will be monitored with both direct and indirect methods. Direct methods include DTS and BHP/T measurements in the MAG 1 and MAG 2, as well as PNLs in the MAG 2. Indirect methods include time-lapse seismic and passive seismicity. During injection operations, pressure falloff testing to demonstrate storage reservoir injectivity in the MAG 1 wellbore will be carried out at least once every 5 years. These efforts will provide additional assurance that surface and near-surface environments are protected and that the injected $CO_2$ is safely and permanently stored in the storage reservoir.

Table 5-6 summarizes the environmental baseline and operational monitoring plans for the Blue Flint $CO_2$ storage project. Further details regarding these efforts are provided in the remainder of this section of the testing and monitoring plan.

**Table 5-6. Summary of Environmental Baseline and Operational Monitoring**

| Activity | Baseline Frequency* | Operational Frequency (20-year period) |
|---|---|---|
| **Atmosphere** | | |
| Wellsite (workplace) Atmosphere Sampling (Figures 5-3 and 5-4) | At start-up, install $CO_2$ detection stations placed outside well enclosures at the MAG 1 location. | Stations provide continuous monitoring of $CO_2$ conditions at the well pad. |
| Ambient Atmosphere Sampling (Figure 5-4) | Sample 3–4 events at each soil gas probe location (SG-1 through SG-5) prior to injection. | Sample 3–4 events per year at each soil gas profile station (SGPS 1 and SGPS 2).<br><br>Sampling will piggyback on the planned soil gas monitoring plan (described below). |
| **Soil Gas Monitoring** | | |
| Soil Gas Sampling (Figures 5-3 through 5-5) | Sample 3–4 events per probe location (i.e., SG-1 through SG-5) prior to injection.<br><br>Perform concentration and isotopic testing on all samples. | Sample 3–4 events per year at each soil gas profile station (i.e., SGPS 1 and SGPS 2).<br><br>Perform concentration and periodic isotopic testing on all samples. |
| **Shallow Groundwater** | | |
| Up to 5 Stock Wells (3 Operated by Falkirk Mining Company) (Figure 5-5) | Sample 3-4 events per well prior to injection.<br><br>Perform water quality and isotopic testing on all samples. | Shift sampling program to the dedicated Fox Hills monitoring well near the MAG 1 well. |
| **Lowest USDW** | | |
| Dedicated Fox Hills Monitoring Well Sampling at MAG 1 (Figure 5-5) | Sample 3–4 events per well.<br><br>Perform water quality and isotopic testing on all samples | Sample 3–4 events per well annually.<br><br>Perform water quality and periodic isotopic testing on all samples. |
| **AZMI** | | |
| DTS | Install during completion of MAG 1 and MAG 2. | Monitor temperature changes continuously in the MAG 1 and MAG 2. |
| PNL | Perform in MAG 2 prior to injection.<br><br>Run log from the Spearfish Formation through the Inyan Kara Formation to establish baseline conditions. | Collect PNL in MAG 2 at Year 4 and every 5 years thereafter until end of injection.<br><br>Run log from the Spearfish Formation through the Inyan Kara Formation to confirm containment in the storage reservoir. |
| **Storage Reservoir (direct)** | | |
| DTS | Install during completion of the MAG 1 and MAG 2. | Monitor temperature changes continuously in the MAG 1 and MAG 2. |
| PNL | Perform in MAG 2 prior to injection.<br><br>Run log from the Amsden Formation through the Spearfish Formation to establish baseline conditions. | Collect PNL in MAG 2 at Year 4 and every 5 years thereafter until end of injection.<br><br>Run log from the Amsden Formation through the Spearfish Formation to determine the Broom Creek Formation's saturation profile. |
| BHP/T Readings | Install BHP/T gauges over the storage reservoir in MAG 1 and MAG 2 prior to injection. | Collect BHP/T readings continuously from the storage reservoir in MAG 1 and MAG 2. |
| Pressure Falloff Testing | Conduct once prior to injection. | Perform at least once every five years. |

* The baseline (preinjection) monitoring effort has not yet begun as of the writing of this permit application.

Continued…

**Table 5-6. Summary of Environmental Baseline and Operational Monitoring (continued)**

| Activity | Baseline Frequency | Operational Frequency (20-year period) |
|---|---|---|
| **Storage Reservoir (indirect)** | | |
| Time-Lapse 2D Seismic Surveys (Figure 5-5) | Collect baseline fence 2D seismic survey. | Repeat 2D seismic survey in Year 1 and Year 4. At Year 4 following the start of injection, reevaluate frequency based on plume growth and seismic results. |
| Passive Seismicity Monitoring (Figure 5-7) | Utilize existing U.S. Geological Survey's network. | Utilize existing U.S. Geological Survey's network and supplement with additional equipment as necessary. |

### *5.7.1 Atmospheric Monitoring*

Figures 5-3 and 5-4 illustrate the planned well pad design at MAG 1 and MAG 2 and the locations of the $CO_2$ detection stations that will be used to monitor workspace atmospheres to ensure a safe work environment. As mentioned in Section 5.2 of this testing and monitoring plan, field personnel will be equipped with multigas detectors with them for wellsite visits or flowline inspections to detect potential leaks as an added safety precaution.

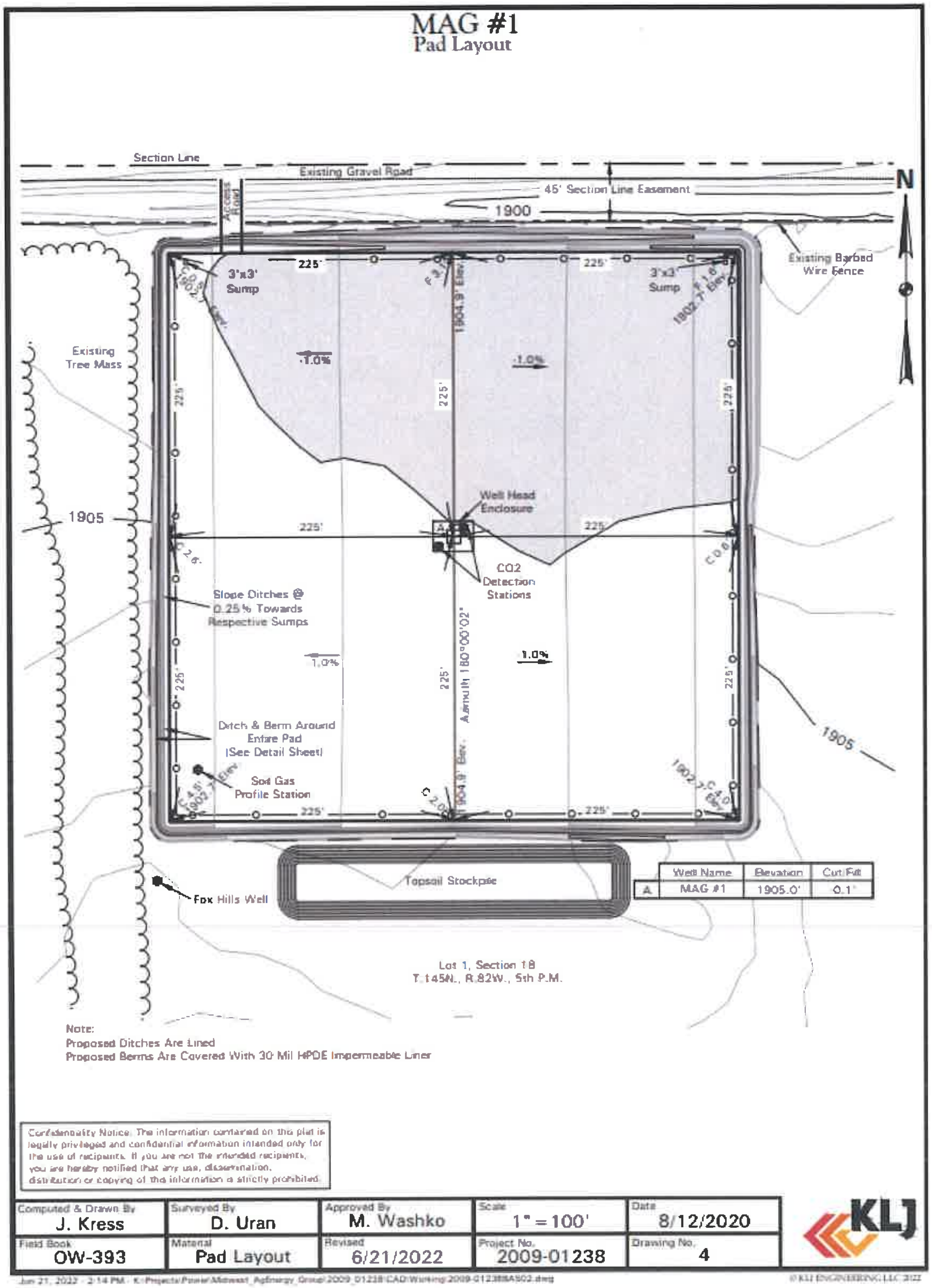



Figure 5-3. Well pad design for the MAG 1 $CO_2$-injection well. Indicated on the drawing are the locations of the $CO_2$ detection stations for atmospheric monitoring at the wellsite, the locations of the soil gas profile stations, and the Fox Hills Formation monitoring well.

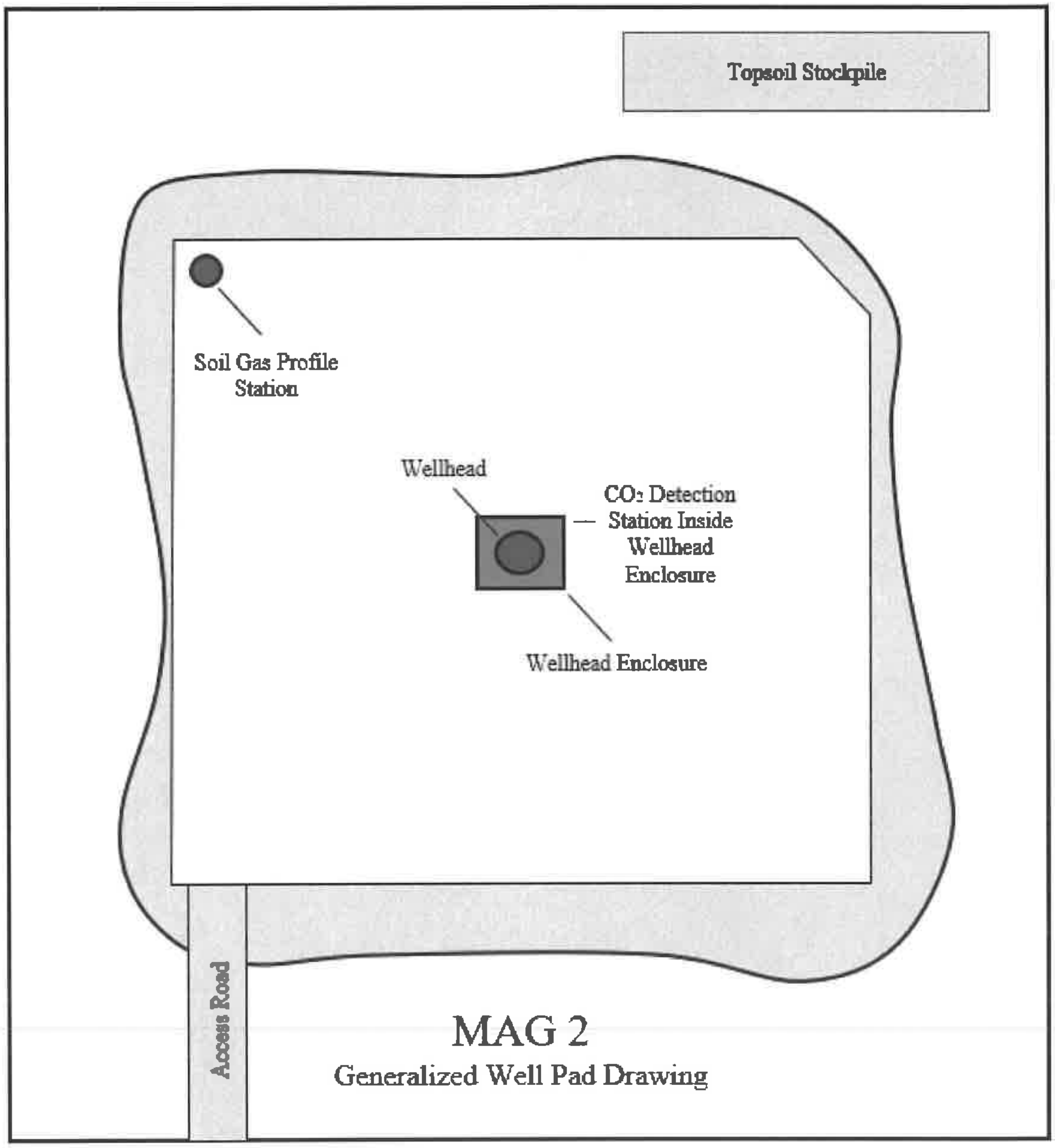



Figure 5-4. Well pad design for the MAG 2 deep monitoring well. Indicated on the drawing are the location of the $CO_2$ detection station as well as the location of the soil gas profile station.

Ambient atmospheric samples will be obtained quarterly at each of the soil gas profile stations (later described in Section 5.6.2). Field personnel collecting the soil gas samples will use a handheld soil gas analyzer to obtain an atmospheric sample to calibrate the instrument before obtaining soil gas measurements, and measurements of ambient $N_2$, $CO_2$, and $O_2$ will be recorded. QA/QC (quality assurance/quality control) methods regarding ambient air sampling are provided in Appendix C.

### *5.7.2 Soil Gas and Groundwater Monitoring*

Blue Flint plans to initiate soil gas sampling (Figure 5-5) in September 2022 to establish baseline conditions at the Blue Flint $CO_2$ storage project site and anticipates completing the sampling program by July 2023. Soil gas will be sampled via semi-permanent probe stations at five locations (SG-1 through SG-5) within the predicted 20-year $CO_2$ plume boundary 3-4 times prior to injection. Once injection begins, the soil gas sampling frequency will remain the same but shift to two soil gas profile stations to be installed: one soil gas profile station near the MAG 1 (SGPS 1); one soil gas profile station near the MAG 2 (SGPS 2).

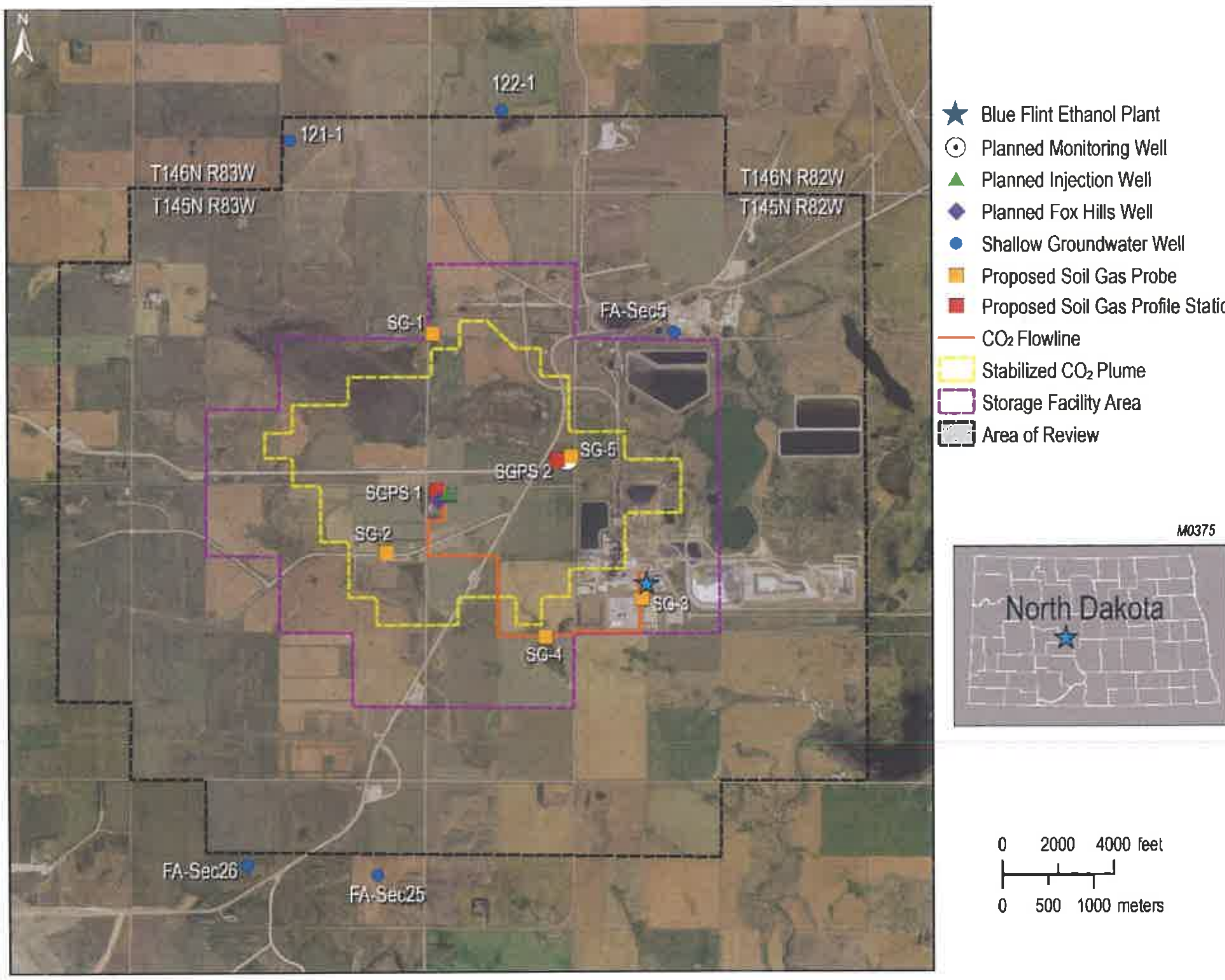



Figure 5-5. Blue Flint's planned baseline and monitoring program for soil gas, shallow groundwater aquifers, and the Fox Hills Aquifer.

Soil gas analytes will include concentrations of $CO_2$, $O_2$, and $N_2$ as well as isotopic ratios for $^{13}CO_2$, $^{14}CO_2$, $\delta^{13}C_1$, and $\delta D_{C_1}$ (further described in Appendix C). The results of the soil gas sampling program will be provided to NDIC prior to injection.

Blue Flint also plans to initiate a baseline groundwater sampling program in up to five existing shallow groundwater (stock) wells within 1 mile of the AOR, collecting 3-4 samples from each well prior to injection. In addition, Blue Flint will drill one dedicated Fox Hills Formation (lowest USDW) monitoring well near the MAG 1 well and acquire samples at the same frequency (Figure 5-5). Once injection begins, groundwater sampling will only occur at the dedicated Fox Hills monitoring well, collecting samples 3-4 times annually. Sample frequencies are further described in Table 5-6, and water analytes will include pH, conductivity, total dissolved solids, and alkalinity as well as major cations/anions and trace metals (further described in Appendix C). A state-certified laboratory analysis will be provided to NDIC prior to injection for all groundwater testing.

Water chemistry reports from active groundwater monitoring sites that are within or near the AOR and operated by the Falkirk Mining Company are provided in Appendix B.

### *5.7.3 Deep Subsurface Monitoring*

Blue Flint will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase $CO_2$ plume and associated pressure relative to the permitted storage reservoir. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and postoperational periods.[2] The methods described in Table 5-6 will be used to characterize the $CO_2$ plume's saturation and pressure within the AOR.

Blue Flint will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan (Ayash and others, 2017) at least once every 5 years. During each review, monitoring and operational data will be analyzed, and the AOR will be reevaluated. Based on this reevaluation, it will either be demonstrated that 1) no amendment to the testing and monitoring program is needed or 2) modifications are necessary to ensure proper monitoring of storage performance is achieved moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the $CO_2$ plume and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will, in turn, be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected $CO_2$ within the permitted geologic storage facility.

---

[2] Monitoring efforts for the postinjection period are described in Section 6: "Postinjection Site Care and Facility Closure Plan."

*5.7.3.1 AZMI Monitoring*

Prior to injection, Blue Flint will acquire PNL data in the MAG 2 well from the storage reservoir (Broom Creek Formation) up through the Spearfish Formation (upper confining zone) and Inyan Kara Formation (upper dissipation interval) (see Figure 2-2 for stratigraphic reference). PNLs will be run in MAG 2 at Year 4 and then every five years thereafter until the end of injection. These time-lapse saturation data will be used to monitor for $CO_2$ saturation in the AZMI (i.e., first few formations above the storage reservoir) as an assurance-monitoring technique to monitor the performance of the storage reservoir complex. Monitoring of the overlying interval can provide an early warning of out-of-zone migration of fluids, providing sufficient time for the development and implementation of mitigation strategies to ensure these migrating fluids do not impact a USDW or reach the surface.

*5.7.3.2 Direct Reservoir Monitoring*

DTS fiber installed in the MAG 1 and MAG 2 will directly monitor the temperature in the storage reservoir continuously. BHP/T readings will also be continuously recorded in the MAG 1 and MAG 2 wellbores via tubing-conveyed gauges. To track the migration of the $CO_2$ plume in the subsurface, PNLs will be performed in the MAG 2 at Year 4 and every five years thereafter until the end of $CO_2$ injection. The temperature and saturation profiles collected over the storage reservoir will provide information about the uniformity of $CO_2$ injectivity within the injection interval. The pressure data will be used primarily to ensure the pressure differential in the Broom Creek Formation conforms to numerical simulations.

*5.7.3.3 Indirect Reservoir Monitoring*

Indirect monitoring at the Blue Flint $CO_2$ storage project will include time-lapse 2D seismic surveys and passive seismicity monitoring. These indirect monitoring methods are described below and presented in Table 5-6.

To track the extent of the $CO_2$ plume within the storage reservoir over time, a 2D seismic survey was selected. The fence design was preferred over an alternative geometry (e.g., radial lines extending in all directions from the MAG 1 well location) or a 3D seismic acquisition for managing field logistics because of nearby active mining activities. Figure 5-6 illustrates the proposed 2D seismic survey that will be acquired prior to injection, in Year 1 of injection, and then in Year 4 of injection. At Year 4 of injection, the seismic survey design and frequency will be reevaluated. If necessary, the time-lapse seismic monitoring plan will be adapted based on updated simulations of the predicted extents of the $CO_2$ plume, including extending the 2D lines to capture additional data as the $CO_2$ plume expands. Repeat 2D seismic surveys will demonstrate conformance between the reservoir model simulation and site performance and monitor the evolution of the $CO_2$ plume. Because the fiber installed in the MAG 1 and MAG 2 wellbores will be capable of collecting distributed acoustic sensing (DAS) information (Figures 9-1 and 9-3), Blue Flint may also evaluate the feasibility of performing vertical seismic profiles (VSPs) to track the migration of the free-phase $CO_2$ plume in the storage reservoir.

Blue Flint plans to utilize the U.S. Geological Survey (USGS) existing seismicity network to monitor for seismic events larger than magnitude 2.7 in or near the AOR to inform the ERRP (emergency and remedial response plan) (Section 7) as an added safety precaution. Figure 5-7 provides the locations of existing USGS seismicity stations in North Dakota and the surrounding region.

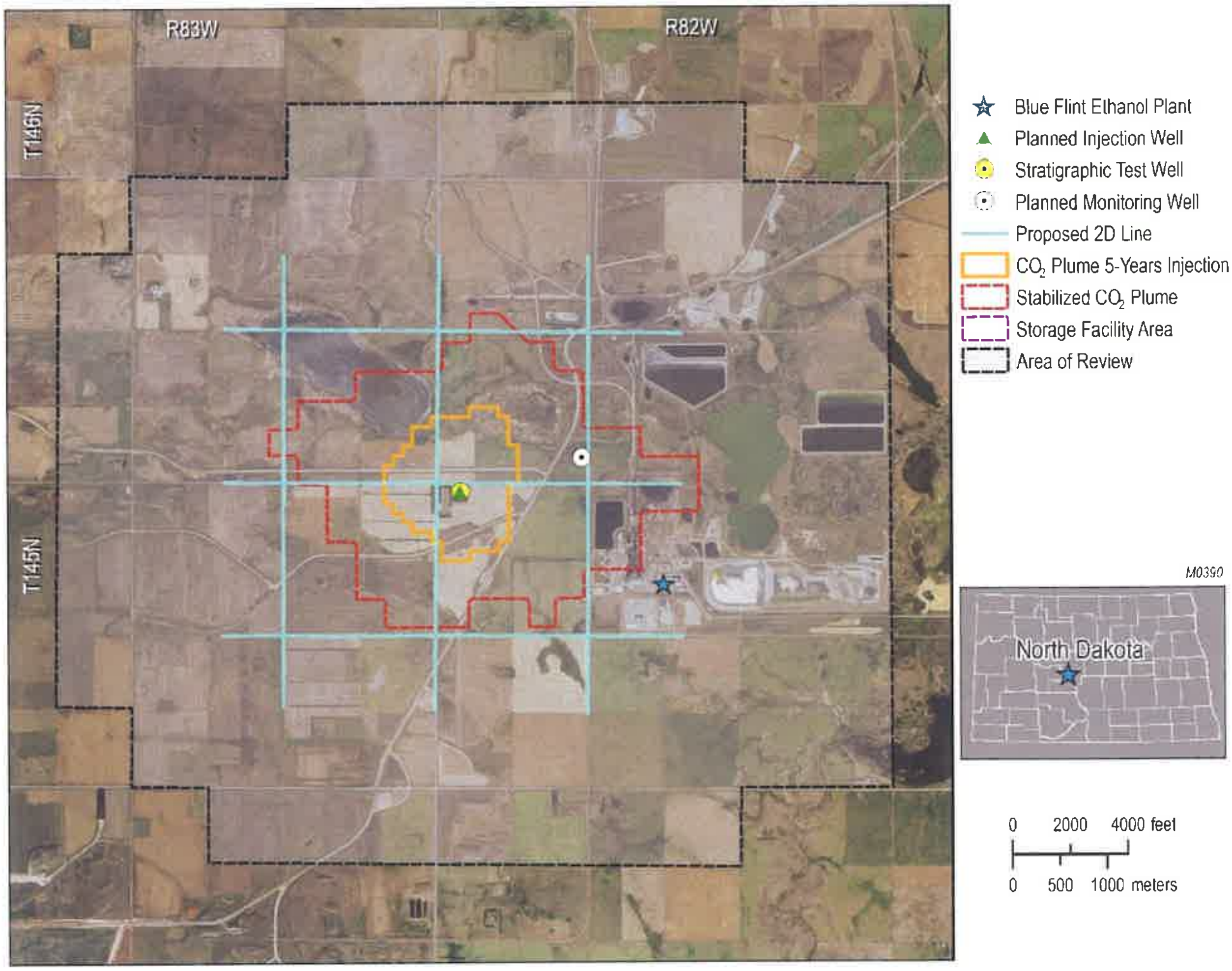



Figure 5-6. Locations of the proposed 2D seismic lines for the fence design near the MAG 1 well to establish a baseline and monitoring for the Blue Flint $CO_2$ storage project during Years 1–4 of injection.

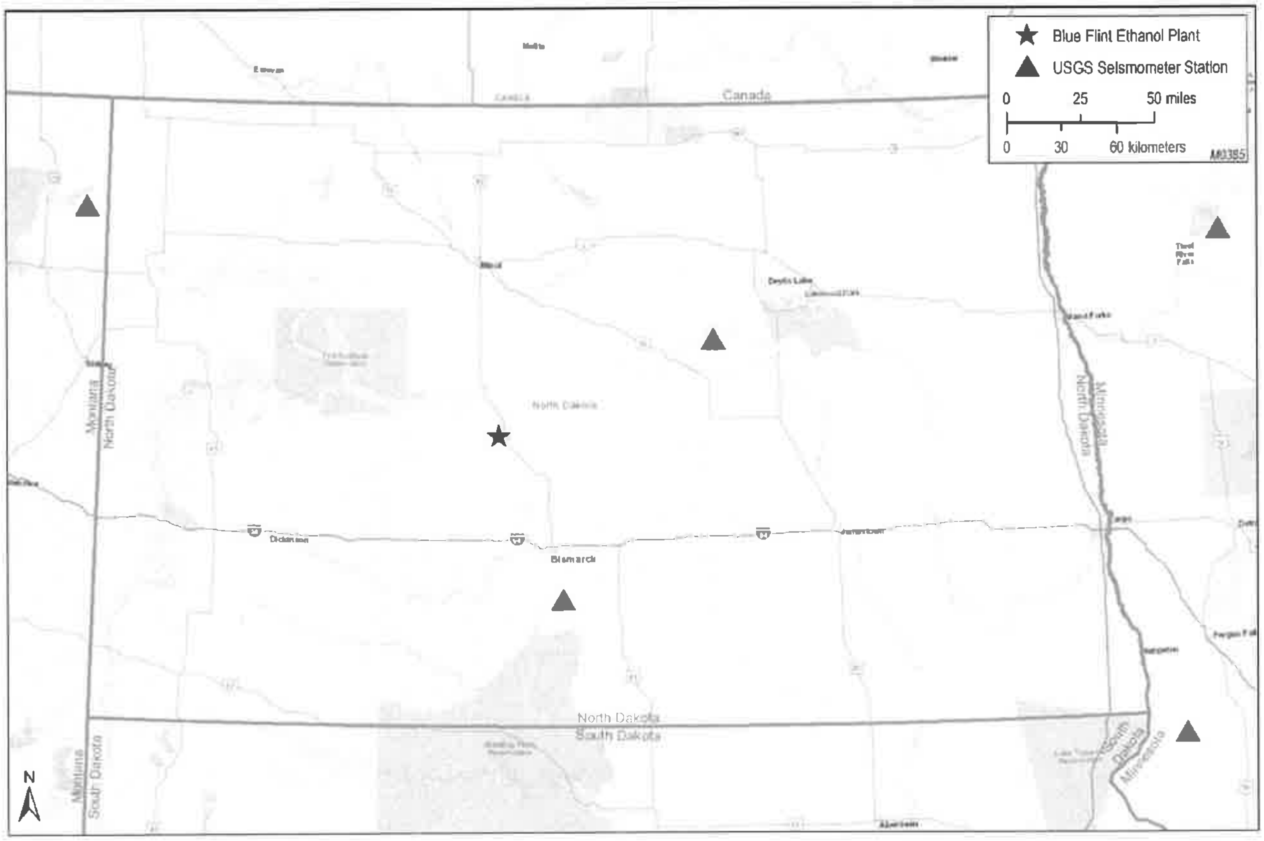



Figure 5-7. Locations of USGS seismometer stations in North Dakota and the surrounding region.

## 5.8 References

API SPEC 17J (R2021), 2017, Specification for unbonded flexible pipe: American Petroleum Institute, 2014, STANDARD 05/01/2014, Fourth Edition, Includes Errata 1 (September 2016), Errata 2 (May 2017), and Addendum 1 (2017).

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.

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.

# 6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

## 6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

This postinjection site care (PISC) and facility closure plan describes the activities that Blue Flint will perform following the cessation of $CO_2$ injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected $CO_2$ plume is stable (i.e., $CO_2$ migration will be unlikely to move beyond the boundary of the storage facility area). Based on simulations of the predicted $CO_2$ plume movement following the cessation of $CO_2$ injection, it is projected that the $CO_2$ plume will stabilize within the storage facility area boundary (Section 3.0). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the $CO_2$ plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable $CO_2$ plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval.

In addition to Blue Flint executing this postinjection monitoring plan, the $CO_2$ injection well will be plugged as described in the plugging plan of this permit application (Section 10.0). All surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site for submission as part of a site-closure report.

### 6.1 Predicted Postinjection Subsurface Conditions

#### *6.1.1 Pre- and Postinjection Pressure Differential*

Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of $CO_2$ injection. The simulations were conducted for 20 years of $CO_2$ injection at a rate of 200,000 metric tons per year, followed by a PISC period of 10 years.

Figure 6-1 illustrates the predicted pressure differential at the conclusion of $CO_2$ injection. At the time that $CO_2$ injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of up to 120 psi at the location of the $CO_2$ injection well. There is insufficient pressure increase caused by $CO_2$ injection to move more than 1 cubic meter of formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the AOR delineation of this permit application (Section 3.0).

Figure 6-2 illustrates the predicted gradual pressure decrease following the cessation of $CO_2$ injection, with the pressure at the injection well at the end of the PISC period anticipated to decrease 80 to 100 psi as compared to the pressure at the time $CO_2$ injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.

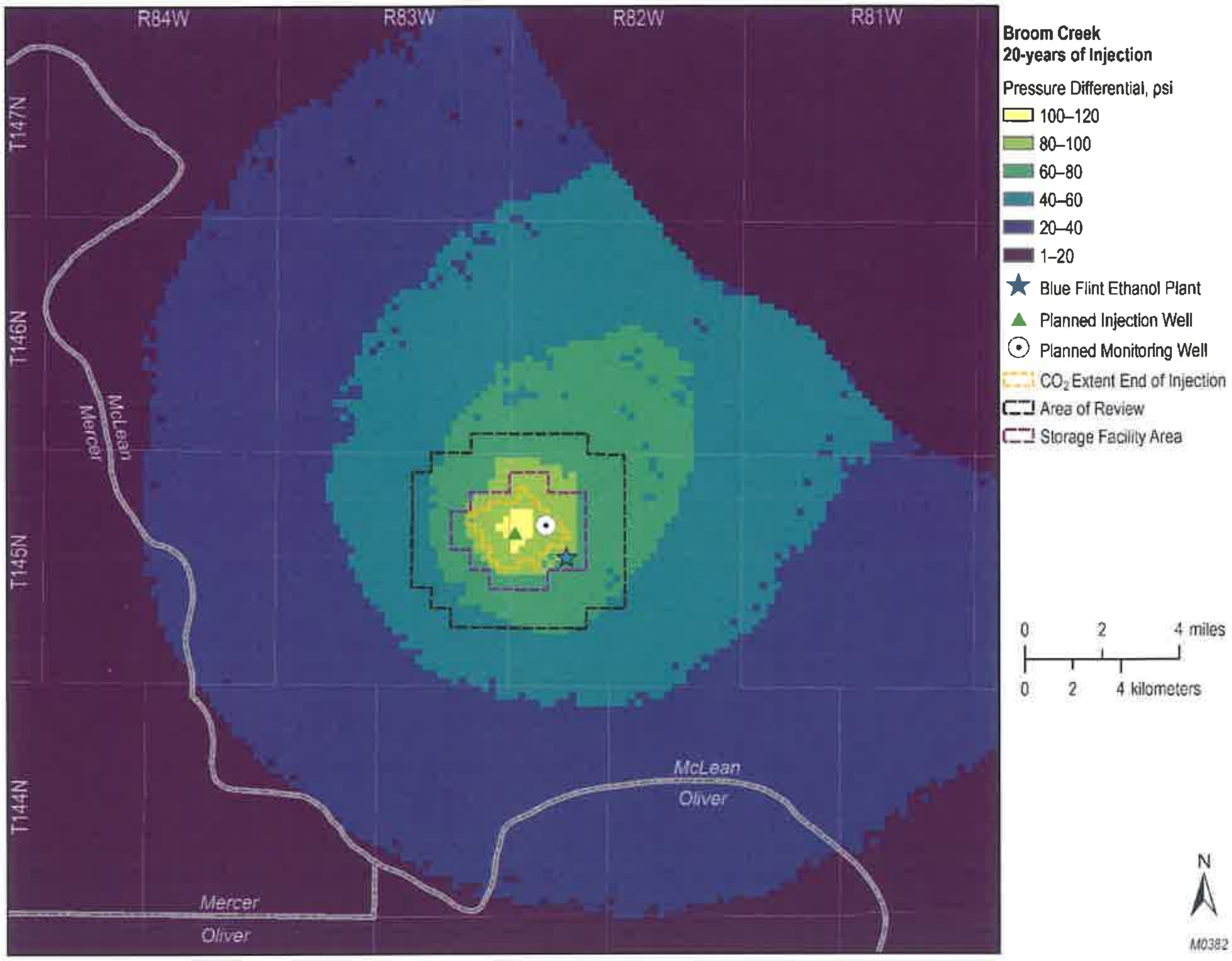



Figure 6-1. Predicted pressure increase in storage reservoir following 20 years of $CO_2$ injection at a rate of 200,000 metric tons per year.

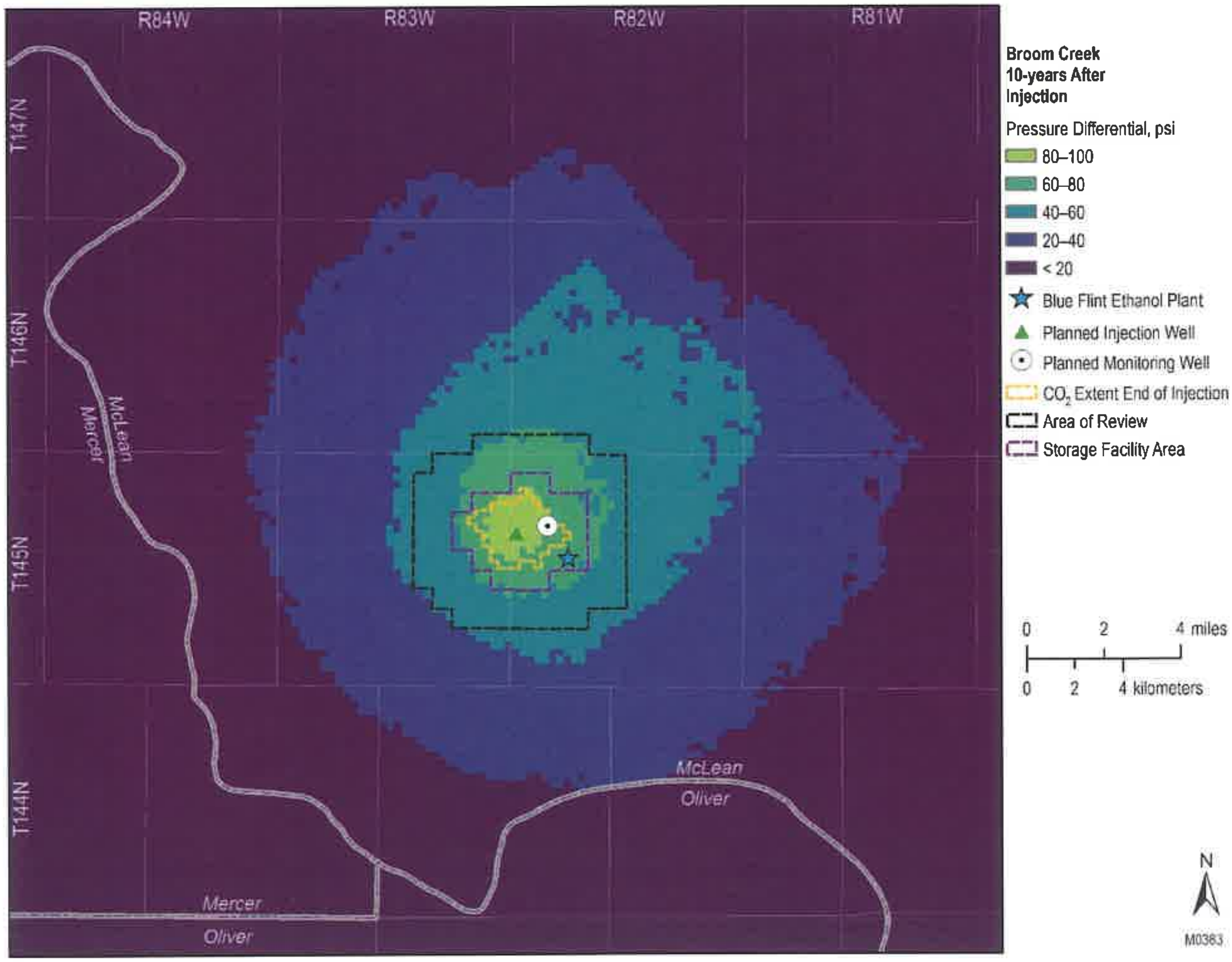



Figure 6-2. Predicted pressure decrease in the storage reservoir over a 10-year period following the cessation of $CO_2$ injection.

### *6.1.2 Predicted Extent of $CO_2$ Plume*

Figure 6-2 illustrates the extent of the $CO_2$ plume following the planned 10-year PISC period (also called the stabilized plume), which is based on numerical simulation predictions. The results of these simulations predict that 99% of the separate-phase $CO_2$ mass would be contained within an area of 2.96 $mi^2$ at the end of $CO_2$ injection. As shown in Figure 6-2, the areal extent of the $CO_2$ plume is not predicted to change substantially over the planned PISC period.

Additional simulations beyond the 10-year PISC period were also performed and predict that at no time will the boundary of the stabilized plume at the site, which is shown in Figure 6-2, extend beyond the boundary of the storage facility area. If such a determination can be made following the planned 10-year PISC period, the $CO_2$ plume will meet the definition of stabilization as presented in NDCC § 38-22-17(5)(d) and qualify the geologic storage site for receipt of a certificate of project completion.

## 6.2 Postinjection Testing and Monitoring Plan

A summary of the postinjection testing and monitoring plan that will be implemented during the 10-year postinjection period is provided in Tables 6-1 and 6-2. Table 6-1 includes a plan to monitor wellbore stability (mechanical integrity and corrosion monitoring plans) and assumes the MAG 1 wellbore will be plugged after injection ceases and that the MAG 2 wellbore will monitor the storage reservoir until site closure. Table 6-2 summarizes environmental monitoring efforts to track the $CO_2$ plume in the storage reservoir and protect USDWs.

**Table 6-1. Overview of Blue Flint's PISC MAG 2 Mechanical Integrity Testing and Corrosion Monitoring Plan**

| Activity | Postinjection Frequency (10-year period) |
|---|---|
| **External Mechanical Integrity Testing** | |
| DTS | Continuous monitoring. |
| USIT or Electromagnetic Casing Inspection Log | Perform during well workovers but no less than once every 5 years. |
| **Internal Mechanical Integrity Testing** | |
| Tubing–Casing Pressure Testing | Perform during well workovers but not more frequently than once every 5 years.<br><br>Digital surface gauges will monitor tubing and annulus pressures continuously. |
| Surface and Tubing-Conveyed BHP/T Gauges | Gauges will monitor temperatures and pressures in the tubing continuously. |
| **Corrosion Monitoring** | |
| USIT or Electromagnetic Casing Inspection Log | Perform during well workovers but no less than once every 5 years. |

### *6.2.1 Soil Gas and Groundwater Monitoring*

Six soil gas-monitoring locations (i.e., two SGPSs and four soil probe locations) will be sampled during the proposed PISC period. Additionally, one dedicated monitoring well in the Fox Hills Formation (i.e., lowest USDW) near the MAG 1 well will be sampled. Figure 6-3 identifies the locations of the soil gas-monitoring locations and the dedicated Fox Hills Formation monitoring well. All samples will likely be analyzed for the same list of parameters as described in the testing and monitoring plan (Section 5.0); however, the final target list of analytical parameters may be reduced for the PISC period based on an evaluation of the monitoring results that are generated during the 20-year injection period of the storage operations. Additional sampling of groundwater in the PISC period may occur on active and accessible shallow groundwater wells within the AOR.

**Table 6-2. Overview of Blue Flint's PISC Monitoring Plan**

| Activity | Postinjection Frequency (10-year period) |
|---|---|
| **Soil Gas** | |
| SGPSs (SGPS01 and SGPS02) (Figure 6-3) | Sample SGPS01 prior to MAG 1 reclamation. Sample SGPS02 annually until site closure. |
| Soil Gas Probe Locations (SG01 to SG04) (Figure 6-3) | Sample soil gas probe locations at the start of the PISC period and prior to site closure. |
| **Shallow Groundwater** | |
| Shallow Groundwater Wells | Sampling may be performed on active and accessible shallow groundwater wells in the AOR prior to site closure. |
| **Lowest USDW** | |
| Dedicated Fox Hills Monitoring Well near the MAG 1 (Figure 6-3) | Sample the dedicated Fox Hills monitoring well annually until site closure. |
| **Above-Zone Monitoring Interval (AZMI) Monitoring** | |
| DTS | Continuous monitoring |
| PNL | Perform PNL in the MAG 2 well annually from the Spearfish up through the Inyan Kara until the near-wellbore environment reaches full $CO_2$ saturation (anticipated during the injection stage). Reduce frequency to every 4 years thereafter. |
| **Storage Reservoir (direct)** | |
| DTS | Continuous monitoring |
| PNL | Perform PNL in the MAG 2 well annually until the near-wellbore environment reaches full $CO_2$ saturation (anticipated during the injection stage). Reduce frequency to every 4 years thereafter. |
| **Storage Reservoir (indirect)** | |
| 2D Time-Lapse Seismic (Figure 6-4) | Actual design and frequency to be determined based on reevaluations of the testing and monitoring plan (Section 5.0) and migration of the $CO_2$ plume over time. |
| Passive Seismicity | USGS seismic network, supplemented with additional stations as needed. |

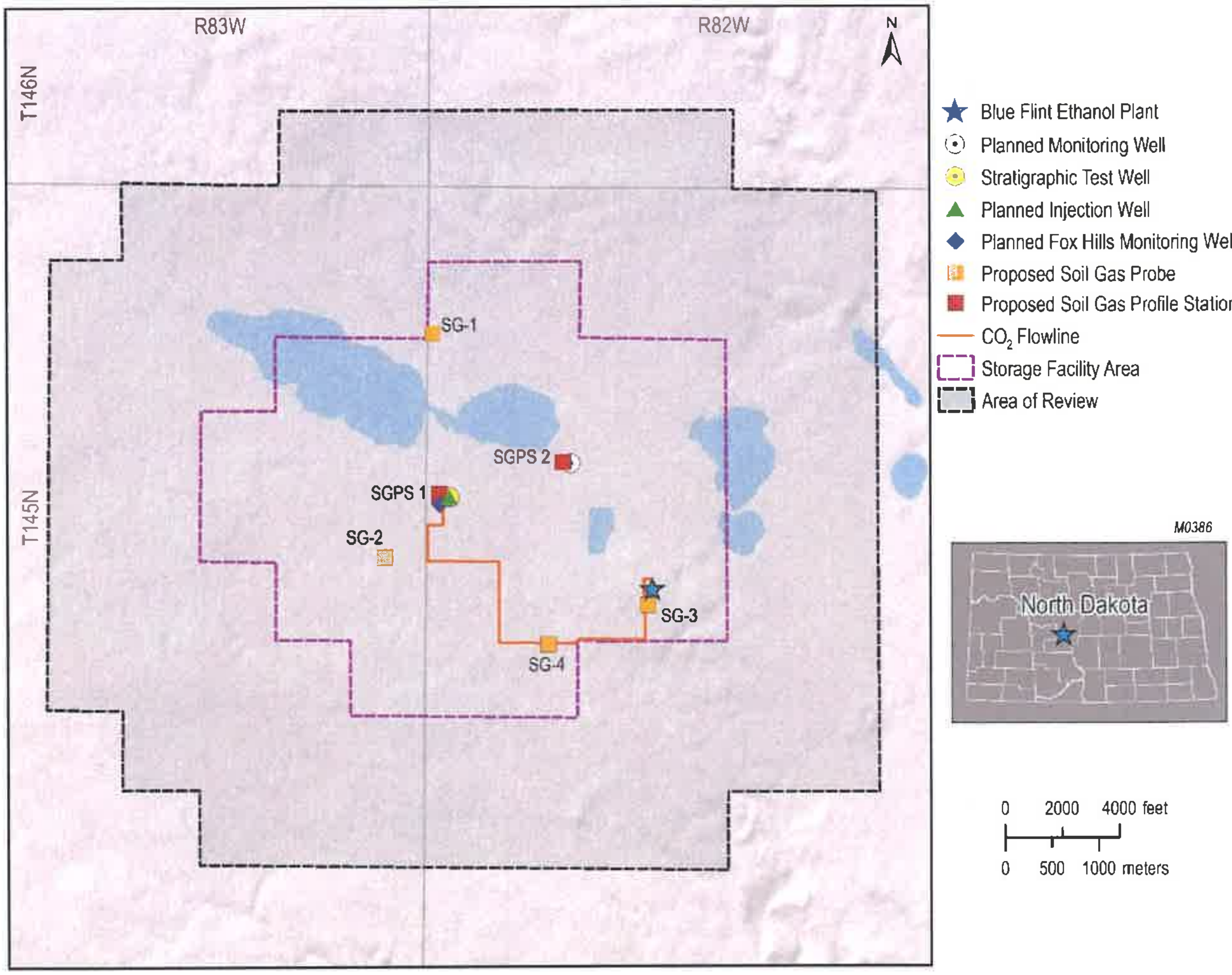



Figure 6-3. Soil gas- and groundwater well-sampling locations included in the PISC monitoring program.

### *6.2.2 $CO_2$ Plume Monitoring*

The design and frequency of the 2D time-lapse seismic survey will depend on how the $CO_2$ plume is migrating and the results of the adaptive management approach (Section 5.6.3). As stated in Table 5-6 and Section 5.6.3.3 of the testing and monitoring plan, the 2D seismic survey design and frequency will be repeatedly reevaluated and updated as necessary starting in Year 4 of injection.

Existing seismicity stations and the network maintained by the USGS (Figure 5-7) will be used to monitor for any seismic events that may occur during the postinjection period of the Blue Flint $CO_2$ storage project.

## 6.3 Schedule for Submitting Postinjection Monitoring Results

All PISC-monitoring data and monitoring results will be submitted to NDIC in annual reports. These reports will be submitted within 60 days of the anniversary date on which the $CO_2$ injection ceased.

The annual reports will contain information and data generated during the reporting period, including seismic data acquisition, formation monitoring data, soil gas and groundwater sample analytical results, and simulation results from updated site models and numerical simulations.

### *6.3.1 PISC Plan*

Blue Flint will submit a final site closure plan and notify NDIC at least 90 days prior to its intent to close the site. The site closure plan will describe a set of closure activities that will be performed, following approval by NDIC, at the end of the PISC period. Site closure activities will include the plugging of all wells that are not planned for continued use in monitoring the closed site; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring; the reclaiming of the surface land of the site to as close as is practical to its original condition; and abandonment of flowlines pursuant to NDAC Section 43-02-03-34.1.

Any flowlines buried less than 3 feet below final contour will be removed (e.g., the planned flowline segment at the capture facility on Blue Flint Ethanol property and the above-ground portion of the flowline at the injection wellsite). Associated costs during the PISC period are outlined in Section 12, which include the type and frequency of monitoring as well as equipment costs, plugging of the injection well, and site reclamation.

As part of the PISC monitoring and closure plan and in accordance with NDAC 43-05-01-19(5), the MAG 1 injection well will be plugged and abandoned and the injection well pad will be reclaimed. Reclamation of the MAG 1 well and the injection pad includes wellhead removal, sump removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, reclamation of the flowline at the injection pad, and the P&A of SGPS01.

The dedicated Fox Hills monitoring well adjacent to the MAG 1 injection wellsite will remain, at a minimum, until site closure. At the time of site closure, NDIC and Blue Flint will decide if the Fox Hills well adjacent to the MAG 1 wellsite will be plugged and abandoned with the site location reclaimed or if the ownership of the Fox Hills well will transfer to the State.

### *6.3.2 Site Closure Plan*

To comply with NDAC 43-05-01-19(2), the MAG 2 well will be used for deep subsurface monitoring during the PISC period and will be plugged and abandoned as part of site closure activities. Reclamation of the MAG 2 well and well pad at site closure includes wellhead removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, and the P&A of SGPS02.

As part of the final assessment, Blue Flint will work with NDIC to determine which wells and monitoring equipment will remain and transfer to the State for continued postclosure monitoring. The dedicated Fox Hills monitoring well drilled adjacent to the MAG 1 injection well

and soil gas profile stations may transfer ownership to the State or a third party, pending NDIC review and approval of the PISC plan and final assessment pursuant to 43-05-01-19. Cost estimates for the PISC and closure periods can be found in Section 12 in the scenario that transfer to the State or a third party does not occur.

### *6.3.3 Submission of Site Closure Report, Survey, and Deed*

A site closure report will be prepared and submitted to NDIC within 90 days of the execution of the PISC and facility closure plan. This report will provide NDIC with a final assessment that documents the location of the stored $CO_2$ in the reservoir, describes its characteristics, and demonstrates the stability of the $CO_2$ plume in the reservoir over time. The site closure report will also document the following:

- Plugging records of the injection well and monitoring well.
- Location of the sealed injection well and monitoring well on a plat survey that has been submitted to the local zoning authority.
- Notifications to state and local authorities as required by NDAC § 43-05-01-19.
- Records regarding the nature, composition, and volume of the injected $CO_2$.
- Postinjection monitoring records.

At the same time, Blue Flint will also provide NDIC with a copy of an accurate plat certified by a registered surveyor that has been submitted to the county recorder's office designated by NDIC. The plat will indicate the location of the injection well and monitoring well relative to permanently surveyed benchmarks pursuant to NDAC § 43-05-01-19.

Lastly, Blue Flint will record a notation on the deed (or any other title search document) to the property on which the injection well and monitoring well were located pursuant to NDAC § 43-05-01-19.

# 7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

## 7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

Blue Flint Sequester Company LLC (Blue Flint) and Blue Flint Ethanol LLC, operator of the Blue Flint Ethanol (BFE) facility, will enter into an agreement whereby Blue Flint employees, contractors and agents are required to follow the BFE facility emergency action plans, including, but not limited to, the BFE facility response plan. This emergency and remedial response plan (ERRP) for the geologic storage project 1) describes the local resources and infrastructure in proximity to the project site; 2) identifies events that have the potential to endanger USDWs during the construction, operation, and postinjection site care periods of the geologic storage project, building upon the screening-level risk assessment (SLRA); and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing BFE facility response plan and risk management plan (and incorporated into the BFE Integrated Contingency Plan [ICP]) is described, emphasizing the facility response team and command structure, facility evacuation plans, HazMat (hazardous materials) capabilities, and emergency communication plans. Lastly, procedures are presented for regularly conducting an evaluation of the adequacy of the ERRP and updating it, if warranted, over the lifetime of the geologic storage project. Copies of this ERRP are available at the Blue Flint's office and the BFE facility.

### 7.1 Background

$CO_2$ produced at the BFE facility will be captured and geologically stored in close proximity to the plant location (see Table 7-1 for a listing of relevant BFE environmental permits). The projected composition of the captured gas is 99.98% dry $CO_2$ (by volume), with trace quantities (0.02% by volume) of water, nitrogen, oxygen, hydrogen sulfide, $C_2^+$ and hydrocarbons. Figure 5-1 identifies the BFE facility location, as well as the planned capture facility, the $CO_2$ flowline, and the $CO_2$ injection well (MAG 1) and monitoring well (MAG 2). The well locations, including latitudes and longitudes, are provided below (Table 7-2).

**Table 7-1. Environmental Permits Issued to BFE**

| Permit | Permit Number | Issuing Agency |
|---|---|---|
| Risk Management Plan | 10000098136 | EPA |
| Facility Response Plan | FRP08D0017 | EPA |
| Air Permit to Operate – Title V | AOP-28450 V2.0 | NDDEQ |
| Industrial Storm Water Permit | NDR05-0000 | NDDEQ |
| Alcohol Fuel Producer Permit | AFP-ND-15003 | ATF |

**Table 7-2. Well Name and Location Information for the $CO_2$ Injection Well (MAG 1) and Monitoring Well (MAG 2) of the Geologic Storage Operations**

| Well Name | Purpose | NDIC File No. | Quarter/Quarter | Section | Township | Range | Latitude | Longitude |
|---|---|---|---|---|---|---|---|---|
| MAG 1 | $CO_2$ Injection Well | 37833 | Lot 1 | 18 | 145N | 82W | 47.385185 | 101.182135 |
| MAG 2 | Monitoring Well | TBD* | SE4 | 19 | 145N | 82W | TBD | TBD |

* TBD = to be determined

The primary Blue Flint contacts for the geologic storage project and their contact information are listed in Table 7-3.

**Table 7-3. Primary Blue Flint Project Contacts**

| | | Contact Information |
|---|---|---|
| **Individual** | **Title** | **Office Phone Number** |
| Jeff Zueger | CEO | (701) 442-7501 |
| Adam Dunlop | Director – Regulatory & Technical Services | (701) 442-7503 |
| Travis Strickland | Plant Manager | (701) 442-7502 |
| Jeff Martian | Process Engineer | (701) 442-7512 |

Contact names and information for the complete facility response team (Table 7-6) as well as key local emergency organizations/agencies (Table 7-8) and specific contractors and equipment vendors able to respond to potential leaks or loss of containment (Table 7-9) are provided in a separate section of this ERRP (Section 7.6, Emergency Communications Plan).

## 7.2 Local Resources and Infrastructure

Local resources in the vicinity of the geologic storage project that may be impacted as a result of an emergency event include: 1) the holding ponds associated with the Coal Creek Station (owned by Rainbow Energy Center); 2) the Weller Slough and Turtle Lake Aquifers; and 3) the Falkirk Mining Company leased mine land, including reclaimed mine land.

The infrastructure in the vicinity of the project that may be impacted as a result of an emergency event is shown in Figure 5-1, and includes: 1) BFE facility; 2) the $CO_2$ injection wellhead (MAG 1) and the monitoring wellhead (MAG 2); 3) nearby commercial and residential structures; and 4) the $CO_2$ flowline. Figure 3-20 shows land use within the area of review (AOR), including commercial, residential, and public lands, if any, as required in NDAC § 43-05-01-13.

## 7.3 Identification of Potential Emergency Events

### *7.3.1 Definition of an Emergency Event*

An emergency event is an event that poses an immediate, or acute, risk to human health, resources, or infrastructure and requires a rapid, immediate response. This ERRP focuses on emergency events that have the potential to move injection fluid or formation fluid in a manner that may endanger USDWs or lead to an accidental release of $CO_2$ to the atmosphere during the construction, operation or postinjection site care project periods.

### *7.3.2 Potential Project Emergency Events and Their Detection*

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

1. Injectivity
2. Storage capacity
3. Containment – lateral migration of $CO_2$

4. Containment – pressure propagation
5. Containment – vertical migration of $CO_2$ or formation water brine via injection wells, other wells, or inadequate confining zones
6. Natural Disasters (induced seismicity)

Based on a review of these technical risk categories, a list of the geologic storage project events that could potentially result in the movement of injection fluid or formation fluid in a manner that may endanger a USDW and require an emergency response was developed for inclusion in this ERRP. These events and means for their detection are provided in Table 7-4.

In addition to the foregoing technical project risks, the occurrence of a natural disaster (e.g., naturally occurring earthquake, tornado, lightning strike, etc.) also represents an event for which an emergency response action may be warranted. For example, an earthquake or weather-related disaster (e.g., tornado or lightning strike) has the potential to result in injection well problems (integrity loss, leakage, or malfunction) and may also disrupt surface and subsurface storage operations. These events are addressed in the BFE emergency response plans and will be extended to the geologic storage operations.

## 7.4 Emergency Response Actions

The response actions that will be taken to address the events listed in Table 7-4, as well as potential natural disasters, will follow the same protocol. This protocol consists of the following actions:

- The facility response plan qualified individual (QI) (see Section 7.6, Emergency Communications Plan) will be notified immediately and, as soon as practical and within 24 hours, of that notification, make an initial assessment of the severity of the event (i.e., does it represent an emergency event?) to ensure all necessary steps have been taken to identify and characterize any release pursuant to NDAC Section 43-05-01-13(2)(b).
- If determined to be an emergency event, the QI or designee shall notify the NDIC Department of Mineral Resources (DMR) Underground Injection Control (UIC) program director (see Section 7.6, Emergency Communications Plan, Table 7-7) within 24 hours of the emergency event determination (pursuant to NDAC § 43-05-01-13) and implement the emergency communications plan.
- Following these actions, the geologic storage project operator will:
    1. Initiate a project shutdown plan and immediately cease $CO_2$ injection. (However, in some circumstances, the operator may, in consultation with the NDIC DMR UIC Program director, determine whether gradual or temporary cessation of injection is more appropriate).
    2. Shut in the $CO_2$ injection well (close flow valve).
    3. Vent $CO_2$ from surface facilities.
    4. Limit access to the wellhead to authorized personnel only, equipped with appropriate personal protection equipment (PPE).

**Table 7-4. Potential Project Emergency Events and Their Detection**

| Potential Emergency Events | Detection of Emergency Events |
|---|---|
| Failure of $CO_2$ Flowline from Capture System to $CO_2$ Injection Wellhead | • Computational flowline continuous monitoring and leak detection system (LDS). Instrumentation at both ends of the flowline for each injection well collects pressure, temperature, and flow data. The LDS software uses the pressure readings and flow rates in and out of the line to produce a real-time model and predictive model. By monitoring deviations between the real-time model and the predictive model, the software detects flowline leaks.<br>• Frozen ground at leak site may be observed.<br>• $CO_2$ monitors located on the flowline risers detect a release of $CO_2$ from the flowline connection and/or wellhead. |
| Integrity Failure of Injection or Monitoring Well | • Pressure monitoring reveals wellhead pressure exceeds the shutdown pressure specified in the permit.<br>• Annulus pressure indicates a loss of external or internal well containment.<br>• Mechanical integrity test results identify a loss of mechanical integrity.<br>• $CO_2$ monitors located inside and outside the enclosed wellhead building detect a release of $CO_2$ from the wellhead. |
| Monitoring Equipment Failure of Injection Well | Failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure is detected. |
| Storage Reservoir Unable to Contain the Formation Fluid or Stored $CO_2$ | Elevated concentrations of indicator parameter(s) in soil gas, groundwater, and/or surface water sample(s) are detected. |

5. If warranted, initiate the evacuation of the BFE plant and associated geologic storage project facilities in accordance with the facility response plan and communicate with local emergency authorities to initiate evacuation plans of nearby residents.

6. Perform the necessary actions to determine the cause of the event and, in consultation with the NDIC DMR UIC program director, identify and implement appropriate emergency response actions (see Table 7-5, for details regarding the specific actions that will be taken to determine the cause and, if required, mitigation of each of the events listed in Table 7-4).

**Table 7-5. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions**

| | |
|---|---|
| Failure of $CO_2$ Flowline from the $CO_2$ Capture System to $CO_2$ Injection Wellhead | • The $CO_2$ release and its location will be detected by the LDS and/or $CO_2$ wellhead monitors, which will trigger a BFE alarm, alerting plant system operators to take necessary action.<br>• If warranted, initiate an evacuation plan in tandem with an appropriate workspace and/or ambient air-monitoring program near the location of failure to monitor the presence of $CO_2$ and its natural dispersion following the shutdown of the flowline using practices similar to those used to develop the risk management plan.<br>• The flowline failure will be inspected to determine the root cause of the flowline failure.<br>• Repair/replace the damaged flowline, and if warranted, put in place the measures necessary to eliminate such events in the future. |
| Integrity Failure of Injection or Monitoring Well | • Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure.<br>• Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the NDIC DMR UIC program director).<br>• If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts.<br>• If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director). |
| Monitoring Equipment Failure of Injection Well | • Monitor well pressure, temperature, and annulus pressure (manually, if necessary) to determine the cause and extent of failure.<br>• Identify and, if necessary, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director). |

Continued . . .

**Table 7-5. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)**

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

- Collect a confirmation sample(s) of groundwater from the Fox Hills monitoring well, and soil gas profile station, and analyze the samples for indicator parameters (see Testing and Monitoring Plan in Section 5.0 of the SFP application).
- If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC program director) a case-specific work plan to:
    1. Install additional monitoring points near the impacted area to delineate the extent of impact:
        a. If a USDW is impacted above drinking water standards, arrange for an alternate potable water supply for all users of that USDW.
        b. If a surface release of $CO_2$ to the atmosphere is confirmed, initiate an evacuation plan, if warranted, in tandem with an appropriate workspace and/or ambient air-monitoring program at the appropriate incident boundary to monitor the presence of $CO_2$ and its natural dispersion following the termination of $CO_2$ injection following practices similar to those used to develop the risk management plan.
        c. If surface release of $CO_2$ to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are exceeded.
    2. Proceed with efforts, if necessary, to a) remediate the USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or $CO_2$ or "pump and treat" the impacted drinking water to mitigate $CO_2$/brine impacts) and/or b) manage surface waters using natural attenuation (i.e., natural processes, e.g., biological degradation, active in the environment that can reduce contaminant concentrations) or active treatment to achieve compliance with applicable water quality standards.
- Continue all remediation and monitoring at an appropriate frequency (as determined by BFE management designee and the NDIC DMR UIC program director) until unacceptable adverse impacts have been fully addressed.

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

Continued . . .

**Table 7-5. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)**

| | |
|---|---|
| Natural Disasters (seismicity) | • Identify when the event occurred and the epicenter and magnitude of the event.<br>• If magnitude is greater than 2.7:<br>1. Determine whether there is a connection with injection activities.<br>2. Demonstrate all project wells have maintained mechanical integrity.<br>3. If a loss of $CO_2$ containment is determined, proceed as described above to evaluate, and if warranted, mitigate the loss of containment. |
| Natural Disasters | • Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure.<br>• If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts.<br>• If impacts or endangerment are detected, identify and implement appropriate response actions in accordance with the facility response plan (in consultation with the NDIC DMR UIC program director). |

## 7.5 Response Personnel/Equipment and Training

### *7.5.1 Response Personnel and Equipment*

All BFE plant and geologic storage project personnel will have undergone hazardous waste operations and emergency response (HAZWOPER) training in accordance with guidelines produced and maintained by the Occupational Safety and Health Administration (OSHA) (OSHA 29 Code of Federal Regulations [CFR] § 1910.120). In addition, assistance has been secured from local (Washburn and Underwood, North Dakota) and McLean County emergency services to implement this ERRP (see Table 7-6).

Equipment (including appropriate PPE) needed in the event of an emergency and remedial response will vary, depending on the emergency event. Response actions (e.g., cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. However, when specialized equipment (such as a drilling rig or logging equipment or potable water hauling, etc.) is required, the Director – Regulatory & Technical Services (see Table 7-3) shall be responsible for its procurement, including maintenance of the list of contractors and equipment vendors (see Section 7.6, Emergency Communications Plan).

### 7.5.2 *Staff Training and Exercise Procedures*

BFE will integrate the training of the emergency response personnel of the geologic storage project into the standard operating procedures and plant operations training programs, which are described in the ICP. Periodic training will be provided, not less than annually, to protect all necessary plant and project personnel. The training efforts will be documented in accordance with the requirements of the BFE plans which, at a minimum, will include a record of the trainee name, date of training, type of training (e.g., initial or refresher), and instructor name. BFE will also work with local emergency response personnel to perform coordinated training exercises associated with potential emergency events such as a significant release of $CO_2$ to the atmosphere.

## 7.6 Emergency Communications Plan

An incident command system is identified in the facility response plan that specifies the organization of a facility response team and team member roles and responsibilities in the event of an emergency. The organizational structure of this system is provided below, along with the identification and contact information of each member of the facility response team (see Table 7-6).

The following table contains the contact information for designated QIs.

**Table 7-6. Internal Emergency Notification Phone List**

| Team Member | Phone Number | Response Time (hours) | Emergency Responsibility | Level of Training |
|---|---|---|---|---|
| Travis Strickland<br>Plant Manager | H: 701-462-3937<br>C: 701-202-7107 | 24 | QI | Initial Facility Response Plan, Training Elements for Oil Spill Response and National Preparedness for Response Exercise Program (PREP) |
| Adam Dunlop, Director – Regulatory & Technical Services | H: 701-250-4893<br>C: 701-527-5198 | 24 | QI | Initial Facility Response Plan, Training Elements for Oil Spill Response and National Preparedness for Response Exercise Program (PREP) |
| Jeff Martian<br>Process Engineer | W:701-442-7512<br>C: 605-201-1587 | 24 | | BFE Employee spill response training |
| Cory Gullickson<br>Maintenance Manager | W: 701-442-7506<br>C: 701-391-2306 | 24 | Assistant QI | BFE Employee spill response training |
| Alyssa Hollinshead<br>HSE Coordinator | W:701-442-7519<br>C: 970-581-0510 | 24 | | BFE Employee spill response training |
| Shift Lead | W: 701-442-7520 | 24 | Assistant QI | BFE Employee spill response training |

**Table 7-7. NDIC DMR UIC Contact**

| Company | Service | Location | Phone |
|---|---|---|---|
| NDIC DMR | Class VI/CCUS Supervisor | Bismarck, ND | 701.328.8020 |

The QI or designee is responsible for establishing and maintaining communications with appropriate off-site persons and/or agencies, including, but not limited to, the following:

**Table 7-8. Off-site Emergency Notification Phone List**

| | |
|---|---|
| Mclean Sheriff Department* | 701.462.8103 |
| Washburn Fire Department (Primary)* | 701.462.8558 |
| Underwood Fire Department (Secondary)* | 701.442.5224 |
| Washburn Ambulance | 701.462.8431 |
| REC CCS Ambulance | 701.442.5696 |
| Falkirk Mine Ambulance/Fire Fighters | 701.442.5751 |
| McLean County Sheriff's Office | 701.462.8103 |
| North Dakota Highway Patrol | 701.327.2447 |
| North Dakota Highway Department | 701.327.2447 |
| North Dakota Poison Control | 800.222.1222 |
| Washburn Medical Clinic | 701.462.3389 |
| Turtle Lake Hospital | 701.448.2331 |
| Bismarck St. Alexius Hospital | 701.530.7000 |
| Bismarck Sanford Hospital | 701.323.6000 |
| Mclean County Emergency Management* | 701.462.8541 |
| State Emergency Response Commission* | 833.997.7455 |

* Those persons/agencies above marked with an asterisk have received a copy of the BFE emergency response action plan.

**Table 7-9. Potential Contractor and Services Providers**

| Company | Service | Phone |
|---|---|---|
| Clean Harbors | Oil spill Removal Organization (OSRO), Collection, & Storage | 701.774.2201 |
| Garner Environmental Services | OSRO & Spill Cleanup Services | 855.774.1200 |

Lastly, the facility response plan contact list also includes addresses and contact information for the neighboring facilities and occupied residences located within a 1-mile radius of geologic storage project. Because indicated local and regional emergency agencies (Table 7-8) are provided a copy of the facility response plan, the QI or designee may rely upon emergency agency assistance when it is necessary and appropriate to alert the applicable neighboring facilities and residents in order to allow the operator to focus time and resources on response measures (see also Section 7.4 [5]).

## 7.7 ERRP Review and Updates

This ERRP shall be reviewed:

- At least annually following its approval by NDIC.
- Within 1 year of AOR reevaluation.
- Within a prescribed period (to be determined by NDIC) following any significant changes to the project, e.g., injection process, the injection rate, etc.
- As required by NDIC DMR.

If the review indicates that no amendments to the ERRP are necessary, BFE will provide the documentation supporting the "no amendment necessary" determination to the UIC program director.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to NDIC as soon as reasonably practicable, but in no event later than 1 year following the commencement of a review.

# 8.0 WORKER SAFETY PLAN

## 8.0 WORKER SAFETY PLAN

Blue Flint Sequester Company LLC (Blue Flint) and Blue Flint Ethanol LLC, operator of the Blue Flint Ethanol (BFE) facility, will enter into an agreement whereby Blue Flint employees, contractors and agents are required to follow the BFE facility worker safety plans. BFE facility maintains and implements a plantwide safety program that meets all state and federal requirements for worker safety protections, including OSHA and the National Fire Protection Association (NFPA). This program is described in the BFE safety plan, which includes a list of training programs that are currently in place and the frequency with which they will be reviewed and, if necessary, updated.

The $CO_2$ safety training program of BFE facility identifies the dangers of $CO_2$ and requires all employees and visitors to wear the proper PPE and to perform their duties in ways that prevent the discharge of $CO_2$. Project personnel will participate in annual safety training to include familiarization with operating procedures and equipment configurations that are appropriate to their job assignment as well as ERRP procedures, equipment, and instrumentation. New personnel, if appropriate, will receive similar instruction prior to beginning their work. Lastly, contractors and visitors will undergo an orientation that ensures all persons on-site are trained and aware of the dangers of $CO_2$. Initial training will be conducted by, or under the supervision of, the safety director or his designated representative, and all trainers will be thoroughly familiar with the project operations plan and ERRP.

Refresher training will be conducted at least annually for all project personnel. Monthly briefings will be provided to operations personnel according to their respective responsibilities and will highlight recent operating incidents, lessons learned based on actual experience in operating the equipment, and recent storage reservoir-monitoring information.

Only personnel who have been properly trained will participate in the project activities of drilling, construction, operations, and equipment repair. A record including the person's name, date and type of training, and the signatures of the trainee and instructor will be maintained.

# 9.0 WELL CASING AND CEMENTING PROGRAM

## 9.0 WELL CASING AND CEMENTING PROGRAM

Blue Flint plans to reenter and convert MAG 1 (API 3305500196, File No. 37833) into a $CO_2$ injection well, complying with NDIC Class VI underground injection control (UIC) injection well construction requirements. The targeted injection horizon is the Broom Creek Formation. The project includes the installation of a monitoring well, MAG 2, to monitor and record real-time pressure and temperature data and monitor $CO_2$ saturations as well as utilize the data for history matching in the modeling and simulations, as required in the testing and monitoring plan.

### 9.1 $CO_2$ Injection Well – MAG 1 Well Casing and Cementing Programs

The MAG 1 well was permitted and drilled as a stratigraphic test well on October 11, 2020, under NDIC governance. The original well design was to drill the entire stratigraphic column from surface to the Precambrian formation to characterize potential storage reservoirs and seals for $CO_2$ geological sequestration.

The surface and intermediate wellbore sections were drilled, logged, cased, and cemented without major operational issues. The 13.375-in. surface casing was set at 1,330 ft, with a 10.75-in. intermediate casing set at 4,163 ft. While drilling the 9.5-in. long-string interval, severe lost circulation events were encountered at the Interlake (8,120 ft) and Red River (8,708 ft) Formations. The drilling reached a depth of 9,213 ft when a lost circulation event caused the drill pipe and bottomhole assembly (BHA) to get stuck. Unsuccessful fishing operations were performed, resulting in a section of drill pipe and the BHA, the "fish," in the wellbore from 7,575 to 9,072 ft.

The well was conditioned from the base of the intermediate casing to the top of the fish, and the sidewall cores and electronic logs were conducted for characterization of the Broom Creek Formation as well as the associated confining formations. Upon completion of the coring and logging, the wellbore was temporarily plugged and abandoned. Because of the inability to reach total depth, cement plugs were set across the following intervals: 1) a $CO_2$-resistant cement plug from 7,566 to 6,531 ft, 2) a conventional cement plug from 4,729 to 4,374 ft, and 3) a cast iron bridge plug (CIBP) set in the 10.75-in. intermediate casing at 4,090 ft and topped with five sacks of conventional cement.

On May 13, 2022, the well was reentered by drilling out the CIBP and the upper cement plug at 4,729 ft. A new $CO_2$-resistant cement plug was set from 4,815 to 5,480 ft to isolate the Madison Formation group in order to collect representative fluid samples and measure the reservoir pressure in the Broom Creek Formation. The reservoir pressure and temperature values were captured, and fluid samples were collected by swabbing the well. The well was temporarily abandoned on June 7, 2022, with a CIBP set at 4,080 ft and topped with ten sacks of conventional cement, as shown in Figure 9-1, for a current, as-constructed wellbore schematic of the MAG 1 well.

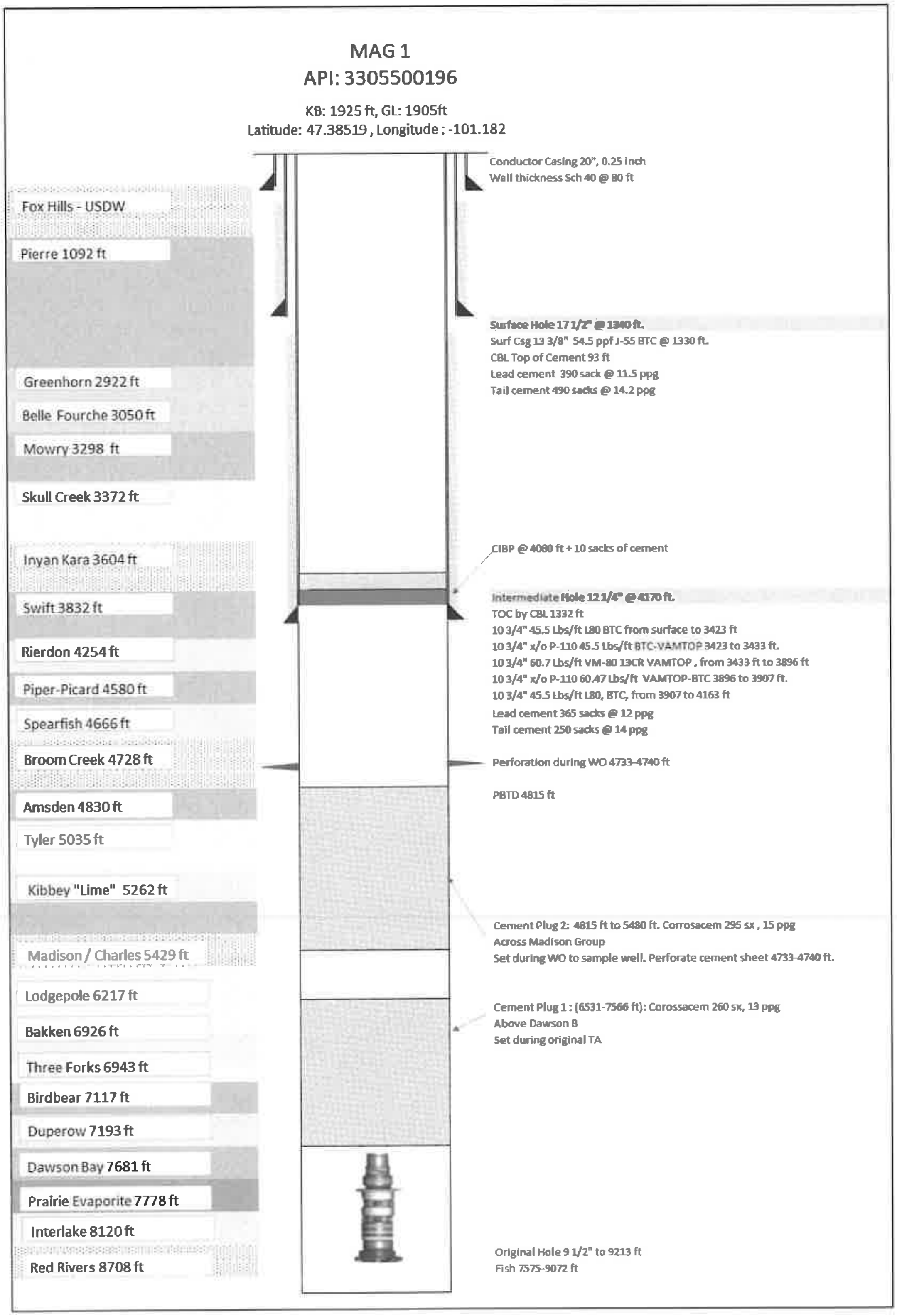



Figure 9-1. MAG 1 as-constructed wellbore schematic.
Note: top of cement (TOC), workover (WO).

To convert the existing stratigraphic wellbore into a $CO_2$ injection well, Blue Flint plans to reenter the MAG 1 well, drill out the CIBP and Cement Plug 2 from 4,815 to 5,150 ft, condition the open hole, install and cement 7-in. long-string casing from surface to 5,150 ft. The Broom Creek Formation will be perforated, and injection will be performed by setting injection tubing and packer above the Broom Creek perforations, as shown in Figure 9-2, the proposed design for the conversion of MAG 1 to a $CO_2$ injection well.

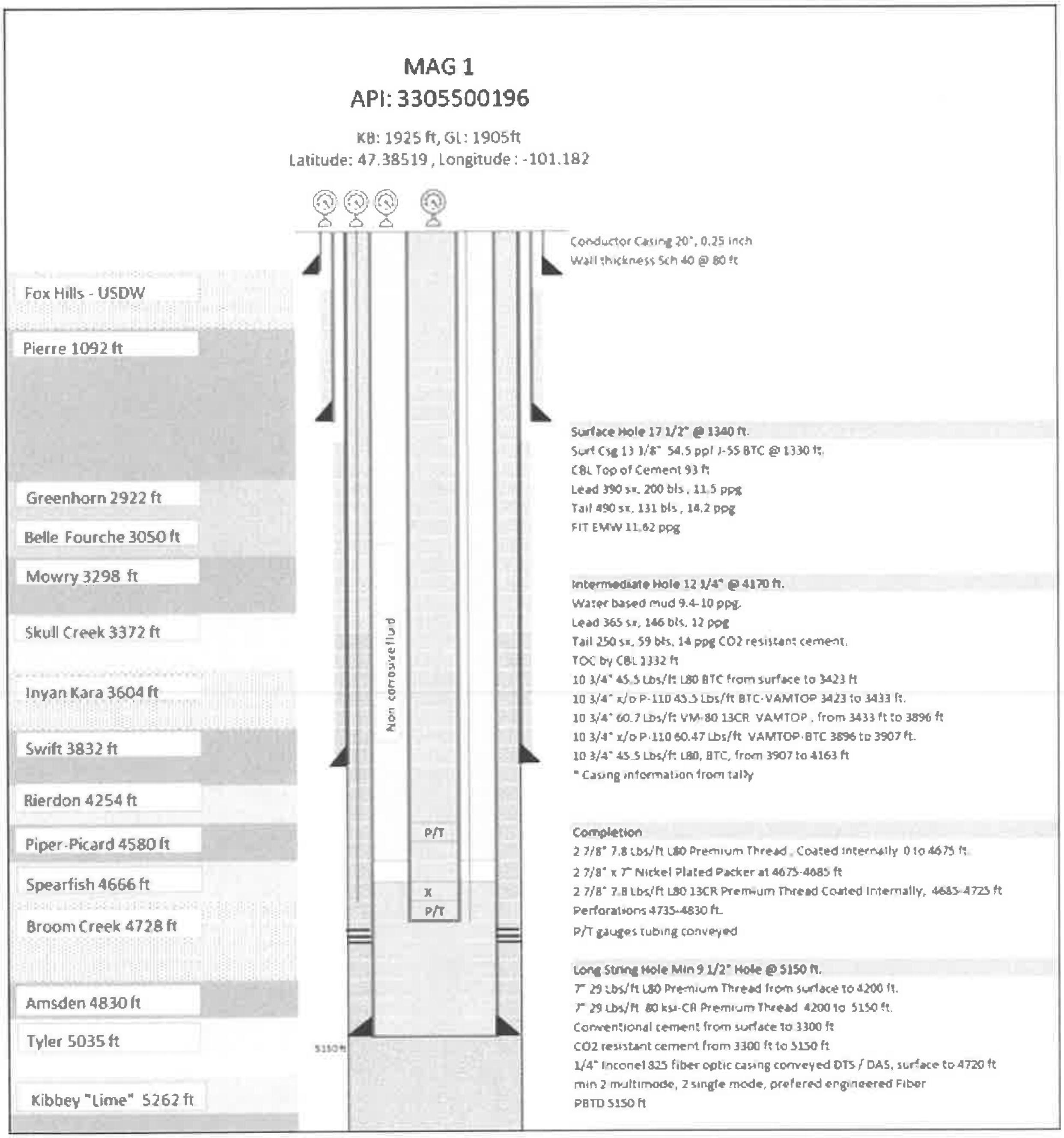



Figure 9-2. MAG 1 Proposed wellbore schematic as a $CO_2$ injection well. Casing-conveyed fiber-optic cable shown in purple from surface to the Broom Creek Formation.

Tables 9-1 through 9-4 provide the casing and cement programs for the MAG 1 drilling program as of October 11, 2020, which demonstrate compliance of the executed well construction program with NDAC § 43-05-01-09 and § 43-05-01-09(2) for conversion into a $CO_2$ storage injection well.

Table 9-1. $CO_2$ Injection Well MAG 1 – Well Information

| | | | | | |
|---|---|---|---|---|---|
| **Well Name:** | **MAG 1** | **NDIC No.:** | | **API No.:** | **3305500196** |
| **County:** | McLean | **State:** | ND | **Operator:** | Midwest AgEnergy Group, LLC |
| **Location:** | Sect. 18, T145N R82W | **Footages:** | 295 FNL 740 FWL | **Total Depth:** | 9,213 ft |

FNL: From the north line.
FWL: From the west line.

Table 9-2. $CO_2$ Injection Well MAG 1 – Casing Program

| Section | Hole Size, in. | Casing o.d., in. | Weight, lb/ft | Grade | Connection* | Top Depth, ft | Bottom Depth, ft | Objective |
|---|---|---|---|---|---|---|---|---|
| Surface | 17½ | 13⅜ | 54.5 | J55 | BTC | 0 | 1,330 | Isolate Fox Hills |
| Intermediate | 12¼ | 10¾ | 45.5 | L80 | BTC | 0 | 3,433 | Isolate Inyan Kara |
| Intermediate | 12¼ | 10¾ | 60.7 | VM-80 13CR | VAM TOP | 3,433 | 3,907 | Isolate Inyan Kara |
| Intermediate | 12¼ | 10¾ | 45.5 | L80 | BTC | 3,907 | 4,163 | Isolate Inyan Kara |
| Long String | 9½ | 7 | 29 | L80 | Premium | 0 | 4,200 | |
| Long String | 9½ | 7 | 29 | L80 CR13 | Premium | 4,200 | 5,150 | Injection target |

BTC: Buttress.

**Table 9-3. $CO_2$ Injection Well MAG 1 – Casing Properties**

| o.d., in. | Grade | Weight, lb/ft | Con-nect. | i.d., in. | Drift, in. | Burst, psi | Collapse, psi | Yield Strength, Klb Body | Yield Strength, Klb Conn. |
|---|---|---|---|---|---|---|---|---|---|
| 13⅜ | J55 | 54.5 | BTC | 12.615 | 12.459 | 2,730 | 1,130 | 853 | 909 |
| 10¾ | L80 | 45.5 | BTC | 9.95 | 9.875 | 5,210 | 2,470 | 1,040 | 1,062 |
| 10¾ | VM-80 13CR | 60.7 | VAM TOP | 9.66 | 9.504 | 7,100 | 5,170 | 1,398 | 1,398 |
| 7 | L80 | 29 | M-M | 6.184 | 6.059 | 8,160 | 7,030 | 676 | 676 |
| 7 | L80 CR13 | 29 | M-M | 6.184 | 6.059 | 8,390 | 7,030 | 676 | 676 |

M-M: Premium metal to metal connection.

**Table 9-4. $CO_2$ Injection Well MAG 1 – Cement Program**

| Casing, in. | Tail Slurry | Tail Interval, ft | Lead Slurry | Lead Interval, ft | Excess, % | Volume, sacks |
|---|---|---|---|---|---|---|
| 13⅜ | Varicem*, 14.2 ppg | 800–1,330 | Varicem*, 11.5 ppg | 93–800** | 50–100 | 880 |
| 10¾ | Corrosacem*** 14 ppg | 2,750–4,163 | Neo Cement* 12 ppg | 1,332–2,750** | 50–100 | 616 |
| 7 | $CO_2$-resistant Slurry 14.5 ppg | 3,300–5,150 | Portland cement + additive 11.5–12.5 ppg | 0–3,300 | 50 | 1,034 |

* Varicem and Neo cement are conventional portland cement slurry plus additives.
** The cement top was obtained from the CBL–USIT log.
*** Corrosacem is an enhanced portland cement blend to resist the degradation by $CO_2$ reaction.

Evaluation of the need for a two-stage cementing job for the long-string section will be conducted considering the wellbore condition and hydraulic pressure simulation of the cementing operation. Communication for approval from the North Dakota Department of Mineral Resources (DMR) will occur prior to installation.

## 9.2 Monitoring Well MAG 2 – Well Casing and Cementing Programs

To meet testing and monitoring requirements, a monitor well, MAG 2, will be drilled through the Broom Creek reservoir into the Amsden/Tyler lower confining seals, as shown in Figure 9-3, MAG 2 proposed wellbore design.

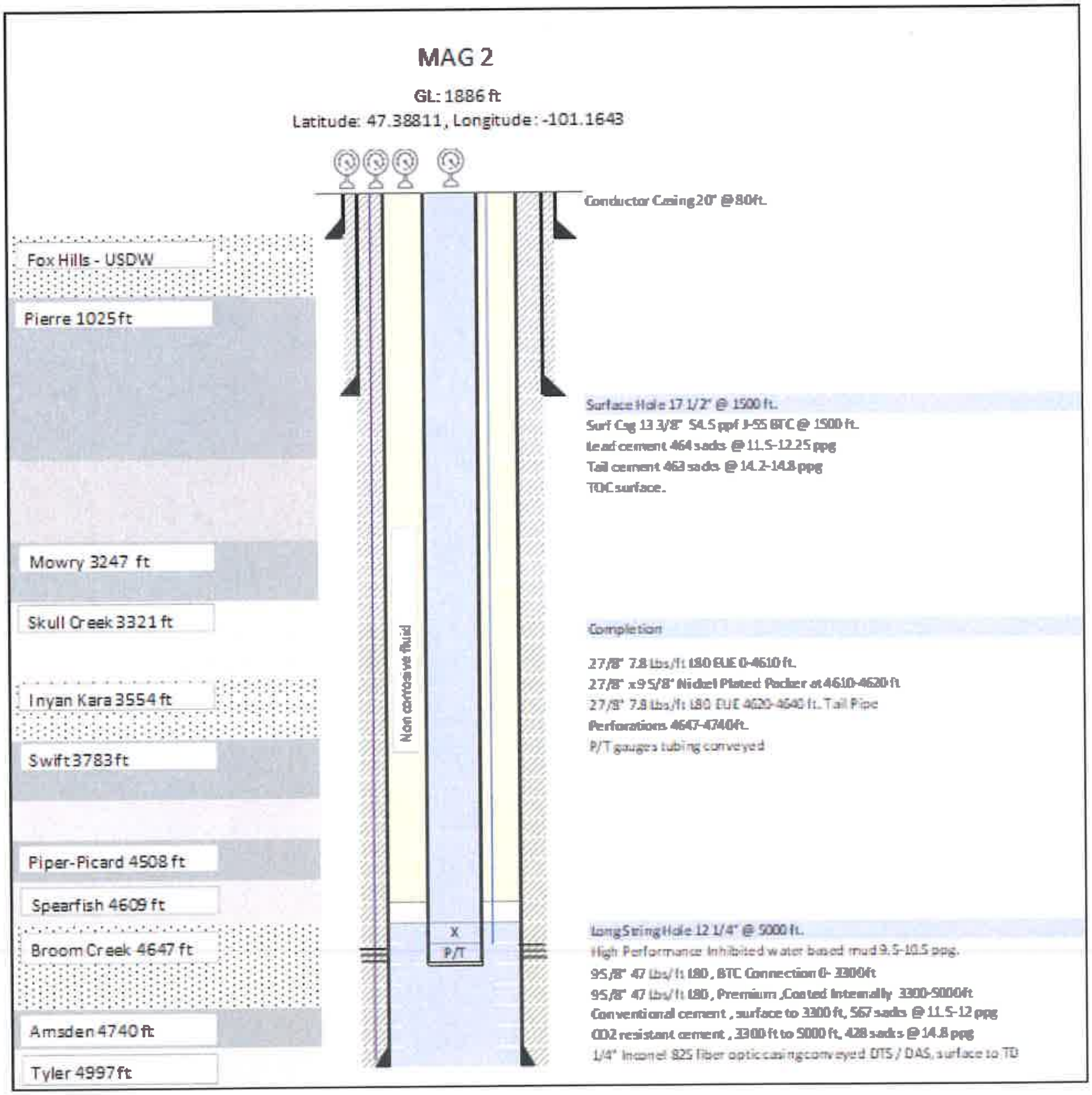



Figure 9-3. Monitor Well MAG 2 proposed wellbore schematic. Casing-conveyed fiber-optic cable shown in purple from surface to the Broom Creek Formation.

Tables 9-5 through 9-8 provide the proposed casing and cement programs for MAG 2, which demonstrate compliance for the well construction program with NDAC § 43-05-01-09 and § 43-05-01-09(2) for a $CO_2$ monitoring well.

**Table 9-5. Monitor Well MAG 2 – Well Information**

| | | | | | |
|---|---|---|---|---|---|
| **Well Name:** | **MAG 2** | | | | |
| **County:** | McLean | **State:** | ND | | |
| **Location:** | Sect. 7, T145N R82W | **Footages*:** | 820 FSL 165 FEL | **Total Depth:** | 5,000 ft |

* Estimates; location has not been surveyed

**Table 9-6. Monitor Well MAG 2 – Casing Program**

| Section | Hole Size, in. | Casing o.d., in. | Weight, lb/ft | Grade | Conn. | Top Depth, ft | Bottom Depth, ft | Objective |
|---|---|---|---|---|---|---|---|---|
| Surface | 17½ | 13⅜ | 54.5 | J55 | BTC | 0 | 1,500 | Isolate Fox Hills |
| Long String | 12¼ | 9⅝ | 47 | L80 | BTC | 0 | 3,300 | |
| Long String | 12¼ | 9⅝ | 47 | L80 Coated | Premium* | 3,300 | 5,000 | Monitoring zone |

**Table 9-7. Monitor Well MAG 2 – Casing Properties**

| o.d., in. | Grade | Weight, lb/ft | Connection | i.d., in. | Drift, in. | Burst, psi | Collapse, psi | Yield Strength, Klb | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Body | Connection |
| 13 ⅜ | J55 | 54.5 | BTC | 12.615 | 12.459 | 2,730 | 1,130 | 853 | 909 |
| 9 ⅝ | L80 | 47 | BTC | 8.681 | 8.525 | 6,870 | 4,750 | 1,086 | 1,122 |
| 9 ⅝ | L80 | 47 | Premium* | 8.681 | 8.525 | 6,870 | 4,750 | 1,086 | 1,086 |

* Connection will be compatible with the internal coating requirements.

**Table 9-8. Monitor Well MAG 2 – Cement Program**

| Casing, in. | Tail | | Lead | | Excess, % | Volume, sacks |
|---|---|---|---|---|---|---|
| | Slurry | Interval, ft | Slurry | Interval, ft | | |
| 13⅜ | Portland cement + additives, 14.2–14.8 ppg | 1,000–1,500 | Portland cement + additives, 11.5–12.5 ppg | 0–1,000 | 100 | 927 |
| 9⅝ | $CO_2$-resistant cement, 14.8 ppg | 3,300–5,000 | Portland cement + additives, 11.5–12 ppg | 0–3,300 | 50 | 996 |

Evaluation of the need for a two-stage cementing job for the long-string section will be conducted considering the wellbore condition and hydraulic pressure simulation of the cementing operation. Communication for approval from the North Dakota DMR will occur prior to installation.

# 10.0 PLUGGING PLAN

## 10.0 PLUGGING PLAN

The proposed plug and abandonment (P&A) procedure for the MAG 1 well is intended to be interpreted as proposed conditions and does not reflect the current as-constructed state for the MAG 1 well. Also, the plugging operations are likely to occur at different times in the life cycle of the injector well, MAG 1, and the monitor well, MAG 2. The MAG 1 well is planned for P&A once the $CO_2$ injection operation ceases. The $CO_2$ monitor well, MAG 2, is planned for P&A after verification and approval that the $CO_2$ plume has stabilization.

A proposed P&A procedure will be provided to the NDIC. After approval, ample notification will be given to allow an NDIC representative to be present during the plugging operations. The P&A events will be documented by a workover supervisor during P&A execution. The records of the P&A events shall demonstrate the utilization of $CO_2$-compatible materials used and complete isolation of the injection zone.

### 10.1 MAG 1: P&A Program

The proposed MAG 1 $CO_2$ injection well schematic is provided in Figure 10-1.

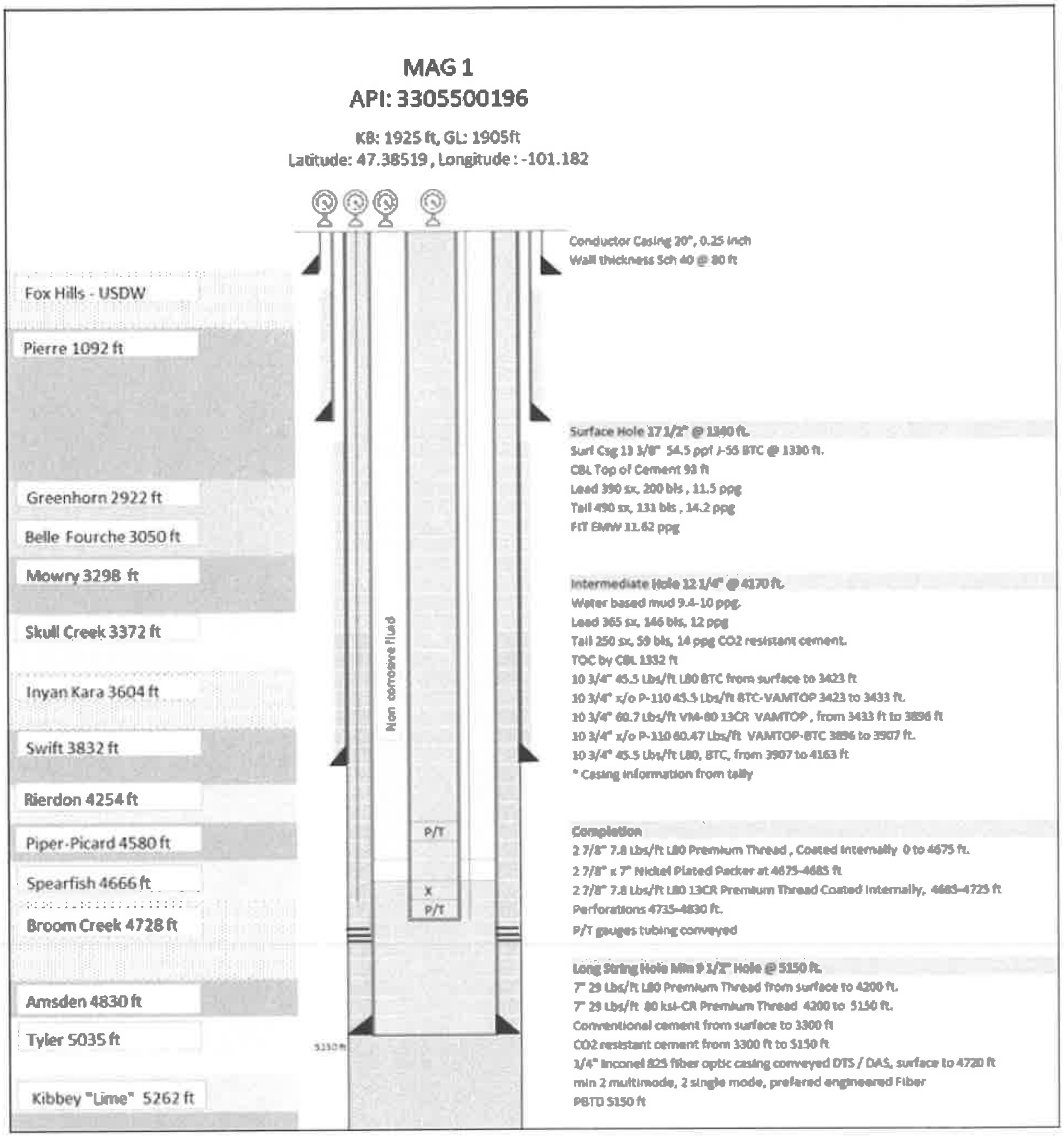



Figure 10-1. Proposed $CO_2$ injection well schematic for MAG 1.

The NDIC will be contacted and an intent to plug and abandon form for MAG 1 will be filed for approval. Final adjustments to the proposed P&A procedure will be made based on current wellbore conditions and NDIC field inspector recommendations. Currently, the proposed P&A procedure for the well is as follows.

Proposed P&A Procedure:

1. After injection operations have been terminated, the well will be flushed with a kill fluid with a calculated fluid weight for proper execution. A minimum of three tubing volumes will be pumped, remaining below the fracture pressure and ensuring control of the well.

2. Move-in (MI) and rig up (RU) workover rig onto the MAG 1 well. All $CO_2$ flowlines and valves will be marked and noted by the rig supervisor prior to MI and RU.

3. Conduct and document a safety meeting.

4. Record bottomhole pressure (BHP) from downhole gauges and calculate kill fluid density. BHP measurements will be taken by using the installed tubing-conveyed downhole pressure gauges. In case the gauges are not functional, the operator may use surface tubing pressure gauges to calculate kill mud density.

5. Test the pump and line to 5,000 psi or 90% of maximum pump pressure. Fill tubing with kill fluid. Bleeding off occasionally may be necessary to remove all air from the system. Wait for well to stabilize. Shut in tubing. Monitor tubing pressure.

6. Test casing annulus to 1,500 psi and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

   Note: If failure in long-string casing is identified, the operator will prepare a plan to repair the well prior to P&A.

7. If both casing and tubing are dead, then nipple up blowout preventers (NU BOPs).

   Contingency: If the well is not dead or the pressure cannot be bled off via tubing, RU wireline and set plug in lower-profile nipple below packer. Unlatch tubing from the packer and circulate tubing and annulus with kill weight fluid until the well is on control. After casing and tubing pressure are zero, nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string in case the packer needs to be unlatched.

8. Pull out of hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packer, RU electric line and make a cut on the tubing string just above the packer. The cut must be made above the packer at least 5 to 10 ft MD. Pull the tubing string out of hole and proceed to the next step. If problems are noted, update the cement remediation plan. A cement retainer might be used to force cement through the packer if it cannot be removed.

9. Pick up work string and trip in hole (TIH) with bit to condition wellbore.

10. Pull out of hole and RU logging unit. Confirm external mechanical integrity by running one of the tests listed below as options. Rig down logging truck.

    - Activated neutron log
    - Noise log
    - Production logging tool (PLT)
    - Tracers
    - Temperature log
    - DTS (distributed-temperature sensing) survey (no required logging unit)

11. TIH with work string and cement retainer to the top of Plug 1. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

12. Mix and pump $CO_2$-resistant slurry to cover the Broom Creek Formation and isolate from the Dakota Group in accordance with program. Under displaced two barrels of cement. Disconnect from retainer and finish displacing the last two barrels on top of the cement retainer. Check for flow. Pull work string 150 ft and circulate.

13. Pull up hole, set a balanced plug with $CO_2$-resistant cement, 15.8 ppg, across Dakota Group and isolate it from the Fox Hills USDW. Pull out above plug and circulate. Wait on setting time and tag top of the plug.

14. Pull up hole, set balanced plug with Class G cement + additive, 15.8 ppg, to cover the shoe of the surface casing. Pull out above the plug and circulate. Wait on setting time and tag top of the plug.

15. Pull up hole, set surface plug with Class G cement + additive, 15.8 ppg, to isolate the top of surface casing.

16. Lay down all work string. Rig down all equipment and move out.

17. Dig out wellhead and cut off casing 5 ft below ground level (GL). Weld ½-in. steel cap on casing with well name, date inscribed, and information that it was used for $CO_2$ injection.

18. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

19. Within 60 days, submit Form 7 plugging report after plugging operations are complete – NDAC § 43-05-01-11.5(4).

20. Submit notice of intent to reclaim to NDIC 30 days in advance prior to reclamation – NDAC § 43-05-01-18(10d).

The proposed P&A plan for MAG 1 is summarized in Table 10-1 and provided in Figure 10-2.

**Table 10-1. Summary of P&A Plan for MAG 1**

| Cement Plug Number | Interval Range, ft | Thickness, ft | Volume, sacks | Notes |
|---|---|---|---|---|
| 1 | 4,550–5,150 | 600 | 225 | $CO_2$-resistant slurry, 15.8 ppg, 1.11 $ft^3$/sx<br>Squeezed cement job to isolate perforations |
| 2 | 3,350–3,850 | 500 | 103 | $CO_2$-resistant slurry, 15.8 ppg, 1.11 $ft^3$/sx<br>Balanced plug |
| 3 | 1,000–1,500 | 500 | 99 | Conventional cement, 15.8 ppg, 1.16 $ft^3$/sx<br>Balanced plug |
| 4 | 0–80 | 80 | 16 | Conventional cement, 15.8 ppg, 1.16 $ft^3$/sx<br>Balanced plug |

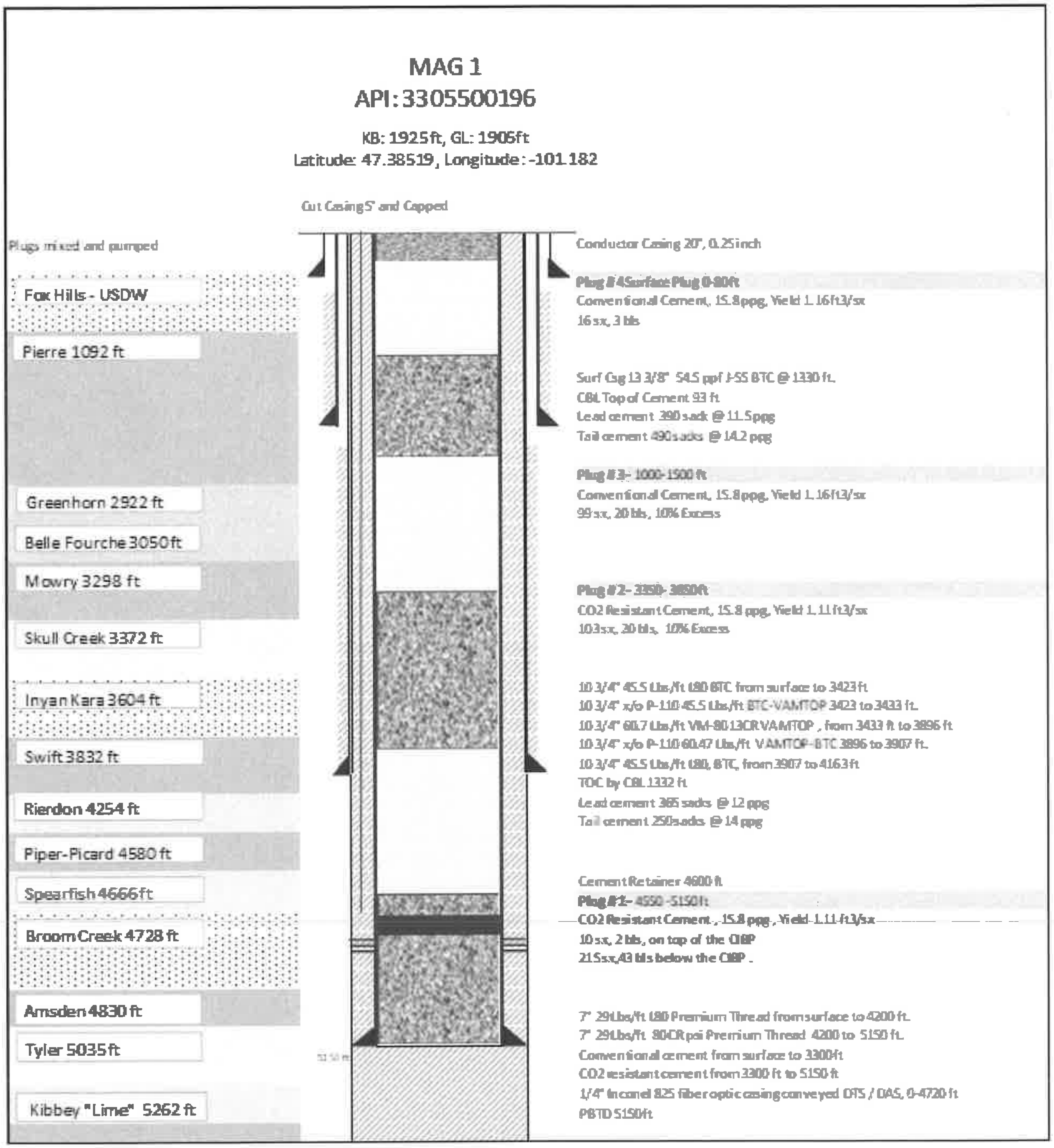



Figure 10-2. Schematic of proposed P&A plan for MAG 1.

## 10.2 MAG 2 P&A Program

The MAG 2 wellbore is to be plugged and abandoned when the $CO_2$ plume has stabilized and monitoring of the plume extent is no longer necessary.

A proposed $CO_2$-monitoring well schematic of MAG 2 is provided in Figure 10-3.

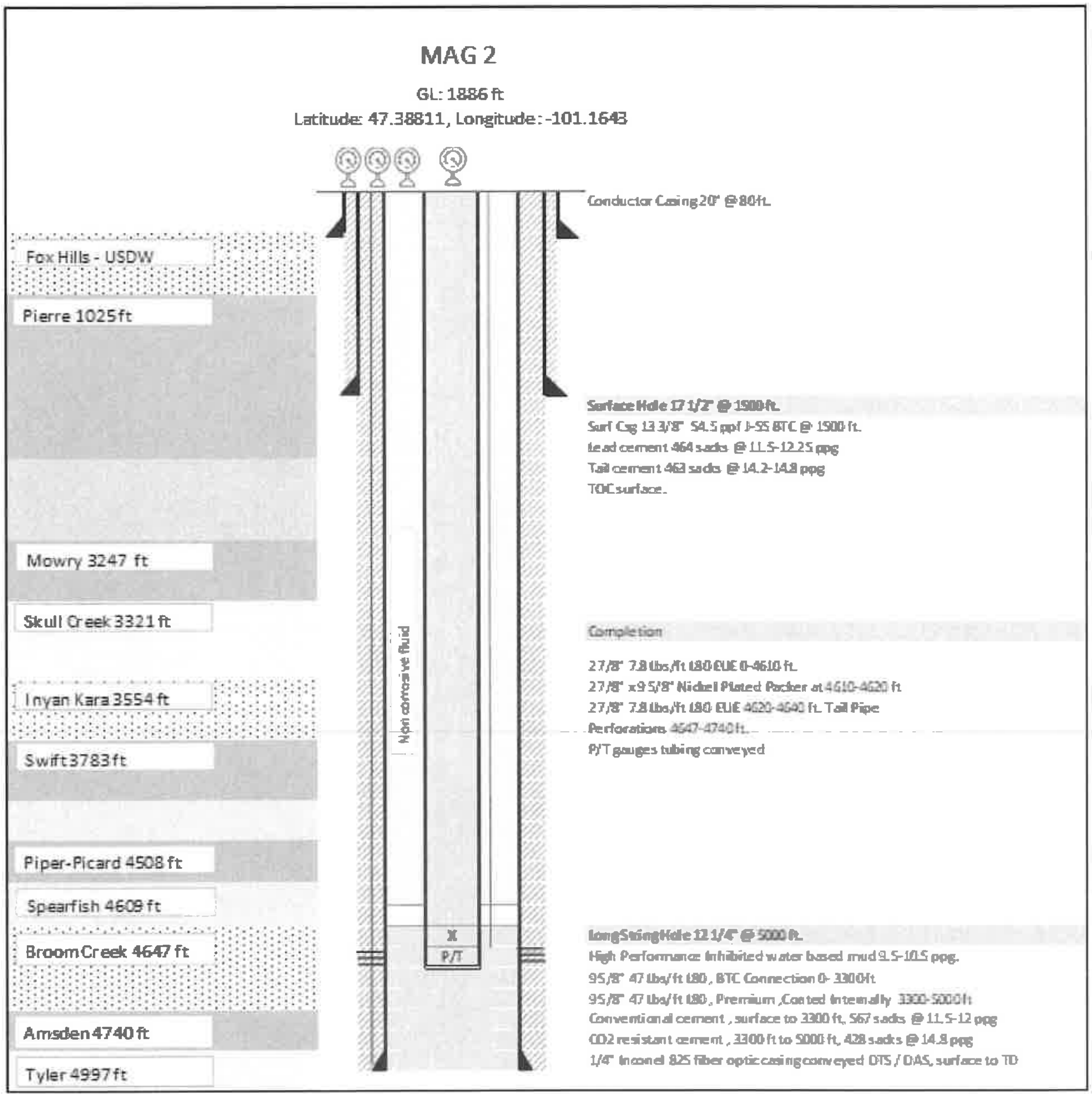



Figure 10-3. Proposed monitoring wellbore schematic for MAG 2.

The proposed procedure for P&A of the MAG 2 wellbore will be performed as follows.

1. MI rig onto MAG 2 and RU.

2. Conduct and document a safety meeting.

3. Test the pump and line to 5,000 psi or 90% of maximum pump pressure. Fill tubing with kill fluid. Bleeding off occasionally may be necessary to remove all air from the system. Monitor tubing and annulus pressure.

4. Test casing annulus to 1,500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

   Note: If failure in long-string casing is identified, the operator will prepare a plan to repair the well prior to P&A.

5. If both casing and tubing are dead, then NU BOPs.

   Contingency: If the well is not dead or the pressure cannot be bled off via tubing, RU wireline and set plug in lower-profile nipple below packer. Unlatch the tubing from the packer and circulate tubing and annulus with kill weight fluid until the well is on control. After casing and tubing pressure are zero, nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string in case the packer needs to be unlatched.

6. Pull out of hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packer, RU electric line and make cut on tubing string just above packer. A cut must be made above the packer at least 5 to 10 ft MD. Pull the work string out of hole and proceed to next step. If problems are noted, update the cement remediation plan. A cement retainer might be used to force cement through the packer if it cannot be removed.

7. Pick up work string and TIH with bit to condition wellbore.

8. Pull out of the hole and RU logging unit. Confirm external mechanical integrity by running one or a combination of the tests listed below as options. Rig down logging truck.

   - Activated neutron log
   - Noise log
   - PLT
   - Tracers
   - Temperature log
   - CBL–USIT
   - DTS survey (no required logging unit)

9. TIH work string with cement retainer to the top of Plug 1. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

10. Mix and pump $CO_2$-resistant slurry to cover the Broom Creek Formation and isolate from the Dakota Group in accordance with program. Under displaced four barrels of cement. Disconnect from retainer and finish displacing the last four barrels on top of the cement retainer. Check for flow. Pull work string 150 ft and circulate.

11. Pull up hole, set balanced plug with $CO_2$-resistant cement, 15.8 ppg, to cover Dakota Group and isolate it from the Fox Hills USDW. Pull out above the plug and circulate. Wait on setting time and tag top of the plug.

12. Pull up hole, set balanced plug with Class G cement + additive, 15.8 ppg, to cover the shoe of the surface casing. Pull out above the plug and circulate. Wait on setting time and tag top of the plug.

13. Pull up hole, set surface plug with Class G cement + additive, 15.8 ppg, to isolate the top of surface casing.

14. Lay down all work string. Rig down all equipment and move out.

15. Dig out wellhead and cut off casing 5 ft below GL. Clean cellar to where a plate can be welded with well information.

16. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

17. Within 60 days, submit Form 7 plugging report after plugging operations are complete – NDAC § 43-05-01-11.5(4).

18. Submit notice of intent to reclaim to NDIC 30 days in advance prior to reclamation – NDAC § 43-05-01-18(10d).

The proposed P&A plan for MAG 2 is summarized in Table 10-2 and provided in Figure 10-4.

**Table 10-2. Summary of P&A Plan for MAG 2**

| Cement Plug Number | Interval Range, ft | Thickness, ft | Volume, sacks | Note |
|---|---|---|---|---|
| 1 | 4,550–5,000 | 450 | 333 | $CO_2$-resistant slurry, 15.8 ppg, 1.11 $ft^3$/sx<br>Squeezed cement job to isolate perforations |
| 2 | 3,300–3,800 | 500 | 203 | $CO_2$-resistant slurry, 15.8 ppg, 1.11 $ft^3$/sx<br>Balanced plug |
| 3 | 1,300–1,800 | 500 | 195 | Conventional cement, 15.8 ppg, 1.16 $ft^3$/sx<br>Balanced plug |
| 4 | 0–80 | 80 | 31 | Conventional cement, 15.8 ppg, 1.16 $ft^3$/sx<br>Balanced plug |

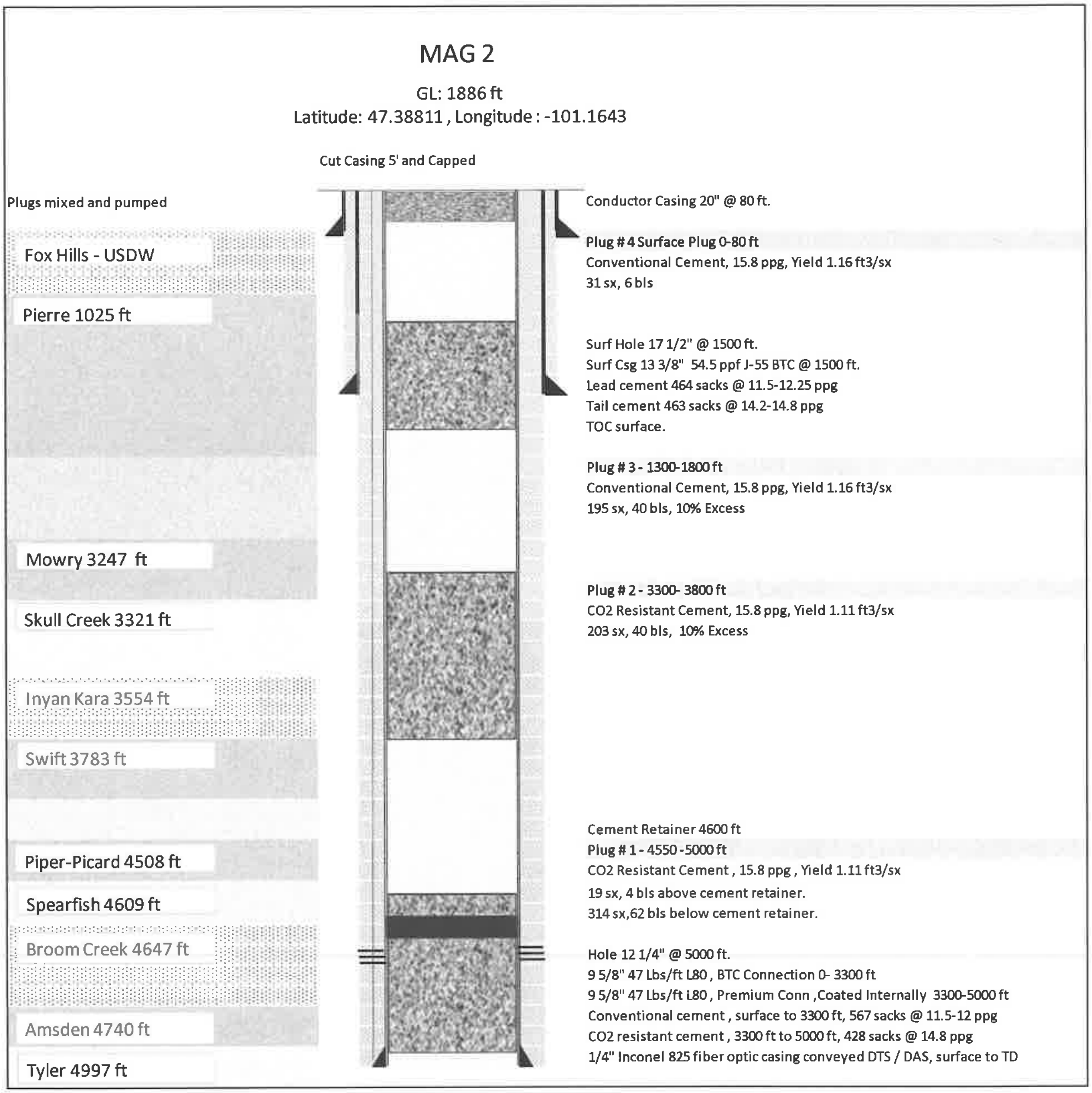



Figure 10-4. Schematic of proposed abandonment plan for monitoring well MAG 2.

# 11.0 INJECTION WELL AND STORAGE OPERATIONS

## 11.0 INJECTION WELL AND STORAGE OPERATIONS

This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.

**Table 11-1. MAG 1 Proposed Injection Well Operating Parameters**

| Item | Values | Description/Comments |
|---|---|---|
| **Injected Volume** | | |
| Total Injected Volume | 4,000,000 tonnes | Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day |
| **Injection Rates** | | |
| Average Injection Rate | 548 tonnes/day (10.35 MMscf/day) | Based on 200,000 tonnes/year for 20 years of injection (using 365 operating days per year) |
| Average Maximum Daily Injection Rate | 2,729 tonnes/day (51.56 MMscf/day) | Based on maximum bottomhole injection pressure (2,970 psi) |
| **Pressures** | | |
| Formation Fracture Pressure at Top Perforation | 3,300 psi | Based on geomechanical analysis of formation fracture gradient as 0.69 psi/ft (see Section 2.0) |
| Average Surface Injection Pressure | 1,158 psi | Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day) using the designed 2.875-inch tubing |
| Surface Maximum Injection Pressure | 4,300 psi | Based on maximum bottomhole injection pressure (2,970 psi) using the designed 2.875-inch tubing |
| Average Bottomhole Pressure (BHP) | 2,570 psi | Based on average daily injection rate of 548 tonnes/day |
| Calculated Maximum BHP | 2,970 psi | Based on 90% of the formation fracture pressure of 3,300 psi |

### 11.1 MAG 1 Well – Proposed Completion Procedure to Conduct Injection Operations

As described in Section 9.1, the MAG 1 well will be reentered and completed as a $CO_2$ injector (Figures 11-1 and 11-2 and Tables 11-2 through 11-4). The following proposed completion procedure outlines the steps necessary to complete and test the well.

1. Rig up workover (WO) rig and equipment, check pressure in the casing, and release pressure if any.

2. Remove night cap and nipple up blowout preventer (BOP).

3. Test BOP to maximum anticipated surface pressure (MASP).

4. Pick up work string, scraper, and bit to clean out residual cement.

5. Run in the hole and tag plug back total depth (PBTD). Condition casing if needed.

6. Circulate the wellbore with brine, compatible with the formation, estimated at 10 ppg, with a reservoir pressure gradient of 0.512 psi/ft.

7. Trip out of hole (TOOH) work string with bit and scraper.

8. Test casing for 30 minutes to 1,500 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the operator will be required to assess the root cause and correct it.

9. Conduct safety meeting to discuss logging and perforating operations.

10. Rig up logging truck.

11. Install and test lubricator.

12. Run cementing evaluation logs by program.
    Note: run cement bond logs without pressure as a first pass and repeat pass with 1,000 psi pressure. If cementing logs show poor bonding or a low top of cement, the results will be communicated to the NDIC and an action plan will be prepared.

13. Round trip a magnetic tool and casing collar locator (CCL) to identify location of the fiber-optic cable.
    Note: DTS/DAS (distributed temperature sensing/distributed acoustic sensing) fiber-optic cable will be run along the exterior of the long-string casing. Special clamps, bands, and centralizers are installed to protect the fiber and provide a marker for wireline operations.

14. Perforate the Broom Creek Formation, minimum of 6 spf (shots per foot), 36.7-inch-deep penetration, 0.37-inch diameter, and 60° phase (ensure shots do not penetrate fiber-optic cable). Actual perforation depths and design will be determined by designated geologist and engineers, and based on the log analysis review, as well as selected contractor.

15. TOOH with perforating guns.

16. Rig down logging truck and lubricator.

17. Pick up retrievable testing packer with downhole gauges and run in the hole with work string to the top of the perforations.

18. Set packer above perforations to isolation and test the annulus to ensure seal and no communication with backside.

19. Perform an injectivity test/step rate test (SRT) with clean brine compatible with formation.

20. If the well shows poor injectivity, perform a near-wellbore/perforation cleanout using a designed concentration of acid. Adjust acid formulation and volumes with water samples and compatibility test. Maximum injection pressure is not to exceed formation fracture pressure as determined in SRT.

21. Unset packer and circulate hole if acid cleanout is performed.

22. TOOH and lay down temporary packer and work string.

23. Rig up spooler and prepare rig floor to install completion injection assembly (injection tubing and packer).

24. Pick up and run completion assembly in accordance with program.

25. Displace the well with inhibited packer fluid.

26. Set injection packer within 50 ft above the top perforations, according to manufacturer recommendations and NDIC requirements. Test backside/annulus of tubing/casing to designated pressure during operations.

27. Install tubing hanger and cable connectors.

28. Nipple down BOP.

29. Install injection tree.

30. Rig down WO rig and equipment.

31. Move in wireline unit and perform through-tubing cased-hole logging in accordance with program (rigless).

**Table 11-2. MAG 1 Proposed Upper Completion**

| Description | o.d., in. | Depth, ft | Grade | Weight, lb/ft | Connection | i.d., in. | Drift i.d., in. |
|---|---|---|---|---|---|---|---|
| Tubing | 2⅞ | 0–4,675 | L80 | 7.8 | Premium | 2.323 | 2.229 |
| 2⅞-in. × 7-in. Nickel-Plated Packer + Pressure/Temperature (P/T) Gauge | | | | | | | |
| Tubing | 2⅞ | 4,685–4,425 | L80 13 CR | 7.8 | Premium | 2.323 | 2.229 |
| P/T Gauge | | | | | | | |

**Table 11-3. MAG 1 Tubing Properties**

| o.d., in. | Grade | Weight, lb/ft | Connection | i.d., in. | Drift i.d., in. | Collapse, psi | Burst, psi | Tension, Klb |
|---|---|---|---|---|---|---|---|---|
| 2⅞ | L80 | 7.8 | Premium | 2.323 | 2.229 | 13,890 | 13,440 | 180 |
| 2⅞ | L80 13 CR | 7.8 | Premium | 2.323 | 2.229 | 13,890 | 13,440 | 180 |

**Table 11-4. MAG 1 Cased-Hole Logging**

| Description | Depth, ft | Comments |
|---|---|---|
| CBL (cement bond log)–VDL (variable density log)–CCL–USIT (ultrasonic imaging tool) | 0–5,120* | Cement/casing log; 30-ft shoe track |
| CIL (casing inspection log) | 0–4,685* | Baseline; run through tubing |
| Temperature Log | 0–4,685* | Baseline; run through tubing |
| Pulsed Activated Neutron | 0–4,685* | Baseline; run through tubing |

* Estimated, will be adjusted with actual tally.

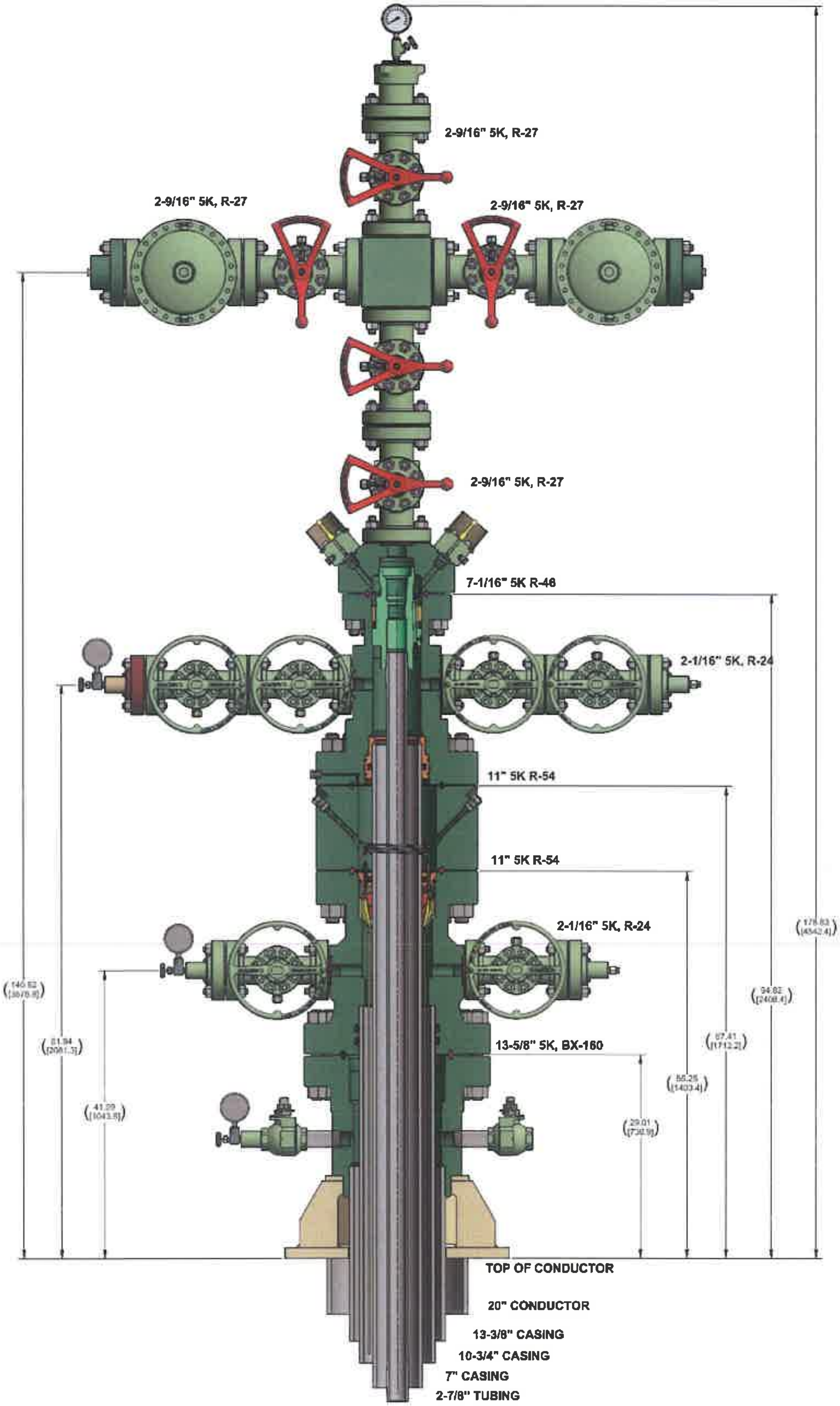



Figure 11-1. MAG 1 proposed $CO_2$-resistant wellhead schematic.

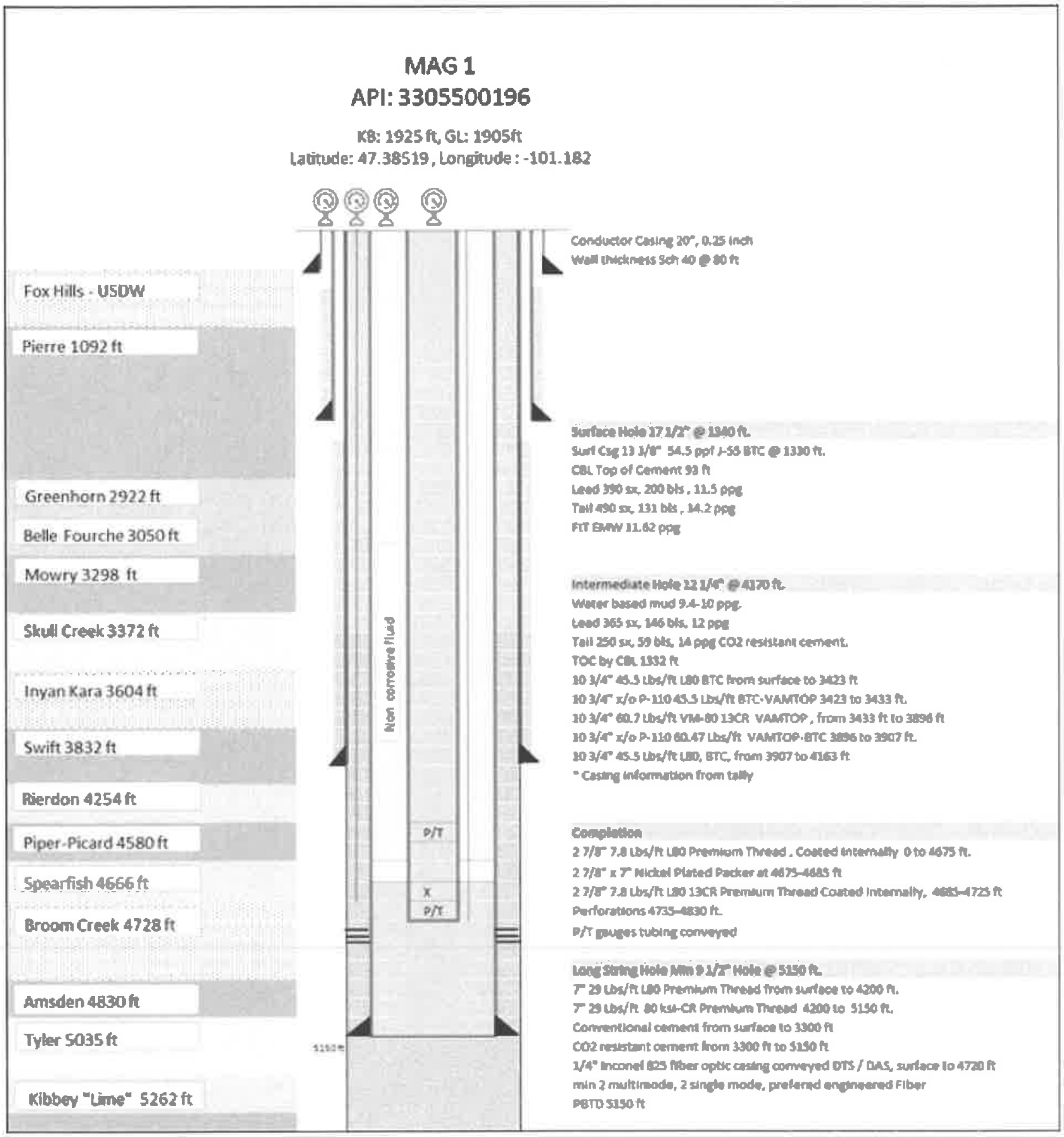



Figure 11-2. MAG 1 proposed completed wellbore schematic.

## 11.2 MAG 2 Well – Proposed Procedure for Monitoring Well Operations

MAG 2 will be constructed as a $CO_2$-monitoring well (Figures 11-3 and 11-4 and Tables 11-5 through 11-7) to support deep subsurface monitoring of MAG 1, the $CO_2$ stream injection well. Monitoring of the $CO_2$ plume extent and the storage reservoir pressure will be conducted continuously through the use of the casing-conveyed fiber-optic cable installed on the outside the long string and pressure/temperature gauges deployed along the outside of the tubing. Monitoring will be conducted during injection operations as well as during the postinjection site closure (PISC) which are also discussed in more detail in the Testing and Monitoring section of this permit application. Monitoring methods will include a combination of formation-monitoring methods (e.g., downhole pressure, downhole temperature, and pulsed-neutron capture/reservoir saturation tool logs) to verify casing mechanical integrity and support $CO_2$ plume stabilization evaluations.

The following proposed completion procedure outlines the steps necessary to complete and test the well.

1. Rig up WO rig and equipment, check pressure in the casing, and release pressure if any.

2. Remove night cap and nipple up BOP.

3. Test BOP to MASP.

4. Pick up work string, scraper, and bit to clean out residual cement.

5. Run in the hole and tag PBTD and condition casing if needed.

6. TOOH work string with bit and scraper.

7. Displace the well with formation-compatible brine, estimated at 10 ppg, with a reservoir pressure gradient of 0.512 psi/ft.

8. Test casing for 30 minutes with 1,500 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the operator will be required to assess the root cause and correct it.

9. Conduct safety meeting to discuss logging and perforating operations.

10. Rig up logging truck.

11. Install and test lubricator.

12. Run cased-hole logs by program.
    Note: run CBL/VDL and USIT logs without pressure as a first pass and repeat run with 1,000 psi of pressure as a second pass.
    Note: If CBLs show poor bonding, the results will be communicated to NDIC and an action plan will be prepared.

13. Run magnetic survey to identify fiber-optic orientation and complement with oriented perforating guns. An oriented gun should be used to avoid any damage to the external fiber optic.

14. Perforate the Broom Creek Formation, minimum 4 spf (shots per foot). Actual perforation depths, design, and phasing will be determined by designated geologist and engineers based on the log analysis review.
Note: DTS/DAS fiber-optic cable will be run along the exterior of the long-string casing. Special clamps, bands, and centralizers are installed to protect the fiber and provide a marker for wireline operations.

15. Pull guns out of the hole.

16. Rig down logging truck.

17. Rig up spooler and prepare rig floor to run upper completion assembly (tubing and packer).

18. Run completion assembly in accordance with program.

19. Circulate well with inhibited packer fluid.

20. Set packer within 50 ft above the top perforations, according to manufacturer recommendations and NDIC requirements. Test backside/annulus of tubing/casing to designated pressure.

21. Install tubing hanger and cable connectors.

22. Nipple down BOP.

23. Install tree.

24. Rig down WO rig and equipment.

25. Move in wireline unit and perform through-tubing cased-hole logging in accordance with program (rigless).

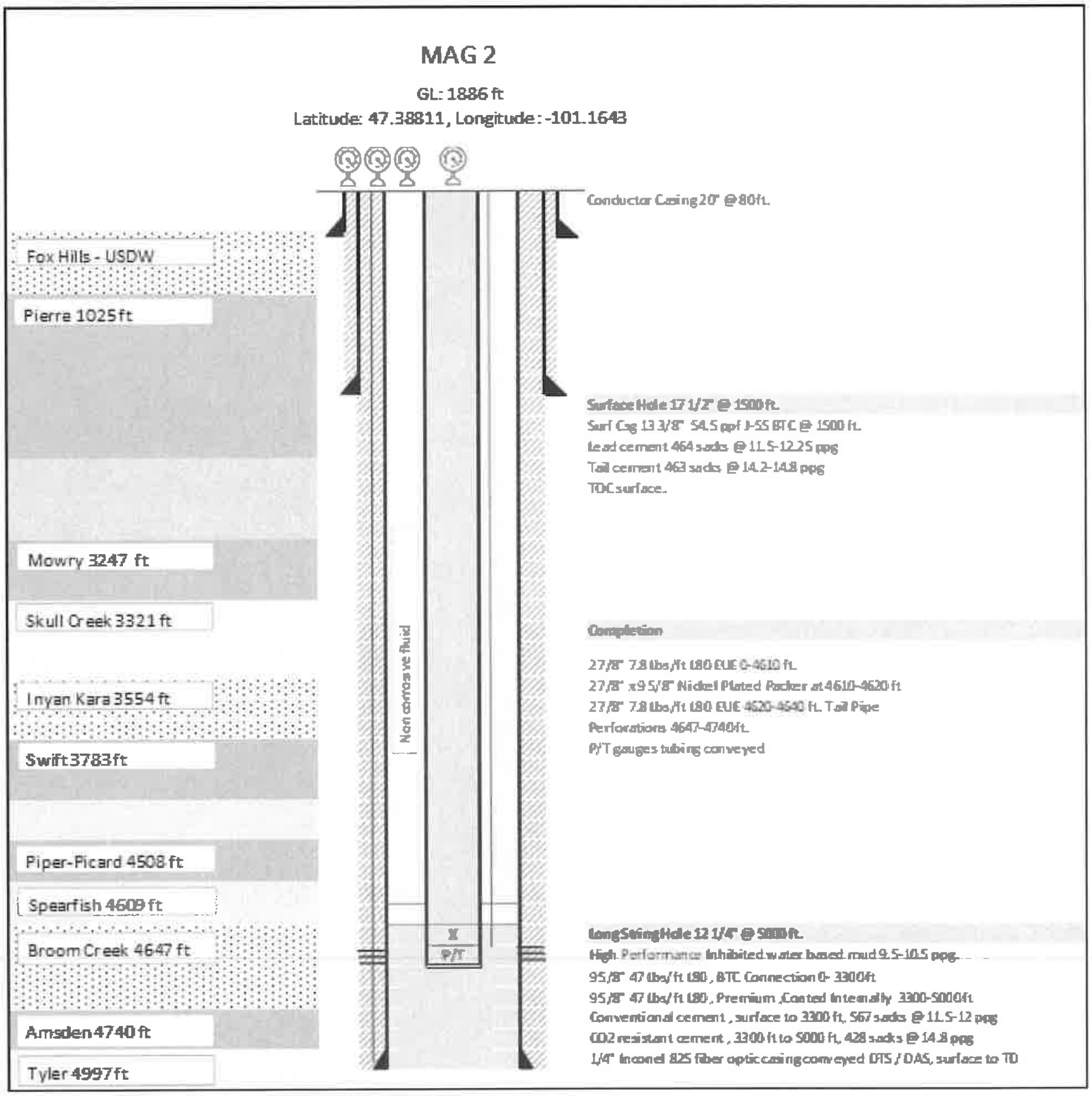



Figure 11-3. MAG 2 proposed completed wellbore schematic.

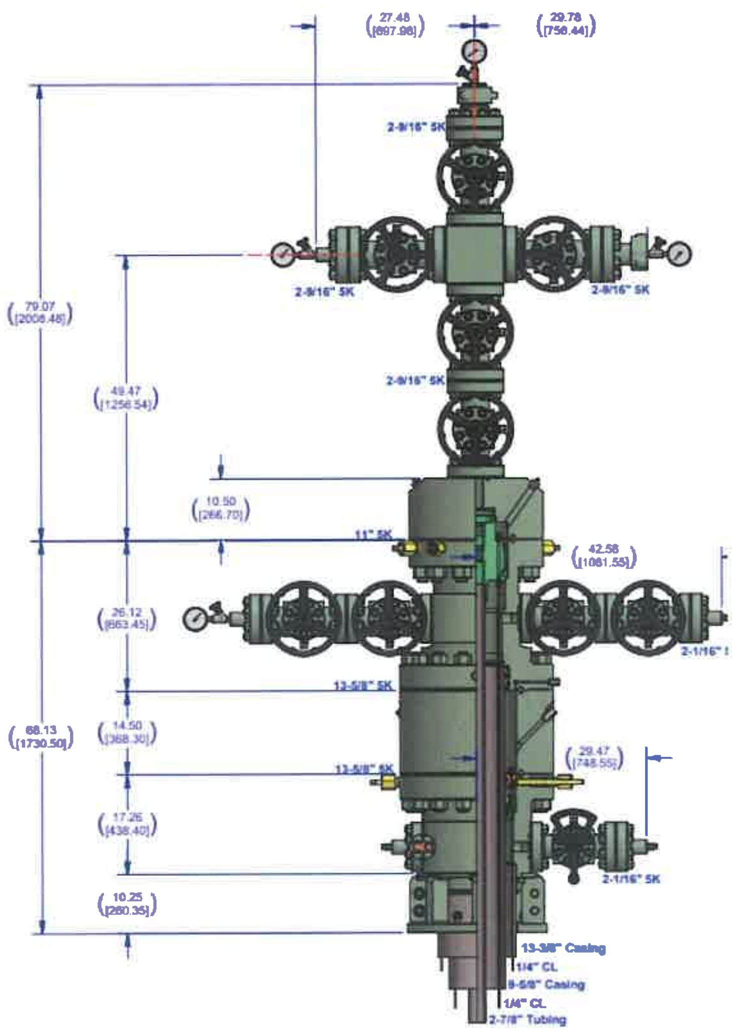



Figure 11-4. MAG 2 proposed wellhead schematic.

**Table 11-5. MAG 2 Proposed Upper Completion**

| Description | o.d., in. | Depth, ft | Grade | Weight, lb/ft | Connection | i.d., in. | Drift i.d., in. |
|---|---|---|---|---|---|---|---|
| Tubing | 2⅞ | 0–4,610 | L80 | 7.8 | EUE (external upset end) | 2.323 | 2.229 |
| 2⅞-in. × 9⅝-in. Nickel-Plated Packer | | | | | | | |
| Tubing (tail pipe) | 2⅞ | 4,620–4,640 | L80 | 7.8 | EUE | 2.323 | 2.229 |

**Table 11-6. MAG 2 Tubing Properties**

| o.d., in. | Grade | Weight, lb/ft | Connection | i.d., in. | Drift i.d., in. | Collapse, psi | Burst, psi | Tension, Klb |
|---|---|---|---|---|---|---|---|---|
| 2⅞ | L80 | 7.8 | Premium | 2.323 | 2.229 | 13,890 | 13,440 | 180 |

**Table 11-7. MAG 2 Cased-Hole Logging**

| Description | Depth, ft | Comments |
|---|---|---|
| CBL–VDL–CCL–USIT | 0–4,970* | Cement/Casing Log; 30-ft shoe track |
| CIL | 0–4,640* | Baseline; run through tubing |
| Temperature Log | 0–4,640* | Baseline; run through tubing |
| Pulsed Activated Neutron | 0–4,640* | Baseline; run through tubing |

* Estimated; will be adjusted with actual tally.

# 12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

## 12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

This financial assurance and demonstration plan (FADP) is provided to meet the regulatory requirements for the geologic storage of $CO_2$ as prescribed by the state of North Dakota in North Dakota Administrative Code (NDAC) § 43-05-01-09.1. The storage facility permit (SFP) application must demonstrate that a financial instrument is in place that is sufficient to cover the costs associated with the following actions:

- Pursuant to NDAC § 43-05-01-05.1, corrective action on all active and abandoned wells, which are within the AOR (area of review) and penetrate the confining zone, and have the potential to endanger USDWs (underground sources of drinking water) through the subsurface movement of the injected $CO_2$ or other fluids.

- Pursuant to NDAC § 43-05-01-11.5, plugging of injection wells.

- Pursuant to NDAC § 43-05-01-19, implementation of postinjection site care (PISC) and facility closure activities, which includes the 10-year PISC monitoring program.

- Pursuant to NDAC § 43-05-01-13, implementation of ERRP (emergency and remedial response plan) actions.

This FADP identifies the financial instruments that will be established (Section 12.2) and provides cost estimates for each of the above actions (Section 12.3) based on the information that is provided in the SFP application.

### 12.1 Facility Information

The facility name, facility contact, and injection well locations are provided below:

| | |
|---|---|
| Facility Name: | Blue Flint Sequester Company, LLC |
| Facility Contact: | Adam Dunlop |
| Injection Well Locations: | MAG 1 (NDIC File No. 37833) NW/NW of Section 18 T145N, R82. |

### 12.2 Financial Instruments

Blue Flint is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments:

- Blue Flint will plan to increase existing well bonding or secure other financial instrument to cover costs of plugging the injection well in accordance with NDAC § 43-05-01-11.5.

- No corrective action estimates have been provided as there are no legacy wellbores within the AOR; thus no action is necessary.

- Blue Flint will establish a bond, escrow account, third-party insurance policy, or other financial instrument to ensure funds are available for PISC and facility closure activities in accordance with NDAC § 43-05-01-19.

- A third-party pollution liability insurance policy with an aggregate limit of $9 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13.

The estimated total costs of these activities are presented in Table 12-1. Section 12.3 of this FADP provides additional details of the financial responsibility cost estimates for each activity.

**Table 12-1. Cost Estimates for Activities to Be Covered**

| Activity | Estimated Total Cost |
|---|---|
| Corrective Action on Wells in the AOR | $0 |
| Plugging of Injection Well | $100,000 |
| PISC and Facility Closure | $2,467,550 |
| Emergency and Remedial Response (including endangerment to USDWs) | $9,000,000 |
| Total | $11,567,550 |

The company providing insurance will meet all the following criteria:

1. The company is authorized to transact business in North Dakota.

2. The company has either passed the specified financial strength requirements based on credit ratings or has met a minimum rating, minimum capitalization, and ability to pass the rating, when applicable.

3. The third-party insurance can be maintained until such time that the North Dakota Industrial Commission (NDIC) determines that the storage operator has fulfilled its financial obligations.

The third-party insurance, which identifies Blue Flint as the covered party, will be provided by one or a combination of the companies shown below: The Applicant has procured indicated terms for commercial Environmental Impairment Liability ('EIL') insurance coverage to fund covered emergency and remedial response actions to protect underground sources of drinking water arising out of sequestration operations. Coverage terms are of an indicative/estimated nature only at this time, as firm and bindable terms are not possible this far in advance of commencement of sequestration operations; however, at this time a coverage limit of $9 million per occurrence/aggregate is contemplated and likely expected to be provided by one or a combination of the following insurers:

- Ascot Insurance Group – AM Best Rated 'A' (Excellent)
- Aspen Insurance Group – AM Best Rated 'A' (Excellent)
- W.R. Berkley Insurance Group – AM Best Rated 'A+' (Superior)
- Ironshore Insurance Company (Liberty Mutual Group) – AM Best Rated 'A' (Excellent)

Final coverage terms and costs will be determined upon full underwriting and firm/bindable quotations to be issued by insurers 30–60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations.

The third-party insurance companies listed above meet both of the following criteria, as specified in NDAC §43-05-01-09.1(1)(g):

1. The companies satisfy financial strength requirements based on credit ratings in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa).

2. The companies meet a minimum rating (minimum rating based on an issuer, credit, securities, or financial strength rating as a demonstration of financial stability) and minimum capitalization (i.e., demonstration that minimum thresholds are met for the following financial ratios: debt–equity, assets–liabilities, cash return on liabilities, liquidity, and net profit) and are able to pass bond rating in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa), when applicable.

## 12.3 Financial Responsibility Cost Estimates

### *12.3.1 Corrective Action*

Blue Flint implemented the following workflow to estimate costs associated with corrective action activities: 1) delineate the AOR and 2) identify and evaluate active and abandoned legacy wells within the AOR (i.e., MAG 1) to ensure they meet the minimum completion standards for geologic storage of $CO_2$ and need no corrective action. Based on the results of the well evaluations, no correction action was needed.

### *12.3.2 Plugging of Injection Wells*

Blue Flint implemented the following approach to estimate costs associated with the plugging of the injection well: assume plugging of one Class VI injection well at a total cost of $100,000 per well, the MAG 1 well.

### *12.3.3 Implementation of PISC and Facility Closure Activities*

The breakdown of estimated costs totaling $2.272 million for implementing the PISC as described in the PISC and facility closure plan is provided in Table 12-2a, which includes the following monitoring activities: a) formation monitoring (i.e., downhole pressure and temperature surveys, pulsed-neutron logs), b) near-surface monitoring (i.e., soil gas and Fox Hills Formation testing) and mechanical integrity well tests (i.e., injection well annulus pressure, ultrasonic logs), and c) coordinated repeat 2D seismic surveys. Table 12-2a covers the estimated costs in the time period between cessation of injection activities and issuance of the certificate of project completion. The MAG 1 wellbore will be plugged upon cessation of injection, with plugging cost estimates provided in Table 12-1. As part of PISC monitoring activities, the deep subsurface monitoring well, MAG 2, and the Fox Hills monitoring well will remain until site closure. The MAG 2 wellbore will monitor the storage reservoir until site closure, with cost estimates for plugging and site closure activities provided in Table 12-2b.

**Table 12-2a Cost Estimate[1] for PISC Activities for the Blue Flint $CO_2$ Storage Project. The Cost Estimate Assumes a 10-year PISC Period.**

| Activity | Frequency | Unit Cost | Total |
|---|---|---|---|
| **Injection Pad Reclamation (MAG 1)** | | | |
| Reclamation Costs of the Injection Pad of MAG 1 | Prior to closure | $50,000 | $50,000 |
| Flowline Abandonment and Closure | Once | $21,000 | $21,000 |
| SGPS01 P&A[3] | Prior to closure | $10,000 | $10,000 |
| **Flowline Reclamation at the Capture Facility** | | | |
| Flowline Abandonment and Closure | Once | $21,000 | $21,000 |
| **Wellbore Monitoring (MAG 2)** | | | |
| Pulsed-Neutron Logging (saturation monitoring, reservoir, and AZMI[2]) | Annually until full $CO_2$ saturation occurs within storage reservoir; reduce to once every 4 years thereafter. | $45,000 | $180,000 |
| Temperature Logging (external mechanical integrity) | Annually (if needed) | $10,000 | $100,000 |
| USIT Logging (corrosion monitoring) | Once every 5 years | $55,000 | $110,000 |
| Annulus Pressure Testing (internal mechanical integrity) | Once every 5 years | $8,000 | $16,000 |
| **Near-Surface Monitoring** | | | |
| SGPS01 – Sampling and Analysis | Once | $4,450 | $4,450 |
| SGPS02 – Sampling and Analysis | Annually | $4,450 | $44,500 |
| SG01-SG04 – Sampling and Analysis | Once at start of PISC and once prior to closure | $4,450 | $35,600 |
| Up to Five Groundwater Wells – Sampling and Analysis | Once prior to closure | $2,000 | $10,000 |
| One Dedicated Fox Hills Well – Sampling and Analysis | Annually | $2,000 | $20,000 |
| **Storage Complex Monitoring** | | | |
| Time-Lapse 2D Fence Seismic Survey Acquisition and Processing | Once every 5 years | $825,000 | $1,650,000 |

**Table 12-2b Cost Estimate[1] for Site Closure and Remediation Activities for the Blue Flint $CO_2$ Storage Project**

| Activity | Timing | Description | Total |
|---|---|---|---|
| **Closure and Reclamation Costs** | | | |
| Plugging of the MAG 2 Monitoring Well | Prior to closure | Plugging activities described in Section 10 Plugging Plan | $100,000 |
| Reclamation Costs of the Monitoring Pad of MAG 2 | Prior to closure | Wellhead removal, sump removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, general labor | $50,000 |
| Fox Hills Monitoring Well P&A[2] | Prior to closure | Pipe removal, pad reclamation (rock removal and soil coverage), reseeding, general labor | $35,000 |
| SGPS02 P&A[2] | Prior to closure | Plugging and abandonment of SGPS01 and SGPS02 | $10,000 |
| Total for Closure Activities | | | $195,000 |

[1] Does not include interpretation and reporting. Costs are based on today's pricing and do not account for inflation.
[2] Plugging and abandonment assumed unless NDIC requests transfer of ownership.

Table 12-2b lists the costs for the closure of the site and activities related to injection and monitoring of CCS activities which demonstrate a total of $195 thousand. As listed in Section 6.0 PISC, Subsection 6.3.1 PISC Plan, Blue Flint plans to initiate site closure activities that will include the plugging of all wells that are not planned for continued use in monitoring the closed site; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring; and the reclaiming of the surface land of the site to as close as is practical to its original condition.

As described in 6.3.2 Site Closure Plan, the Fox Hills monitoring well and the two soil gas profile stations are available for transfer of ownership to the state. Table 12-2b demonstrates the costs for the plugging and abandonment of one of two soil gas profile stations (SGPS02) and the Fox Hills monitoring well in the case the state does not request transfer of ownership. SGPS01's plugging and abandonment cost is shown in Table 12-2a in the case it is not transferred to the state. The five groundwater sampling wells listed in Table 12-2a do not require remediation and were not incorporated into cost estimates as the wells were not constructed as part of the project and are privately owned by third parties. This brings the total for PISC and closure activities to $2.467 million.

### *12.3.4 Implementation of Emergency and Remedial Response Actions*

#### *12.3.4.1 Emergency Response Actions*

A review of the technical risk categories for Blue Flint identified a list of events that could potentially result in the movement of injected $CO_2$ or formation fluids in a manner that may endanger a USDW and require an emergency response. These events are as follows:

- Injectivity
- Storage capacity
- Containment – lateral migration of $CO_2$
- Containment – pressure propagation
- Containment – vertical migration of $CO_2$ or formation water brine via injection wells, other wells, or inadequate confining zones
- Natural disasters (induced seismicity)

If it is determined that one or more of these events have occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7). These response actions are summarized in Tables 7-3 and 7-4.

#### *12.3.4.2 Estimation of Costs of Emergency Response Actions*

Estimating the costs of implementing the emergency response actions in Tables 7-3 and 7-4 is challenging since remediation measures specifically dedicated to $CO_2$ storage impacts are poorly documented, with one of the more important data gaps being the lack of precise knowledge of the leakage mechanisms and associated impacts (Manceau and others, 2014). Without this knowledge, it is not possible to design appropriate remedial measures. Furthermore, to date, no remediation action following $CO_2$ leakage after geologic storage has ever been implemented mainly because of the absence of established impacts (Manceau and others, 2014). Consequently, the degree of maturity of remediation measures in the carbon capture and storage (CCS) field is low, making it necessary to rely on literature that is primarily based on modeling or analogies with other pollutants, e.g., the analogy between $CO_2$ and volatile organic compounds, the latter having been addressed extensively in the literature. Additionally, for the remedial measures, costs and time for adequate removal are generally site-dependent, and no information is specifically available in this area in the CCS field.

Based on this current situation, two key technical manuscripts were relied upon to identify and estimate the costs of mitigation/remediation technologies to address undesired migration of $CO_2$ from a geological storage unit (Manceau and others, 2014; Bielicki and others, 2014).

##### 12.3.4.2.1 Identification of Remediation Technologies

Manceau and others (2014) identified several remediation technologies/strategies that are available to address the potential impacted media that may result from an emergency event. These impacted media and remediation measures are listed in Table 12-3. The impacted media in Table 12-3 include surface and groundwater/USDWs, vadose zone, indoor settings, and atmosphere; the

**Table 12-3. Proposed Technologies/Strategies for Remediation of Potential Impacted Media**

| Impacted Media | Potential Remedial Measures |
|---|---|
| Groundwater/USDW | Monitored natural attenuation |
| | Pump-and-treat |
| | Air sparging |
| | Permeable reactive barrier |
| | Extraction/injection |
| | Biological remediation |
| Vadose Zone | Monitored natural attenuation |
| | Soil vapor extraction |
| | pH adjustment (via spreading of alkaline supplements, irrigation, and drainage) |
| Surface Water | Passive systems, e.g., natural attenuation |
| | Active treatment systems |
| Atmosphere | Passive systems, e.g., natural mixing, dispersion |
| Indoor/Workplace Settings | Sealing of leak points |
| | Depressurization |
| | Ventilation |

remedial measures include a combination of active (e.g., air sparging) and passive (e.g., dispersion, natural attenuation) systems. However, it is important to note that, at this time, there is no widely accepted methodology for designing intervention and remediation plans for $CO_2$ geologic storage projects. Consequently, there remains a need for establishing the best field-applied and test practices for mitigating an undesired $CO_2$ migration. This effort will be based on a combination of available literature and experience that is gained over time in existing $CO_2$ storage projects.

#### 12.3.4.2.2 Estimation of Costs for Implementing Emergency Event Responses

Given the lack of a site-specific estimate of implementing the emergency event responses at the $CO_2$ geologic storage site of Blue Flint, cost estimates developed by Bielicki and others (2014) were used to derive a cost range for the project related to the undesired migration of $CO_2$ from a geologic storage unit. Extrapolating these literature costs, which were based on a case study site in the Michigan Sedimentary Basin, to Blue Flint only provides an order-of-magnitude estimate of the potential costs because of the significant site-specific differences in the storage projects; however, the range of costs estimated in this manner are believed to be conservatively high in nature, making them more than sufficient for informing the value of the financial instrument that must be secured for the project, as described in the financial responsibility demonstration plan.

#### Case Study Description

Bielicki and others (2014) examined the costs associated with remediating undesired migration of $CO_2$ from a geologic storage unit as part of a case study of an extreme leakage situation. The case study involved the continuous annual injection of 9.5 Mt (9,500,000 metric tons) of $CO_2$ into the Mt. Simon sandstone of the Michigan Sedimentary Basin over a period of 30 years. It assumed every well in the basin was a potential leakage pathway and that no action was taken to mitigate any of these leakage pathways. In addition, eight UIC (underground injection control) Class I injection wells, which were located within approximately 1 mile of the $CO_2$ injection well, were also identified as leakage pathways. Four hundred probabilistic simulations of the $CO_2$ injection were performed and produced estimates of the area of the $CO_2$ plume as well as leakage rates of $CO_2$ from the storage reservoir to four aquifers as well as to the surface.

Cost Estimates

Story lines were developed for the site based on 1) risk assessments for the geologic storage of $CO_2$; 2) consequences of leakage; 3) lay and expert opinion of leakage risk; 4) modeling of $CO_2$ injection and leakage for the case study; and 5) input from local experts, oil and gas engineers, academics, attorneys, and other environmental professionals familiar with the Michigan Sedimentary Basin. Cost estimates for managing leakage events were then generated for first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) projects based on a low-cost and high-cost story line. These cost estimates provided a breakdown of the costs into the following categories:

- Find and fix a leak
- Environmental remediation
- Injection interruption
- Technical remedies for damages
- Legal costs
- Business disruption to others, e.g., natural gas storage
- Labor burden to others

Of interest for the financial responsibility demonstration plan is the environmental remediation cost estimate, which was provided for a leak scenario where there was interference with groundwater as well as a scenario where there was groundwater interference combined with $CO_2$ migration to the surface.

Environmental Remediation – Low-Cost and High-Cost Story Line

The low-cost and high-cost story lines for the two components of environmental remediation, groundwater interference and migration to the surface, are summarized in Table 12-4. As shown in Table 12-4, the low-cost story lines are characterized by independent leak scenarios that either result in interference with groundwater or $CO_2$ migration to the surface. On the other hand, the high-cost story lines are interrelated, where it is assumed that the high-cost story line for $CO_2$ migration to the surface is conditional upon the existence of the high-cost story line for groundwater interference.

Estimated Environmental Remediation Costs – FOAK and NOAK Projects

Based on the above story lines, the estimated environmental remediation costs for the high-cost story lines are basically the same for both FOAK and NOAK projects:

- High-cost story line – Groundwater interference alone: ~ $13M
- High-cost story line – Groundwater interference with $CO_2$ migration to the surface: $15M to $16M

**Table 12-4. Low-Cost and High-Cost Story Line for Environmental Remediation**

| | |
|---|---|
| **Low-Cost Story Line** | |
| Groundwater Interference | • A small amount of $CO_2$ migrates into a deep formation that has a total dissolved solids concentration of ~9000 ppm. By definition, this unit is a USDW, but the state has abundant water resources, and there are no foreseeable uses for water from this unit.<br>• 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.<br>• Injection is halted from the time that the leak is discovered until monitoring confirms that containment is effective (9 months).<br>• 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.<br>• Neither $CO_2$ nor brine leaks into the subsurface formation outside the injection formation in significant quantities.<br>• 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.<br>• A new water supply well is installed to serve the community, and the former water supply wells are plugged and capped.<br>• Potable water is provided to the affected households during the 6 months required to drill the new water supply wells.<br>• Groundwater regulators take legal action on the geologic storage operator to force remediation of the affected USDW using pump-and-treat technology.<br>• 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.<br>• $CO_2$ 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.<br>• A hyperspectral survey completed during the diagnostic monitoring program identifies surface leakage in a sparsely populated area.<br>• Elevated $CO_2$ concentrations are detected by a soil gas survey and by indoor air quality sampling in the basements of several residences.<br>• Affected residents are housed in a local hotel for several nights while venting systems are installed in their basements.<br>• A soil-venting system is installed at the site.<br>• $CO_2$ injection is halted for a year during these remediation activities. |

12.3.4.2.3 Input for the Financial Responsibility Demonstration Plan

The estimated costs for the environmental remediation of the high-cost story line for the case study, \$15M to \$16M, likely represents a high estimate of similar costs for Blue Flint. This statement is based primarily on the fact that the quantity of $CO_2$ injection of the case study (9,500,000 metric tons of $CO_2$ per year) is significantly larger than the planned injection quantity of Blue Flint (from 200,000 metric tons of $CO_2$ per year). Furthermore, the case study site had 450,000 active and abandoned wells, 400,000 of which penetrate the shallow subsurface to provide for drinking water, irrigation, and industrial uses. In contrast, there is one proposed $CO_2$ injection well (MAG 1) and one monitoring well (MAG 2) located in the area of Blue Flint. As such, the extreme leakage scenario of the case study represents a more extensive leakage scenario than could exist at the Blue Flint site. Accordingly, even though the same remedial technologies and strategies may be used at both sites to address $CO_2$ migration, it is assumed that the cost estimates provided for the case study represent a high cost that is unlikely to be incurred for the Blue Flint project. It is on this basis that the value of $9M has been used for the emergency and remedial response portion of the financial instrument that will be put in place for Blue Flint.

To provide additional perspective for this $9M cost estimate for environmental remediation, two other cost estimates for the remediation of potential environmental impacts associated with the geologic storage of $CO_2$ were found in the literature. These costs ranged from $9M to $34M. The source of the lower limit ($9M) was a 2012 study (Trabucchi and others, 2012) which estimated the damages, i.e., dollars necessary to remediate or compensate for harm should a release occur at a commercial storage site (i.e., FutureGen 1.0 located in Jewett, Texas) that planned to inject 1,000,000 metric tons of $CO_2$ per year. This study estimated the "most likely" (50th percentile) total damages to be approximately $8.7M and the "upper end" (95th and 99th percentiles) of the total damages to be approximately $20.1M and $26.2M, respectively (all estimates in 2020 dollars). Given that that the quantity of $CO_2$ injection of this case study (1,000,000 metric tons of $CO_2$ per year) is significantly larger than the planned injection quantity of Blue Flint (from 200,000 metric tons of $CO_2$ per year) the lower limit of $9M is a conservatively high estimate for Blue Flint.

The upper limit of the range ($34M) came from a Class VI UIC permit, which was issued to Archer Daniels Midland (ADM) by the U.S. Environmental Protection Agency (Underground Injection Control Permit – Class VI, Permit No. IL-115-6A-0001). As part of the financial responsibility demonstration plan of the ADM permit, a cost estimate of $33.8M was provided for the cost element, emergency, and remedial response, which is slightly higher than the 99th percentile cost estimate of $26.2M for the FutureGen 1.0 site. The planned injection rate for the ADM geologic storage project was ~1,200,000 metric tons per year.[1]

### 12.4 References

Bielicki, J.M., Pollak, M.F., Fitts, J.P., Peters, C.A., and Wilson, E.J., 2013, Causes and financial consequences of geologic $CO_2$ storage reservoir leakage and interference with other subsurface resources: International Journal of Greenhouse Gas Control, v. 20, p. 272–284.

Manceau, J.C., Hatzignatiou, D.G., Latour, L.L, Jensen, N.B., and Réveillére, A., 2014, Mitigation and remediation technologies and practices in case of undesired migration of $CO_2$ from a geological storage unit—current status: International Journal of Greenhouse Gas Control, v. 22, p. 272–290.

[1] It should be noted that both of these examples are injecting $CO_2$ at a rate 5–6 times higher than the planned injection at the Blue Flint facility, which suggests that these cost estimates are likely higher than the costs that will be required for Blue Flint Sequester Company, LLC.

Trabucchi, C., Donlan, M., Huguenin, M, Konopka, M., and Bolthrunis, S., 2012, Valuation of potential risks arising from a model, commercial-scale CCS project site: Prepared for CCS Valuation Sponsor Group, June 1, 2012.

# APPENDIX A

# MAG 1 FORMATION FLUID SAMPLING

# *MINNESOTA VALLEY TESTING LABORATORIES, INC.*

MVTL

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL






Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Report Date: 12 Nov 20
Lab Number: 20-W4389
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:45
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

Project Name: MAG1

PO #: CC#990-81100-002

Sample Description: Inyan Kara Upper

Temp at Receipt: 5.5C ROI

| | As Received Result | | Method RL | Method Reference | Date Analyzed | Analyst |
|---|---|---|---|---|---|---|
| Metal Digestion | | | | EPA 200.2 | 3 Nov 20 | HT |
| pH | * 7.7 | units | N/A | SM4500-H+-B-11 | 3 Nov 20 17:00 | HT |
| Conductivity (EC) | 24500 | umhos/cm | N/A | SM2510B-11 | 3 Nov 20 17:00 | HT |
| pH - Field | 7.87 | units | NA | SM 4500 H+ B | 2 Nov 20 13:45 | DJN |
| Temperature - Field | 19.7 | Degrees C | NA | SM 2550B | 2 Nov 20 13:45 | DJN |
| Total Alkalinity | 428 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Phenolphthalein Alk | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Bicarbonate | 428 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Carbonate | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Hydroxide | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Conductivity - Field | 26360 | umhos/cm | 1 | EPA 120.1 | 2 Nov 20 13:45 | DJN |
| Total Organic Carbon | 746 | mg/l | 0.5 | SM5310C-11 | 11 Nov 20 23:56 | NAS |
| Sulfate | 1100 | mg/l | 5.00 | ASTM D516-11 | 6 Nov 20 10:02 | SD |
| Chloride | 11500 | mg/l | 2.0 | SM4500-Cl-E-11 | 4 Nov 20 8:37 | EV |
| Nitrate-Nitrite as N | < 1 @ | mg/l | 0.20 | EPA 353.2 | 5 Nov 20 10:12 | EV |
| Ammonia-Nitrogen as N | 36.2 | mg/l | 0.20 | EPA 350.1 | 10 Nov 20 11:46 | SD |
| Mercury - Dissolved | < 0.0002 | mg/l | 0.0002 | EPA 245.1 | 6 Nov 20 13:06 | MDE |
| Total Dissolved Solids | 17000 | mg/l | 10 | USGS I1750-85 | 4 Nov 20 9:30 | HT |
| Calcium - Total | 591 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Magnesium - Total | 39.9 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Sodium - Total | 5600 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Potassium - Total | 139 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Iron - Total | 0.74 | mg/l | 0.10 | 6010D | 11 Nov 20 10:12 | MDE |
| Manganese - Total | 0.25 | mg/l | 0.05 | 6010D | 11 Nov 20 10:12 | MDE |

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
# = Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

# *MINNESOTA VALLEY TESTING LABORATORIES, INC.*

MVTL

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL






Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Report Date: 12 Nov 20
Lab Number: 20-W4389
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:45
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

Project Name: MAG1

PO #: CC#990-81100-002

Sample Description: Inyan Kara Upper

Temp at Receipt: 5.5C ROI

| | As Received Result | | Method RL | Method Reference | Date Analyzed | Analyst |
|---|---|---|---|---|---|---|
| Strontium - Dissolved | 23.4 | mg/l | 0.10 | 6010D | 9 Nov 20 12:31 | MDE |
| Arsenic - Dissolved | < 0.004 + | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Barium - Dissolved | 0.4902 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Cadmium - Dissolved | < 0.002 + | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |
| Chromium - Dissolved | < 0.004 + | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Copper - Dissolved | < 0.004 + | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Lead - Dissolved | < 0.0005 | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |
| Molybdenum - Dissolved | 0.0353 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Selenium - Dissolved | < 0.02 + | mg/l | 0.0050 | 6020B | 9 Nov 20 11:20 | MDE |
| Silver - Dissolved | < 0.002 + | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:

@ = Due to sample matrix
# = Due to concentration of other analytes
! = Due to sample quantity
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

*MINNESOTA VALLEY TESTING LABORATORIES, INC.*

MVTL

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL





Report Date: 12 Nov 20
Lab Number: 20-W4390
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:52
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Project Name: MAG1

PO #: CC#990-81100-002

Sample Description: Inyan Kara Lower

Temp at Receipt: 5.5C ROI

| | As Received Result | | Method RL | Method Reference | Date Analyzed | Analyst |
|---|---|---|---|---|---|---|
| Metal Digestion | | | | EPA 200.2 | 3 Nov 20 | HT |
| pH | * 8.1 | units | N/A | SM4500-H+-B-11 | 3 Nov 20 17:00 | HT |
| Conductivity (EC) | 22524 | umhos/cm | N/A | SM2510B-11 | 3 Nov 20 17:00 | HT |
| pH - Field | 8.35 | units | NA | SM 4500 H+ B | 2 Nov 20 13:52 | DJN |
| Temperature - Field | 19.0 | Degrees C | NA | SM 2550B | 2 Nov 20 13:52 | DJN |
| Total Alkalinity | 393 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Phenolphthalein Alk | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Bicarbonate | 393 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Carbonate | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Hydroxide | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Conductivity - Field | 24178 | umhos/cm | 1 | EPA 120.1 | 2 Nov 20 13:52 | DJN |
| Total Organic Carbon | 889 | mg/l | 0.5 | SM5310C-11 | 11 Nov 20 23:56 | NAS |
| Sulfate | 1110 | mg/l | 5.00 | ASTM D516-11 | 6 Nov 20 10:02 | SD |
| Chloride | 9520 | mg/l | 2.0 | SM4500-Cl-E-11 | 4 Nov 20 8:37 | EV |
| Nitrate-Nitrite as N | < 1 @ | mg/l | 0.20 | EPA 353.2 | 5 Nov 20 10:12 | EV |
| Ammonia-Nitrogen as N | 37.1 | mg/l | 0.20 | EPA 350.1 | 10 Nov 20 11:46 | SD |
| Mercury - Dissolved | < 0.0002 | mg/l | 0.0002 | EPA 245.1 | 6 Nov 20 13:06 | MDE |
| Total Dissolved Solids | 15600 | mg/l | 10 | USGS I1750-85 | 4 Nov 20 9:30 | HT |
| Calcium - Total | 516 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Magnesium - Total | 34.6 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Sodium - Total | 5130 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Potassium - Total | 140 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Iron - Total | < 0.5 @ | mg/l | 0.10 | 6010D | 11 Nov 20 10:12 | MDE |
| Manganese - Total | < 0.25 @ | mg/l | 0.05 | 6010D | 11 Nov 20 10:12 | MDE |

RL : Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = 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.

MVTL

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL






Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Report Date: 12 Nov 20
Lab Number: 20-W4390
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:52
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

Project Name: MAG1

PO #: CC#990-81100-002

Sample Description: Inyan Kara Lower

Temp at Receipt: 5.5C ROI

| | As Received Result | | Method RL | Method Reference | Date Analyzed | Analyst |
|---|---|---|---|---|---|---|
| Strontium - Dissolved | 21.4 | mg/l | 0.10 | 6010D | 9 Nov 20 12:31 | MDE |
| Arsenic - Dissolved | < 0.002 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Barium - Dissolved | 0.2619 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Cadmium - Dissolved | < 0.0005 | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |
| Chromium - Dissolved | 0.0020 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Copper - Dissolved | 0.0041 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Lead - Dissolved | < 0.0005 | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |
| Molybdenum - Dissolved | 0.0523 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Selenium - Dissolved | < 0.01 ^ | mg/l | 0.0050 | 6020B | 9 Nov 20 11:20 | MDE |
| Silver - Dissolved | < 0.0005 | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
# = Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

EERC
Energy & Environmental Research Center
UNIVERSITY OF NORTH DAKOTA
15 North 23rd Street – Stop 9018 | Grand Forks, ND 58202-9018 | Phone: (701) 777-5000 Fax: 777-5181
Web Site: www.undeerc.org

# ANALYTICAL RESEARCH LAB - Final Results

*July 20, 2022*

**Set Number:** 55028
**Fund#:** 27026
**PI:** Ian Feole
**Contact Person:** Ian Feole

**Request Date:** Tuesday, June 7, 2022
**Due Date:** Tuesday, June 21, 2022
**Set Description:** Midwest AgEnergy - MAG-1 Broom Creek Formation Water

| Sample | Parameter | Result | |
|---|---|---|---|
| 55028-01 | MAG-1 Broom Creek 6/4/22 | | |
| | Alkalinity, as Bicarbonate (HCO3-) | 249 | mg/L |
| | Alkalinity, as Carbonate (CO3=) | 0 | mg/L |
| | Alkalinity, as Hydroxide (OH-) | 0 | mg/L |
| | Alkalinity, Total as CaCO3 | 204 | mg/L |
| | Bromide | 21.8 | mg/L |
| | Calcium | 823 | mg/L |
| | Chloride | 11600 | mg/L |
| | Conductivity at 25°C | 39900 | µS/cm |
| | Density | 1.02 | g/mL |
| | Magnesium | 187 | mg/L |
| | pH | 7.48 | |
| | Potassium | 90.9 | mg/L |
| | Sodium | 9020 | mg/L |
| | Strontium | 18.4 | mg/L |
| | Sulfate | 7350 | mg/L |
| | Total Dissolved Solids | 28600 | mg/L |

Distribution ____________________ Date __________

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 74217 **Client:** Neset Consulting
**Workorder:** Mag #1 (1427)

Jean Datahan
Neset Consulting
6844 Hwy 40
Tioga, ND 58852

**Certificate of Analysis**

## Approval

**All data reported has been reviewed and approved by:**

C Carroll

Claudette Carroll, Lab Manager Bismarck, ND

Analyses performed under Minnesota Department of Health Accreditation conforms to the current TNI standards.

NEW ULM LAB CERTIFICATIONS:
MN LAB # 027-015-125 ND WW/DW # R-040

BISMARCK LAB CERTIFICATIONS:
MN LAB # 038-999-267 ND W/DW # ND-016 SD SDWA

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 74217 **Client:** Neset Consulting

## Workorder Summary

### Workorder Comments

All analytes with dilution factors greater than 1 (displayed in DF column) required dilution due to matrix or high concentration of target analyte unless otherwise noted and reporting limits (RDL column) have been adjusted accordingly.

Workorder amended (project name). 14 Jul 22

### Sample Comments

***1427001 (Broom Creek) - Sample***

Temperature received outside of the 0 - 6 °C range specified by EPA requirements. Client has authorized MVTL to proceed with analysis through direct communication or authorization letter retained on file with customer service.

### Task Comments

***1427001 - 619013 - GENb/346***

Sample required dilution due to matrix. Reporting limit has been raised.

### Analysis Results Comments

***1427001 (Broom Creek)***

The reporting limit for this analyte has been raised to account for the reporting limit verification standard.
(Copper, Dissolved)

***1427001 (Broom Creek)***

Sample required dilution due to matrix. Reporting limit has been raised.
(Nitrate + Nitrite as N)

***1427001 (Broom Creek)***

Sample analyzed beyond holding time.(pH)

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 74217 **Client:** Neset Consulting

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 1427001 | **Date Collected:** | 06/04/2022 13:40 | **Matrix:** | Groundwater |
| **Sample ID:** | Broom Creek | **Date Received:** | 06/06/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 26.6 | **Received on Ice:** | Yes | | |

### Calculated

**Method: SM1030F**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Cation Summation | 463 | meq/L | | 1 | 07/14/2022 15:43 | 07/14/2022 15:43 | CW | | |
| Anion Summation | 557 | meq/L | | 1 | 07/14/2022 15:43 | 07/14/2022 15:43 | CW | | |
| Percent Difference | -9.20 | % | | 1 | 07/14/2022 15:43 | 07/14/2022 15:43 | CW | | |

### Inorganic Chemistry

**Method: ASTM D516-11**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfate | 7940 | mg/L | 250 | 50 | 06/10/2022 11:25 | 06/10/2022 11:25 | EJV | MA,NDA | |

**Method: EPA 350.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Ammonia as N | 14.5 | mg/L | 0.2 | 2 | 06/07/2022 15:37 | 06/07/2022 15:37 | EMS | | |

**Method: EPA 353.2**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Nitrate + Nitrite as N | <2 | mg/L | 2 | 10 | 06/09/2022 09:27 | 06/09/2022 09:27 | EJV | MA,NDA | * |

**Method: SM 5310C-2014**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Total Organic Carbon | 89.8 | mg/L | 0.5 | 500 | 06/14/2022 08:48 | 06/14/2022 08:48 | NS | MA,NDA | |

**Method: SM2320 B-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Alkalinity, Total | 176 | mg/L as CaCO3 | 20.5 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | MA,NDA | |
| Alkalinity, Phenolphthalein | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | | |
| Carbonate | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | | |
| Bicarbonate | 176 | mg/L as CaCO3 | 20.5 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | | |
| Hydroxide | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | | |

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 74217 **Client:** Neset Consulting

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 1427001 | **Date Collected:** | 06/04/2022 13:40 | **Matrix:** | Groundwater |
| **Sample ID:** | Broom Creek | **Date Received:** | 06/06/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 26.6 | **Received on Ice:** | Yes | | |

### Inorganic Chemistry

**Method: SM2510 B-2011 EC**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Specific Conductance | 34490 | umhos/cm | 1 | 1 | 06/06/2022 18:31 | 06/06/2022 18:31 | AMC | MA,NDA | |

**Method: SM4500 H+ B-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| pH | 7.6 | units | 0.1 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | MA,NDA | * |

**Method: SM4500-Cl-E 2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Chloride | 13800 | mg/L | 200 | 100 | 06/09/2022 17:05 | 06/09/2022 17:05 | EJV | MA,NDA | |

**Method: USGS I-1750-85**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Total Dissolved Solids | 28700 | mg/L | 10 | 1 | 06/07/2022 15:49 | 06/07/2022 15:49 | AMC | MA,NDA | |

### Metals

**Method: EPA 245.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Mercury, Dissolved | <0.0002 | mg/L | 0.0002 | 1 | 06/24/2022 11:00 | 06/28/2022 09:00 | MDE | MA,NDA | |

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Calcium | 937 | mg/L | 10 | 10 | 06/06/2022 17:20 | 06/23/2022 12:06 | SLZ | MA,NDA | |
| Magnesium | 197 | mg/L | 10 | 10 | 06/06/2022 17:20 | 06/23/2022 12:06 | SLZ | MA,NDA | |
| Sodium | 9080 | mg/L | 50 | 50 | 06/06/2022 17:20 | 06/23/2022 12:13 | SLZ | MA,NDA | |
| Potassium | 110 | mg/L | 10 | 10 | 06/06/2022 17:20 | 06/23/2022 12:06 | SLZ | MA,NDA | |
| Iron | 33.8 | mg/L | 1 | 10 | 06/06/2022 17:20 | 06/09/2022 14:46 | SLZ | MA,NDA | |
| Manganese | <0.5 | mg/L | 0.5 | 10 | 06/06/2022 17:20 | 06/09/2022 14:46 | SLZ | MA,NDA | |
| Barium, Dissolved | <1 | mg/L | 1 | 10 | 06/06/2022 17:20 | 06/09/2022 14:44 | SLZ | MA,NDA | |
| Strontium, Dissolved | 17.0 | mg/L | 1 | 10 | 06/06/2022 17:20 | 06/09/2022 14:44 | SLZ | MA,NDA | |



Report Date: Thursday, July 14, 2022 3:47:06 PM

Corrected 1427 - 674856

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 74217 **Client:** Neset Consulting

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 1427001 | **Date Collected:** | 06/04/2022 13:40 | **Matrix:** | Groundwater |
| **Sample ID:** | Broom Creek | **Date Received:** | 06/06/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 26.6 | **Received on Ice:** | Yes | | |

**Metals**

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Arsenic, Dissolved | <0.008 | mg/L | 0.008 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Chromium, Dissolved | **0.0085** | mg/L | 0.008 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Lead, Dissolved | <0.002 | mg/L | 0.002 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Selenium, Dissolved | <0.02 | mg/L | 0.02 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Silver, Dissolved | <0.002 | mg/L | 0.002 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Cadmium, Dissolved | <0.002 | mg/L | 0.002 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Molybdenum, Dissolved | **1.010** | mg/L | 0.008 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Copper, Dissolved | <0.008 | mg/L | 0.008 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | * |

**Sampling Information**

**Method: 120.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Specific Conductance - Field | **35976** | umhos/cm | 1 | 1 | 06/04/2022 13:40 | 06/04/2022 13:40 | JSM | | |

**Method: 150.2**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| pH - Field | **7.36** | units | 0.01 | 1 | 06/04/2022 13:40 | 06/04/2022 13:40 | JSM | | |

**Method: 170.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Temperature - Field C | **31.21** | degrees C | | 1 | 06/04/2022 13:40 | 06/04/2022 13:40 | JSM | | |

**Method: SM2110**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Appearance - Field | Slightly Turbid | | | 1 | 06/04/2022 13:40 | 06/04/2022 13:40 | JSM | | |



Report Date: Thursday, July 14, 2022 3:47:09 PM

Corrected 1427 - 674856

Minnesota Valley Testing Laboratories
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Nesel Consulting
W0: 1427

# Chain of Custody Record

| | | | |
|---|---|---|---|
| Report To: | Neset Consulting | CC: | |
| Attn: | Jean Datahan | | |
| Address: | 6844 Hwy 40<br>Tioga, ND 58852 | | |
| Phone: | 701-664-1492 | | |
| Email: | jeandatahan@nestconsulting.com | | |

Project Name: May #1
Event:
Sampled By: Jenny [illegible]

| Lab Number | Sample Information | | | | Sample Containers | | | | | | | | | | Field Readings | | | | Analysis Required |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Sample ID | Date | Time | Sample Type | 1 Liter Raw | 500 mL HNO3 | 500 mL HNO3 (filtered) | 250 mL H2SO4 | | TOC (set of 3) | | | | | Temp (°C) | Spec. Cond. | pH | Appearance | |
| 001 | Broom Creek | 4 Jun 22 | 1340 | GW | X | X | X | X | | X | | | | | 31.21 | 35,976 | 7.36 | ST | Neset GW well List |

Comments: ST = Slightly Turbid

| Relinquished By | | Sample Condition | | Received By | |
|---|---|---|---|---|---|
| Name | Date/Time | Location | Temp (°C) | Name | Date/Time |
| 1 [signature] | 4 June 22 1520 | Log In Walk In #2 | ROI 26.6 TM562 / TM805 | [signature] | 6 Jun 22 0800 |
| 2 | | | | | |

A-11

# APPENDIX B

# HISTORIC FRESHWATER WELL FLUID SAMPLING

## HISTORIC FRESHWATER WELL FLUID SAMPLING

The Falkirk Mining Company (FMC), a wholly owned subsidiary of North American Coal Corporation, has implemented a shallow groundwater monitoring program since the 1970s as part of its operations at the Falkirk Mine. The shallow groundwater monitoring program has established baselines of water quality for many of the freshwater aquifer systems within the Blue Flint $CO_2$ storage project AOR.

Hundreds of shallow groundwater wells (monitoring sites) have been drilled to date over the >50,000 acres leased to FMC. Each of the monitoring sites is tested annually to assess groundwater quality in the area. The monitoring sites sample from either surficial glacial aquifers of the Coleharbor Group (Pleistocene) or water-bearing coalbed (lignite) horizons of the Sentinel Butte and Bullion Creek Formations of the Fort Union Group (Paleocene) (U.S. Bureau of Land Management, 2017). Figure B-1 summarizes the stratigraphy and identifies which freshwater aquifers are present and under surveillance in the Underwood area.

| ERATHEM | SYSTEM | | SERIES | ROCK UNIT: GROUP | ROCK UNIT: FORMATION | | FRESHWATER AQUIFER(S) PRESENT | FRESHWATER AQUIFER NAMES |
|---|---|---|---|---|---|---|---|---|
| CENOZOIC | Quaternary | | Holocene | | Oahe | | No | |
| | | | Pleistocene | Coleharbor | "Glacial Drift" | | Yes | Weller Slough and Turtle Lake |
| | Tertiary | Paleogene | Eocene | | Golden Valley | | No | |
| | | | Paleocene | Fort Union | Sentinel Butte | | Yes | Hagel A and B coal beds and C sand |
| | | | | | Tongue River | Bullion Creek | Yes | Tavis Creek and Coal Lake Coulee coal beds and Hensler sand |
| | | | | | | Slope | No | |
| | | | | | Cannonball | | Yes | |
| | | | | | Ludlow | | Yes | |
| MESOZOIC | Cretaceous | | Upper | Montana | Hell Creek | | Yes | |
| | | | | | Fox Hills | | Yes | |
| | | | | | Pierre | | No | |

Figure B-1. Stratigraphic column showing the shallow subsurface geologic units and freshwater aquifer systems for the region in and around Underwood, North Dakota. Major freshwater aquifer systems under FMC's surveillance are indicated at far right (modified from Murphy and others [2009]).

Table B-1 summarizes the ranges of pH, electrical conductivity (EC), total dissolved solids (TDS), and total alkalinity measured from 15 active monitoring sites within the AOR. Figure B-2 is a map showing the locations of the selected monitoring sites. Monitoring sites were selected to establish baseline conditions for the Blue Flint $CO_2$ storage project if the wells 1) are operated by FMC, 2) have multiple years of recent (i.e., 2015 or later) geochemical results available, 3) and fall within a mile of the AOR.

The groundwater wells were drilled no more than 150 ft below ground surface and were perforated or screened along a 5–20-ft zone for sampling the horizons of interest. Groundwater wells represented in Table B-1 each have a minimum of four water chemistry samples collected and a maximum of seven. All water chemistries were determined by MVTL.

**Table B-1. Summary of Water Chemistries at 15 Monitoring Sites in the AOR**

| Number of Wells | Water Samples | Data Vintage | Sampling Horizon | pH | EC, mS/cm | TDS, mg/L | Total Alkalinity, mg/L $CaCO_3$ |
|---|---|---|---|---|---|---|---|
| 3 | 19 | 2015–2021 | Spoils | 7.0–8.3 | 1,958–3,632 | 1,290–2,610 | 549–1,370 |
| 2 | 13 | 2015–2021 | Sheet Sand | 6.1–6.9 | 1,458–2,628 | 991–1,960 | 282–887 |
| 2 | 11 | 2015–2021 | Coleharbor | 6.7–7.6 | 1,673–2,210 | 1,130–1,670 | 399–496 |
| 1 | 7 | 2015–2021 | Hagel A | 6.4–6.8 | 1,496–1,819 | 1,010–1,400 | 360–388 |
| 1 | 7 | 2015–2021 | Hagel A&B | 5.9–6.2 | 2,538–3,560 | 2,040–3,070 | 261–278 |
| 3 | 21 | 2015–2021 | Hagel B | 6.2–7.5 | 1,329–2,013 | 830–1,450 | 270–443 |
| 1 | 5 | 2017–2021 | C Sand | 8.2–8.4 | 2,323–2,362 | 1,440–1,950 | 999–1,240 |
| 2 | 14 | 2015–2021 | Tavis Creek | 7.0–8.4 | 2,215–2,367 | 1,330–2,020 | 524–1,260 |

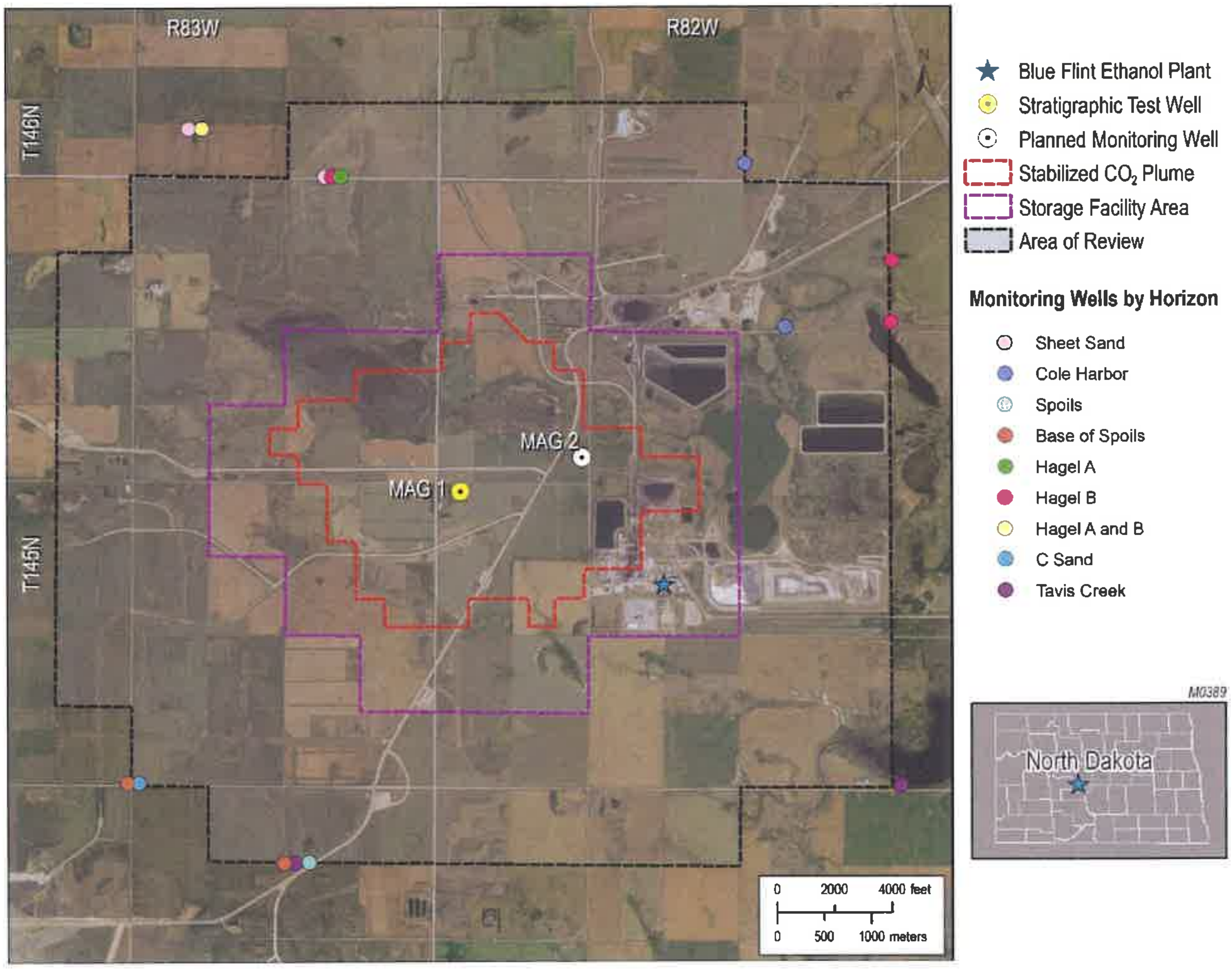



Figure B-2. Locations of the 15 monitoring sites operated by FMC with multiple years of recent (i.e., 2015 or later) water chemistry results available.

## REFERENCES

Murphy, E.C., Nordeng, S.H., Juenker, B.J., and Hoganson, J.W., 2009, North Dakota stratigraphic column: North Dakota Geological Survey Miscellaneous Series 91.

U.S. Department of the Interior Bureau of Land Management, 2017, Environmental assessment DOI-BLM-MT-C030-2016-0020-EA: The Falkirk Mining Company Federal Coal Lease by Application, Dickinson, North Dakota, 121 p.

# APPENDIX C

# QUALITY ASSURANCE SURVEILLANCE PLAN

## C1.0 QUALITY ASSURANCE AND SURVEILLANCE PLAN

The primary goal of the testing and monitoring plan (Section 5) of this storage facility permit application is to ensure that the geologic storage project is operating as permitted and is not endangering USDWs. In compliance with NDAC § 43-05-01-11.4 (Testing and Monitoring Requirements), this quality assurance and surveillance plan (QASP) was developed and is provided as part of the testing and monitoring plan.

### C1.1 $CO_2$ Stream Analysis

NDAC § 43-05-01-11.4(1)(a) requires analysis of the $CO_2$ stream in compliance with applicable analytical methods and standards generally accepted by industry and with sufficient frequency to yield data representative of its chemical and physical characteristics. Blue Flint will collect samples of the injected $CO_2$ stream quarterly at the liquefaction outlet and analyze the $CO_2$ stream to determine the concentrations of $CO_2$, nitrogen, oxygen, hydrogen, water, hydrogen sulfide, carbon monoxide, and a suite of hydrocarbons (e.g., ethane, propane, n-butane, and methane) via a third party. Selected stable isotopes (i.e., isotopes of carbon dioxide [$^{12}C$ and $^{13}C$], methane [$^{12}C$ and $^{13}C$], and deuterium [$^{2}H$]) will also be sampled in the first year to establish a baseline. The isotopic analyses will be outsourced to commercial laboratories that will employ standard analytical QA/QC protocols used in the industry.

### C1.2 Surface Facilities Leak Detection Plan

The surface leak detection and monitoring plan is outlined in Section 5.2. The SCADA system (described in Attachment A-1) will continuously monitor surface facilities operations in real time and be equipped with automated alarms that will notify the Blue Flint operations center in the event of an anomalous reading. A generalized specification sheet for the $CO_2$ detection stations (see Attachment A-2) will monitor $CO_2$ levels at each wellsite to ensure workspace atmospheres are safe.

### C1.3 Corrosion Monitoring and Prevention Plan

#### *C1.3.1 Corrosion Monitoring*

The flow line will use the corrosion coupon method to monitor for corrosion in the flow line and injection wellbore throughout the operational phase of the project, focusing on loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. The coupon sample port will be located near the liquefaction outlet, and sampling will occur quarterly during the first year of injection and once a year thereafter.

The process that will be used to conduct each coupon test is described below.

##### *C1.3.1.1 Sample Description*

Corrosion coupons that are representative of the construction materials of the flowline and injection well that contact the $CO_2$ stream will be tested. Materials from these process components and/or conventional corrosion coupons of similar composition and specifications will be weighed, measured, and photographed prior to initial exposure.

*C1.3.1.2 Sample Exposure*
Each sample will be suspended in a flow-through apparatus, which will be located downstream of all processes (i.e., at the liquefaction outlet which connects to the start of the flowline). A parallel stream of high-pressure $CO_2$ will be withdrawn from the flowline, passed through the flow-through apparatus, and then routed back into a lower-pressure point upstream in the compression system. This loop will operate any time injection is occurring. The operation of this system will provide exposure of the samples to $CO_2$ representative of the composition, temperature, and pressures that will be present along the flowline, at the wellhead, and in the injection tubing.

*C1.3.1.3 Sample Handling and Monitoring*
The exposed materials/coupons will be handled and assessed for corrosion in accordance with either National Association of Colleges and Employers (NACE) Standard SP0775—Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations—(2018) or American Society for Testing Materials (ASTM) International Method G1-03—Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens—(2017) to determine and document corrosion rates based on mass loss. The coupons will be photographed, visually inspected for cracking and pitting with a minimum of 10× power, dimensionally measured (to within 25.4 micrometers), and weighed (to within 0.0001 gram).

### *C1.3.2 Corrosion Prevention*
The corrosion prevention plan for the surface facilities and the wellbores is outlined in Sections 5.3.1 and 5.6, respectively. Attachment A-3 describes the specifications of the FlexSteel flowline. The wellbore designs, which show what corrosion-resistant materials will be used in the MAG 1 and MAG 2 wells, are shown in Section 9, Figures 9-1 and 9-3, respectively.

## C1.4 Wellbore Mechanical Integrity Testing Plan
The plan for mechanical integrity testing of the $CO_2$ injection well and deep monitoring well can be found in Section 5.4 of this application. The specification sheet for the USIT is provided in Attachment A-4. Blue Flint will select third parties to perform logging and testing specified in the testing and monitoring plan. Blue Flint will also ensure that third parties apply proper QA/QC protocols to the tools to ensure their effectiveness and functionality and that all well testing procedures follow industry standards.

## C1.5 Near-Surface Soil Gas and Groundwater Monitoring
Near-surface sampling discussed herein comprises 1) sampling of soil gas in the shallow vadose zone and 2) sampling groundwater aquifers (to the lowest USDW). Sampling and chemical analysis of these zones will provide concentrations of chemical constituents, including stable and radiogenic carbon isotopes to detect movement of the $CO_2$ out of the reservoir. These monitoring efforts will provide data to confirm that near-surface environments are not adversely impacted by $CO_2$ injection and storage operations.

### *C1.5.1 Soil Gas*
Vadose zone soil gas monitoring directly measures the characteristics of the air space between soil components and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of five semi-permanent soil gas locations will be sampled in the

SFA (as shown in Figure 5-5) to establish baseline conditions. Figure C-1 illustrates the schematic for the semi-permanent soil gas probes that will be used to collect baseline data.

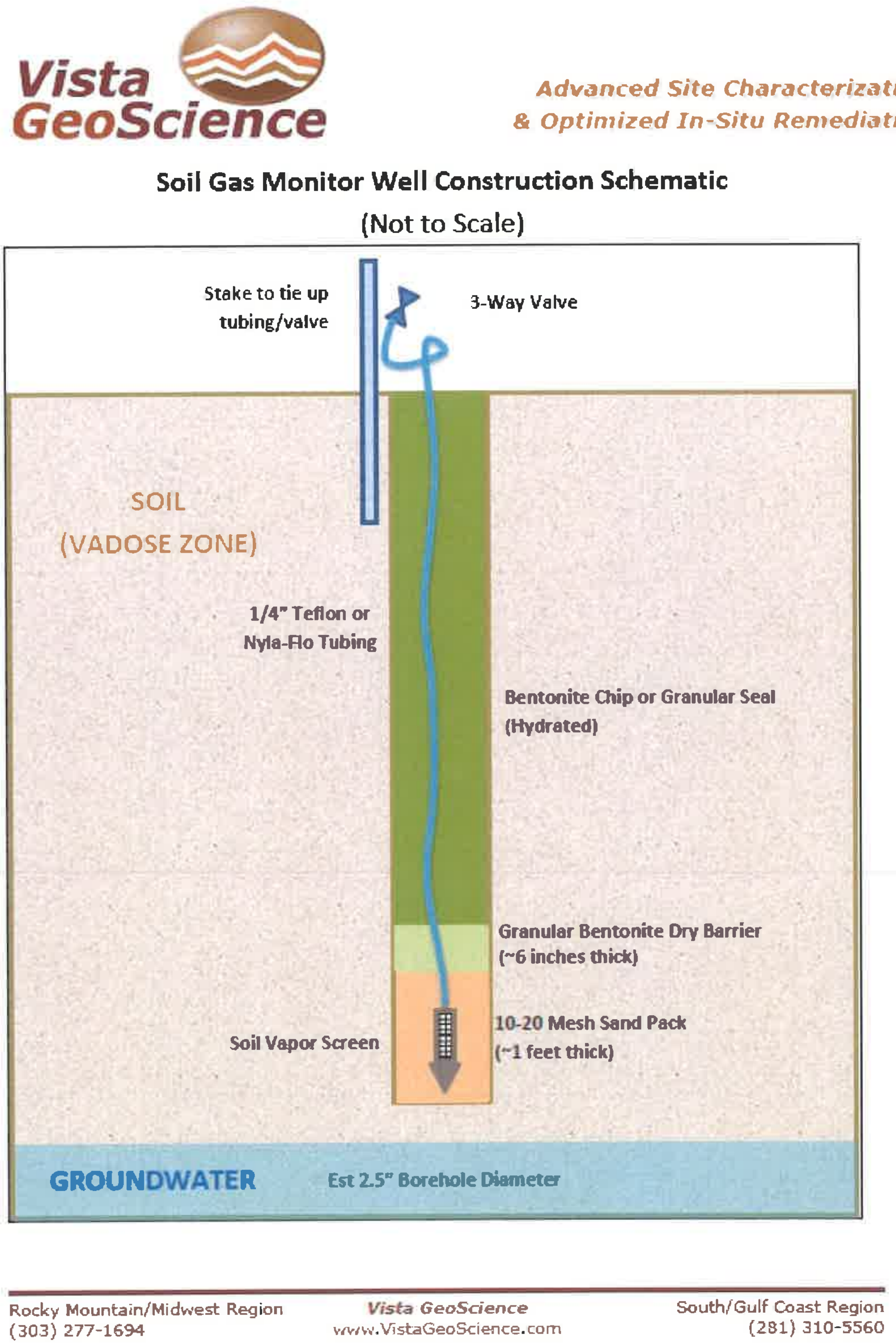



Figure C-1. Well schematic of the soil gas probe locations.

*C1.5.1.1 Soil Gas-Sampling and Analysis Protocol*
Section 5.7.2 of this application outlines the sampling plan for soil gas. Tables C-1 and C-2 indicate the analytes planned to be included in each soil gas analysis.

Blue Flint will select North Dakota service providers to install semi-permanent soil gas probe locations and soil gas profile stations, as well as sample soil gas and analyze all soil gas data. All soil gas samples are expected to be collected using a Post Run Tubing (PRT) sampling system from a projected target depth interval. Each location will be purged using a Landtec GEM 2000 or 5000 model equivalent. Field technicians will monitor and record $O_2$, $CH_4$, $CO_2$, and $H_2S$ readings while purging each location. The purging of each location should continue until either an estimated three system volumes have been purged or until readings have stabilized. The samples will then be collected in sample bags. A duplicate pair of samples should be collected from one of the soil gas sampling locations, and a pair of ambient air "sample blank" samples should be collected from each location as well. After all samples have been collected, the samples will be shipped or delivered to a commercial laboratory in North Dakota for analysis.

*C1.5.1.2 QA/QC Procedures*
Commercial laboratories selected for the performing the chemical analyses on the soil gas samples will employ standard analytical QA/QC protocols used in the industry.

**Table C-1. Soil Gas Analytes Identified with Field and Laboratory Instruments**

| ***Landtec GEM 2000 or 5000*** |
|---|
| **Analyte** |
| $CO_2$ |
| $O_2$ |
| $H_2S$ |
| $CH_4$ |

**Table C-2. Isotope Measurements of Soil Gas Samples**

| Isotope | Units |
|---|---|
| $\delta^{13}C$ of $CO_2$* | ‰ (per mil) |
| $\delta^{13}C$ of $CH_4$* | ‰ (per mil) |
| $\delta D$ of $CH_4$* | ‰ (per mil) |

* Only measured if high enough concentration detected.

***C1.5.2 Groundwater/USDW***
Section 5.7.2 of this application describes the plan for monitoring groundwater (to the lowest USDW). The sampling procedure that Minnesota Valley Testing Laboratories (MVTL) (Bismarck, North Dakota) will utilize is described below.

*C1.5.2.1 Groundwater-Sampling and Analysis Protocol*

Baseline Groundwater Wells (five groundwater wells within 1 mile of the AOR and a dedicated Fox Hills monitoring well near the MAG 1 location)
Groundwater samples will be collected by MVTL from these wells using the wells' submersible pumps. MVTL will apply the following standard procedure for sampling the wells:

1. Determine the use of the well prior to sample collection (e.g., domestic, livestock, irrigation, municipal).

2. Purge the well using a measured bucket to determine the pumping rate when the valve is fully open.

    a. The longer the well has not been in use, the longer the well will need to be purged before sample collection. Purge time will also depend on the total depth of the well.

    b. For wells used daily, purge the well for 1–2 minutes. For wells used on a seasonal basis, such as livestock or irrigation, purge the well for 15 minutes, or longer if the well is over 100 feet deep. If the well has not been in use in the past year, three well volumes may need to be removed to ensure a freshwater sample can be collected.

3. Collect the sample.

    a. Once the well has been sufficiently purged, sample collection can proceed.
    b. Record the location of the sample point.
    c. Record the pumping rate and volume purged.
    d. Collect field readings: temperature, conductivity, and pH.
    e. Fill appropriate sample containers for analysis.

Two laboratories will be used to analyze the water samples: 1) MVTL will analyze samples for general parameters, anions, cations, metals (dissolved and total), and nonmetals (Tables C-3 and C-4); and 2) Blue Flint will select another North Dakota commercial laboratory for analyzing samples for stable isotopes (Table C-5).

**Table C-3. Measurements of General Parameters for Groundwater Samples**

| Parameter | Method |
|---|---|
| pH | SM[1]4500-H+-B-11 |
| Conductivity | SM2510B-11 |
| Alkalinity | SM 2320B |
| Temperature | SM2550B |
| Total Dissolved Solids | SM 2540C |
| Total Inorganic Carbon | EPA[2] 9060 |
| Dissolved Inorganic Carbon (DIC) | EPA 9060 |
| Total Organic Carbon | SM 5310B |
| Dissolved Organic Carbon | SM 5310B |
| Total Mercury | EPA 7470A |
| Dissolved Mercury | EPA 245.2 |
| Total Metals[3] (26 metals) | EPA 6010B/6020 |
| Dissolved Metals[3] (26 metals) | EPA 200.7/200.8 |
| Bromide | EPA 300.0 |
| Chloride | EPA 300.0 |
| Fluoride | EPA 300.0 |
| Sulfate | EPA 300.0 |
| Nitrite | EPA 353.2 |

[1] Standard method
[2] U.S. Environmental Protection Agency.
[3] See Table B-2 for entire sampling list of total and dissolved metals.

**Table C-4. Total and Dissolved Metals and Cation Measurements for Groundwater Samples**

| Metals | Major Cations | Trace Metals |
|---|---|---|
| Antimony | Barium | Aluminum |
| Arsenic | Boron | Cobalt |
| Beryllium | Calcium | Lithium |
| Cadmium | Iron | Molybdenum |
| Chromium | Magnesium | Vanadium |
| Copper | Manganese | |
| Lead | Potassium | |
| Mercury | Silicon | |
| Nickel | Sodium | |
| Selenium | Strontium | |
| Silver | Phosphorus | |
| Thallium | | |
| Zinc | | |

**Table C-5. Stable Isotope Measurements and Dissolved Gases in Groundwater**

| Isotope | Units |
|---|---|
| δD $H_2O$ | ‰ (per mil) |
| $\delta^{18}O$ $H_2O$ | ‰ (per mil) |
| $\delta^{13}C$ DIC | ‰ (per mil) |
| $\delta^{13}C$ Methane (if present) | ‰ (per mil) |
| $\delta^{13}C$ Ethane (if present) | ‰ (per mil) |
| $\delta^{13}C$ Propane (if present) | ‰ (per mil) |
| δD Methane (if present) | ‰ (per mil) |
| $\delta^{13}C$ $CO_2$ (if present) | ‰ (per mil) |

*C1.5.2.2 Quality Assurance/Quality Control*

Groundwater Wells
The laboratory analyses will be performed in accordance with the commercial laboratories' internal QA/QC procedures (e.g., Table C-3 and www.mvtl.com/QualityAssurance). In addition, duplicate samples will be taken to assess the combined accuracy of the field sampling and laboratory analysis methods. These duplicate samples will be collected at the same time and location for each of the groundwater wells.

## C1.6 Storage Reservoir Monitoring

Monitoring of the storage reservoir during the injection operation includes monitoring with direct and indirect methods, as described in Section 5.7 of this application. Direct methods include monitoring: the injection flow rates and volumes; wellhead injection temperature and pressure; bottomhole injection pressure and temperature; saturation profile from the storage reservoir to the AZMI; and the tubing–casing annulus pressure or casing pressure. Indirect methods include time-lapse 2D seismic surveys and passive seismicity monitoring.

### *C1.6.1 Direct Methods*

*C1.6.1.1 Wireline Logging and Retrievable Monitoring*
The wireline logging and retrievable monitoring that will be performed comprise PNLs, which include temperature and pressure data, ultrasonic logs, injection zone pressure falloff tests, and corrosion/wellbore integrity monitoring. The information provided by these monitoring efforts is as follows:

- USIT (described in Attachment A-4) or alternative casing inspection logging provides an assessment of the mechanical integrity and assessment of corrosion of the wellbore.

- PNL (example in Attachment A-5) provides information regarding gas saturation in the formations, which can be used to determine if the injected $CO_2$ is contained within the storage formation as well as ground truth information provided by the seismic surveys.

- Pressure falloff tests provide an assessment of the storage reservoir injectivity.

All wireline logging events will follow API (American Petroleum Institute) guidelines along with the standard operating procedures of a third-party wireline operator. More details regarding each of these monitoring techniques are provided below.

Ultrasonic Imaging Tool

The USIT indicates the quality of the cement bond at the cement–casing interface and provides casing inspection (corrosion detection, monitoring, and casing thickness analysis). The tool is deployed on wireline with a transmitter emitting ultrasonic pulses and measuring the reflected ultrasonic waveforms received from the internal and external casing interfaces. The entire circumference of the casing is scanned, enabling the evaluation of the radial cement bond and the detection of internal and external casing damage or deformation. The high angular and vertical tool resolutions can detect cement channels as narrow as 1.2 inches. Detailed measurement and mechanical specifications for the USIT tool are provided in Attachment A-4. The wireline operator will provide QA/QC procedures and tool calibration for this equipment.

Pulsed-Neutron Logs

PNLs provide formation evaluation and reservoir monitoring in cased holes. PNL is deployed as a wireline logging tool with an electronic pulsed-neutron source and one or more detectors that typically measure neutrons or GRs (Rose and others, 2015). High-speed digital signal electronics process the GR response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the GR energy and time relationship into concentrations of elements (Schlumberger, 2017).

Detection limits for $CO_2$ saturation for PNL tools vary with the logging speed as well as the formation porosity. Blue Flint plans to select a PNL service provider and tool and ensure the wireline operator provides QA/QC procedures and tool calibration for their equipment.

Description of Regular PNL Protocol

After the drilling and before $CO_2$ injection, a PNL will be run in the injection well and deep monitoring well to provide a baseline to which future PNL runs will be compared.

The following general procedure will be followed when running a PNL in the injection well and deep monitoring well:

1. Hold a safety meeting and ensure that all personnel are wearing proper PPE:
   a. Rig up PPE.
   b. Ensure that all safety precautions are taken.

2. Shut well in by closing the outside wing valve and upper master valve.

3. Rig up lubricator, and pressure-test connections and seals to 2000 pounds per square inch.

4. Open crown valve.

5. Open top master valve and proceed downhole to the injection packer with the PNL tool.

6. Make a 30-minute stop at the bottom of the hole and record a static BHP.
7. Proceed with running the PNL, making stops every 500 feet for five minutes each to record a static fluid pressure.
8. Once the logging tool is at the surface and in the lubricator, make a 5-minute stop to record the surface pressure in the tubing.
9. Close the crown valve and top master valve. Bleed pressure from the tree and lubricator.
10. Remove lubricator and replace the top cap and pressure gauge.
11. Open the top master valve, and again record the tubing and annular pressures.
12. Rig down the wireline company and clean the location.
13. Return the well to injection service by opening the outside wing valve.

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.

#### *C1.6.2 Indirect Monitoring Methods*

The indirect monitoring that is planned for the project includes time-lapse seismic surveys and passive seismicity monitoring. This indirect monitoring method will characterize attributes associated with the injected $CO_2$, including plume extents, mass changes, pressure changes, and potential seismicity. Details regarding the application and quality of this method are provided in the remainder of this section:

##### *C1.6.2.1 Time-Lapse Seismic Surveys*

Application of time-lapse seismic surveys for monitoring changes in acoustic properties requires a quality preoperational seismic survey for baseline conditions. The monitor survey should be repeated as closely to the baseline conditions and parameters as possible. The seismic monitor data should be reprocessed simultaneously with the original baseline data or processed with the same steps and workflow to ensure repeatability. Repeatability is a measure of 4D seismic quality (Lumley and others, 1997, 2000) that can be quantified once the processed data are analyzed by an experienced 4D seismic interpreter.

##### *C1.6.2.2 Passive Seismic Recording*

Continuous monitoring of seismic activity will include USGS seismometer stations already operating in North Dakota (Figure 5-7). Additional seismometer stations may be installed as needed. The distributed acoustic sensing (DAS) fiber optic systems installed on the injection well MAG 1 and the monitoring well MAG 2, capable of autonomously and continuously measuring a wide range of seismicity (micro/macro events) with the installation of additional seismometer stations, may be used to supplement passive seismicity monitoring efforts as needed.

### C1.7 Completed Well Logging

The well testing and logging plan is described in Section 5.5 of this application. Several continuous measurements of the storage formation properties were either made in the MAG 1 wellbore or are planned for the MAG 2 wellbore using wireline-logging techniques.

All wireline logging companies who perform work for the Blue Flint $CO_2$ Storage Project will employ standard analytical QA/QC protocols used in the industry.

### C1.8 References


ASTM International, 2017, ASTM G1-03(2017)e1, Standard practice for preparing, cleaning, and evaluating corrosion specimens: West Conshohocken, Pennsylvania, ASTM International, www.astm.org/g0001-03r17e01.html (accessed April 2022).

Lumley, D.E., Behrens, R.A., and Wang, Z., 1997, Assessing the technical risk of a 4-D seismic project: The Leading Edge, v. 16, p. 1287–1292, doi: 10.1190/1.1437784.

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.

National Association of Colleges and Employers, 2018, NACE SP0775, Preparation, installation, preparation, and interpretation of corrosion coupons in oilfield operations: https://standards.globalspec.com/std/10401680/nace-sp0775 (accessed April 2022).

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 – Supervisory Control and Data Acquisition (SCADA) System**

The SCADA system is a computer-based system or systems used by personnel in a control room that aims to collect and display information about the Blue Flint $CO_2$ storage injection operations in real time. This supervisory system collects data at an assigned time interval and stores the data in the historian server. Using Blue Flint operator process control selections, the SCADA will have the ability to send commands and control the storage injection network (i.e., start or stop pumps, open or close valves, control process equipment remotely, etc.).

In addition to monitoring and control ability, the SCADA system will include warnings, both audible and visual, to alert the Blue Flint control room, which is staffed 24/7, of near or excessive violations of set parameters within the system.

## Atachment A-2 – $CO_2$ Detection Station Overview

Honeywell

# Sensepoint XCD SPECIFICATIONS

## Flammable, toxic and oxygen gas detector for industrial applications

| | |
|---|---|
| **Use** | 3 wire, 4-20mA and RS485 MODBUS output fixed point detector with in-built alarm and fault relays for the protection of personnel and plant from flammable, toxic and Oxygen hazards. Incorporates a transmitter with local display and fully configurable via non-intrusive magnetic switch interface. |
| **Electrical** | |
| **Input Voltage Range** | 12 to 32VDC (24VDC nominal) |
| **Max Power Consumption** | Maximum power consumption is dependent on the type of gas sensor being used. Electrochemical cells = 3.7W, IR = 3.7W and catalytic = 4.9W. Maximum inrush current = 800mA at 24VDC |
| **Current Output** | 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** | -40°F to +149°F (-40°C to +65°C) |

**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<br>** Lowest Alarm Limit = 15 ppm; Lowest Detection Limit = 10ppm<br>*** Lowest Alarm Limit = 0.6 ppm; Lowest Detection Limit = 0.3ppm | | | | | | | | | | | |
| **Catalytic Bead Sensors** | | | | | | | | | | | |
| Flammable 1 to 6 | 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 -40°C to +65°C: 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-2. Measurement and mechanical specifications for Honeywell's $CO_2$ detection station.

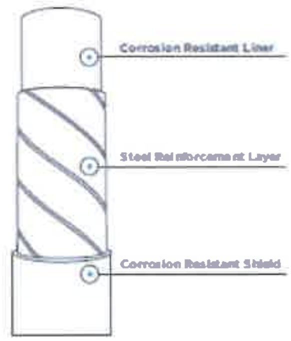
## Attachment A-3 – FlexSteel™ Overview

PRODUCT SHEET

FLEXSTEEL

# FLEXSTEEL™ LINE PIPE

FlexSteel is the pipeline solution that couples the durability of steel with the installation, performance and cost benefits of spoolable pipe products. Highly corrosion resistant and more dependable than other pipeline solutions, FlexSteel combines the best features of all currently available line pipe options to deliver superior life cycle performance and value.




### DURABLE BY DESIGN

Reinforced with a helically wound, steel-reinforced layer for structural integrity, FlexSteel line pipe performs where other pipeline solutions often fail. Durable enough to withstand pulsating and cyclic pressures, the system continues to perform to its original design specifications and will not derate over time.

### APPLICATIONS

FlexSteel pipeline's unique characteristics make it the clear choice for increased safety and reliability in various environments and applications.

**PRODUCTION LINES:** FlexSteel is a smart investment that yields indisputable quality, safety, and performance advantages in multiphase, oil, and gas applications.

**DISPOSAL LINES:** Abrasion resistant and built to last, FlexSteel line pipe minimizes the risks associated with the transportation of highly corrosive produced water.

**INJECTION LINES:** Engineered to the highest quality standards, FlexSteel line pipe withstands pulsating and cyclic pressures often found in injection lines.

**GATHERING LINES:** Fast, easy, and cost effective installation coupled with extreme corrosion resistance make FlexSteel line pipe a natural choice for gathering pipelines.

**2-INCH TO 8-INCH DIAMETER**

Only 8-inch onshore spoolable pipeline with design pressures up to 3,000 psi.

**CORROSION RESISTANT DESIGN**

Designed to resist corrosion including microbiologically influenced corrosion (MIC).

**BEST VALUE PIPELINE SOLUTION**

Eliminates the need for expensive integrity management programs, and continuous maintenance services.



EXTREME PERFORMANCE VALUE DURABILITY | FLEXSTEELPIPE.COM

Attachment A-3. Measurement and mechanical specifications for FlexSteel's $CO_2$ flow line (continued).

## PRODUCT SHEET
US CUSTOMARY UNITS

FLEXSTEEL

| Product | Nominal Size (in) | Nominal Pressure Rating (PSI) | Reel Pipe Length (ft) | Coil Pipe Length (ft) | Pipe Inside Diameter (in) | Pipe Outside Diameter (in) | Operating Bend Radius, OBR (ft) | Weight Empty in Air (lb/ft) | Specific Gravity | Minimum Burst Pressure (PSI) | OHTC, U (based on ID) (BTU/hr ft²°F) | Maximum Installation Tension (lbf) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STANDARD PRODUCT | 2 | 1,500 | 6,578 | - | 1.94 | 2.69 | 2.1 | 2.40 | 0.93 | 3,000 | 6.72 | 3,800 |
| STANDARD PRODUCT | 2 | 2,250 | 4,462 | - | 1.94 | 2.85 | 2.2 | 3.53 | 1.23 | 4,500 | 6.91 | 10,500 |
| STANDARD PRODUCT | 2 | 3,000 | 4,298 | - | 1.94 | 2.85 | 2.2 | 3.77 | 1.32 | 6,000 | 6.91 | 10,500 |
| STANDARD PRODUCT | 3 | 750 | 4,560 | - | 2.82 | 3.65 | 2.8 | 3.53 | 0.74 | 1,500 | 5.75 | 8,000 |
| STANDARD PRODUCT | 3 | 1,500 | 4,003 | - | 2.82 | 3.68 | 2.8 | 4.03 | 0.84 | 3,000 | 5.77 | 8,000 |
| STANDARD PRODUCT | 3 | 2,250 | 2,871 | - | 2.82 | 3.81 | 2.9 | 5.46 | 1.06 | 4,500 | 5.86 | 9,000 |
| STANDARD PRODUCT | 3 | 3,000 | 2,461 | - | 2.82 | 3.89 | 3.0 | 6.63 | 1.25 | 6,000 | 5.90 | 14,000 |
| STANDARD PRODUCT | 4 | 750 | 3,264 | - | 3.67 | 4.58 | 3.5 | 4.76 | 0.63 | 1,500 | 5.08 | 8,000 |
| STANDARD PRODUCT | 4 | 1,500 | 2,690 | - | 3.67 | 4.65 | 3.6 | 6.30 | 0.82 | 3,000 | 5.11 | 12,500 |
| STANDARD PRODUCT | 4 | 2,250 | 1,821 | - | 3.67 | 4.81 | 3.7 | 8.79 | 1.08 | 4,500 | 5.17 | 20,000 |
| STANDARD PRODUCT | 4 | 3,000 | 1,476 | - | 3.67 | 4.94 | 3.8 | 11.33 | 1.31 | 6,000 | 5.22 | 22,000 |
| STANDARD PRODUCT | 6 | 750 | 1,230 | 2,543 | 5.60 | 6.89 | 5.3 | 8.52 | 0.56 | 1,500 | 3.67 | 20,000 |
| STANDARD PRODUCT | 6 | 1,500 | 1,181 | 2,608 | 5.60 | 7.01 | 5.4 | 13.36 | 0.77 | 3,000 | 3.70 | 30,000 |
| STANDARD PRODUCT | 6 | 2,250 | 837 | 1,509 | 5.60 | 7.17 | 5.5 | 18.34 | 1.02 | 4,500 | 3.73 | 30,000 |
| STANDARD PRODUCT | 6 | 3,000 | 640 | 1,529 | 5.60 | 7.31 | 5.6 | 22.79 | 1.23 | 6,000 | 3.76 | 45,000 |
| STANDARD PRODUCT | 8 | 750 | 607 | - | 7.63 | 9.19 | 7.1 | 15.87 | 0.53 | 1,500 | 2.97 | 30,000 |
| STANDARD PRODUCT | 8 | 1,500 | 607 | - | 7.63 | 9.36 | 7.2 | 23.04 | 0.75 | 3,000 | 2.99 | 40,000 |
| STANDARD PRODUCT | 8 | 2,250 | 459 | - | 7.63 | 9.58 | 7.4 | 32.11 | 1.01 | 4,500 | 3.02 | 45,000 |
| MXL | 8 | 750 | - | 1,260 | 7.25 | 8.77 | 6.8 | 15.85 | 0.58 | 1,500 | 3.18 | 25,000 |
| MXL | 8 | 1,500 | - | 1,260 | 7.25 | 8.90 | 6.9 | 21.10 | 0.76 | 3,000 | 3.20 | 35,000 |
| MXL | 8 | 2,250 | - | 1,260 | 7.25 | 9.12 | 7.0 | 29.52 | 1.02 | 4,500 | 3.22 | 40,000 |
| MXL | 8 | 3,000 | - | 912 | 7.25 | 9.27 | 7.1 | 34.83 | 1.17 | 6,000 | 3.13 | 45,000 |

**Standard Properties for All Pipe Sizes**

| | |
|---|---|
| Absolute Roughness, ε (ft) | 5.0E-06 ft |
| Design Temperature (Water) | 150°F |
| Design Temperature (Oil/Gas) | 150°F |

**High-Temp Properties for All Pipe Sizes**

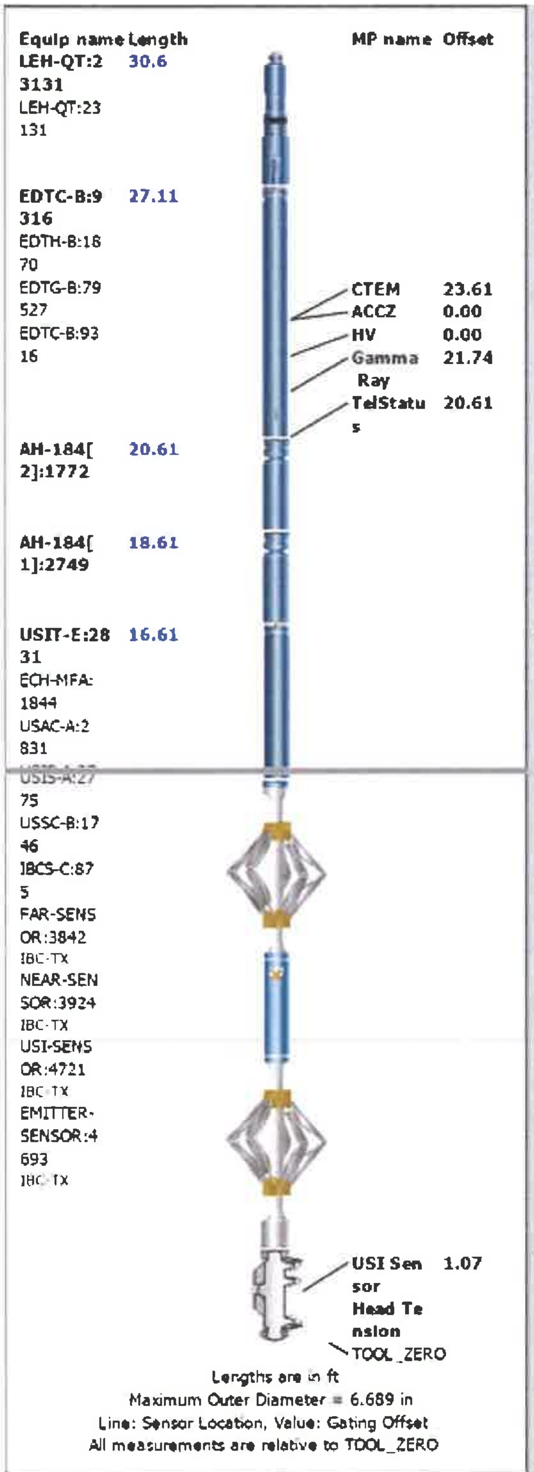
| | |
|---|---|
| Absolute Roughness, ε (ft) | 5.0E-06 ft |
| Design Temperature (Water) | 194°F |
| Design Temperature (Oil/Gas) | 185°F |



EXTREME PERFORMANCE VALUE DURABILITY    FLEXSTEELPIPE.COM

Attachment A-3 (continued). Measurement and mechanical specifications for FlexSteel's $CO_2$ flow line.

# Attachment A-4 – Ultrasonic Imaging Tool (USIT)




## Measurement Specifications

| | Isolation Scanner Tool |
|---|---|
| Output[†] | Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image |
| Max. logging speed | Standard resolution (6 in, 10° sampling): 823 m/h [2,700 ft/h]<br>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]<br>Max. casing thickness: 2.01 cm [0.79 in] |
| Vertical resolution | High resolution: 1.52 cm [0.6 in]<br>High speed: 15.24 cm [6 in] |
| Acoustic impedance[‡] | Range: 0 to 10 Mrayl<br>Resolution: 0.2 Mrayl<br>Accuracy: 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15% |
| Flexural attenuation | Range: 0 to 2 dB/cm[§]<br>Resolution: 0.05 dB/cm[§]<br>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<br>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]<br>IBCS-B: 11.36 cm [4.472 in]<br>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]<br>IBCS-B: 60.32 cm [23.75 in], 9.36 kg [20.64 lbm]<br>IBCS-C: 60.32 cm [23.75 in], 10.73 kg [23.66 lbm] |
| Sub max. tension | 10,000 N [2,250 lbf] |
| Sub max. compression | 50,000 N [12,250 lbf] |

[†] Limits for casing size depend on the sub used. Data can be acquired in casing larger than 9⅝ in with low-attenuation mud (e.g., water, brine).

Attachment A-4. Schlumberger's isolation scanner USIT used to provide evidence of external and internal mechanical integrity.

## Attachment A-5 – Example of a Pulsed-Neutron Logging Tool

***Better resolution leads to more accurate evaluation***

The Reservoir Analysis tool features three gamma detectors for measuring reservoir saturation using Sigma and Carbon-Oxygen (C/O) techniques. Near and far detectors are high-resolution Lanthanum Chloride for Sigma and C/O detection, while the long spacing Sodium Iodide detector incorporates a spacing that is sensitive to gas and porosity.

The combined RAS/SGR log provides all the necessary measurements for computing accurately the volumes of clay, rock porosity and fluid saturations; and obtain a better assessment of reservoir properties which can help optimizing completion programs that reduce CAPEX by eliminating poor frac stages.

***High-quality log data, and the expertise for advanced interpretation***

Because data is only as good as its interpretation, our experienced Production Petrophysists, backed by available Reservoir Geoscience support from Hunter Well Science, employ advanced interpretation techniques to map RAS measurements into such properties as hydrocarbon saturation, porosity and rock type, delivering accurate information about reservoir properties.

| Specifications | | |
|---|---|---|
| Temperature rating | 320°F | 160°C |
| Pressure rating | 15,000 psi | 103.4 MPa |
| Diameter | 1 11/16 in. | 43 mm |
| Length | 140.7 in. | 3573 mm |
| Weight | 44 lb | 20 kg |
| Measure point - Near | 84 in. | 2134 mm |
| Measure point - Far | 91 in. | 2311 mm |
| Measure point - Long | 101 in. | 2565 mm |
| Materials | Corrosion resistant throughout | |

Specifications courtesy of Hunter Well Science Limited

***...when experience matters***

Wireline Logging Solutions is staffed top to bottom by knowledgeable personnel, with deep understanding of this technology and how to get the most value from it. Our focus on service quality ensures rapid turnaround of a quality answer product, so you get the information you need, when you need it.

Attachment A-5. Measurement and mechanical specifications for Wireline Logging Solution's Reservoir Analysis tool.

# APPENDIX D

# STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| **Pore Space Amalgamation** | NDCC §§ 38-22-06(3) and (4)<br><br>NDAC §§ 43-05-01-08(1) and (2) | **NDCC § 38-22-06**<br>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.<br><br>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.<br><br>**NDAC § 43-05-01-08**<br>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:<br><br>a. Each operator of mineral extraction activities within the facility area and within one-half mile [.80 kilometer] of its outside boundary;<br><br>b. Each mineral lessee of record within the facility area and within one-half mile [.80 kilometer] of its outside boundary;<br><br>c. Each owner of record of the surface within the facility area and one-half mile [.80 kilometer] of its outside boundary;<br><br>d. Each owner of record of minerals within the facility area and within one-half mile [.80 kilometer] of its outside boundary; | a. An affidavit of mailing certifying that all pore space owners and lessees within the storage reservoir boundary and within one-half mile outside of its boundary have been notified of the proposed carbon dioxide storage project; | **1.0 PORE SPACE ACCESS** (p. 1-1, paragraph 2)<br>Blue Flint has identified the surface and mineral estate owners within the horizontal boundaries of the Blue Flint $CO_2$ storage facility area. With the exception of coal extraction, no mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles (0.8 kilometers) of its outside boundary. Blue Flint will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed $CO_2$ storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made (NDCC §§ 38-22-06(3) and (4) and North Dakota Administrative Code [NDAC] §§ 43-05-01-08(1) and (2)). | The affidavit has not yet been prepared. |
| | | | b. A map showing the extent of the pore space that will be occupied by carbon dioxide over the life of the project; | **1.0 PORE SPACE ACCESS** (p. 1-1)<br>North Dakota statute explicitly grants title to pore space in all strata underlying the surface of lands and waters to the owner of the overlying surface estate; i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] § 47-31-03). Prior to issuance of the SFP, the storage operator is mandated by North Dakota statute for geologic storage of CO2 to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir (NDCC § 38-22-08(5)). The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation (NDCC § 38-22-10). Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application. Surface access for any potential above ground activities is not included in pore space amalgamation.<br><br>Blue Flint has identified the surface and mineral estate owners within the horizontal boundaries of the Blue Flint $CO_2$ storage facility area. With the exception of coal extraction, no mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles (0.8 kilometers) of its outside boundary. Blue Flint will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed $CO_2$ storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made (NDCC §§ 38-22-06(3) and (4) and North Dakota Administrative Code [NDAC] §§ 43-05-01-08(1) and (2)).<br><br>All owners, lessees, and operators that require notification have been identified in accordance with North Dakota law, which vests the title to the pore space in all strata underlying the surface of lands and water to the owner of the overlying surface estate (NDCC § 47-31-03). The identification of pore space owners indicates that there was no severance of pore space or leasing of pore space to a third-party from the surface estate prior to 2009. All surface owners and pore space owners and lessees are the same owner of record.<br><br>A map showing the extent of the pore space that will be occupied by $CO_2$ over the life of the Blue Flint $CO_2$ storage project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record is illustrated in Figure 1-1. | **Figure 1-1.** Storage facility area map showing pore space ownership. |
| | | | c. A map showing the storage reservoir boundary and one-half mile outside of the storage reservoir boundary with a description of pore space ownership; | | **Figure 1-1.** Storage facility area map showing pore space ownership. |
| | | | d. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each operator of mineral extraction activities; | | **Figure 1-1.** Storage facility area map showing pore space ownership |
| | | | e. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each mineral lessee of record; | | |
| | | | f. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each surface owner of record; | | **Figure 1-1.** Storage facility area map showing pore space ownership. |
| | | | g. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each owner of record of minerals | | **Figure 1-1.** Storage facility area map showing pore space ownership. |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | e. Each owner and each lessee of record of the pore space within the storage reservoir and within one-half mile [ 80 kilometer] of the reservoir's boundary; and<br><br>f. Any other persons as required by the commission<br><br>2. The notice given by the applicant must contain:<br><br>a. A legal description of the land within the facility area<br><br>b. The date, time, and place that the commission will hold a hearing on the permit application<br><br>c. A statement that a copy of the permit application and draft permit may be obtained from the commission. | | | |
| Geologic Exhibits | NDAC § 43-05-01-05 (1)(b)(1) | **NDAC § 43-05-01-05 (1)(b)**<br>(1) The name, description, and average depth of the storage reservoirs; | a. Geologic description of the storage reservoir:<br>Name<br>Lithology<br>Average thickness<br>Average depth | **2.1 Overview of Project Area Geology** (p. 2-1)<br>The proposed Blue Flint $CO_2$ storage project will be situated near the BFE facility, located south of Underwood, North Dakota (Figure 2-1). This project site is on the eastern flank of the Williston Basin.<br><br>Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the Plains $CO_2$ Reduction (PCOR) Partnership, the Williston Basin has been identified as an excellent candidate for long-term $CO_2$ storage because of the thick sequence of clastic and carbonate sedimentary rocks and subtle structural character and tectonic stability of the basin (Peck and others, 2014; Glazewski and others, 2015).<br><br>The target $CO_2$ storage reservoir for the project is the Broom Creek Formation, a predominantly sandstone unit 4,708 ft below the surface at the MAG 1 stratigraphic test well location (Figure 2-1). Sixty-one feet of shales, siltstones, and interbedded evaporites of the undifferentiated Spearfish and Opeche Formations, hereinafter referred to as the Spearfish Formation, unconformably overlie the Broom Creek Formation. Eighty-seven feet of shales, siltstones, and anhydrites of the lower Piper Formation (undifferentiated Picard, Poe, and Dunham Members) overlie the Spearfish Formation. Together, the lower Piper and Spearfish Formations serve as the primary upper confining zone (Figure 2-2). The Amsden Formation (dolostone, limestone, anhydrite, and sandstone) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-2). Together, the lower Piper, Spearfish, Broom Creek, and Amsden Formations make up the $CO_2$ storage complex for the Blue Flint project (Table 2-1).<br><br>Including the Spearfish and lower Piper Formations, there is 859 ft (average thickness across the simulation area) of impermeable rock formations between the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. An additional 2,442 ft (average thickness across the simulation area) of impermeable rock formations separates the Inyan Kara Formation and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-2). | **Figure 2-1.** Topographic map of the project area showing the planned injection well, the planned monitoring well, and the Blue Flint Ethanol Plant (blue star). (p. 2-2)<br><br>**Figure 2-2.** Stratigraphic column identifying the potential storage reservoirs and confining zones (outlined in red) and the lowest USDW (outlined in blue). (p. 2-3)<br><br>**Table 2-1** Formations Making up the Blue Flint CO2 Storage Complex (average values calculated from the geologic model properties within simulation model area shown in Figure 2-3) (p. 2-4) |

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application<br>(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description<br>(Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>Table 2-1. Formations Comprising the Blue Flint $CO_2$ Storage Complex (average values calculated from the simulation model and well log data)
<table>
<tr><th></th><th>Formation</th><th>Purpose</th><th>Average Thickness, ft</th><th>Average Depth, MD ft</th><th>Lithology</th></tr>
<tr><td rowspan="4">Storage Complex</td><td>Lower Piper Formation</td><td>Upper confining zone</td><td>153</td><td>4,458</td><td>Shale/anhydrite/ siltstone</td></tr>
<tr><td>Spearfish Formation</td><td>Upper confining zone</td><td>22</td><td>4,611</td><td>Shale/anhydrite/siltstone</td></tr>
<tr><td>Broom Creek Formation</td><td>Storage reservoir (i.e., injection zone)</td><td>102</td><td>4,633</td><td>Sandstone/dolostone</td></tr>
<tr><td>Amsden Formation</td><td>Lower confining zone</td><td>217</td><td>4,735</td><td>Dolostone/limestone/ anhydrite/sandstone</td></tr>
</table></td><td></td></tr>
<tr><td></td><td>NDAC<br>§ 43-05-01-05(1)(b)(2)(k)</td><td>NDAC § 43-05-01-05(1)(b)(2)<br>(k) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;</td><td>b. Data on the injection zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:<br>Depth<br>Areal extent<br>Thickness<br>Mineralogy<br>Porosity<br>Permeability<br>Capillary pressure<br>Facies changes</td><td>SOURCE OF THE DATA:<br>2.2.1 Existing Data (p. 2-4)<br>Existing data used to characterize the geology beneath the Blue Flint project site included publicly available well logs and formation top depths acquired from NDIC's online database. Well log data and interpreted formation top depths were acquired for 120 wellbores within the 5,500-square-mile (mi2) area covered by the geologic model of the proposed storage site (Figure 2-3). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations. Legacy 2D seismic data (70 miles) were licensed to characterize the subsurface geology in the project area and confirm the interpreted extent of the Broom Creek Formation (Figure 2-3)<br><br>Existing laboratory measurements for core samples from the Broom Creek Formation and its confining zones were available from four wells shown in Figure 2-4: Flemmer-1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), J-LOC1 (NDIC File No. 37380), and ANG 1 (Well No. ND-UIC-101) in addition to data from the site-specific stratigraphic test well, MAG 1 (NDIC File No. 37833). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and were integrated with newly acquired site-specific data.<br><br>2.2.2 Site-Specific Data (p. 2-6)<br>Site-specific efforts to characterize the proposed storage complex generated multiple data sets, including geophysical well logs, petrophysical data, and 3D seismic data. The MAG 1 well was drilled in 2020 specifically to gather subsurface geologic data to support the development of a $CO_2$ storage facility permit and serve as a future $CO_2$ injection well. Downhole logs were acquired, and sidewall core (SW Core) was collected from the proposed storage complex (i.e., the Lower Piper, Spearfish, Broom Creek, and Amsden Formations) at the time the well was drilled (Figure 2-5). In May 2022, fluid samples and temperature and pressure measurements were collected from the Broom Creek in the MAG 1 well.<br><br>Site-specific and existing data were used to assess the suitability of the storage complex for safe and permanent storage of $CO_2$. Site-specific data were also used as inputs for geologic model construction (Section 3.2), numerical simulations of $CO_2$ injection (Section 3.3.1), geochemical simulation (Sections 2.3.3, 2.4.1.2, and 2.4.3.2), and geomechanical analysis (Section 2.4.4). The site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency of collecting monitoring data, and interpretation of monitoring data with respect to potential subsurface risks. Furthermore, these data guided and influenced the design and operation of site equipment and infrastructure.</td><td>Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. (p. 2-5)<br><br>Figure 2-4. Map showing the spatial relationship between the Blue Flint project area and wells where the Broom Creek Formation core samples were collected. (p. 2-6)<br><br>Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota. (p. 2-12)<br><br>Figure 2-8. Isopach map of the Broom Creek Formation in the greater Blue Flint project area. (p. 2-13)<br><br>Figure 2-9. Well log display of the interpreted lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations in MAG 1 (p. 2-14)<br><br>Figure 2-10. Regional well log stratigraphic cross</td></tr>
</table>

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|

DATA ON THE INJECTION ZONE:

**2.3 Storage Reservoir (injection zone)** (p. 2-11)

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

***2.3.1 Mineralogy*** (p. 2-21)

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

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

| **Injection Zone Properties** | | | |
|---|---|---|---|
| **Property** | **Description** | | |
| **Formation Name** | **Broom Creek** | | |
| **Lithology** | **Sandstone, dolomitic sandstone, dolostone** | | |
| **Formation Top Depth, ft** | **4,708** | | |
| **Thickness, ft** | **103 (sandstone 66, dolomitic sandstone 13, dolostone 24)** | | |
| **Capillary Entry Pressure (brine/$CO_2$), psi** | **0.866** | | |
| **Geologic Properties** | | | |
| **Formation** | **Property** | **Laboratory Analysis** | **Simulation Model Property Distribution** |
| **Broom Creek (sandstone)** | **Porosity, %*** | **24.12 (21.42–27.80)** | **19.15 (0.0–36.00)** |
| | **Permeability, mD**** | **298.16 (140.70–929.84)** | **132.83 (0–3237.4)** |
| **Broom Creek (dolomitic sandstone)** | **Porosity, %*** | **20.85 (16.13–23.83)** | **15.87 (1.0–29.25)** |
| | **Permeability, mD**** | **81.91 (16.40–257.00)** | **50.13 (0–650.70)** |
| **Broom Creek (dolostone)** | **Porosity, %*** | **10.50 (5.83–15.91)** | **7.85 (0.0–24.65)** |
| | **Permeability, mD**** | **1.01 (0.01–178.60)** | **0.76 (0.0–519.32)** |

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses

** Permeability values are reported as the geometric mean followed by the range of values in parentheses

sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15)

**Figure 2-11.** Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16)

**Figure 2-12.** Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-17)

**Figure 2-13.** Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. (p. 2-18)

**Table 2-5.** Description of $CO_2$ Storage Reservoir (injection zone) at the MAG 1 Well (p. 2-19)

**Figure 2-14.** Vertical distribution of core-derived porosity and permeability values and the laboratory-derived mineralogic characteristics in the Blue Flint storage complex from MAG 1. (p. 2-20)

**Figure 2-15.** Thin section in upper Broom Creek Formation. This interval is primarily dolomite (grey) with anhydritic cement. (p. 2-21)

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

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | See below | See below |

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

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

***2.3.3 Geochemical Information of Injection Zone*** (p. 2-26)
Geochemical simulation has been performed to calculate the effects of introducing the $CO_2$ stream to the injection zone

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

The scenario with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (80% of bulk reservoir volume) and average formation brine composition (20% of bulk reservoir volume). XRD data from the 15 Broom Creek formation core samples were used to inform the mineralogical composition of the Broom

Porosity is high in this interval. (p. 2-22)

**Figure 2-17.** Thin section in lower Broom Creek Formation. This interval is a laminated silty mudstone. The matrix is dominated by clay and quartz. (p. 2-23)

**Table 2-6.** XRD Analysis in the Broom Creek Reservoir from MAG 1. Only major constituents are shown. (p. 2-24)

**Figure 2-18.** XRF analysis in Broom Creek Formation from MAG 1 (p. 2-25)

**Table 2-7.** Injection Stream Composition (p. 2-27)

**Table 2-8.** XRD Results for MAG 1 Broom Creek Core Sample (p. 2-27)

**Figure 2-19.** Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions. (p. 2-28)

**Figure 2-20.** Upper graph shows wellhead pressure vs time; the bottom figure shows the bottomhole pressure vs. time. There is no observable difference in pressures due to geochemical reactions. (p. 2-29)

**Table 2-9.** Broom Creek Water Ionic Composition, expressed in molality (p. 2-30)

**Figure 2-21.** CO2 molality for the geochemistry case simulation results after 20

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | Creek Formation (Table 2-8). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Reported ionic composition of the Broom Creek Formation water is listed in Table 2-9.<br><br>Figure 2-24 shows the mass of mineral dissolution and precipitation due to geochemical reaction in the Broom Creek Formation. Dolomite is the most prominent dissolved mineral. Albite and K-feldspar gradually dissolves over time. Illite initially dissolves and then starts precipitating 3 years after injection stops. Quartz and anhydrite are the minerals that experienced the most precipitation over time.<br><br>Figures 2-25 and 2-26 provide an indication of the change in distribution of the mineral that experienced the most dissolution, dolomite, and the mineral that experienced the most precipitation, quartz, respectively. Considering the apparent net dissolution of minerals in the system, as indicated in Figure 2-24, there is an associated net increase in porosity in the affected areas, as shown in Figure 2-27. However, the porosity change is small, less than 0.04% porosity units, equating to a maximum increase in average porosity from 22.6% to 22.64% after the 20-year injection period. | years of injection + 25 years postinjection showing the distribution of $CO_2$ molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of simulation in Layer k = 39. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-31)<br><br>**Figure 2-22.** $CO_2$ molality for the non-geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of $CO_2$ molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of simulation in Layer k = 39. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-32)<br><br>**Figure 2-23.** Geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-33)<br><br>**Figure 2-24.** Dissolution and precipitation quantities of reservoir minerals because of CO2 injection. Dissolution of albite, K-feldspar (K-fe_fel), and dolomite with |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | | precipitation of illite, quartz, and anhydrite was observed. (p. 2-34)<br><br>**Figure 2-25.** Change in molar distribution of dolomite, the most prominent dissolved mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-35)<br><br>**Figure 2-26.** Change in molar distribution of quartz, the most prominent precipitated mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p 2-36)<br><br>**Figure 2-27.** Change in porosity due to net geochemical dissolution at the end of the 20-year injection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-37) |
| | | | c. Data on the confining zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:<br>Depth<br>Areal extent<br>Thickness<br>Mineralogy<br>Porosity<br>Permeability<br>Capillary pressure<br>Facies changes | SOURCE OF THE DATA:<br>*See discussion above under 2.2.1 Existing Data*<br><br>AND<br><br>**2.4 Confining Zones** (p. 2-38)<br>The confining zones for the Broom Creek Formation are the overlying Spearfish Formation and the lower Piper Formation and the underlying Amsden Formation (Figure 2-2, Table 2-10). Both the overlying and underlying confining formations consist primarily of impermeable rock layers. | **Table 2-10.** Properties of Upper and Lower Confining Zones in Simulation Area (p. 2-38)<br><br>**Figure 2-28.** Areal extent of the lower Piper Formation in western North Dakota (modified from Carlson, 1993) (p. 2-39)<br><br>**Figure 2-29.** Structure map of the lower Piper Formation |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | (see below) | (see below) |

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

| Confining Zone Properties | Upper Confining Zone | | Lower Confining Zone |
|---|---|---|---|
| Stratigraphic Unit | Lower Piper | Spearfish | Amsden |
| Lithology | Shale/anhydrite/ siltstone | Shale/anhydrite/ siltstone | Dolostone/limestone/ anhydrite/sandstone |
| Average Formation Top Depth (MD), ft | 4,458 | 4,611 | 4,735 |
| Thickness, ft | 153 | 22 | 217 |
| Capillary Entry Pressure (brine/$CO_2$), psi | 2,512 | 12,245 | 26,134 |
| Depth below Lowest Identified USDW, ft (MAG 1) | 3,488 | 3,575 | 3,738 |

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

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

***2.4.1 Upper Confining Zone*** (p. 2-39)
In the Blue Flint project area, the upper confining zone, the lower Piper and Spearfish Formations, consists of siltstone with interbedded anhydrite (Table 2-10). The upper confining zone is laterally extensive across the project area (Figure 2-28) and is 4,560 ft below the land surface and 148 ft thick (lower Piper Formation, 87 ft [Figures 2-29 and 2-30], Spearfish Formation, 61 ft [Figures 2-31 and 2-32]) as observed in the MAG 1 well. The contact between the underlying Broom Creek Formation sandstone and the upper confining zone is an unconformity that can be correlated across the Broom Creek Formation extent where the resistivity and GR logs show a significant change across the contact. A relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation changes to a relatively high GR signature representing the siltstones of the Spearfish Formation (Figure 2-9).

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

across the greater Blue Flint project area in feet below mean sea level (p. 2-40)

**Figure 2-30.** Isopach map of the lower Piper Formation in the greater Blue Flint project area (p. 2-41)

**Figure 2-31.** Structure map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area(p. 2-42)

**Figure 2-32.** Isopach map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area (p. 2-43)

**Table 2-11.** Spearfish and Lower Piper Formation SW Core Sample Porosity and Permeability from MAG 1 (p. 2-44)

**Figure 2-33:** Thin section of Piper Formation. In this example, clay (brown) and anhydrite (white) dominate the depth interval. Minor porosity is observed (blue). (p. 2-45)

**Figure 2-34:** Thin section of Spearfish Formation. In this example, clay (brown), quartz (small white grains), anhydrite (large white grains), and iron oxides (black grains) dominate the depth interval. No porosity is observed. (p. 2-46)

**Figure 2-35:** Thin section of Spearfish Formation. In this example, clay (brown) and quartz (white) dominate the depth interval. Minor intergranular and intragranular porosity are observed (blue). (2-47)

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|

In situ fluid pressure testing was not performed in the Spearfish or lower Piper Formations in the MAG 1 well. The low permeability values shown in Table 2-11 suggest any fluid within the Spearfish Formation is pore- and capillary-bound fluid and likely not mobile. Several documented attempts by others to draw down reservoir fluid in order to measure the reservoir pressure or collect an in situ fluid sample using a modular formation dynamics tester (MDT) tool in the undifferentiated Spearfish/Opeche and other similar low-permeability intervals suggest collecting this information is not feasible. The Tundra SGS (secure geologic storage) SFP applications describe unsuccessful attempts to measure in situ fluid pressure because of the low permeability of the formations tested, the undifferentiated Spearfish/Opeche Formation, and the Icebox Formation (North Dakota Industrial Commission, 2021a, b). The Red Trail Energy SFP application also describes unsuccessful attempts to collect these data in the low-permeability Opeche Formation (North Dakota Industrial Commission, 2021c).

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

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

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

XRD data from the sidewall core samples in the cap rock intervals supported the thin-section analysis. Table 2-11 shows the major mineral phases identified for the samples representing these intervals. XRF data related to the upper confining zones are presented in Figure 2-33.

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

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

**Table 2-12.** XRD Analysis in the Upper Confining Intervals (Spearfish and Lower Piper) from MAG 1 Well. Only major constituents are shown. (p. 2-48)

**Figure 2-36.** XRF analysis in the upper confining zone (Spearfish and lower Piper Formations) from MAG 1 (p. 2-49)

**Table 2-13.** Mineral Composition of the Spearfish Derived from XRD Analysis of MAG 1 Core Samples (p. 2-50)

**Table 2-14.** Formation Water Chemistry from Broom Creek Formation Fluid Samples from MAG 1 (p. 2-50)

**Figure 2-37.** Change in fluid pH vs. time. Red line shows pH for the center of Cell C1, 0.5 meters above the Spearfish Formation cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to change until after Year 16 (p. 2-52)

**Figure 2-38.** Dissolution and precipitation of minerals in the Spearfish Formation cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible. Results from Cell C3, 2.5 meters above

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Spearfish** | 130074 | 4,710 | 8.3 | 5.3 | 11.8 | 38.5 | 4.6 | 11.0 | 0.0 | 19.7 | 0.4 |
| Spearfish | 130073 | 4,715 | 9.6 | 6.6 | 11.4 | 37.9 | 4.5 | 13.9 | 0.0 | 15.4 | 0.4 |
| **Spearfish** | 130071 | 4,721 | 8.0 | 6.7 | 10.2 | 39.6 | 0.0 | 34.9 | 0.0 | 0.0 | 0.0 |
| Spearfish | 130070 | 4,724 | 13.8 | 9.8 | 15.3 | 46.0 | 10.2 | 3.3 | 0.0 | 0.8 | 0.6 |

***2.4.1.1 Mineralogy*** (p. 2-44)
The combined interpretation of SW Core samples, well logs, and thin sections shows that the Spearfish and lower Piper Formations are dominated by clays (mainly illite/muscovite), quartz, anhydrite, feldspar (mainly K-feldspar), and dolomite. Sixteen depth intervals in the Spearfish and Lower Piper Formations were sampled for thin-section creation, XRD mineralogical determination, and XRF bulk chemical analysis. For the assessment, thin sections and XRD provide independent confirmation of the mineralogical constituents of each of these intervals. Thin-section analysis of the siltstone intervals shows that clay, quartz, and anhydrite are the dominant minerals. Throughout these intervals are occurrences of dolomite, feldspar, and iron oxides (Figures 2-33, 2-34, and 2-35). The contacts between grains are typically separated by a clay matrix, with more rare occurrences of contacts between quartz grains as tangential to long.

***2.4.1.2 Geochemical Interaction*** (p. 2-50)
Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected $CO_2$ stream on the Spearfish Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to $CO_2$ at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Spearfish Formation by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the confining zone. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock–$CO_2$ exposure boundary. The mineralogical composition of the Spearfish Formation was honored (Table 2-13). Formation brine composition was assumed to be the same as the known composition from the Broom Creek Formation injection zone below (Table 2-14). For simulation, 100% $CO_2$ was used as discussed in Section 2.3.1. The exposure level, expressed in moles per year, of the $CO_2$ stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). This overestimate was done to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection. The simulation was performed at reservoir pressure and temperature conditions.

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

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

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

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

the cap rock base, are not shown as they are too small to be seen at this scale (p. 2-52)

**Figure 2-39.** Weight percentage (wt%) of potentially reactive minerals present in the Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray, too small to see in the figure) after 20 years of injection plus 25 years of postinjection (p. 2-53)

**Figure 2-40.** Weight percentage (wt%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time (p. 2-54)

**Figure 2-41.** Change in percent porosity of the Spearfish cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation. (p. 2-55)

**Table 2-15.** Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the MAG 1 well) (p. 2-56)

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|

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

***2.4.2 Additional Overlying Confining Zones*** (p. 2-55)
Several other formations provide additional confinement above the lower Piper interval. Impermeable rocks above the primary seal include the upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-15). Together with the Spearfish and lower Piper intervals, these intervals are 859 ft thick on average across the simulation area and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-42). Above the Inyan Kara Formation at the MAG 1 well, 2,512 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and lowermost USDW, the Fox Hills Formation (see Figure 2-43). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-15).

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

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

***2.4.3 Lower Confining Zones*** (p. 2-58)
The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, limestone, and anhydrite. The Amsden Formation does include some thin sandstone and dolomitic sandstone intervals on the order of 4–6 inches thick (Figure 2-9). The sandstone intervals in the Amsden Formation are isolated from the sandstones of the Broom Creek Formation by thick impermeable dolostone intervals (Figure 2-9). The top of the Amsden Formation was placed at the top of an argillaceous dolostone, which has relatively high GR character that can be correlated across the project area (Figure 2-9). The Amsden Formation is 4,810 ft below land surface and 276 ft thick at the Blue Flint site as determined at the MAG 1 well (Figures 2-44 and 2-45).

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

**Table 2-15. Amsden SW Core Sample Porosity and Permeability from MAG 1**

| Sample Depth, ft | Porosity % | Permeability, mD |
|---|---|---|
| 4,845 | 9.59 | 0.003 |
| 4,851* | 18.80 | 117 |
| 4,860* | 8.86 | 1.46 |
| 4,865 | 2.15 | 0.0003 |

**Figure 2-42.** Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. (p. 2-56)

**Figure 2-43.** Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. (p. 2-57)

**Figure 2-44.** Structure map of the Amsden Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-58)

**Figure 2-45.** Isopach map of the Amsden Formation across the greater Blue Flint project area. (p. 2-59)

**Table 2-16.** Amsden SW Core Sample Porosity and Permeability from MAG 1 (p. 2-60)

**Figure 2-46.** Thin section in the Amsden Formation. This example shows a dolomite matrix (gray/brown) with quartz grains distributed throughout. Minor porosity is observed. (p. 2-61)

**Figure 2-47.** Thin section in the Amsden Formation. This interval is dominated by anhydrite and quartz. In this example, quartz grains are tightly cemented, and almost no porosity is observed. (p. 2-62)

**Figure 2-48.** Thin section in the Amsden Formation. This interval shows a fine micritic dolomite with minor quartz grains. Porosity is generally

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | (continued below) | low and found to be intergranular or due to the dissolution of dolomite in this example (p. 2-63)<br><br>**Table 2-17.** XRD Analysis in the Lower Confining Zone (Amsden Formation) from MAG 1 Well. Only major constituents are shown (p. 2-64)<br><br>**Figure 2-49**. XRF analysis in the lower confining zone (Amsden Formation) from MAG 1 (p. 2-65) |
| | NDAC § 43-05-01-05(1)(b)(2) | **NDAC § 43-05-01-05(1)(b)**<br>(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 | 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:<br>Rock properties<br>Regional pressure gradients<br>Adsorption processes | (continued below) | **Table 2-2.** Description of MAG 1 Temperature Measurements and Calculated Temperature Gradients (p. 2-9)<br><br>**Table 2-3.** Description of MAG 1 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-9)<br><br>**Figure 2-63.** Geomechanical parameters in the Spearfish Formation. (p. 2-81) |

Storage Facility Permit Application column, first row:

| | | |
|---|---|---|
| 4,869 | 11.56 | 0.009 |
| 4,875** | 2.9 | 0.005 |
| **4,880*** | **3.74** | **0.134** |
| 4,889* | 10.26 | 0.239 |
| **Range** | (2.15–18.80) | (0.0003–117) |
| Values measured at 2,400 psi | | |

* Sample is fractured or chipped. The measured permeability and/or porosity may be higher than its real value.
** Sample is very short; the measured porosity may be higher than its real value because of lack of conformation of boot material to plug surface.

***2.4.3.1 Mineralogy*** (p. 2-60)
Well logs and the thin-section analyses show that the Amsden Formation comprises dolostone, sandstone, anhydrite, and limestone. The porosity averages 7%, and permeability is very low. Figures 2-46, 2-47, and 2-48 show thin-section images representative of the Amsden Formation.

XRD was performed, and the results confirm the observations made during core observation, thin-section description, and well log analysis. Amsden intervals show that dolomite, anhydrite, quartz, and clay are the dominant minerals (Table 2-16). XRF data are presented in Figure 2-46 for the Amsden Formation.

**Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the MAG 1 well)**

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

Storage Facility Permit Application column, second row:

***2.2.2.3 Formation Temperature and Pressure*** (p. 2-8)
Broom Creek Formation temperature and pressure measurements were collected from MAG 1 with a packer module. To collect a formation fluid sample, the Broom Creek Formation had to be perforated due to the cement sheath created while drilling out an extended cement plug in the lower portion of the wellbore. The Broom Creek Formation was perforated from 4,733 to 4,740 ft, and a packer was set at 4,096 ft with a tailpipe, dual sensor mandrel, and 4-ft perforated sub below the packer. Pressure and temperature sensors were set at depths of 4,735 and 4,741 ft, and the measurements recorded are shown in Tables 2-2 and 2-3. The calculated pressure and temperature gradients from MAG 1 were used to model the formation temperature and pressure profiles for use in the numerical simulations of $CO_2$ injection.

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

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

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

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application<br>(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description<br>(Page Number)</th></tr>
<tr><td></td><td></td><td>comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:</td><td></td><td>
Table 2-3. Description of MAG 1 Formation Pressure Measurements and Calculated Pressure Gradients
<table>
<tr><th>Formation</th><th>Sensor Depth, ft</th><th>Formation Pressure, psi</th></tr>
<tr><td>Broom Creek</td><td>4,735</td><td>2,427.00</td></tr>
<tr><td>Broom Creek</td><td>4,741</td><td>2,427.28</td></tr>
<tr><td>Mean Broom Creek Pressure, psi</td><td>2,427.14</td><td></td></tr>
<tr><td>Broom Creek Pressure Gradient, psi/ft</td><td>0.50*</td><td></td></tr>
</table>
* The pressure gradient is an average of the sensor measured pressures minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.<br><br>
2.3.2 Mechanism of Geologic Confinement (p. 2-26)<br>
For the Blue Flint project area, the initial mechanism for geologic confinement of $CO_2$ injected into the Broom Creek Formation will be the upper confining formations (Spearfish Formation and the lower Piper Formation), which will contain the initially buoyant $CO_2$ under the effects of relative permeability and capillary pressure. Lateral movement of the injected $CO_2$ will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the $CO_2$ into the native formation brine), confining the $CO_2$ within the proposed storage reservoir. After injected $CO_2$ becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period (>100 years), mineralization of the injected $CO_2$ will ensure long-term, permanent geologic confinement. Injected $CO_2$ is not expected to adsorb to any of the mineral constituents of the target formation; therefore, this process is not considered to be a viable trapping mechanism in this project. Adsorption of $CO_2$ is a trapping mechanism notable in the storage of $CO_2$ in deep unminable coal seams.<br><br>
2.4.4.2 Stress, Ductility, and Rock Strength (p. 2-80)<br>
A 1D MEM was derived using the log data from MAG 1 well. Logs were edited to account for washouts in the Broom Creek and Amsden Formation sections using multilinear regressions. Geomechanical parameters in the Spearfish, Broom Creek, and Amsden Formations were estimated using the 1D MEM. The 1D MEM was used to estimate the vertical stress, pore pressure, minimum and maximum horizontal stresses (Shmin, SHmax), Poisson's ratio, Young's modulus, shear and bulk moduli, tensile, uniaxial compressive strength, and friction angle (Figure 2-63, Figure 2-64, and Figure 2-65). Table 2-19 shows the average and range of elastic and dynamic parameters, and stresses in the Spearfish, Broom Creek, and Amsden Formations.<br><br>
Table 2-19. Ranges and Averages of the Elastic Properties Estimated from 1D MEM in Spearfish, Broom Creek and Amsden Formations: Static Young's Modulus (E_Stat), Static Poisson's Ratio (n_Stat), Static Bulk Modulus (K), Static Shear Modulus (G), Uniaxial Strain Modulus (P), Dynamic Young's Modulus (E_Dyn), and Dynamic Poisson's ratio (n_Dyn) in the Spearfish, Broom Creek, and Amsden Formations
<table>
<tr><th>Formation</th><th>Stats</th><th>E_Stat, Mpsi</th><th>n_Stat, unitless</th><th>K, Mpsi</th><th>G, Mpsi</th><th>P, psi</th><th>E_Dyn, Mpsi</th><th>n_Dyn, unitless</th></tr>
<tr><td rowspan="3">Spearfish</td><td>Min</td><td>0.665</td><td>0.243</td><td>0.493</td><td>0.256</td><td>2821</td><td>3.090</td><td>0.243</td></tr>
<tr><td>Max</td><td>1.554</td><td>0.347</td><td>1.365</td><td>0.616</td><td>6591</td><td>5.213</td><td>0.347</td></tr>
<tr><td>Average</td><td>1.159</td><td>0.281</td><td>0.884</td><td>0.453</td><td>4916</td><td>4.331</td><td>0.281</td></tr>
<tr><td rowspan="3">Broom Creek</td><td>Min</td><td>0.089</td><td>0.231</td><td>0.084</td><td>0.034</td><td>378</td><td>0.896</td><td>0.231</td></tr>
<tr><td>Max</td><td>3.774</td><td>0.347</td><td>3.288</td><td>1.429</td><td>15884</td><td>8.963</td><td>0.347</td></tr>
<tr><td>Average</td><td>0.573</td><td>0.313</td><td>0.479</td><td>0.221</td><td>2430</td><td>2.444</td><td>0.313</td></tr>
<tr><td rowspan="3">Amsden</td><td>Min</td><td>0.117</td><td>0.152</td><td>0.137</td><td>0.043</td><td>495</td><td>1.057</td><td>0.152</td></tr>
<tr><td>Max</td><td>6.869</td><td>0.364</td><td>6.774</td><td>2.581</td><td>29140</td><td>13.026</td><td>0.364</td></tr>
<tr><td>Average</td><td>1.945</td><td>0.286</td><td>1.47</td><td>0.764</td><td>8249</td><td>5.707</td><td>0.286</td></tr>
</table>
</td><td>Figure 2-64. Geomechanical parameters in the Broom Creek Formation. (p. 2-82)<br><br>Figure 2-65. Geomechanical parameters in the Amsden Formation. (p. 2-83)<br><br>Table 2-19. Ranges and Averages of the Elastic Properties Estimated from 1D MEM in Spearfish, Broom Creek and Amsden Formations (p. 2-84)</td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(2)(g)</td><td>NDAC § 43-05-01-05(1)(b)(2)<br>(g) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored carbon dioxide and</td><td>e. Identification of all characteristics controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir, including:<br>Structural spill points</td><td>2.2.2.6 Seismic Survey (p. 2-10)<br>A 9-square-mile 3D seismic survey centered on the BFE facility was conducted December 2019 through January 2020 (Figure 2-6). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The seismic data were used for assessment of the geologic structure and well placement.</td><td>Figure 2-9. Well log display of the interpreted lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations in MAG 1 (p. 2-14)</td></tr>
</table>

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | associated fluids within the storage reservoir; | Stratigraphic discontinuities | Data products generated from the interpretation of the 3D seismic data were used as inputs into the geologic model that was used to simulate migration of the $CO_2$ plume. The 3D seismic data and MAG 1 well logs were used to interpret surfaces for the formations of interest within the survey area. These surfaces were converted to depth using the time-to-depth relationship derived from the MAG 1 dipole sonic log. The depth-converted surfaces for the storage reservoir and upper and lower confining zones were used as inputs for the geologic model. These surfaces captured detailed information about the structure and varying thickness of the formations between wells. A poststack inversion of the 3D seismic data was done using the MAG 1 well logs. Given the uncertainty in sonic log values related to washouts in the Broom Creek Formation in the MAG 1 well, indicated by the caliper log shown in Figure 2-5, inversion results of the 3D seismic data were not used to inform property distribution in the geologic model.<br><br>Interpretation of the 3D seismic data and legacy 2D seismic data suggests there are no major stratigraphic pinch-outs or structural features with associated spill points in the area of review. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the 2D and 3D seismic data in the area of review.<br><br>***2.3.2 Mechanism of Geologic Confinement*** (p. 2-26)<br>*See discussion above under 2.3.2Mechanism of Geologic Confinement* | **Figure 2-10.** Regional well log stratigraphic cross sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15)<br><br>**Figure 2-11**. Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16)<br><br>**Figure 2-12.** Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map. (p. 2-17)<br><br>**Figure 2-13.** Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. (p. 2-18) |
| | NDAC § 43-05-01-05(1)(b)(2)(c) | **NDAC § 43-05-01-05(1)(b)(2)** (c) Any regional or local faulting; | f. Any regional or local faulting; | **2.5 Faults, Fractures, and Seismic Activity** (First two paragraphs on p. 2-85)<br>In the area of review, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from MAG 1 that suggest the injection interval, Broom Creek Formation (28,600 mg/L), is isolated from the next permeable interval, the Inyan Kara Formation (15,600 mg/L) (Appendix A).<br><br>A regional structural feature, the Stanton Fault, is discussed in this section. This section also discusses the seismic history of North Dakota and the low probability that seismic activity will interfere with containment.<br><br>***2.5.1 Stanton Fault*** (p. 2-86)<br>The Stanton Fault is a suspected Precambrian basement fault interpreted by Sims and others (1991), who interpreted this northeast-southwest trending feature using available borehole data and regional gravity and magnetic data. The Stanton Fault is interpreted by Sims and others (1991) to be approximately 0.7 miles from the MAG 1 well (Figure 2-66). Given the resolution of the regional gravity and magnetic data and limited amount of borehole data used to interpret this suspected fault, there is a lot of uncertainty in the lateral extent and the location of the feature. No studies describing the possible vertical extent of this feature or impact on overlying sedimentary layers have been published. Lack of historical earthquakes in the area suggests that if the suspected Stanton Fault does exist it is inactive | **Figure 2-66.** Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016). (p. 2-87)<br><br>**Figure 2-67**. Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box). (p. 2-88)<br><br>**Figure 2-68.** Cross section of Line 1 showing interpreted seismic horizons |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | 2D and 3D seismic data were used to characterize the subsurface within the project area and determine if the suspected Stanton Fault or other faults are present within the area of review. There is no indication of faulting within the 3D seismic data. Along the 2D seismic lines, there are areas where diffractions within the Precambrian basement can be seen and areas where there are discontinuities and flexures along seismic reflection events at the top of and within the Precambrian basement. These features may indicate the presence of faults.<br><br>On Lines 1 and 2, shown in Figure 2-67 and 2-68, respectively, the diagonal seismic features within the Precambrian basement may be diffractions indicating the location of a structural feature such as a fault. However, there is no visible offset within the formations that directly overly the Precambrian basement, suggesting that if a fault is present it is confined to the Precambrian basement.<br><br>On Lines 1 and 2, there are also discontinuities and flexures in several places along the interpreted top of the Precambrian basement and within the Precambrian basement that may also indicate the presence of faults. If these seismic features do correspond to faults, there is no indication that these features are present in the formations overlying the Precambrian basement and, therefore, do not have sufficient vertical extent to transect the storage reservoir and confining zones which are more than 5,000 feet above the basement. | (red lines) and area where diffractions are present withing the Precambrian basement (green box). (p. 2-88) |
| | NDAC § 43-05-01-05(1)(b)(2)(j) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(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:<br>Location<br>Orientation<br>Determination of the probability that they would interfere with containment | ***2.5.1 Stanton Fault*** (p. 2-86)<br>*See discussion above under 2.5.1 Stanton Fault* | **Figure 2-66.** Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016) (p. 2-87)<br><br>**Figure 2-67.** Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box) (p. 2-88)<br><br>**Figure 2-68.** Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box) (p. 2-88) |
| | NDAC §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(m) | **NDAC § 43-05-01-05(1)(b)**<br>(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, | h. Information on any regional tectonic activity, and the seismic history, including:<br>The presence and depth of seismic sources;<br>Determination of the probability that seismicity would interfere with containment; | ***2.5.2 Seismic Activity*** (p. 2-89)<br>The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2022)<br><br>Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-21) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-69). The earthquake recorded closest to the project area occurred in 2008 52.3 miles to the east, near Goodrich, North Dakota (Table 2-21). The magnitude of this earthquake is estimated to have been 2.6 | **Table 2-21.** Summary of Earthquakes Reported to Have Occurred in North Dakota (p. 2-90)<br><br>**Figure 2-69.** Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016) (p. 2-91)<br><br>**Figure 2-70.** Probabilistic map showing how often scientists expect damaging earthquake shaking around |

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application<br>(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description<br>(Page Number)</th></tr>
<tr><td></td><td></td><td>local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:<br><br>NDAC § 43-05-01-05(1)(b)(2)<br>(m) Information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment;</td><td></td><td>Table 2-21. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)
<table>
<tr><th>Date</th><th>Magnitude</th><th>Depth, miles</th><th>Longitude</th><th>Latitude</th><th>City or Vicinity of Earthquake</th><th>Map Label</th><th>Distance to Blue Flint Ethanol, miles</th></tr>
<tr><td>Sept. 28, 2012</td><td>3.3</td><td>0.4*</td><td>−103.48</td><td>48.01</td><td>Southeast of Williston</td><td>A</td><td>117.0</td></tr>
<tr><td>June 14, 2010</td><td>1.4</td><td>3.1</td><td>−103.96</td><td>46.03</td><td>Boxelder Creek</td><td>B</td><td>162.9</td></tr>
<tr><td>March 21, 2010</td><td>2.5</td><td>3.1</td><td>−103.98</td><td>47.98</td><td>Buford</td><td>C</td><td>136.4</td></tr>
<tr><td>Aug. 30, 2009</td><td>1.9</td><td>3.1</td><td>−102.38</td><td>47.63</td><td>Ft. Berthold southwest</td><td>D</td><td>60.1</td></tr>
<tr><td>Jan. 3, 2009</td><td>1.5</td><td>8.3</td><td>−103.95</td><td>48.36</td><td>Grenora</td><td>E</td><td>146.7</td></tr>
<tr><td>Nov. 15, 2008</td><td>2.6</td><td>11.2</td><td>−100.04</td><td>47.46</td><td>Goodrich</td><td>F</td><td>52.3</td></tr>
<tr><td>Nov. 11, 1998</td><td>3.5</td><td>3.1</td><td>−104.03</td><td>48.55</td><td>Grenora</td><td>G</td><td>156.2</td></tr>
<tr><td>March 9, 1982</td><td>3.3</td><td>11.2</td><td>−104.03</td><td>48.51</td><td>Grenora</td><td>H</td><td>154.8</td></tr>
<tr><td>July 8, 1968</td><td>4.4</td><td>20.5</td><td>−100.74</td><td>46.59</td><td>Huff</td><td>I</td><td>58.0</td></tr>
<tr><td>May 13, 1947</td><td>3.7**</td><td>U</td><td>−100.90</td><td>46.00</td><td>Selfridge</td><td>J</td><td>96.1</td></tr>
<tr><td>Oct. 26, 1946</td><td>3.7**</td><td>U</td><td>−103.70</td><td>48.20</td><td>Williston</td><td>K</td><td>131.5</td></tr>
<tr><td>April 29, 1927</td><td>0.2**</td><td>U</td><td>−102.10</td><td>46.90</td><td>Hebron</td><td>L</td><td>55.8</td></tr>
<tr><td>Aug. 8, 1915</td><td>3.7**</td><td>U</td><td>−103.60</td><td>48.20</td><td>Williston</td><td>M</td><td>127.3</td></tr>
</table>
* Estimated depth.<br>** Magnitude estimated from reported modified Mercalli intensity (MMI) value.</td><td>the United States (U.S. Geological Survey, 2019). (p. 2-92)</td></tr>
<tr><td></td><td>NDAC §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(n)</td><td>NDAC § 43-05-01-05(1)(b)<br>(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any</td><td>i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area:<br>Geologic maps<br>Topographic maps<br>Cross sections</td><td>2.1 Overview of Project Area Geology (p. 2-1)<br>See discussion above under 2.1 Overview of Project Area Geology<br><br>4.4.3 Hydrology of USDW Formations (p. 4-16)<br>The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the northeast (Figure 4-9). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,500 ppm (Klausing, 1974). Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Honeyman, 2007). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering.</td><td>Figure 2-1. Topographic map of the project area showing the planned injection well, the planned monitoring well, and the Blue Flint Ethanol Plant (p. 2-2)<br><br>Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (red dashed line). (p. 2-12)<br><br>Figure 2-10. Regional well log stratigraphic cross</td></tr>
</table>

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | 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:<br><br>**NDAC § 43-05-01-05(1)(b)(2)**<br>(a) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the facility area; and | | Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the area of investigation. A cross section of these formations is presented in Figure 4-10. The upper formations are generally used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. The basal sandstone member of the Tongue River is persistent and a reliable source of groundwater in the region. The thickness of this basal sand ranges from approximately 50 to 200 ft and can be found at a depth of approximately 550 ft. Tongue River groundwaters are generally sodium bicarbonate with a TDS of approximately 1,000 ppm (Klausing, 1974).<br><br>The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. The upper Sentinel Butte is approximately 150 ft thick in the area of investigation (Hemish, 1975). TDS concentrations in the Sentinel Butte Formation are approximately 1,000 ppm (Klausing, 1974). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers. | sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15)<br><br>**Figure 2-11.** Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16)<br><br>**Figure 2-13.** Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. (p. 2-18)<br><br>**Figure 2-29.** Structure map of the lower Piper Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-40)<br><br>**Figure 4-9.** Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. (p. 4-17)<br><br>**Figure 4-10.** Southwest to northeast cross section of the major aquifer layers in McLean County. (p. 4-18) |
| | NDAC § 43-05-01-05(1)(b)(2)(d) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(d) An isopach map of the storage reservoirs; | j. An isopach map of the storage reservoir(s); | See Figure 2-8 on p. 2-13 | **Figure 2-8.** Isopach map of the Broom Creek Formation in the greater Blue Flint project area. (p. 2-13) |
| | NDAC § 43-05-01-05(1)(b)(2)(e) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(e) An isopach map of the primary and any secondary containment barrier for the storage reservoir; | k. An isopach map of the primary containment barrier for the storage reservoir; | See Figure 2-32 on p. 2-43 | **Figure 2-32.** Isopach map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area. (p. 2-43) |
| | | | l. An isopach map of the secondary containment barrier for the storage reservoir; | See Figure 2-30 on p. 2-41 and Figure 2-43 on p. 2-57 | **Figure 2-30.** Isopach map of the lower Piper Formation in the greater Blue Flint project area. (p. 2-41) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | | **Figure 2-43.** Isopach map of the interval between the top of the Invan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone (p. 2-57) |
| | NDAC § 43-05-01-05(1)(b)(2)(f) | **NDAC § 43-05-01-05(1)(b)(2)** (f) A structure map of the top and base of the storage reservoirs; | m. A structure map of the top of the storage formation; | See Figure 2-12 on p. 2-17 | **Figure 2-12.** Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-17) |
| | | | n. A structure map of the base of the storage formation; | See Figure 2-44 on p. 2-58 | **Figure 2-44.** Structure map of the Amsden Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-58) |
| | NDAC § 43-05-01-05(1)(b)(2)(i) | **NDAC § 43-05-01-05(1)(b)(2)** (i) Structural and stratigraphic cross sections that describe the geologic conditions at the storage reservoir; | o. Structural cross sections that describe the geologic conditions at the storage reservoir; | See Figure 2-11 on p. 2-16 and Figure 2-13 on p. 2-18 | **Figure 2-11.** Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16)<br><br>**Figure 2-13.** Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. (p. 2-18) |
| | | | p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir; | See Figure 2-10 on p. 2-15 | **Figure 2-10.** Regional well log stratigraphic cross sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15) |
| | NDAC § 43-05-01-05(1)(b)(2)(h) | **NDAC § 43-05-01-05(1)(b)(2)** (h) Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any; | q. Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any; | **3.4 Simulation Results** (p. 3-11)<br>The target injection rate of 200,000 tonnes per year (tpy) (548 tonnes per day) was consistently achievable over 20 years (Figure 3-9), translating to a cumulative 4 MMt of $CO_2$ injection (Figure 3-10). Simulations of $CO_2$ injection with the given well constraints, listed in Table 3-3, predicted the BHP would not reach the maximum BHP constraint of 2,970 psi (90% of the formation fracture pressure) as a result of injecting the target $CO_2$ volume of 200,000 tpy. The predicted maximum BHP and the average BHP during the 20 year injection period were 2,661 and 2,570 psi (Figure 3-11), respectively.<br><br>Long-term $CO_2$ migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase $CO_2$ injected into the formation rises to the bottom of the upper confining zone or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of $CO_2$ at the center which gradually spreads out toward the model edges where the $CO_2$ saturation is lower. Trapped $CO_2$ saturations, employed in the model to represent fractions of $CO_2$ trapped in small pores as immobile, tiny bubbles, ultimately immobilize | **Figure 3-13.** Top left, top right, and bottom left display average pressure increase within the Broom Creek Formation after 1, 10, and 20 years of simulated $CO_2$ injection operation. (p. 3-16)<br><br>**Figure 6-1.** Predicted pressure increase in storage reservoir following 20 years of $CO_2$ injection at a rate of |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | the $CO_2$ plume and limit the plume's lateral migration and spreading. Figure 3-14 shows the $CO_2$ saturation at the injection well at the end of injection in north-to-south and east-to-west cross-sectional views.<br><br>***6.1.1 Pre- and Postinjection Pressure Differential*** (p. 6-1)<br>Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of $CO_2$ injection. The simulations were conducted for 20 years of $CO_2$ injection at a rate of 200,000 metric tons per year, followed by a PISC period of 10 years.<br><br>Figure 6-1 illustrates the predicted pressure differential at the conclusion of $CO_2$ injection. At the time that $CO_2$ injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of up to 120 psi at the location of the $CO_2$ injection well. There is insufficient pressure increase caused by $CO_2$ injection to move more than 1 cubic meter of formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the AOR delineation of this permit application (Section 3.0).<br><br>Figure 6-2 illustrates the predicted gradual pressure decrease following the cessation of $CO_2$ injection, with the pressure at the injection well at the end of the PISC period anticipated to decrease 80 to 100 psi as compared to the pressure at the time $CO_2$ injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions. | 200,000 metric tons per year (p. 6-2)<br><br>**Figure 6-2.** Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of $CO_2$ injection (p. 6-3) |
| | NDAC § 43-05-01-05(1)(b)(2)(l) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(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; | l. 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<br>Fractures<br>Stress<br>Ductility<br>Rock strength<br>In situ fluid pressure | *2.4.4.1 Borehole Image Fracture Analysis* (p. 2-71)<br>Borehole image logs were used to evaluate fractures within the upper and lower confining zones. The natural fractures and in situ stress directions were assessed through the interpretation of the FMI log acquired from the MAG 1 well. The FMI log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed.<br><br>Figures 2-56a, 2-56b, 2-57, 2-58, and 2-59 show sections of the interpreted borehole imagery and the primary features observed in the Piper, Spearfish Formation and Amsden Formation, respectively. Drilling induced fractures were observed in the Piper Formation as shown in Figure 2-56a in the far-right track. The far-right track on Figure 2-56b demonstrates that the tool provides information on surface boundaries and bedding features that characterize the Spearfish Formation. Figure 2-57 shows that features that have an electrically conductive signal in Spearfish Formation are observed. The logged interval of the Amsden Formation shows the main features represented by horizontal and oblique stratification fractures (Figure 2-58) and the presence of rare resistive fractures (Figure 2-59). Rose diagrams showing dip, dip azimuth, and strikes for conductive and drilling induced fractures observed in the borehole imagery are shown in Figures 2-60–2-62. These two fracture types were studied to evaluate potential leakage pathways as well as maximum horizontal stress. The diagrams shown in Figures 2-60 and 2-61 provide the dip orientation of the electrically conductive features in Spearfish and Amsden Formations, respectively. Breakouts were not identified in Spearfish or Amsden Formations. The drilling-induced fractures observed in the Piper Formation are oriented NE–SW ; these features are parallel to the maximum horizontal stress (SHmax). (Figure 2-62)<br><br>*2.4.4.2 Stress, Ductility and Rock Strength* (p. 2-80)<br>A 1D MEM was derived using the log data from MAG 1 well. Logs were edited to account for washouts in the Broom Creek and Amsden Formation sections using multilinear regressions. Geomechanical parameters in the Spearfish, Broom Creek, and Amsden Formations were estimated using the 1D MEM. The 1D MEM was used to estimate the vertical stress, pore pressure, minimum and maximum horizontal stresses (Shmin, SHmax), Poisson's ratio, Young's modulus, shear and bulk moduli, tensile, uniaxial compressive strength, and friction angle (Figure 2-63, Figure 2-64, and Figure 2-65). Table 2-19 shows the average and range of elastic and dynamic parameters, and stresses in the Spearfish, Broom Creek, and Amsden Formations.<br><br>Since the SW Core samples collected from the MAG 1 well were horizontally oriented, it was not possible to determine ductility and rock strength through laboratory testing. The dimensions of the SW Core samples were inadequate for multistage triaxial testing. The static properties (Young's modulus, Poisson's ratio, bulk modulus, shear modulus, uniaxial strain modulus) and the dynamic properties (Young's modulus, Poisson's ratio) were estimated through the evaluation of the 1D MEM in the Spearfish, Broom Creek, and Amsden Formations. The dynamic parameters determined using the 1D MEM were converted into static parameters using specific equations derived from global correlations of dynamic to static parameters (Tutuncu and Sharma, 1992; Yale and Walters, 2016; Nowakowski, 2005; Yale and others, 1995; Zhang and Bentley, 2005; Yale and Jamieson, 1994). | **Figure 2-56a.** Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Piper-Picard Formation FMI image analysis. (p. 2-73)<br><br>**Figure 2-56b.** Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Spearfish Formation FMI image analysis. (p. 2-74)<br><br>**Figure 2-57.** Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, resistive fracture, mixed fracture, horizontal stratification, and oblique stratification) seen in Spearfish Formation FMI image analysis. (p. 2-75) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | Log data were used to characterize stress in the storage complex to determine the fracture pressure gradient. In the injection zone, the parameters used to calculate stress were determined from the sand intervals in the Broom Creek Formation section. Rock strength defines the limit at which the stress conditions might induce the rock to mechanically fail. The unconfined compressive strength can be determined directly from rock mechanics tests, but in the MAG 1 well case, it was empirically estimated from well log data. Poisson's ratio was estimated using the available well logs, which resulted in an average value for the Broom Creek Formation of 0.32. The Biot factor was calculated using the effective porosity, static bulk modulus, and permeability, resulting in a range of 0.89-1. The pore pressure and hydropressure gradient were estimated using the true vertical depth (TVD), vertical stress (Sv), compressional slowness, and compressional velocity, respectively. The pore pressure and hydropressure gradients are equal to 0.448 and 0.429 psi/ft, respectively. In situ stresses such as Sv, maximum horizontal stress (SHmax), and minimum horizontal stress (Shmin) were calculated using specific parameters and methods (Table 2-20). Sv, which is related to the overburden or lithostatic pressure, is an important parameter in geomechanical modeling. In the Broom Creek Formation, overburden pressure was estimated through the bulk density log to the surface using the extrapolation method, resulting in an overburden gradient of 0.911 psi/ft. The poroelastic horizontal strain model is the most used method for horizontal stress calculation. The poroelastic horizontal strain model can be expressed using static Young's modulus, Poisson ratio, Biot's constant, overburden stress, and pore pressure. The poroelastic horizontal strain model was used to estimate the minimum horizontal stress (Plumb and Hickman, 1985; Aadnoy, 1990; Aadnoy and Bell, 1998; Brudy and Zoback, 1999). The SHmax is estimated from Shmin and process zone stress (as function of porosity). Based on the calculated stresses, the stress regime that can be seen in the Spearfish, Broom Creek, and Amsden Formations is a normal stress regime where Sv > SHmax > Shmin. Shmin magnitude could not be calibrated using the closure pressure measurements obtained from the openhole MDT microfracture in situ stress test because it was not performed in the MAG 1 well because of the large washout in the vicinity of the intervals of interest. The fracture gradient (FG) is calculated from pore pressure and overburden gradient. With the absence of closure pressure measurements in the Broom Creek Formation from in situ testing, a fracture gradient of 0.69 psi/ft was calculated in Schlumberger's Techlog software through the Matthew and Kelly method (Zhang and Yin, 2017). Equation 1 shows the equation used to derive the fracture gradient.<br><br>$\textit{Fracture Gradient} = K \cdot (\sigma_v - \alpha P_p) + \alpha P_p$ [Eq 1]<br><br>Where:<br>σ_v is the overburden gradient<br>α is Biot coefficient<br>P_p is pore pressure<br>K is the stress ratio (unitless) which Mathews and Kelly calculate with empirical correlation shown in Equation 2<br><br>K=(-3.0*10^(-9))* 〖〖TVD〗_RefGL〗^2+(8.0*10^(-5))* 〖TVD〗_RefGL+0.2347 [Eq 2]<br><br>Where:<br>〖TVD〗_RefGL is true vertical depth minus Kelly Bushing. | **Figure 2-58.** Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis. (p. 2-77)<br><br>**Figure 2-59.** Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, stylolites, horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis. (p. 2-77)<br><br>**Figure 2-60.** This example shows the dip azimuth and dip angle for conductive fractures seen in the Spearfish Formation. (p. 2-78)<br><br>**Figure 2-61.** This example shows the dip azimuth and dip angle for conductive fractures seen in the Amsden Formation. (p. 2-79)<br><br>**Figure 2-62.** This example shows the orientation of drilled-induced fractures in the Piper Formation. (p. 2-80)<br><br>**Figure 2-63.** Geomechanical parameters in the Spearfish Formation. (p. 2-81)<br><br>**Figure 2-64.** Geomechanical parameters in the Broom Creek Formation. (p. 2-82)<br><br>**Figure 2-65.** Geomechanical parameters in the Amsden Formation. (p. 2-83) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | | **Table 2-19.** Ranges and Averages of the Elastic Properties Estimated from 1D MEM in Spearfish, Broom Creek and Amsden Formations (p. 2-84)<br><br>**Table 2-20.** Ranges and Averages of the Sv, Hydropressure, Shmin, and Friction Angle (Fang) Estimated from 1D MEM in the Spearfish, Broom Creek, and Amsden Formations (p. 2-85) |
| | NDAC § 43-05-01-05(1)(b)(2)(o) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(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:<br>Free of transmissive faults<br>Free of transmissive fractures<br>Effect on pressure dissipation<br>Utility for monitoring, mitigation, and remediation | ***2.4.2 Additional Overlying Confining Zones*** (pp. 2-55 and 2-56)<br>Several other formations provide additional confinement above the lower Piper interval. Impermeable rocks above the primary seal include the upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-15). Together with the Spearfish and lower Piper intervals, these intervals are 859 ft thick on average across the simulation area and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-42). Above the Inyan Kara Formation at the MAG 1 well, 2,512 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and lowermost USDW, the Fox Hills Formation (see Figure 2-43). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-15).<br><br>The formations between the Broom Creek and Inyan Kara Formations and between the Inyan Kara Formation and lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988).<br><br>Sandstones of the Inyan Kara Formation comprise the first unit, with relatively high porosity and permeability above the injection zone and the primary sealing formation. The Inyan Kara represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring digital temperature sensor (DTS) data for the Inyan Kara Formation using the downhole fiber-optic cable provides an additional opportunity for mitigation and remediation (Section 5). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, $CO_2$ would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at MAG 1 is approximately 3,604 ft, and the interval itself is about 228 ft thick. | **Table 2-15** Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the MAG 1 well) (p. 2-56)<br><br>**Figure 2-42**. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. (p. 2-56)<br><br>**Figure 2-43.** Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. (p. 2-57) |
| Area of Review Delineation | NDAC §§ 43-05-01-05(1)(j) and (1)(b)(3) | **NDAC § 43-05-01-05(1)**<br>**j. An area of review and corrective action plan that meets the requirements pursuant to section 43-05-01-05.1;**<br><br>**NDAC § 43-05-01-05(1)(b)**<br>**(3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one** | The carbon dioxide storage reservoir area of review includes the areal extent of the storage reservoir and one mile outside of the storage reservoir boundary, plus the maximum extent of the pressure front caused by injection activities. The area of review delineation must include the following: | ***4.1.1 Written Description*** (p. 4-1)<br>North Dakota geologic storage of $CO_2$ regulations require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water [USDW] may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concerns regarding the endangerment of USDWs is related to the potential vertical migration of $CO_2$ and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase $CO_2$ plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the MAG 1 well (NDIC File No. 37833) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-5]).<br><br>NDAC § 43-05-01-05(1)(b)(3) requires "[a] review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate $CO_2$ injection activities and associated pressure front (Figure 4- | **Figure 4-2**. AOR map in relation to nearby groundwater wells. (p. 4-4) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: | | 1), the resulting AOR for the geologic storage project is delineated as being 1 mile from the SFP boundary. This extent ensures compliance with existing state regulations.<br><br>All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-20 and 4-2) by a professional engineer pursuant to NDAC § 43-05-01-05(1)(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected $CO_2$ from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 and 4-3, and Figure 4-3 and Figure 4-4).<br><br>An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC uncovered no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.<br><br>This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05(1)(a) and (b) and § 43-05-01-05.1(2), such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05(1)(a) and (b)(3) and § 43-05-01-05.1(2). Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1.<br><br>See Figure 4-2 on p. 4-4 | |
| | NDAC §§ 43-05-01-05(1)(b)(3) and (1)(a) | **NDAC § 43-05-01-05(1)(b)**<br>(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:<br><br>**NDAC § 43-05-01-05(1)**<br>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:<br>i. Boundaries of the storage reservoir<br>ii. Location of all proposed wells<br>iii. Location of proposed cathodic protection boreholes<br>iv. Any existing or proposed aboveground facilities; | **2.3 Storage Reservoir (Injection zone)** (p. 2-11)<br>See Figure 2-7 on page 2-12.<br><br>***5.7.2 Soil Gas and Groundwater Monitoring*** (p. 5-14)<br>See Figure 5-5 on page 5-14.<br><br>*3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29)<br>See Figure 3-21 on page 3-33.<br><br>**5.2 Surface Facilities Leak Detection Plan** (p. 5-3)<br>See Figure 5-1 on page 5-3. | **Figure 2-7.** Areal extent of the Broom Creek Formation in North Dakota (p. 2-12)<br><br>**Figure 5-5.** Blue Flint's planned baseline and monitoring program for soil gas, shallow groundwater aquifers, and the Fox Hills Aquifer. (p. 5-14)<br><br>**Figure 3-21.** Land use in and around the AOR. (p. 3-33)<br><br>**Figure 5-1.** Site map showing the surface facilities layout for the Blue Flint $CO_2$ storage project. (p. 5-3) |
| | NDAC § 43-05-01-05(1)(b)(2)(a) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(a) All wells, including water, oil, and natural gas exploration and | b. A map showing the following within the storage reservoir area and within one mile outside of its boundary: | ***4.1.2 Supporting Maps*** (p. 4-3)<br>See Figure 4-2 on page 4-4. | **Figure 4-2.** AOR map in relation to nearby groundwater wells. (p. 4-4) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | development wells, and other manmade subsurface structures and activities, including coal mines, within the facility area and within one mile [1.61 kilometers] of its outside boundary; | i. All wells, including water, oil, and natural gas exploration and development wells<br>ii. All other manmade subsurface structures and activities, including coal mines; | *3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29)<br>See Figure 3-21 on page 3-33. | **Figure 3-21.** Land use in and around the AOR. (p. 3-33) |
| | NDAC § 43-05-01-05(1)(c) and NDAC § 43-05-01-05.1(1)(a) | **NDAC § 43-05-01-05(1)**<br>c. The extent of the pore space that will be occupied by carbon dioxide as determined by utilizing all appropriate geologic and reservoir engineering information and reservoir analysis, which must include various computational models for reservoir characterization, and the projected response of the carbon dioxide plume and storage capacity of the storage reservoir. The computational model must be based on detailed geologic data collected to characterize the injection zones, confining zones, and any additional zones;<br><br>**NDAC § 43-05-01-05.1(1)**<br>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<br>i. The computational model to be used<br>ii. The assumptions that will be made<br>iii. The site characterization data on which the model will be based; | ***3.5.2 Risk-Based AOR Delineation*** (p. 3-20)<br>The methods described by EPA (2013) for estimating the AOR under the Class VI rule (40 U.S. Code of Federal Regulations [CFR] 146.81 et seq.) were developed assuming that the storage reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and potentially elsewhere around the United States, candidate storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW, even prior to the planned storage project. Consequently, applying EPA (2013) methods to these geologic situations essentially results in an infinite AOR, which makes regulatory compliance infeasible.<br><br>Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer and others (2014) described the unnecessary conservatism in EPA's definition of critical pressure, which could lead to a heavy burden on storage facility permit (SFP) applicants. As an alternative, Burton-Kelly and others (2021) proposed a risk-based reinterpretation of this framework that would allow for a reduction in the AOR while ensuring protection of drinking water resources.<br><br>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").<br><br>Recently, White and others (2020) outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, NRAP-IAM-CS and the subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers.<br><br>Building a geologic model in a commercial-grade software platform (like Petrel; Schlumberger, 2020) and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform (like CMG's compositional simulator, GEM) provide the "gold standard" for estimating pressure buildup in response to $CO_2$ injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that are unwarranted given the amount of uncertainty that may be present if only a few nearby wells can be used for characterization activities. Earlier studies (e.g., Nicot and others, 2008; Birkholzer and others, 2009; Bandilla and others, 2012; Cihan and others, 2011, 2012) have shown that far-field fluid pressure changes outside of the $CO_2$ plume domain can be reasonably described by a single-phase flow calculation by representing $CO_2$ injection as an equivalent-volume injection of brine (Oldenburg and others, 2014).<br><br>The semianalytical solutions embedded within the ASLMA Model have been shown to compare with the numerical model, TOUGH2-ECO2-N, and provided accurate results for pressures beyond the $CO_2$ plume zone (Birkholzer and others, 2009; Cihan and others, 2011, 2012). Therefore, the proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and resultant effects of this buildup on the vertical migration of formation fluid via (single) hypothetical leaky wellbores located at progressively greater distances from the injection well (Figure 3-16). | **Figure 3-16.** Workflow for delineating a risk-based AOR for a SFP. (p. 3-22) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | 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 $\Delta P_c$ 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. | |
| | NDAC § 43-05-01-05.1(1)(b)(1-4) | **NDAC § 43-05-01-05.1(1)**<br>b. A description of:<br>(1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review;<br>(2) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date;<br>(3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and<br>(4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action. | d. A description of:<br>(1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review;<br>(2) Any monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date;<br>(3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation;<br>(4) How corrective action will be conducted if necessary, including:<br>a. What corrective action will be performed prior to injection<br>b. How corrective action will be adjusted if there are changes in the area of review; | **4.3 Reevaluation of AOR and Corrective Action Plan** (p. 4-13)<br>BFE will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place no later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following:<br>• Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date will be identified.<br>• Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and the computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and the operational data to be utilized as the basis for that update will be identified.<br>• The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR. | N/A |
| | NDAC § 43-05-01-05(1)(b)(2)(b) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(b) All manmade surface structures that are intended for temporary or permanent human occupancy within the | e. A map showing the areal extent of **all** manmade surface structures that are intended for temporary or permanent human occupancy within the storage reservoir area. | *3.3.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29)<br>See Figure 3-21 on p. 3-33 | **Figure 3-21.** Land use in and around the AOR. (p. 3-33) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | facility area and within one mile [1.61 kilometers] of its outside boundary; | and within one mile outside of its boundary; | | |
| | NDAC § 43-05-01-05(1)(b)(2) | **NDAC § 43-05-01-05(1)(b)**<br>(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following: | f. A map and cross section identifying any productive existing or potential mineral zones occurring within the storage reservoir area and within one mile outside of its boundary; | **2.6 Potential Mineral Zones** (p. 2-92)<br>See Figure 2-71 and Figure 2-72. | **Figure 2-71.** Coal beds of the Sentinel Butte and Bullion Creek (Tongue River) Formations showing the lignite coals in western North Dakota (p. 2-94)<br><br>**Figure 2-72.** Hagel net coal isopach map. (p. 2-95) |
| | NDAC § 43-05-01-05(1)(b)(3) and NDAC § 43-05-01-05.1(2)(b) | **NDAC § 43-05-01-05(1)(b)**<br>(3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, | g. A map identifying all wells within the area of review, which penetrate the storage formation or primary or secondary seals overlying the storage formation. | *3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29)<br>See Figure 3-20 on p. 3-32 for nearby legacy wells. | **Figure 3-20.** Final AOR in relation to nearby legacy wells. (p. 3-32) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | 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:<br><br>**NDAC § 43-05-01-05.1(2)**<br>b. Using methods approved by the commission, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone. Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the commission may require; | | | |
| | NDAC § 43-05-01-05(1)(b)(3)(a)<br><br>NDAC § 43-05-01-05(1)(b)(3)(b)<br><br>NDAC § 43-05-01-05(1)(b)(3)(c) | **NDAC § 43-05-01-05(1)(b)(3)**<br>(a) A determination that all abandoned wells have been plugged and all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping from the storage reservoir;<br><br>**NDAC § 43-05-01-05(1)(b)(3)**<br>(b) A description of each well's type, construction, date drilled, location, depth, record of plugging, and completion;<br><br>**NDAC § 43-05-01-05(1)(b)(3)**<br>(c) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all underground sources of drinking water, water wells, and springs | h. A review of these wells must include the following:<br>(1) A determination that all abandoned wells have been plugged in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation;<br>(2) A determination that all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation;<br>(3) A description of each well:<br>a. Type<br>b Construction<br>c. Date drilled<br>d. Location<br>e. Depth | ***4.1.1 Written Description*** (4th paragraph, p. 4-1)<br>North Dakota geologic storage of $CO_2$ regulations require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water [USDW] may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of $CO_2$ and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase $CO_2$ plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the MAG 1 well (NDIC File No. 37833) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-5]).<br><br>NDAC § 43-05-01-05(1)(b)(3) requires "[a] review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate $CO_2$ injection activities and associated pressure front (Figure 4-1), the resulting AOR for the geologic storage project is delineated as being 1 mile from the SFP boundary. This extent ensures compliance with existing state regulations.<br><br>***4.1.2 Supporting Maps***<br>See Figure 4-2 on p. 4-4.<br><br>**4.2 Corrective Action Evaluation (p. 4-8)**<br>See Table 4-2 on p. 4-6, Table 4-3 on p. 4-7, Table 4-4 on p. 4-8, and Table 4-5 on p. 4-9. | **Figure 4-2.** AOR map in relation to nearby groundwater wells. Shown are the stabilized CO2 plume extent postinjection (dashed red boundary), storage facility area (dashed purple boundary), and 1-mile AOR (dashed black boundary). All groundwater wells in the AOR are identified above. All observation/monitoring wells shown are shallow groundwater wells associated with the mine activities. No springs are present in the AOR. (p. 4-4)<br><br>**Figure 3-20.** Final AOR in relation to nearby legacy wells. Shown is the storage facility area (purple polygon) and AOR (black polygon). Orange circles represent legacy oil and gas wells near |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | NDAC §§ 43-05-01-05(1)(b)(3)(d) and (e)<br><br>NDAC § 43-05-01-05(1)(b)(3)(f) | within the area of review, their positions relative to the injection zone; and the direction of water movement, where known;<br><br>**NDAC § 43-05-01-05(1)(b)(3)**<br>(d) Maps and cross sections of the area of review;<br><br>**NDAC § 43-05-01-05(1)(b)(3)**<br>(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;<br><br>**NDAC § 43-05-01-05(1)(b)(3)**<br>(f) A list of contacts, submitted to the commission, when the area of review extends across state jurisdiction boundary lines; | f. Record of plugging<br>g. Record of completion<br><br>(4) Maps and stratigraphic cross sections of all underground sources of drinking water within the area of review indicating the following:<br>a. Their positions relative to the injection zone<br>b. The direction of water movement, where known<br>c. General vertical and lateral limits<br>d. Water wells<br>e. Springs<br><br>(5) Map and cross sections of the area of review;<br><br>(6) A map of the area of review showing the following:<br>a. Number or name and location of all injection wells<br>b. Number or name and location of all producing wells<br>c. Number or name and location of all abandoned wells<br>d. Number of name and location of all plugged wells or dry holes<br>e. Number or name and location of all deep stratigraphic boreholes<br>f. Number or name and location of all state-approved or United States Environmental Protection Agency-approved subsurface cleanup sites<br>g. Name and location of all surface bodies of water | See Figure 4-3 on p. 4-10, Figure 4-4 on p. 4-11, and Figure 4-5 on p. 4-12.<br><br>**4.4 Protection of USDWs (Broom Creek Formation)** (p. 4-13)<br>Figure 4-9 on page 4-17 and Figure 4-10 on page 4-18 | the storage facility area. (p. 3-32)<br><br>**Table 4-2.** Wells in AOR Evaluated for Corrective Action (p. 4-6)<br><br>**Table 4-3.** Ellen Samuelson 1 (NDIC File No. 1516) Well Evaluation (p. 4-7)<br><br>**Table 4-4.** Well #1 (ND-UIC-106) Well Evaluation (p. 4-8)<br><br>**Table 4-5.** Wallace O. Gradin 1 (NDIC File No. 4810) Well Evaluation (p. 4-9)<br><br>**Figure 4-3** Ellen Samuelson 1 (NDIC File No. 1516) well schematic showing the location of cement plugs. (p. 4-9)<br><br>**Figure 4-4.** Well #1 (ND-UIC-106) well schematic. (p. 4-10)<br><br>**Figure 4-5.** Wallace O. Gradin 1 (NDIC File No. 4810) well schematic showing the location of cement plugs. (p. 4-12)<br><br>**Figure 4-9.** Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central McLean County (modified from Fischer, 2013). (p. 4-17)<br><br>**Figure 4-10.** Southwest to northeast cross section of the major aquifer layers in McLean County. The black dots on the inset map represent the locations of the |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | h. Name and location of all springs<br>i. Name and location of all mines (surface and subsurface)<br>j. Name and location of all quarries<br>k. Name and location of all water wells<br>l. Name and location of all other pertinent surface features<br>m. Name and location of all structures intended for human occupancy<br>n. Name and location of all state, county, or Indian country boundary lines<br>o. Name and location of all roads<br><br>(7)A list of contacts, submitted to the Commission, when the area of review extends across state jurisdiction boundary lines. | | six wells used to create the cross section. The wells are labeled with their designation at the top of the cross section. (p. 4-18) |
| | NDAC § 43-05-01-05(1)(b)(3)(g) | **NDAC § 43-05-01-05(1)(b)(3)** **(g)** Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review; and | i. Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review. | See Appendices A (p. A-1) and B (p. B-1) | N/A |
| **Required Plans** | NDAC § 43-05-01-05(1)(k) | **NDAC § 43-05-01-05(1)** k. The storage operator shall comply with the financial responsibility requirements pursuant to section 43-05-01-9.1; | a. Financial Assurance Demonstration | **12.2 Financial Instruments** (pp. 12-1 and p. 12-2)<br>Blue Flint is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments:<br>• Blue Flint will increase the existing MAG 1 well bond to cover the costs of plugging the injection well in accordance with NDAC § 43-05-01-11.5.<br>• Blue Flint will establish a bond, escrow account or other financial instrument to implement PISC and facility closure activities in accordance with NDAC § 43-05-01-19.<br>• A third-party pollution liability insurance policy with an aggregate limit of $9 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13. | **Table 12-1.** Cost estimates for Activities to Be Covered (p. 12-2) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | The estimated total costs of these activities are presented in Table 12-1. Section 12.2 of this FADP provides additional details of the financial responsibility cost estimates for each activity. | |
| | NDAC § 43-05-01-05(1)(d) | **NDAC § 43-05-01-05(1)(d)**<br>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)<br>Blue Flint Sequester Company LLC (Blue Flint) and Blue Flint Ethanol LLC, operator of the Blue Flint Ethanol (BFE) facility, will enter into an agreement whereby Blue Flint employees, contractors and agents are required to follow the BFE facility emergency action plans, including, but not limited to, the BFE facility response plan. This emergency and remedial response plan (ERRP) for the geologic storage project 1) describes the local resources and infrastructure in proximity to the project site; 2) identifies events that have the potential to endanger USDWs during the construction, operation, and postinjection site care periods of the geologic storage project, building upon the screening-level risk assessment (SLRA); and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing BFE facility response plan and risk management plan (and incorporated into the BFE Integrated Contingency Plan [ICP]) is described, emphasizing the facility response team and command structure, facility evacuation plans, HazMat (hazardous materials) capabilities, and emergency communication plans. Lastly, procedures are presented for regularly conducting an evaluation of the adequacy of the ERRP and updating it, if warranted, over the lifetime of the geologic storage project. Copies of this ERRP are available at the Blue Flint's office and the BFE facility.<br><br>Note: Refer to the following key tables: Table 7-4 on p. 7-5 and Table 7-5 on p. 7-6 through 7-8 | **Table 7-4**. Potential Project Emergency Events and Their Detection (p. 7-5)<br><br>**Table 7-5.** Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (pp. 7-6 through 7-8) |
| | NDAC § 43-05-01-05(1)(e) | **NDAC § 43-05-01-05(1)**<br>e. A detailed worker safety plan that addresses carbon dioxide safety training and safe working procedures at the storage facility pursuant to section 43-05-01-13; | c. A detailed worker safety plan that addresses the following:<br>i. Carbon dioxide safety training<br>ii. Safe working procedures at the storage facility; | **8.0 WORKER SAFETY PLAN** (p. 8-1) | N/A |
| | NDAC § 43-05-01-05(1)(f) | **NDAC § 43-05-01-05(1)**<br>f. A corrosion monitoring and prevention plan for all wells and surface facilities pursuant to section 43-05-01-15; | d A corrosion monitoring and prevention plan for all wells and surface facilities; | **5.3 Flowline Corrosion Prevention and Detection Plan (p. 5-5)**<br>The purpose of this corrosion prevention and detection plan is to monitor the flowline and well materials during the operational phase of the project to ensure that all materials meet the minimum standards for material strength and performance.<br><br>**5.3.1 Corrosion Prevention (p. 5-5)**<br>The chemical composition of the $CO_2$ stream is highly pure and dry (Table 5-2), and the target moisture level for the $CO_2$ stream is estimated to be up to 12 ppm by volume. These factors help to prevent corrosion of the surface facilities. In addition, the flowline construction materials will be $CO_2$-resistant in accordance with API 17J (2017) requirements. The flowline will be constructed using FlexSteel, a 3-layer flexible steel pipe product. The inner and outer layers contain a $CO_2$-resistant polyethylene liner, and the middle layer comprises reinforcing steel. FlexSteel product specifications can be found in Appendix C (Attachment A-3).<br><br>**5.3.2 Corrosion Detection (p. 5-5)**<br>The flowline will use the corrosion coupon method to monitor for corrosion throughout the operational phase of the project, focusing on the loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. A coupon sample port will be located near the liquefaction outlet, and sampling will occur quarterly during the first year of injection and once a year thereafter. The process that will be used to conduct each coupon test is described in Appendix C under Section 1.3.<br><br>**5.6 Wellbore Corrosion Prevention and Detection Plan (p. 5-9)**<br>To prevent corrosion of the well materials, the following preemptive measures will be implemented in the MAG 1 and MAG 2 wellbores: 1) cement in the injection well opposite the injection interval and extending 1850 feet uphole will be $CO_2$-resistant; 2) the well casing will also be $CO_2$-resistant from the bottomhole to a depth just above the Spearfish Formation (upper confining zone); 3) the well tubing (poly-lined) will be $CO_2$-resistant from the injection interval to surface; 4) the packer (Ni-Plated) will be $CO_2$-resistant; and 5) the packer fluid will be an industry standard corrosion inhibitor.<br><br>To detect possible signs of corrosion in the MAG 1 and MAG 2, corrosion coupon samples will be used which will be constructed from the well materials. The corrosion coupon method is described in Section 5.3.2 of this testing and monitoring plan. In addition, the USIT or an equivalent wall thickness or imaging tool (e.g., EMCIL) may also be considered for detecting corrosion in the MAG 1 and MAG 2 wellbores. The USIT (or equivalent tool) may be used during workovers but no less than every 5 years. | **Figure 5-1.** Site map showing the surface facilities layout for the Blue Flint CO2 Storage Project (p. 5-3)<br><br>**Figure 5-2.** Diagram of surface connections and major components of the CCS system from the liquefaction outlet to the MAG 1 wellsite (p. 5-4)<br><br>**Table 5-2.** Chemical Content of the CO2 Stream (p. 5-3) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | **Table 5-2. Chemical Content of the captured $CO_2$**<br>**Chemical Content** — **Volume %**<br>Carbon Dioxide — 99.98<br>Water, Oxygen, Nitrogen, Hydrogen Sulfide, $C_2^+$, and Hydrocarbons — Trace amounts of each (0.02 total)<br>Total — 100.00 | |
| | NDAC § 43-05-01-05(1)(g) | **NDAC § 43-05-01-05(1)**<br>g. A leak detection and monitoring plan for all wells and surface facilities pursuant to section 43-05-01-14. The plan must:<br>(1) Identify the potential for release to the atmosphere;<br>(2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and<br>(3) Identify potential migration of carbon dioxide into any mineral zone in the facility area | e. A surface leak detection and monitoring plan for all wells and surface facilities pursuant to NDAC § 43-05-01-14; | **5.2 Surface Facilities Leak Detection Plan** (p. 5-3)<br>The purpose of this leak detection plan is to monitor the surface facilities from the liquefaction outlet to the injection wellsite during the operational phase of the Blue Flint $CO_2$ storage project.<br><br>Surface components of the injection system, including the flowline and $CO_2$ injection wellhead, will be monitored with leak detection equipment. The flowline will be monitored continuously via dual flowmeters located at the liquefaction outlet and near the wellhead for performing mass balance calculations. The flowline will also be regularly inspected for any visual or auditory signs of equipment failure and monitored continuously with one pressure gauge at the capture facility outlet and one at the wellhead. $CO_2$ detection stations will be located on the flowline risers and the $CO_2$ injection wellhead. The leak detection equipment will be integrated with automated warning systems that notify Blue Flint's operations center, giving the operator the ability to remotely close the valves in the event of an anomalous reading.<br><br>Performance targets designed for the Blue Flint $CO_2$ storage project to detect potential leaks in the flowline are provided in Table 5-3. The performance targets are dependent upon the actual performance of instrumentation (e.g., pressure gauges) and the SCADA system (described further in Attachment A-1 of Appendix C), which uses software to track the status of the flowline in real time by comparing live pressure and flow rate data to a comprehensive predictive model. The performance targets assume a flow rate of approximately 550 metric tons of $CO_2$ per day. An alarm will trigger on the SCADA system if a volume deviation of more than 1% is registered.<br><br>$CO_2$ detection stations will be mounted on the inside of the wellhead enclosures to detect any potential indoor leaks. An additional $CO_2$ detection station will be mounted outside the injection wellhead enclosure to detect any potential atmospheric leaks at the wellsite. The stations can detect $CO_2$ concentrations as low as 2% by volume and have an integrated alarm system for increases of from 0% to 0.4% and 0.4% to 0.8% by volume. The stations are further described in Appendix C (Attachment A-2).<br><br>Field personnel will have multigas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multigas detectors will primarily monitor $CO_2$ levels in workspace atmospheres.<br><br>Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be made available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC. | N/A |
| | NDAC § 43-05-01-05(1)(h) | **NDAC § 43-05-01-05(1)**<br>h. A leak detection and monitoring plan to monitor any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile [1.61 kilometers] of the facility area's | f. A subsurface leak detection and monitoring plan to monitor for any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile of the facility area's outside boundary; | **5.7 Environmental Monitoring Plan** (p. 5-9, paragraphs 1, 3, and 4)<br>To verify the injected $CO_2$ is contained in the storage reservoir and to protect all USDWs, multiple environments will be monitored.<br><br>The deep subsurface environment, defined as the region from below the lowest USDW to the base of the storage reservoir, will be monitored with multiple methods, starting with the above-zone monitoring interval (AZMI) or the geologic interval from the Spearfish Formation to the Inyan Kara Formation. The AZMI will be monitored with DTS in the MAG 1 and MAG 2 as well as PNLs in the MAG 2 (further described in Attachment A-5 of Appendix C).<br><br>The storage reservoir will be monitored with both direct and indirect methods. Direct methods include DTS and BHP/T measurements in the MAG 1 and MAG 2, as well as PNLs in the MAG 2. Indirect methods include time-lapse seismic and passive seismicity. During injection operations, pressure falloff testing to demonstrate storage reservoir injectivity in the MAG 1 wellbore will be carried out at least once every 5 years. These efforts will provide additional assurance that surface and near-surface environments are protected and that the injected $CO_2$ is safely and permanently stored in the storage reservoir. | |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | outside boundary. Provisions in the plan will be dictated by the site characteristics as documented by materials submitted in support of the permit application but must:<br><br>(1) Identify the potential for release to the atmosphere;<br><br>(2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and<br><br>(3) Identify potential migration of carbon dioxide into any mineral zone in the facility area. | | ***5.7.3 Deep Subsurface Monitoring*** (p. 5-15)<br>Blue Flint will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase $CO_2$ plume and associated pressure relative to the permitted storage reservoir. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and postoperational periods. The methods described in Table 5-6 will be used to characterize the $CO_2$ plume's saturation and pressure within the AOR.<br><br>Blue Flint will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan (Ayash and others, 2017) at least once every 5 years. During each review, monitoring and operational data will be analyzed, and the AOR will be reevaluated. Based on this reevaluation, it will either be demonstrated that 1) no amendment to the testing and monitoring program is needed or 2) modifications are necessary to ensure proper monitoring of storage performance is achieved moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.<br><br>Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the $CO_2$ plume and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will, in turn, be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected $CO_2$ within the permitted geologic storage facility. | |
| | NDAC § 43-05-01-05(1)(f) | **NDAC § 43-05-01-05(1)**<br>f. 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**<br><br>Note: See Table 5-1 on p. 5-2; Table 5-4 on p. 5-7; Table 5-5 on pp. 5-8 through 5-9; and Table 5-6 on pp. 5-10 through 5-11, for detailed summaries of the testing and monitoring plan. | **Table 5-1.** Overview of Blue Flint's Testing and Monitoring Plan (p. 5-2)<br><br>**Table 5-4.** Overview of Blue Flint's Mechanical Integrity Testing Plan (p. 5-7)<br><br>**Table 5-5.** Testing and Logging Plan for the MAG 1 Wellbore (pp. 5-8 through 5-9)<br><br>**Table 5-6.** Summary of Environmental Baseline and Operational Monitoring (pp. 5-10 through 5-11) |
| | NDAC § 43-05-01-05(1)(i) | **NDAC § 43-05-01-05(1)**<br>i. The proposed well casing and cementing program detailing compliance with section 43-05-01-09; | h. The proposed well casing and cementing program, | **9.0 WELL CASING AND CEMENTING PROGRAM** (p. 9-1) | **Figure 9-1.** MAG 1 as-constructed wellbore schematic. Note: top of cement (TOC), workover (WO). (p. 9-2)<br><br>**Figure 9-2.** MAG 1 Proposed wellbore schematic as CO2 injector. (p. 9-3)<br><br>**Figure 9-3.** Monitor Well MAG 2 proposed wellbore schematic. (p. 9-7) |

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application<br>(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description<br>(Page Number)</th></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(m)</td><td>NDAC § 43-05-01-05(1)<br>m. A plugging plan that meets requirements pursuant to section 43-05-01-11.5;</td><td>i. A plugging plan;</td><td>10.1 MAG 1: P&A Program (p. 10-1)<br><br>10.2 MAG 2 P&A Program (p. 10-7)</td><td>Figure 10-1. Proposed CO2 injection well schematic for MAG 1. (p. 10-2)<br><br>Figure 10-2. Schematic of proposed P&A plan for MAG 1. (p. 10-6)<br><br>Figure 10-3. Proposed monitoring wellbore schematic for MAG 2. (p. 10-7)<br><br>Figure 10-4. Schematic of proposed abandonment plan for monitoring well MAG 2 (p. 10-11)</td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(n)</td><td>NDAC § 43-05-01-05(1)<br>n. A postinjection site care and facility closure plan pursuant to section 43-05-01-19; and</td><td>j. A post-injection site care and facility closure plan.</td><td>6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN (p. 6-1)<br><br>Note: Refer to Tables 6-1 on p. 6-4, and 6-2 on p. 6-5 for a summary of the postinjection site care monitoring plan.</td><td>Table 6-1. Overview of Blue Flint's PISC MAG 2 Mechanical Integrity Testing and Corrosion Monitoring Plan (p. 6-4)<br><br>Table 6-2. Overview of Blue Flint's PISC Environmental Monitoring Plan. (p. 6-5)</td></tr>
<tr><td rowspan="2">Storage Facility Operations</td><td>NDAC § 43-05-01-05(1)(b)(4)</td><td>NDAC § 43-05-01-05(1)(b)<br>(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;</td><td>The following items are required as part of the storage facility permit application:<br><br>a. The proposed average and maximum daily injection rates;</td><td rowspan="2">11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)<br>This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.<br><br>Table 11-1. Proposed Injection Well Operating Parameters
<table>
<tr><th>Item</th><th>Values</th><th>Description/Comments</th></tr>
<tr><td colspan="3">Injected Volume</td></tr>
<tr><td>Total Injected Volume</td><td>4,000,000 tonnes</td><td>Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day</td></tr>
<tr><td>Injection Rates</td><td></td><td></td></tr>
<tr><td>Average Injection Rate</td><td>548 tonnes/day<br>(10.35 MMscf/day)</td><td>Based on 200,000 tonnes/year for 20 years of injection (using 365 operating days per year)</td></tr>
<tr><td>Average Maximum Daily Injection Rate</td><td>2,729 tonnes/day<br>(51.56 MMscf/day)</td><td>Based on maximum bottomhole injection pressure (2,970 psi)</td></tr>
</table></td><td>Table 11.1. Proposed Injection Well Operating Parameters<br>(p. 11-1)</td></tr>
<tr><td></td><td></td><td>b. The proposed average and maximum daily injection volume;<br>c. The proposed total anticipated volume of the carbon dioxide to be stored;</td><td></td></tr>
</table>

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application<br>(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description<br>(Page Number)</th></tr>
<tr><td rowspan="2"></td><td rowspan="2">NDAC § 43-05-01-05(1)(b)(5)</td><td rowspan="2">NDAC § 43-05-01-05(1)(b)<br>(5) The proposed average and maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in pounds per square inch gauge, shall be approved by the commission and specified in the permit. In approving a maximum injection pressure limit, the commission shall consider the results of well tests and other studies that assess the risks of tensile failure and shear failure. The commission shall approve limits that, with a reasonable degree of certainty, will avoid initiating a new fracture or propagating an existing fracture in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water;</td><td>d. The proposed average and maximum bottom hole injection pressure to be utilized;</td><td rowspan="2">
<table>
<tr><th>Pressures</th><th></th><th></th></tr>
<tr><td>Formation Fracture Pressure at Top Perforation</td><td>3,300 psi</td><td>Based on geomechanical analysis of formation fracture gradient as 0.69 psi/ft (see Section 2.0)</td></tr>
<tr><td>Average Surface Injection Pressure</td><td>1,158 psi</td><td>Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day) using the designed 2.875-inch tubing</td></tr>
<tr><td>Surface Maximum Injection Pressure</td><td>4,300 psi</td><td>Based on maximum bottomhole injection pressure (2,970 psi) using the designed 2.875-inch tubing</td></tr>
<tr><td>Average Bottomhole Pressure (BHP)</td><td>2,570 psi</td><td>Based on average daily injection rate of 548 tonnes/day</td></tr>
<tr><td>Calculated Maximum BHP</td><td>2,970 psi</td><td>Based on 90% of the formation fracture pressure of 3,300 psi</td></tr>
</table>
</td><td rowspan="2"></td></tr>
<tr><td>e. The proposed average and maximum surface injection pressures to be utilized;</td></tr>
<tr><td rowspan="2"></td><td rowspan="2">NDAC § 43-05-01-05(1)(b)(6)</td><td rowspan="2">NDAC § 43-05-01-05(1)(b)<br>(6) The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone pursuant to section 43-05-01-11.2;</td><td>f. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone;</td><td rowspan="2">5.5 Well Testing and Logging Plan (p. 5-7)<br>Table 5-5 describes the testing and logging plan developed for the MAG 1 wellbore (exclusive of any coring) to establish baseline conditions. Included in the table is a description of fluid sampling and pressure testing performed. The logging and testing plan for the MAG 2 wellbore will be the same as what is presented in Table 5-5, with the addition of a PNL but excluding dipole, elemental capture spectroscopy (ECS), fluid swab, and FMI. Table 5-4 and Table 5-6 (see Section 5.7) detail the frequency with which logging data will be acquired and in which wellbores throughout the operational period of the project.<br>See Appendix A: MAG 1 FORMATION FLUID SAMPLING<br><br>2.0 GEOLOGIC EXHIBITS<br>2.2 Data and Information Services (p. 2-4)<br>Several sets of data were used to characterize the injection and confining zones to establish their suitability for the storage and containment of injected $CO_2$. Data sets used for characterization included both existing data (e.g., from published literature, publicly available databases, private data from brokers) and site-specific data acquired specifically to characterize the storage complex.<br><br>2.2.2 Site-Specific Data (p. 2-6)<br>Site-specific efforts to characterize the proposed storage complex generated multiple data sets, including geophysical well logs, petrophysical data, and 3D seismic data. The MAG 1 well was drilled in 2020 specifically to gather subsurface geologic data to support the development of a $CO_2$ storage facility permit and serve as a future $CO_2$ injection well. Downhole logs were acquired, and sidewall core (SW Core) was collected from the proposed storage complex (i.e., the Lower Piper, Spearfish, Broom Creek, and Amsden Formations) at the time the well was drilled (Figure 2-5). In May 2022, fluid samples and temperature and pressure measurements were collected from the Broom Creek in the MAG 1 well.<br><br>2.2.2.2 Core Sample Analyses (p. 2-8)<br>Fifty 1.5" SW Core samples were recovered from the Broom Creek storage complex in MAG 1: five samples from the lower Piper Formation, twelve from the Spearfish Formation, twenty-three from the Broom Creek Formation, and ten from the Amsden Formation. Forty-two of the SW Core samples were analyzed to determine petrophysical properties. This core was analyzed to characterize the lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations and correlated to the well log data. Core analysis also</td><td rowspan="2">Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore (p. 5-8 through 5-9)</td></tr>
<tr><td>g. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the confining zone;</td></tr>
</table>

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), thin-section analysis, and capillary entry pressure measurements. The results were used to inform geologic modeling and predictive simulation inputs and assumptions. | |

**Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore**

| OH/CH* Depth, ft | Logging/Testing | Justification | NDAC § 43-05-01 |
|---|---|---|---|
| | | **Surface Section** | |
| OH 1340-0 | Triple combo (resistivity, bulk density, density and neutron porosity, GR, caliper, and spontaneous potential [SP]) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume | 11.2(1)(b)(1) |
| CH 1260-0 | Ultrasonic, casing collar locator (CCL), variable-density log (VDL), GR, and temperature log | Identified cement bond quality radially. Interpreted minor cement channeling throughout several isolated intervals and determined good azimuthal cement coverage and zonal isolation. | 11.2(1)(b)(2) |
| | | **Intermediate Section** | |
| OH 4170-1334 | Triple Combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for enhanced geomodeling and predictive simulation of $CO_2$ injection into the interest zones to improve test design and interpretations. Generated core-log correlations. | 11.2(1)(c)(1) |
| OH 4170-1334 | Dipole sonic | Identified mechanical properties in intermediate section. | 11.2(1)(c)(1) |
| OH 4170-3070 | Dielectric scanner | Quantified petrophysical properties and salinity calculations within the intermediate zones (Inyan Kara Formation). Provided information on rock properties and fluid distribution as inputs for reservoir evaluation and management. | 11.2(4) |
| CH 4070-30 | Ultrasonic, CCL, VDL, GR, and temperature log | Identified cement bond quality radially. Interpreted good azimuthal cement coverage and casing condition. Evaluated the cement top and zonal isolation. | 11.2(1)(c)(2) |

* OH/CH – openhole/cased-hole

**Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore (continued)**

| OH/CH Depth, ft | Logging/Testing | Justification | NDAC Code § 43-05-01 |
|---|---|---|---|
| | | **Long-string Section** | |
| OH 7068-4163 | Triple combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. | 11.2(1)(c)(1) |
| OH 7556-4163 | Dipole sonic | Identified mechanical properties of the rock including stress anisotropy. Provided compression | 11.2(1)(c)(1) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | and shear waves for seismic tie in and quantitative analysis of seismic data.<br><br>OH 5250-4250 \| Fullbore FMI \| Verified no fracture networks exist in the Broom Creek Formation or confining layers to ensure safe storage of $CO_2$. \| 11.2(1)(e)(1)<br>OH 4741 and 4735 \| BHP/T survey \| Measured Broom Creek Formation pressure and temperature in the wellbore. \| 11.2(2)<br>OH 4740-4733 \| Fluid swab \| Collected fluid sample from the Broom Creek Formation for analysis. \| 11.2(2)<br>CH** TBD \| Ultrasonic, CCL, VDL, and GR \| Will identify cement bond quality radially and determine azimuthal cement coverage. Will evaluate the cement top and zonal isolation. \| 11.2(1)(b)(2)<br>** Planned activity at the time of writing this permit to be completed prior to injection. | |
| | NDAC § 43-05-01-05(1)(b)(7) | **NDAC § 43-05-01-05(1)(b)**<br>(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:<br>1. A description of the stimulation fluids to be used<br>2. A determination of the probability that stimulation will interfere with containment; | **11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)**<br>This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.<br><br>**11.1 MAG 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-1)**<br>As described in Section 9.1, the MAG 1 well will be reentered and completed as a CO2 injector (Figures 11-1 and 11-2 and Tables 11-2 through 11-4). The following proposed completion procedure outlines the steps necessary to complete and test the well.<br><br>Note: See full procedure provided on pp. 11-1 through 11-3. | N/A |
| | NDAC § 43-05-01-05(1)(b)(8) | **NDAC § 43-05-01-05(1)(b)**<br>(8) The proposed procedure to outline steps necessary to conduct injection operations. | i. Steps to begin injection operations | **11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)**<br>This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.<br><br>**11.1 MAG 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-1)**<br><br>Note: See full procedure provided on pp. 11-1 through 11-3. | N/A |

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
DATE 3/21/23 CASE NO. 29888-90
Introduced By Blue Flint
Exhibit 2
Identified By Dunlop

**EXHIBIT 2**

**CASES 29888, 29889, AND 29890**

Blue Flint Sequester Company, LLC
Summary of Pore Space Leases

| Tract No. | Land Description | Owner Name | Tract Net Acres | Tract Participation | Storage Facility Participation | Acreage Leased |
|---|---|---|---|---|---|---|
| 1 | Section 6-T145N-R82W | The Falkirk Mining Company | 318.770 | 100.00000000% | 6.43497500% | 318.770 |
| | | **Tract Total:** | **318.770** | **100.00000000%** | | |
| 2 | Section 8-T145N-R82W | Rainbow Energy Center, LLC | 590.730 | 92.30156250% | 11.92500167% | 590.730 |
| | | Great River Energy | 49.270 | 7.69843750% | 0.99460808% | 0.000 |
| | | **Tract Total:** | **640.000** | **100.00000000%** | | |
| 3 | Section 7-T145N-R82W | The Falkirk Mining Company | 558.760 | 87.56895687% | 11.27962678% | 558.760 |
| | | Mary Schafer Conlon | 19.830 | 3.10776078% | 0.40030603% | 19.830 |
| | | Macy J. Schafer | 19.830 | 3.10776078% | 0.40030603% | 19.830 |
| | | Monty R. Schafer | 19.830 | 3.10776078% | 0.40030603% | 19.830 |
| | | Marty J. Schafer | 19.830 | 3.10776078% | 0.40030603% | 19.830 |
| | | **Tract Total:** | **638.080** | **100.00000000%** | | |
| 4 | Section 12-T145N-R83W | The Falkirk Mining Company | 420.000 | 65.62500000% | 8.47849390% | 420.000 |
| | | Curtis Schafer | 200.000 | 31.25000000% | 4.03737805% | 0.000 |
| | | Estate of Edna B. Schafer | 5.000 | 0.78125000% | 0.10093445% | 0.000 |
| | | Rodney C. Schafer | 5.000 | 0.78125000% | 0.10093445% | 0.000 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | Ervin R. Schafer Revocable Trust | 5.000 | 0.78125000% | 0.10093445% | 0.000 |
| | | Dale J. Schafer | 5.000 | 0.78125000% | 0.10093445% | 0.000 |
| | | **Tract Total:** | **640.000** | **100.00000000%** | | |
| 5 | Section 11-T145N-R83W | The Falkirk Mining Company | 160.000 | 100.00000000% | 3.22990244% | 160.000 |
| | | **Tract Total:** | **160.000** | **100.00000000%** | | |
| 6 | Section 14-T145N-R83W | The Falkirk Mining Company | 160.000 | 100.00000000% | 3.22990244% | 160.000 |
| | | **Tract Total:** | **160.000** | **100.00000000%** | | |
| 7 | Section 13-T145N-R83W | The Falkirk Mining Company | 640.000 | 100.00000000% | 12.91960975% | 640.000 |
| | | **Tract Total:** | **640.000** | **100.00000000%** | | |
| 8 | Section 18-T145N-R82W | The Falkirk Mining Company | 477.600 | 74.90589711% | 9.64125877% | 477.600 |
| | | Janice Berget | 40.000 | 6.27352572% | 0.80747561% | 0.000 |
| | | Michael Johnson | 60.000 | 9.41028858% | 1.21121341% | 0.000 |
| | | Chad Stevahn | 16.667 | 2.61396905% | 0.33644817% | 0.000 |
| | | Tammy Stevahn | 16.667 | 2.61396905% | 0.33644817% | 0.000 |
| | | Michelle Albrecht | 16.667 | 2.61396905% | 0.33644817% | 0.000 |
| | | Brandy Schmidt | 3.333 | 0.52279381% | 0.06728963% | 0.000 |
| | | Kevin L. Johnson | 3.333 | 0.52279381% | 0.06728963% | 0.000 |
| | | Keith Johnson | 3.333 | 0.52279381% | 0.06728963% | 0.000 |
| | | **Tract Total:** | **637.600** | **100.00000000%** | | |
| 9 | Section 17-T145N-R82W | Rainbow Energy Center, LLC | 552.000 | 86.25000000% | 11.14316341% | 552.000 |
| | | Blue Flint Ethanol LLC | 49.460 | 7.72812500% | 0.99844359% | 49.460 |
| | | Nexus Line, LLC | 38.540 | 6.02187500% | 0.77800275% | 38.540 |
| | | **Tract Total:** | **640.000** | **100.00000000%** | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 10 | Section 19-T145N-R82W | The Falkirk Mining Company | 319.260 | 100.00000000% | 6.44486657% | | 319.260 |
| | | **Tract Total:** | **319.260** | **100.00000000%** | | | |
| 11 | Section 24-T145N-R83W | The Falkirk Mining Company | 160.000 | 100.00000000% | 3.22990244% | | 160.000 |
| | | **Tract Total:** | **160.000** | **100.00000000%** | | | |
| | | **Total Acres:** | **4953.710** | **Total Participation:** | **100.00000000%** | **Percentage Leased:** | **91.33437363%** |

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
DATE 3/21/23 CASE NO. 29888-90
Introduced By Blue Flint
Exhibit 3
Identified By Hunt

# EXHIBIT 3

## CASES 29888, 29889, & 29890

Blue Flint Sequester Company, LLC

**Summary of Blue Flint's Testing and Monitoring Plan**

| SFP Reference | Monitoring Type | | Parameter | Activity Description | Sampling Location/Equipment | Sampling Frequency: Preinjection | Sampling Frequency: Injection (20 years) | Sampling Frequency: Postinjection (10 years minimum) | Primary Purpose(s) of Activity |
|---|---|---|---|---|---|---|---|---|---|
| 5.1 | $CO_2$ Stream Analysis | | Volume/mass<br>Flow rate<br>Pressure<br>Temperature | Real-time, continuous data recording via Supervisory Control and Data Acquisition (SCADA) system | Mass flowmeter near the injection wellhead<br>Surface pressure/temperature (P/T) gauges | None | Continuous | None | $CO_2$ accounting and operational safety assurance |
| | | | Composition | $CO_2$ stream sampling | Sample port near injection wellhead | At least once | Quarterly | None | $CO_2$ accounting and assurance of stream compatibility with project materials in contact with $CO_2$ |
| 5.2 | Surface Facilities Leak Detection Plan | | Mass balance | Real-time, continuous data recording via SCADA system and remote-controlled shutoff devices | Dual P/T gauges and flowmeters placed at the liquefaction outlet and near the injection wellhead | None | Continuous | None | $CO_2$ accounting, leak detection, and operational safety assurance |
| | | | $CO_2$ concentrations | Real-time, continuous data recording via SCADA system | $CO_2$ detection stations placed on injection wellhead, flowline risers, and inside and outside enclosures | None | Continuous | None | |
| 5.3.2 and 5.6 | $CO_2$ Flowline and Wellbore Corrosion Detection Plan | | Mass/thickness loss<br>Pitting<br>Cracking | Corrosion coupon testing | Corrosion coupon sample port near the liquefaction outlet | None | Quarterly in Year 1 and annually thereafter | None | Corrosion detection of project materials in contact with $CO_2$ and operational safety assurance |
| 5.4 and Table 5-4<br><br>6.2 and Table 6-1 | Wellbore Mechanical Integrity Testing (external) | | Material wall thickness (casing)<br>Radial cement bond | Ultrasonic logging (or alternative casing inspection logging (CIL) method) | MAG 1 and MAG 2 | Once per well | During workovers but no less than once every 5 years | During workovers but no less than once every 5 years (MAG 2 only) | Mechanical integrity confirmation and operational safety assurance |
| | | | Temperature profile | Real-time, continuous data recording via SCADA system | Distributed temperature sensing (DTS) fiber in MAG 1 and MAG 2 | Install at well completion | Continuous | Continuous (MAG 2) | |
| | | | Temperature profile | Temperature logging | MAG 1 and MAG 2 | Once per well | Annually (backup if DTS fails) | Annually (backup if DTS fails) | |
| | Wellbore Mechanical Integrity Testing (internal) | | Pressure/temperature | Tubing-casing annulus pressure testing | MAG 1 and MAG 2 | Once per well | During workovers but no less than once every 5 years | During workovers but no less than once every 5 years (MAG 2) | |
| | | | | Real-time, continuous data recording via SCADA system | Surface and tubing-conveyed P/T gauges in MAG 1 and MAG 2 | Install at well completion | Continuous | Continuous (MAG 2) | |
| | | | Material wall thickness (tubing) | Ultrasonic logging (or alternative CIL method) | MAG 1 and MAG 2 | Once per well | During workovers but no less than once every 5 years | During workovers but no less than once every 5 years (MAG 2) | |
| 5.7.1 and Table 5-6 | Atmosphere Monitoring | Ambient | Ambient air conditions | Sample blanks from soil gas sampling | Probe locations SG-1–SG-5 and permanent stations SGPS 1 and SGPS 2 | Sample 3–4 events at SG-1–SG-5 | Sample 3–4 events per year at SGPS 1 and SGPS 2 | None | Leak detection and worker safety |
| | | Workplace | $CO_2$ concentrations | Real-time, continuous data recording via SCADA system | $CO_2$ detection stations placed inside and outside enclosures | None | Continuous | None | |
| 5.7.2 and Table 5-6<br><br>6.2.1 and Table 6-2 | Near-Surface Monitoring | Soil Gas | Soil gas composition (e.g., $CO_2$, $N_2$, and $O_2$) | Soil gas sampling | Probe locations SG-1–SG-5 and permanent stations SGPS 1 and SGPS 2 | 3–4 seasonal samples per probe (SG-1–SG-5) | 3–4 seasonal samples per station (SGPS 1 and SGPS 2) | Sample SGPS 1 prior to MAG 1 reclamation. Sample SGPS 2 annually until facility closure. Sample probe locations at postinjection start and before facility closure | Protection of near-surface environments |
| | | | Soil gas isotopes | | | | | | Source attribution |
| | | Groundwater | Water composition (e.g., pH, total dissolved solids [TDS], and conductivity) | Existing shallow groundwater well sampling | Up to five groundwater well locations (shown in Figure 5-5) | 3–4 seasonal samples per well | At start of injection, shift sampling program to dedicated Fox Hills monitoring well location near MAG 1 | Sampling may be performed on active and accessible shallow groundwater wells in the area of review (AOR) prior to site closure | Protection of underground sources of drinking water (USDWs) |
| | | | Water isotopes | | | | | | Source attribution |
| | | | Water composition (same as above) | Fox Hills Aquifer sampling | Dedicated Fox Hills monitoring well near MAG 1 | 3–4 seasonal samples | 3–4 seasonal samples annually | Annually until facility closure | Protection of USDWs |
| | | | Water isotopes | | | | | | Source attribution |

Continued…

**Summary of Blue Flint's Testing and Monitoring Plan (continued)**

| SFP Reference | Monitoring Type | | Parameter | Activity Description | Sampling Location/Equipment | Sampling Frequency | | | Primary Purpose(s) of Activity |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Preinjection | Injection (20 years) | Postinjection (10 years minimum) | |
| 5.7.3 and Table 5-6<br>6.2.1 and Table 6-2 | Deep Subsurface Monitoring | Above-Zone Monitoring Interval | Temperature profile (from Spearfish through Inyan Kara) | Real-time, continuous data recording via SCADA system | DTS fiber optics in MAG 1 and MAG 2 | Install at well completion | Continuous | Continuous (MAG 2) | Assurance of containment in the storage reservoir |
| | | | Saturation profile (from Spearfish through Inyan Kara) | Pulsed-neutron logging | MAG 2 | Once per well | Year 4 and every 5 years thereafter (Year 9, Year 14, and Year 19) | Annually until full $CO_2$ saturation reached; once every 4 years thereafter (MAG 2) | |
| | | Storage Reservoir (direct) | Temperature profile (from Amsden through Spearfish) | Real-time, continuous data recording via SCADA system | DTS fiber optics in MAG 1 and MAG 2 | Install at well completion | Continuous | Continuous (MAG 2) | Determination of storage reservoir performance |
| | | | Saturation profile (from Amsden through Spearfish) | Pulsed-neutron logging | MAG 2 | Once per well | Year 4 and every 5 years thereafter (Year 9, Year 14, and Year 19) | Annually until full $CO_2$ saturation reached; once every 4 years thereafter (MAG 2) | |
| | | | Pressure/temperature | Real-time, continuous data recording via SCADA system | Tubing-conveyed P/T gauge in MAG 1 and MAG 2 to monitor the Broom Creek | Install at well completion | Continuous | Continuous (MAG 2) | $CO_2$ pressure front tracking to ensure conformance with model and simulation projections |
| | | | Injectivity | Pressure falloff testing | MAG 1 | Once in MAG 1 | Once every 5 years in MAG 1 | None | Assurance of storage reservoir performance |
| | | Storage Reservoir (indirect) | $CO_2$ saturation | Vertical seismic profiles | $CO_2$ plume extents | May collect baseline | To be determined | To be determined | $CO_2$ plume tracking to ensure conformance with model and simulation projections |
| | | | | Time-lapse 2D seismic surveys | $CO_2$ plume extents (see Figure 5-6) | Collect baseline | Repeat 2D seismic survey in Year 1 and Year 4. At Year 4, reevaluate frequency based on plume growth and seismic results. | To be determined | |
| | | | Seismicity | Real-time, continuous data recording | U.S. Geological Survey's (USGS's) existing network | Utilize USGS existing network | Utilize USGS existing network and supplement with additional equipment as necessary | None | Seismic event detection and operational safety assurance |

March 21, 2023

To: North Dakota Industrial Commision

From: Steven Heger
2896 3rd St NW

Underwood, ND 58576

701-220-0116

Hegfarms@westriv.com

Dear North Dakota Industrial Commision,

My concern today is specifically with Sec 38-22-07 of the Carbon Dioxide Underground Storage Rules. The rules state that the applicant is required to get 60% consent of the pore space owners to go forward with the project. This rule was written in good faith, but as it relates to this project it falls short of the original intent. Looking at the proposed Hearing Notification Area for this project, the land ownership as follows:

Falkirk Mine: 56%

Rainbow Energy/Midwest Ag: 23%

Private Landowner: 21%

When you look specifically at the actual Projected Storage Area the breakdown is:
Falkirk Mine: 64%

Rainbow Energy/Midwest Ag: 26%

Private Landowner: 10%`

With such a small percentage of private landownership in the proposed area, there really is no incentive for the energy industry to work with local private landowners. It is vital that private landowners have a real voice in this process. This may mean adjusting the formula for the Hearing Notification Area and/ or Projected Storage Area to allow private landowners a voice that has weight in the discussion and decision of CO2 Underground Storage below their land. If private landowners do not have at least 40% of the breakdown, industry ends up negotiating with themselves and subsequently have little incentive to work with private landowners. I am not against this project, but I would like to be assured that the private landowner has a voice in this process and is compensated similarly to other projects in the area.

Sincerely,

Steven Heger

INDUSTRIAL COMMISSION
STATE OF NORTH DAKOTA
DATE 3/21/23 CASE NO. 29888-90
Introduced By Heger
Exhibit 1
Identified By Heger

## Kadmas, Bethany R.

**From:** Entzi-Odden, Lyn <lodden@fredlaw.com>
**Sent:** Monday, March 20, 2023 9:55 AM
**To:** Kadrmas, Bethany R.
**Subject:** Blue Flint Cases 29888, 29889 and 29890 filing
**Attachments:** Blue Flint 29888, 29889, 29890 filing.pdf



Bethany,

Please see the attached for filing.

Thank you.

Fredrikson

**Lyn Entzi-Odden**
**Executive Legal Assistant**
1133 College Drive | Suite 1000 | Bismarck, ND 58501
Ph: 701.221.8700|lodden@fredlaw.com

Fredrikson

**Fredrikson & Byron, P.A.**
Attorneys and Advisors

1133 College Drive, Suite 1000
Bismarck, ND 58501-1215
Main: 701.221.8700
fredlaw.com

March 17, 2023

***VIA EMAIL***

Ms. Bethany Kadrmas
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

**RE: CASE NOS. 29888, 29889 AND 29890**
**Blue Flint Sequester Company, LLC**

Dear Bethany:

Please find attached herewith the following for filing with regard to the captioned matter:

1. Memo from Blue Flint Sequester Company, LLC, a subsidiary of Midwest AgEnergy, with attached Fact Sheet;
2. Notice of Hearing; and
3. numerous Affidavits of Service by Mail indicating service on parties via certified mail, return receipt requested.

Should you have any questions, please advise.

Sincerely,

LAWRENCE BENDER

LB/leo
Enclosure
cc: Mr. Adam Dunlop – (w/enc.) *Via Email*

78659549 v1

MIDWEST AgEnergy

2841 3rd St SW
Underwood, ND 58576
(701) 442-7500

January 26, 2023

TO: OWNER, LESSEE OR OPERATOR OF RECORD

**RE: APPLICATION OF BLUE FLINT SEQUESTER COMPANY, LLC FOR CARBON DIOXIDE STORAGE FACILITY**

Dear Sir/Madam:

Blue Flint Sequester Company, LLC ("Blue Flint"), a subsidiary of Midwest AgEnergy Group, LLC, has made application to the North Dakota Industrial Commission ("Commission") requesting an order providing approval of a carbon dioxide storage facility project ("Project"). A hearing to consider the application of Blue Flint for the Project has been scheduled before the Commission as set forth in the attached Notice of Hearing ("Notice"). You are receiving this Notice because you have been identified as an owner, lessee or operator of record within the lands identified in the Notice or within one-half mile of the outside boundary of the proposed Project.

Details concerning the Project are included in the enclosed information pamphlet or are available from the Commission; however, should you have any questions regarding the Project or Blue Flint's application, please contact me at (701) 442-7500 or adunlop@midwestagenergy.com.

Sincerely,

*Adam Dunlop*

Adam Dunlop
Blue Flint Sequester Company, LLC

Enclosure(s)
78153458 v1

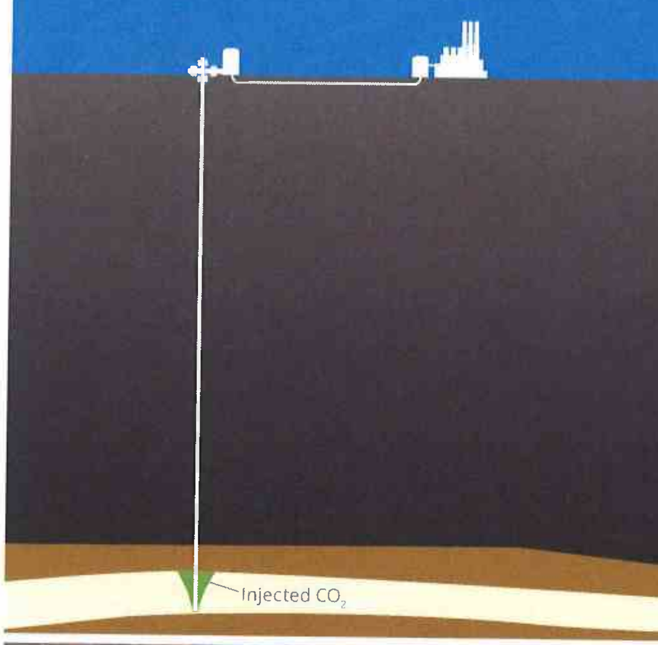
**BLUE FLINT ETHANOL**

# CCS PROJECT FACT SHEET

## Blue Flint Ethanol CCS Project


Blue Flint Ethanol, an ethanol plant in Underwood, North Dakota, operated by Midwest AgEnergy, is seeking to make its facility more sustainable and ensure long-term viability by integrating carbon capture and storage, or CCS, to reduce carbon dioxide ($CO_2$) emissions from ethanol production. **This reduction in $CO_2$ emissions will be the equivalent of taking 43,500 cars off the road each year.** Keeping $CO_2$ out of the atmosphere will help Blue Flint qualify for tax credits and low-carbon fuel standards to offset the costs of integrating and operating CCS.

## What Is Carbon Capture and Storage?

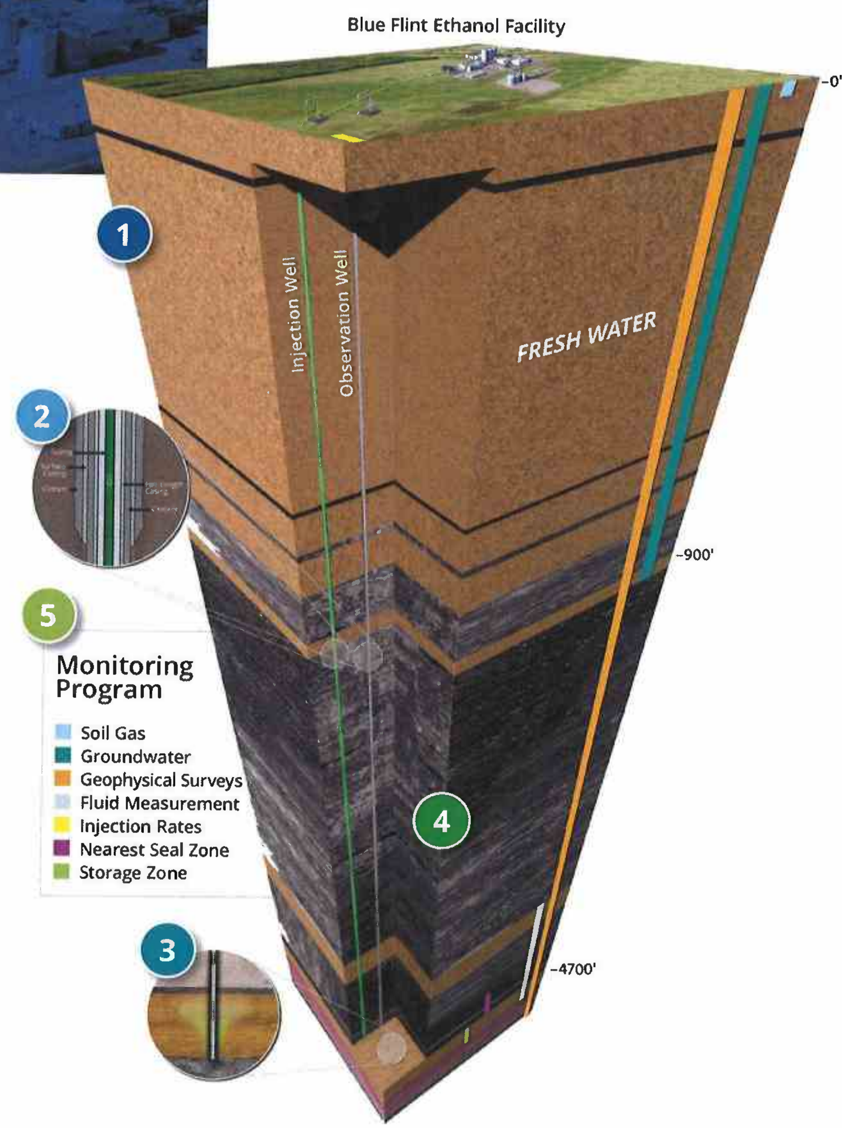



CCS is the practice of capturing $CO_2$ emission from an industrial facility instead of releasing it to the atmosphere. Once captured, the $CO_2$ is transported to a site for injection and safe, permanent storage deep underground. $CO_2$ injection is currently practiced in over 100 locations in the United States, typically for extending the life of older oil fields.

## Collaboration with Experts

Geologic $CO_2$ storage requires a deep porous layer to hold $CO_2$ and overlying impermeable rock layers as seals to keep the $CO_2$ in place. Midwest AgEnergy is collaborating with the Energy & Environmental Research Center (EERC) at the University of North Dakota, a global leader in CCS research. The EERC's proven approach features monitoring, characterization, modeling, and simulations to ensure the safety of injecting $CO_2$ into a suitable geologic container nearly a mile deep.

# BLUE FLINT CCS PROJECT WILL ENSURE HUMAN SAFETY AND PROTECT THE ENVIRONMENT.




## 1 Protection of Human Health and the Environment

Groundwater resources are important, and we make sure that they are protected—so does the state through its regulatory and permitting process.

## 2 Drinking Water Protection

Strict regulations govern all subsurface activities. All drilling and wells are engineered to protect groundwater resources. Typically, three layers of steel (casing and tubing) and two layers of durable, long-lasting cement isolate the freshwater aquifers, protecting them from drilling fluids, saltwater from deep rock layers, and injected $CO_2$.

## 3 Storage Zone

The storage zone target for the Blue Flint CCS project is a 100-foot-thick sandstone layer nearly a mile beneath the Blue Flint facility. The sandstone layer holds very salty water and has no oil.

## 4 Nature's Seals

Some underground rock layers make excellent barriers to upward flow of fluids. These cap rocks make effective traps for oil, water, natural gas, and $CO_2$. Cap rocks are usually shales and salts. Beneath the surface at Blue Flint, thousands of feet of shales and other impermeable rock layers already protect the fresh groundwater from the salty water of the target storage zone.

## 5 Ensuring Safety

Confirming that the $CO_2$ stays in the storage layer is critical to the CCS project. Techniques include controlling the injection, monitoring conditions in the container (storage and overlying seals), and tracking $CO_2$ movement in the reservoir with recurring geophysical surveys. Other measures will be used to confirm that $CO_2$ has not moved beyond the storage container and is not affecting groundwater or the surface environment.

**For More Information, Contact:**

**Adam Dunlop**
Executive Vice President
Harvestone Low Carbon Partners
adunlop@midwestagenergy.com
701.442.7500

**Blue Flint Ethanol**
Underwood, ND 58576
**www.midwestagenergy.com**

MIDWEST AgEnergy

## BEFORE THE INDUSTRIAL COMMISSION

## STATE OF NORTH DAKOTA

**CASE NO. _____**

**On a motion of the Commission to consider the application of Blue Flint Sequester Company, LLC for a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.**

## NOTICE OF HEARING

**PLEASE TAKE NOTICE** that Blue Flint Sequester Company, LLC ("Blue Flint") has made application to the North Dakota Industrial Commission ("Commission") requesting an order providing approval of a carbon dioxide storage facility permit as follows.

1. The carbon dioxide storage facility will be located near the city of Underwood, McLean County, North Dakota, and comprised of the following described lands:

   Township 145 North, Range 82 West
   Section 6: S/2
   Section 7: ALL
   Section 8: ALL
   Section 17: ALL
   Section 18: ALL
   Section 19: N/2

   Township 145 North, Range 83 West
   Section 11: SE/4
   Section 12: ALL
   Section 13: ALL
   Section 14: NE/4
   Section 24: NE/4

2. A hearing to consider the application of Blue Flint will be held before the Commission at 9:00 a.m. on March 21, 2023, at the Department of Mineral Resources Conference Room, Oil and Gas Division, 1000 East Calgary Avenue, Bismarck, North Dakota.
3. A copy of the permit application and draft permit may be obtained from the Commission.
4. All comments regarding the application for the storage facility permit must be in writing and submitted to the Commission prior to hearing or presented at the hearing.
5. Amalgamation of the storage reservoirs pore space is required to operate the storage facility and the Commission may require that the pore space owned by nonconsenting owners be included in the storage facility and subject to geologic storage. The amalgamation of pore space will be considered at the hearing.

**DATED** ~~this~~ 26 day of January, 2023.

FREDRIKSON & BYRON, P.A.

By________________________

LAWRENCE BENDER, ND Bar #03908
*Attorneys for Applicant,*
*Blue Flint Sequester Company, LLC*
1133 College Drive, Suite 1000
P. O. Box 1855
Bismarck, ND 58502-1000
(701) 221-8700

78153386 v1

**BEFORE THE INDUSTRIAL COMMISSION**

**STATE OF NORTH DAKOTA**

**CASE NO. 29888**

**On a motion of the Commission to consider the application of Blue Flint Sequester Company, LLC for a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.**

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA )
) ss.
COUNTY OF BURLEIGH )

Amber Nelson, being first duly sworn, deposes and says that on the 1st day of February, 2023, she served the attached:

**Memo;**
**Blue Flint Ethanol Fact Sheet;** and
**Notice of Hearing**

by placing a true and correct copy thereof in an envelope addressed as follows:

**See attached Exhibit A**

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Amber Nelson

Subscribed and sworn to before me this 1st day of February, 2023.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden
Notary Public
My Commission expires:

78306288 v1

August R. Johnson
c/o ABB Lummus Global BV
Oosteinde #208
2272 All Voorburg
The Netherlands

August R. Johnson
c/o ABB Lummus Global BV
Oostduinlaan 75
2596 JJ The Hague, The Netherlands

Claudette Molicard
39 Queensway Crescent
Winnipeg, MB, Canada R2J 3P3

Claudette Molieard
39 Queensway Crescent
Winnipeg, MB, Canada R2J 3P3

Torben Hendrik Thies
Oedenweg 62
22397 Hamburg, Germany

AgriBank, FCB
375 Jackson Street
P.O. Box 64949
St. Paul, MN 55164-0949

AgriBank, FCB, f/k/a Farm Credit Bank of St. Paul, f/k/a The Federal Land Bank of St. Paul
375 Jackson Street
P.O. Box 64949
St. Paul, MN 55164-0949

Alida B. Baska
1900 Oakhill Road
Bethany, OK 73008

American National Bank and Trust Company
777 Marquette Avenue
Minneapolis, Minnesota 55480

Andary Resources LLC
c/o Angela Thompson
108 Charles Street
Park River, ND 58270

Ann Teresa Reuter
4915 Nadine Drive Southeast
Salem, OR 97302

Anne Teresa Reuter
4915 Nadine Drive Southeast
Salem, OR 97302

Anne M. Johnson, Trustee of the Margaret M. Olson Trust
31219 River Road
Redwood Falls, MN 56283

Arkansas Minerals, Inc.
101 W. Main Str.
Suite 300
El Dorado, AR 71730

Arthur Seay, III
39599 W. 16th Street
Mannford, OK 74044

Arthur Seay, III, a/k/a Arthur V. Seay, III
39599 W. 16th Street
Mannford, OK 74044

Arthur V. Seay III
P.O. Box 2324
Nixa, MO 65714

Arthur V. Seay, Jr.
P.O. Box 697
Bismarck, ND

Arthur V. Seay, Jr.
P.O. Box 1980
Salt Lake City, UT

Audrey M. Crum as Trustee of the Audrey M. Crum Revocable Trust
4133 Stoney Creek Drive
Fort Collins, CO 80525

B.M. Kennelly Farm Management Group, LLP
c/o Rebecca Heazlett
17149 Pheasant Meadow Lane SW
Prior Lake, MN 55372

Barbara Ann Johnson
11671 Chieftain Drive
St. Louis, MO 63141

Barbara Lee Jones
1066 Apache Falls Drive
Katy, TX 77450

Barbara Lee Jones AND
1066 Apache Falls Drive
Katy, TX 77450

Barbara Lee Jones, FOR THE LIFE OF DONNA M. BARTSCH
1066 Apache Falls Drive
Katy, TX 77450

Betty L. Brumfield and Richard S. Brumfield
1425 16th Ave. South
Fargo, ND 58102

Black Stone Minerals Company, L.P.
1001 Fannin
Suite 2020
Houston, TX 77002-6709

Blaire Christie
7316 Cornelia Drive
Edina, MN 55435

Blanche W. McKnight
3312 W. Capital Ave.
Little Rock, AR 72205

Blanche W. McKnight and Mary Josephine McKnight Runge
3312 W. Capitol Avenue
Little Rock, AR 72205

EXHIBIT A

Blanche W. McKnight and Mary Josephine McKnight Runge, Co-Trustees under Will of Paul H. McKnight
3312 W. Capital Ave.
Little Rock, AR 72205

Blanche W. McKnight as Personal Representative of the Estate of Paul H. McKnight
3312 W. Capital Ave.
Little Rock, AR 72205

Estate of Paul H. McKnight
c/o Blanche McKnight, Personal Representative
Hall Bldg
Little Rock, AR 72205

Blue Flint Ethanol LLC
2841 3rd Str. SW
Underwood, ND 58576

BNC National Bank
322 East Main Avenue
Bismarck, ND 58501

BNC National Bank, NA
322 East Main Avenue
Bismarck, ND 58501

Bonnie Bergan
P.O. Box 283
Spearman, TX 79081

Bradley A. Landenberger and Carla J. Landenberger
59 32nd Ave. SW
Underwood, ND 58576

Bradley Sayler
P.O. Box 74
Underwood, ND 58576

Bradley Schafer
600 E. Boulevard Avenue, Dept 405
Bismarck, ND 58505-0840

Brandy Schmidt
1119 University Drive
#1517
Bismarck, ND 58504

Brent Sayler
16144 225th Avenue North
Elk River, MN 55330

Bruce Allen Gradin
16621 Madison Street
Omaha, NE 68135

Bruce Allen Gradin, FOR THE LIFE OF DONNA M. BARTSCH
16621 Madison Street
Omaha, NE 68135

Candice Stewart Robinson
103 Nickerson Parkway
Lafayette, LA 70501

Capital Credit Union
204 West Thayer Ave
Bismarck, ND 58501

Carmen K. Barkie
1716 48th Street S.E.
Minot, ND 58701

Carol A. Heringer
2505 Larson Road
Bismarck, ND 58504

Carol A. Heringer and Everett E. Heringer
2505 Larson Road
Bismarck, ND 58504

Carol J. Reinhiller and Thomas R. Reinhiller
1213 Chestnut Drive
Washburn, ND 58577

Central Power Electric Cooperative, Inc.
525 20th Ave. SW
Minot, ND 58701-6436

Chad A. Winter
67 Bidwell Square
Unionville, CT 06085

Chad Stevahn
74 Custer Drive
Lincoln, ND 58504

Chrysler Capital Corporation
225 High Ridge Road
Stanford, CT 06905

Clarence J. Reuter
4915 Nadine Drive Southeast
Salem, OR 97302

Clayton Rivenbark, Jr.
15504 Bay Point Drive
Dallas, TX 75248

Clayton Steinwand
1200 Meadowbrook Dr.
#104A
Washburn, ND 58577

Cleora C. Shearer and Donald B. Shearer a/k/a Donald Shearer
W 1905 Mile Drive
Pulaski, WI 54162

Coal Creek Drying and Storage, L.L.C.
2839 3rd Str. SW
Underwood, ND 58576

Coal Creek Station
Great River Energy
2875 Third Str. SW
Underwood, ND 58576

McLean County Resource District
712 5th Avenue
PO Box 1108
Washburn, ND

McLean County Water Resource District
712 5th Avenue
PO Box 1108
Washburn, ND

McLean County, North Dakota
712 5th Avenue
PO Box 1108
Washburn, ND 58577

McLean-Sheridan Joint Water
Resources Board
R.R. 1
Box 170-A
Turtle Lake, ND 58575

Curtis Schafer
811 Ashford Dr. NE
Cedar Rapids, IA 52402

Cynthia A. Olson
3141 Arizona Drive
Bismarck, ND 58503

Dale J. Schafer
Rural Route 1
Menoken, ND 58558

Daniel Dean Reuter
22384 Ramona Court
Cupertino, CA 95014

Daniel Sayler
1102 2nd Street East
Dickinson, ND 58601

David A. Lindell, as Trustee of the Iain
McCreary Revocable Trust
PO Box 427
Washburn, ND 58577

David Scott Johnson
11671 Chieftain Drive
St. Louis, MO 63141

David W. Reiland
1511 West Wren Drive
Visalia, CA 93291-1709

Debbie Marie Johnson
11671 Chieftain Drive
St. Louis, MO 63141

Deborah Miller, a/k/a Deborah Miller
Dyste
973 Forrest Blvd.
Decatur, GA 30030

Deborah Siem, Laurance Heger, Carl
Heger as Trustees of the Heger Land
Trust
2519 4th Street NW
Underwood, ND 58576

Debra J. Trekell
501 Glenmoor Rd.
Canon City, CO 81212

Deidre Moates
4414 South 9th Street
Tacoma, WA 98405

Dennis Helming
2301 Wyoming Ave. NW
Washington, DC 20008

Dennis Schafer
441 Sioux Drive

Diane Baker Rowland and Lisa Baker
Wilson, Co-trustees of the Baker
Mineral Trust
816 Apache Court
Frederick, MD 21701

Dianne Bakken
10823 Big Chip Road
Brandon, MN 56315

Donald S. Sayler and Velma Sayler
114 First Str. East
Mobridge, SD 57601

Donna Bartsch f/k/a Donna Gradin
1812 6th Str. SE
Apt. A
Minot, ND 58701

Douglas Jones
1004 Silbury Drive
Austin, TX 58758

Douglas Jones
1066 Apache Falls Drive
Katy, TX 77450

Edward Laxdal
P.O. Box 146
Hillsboro, ND 58045-0146

Elmer H. Schafer and Clara Schafer
Box 312
Underwood, ND 58576

County of McLean for the benfit of
McLean County Highway Department
712 5th Avenue
PO Box 1108
Washburn, ND 58577

McLean County Highway Dept
712 5th Avenue
PO Box 1108
Washburn, ND 58577

Emily Laxdal Sommer
3645 Trenton Lane North
Plymouth, MN 55441

Ervin R. Schafer and Adleine L. Schafer
1120 North 12th Str.
Bismarck, ND 58501

Ervin R. Schafer Revocable Trust
Box 739
Underwood, ND

Estate of A.O. Ernsdorf
c/o Richard Ernsdorf
10821 Foothill Boulevard
Lake View Terrace, CA 91342

Estate of Anton O. Ernsdorf
c/o Richard Ernsdorf
10821 Foothill Boulevard
Lake View Terrace, CA 91342

Estate of Clayton D. Rivernbark, Sr.
c/o Penelope Anne Rivenbark
9345 Sunnybrook Lane
Dallas, TX 75220

Estate of Elizabeth Reiland
c/o Gilbert J. Reiland
2242 North 11th Ave.
Hanford, CA 93230

Estate of Ella M. Sayler
c/o Carol Heringer, Personal Representative
2505 Laron Road
Bismarck, ND 58504

Estate of Gail K. DeMoe
c/o Karla Hornstein, Personal Representative
1518 12th St. S.
Fargo, ND 58103

Estate of Inda Watters
P.O. Box 87
Haynesville, LA 71038

Estate of Jean Sayler
c/o Stanley E. Sayler, Sr.
612 94th
Duluth, MN 55808

Estate of Jean Sayler
612 94th
Duluth, MN 55808

Estate of LeRoy D. Traxel
c/o Norma E. Traxel, Personal Representative
10601 52nd Street NE
Bismarck, ND

Estate of Mathew Sayler
c/o John Sayler
4152 West Arlington Drive
Bismarck, ND 58503

Estate of Maurice Heger
410 Grant
Box 596
Underwood, ND 58576

Estate of Paul D. Sayler
c/o Dawn G. Sayler
PO Box 462
Hazen, ND 58554

Estate of R.J. Stewart
c/o Richard J. Stewart a/k/a R. James
P.O. Box 7102
Mesa, AZ 85206

Estate of R.J. Stewart
c/o Richard J. Stewart, a/k/a R. James Stewart
P.O. Box 7102
Mesa, AZ 85206

Estate of R.J. Stewart
c/o Sheila M. Wenzel, f/k/a Sheila M. James
P.O. Box 7102
Mesa, AZ 85206

Estate of R.J. Stewart
c/o Sheila M. James
P.O. Box 7102
Mesa, AZ 85206

Estate of Ruby Comeaux Aillet
1211 Dubach Street
Rustin, LA 71270

Estate of Ruth Bader
5714 Hawthorne Road
Little Rock, AR 72207

Estate of Ruth R. Baker
5714 Hawthorne Rd.
Little Rock, AR 72207

Estate of Terrence R. Sayler
c/o Royann Archer, Personal Representative
2810 15th Street South, Unit C
Fargo, ND 58103

Farm Credit Services of North Dakota, FLCA
1400 31st Ave. SW
Minot, ND 58702-0070

First Security Bank
P.O. Box 40
Underwood, ND 58576

FME, LLC
c/o Wayne Bernhoft
12963 87th Street NE
Mountain, ND 58262

Francis P. Borden III, as Personal Representative of the Estate of Francis P. Borden, Jr.
P.O. Box 10086
El Dorado, AR 71730-0022

Eric Kevin Johnson
11671 Chieftain Drive
St. Louis, MO 63141

Erica Suzuki
4414 South 9th Street
Tacoma, WA 98405

Francis P. Borden, III
P.O. Box 10086
El Dorado, AR 71730-0022

Galye Sette, Trustee of the Sette Bypass Trust
190 Oakridge Way
Rio Vista, CA 94571

Garold G. O'Hair and Gwendolyn J. O'Hair
11209 N.W. 113th Str.
Yukon, OK 73099

Gary N. Hagen
4310 Puma Drive
Casper, WY 82604

Gene Thomas Peltier
15257 Eventon Avenue North
Hugo, MN 55038

Gilbert J. Reiland
2242 North 11th Avenue
Hanford, CA 93230

Glorene E. Drake
2112 SE Eagle Avenue
Greshem, OR 97080-9120

Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369-4718

Great River Energy
12300 Elm Creek Blvd. N.
Maple Grove, MN 55369

Great River Energy
PO Box 800
Elk River, MN 55330-0800

Great River Energy, agent for Cooperative Power Association
P.O. Box 800
Bozeman, MT 59718

Great River Energy, agent for United Power Association
P.O. Box 800
Bluebells, PA 19422

Gregory Paul Eizensimmer
212 4th Avenue
Munich, ND 58352

Gwendolyn M. Schaeffer
24057 Fawnskin Drive
Corona, CA 92883

Harry W. Samuelson
2931 Winnipeg Dr.
Bismarck, ND 58503

Harry W. Samuelson and Lois A. Samuelson
1616 Braman Avenue
Bismarck, ND 58501

Home Stake Oil & Gas Company
2805 North Dallas Parkway
Suite 100
Plano, TX 75093

Ione Heger
410 Grant
Box 596
Underwood, ND 58576

J. Hiram Moore, Ltd.
16400 N. Dallas Parkway
Suite 400
Dallas, TX 75248

Jack Jay Sauter and Bethany Sauter
6770 58th Ave. S.W.
Carson, ND 58529-9740

Jacob William Reuter
400 3rd Street
Box 176
Underwood, ND 58576

James C. Reeder
512 N. Foothill Road
Beverly Hills, CA 90210-3402

James M. Borden
4190 Hidden Acres
Fayetteville, AR 72704

James Sayler
P.O. Box 594
Underwood, ND 58576

James V. Miller, a/k/a James Vincent Miller
413 13th Ave. NE
Minot, ND 58703

Janet Steckler
688 Main
Dickinson, ND 58601

Janice Berget
284 Taylor Road
Libby, MT 59923

Janice K. Cottingham and Earl W. Cottingham
P.O. Box 83
Underwood, ND 58576

Francis P. Borden, Jr., Trustee
917 Euclid
El Dorado, AR 71730

Francis Reuter
3306 Monte Buena
San Pablo, CA 94806

Jennifer J. Cordesman f/k/a Jennifer J. Robson
12410 Bundle Rd.
Chesterfield, VA 23839

Joann Hall Swenson
4865 Island View Drive
Mound, MN 55364-9392

Joanne Theilen
1719 5th St. SW
Minot, ND 58701

John A. DePuy
4113 B Latricia Lane
Wichita Falls, TX 76302-2751

John A. Reiland
2433 Ship Rock Avenue
Tulare, CA 93274-7423

John C. Bradford
P.O. Box 873
Shreveport, LA 71162-0873

John C. Samuelson
Rt. 1, 1000 Jennifer Dr.
Washburn, ND 58577

John C. Samuelson and Helen K. Samuelson
1813 North 21st Street
Bismarck, ND 58501

John E. Sayler
4152 West Arlington Drive
Bismarck, ND 58503

John Knudson, Jr.
4516 Belmont Road
Grand Forks, ND 58201

John Sayler and Mark Sayler, Guardians of Matthew Sayler
c/o John E. Sayler
4152 West Arlington Drive
Bismarck, ND 58503

Joy M. Ochsner and Gary L. Ochsner
310 16th Ave S.E.
Minot, ND 58701

Judith K. Simpfenderfer and Jerome D. Simpfendefer
RR1
Box 116A
Washburn, ND 58577

Julie Dickelman
404 2nd Avenue SE
Dilworth, MN 56529

Kathy Sayler
9908 E. Louisiana Dr.
#5-108
Denver, CO 80247

Keith Johnson
1119 University Drive
#1520
Bismarck, ND 58504

Kenneth H. Pfaff
2487A 4th Str. SW
Washburn, ND 58577-9425

Kenneth H. Pfaff
3226 Impala Ln
Bismarck, ND 58503-0150

Kent S. Pfaff
2487A 4th Street SW
Washburn, ND 58577

Kent S. Pfaff, as Trustee of the Wanda L. Pfaff Family Trust
2487A 4th Str. SW
Washburn, ND 58577-9425

Kevin L. Johnson
422 11th Street East
Williston, ND 58801

Kevin Olson
3141 Arizona Drive
Bismarck, ND 58503

Kristie Seidler
464 23RD Ave. NW
Underwood, ND 58576

Lagness Properties
c/o Gail A Barsness
6913 West Shore Drive
Edina, MN 55435

Larry Sayler
30316 Jasmine Valley Drive
Canyon Country, CA 91387

Laurance Heger
P.O. Box 1092
Underwood, ND 58576

Laurance Heger and Nancy Heger
607 Kennedy Street
Underwood, ND 58576

Laurance L. Heger and Nancy L. Heger
HCR 1, Box 87
Underwood, ND 58576

Jennifer Kraft, f/k/a Jennifer Miller
1112 11th St. SW
Minot, ND 58701

Jennifer S. Rova
2946 Point Hayden Drive
Hayden Lake, ID 83835-9537

Nancy Heger
P.O. Box 1092
Underwood, ND 58576

LaVerna McKelby
1665 Pulaski Drive
Bozeman, MT 59718

LaVerna McKelby
1665 Pulaski Drive
Bismarck, ND 58501

Laverna Scheid
RR1
Box 171
Hazen, ND 58545

Linda G. Sayler Hoenek
4th Street SW
Mandan, ND 58554

Linda G. Sayler Hoenek or Hoener
4th Street SW
Mandan, ND 58554

Linda J. Dillon
64 Weatherstone Way
Sharpsburg, GA 30277

Linda L. Schmidt
11704 S. Kingston Ave
Tulsa, OK 74137

Linda L. Schmidt
8218 East 73rd Street South
Tulsa, OK 74133

Linda L. Schmidt, Trustee
8218 East 73rd Street South
Tulsa, OK 74133

Linda L. Schmidt, Trustee of the Linda L. Schmidt Revocable Trust
11704 S. Kingston Ave
Tulsa, OK 74137

Linda L. Schmidt, Trustee of the Linda L. Schmidt Trust
11704 S. Kingston Ave
Tulsa, OK 74137

Linda Louise Seay, a/k/a Linda L. Schmidt
9732 S. Lakewood Place
Tulsa, OK 74137

Linda S. Smith
618 Dohn Avenue
Bismarck, ND 58501-1012

Lorella Donline
4020 Penrose Place
Rapid City, SD 57702

Loretta Moe
1416 Dogwood Avenue
Grafton, ND 58237

Lowell Thomas Vizenor
510 Other Trail
Greenville, TX 75401

Lowell Wood and
584 29th Ave SW
Washburn, ND 58577

Lucille Ann Gardella
1675 Weld County Road #12
Erie, CO 80516

M.J. Rivenbark
204 West Main
Haynesville, LA 71038

M.J. Riverbark
204 West Main
Haynesville, LA 71038

Macy J. Schafer
22639 200th Avenue North
Ulen, MN 56585

Macy J. Schafer
76 32nd Ave. SW
Underwood, ND 58576

Margaret E. Tollerud, as Trustee of the Margaret E. Tollerud Revocable Trust
18022 65th Avenue North
Maple Grove, MN 55311

Mark S. Wilhelm
8561 4th Avenue SE
Bismarck, ND 58501

Mark Sayler
75 Haywood Drive
Lincoln, ND 58504

Marlyn Seidler
464 23RD Ave. NW
Underwood, ND 58576

Marquette National Bank of Minneapolis
777 Marquette Avenue
Minneapolis, Minnesota 55480

Laurel A. Ross
110 Maple Court
Fayetteville, GA 30214

Laurel Miller and Kenneth Stadick
2259 2nd Str. NW
Underwood, ND 58576

Marty J. Schafer
P.O. Box 543
Washburn, ND 58577

Mary Sandbergen
937 Valley View Circle
Palm Harbor, FL 34684

Mary Schafer Conlon
19B Stefaniak Ave.
Webster, MA 01570

Mary Schafer Conlon
2907 Winnipeg Drive
Bismarck, ND 58503

Matthew S. Johnson
145 S.E. 29th Terr.
Cape Coral, FL 33904

Megan R. Harris
1900 No Name Road
Loomis, CA 95650

MHM Resources, LP
P.O. Box 51570
Midland, TX 79710-1570

Michael Anthony Reuter
400 3rd Street
Box 176
Underwood, ND 58576

Michael Anthony Reuter
400 3rd Street
Underwood, ND 58576

Michael Berg
HCR 1
Box 146
Underwood, ND 58576

Michael Johnson
8230 Green Meadow Drive
Helena, MT 59601

Michelle Albrecht
11850 435th Ave NE
Regan, ND 58477

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

Miles Miller
415 18th St.
Sacramento, CA 95811

Missouri River Royalty Corporation
919 S. 7th Street
Suite 405
Bismarck, ND 58504

Monte R. Schafer
3645 Northwest Jasmine Street
Camas, WA 98607

Monte R. Schafer a/k/a Monty R. Schafer
3645 NW Jasmine Str.
Camas, WA 98607

Monty R. Schafer
87 Marlboro Lane
Eugene, OR 97405

Mueller Industries, Inc.
One Tabor Center
1200 17th Str., Suite 1390
Denver, CO 80202

Mueller Industries, Inc., successor-in-interest to Sharon Steel Corporation, successor-in-interest to UV Industries, Inc.
One Tabor Center
1200 17th Str., Suite 1390
Denver, CO 80202

Sharon Steel Corporation
One Tabor Center
1200 17th Str., Suite 1390
Denver, CO 80202

UV Industries, Inc.
P.O. Box 1980
Salt Lake City, UT 84104

Myrtle Breeding
PO Box 565
Riverdale, ND 58565

Nexus Line, LLC
919 South 7th Street
Suite 405
Bismarck, ND 58504

Nexus Line, LLC
c/o Rainbow Energy Center, LLC
919 South 7th Str., Ste. 405
Bismarck, ND 58504

Norma Sayler Schacher
508 3rd Avenue NW
Mandan, ND 58554

North American Coal Royalty Company
2000 Schafer Street
Suite D
Bismarck. ND 58501-1204

North Dakota Child Support
P.O. Box 7190
Bismarck, ND 58507-7190

Marvin F. Johnson
P.O. Box 1804
Kingston, WA 98346-1804

Mary J. Schafer
22639 200th Ave. N.
Ulen, MN 56585

North Dakota Refined Coal Project Company A LLC
c/o NoDak Energy Services, L.L.C.
2875 Third Street SW
Underwood, ND 58576

North Dakota Transmission Authority
State Capital, 14th Floor
Bluebells, PA 19422

Northwestern Bell Telephone Company
220 North 5th Street
Bismarck, ND 58501

Otter Tail Power Company
P.O. Box 496
Fergus Falls, MN 56538-0496

Pamela Stewart Owens
1013 Barranger Drive
Danville, CA 94526

Patricia Borden Mosier
P.O. Box 94233
North Little Rock, AR 72190

Patricia Lee Peltier
309 Haycreek Court
Bismarck, ND 58501

Patricia Lee Peltier
15257 Eventon Avenue North
Hugo, MN 55038

Patricia Lindell
P.O. Box 427
Washburn, ND 58577

Patricia Reeder Eubank
3350 Calle Bonita
Santa Ynez, CA 95460

Patrick Michael Reuter
4915 Nadine Drive Southeast
Salem, OR 97302

Patrick W. Fisher Minerals LLC
3117 Edgewood Pointe
Bismarck, ND 58503

Paul Anthony Peltier
15257 Eventon Avenue North
Hugo, MN 55038

PEC Minerals LP
14860 Montfort Drive
Suite 209
Dallas, TX 75254

Penelope Anne Rivenbark
9345 Sunnybrook Lane
Dallas, TX 75220

Peter Sayler
PO Box 125
Hettinger, ND 58639

Pheasant Energy, LLC
P.O. Box 2487
Fort Worth, TX 76113

Pheasant Energy, LLC
P.O. Box 471458
Fort Worth, TX 76147

Phyllis Schauer and Kermit Schauer
675 E. Farney Lane
Las Cruces, NM 88005

Phyllis Wood
2769 28th Str. NW
Baudette, MN 56623

Pierce Exploration & Production Corporation
1133 Bal Harbor Blvd. #1139
Punta Gorda, FL 33950

Qwest Corporation
Corporation Section
1560 Broadway, Suite 200
Denver, CO 80202

Rachael J. Webb
4204 Rocky Face Dr.
Douglasville, GA 30135

Rainbow Energy Center, LLC
919 South 7th Street
Suite 405
Bismarck, ND 58504

Ralph H. Baker Jr. and Diane B. Rowland, Trustees of the Baker Mineral Trust
c/o Ralph H. Baker, Jr.
1420 Stafford
Sherwood, AR 72116

Ralph H. Baker Jr. and Diane B. Rowland, Trustees of the Baker Mineral Trust
1420 Stafford
Sherwood, AR 72116

Ralph H. Baker, Jr., Diane B. Rowland, and Lisa Baker Wilson, as Trustees of the Baker Mineral Trust
816 Apache Court
Frederick, MD 21701

Randy VanAsperen
HCR 1
Box 88
Underwood, ND 58576

North Dakota Refined Coal Project Company A LLC
2875 Third Str. SW
Underwood, ND 58576

North Dakota Transmission Authority
State Capitol, 14th Floor
600 E. Boulevard Ave., Dept. 405
Bismarck, ND 58505-0840

Rebeccah Eman, a/k/a Rebecca Miller
215 8th St. NW
Minot, ND 58703

Rhonda J. Pfaff
2487A 4th Street SW
Washburn, ND 58577

Richard D. Johnson as Power of
Attorney for Shirley Johnson
P.O. Box 305
Washburn, ND 58577-0305

Richard D. Johnson as Power of
Attorney for Shirley Johnson
P.O. Box 5523
Washburn, ND 58577-0305

Richard Ernsdorf
10821 Foothill Boulevard
Lake View Terrace, CA 91342

Richard J. Stewart, a/k/a R. James
Stewart
P.O. Box 7102
Mesa, AZ 85206

Richard Johnson and Ronald Johnson,
as Co-Successor Trustees of the Lavern
L. Johnson Revocable Trust
1127 Cannon Lane
Washburn, ND 58577

Richard S. Johnson
823 13th Avenue
Langdon, ND 58249

Rita A. Johnson
3124 Colorado Lane #224
Bismarck, ND 58503

Robert David Reuter
4915 Nadine Drive Southeast
Salem, OR 97302

Robert L. Neville
1118 Wimbeldon Boulevard
Columbus, OH 43228

Robert Mann and Marilyn Mann
119 North Main Street
Plentywood, MT 59254

Robert Tibbetts
3175 Glenn Iris Drive
Commerce Township, MI 48382

Roberta Dodson
300 Ocean Trailway
Apt. 203
Jupiter, FL 33477

Rocky Mountain Oil, Gas and Minerals,
LLC
P.O. Box 4344
Greenwood Village, CO 80155-4344

Rodney C. Schafer
345 Huntleigh Manor Dr.
St. Charles, MO 63303

Rodney C. Schafer, as Trustee of the
Rodney C. Schafer Trust
345 Huntleigh Manor Drive
St. Charles, Missouri 63303

Roger Sayler
252 West 85th St.
Apt 6A
New York, NY 10024

Ronnie W. Landenberger
3505 42nd St. NW
Mandan, ND 58554

Roy Ann Schmidgall
4869 S. Kirk Way
Aurora, CO 80015

Royann Archer
2810 15th Street South
Unit C
Fargo, ND 58103

Ruth Ellen Crowe
1220 N. 6th Str.
Durant, OK 74701

Ruth Reberg
4178 West Arlington Drive
Bismarck, ND 58503

Sheila M. Wenzel, f/k/a Sheila M. James
P.O. Box 7102
Mesa, AZ 85206

Sheryl Ann Reuter Newstrom
309 Haycreek Court
Bismarck, ND 58501

Shirley Johnson
P.O. Box 305
Washburn, ND 58577

Sidney Rae Lawler, f/k/a Sidney Ray
Seay
2944 S. Delaware Ave.
Tulsa, OK 74114

Sidney Rae Seay
5521 East 51st Street
Tulsa, OK 74135

Red Crown Royalties, LLC
1490 W. Canal Court
Suite 3000
Littleton, Co 80120

Red Crown Royalties, LLC
1490 W. Canal Court
Littleton, CO 80120

Sidney S. Lawler
3906 South Delaware Place
Tulsa, OK 74106-3745

Stanley E. Sayler, Sr.
612 94th
Duluth, MN 55808

Starion Bank
109 1st Str. NW
Mandan, ND 58554

Starion Bank
333 N. 4th Str.
Bismarck, ND 58502

State of North Dakota
Department of Trust Lands
1707 N. 9th Street
Bismarck, ND 58501

State of North Dakota
1707 N. 9th Street
Bismarck, ND 58501

State of North Dakota
1707 North 9th Str.
P.O. Box 5523
Bismarck, ND 58506-5523

The State of North Dakota c/o State Land Department
918 E. Divide
P.O. Box 5523
Bismarck, ND 58502-5523

The State of North Dakota d/b/a/ The Bank of North Dakota
1200 Memorial Highway
P.O. Box 5509
Bismarck, ND 58506-5509

Stefan D. Laxdal
211 Peninsula Road
Medicine Lake, MN 55441

Stephen John Reuter
22384 Ramona Court
Cupertino, CA 95014

Steve Charles Johnson
11671 Chieftain Drive
St. Louis, MO 63141

Steven Heger and Katie Heger
2896 3rd Str. NW
Underwood, ND 58576

Steven Pfaff and Cherise Pfaff
1046 Sibley Way
Washburn, ND 58577

Sylvia Thompson
P.O. Box 26
Washburn, ND 58577

T.S. Snydal
95 Wedgefield Drive
Hilton Head Island, SC 29926

T.S. Snydal
9 Wedgefield Drive
Hilton Head Island, SC 29926

Tami Clark
P.O. Box 5
Underwood, ND 58576

Tammy Stevahn
2529 Colonial Drive
Bismarck, ND 58503

Tara J. Ward
8015 Jalane Park
San Antonio, TX 78255

Tara Marie Vizenor
510 Other Trail
Greenville, TX 75401

Tenneco Oil Company
P.O. Box 2511
Houston, TX 77252

Teri Rae Smith
4869 S. Kirk Way
Aurora, CO 80015

The Adeline L. Schafer Revocable Trust
1120 N. 12th Str.
Bismarck, ND 58501

The Ervin R. Schafer Revocable Trust
1120 North 12 Street
Bismarck, ND 58501

The Ervin R. Schafer Trust
1120 North 12 Street
Bismarck, ND 58501

The Falkirk Mining Company
2000 Schafer Street
Suite D
Bismarck, ND 58501-1204

The Falkirk Mining Company
2801 1st Str. SW
Underwood, ND 58576

Sidney S. Lawler, Trustee of the Sidney S. Lawler Trust
3906 South Delaware Place
Tulsa, OK 74106-3745

Spotted Dog Holdings, LLC
c/o Randolph E. Stefanson
428 8th Street South
Moorhead, MN 56560

The Falkirk Mining Company
2000 Schafer Street
Gardensville, TX 96245

The Nokota Company
P.O. Box 1633
Bismarck, ND 58502

The Reiland Family Revocable Living Trust
c/o Gilbert J. Reiland
2242 North 11th Ave.
Hanford, CA 93230

Therese Borden Sloane
P.O. Box 3968
2205 Santiago
Farmington, NM 87499

Therese Borden Sloane
P.O. Box 3968
Farmington, NM 87499

Thomas Joseph Reuter
400 3rd Street
Box 176
Underwood, ND 58576

Thomas Joseph Reuter
400 3rd Street
Underwood, ND 58576

Tina Marie Reuter
400 3rd Street
Underwood, ND 58576

Tina Marie Reuter
400 3rd Street
Box 176
Underwood, ND 58576

Todd Heidbreder
P.O. Box 963
Stanley, ND 58784

Toni Cottingham
P.O. Box 23
Underwood, ND 58576

Tracy L. Fischer
4001 36th Avenue NW
Mandan, ND 58554

Troy Nelson and Kree Nelson
6501 Misty Waters Drive
Bismarck, ND 58503

Trudy Bergstrom
5972 102C Ave. NW
Tioga, ND 58852

U.S. Bank Trust Company, N.A., Trustee
Mail Stop EP-MN-WS3C
60 Livingston Avenue
St. Paul, MN 55107-2292

U.S. Bank Trust Company, National Association
Mail Stop EP-MN-WS3C
60 Livingston Ave.
St. Paul, MN 55107-2292

U.S. Bank, N.A.
60 Livingston Avenue
EP MM WS3C
St. Paul, MN 55107-2292

US Bank National Association
Corporate Trust Services
EP-MN-WS3C
60 Livingston Ave.
St. Paul, MN 55107

US Bank Trust Company, NA
Mail Stop EP-MN-WS3C
60 Livingston Ave.
St. Paul, MN 55107-2292

United States of America
c/o Bureau of Land Management
5001 Southgate Drive
Billings, MT 59101

United States of America
Bureau of Reclamation
P.O. Box 36900
Billings, MT 59107-6900

US West Communications
105 North 5th Street
Fargo, ND 58102

Vivian Dunbar
618 Hickory Road
Hudson, WI 54016

Ward Heidbreder
P.O. Box 272
Stanley, ND 58784

Washburn United Methodist Church
P.O. Box 66
Washburn, ND 58577

WBI Energy Transmission, Inc.
1250 W. Century Ave.
Bismarck, ND 58503

WBI Energy Transmission, Inc.
Attn: Land Department
2010 Montana Ave.
Glendive, MT 59330

Wells Fargo Bank, N.A., Successor Trustee of the Robert Stead Trust
P.O. Box 5383
Denver, CO 80217

The Home-Stake Royalty Corporation
507 Philtower
Tulsa, OK 74103

The Nakota Company
P.O. Box 1633
Bismarck, ND 58502

West River Communications
P.O. Box 467
Hazen, ND 58545

West River Telephone Co-Op
Box 467
Washburn, ND 58577

Wilfred M. Baska
1900 Oakhill Road
Bethany, OK 73008

West River Telephone Co-op
Box 467
Hazen, ND 58545

Wilmington Trust Company
Rodney Square North
100 N. Market Str.
Wilmington, DE 19890-0001

Zachary Pfaff
1046 Sibley Way
Washburn, ND 58577

William Frederick Lindell
P.O. Box 427
Washburn, ND 58577

West River Telecommunications
Cooperative
P.O. Box 467
Hazen, ND 58545

Sherrie Lynne Gradin
10232 Sand Ridge Road
Millfield, OH 45761-9600

Renee C. Thorp, Trustee of the
W.L.Braun Oil Properties Revocable
Trust
85 Wylie Creek Boulevard
Bozeman, MT 59718-7259

Estate of Arthur V. Seay, Jr.
c/o Arthur Seay III
2024 W. Shelvin Rock Road
Nixa, MO 65714-7153

The Farmers Security Bank of
Washburn
710 Main Street
Washburn, ND 58577

Robert R. Aillet
330 Benton Drive
Pea Ridge, AR 72751-2935

Brian Schafer
1512 South 3rd Street
Bismarck, ND 58504-7109

UTE Royalty Corporation
3100 East Cherry Creek Drive
205 Cherry Creek Tower
Denver, CO 80209

Talley Family Partnership
c/o David L. Talley
20440 Road 7
Chowchilla, CA 93610

Cynthia Darlene Graden n/k/a Darlene
Bivins Skaar
2606 13th Avenue South, Apt. 208
Grand Forks, ND 58201-5119

Audrey Pauling and Lester Pauling
2368 9V Street SW
Washburn, ND 58577-9403

The Mountain States Telephine and
Telegraph Company, n/k/a Qwest
100 Centrylink Drive
Monroe, LA 71203

El Paso Energy Engineering Company
1001 Louisiana Street
Houston, TX 77002-5089

Bruce Schafer
911 East Ingalls Avenue
Bismarck, ND 58504-5845

United States of America, c/o Mac Schneider,
USDA Quentin N. Burdick United States
Courthouse
U.S. Attorney's Office
655 First Avenue North, Suite 250
Fargo, ND 58102-4923

Estate of Jacob Schafer
c/o Jacob Lantz Schafer
1100 Lohstreter Road
Mandan, ND 58554-2331

Cindy Ann Gradin
46093 Highway 6, #24
Glenwood Springs, CO 81601-9788

Brent Schafer
1025 Laramie Drive, Apt. 3
Bismarck, ND 58504-6371

Norma E. Traxel
3554 North 19th Street, Apt. 4
Bismarck, ND 58503-0696

Estate of Edna B. Schafer
158 East Indiana Avenue, Apt. 205
Bismarck, ND 58504-5778

Buffalo Lake Township
c/o McLean County State's Attorney -
Ladd Erickson
PO Box 1108
Washburn, ND 58577

Robert Miller
621 S. Main St.
Minot, ND 58701

McLean Electric Cooperative, Inc.
4031 ND-37
PO Box 399
Garrison, ND 58540

Cynthia Ann Aillet Kavanaugh
208 Long Plantation Boulevard, Apt. A
Lafayette, LA 70508-6153

Estate of Jacob Schafer
c/o Jacob Adam Schafer
68 6th Avenue East
Flasher, ND 58535-7241

Myldred Swanson
c/o Sheridan Memorial Home
610 Main Street South
McClusky, ND 58463

Robert L. Doepke and Lee Ann Doepke
1412 Highway 83 SW
Wilton, ND 58579-9380

Shirley Jean Larson
8054 149th Avenue NW
Grenora, ND 58845-9304

Estate of Louise Schafer
DECEASED

Jesse Nermoe
DECEASED
Upham, ND

L.M. Brand, Trustee, c/o Jane C. Brand, as Personal Representative of the estate of Lewis M. Brand, a/k/a L.M. Brand
DECEASED

Texota Oil Company
358 Petro Building
5th & Pine
Abilene, TX 79604

Utana Basins Oil Co.
4571 South Holladay Boulevard
Holladay, UT 84117

United States of America
Western Area Power Administration
PO Box 2821213
Lakewood, CO 80228-8213

Estate of B.C. Campbell, aka Byram C. Campbell
ADDRESS UNKNOWN

Gail Irene Engel
DECEASED

Joe Talley
DECEASED
Lansford, ND

Marie Gunn
DECEASED
Antler, ND

Estate of Bernard M. Watters
629 Longue View Lane
Madisonville, LA 70447

First Western Bank & Trust, as conservator for Kenneth H. Pfaff
304 East Front Avenue
Bismarck, ND 58504

Luthern Social Service of Minnesota as guardian of Kenneth H. Pfaff
2485 Como Avenue
St. Paul, MN 55108

Estate of Joe Aillet
DECEASED

H.W. Gunn
DECEASED
Antler, ND

L.M. Brand, Trustee
DECEASED
Haynesville, LA 71038

**BEFORE THE INDUSTRIAL COMMISSION**

**STATE OF NORTH DAKOTA**

**CASE NO. 29888**

**On a motion of the Commission to consider the application of Blue Flint Sequester Company, LLC for a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.**

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA )
) ss.
COUNTY OF BURLEIGH )

Amber Nelson, being first duly sworn, deposes and says that on the 6th day of February, 2023, she served the attached:

**Memo;**
**Blue Flint Ethanol Fact Sheet;** and
**Notice of Hearing**

by placing a true and correct copy thereof in an envelope addressed as follows:

**AgriBank, FCB**
**Wells Fargo Place**
**30 East 7th Street**
**St. Paul, MN 55101**

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Amber Nelson

Amber Nelson

Subscribed and sworn to before me this 6th day of February, 2023.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden

Notary Public
My Commission expires:

78306427 v1

**BEFORE THE INDUSTRIAL COMMISSION**

**STATE OF NORTH DAKOTA**

**CASE NO. 29888**

**On a motion of the Commission to consider the application of Blue Flint Sequester Company, LLC for a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.**

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA )
) ss.
COUNTY OF BURLEIGH )

Amber Nelson, being first duly sworn, deposes and says that on the 10th day of February, 2023, she served the attached:

**Memo;**
**Blue Flint Ethanol Fact Sheet;** and
**Notice of Hearing**

by placing a true and correct copy thereof in an envelope addressed as follows:

**Patricia Lindell**
**P.O. Box 427**
**Washburn, ND 58577**

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Amber Nelson
Amber Nelson

Subscribed and sworn to before me this 10 day of February, 2023.

Lyn Odden
Notary Public
My Commission expires:

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

78351357 v1

**BEFORE THE INDUSTRIAL COMMISSION**

**STATE OF NORTH DAKOTA**

**CASE NO. 29888**

**On a motion of the Commission to consider the application of Blue Flint Sequester Company, LLC for a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.**

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA )<br>
) ss.<br>
COUNTY OF BURLEIGH )

Amber Nelson, being first duly sworn, deposes and says that on the 16th day of February, 2023, she served the attached:

**Memo;**<br>
**Blue Flint Ethanol Fact Sheet;** and<br>
**Notice of Hearing**

by placing a true and correct copy thereof in an envelope addressed as follows:

**Kenneth H. Pfaff**<br>
**11004 Acadia Circle**<br>
**Bismarck ND, 58503-8623**

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Amber Nelson

Subscribed and sworn to before me this 16 day of February, 2023.

LYN ODDEN<br>
Notary Public<br>
State of North Dakota<br>
My Commission Expires June 26, 2023

Notary Public<br>
My Commission expires:

**BEFORE THE INDUSTRIAL COMMISSION**

**STATE OF NORTH DAKOTA**

**CASE NO. 29888**

**On a motion of the Commission to consider the application of Blue Flint Sequester Company, LLC for a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.**

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA )<br>
) ss.<br>
COUNTY OF BURLEIGH )

Amber Nelson, being first duly sworn, deposes and says that on the 17th day of February, 2023, she served the attached:

**Memo;**
**Blue Flint Ethanol Fact Sheet;** and
**Notice of Hearing**

by placing a true and correct copy thereof in an envelope addressed as follows:

**See attached Exhibit A**

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Amber Nelson

Amber Nelson

Subscribed and sworn to before me this 17 day of February, 2023.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden

Notary Public
My Commission expires:

78306288 v1

Linda J. Dillon
140 Timber View Lane
Sharpsburg, GA 30277

American National Bank
and Trust Company
628 Main St
Danville, VA 24541

Dale J. Schafer
3419 Valley Drive
Bismarck, ND 58503-1719

Dennis Schafer
224 Main Street W
Mayville, ND 58257-1318

Jacob William Reuter
6675 57th Ave S
Fargo, ND 58104-5654

James V. Miller
a/k/a James Vincent Miller
104 3rd Street
Riverdale, ND 58565-7703

Judith K. Simpfenderfer
and Jerome D. Simpfendefer
1530 Sharloh Loop
Bismarck, ND 58501-7773

Laurance Heger
303 N Lindsay Road Lot I101
Mesa, AZ 85213-8168

Nancy Heger
303 N Lindsay Road Lot I101
Mesa, AZ 85213-8168

Laurance Heger, & Nancy Heger
303 N Lindsay Road Lot I101
Mesa, AZ 85213-8168

Linda G. Sayler
62940 Argyle Road
King City, CA 93930-9660

Margaret E. Tollerud, as Trustee of the
Margaret E. Tollerud Revocable Trust
4345 Oakview Lane N,
Minneapolis, MN 55442-2776

U.S. Bank f/k/a Marquette National
Bank of Minneapolis
800 Nicollet Mall
Minneapolis, MN 55402

Michael Anthony Reuter
494 E Lake Hwy # 76
Medicine Lake, MT 59247-7759

Patrick Michael Reuter
11770 SW Fox Ridge Rd
McMinnville, OR 97128-9521

Roberta Dodson
1311 17th Ave NW
Minot, ND 58703-1164

Tina Marie Reuter
605 16th Street Northwest
Minot, ND 58703

Toni Cottingham
107 Borchardt Ave
Underwood, ND 58576-4008

Betty L. Brumfield and Richard S.
Brumfield
DECEASED

Elmer H. Schafer and Clara Schafer
DECEASED

Estate of Maurice Heger
UNKNOWN

Ione Heger
DECEASED



EXHIBIT A

**BEFORE THE INDUSTRIAL COMMISSION**

**STATE OF NORTH DAKOTA**

**CASE NO. 29888**

**On a motion of the Commission to consider the application of Blue Flint Sequester Company, LLC for a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.**

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA )
) ss.
COUNTY OF BURLEIGH )

Amber Nelson, being first duly sworn, deposes and says that on the 28th day of February, 2023, she served the attached:

**Memo;**
**Blue Flint Ethanol Fact Sheet;** and
**Notice of Hearing**

by placing a true and correct copy thereof in an envelope addressed as follows:

**See attached Exhibit A**

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Amber Nelson

Subscribed and sworn to before me this 28 day of February, 2023.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Notary Public
My Commission expires:

78306288 v1

Anne T. Kerzel
4016 Cloudview Drive
Salem, OR 97302-2776

Barbara Lee Jones
303 Arbor Green Lane
Rosenberg, TX 77469-4767

Barbara Lee Jones, for the Life of
Donna M. Bartsch
303 Arbor Green Lane
Rosenberg, TX 77469-4767

Bonnie Bergan
6900 County Road 569
Brownwood, TX 76801-0879

Bruce Allen Gradin
3714 W Goldmine Mountain Dr.
Queen Creek, AZ 85142-6594

Bruce Allen Gradin, for the Life of
Donna M. Bartsch
3714 W Goldmine Mountain Dr.
Queen Creek, AZ 85142-6594

Chrysler Capital Corporation
PO Box 961275
Fort Worth, TX 76161

Deborah Miller
a/k/a Deborah Miller Dyste
609 4th Street SE
Minot, ND 58701-4740

Estate of LeRoy D. Traxel, c/o Norma
E. Traxel Personal Representative
3554 N 19th Street, Apt 4
Bismarck, ND 58503-0696

Galye Sette
Trustee of the Sette Bypass Trust
799 Yellowstone Drive, Apt. 281
Vacaville, CA 95687-3473

Larry Sayler
c/o Lawrence A. Sayler
67 Goose Point Lane, Apt 406
Fishersville, VA 22939-2447

Larry Sayler
c/o Lawrence Dean Sayler
47821 Shawnee Ave, #103414
Coarsegold, CA 93614-9738

Lorella Donlin
921 Waterford Drive
Bismarck, ND 58503-0902

Lowell Thomas Vizenor
1579 Inlet Court
Reston, VA 20190-4425

Lucille Ann Gardella
17200 W Bell Road, Lot 1244
Surprise, AZ 85374-9850

Miles Miller
4061 Lower Roswell Road
Marietta, GA 30068-4064

Mueller Industries, Inc.
8285 Tournament Drive, Suite 150
Memphis, Tennessee 38125-1743

Mueller Industries, Inc., successor-in-interest to Sharon Steel Corporation,
successor-in-interest to UV Industries, Inc.
8285 Tournament Drive, Suite 150
Memphis, Tennessee 38125-1743

Sharon Steel Corporation
15 Roemer Blvd
Farrell, PA - 16121-2201

PEC Minerals LP
307 West 7th Street, Suite 1110
Fort Worth, TX 76102-5199

Diane B. Rowland, Trustee of the
Baker Mineral Trust
2520 Waterside Dr. Unit 107
Frederick, MD 21701-3023

Randy VanAsperen
3099 3rd Street NW
Underwood, ND 58576-0301

Robert Miller
5135 Nolensville Pike, Apt. Y12
Nashville, TN 37211-6073

Tara Marie Vizenor
n/k/a Tara M Miskowiak
637 Janick Circle West
Stevens Point, WI 5481-2407

The Reiland Family Revocable Living
Trust, c/o Gilbert J. Reiland
2433 Ship Rock Ave.
Tulare, CA 93274-7423

Thomas Joseph Reuter
15418 Flourine Street NW
Anoka, MN 55303-6113

Cleora C. Shearer and Donald B.
Shearer a/k/a Donald Shearer
DECEASED

Donald S. Sayler and Velma Sayler
DECEASED

M.J. Rivenbark
DECEASED

78497920 v1

EXHIBIT A

**BEFORE THE INDUSTRIAL COMMISSION**

**STATE OF NORTH DAKOTA**

**CASE NO. 29888**

**On a motion of the Commission to consider the application of Blue Flint Sequester Company, LLC for a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.**

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA )
) ss.
COUNTY OF BURLEIGH )

Amber Nelson, being first duly sworn, deposes and says that on the 2nd day of March, 2023, she served the attached:

**Memo;**
**Blue Flint Ethanol Fact Sheet;** and
**Notice of Hearing**

by placing a true and correct copy thereof in an envelope addressed as follows:

**See attached Exhibit A**

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Amber Nelson

Subscribed and sworn to before me this 2nd day of March, 2023.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Notary Public
My Commission expires:

78527637 v1

Arkansas Minerals, Inc.
314 East Oak Street
El Dorado, AR 71730

Audrey M. Crum as Trustee of the
Audrey M. Crum Revocable Trust
1913 Canopy Court
Fort Collins, CO 80528-6344

Barbara Ann Johnson
5873 W Riverbend Lane
Boise, ID 83703-6250

Clarence J. Reuter
2787 Vibbert Street South
Salem, OR 97302-5824

David Scott Johnson
314 S 46th West Ave
Tulsa, OK 74127-7633

Debbie Marie Johnson
822 N Division Ave
Sandpoint, ID 83864-2179

Douglas Jones
303 Arbor Green Lane
Rosenberg, TX 77469-4767

Home Stake Oil & Gas Company
n/k/a Denbury, Inc.
5851 Legacy Circle, Suite 1200
Plano, TX 75024

Kathy Sayler
6165 E Iliff Ave, Apt 117A
Denver, CO 80222-5826

Robert David Reuter
3145 Mulberry Drive South
Salem, OR 97302-5912

Rodney C. Schafer
26622 W Abraham Lane
Buckeye, AZ 85396-8003

Rodney C. Schafer, as Trustee of the
Rodney C. Schafer Trust
26622 W Abraham Lane
Buckeye, AZ 85396-8003

Steve Charles Johnson
235 Saint Patrick Lane
Florissant, MO 63031-6850

Therese Borden Sloane
6362 W Blackhawk Drive
Glendale, AZ 85308-6678



EXHIBIT A

**BEFORE THE INDUSTRIAL COMMISSION**

**STATE OF NORTH DAKOTA**

**CASE NO. 29888**

**On a motion of the Commission to consider the application of Blue Flint Sequester Company, LLC for a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.**

AFFIDAVIT OF SERVICE BY MAIL

STATE OF NORTH DAKOTA )
) ss.
COUNTY OF BURLEIGH )

Karen Phillips, being first duly sworn, deposes and says that on the 10th day of March, 2023, she served the attached:

**Memo;**
**Blue Flint Ethanol Fact Sheet;** and
**Notice of Hearing**

by placing a true and correct copy thereof in an envelope addressed as follows:

**Debra J. Trekell**
**501 Glenmoor Rd.**
**Canon City, CO 81212**

and depositing the same, with postage prepaid, certified mail, return receipt requested, in the United States mail at Bismarck, North Dakota.

Karen Phillips

Subscribed and sworn to before me this 10th day of March, 2023.

LYN ODDEN
Notary Public
State of North Dakota
My Commission Expires June 26, 2023

Lyn Odden
Notary Public
My Commission expires:

78610807 v1

## Kadrmas, Bethany R.

**From:** Meidinger, Lorna B.
**Sent:** Monday, March 13, 2023 10:04 AM
**To:** Kadrmas, Bethany R.
**Subject:** RE: North Dakota Industrial Commission Notice of Hearing
**Attachments:** 23-0123 survey.pdf

Bethany,

Attached are our comments for this one.

Respectfully,

Lorna Meidinger
Lead Historic Preservationist
State Historical Society of North Dakota
612 E Boulevard Ave
Bismarck, ND 58505
701.328.2089

---

**From:** Peterson, Bill <billpeterson@nd.gov>
**Sent:** Monday, January 30, 2023 4:43 PM
**To:** Clark, Andrew <andrewclark@nd.gov>; Robinson, Andrew J. <andrewrobinson@nd.gov>; Steckler, Lisa L. <lsteckler@nd.gov>; Meidinger, Lorna B. <lbmeidinger@nd.gov>
**Subject:** FW: North Dakota Industrial Commission Notice of Hearing

Bill Peterson, PhD
Director and ND SHPO
State Historical Society of North Dakota
612 E. Boulevard Ave
Bismarck, ND 58505
701.328.2724
billpeterson@nd.gov
history.nd.gov statemuseum.nd.gov

HISTORY FOR everyone.

---

**From:** Kadrmas, Bethany R. <brkadrmas@nd.gov>
**Sent:** Monday, January 30, 2023 4:38 PM
**Subject:** North Dakota Industrial Commission Notice of Hearing

The attached hearing notice is sent pursuant to North Dakota Administrative Code Section 43-05-01-08(5).

The fact sheet, storage facility permit application, and draft permit are available for download at: https://www.dmr.nd.gov/oilgas/GeoStorageofCO2.asp

Please contact our office if you have any questions.

Bethany Kadrmas
*Legal Assistant, Oil and Gas Division*

701.328.8020 • brkadrmas@nd.gov • www.dmr.nd.gov

NORTH Dakota | Mineral Resources
Be Legendary.

600 E Boulevard Ave, Dept. 405 • Bismarck, ND 58505

STATE HISTORICAL SOCIETY
OF NORTH DAKOTA

HISTORY FOR everyone.

March 13, 2023

Lynn Helms
NDDMR Oil & Gas Division
1016 E Calgary Ave
Bismarck, ND 58503-5512

**ND SHPO Ref.: 23-0123 Blue Flint Ethanol Facility, Case No. 29888 in portions of [T145N R82W Sections 6/8, 17-19 and T145N R83W Sections 11-14 & 24] in McLean County, North Dakota**

Dear Director Helms,

We reviewed ND SHPO Ref.: 23-0123 Blue Flint Ethanol Facility, Case No. 29888 in portions of [T145N R82W Sections 6/8, 17-19 and T145N R83W Sections 11-14 & 24] in McLean County, North Dakota. We recommend a Class III (pedestrian survey) of archaeological resources due to existing cultural resources within the proposed project area and the potential for additional cultural resources.

Thank you for the opportunity to review this project to date. We look forward to review of the Class III survey for archaeological resources. If you have any questions please contact Lorna Meidinger, Lead Historic Preservation Specialist at (701) 328-2089 or lbmeidinger@nd.gov.

Sincerely,

for William D. Peterson, PhD
Director, State Historical Society of North Dakota

23-0123

| | |
|---|---|
| **From:** | McPherson, Madie |
| **To:** | Kadrmas, Bethany R. |
| **Cc:** | Entzi-Odden, Lyn |
| **Subject:** | Blue Flint Sequester Co., LLC/Blue Flint Ethanol Facility - Notice to Participate by Telephonic Means CASES 29888, 29889, 29890 |
| **Date:** | Tuesday, February 28, 2023 9:35:58 AM |
| **Attachments:** | Blue Flint - Notice to Participate by Tel Means CASES 29888, 29889, & 29890_78493559(1).PDF |



Bethany,

Please see the attached for filing in the above-referenced cases.

**Madie McPherson | Legal Administrative Assistant | Fredrikson & Byron, P.A.**
1133 College Drive, Suite 1000 | Bismarck, North Dakota 58501
Main: 701.221.8700 | Direct: 701.221.8654 | mmcpherson@fredlaw.com

Fredrikson

Fredrikson & Byron, P.A.
Attorneys and Advisors

1133 College Drive, Suite 1000
Bismarck, ND 58501-1215
Main: 701.221.8700
fredlaw.com

February 28, 2023

***VIA EMAIL***

Mr. Bruce Hicks
Assistant Director
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

**RE: CASE NOS. 29888, 29889, & 29890**
**Blue Flint Sequester Company, LLC**
**Blue Flint Ethanol Facility**

Dear Mr. Hicks:

Please find enclosed herewith for filing a NOTICE TO PARTICIPATE BY TELEPHONIC MEANS OF BLUE FLINT SEQUESTER COMPANY, LLC AND BLUE FLINT ETHANOL FACILITY for the above-captioned matters.

Should you have any questions, please advise.

Sincerely,

LAWRENCE BENDER

LB/mlm
Enclosure

cc: Mr. Adam Dunlop (w/enc.) – *via email*

78481371 v1

**BEFORE THE INDUSTRIAL COMMISSION**

**OF THE STATE OF NORTH DAKOTA**

**CASE NO. 29888:** **Application of Blue Flint Sequester Company, LLC requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Blue Flint Sequester Company, LLC intends to capture carbon dioxide from the Blue Flint Ethanol Facility and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT March 20, 2023. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Tammy Madche, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Blue Flint Sequester Company, LLC, 2841 3rd St. SW, Underwood, North Dakota 58576.**

**CASE NO. 29889:** **A motion of the Commission to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Blue Flint Sequester Company, LLC storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.**

**CASE NO. 29890:** **A motion of the Commission to determine the amount of financial responsibility for the geologic storage of carbon dioxide from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.**

## NOTICE TO PARTICIPATE BY TELEPHONIC MEANS

In accordance with the provisions of Section 43-02-03-88.2 of the North Dakota Administrative Code, Blue Flint Sequester Company, LLC and Blue Flint Ethanol Facility (collectively "Blue Flint"), an interested party in the above-captioned matters, hereby notifies the North Dakota Industrial Commission, that it intends to appear in the above-entitled matters by telephonic means. The telephone number for Blue Flint is (701) 442-7500. Lawrence Bender, Fredrikson & Byron, P.A., 1133 College Drive, Suite 1000, Bismarck, North Dakota 58501, (701) 221-8700, is counsel for Blue Flint and will be present at the hearing.

**DATED** this 28th day of February, 2023.

FREDRIKSON & BYRON, P.A.

By______________________________

LAWRENCE BENDER, ND Bar #03908
*Attorneys for Applicant,*
*Blue Flint Sequester Company, LLC*
*Blue Flint Ethanol Facility*
1133 College Drive, Suite 1000
P.O. Box 1855
Bismarck, ND 58501-1215
(701) 221-8700

MIDWEST AgEnergy

2841 3rd St SW
Underwood, ND 58576
(701) 442-7500

RECEIVED
FEB - 6 2023
N.D. INDUSTRIAL COMMISSION

January 26, 2023

TO: OWNER, LESSEE OR OPERATOR OF RECORD

**RE: APPLICATION OF BLUE FLINT SEQUESTER COMPANY, LLC FOR CARBON DIOXIDE STORAGE FACILITY**

Dear Sir/Madam:

Blue Flint Sequester Company, LLC ("Blue Flint"), a subsidiary of Midwest AgEnergy Group, LLC, has made application to the North Dakota Industrial Commission ("Commission") requesting an order providing approval of a carbon dioxide storage facility project ("Project"). A hearing to consider the application of Blue Flint for the Project has been scheduled before the Commission as set forth in the attached Notice of Hearing ("Notice"). You are receiving this Notice because you have been identified as an owner, lessee or operator of record within the lands identified in the Notice or within one-half mile of the outside boundary of the proposed Project.

Details concerning the Project are included in the enclosed information pamphlet or are available from the Commission; however, should you have any questions regarding the Project or Blue Flint's application, please contact me at (701) 442-7500 or adunlop@midwestagenergy.com.

Sincerely,

*Adam Dunlop*

Adam Dunlop
Blue Flint Sequester Company, LLC

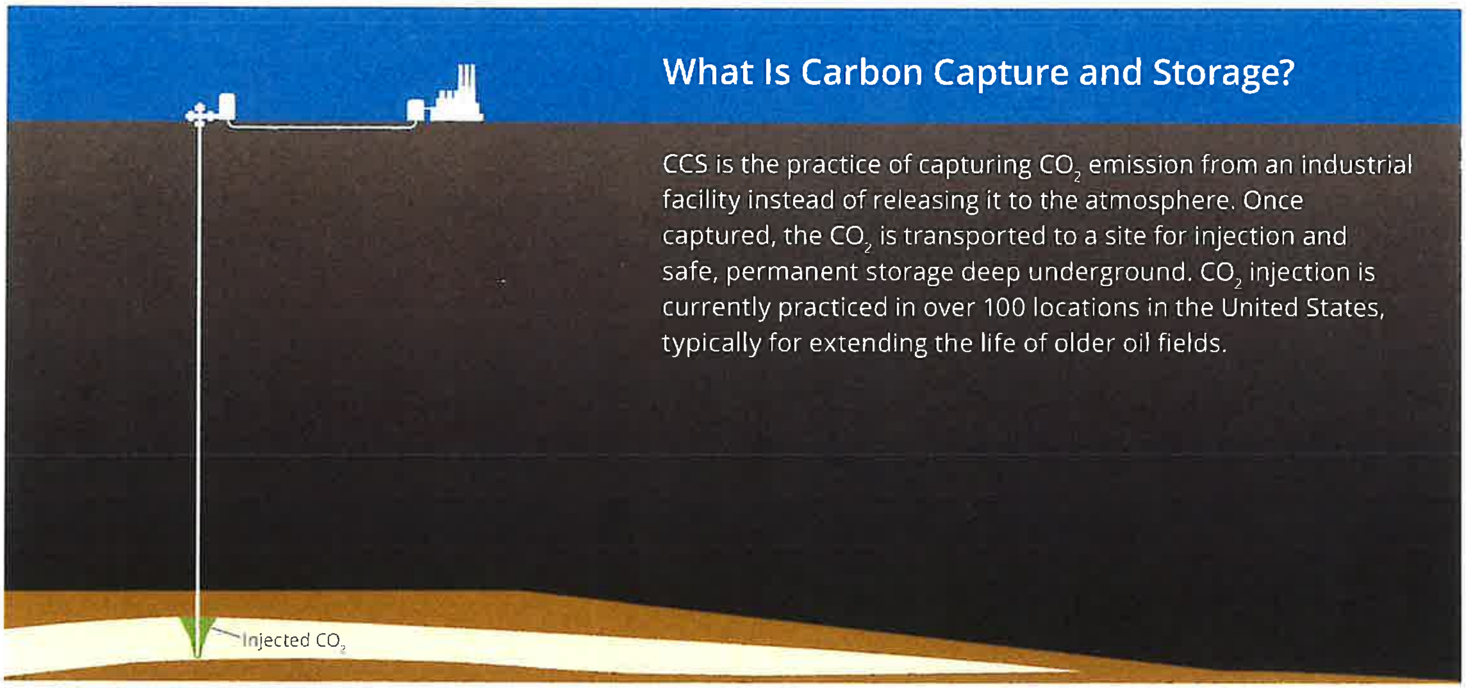
Enclosure(s)
78153458 v1

**BLUE FLINT ETHANOL**

# CCS PROJECT FACT SHEET

## Blue Flint Ethanol CCS Project


Blue Flint Ethanol, an ethanol plant in Underwood, North Dakota, operated by Midwest AgEnergy, is seeking to make its facility more sustainable and ensure long-term viability by integrating carbon capture and storage, or CCS, to reduce carbon dioxide ($CO_2$) emissions from ethanol production. **This reduction in $CO_2$ emissions will be the equivalent of taking 43,500 cars off the road each year.** Keeping $CO_2$ out of the atmosphere will help Blue Flint qualify for tax credits and low-carbon fuel standards to offset the costs of integrating and operating CCS.



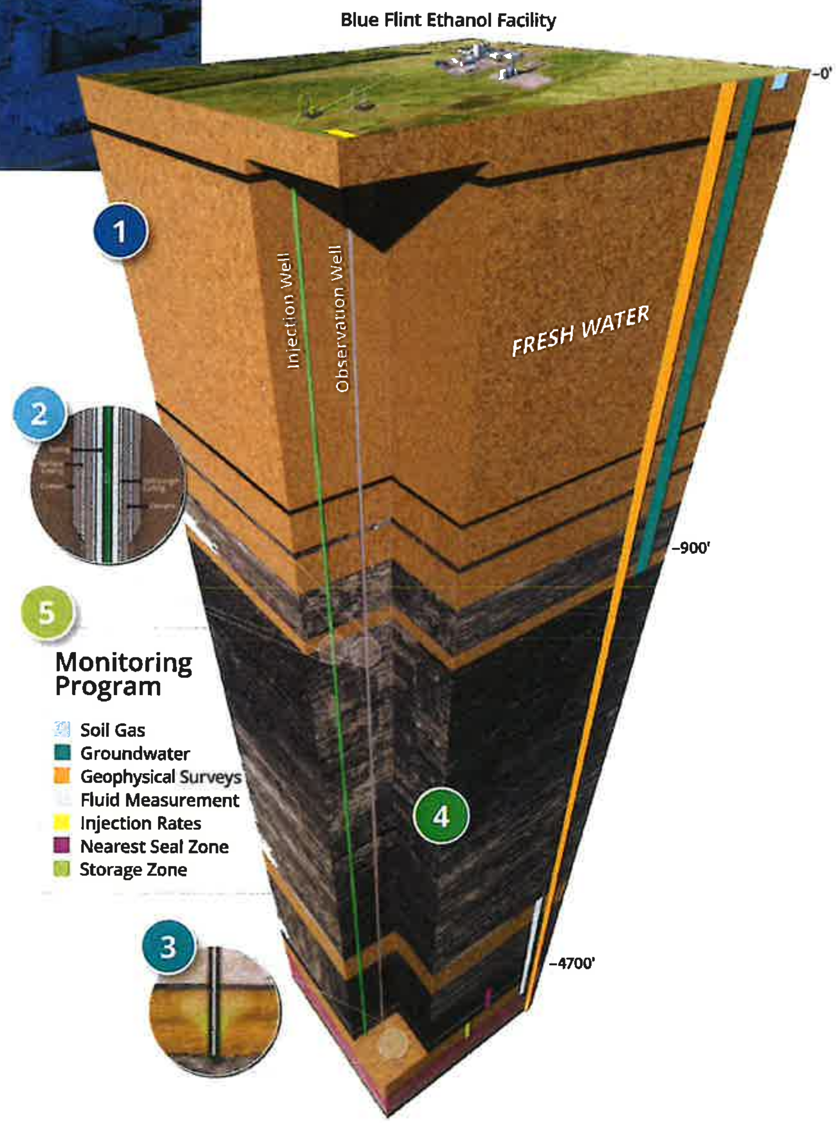

## What Is Carbon Capture and Storage?

CCS is the practice of capturing $CO_2$ emission from an industrial facility instead of releasing it to the atmosphere. Once captured, the $CO_2$ is transported to a site for injection and safe, permanent storage deep underground. $CO_2$ injection is currently practiced in over 100 locations in the United States, typically for extending the life of older oil fields.

## Collaboration with Experts

Geologic $CO_2$ storage requires a deep porous layer to hold $CO_2$ and overlying impermeable rock layers as seals to keep the $CO_2$ in place. Midwest AgEnergy is collaborating with the Energy & Environmental Research Center (EERC) at the University of North Dakota, a global leader in CCS research. The EERC's proven approach features monitoring, characterization, modeling, and simulations to ensure the safety of injecting $CO_2$ into a suitable geologic container nearly a mile deep.

# BLUE FLINT CCS PROJECT WILL ENSURE HUMAN SAFETY AND PROTECT THE ENVIRONMENT.




## 1 Protection of Human Health and the Environment

Groundwater resources are important, and we make sure that they are protected—so does the state through its regulatory and permitting process.

## 2 Drinking Water Protection

Strict regulations govern all subsurface activities. All drilling and wells are engineered to protect groundwater resources. Typically, three layers of steel (casing and tubing) and two layers of durable, long-lasting cement isolate the freshwater aquifers, protecting them from drilling fluids, saltwater from deep rock layers, and injected $CO_2$.

## 3 Storage Zone

The storage zone target for the Blue Flint CCS project is a 100-foot-thick sandstone layer nearly a mile beneath the Blue Flint facility. The sandstone layer holds very salty water and has no oil.

## 4 Nature's Seals

Some underground rock layers make excellent barriers to upward flow of fluids. These cap rocks make effective traps for oil, water, natural gas, and $CO_2$. Cap rocks are usually shales and salts. Beneath the surface at Blue Flint, thousands of feet of shales and other impermeable rock layers already protect the fresh groundwater from the salty water of the target storage zone.

## 5 Ensuring Safety

Confirming that the $CO_2$ stays in the storage layer is critical to the CCS project. Techniques include controlling the injection, monitoring conditions in the container (storage and overlying seals), and tracking $CO_2$ movement in the reservoir with recurring geophysical surveys. Other measures will be used to confirm that $CO_2$ has not moved beyond the storage container and is not affecting groundwater or the surface environment.

**For More Information, Contact:**

**Adam Dunlop**
Executive Vice President
Harvestone Low Carbon Partners
adunlop@midwestagenergy.com
701.442.7500

**Blue Flint Ethanol**
Underwood, ND 58576
www.midwestagenergy.com

MIDWEST AgEnergy

**BEFORE THE INDUSTRIAL COMMISSION**

**STATE OF NORTH DAKOTA**

**CASE NO. _____**

**On a motion of the Commission to consider the application of Blue Flint Sequester Company, LLC for a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.**

**NOTICE OF HEARING**

**PLEASE TAKE NOTICE** that Blue Flint Sequester Company, LLC ("Blue Flint") has made application to the North Dakota Industrial Commission ("Commission") requesting an order providing approval of a carbon dioxide storage facility permit as follows.

1. The carbon dioxide storage facility will be located near the city of Underwood, McLean County, North Dakota, and comprised of the following described lands:

   Township 145 North, Range 82 West
   Section 6: S/2
   Section 7: ALL
   Section 8: ALL
   Section 17: ALL
   Section 18: ALL
   Section 19: N/2

   Township 145 North, Range 83 West
   Section 11: SE/4
   Section 12: ALL
   Section 13: ALL
   Section 14: NE/4
   Section 24: NE/4

2. A hearing to consider the application of Blue Flint will be held before the Commission at 9:00 a.m. on March 21, 2023, at the Department of Mineral Resources Conference Room, Oil and Gas Division, 1000 East Calgary Avenue, Bismarck, North Dakota.
3. A copy of the permit application and draft permit may be obtained from the Commission.
4. All comments regarding the application for the storage facility permit must be in writing and submitted to the Commission prior to hearing or presented at the hearing.
5. Amalgamation of the storage reservoirs pore space is required to operate the storage facility and the Commission may require that the pore space owned by nonconsenting owners be included in the storage facility and subject to geologic storage. The amalgamation of pore space will be considered at the hearing.

**DATED** ~~this~~ 26 day of January, 2023.

FREDRIKSON & BYRON, P.A.

By______________________________

LAWRENCE BENDER, ND Bar #03908
*Attorneys for Applicant,*
*Blue Flint Sequester Company, LLC*
1133 College Drive, Suite 1000
P. O. Box 1855
Bismarck, ND 58502-1000
(701) 221-8700

78153386 v1

Case No.: 29888
Date Established: January 30, 2023

# DRAFT STORAGE FACILITY PERMIT

STORAGE FACILITY FOR CARBON SEQUESTRATION UNDER THE NORTH DAKOTA UNDERGROUND INJECTION CONTROL PROGRAM

In compliance with North Dakota Century Code Chapter (NDCC) 38-22 (Carbon Dioxide Underground Storage) and North Dakota Administrative Code (NDAC) Chapter 43-05-01 (Geologic Storage of Carbon Dioxide), Blue Flint Sequester Company, LLC has applied for a carbon dioxide storage facility permit. A draft permit does not grant the authorization to inject. This is a document prepared under NDAC 43-05-01-07.2 indicating the Commission's tentative decision to issue a storage facility permit. Before preparing the draft permit, the Commission has consulted with the Department of Environmental Quality and determined the storage facility permit application to be complete. The draft permit contains permit conditions required under NDAC 43-05-01-07.3 and 43-05-01-07.4. A fact sheet is included and contains the following information:

1. A brief description of the type of facility or activity which is the subject of the draft permit.
2. The quantity and quality of the carbon dioxide which is proposed to be injected and stored.
3. A brief summary of the basis for the draft permit conditions, including references to applicable statutory or regulatory provisions.
4. The reasons why any requested variances or alternatives to required standards do or do not appear justified.
5. A description of the procedures for reaching a final decision on the draft permit, including:
    a. The beginning and ending dates of the comment period.
    b. The address where comments will be received.
    c. The date, time, and location of the storage facility permit hearing.
    d. Any other procedures by which the public may participate in the final decision.
6. The name and telephone number of a person to contact for additional information.

This draft permit has been established on January 30, 2023 and shall remain in effect until a storage facility permit is granted under NDAC 43-05-01-05, unless amended or terminated by the Department of Mineral Resources (commission).

Tamara Madche, Geologist
Department of Mineral Resources
Date: January 30, 2023

## I. APPLICANT

Blue Flint Sequester Company, LLC
2841 3rd St SW
Underwood, ND 58576

## II. PERMIT CONDITIONS (NDAC 43-05-01-07.3)

1. The storage operator shall comply with all conditions of the permit. Any noncompliance with the permit constitutes a violation and is grounds for enforcement action, including permit termination, revocation, or modification pursuant to NDAC 43-05-01-12.

2. In an administrative action, it shall not be a defense that it would have been necessary for the storage operator to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

3. The storage operator shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with the storage facility permit.

4. The storage operator shall develop and implement an emergency and remedial response plan pursuant to section 43-05-01-13.

5. The storage operator shall at all times properly operate and maintain all storage facilities which are installed or used by the storage operator to achieve compliance with the conditions of the storage facility permit. Proper operation and maintenance include effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the storage facility permit.

6. The permit may be modified, revoked and reissued, or terminated pursuant to section 43-05-01-12. The filing of a request by the storage operator for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. The injection well permit or the permit to operate an injection well does not convey any property rights of any sort or any exclusive privilege.

8. The storage operator shall furnish to the commission, within a time specified by the commission, any information which the commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. The storage operator shall also

furnish to the commission, upon request, copies of records required to be kept by the storage facility permit.

9. The storage operator shall allow the commission, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

    a. Enter upon the storage facility premises where records must be kept under the conditions of the permit;
    b. At reasonable times, have access to and copy any records that must be kept under the conditions of the permit;
    c. At reasonable times, inspect any facilities, equipment, including monitoring and control equipment, practices, or operations regulated or required under the permit; and
    d. At reasonable times, sample or monitor for the purposes of assuring permit compliance, any substances or parameters at any location.

10. The storage operator shall prepare, maintain, and comply with a testing and monitoring plan pursuant to section 43-05-01-11.4.

11. The storage operator shall comply with the reporting requirements provided in section 43-05-01-18.

12. The storage operator must obtain an injection well permit under section 43-05-01-10 and injection wells must meet the construction and completion requirements in section 43-05-01-11.

13. The storage operator shall prepare, maintain, and comply with a plugging plan pursuant to section 43-05-01-11.5.

14. The storage operator shall establish mechanical integrity prior to commencing injection and maintain mechanical integrity pursuant to section 43-05-01-11.1.

15. The storage operator shall implement the worker safety plan pursuant to section 43-05-01.13.

16. The storage operator shall comply with leak detection and reporting requirements pursuant to section 43-05-01-14.

17. The storage operator shall conduct a corrosion monitoring and prevention program pursuant to section 43-05-01-15.

18. The storage operator shall prepare, maintain, and comply with the area of review and corrective action plan pursuant to section 43-05-01-05.1.

19. The storage operator shall maintain financial responsibility pursuant to section 43-05-01-09.1

20. The storage operator shall maintain and comply with the postinjection site care and facility closure plan pursuant to section 43-05-01-19.

## III. CASE SPECIFIC PERMIT CONDITIONS

1. NDAC 43-05-01-11.4, subsection 1, subdivision b; The operator shall notify the commission within 24 hours of failure or malfunction of any surface or bottom hole gauge in the MAG 1 (WF# 37833 – LOT 1 18-145N-82W) injector and the proposed MAG 2 monitor well.

2. NDAC 43-05-01-11.4, subsection 1, subdivision c and NDAC 43-05-01-11, subsection 14; The operator shall run an ultrasonic or another log capable of evaluating internal and external pipe condition to establish a baseline for corrosion monitoring for the MAG 1 and proposed MAG 2. The operator shall run logs with the same capabilities for the MAG 1 on a 5 year schedule unless analysis of corrosion coupons or subsequent logging necessitates a more frequent schedule.

3. NDAC 43-05-01-11.4, subsection 1, subdivision d and NDAC 43-05-01-13, subsection 2; The operator shall cease injection immediately, take all steps reasonably necessary to identify and characterize any release, implement the emergency and remedial response plan approved by the commission, and notify the commission within 24 hours of carbon dioxide detected above the confining zone.

4. NDAC 43-05-01-11.4, subsection 1, subdivision e and NDAC 43-05-01-11.1 subsections 3 and 5; External mechanical integrity shall be continuously monitored with the proposed fiber optic lines for the MAG 1 and MAG 2. The MAG 1 fiber optic line shall be run in the intermediate-long string casing annulus. The commission must be notified within 24 hours should a fiber optic line fail. The commission must be notified prior to severing the line above the confining zone if such an action becomes necessary for remedial work or monitoring activities.

5. NDAC 43-05-01-11.4, subsection 1, subdivision h, paragraph 1; Surface air and soil gas monitoring is required and is planned by the operator in Section 5.7 (Environmental Monitoring Plan), Section 5.7.1 (Atmospheric Monitoring), and Section 5.7.2 (Soil Gas and Groundwater Monitoring) of its permit.

6. NDAC 43-05-01-10, subsection 9, subdivision c, NDAC 43-05-01-11, subsection 15, and NDAC 43-05-01-11.1, subsection 2; The operator shall notify the commission at least 48 hours in advance to witness a mechanical integrity test of the tubing-casing annulus. The packer must be set within 100’ of the upper most

perforation and in the 13CR-80 casing. Dependent on evaluation, the operator shall run the same test on a 5 year schedule for the MAG 1 injection well.

7. NDAC 43-05-01-11, subsections 3 and 5; The operator shall continuously monitor surface-intermediate casing annulus with a gauge not to exceed 300psi. The operator shall continuously monitor the intermediate-long string casing annulus with the proposed fiber optic line, and a gauge not to exceed 300psi. The commission must be notified in advance if there is pressure that needs to be bled off.

# Fact Sheet

## 1. Description of Facility

The Blue Flint Sequester Company, LLC (Blue Flint), is a subsidiary of Midwest AgEnergy Group, LLC (MAG). The Blue Flint Ethanol (BFE) facility, owned and operated by MAG, is a 70 million gallon dry mill ethanol production plant located in McLean County, North Dakota, near the city of Underwood. BFE emits carbon dioxide from the fermentation process during ethanol production.

## 2. Quantity and Quality of Carbon Dioxide Stream

The BFE emits an annual average of 200,000 metric tons of carbon dioxide that is expected to be captured, dehydrated, compressed, and then injected. The projected composition of the carbon dioxide stream is greater than 99.98% carbon dioxide with trace quantities of water, oxygen, nitrogen, methane, acetaldehyde, hydrogen sulfide, dimethyl sulfide, ethyl acetate, isopentyl acetate, methanol, ethanol, acetone, n-Propanol, and n-Butanol, equaling less than 0.02% combined.

## 3. Summary of Basis of Draft Permit Conditions

The case specific permit conditions are unique to this storage facility, and not indicative of conditions for other storage facility permits. The conditions take into consideration the equipment proposed for this storage facility. Regulatory provisions for these conditions are all cited from NDAC Chapter 43-05-01 (Geologic Storage of Carbon Dioxide).

## 4. Reasons for Variances or Alternatives

<u>Draft Permit Section III. Case Specific Conditions are referenced below by number from aforementioned section</u>

4. NDAC 43-05-01-11.4, subsection 1, subdivision e, requires a demonstration of external mechanical integrity at least once per year until the injection well is

plugged. NDAC 43-05-01-11.1, subsection 3 requires the storage operator to, at least annually, determine the absence of significant fluid movement by running an approved tracer survey or temperature log or noise log. The installed fiber optic line shall provide a continuous temperature log for the length of the wellbore.

## 5. Procedures Required for Final Decision

**The beginning and ending dates of the comment period:**
January 30, 2023 to 5:00 P.M. CDT March 20, 2023

**The address where comments will be received:**
Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov

**Date, time, and location of the storage facility permit hearing:**
March 21, 2023 9:00 A.M. CDT at 1000 East Calgary Avenue, Bismarck, North Dakota 58503

**Any other procedures by which the public may participate in the final decision:**
At the hearing, the Commission will receive testimony and exhibits of interested parties.

## 6. Contact for Additional Information

Draft Permit Information: Tamara Madche – tjmadche@nd.gov – 701-328-8020
Hearing Information: Bethany Kadrmas – brkadrmas@nd.gov – 701-328-8020#

MIDWEST
AgEnergy

2841 3rd St SW
Underwood, ND 58576
(701) 442-7500

September 30, 2022

RECEIVED
OCT - 6 2022
N.D. INDUSTRIAL COMMISSION

Mr. Lynn Helms
North Dakota Industrial Commission
State Capitol, Department 405
600 East Boulevard Avenue
Bismarck, ND 58505-0840

Dear Mr. Helms:

Subject: Development of CCS Facility Permit Application and CCS Incentive Program Compliance – Storage Facility Permit Application

Midwest AgEnergy Group, LLC, together with its partners and affiliates, respectfully submits a storage facility permit application for the dedicated geologic storage of carbon dioxide at Blue Flint Ethanol facility in McLean County, North Dakota.

Following is a link to the application: SFP Application

Please find attached the permit application certification for filing.

If you have any questions, please contact Adam Dunlop of my staff by phone at (701) 442-7500 or by e-mail at adunlop@midwestagenergy.com.

Sincerely,

Jeff Zueger
Chief Executive Officer
Midwest AgEnergy Group, LLC

RECEIVED

OCT - 6 2022

N.D. INDUSTRIAL COMMISSION

## STORAGE FACILITY PERMIT APPLICATION CERTIFICATION

BEFORE ME, the undersigned authority, personally appeared Jeff Zueger of Midwest AgEnergy Group, LLC, who being duly sworn upon oath stated and certifies that:

1. I, Jeff Zueger, am over 18 years of age. I have personal knowledge of the information and facts stated by me in this Certification, and they are true and correct. I have never been convicted of any felony or of any crime involving moral turpitude and am fully competent to make these representations.

2. I hold the position of Chief Executive Officer for Midwest AgEnergy Group, LLC. As required in accordance with North Dakota Administrative Code 43-05-01-07.1 and by virtue of my position with Midwest AgEnergy Group, LLC, I am authorized to make the representations on behalf of Midwest AgEnergy Group, LLC.

3. Attached is the storage facility permit application requesting a permit under Chapter 38-22 of the North Dakota Century Code and in accordance with Article 43-05 of the North Dakota Administrative Code for the establishment of a carbon dioxide storage facility located in McLean County, North Dakota.

4. Based upon information and reports provided by individuals immediately responsible for compiling and preparing the enclosed permit applications and supporting information, I have personal knowledge and am familiar with the information being submitted in the attached documents to the permit application. Based upon information and belief, the information contained herein is true, accurate, and complete.

5. I affirm under penalty of perjury that the representations contained in this affidavit are true to the best of my knowledge, information, and belief. I understand that there are significant penalties for submitting false information, including the possibility of a fine and imprisonment.

6. By my signature below, I hereby submit the attached application and supporting documentation and information on behalf of Midwest AgEnergy Group, LLC.

Executed this 30th day of September 2022.

Jeff Zueger

STATE OF NORTH DAKOTA )
)
COUNTY OF MCLEAN )

Subscribed and sworn to before me this 30th day of September 2022.

KYLIE L LANDEIS
Notary Public
State of North Dakota
My Commission Expires Sept. 15, 2026

Notary Public

| | |
|---|---|
| **From:** | Regorrah, Josh |
| **To:** | Madche, Tamara J.; Suggs, Richard A. |
| **Cc:** | Adam Dunlop; Livers-Douglas, Amanda; Connors, Kevin; Riter, Charlotte |
| **Subject:** | Midwest AgEnergy Storage Facility Permit Submission |
| **Date:** | Tuesday, December 13, 2022 10:00:50 AM |
| **Attachments:** | image002.png<br>MAG Supplements and Changes 2022-12-13.docx |



Tammy and Richard,

Midwest AgEnergy respectfully resubmits for the review and consideration of the North Dakota Industrial Commission, the application for a carbon dioxide storage facility permit. A link to the application is provided below. The application is submitted pursuant to and in accordance with Chapter 38-22 of the North Dakota Century Code and Chapter 43-05-01 of the North Dakota Administrative Code. Simulation files, high-resolution figures, and supplemental well logs are included with the link. A list of changes that were made to the SFP have been attached.

SFP Folder: SFP Application

Please let me and the team know if there are any questions or concerns.

Josh Regorrah
EERC | UND UNIVERSITY OF NORTH DAKOTA
Permitting and Regulatory Specialist
**Energy & Environmental Research Center**
**University of North Dakota**
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018
| Cell: (218) 779-2781
jregorrah@undeerc.org|www.undeerc.org

# BLUE FLINT SEQUESTER COMPANY, LLC

Carbon Dioxide Geologic Storage Facility Permit Application

*Prepared for*:

Tamara Madche

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

*Prepared by*:

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

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

December 2022

## TABLE OF CONTENTS



Continued . . .

## TABLE OF CONTENTS (continued)



Continued . . .

**TABLE OF CONTENTS (continued)**

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

### PERMIT APPLICATION SUMMARY

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

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

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

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

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

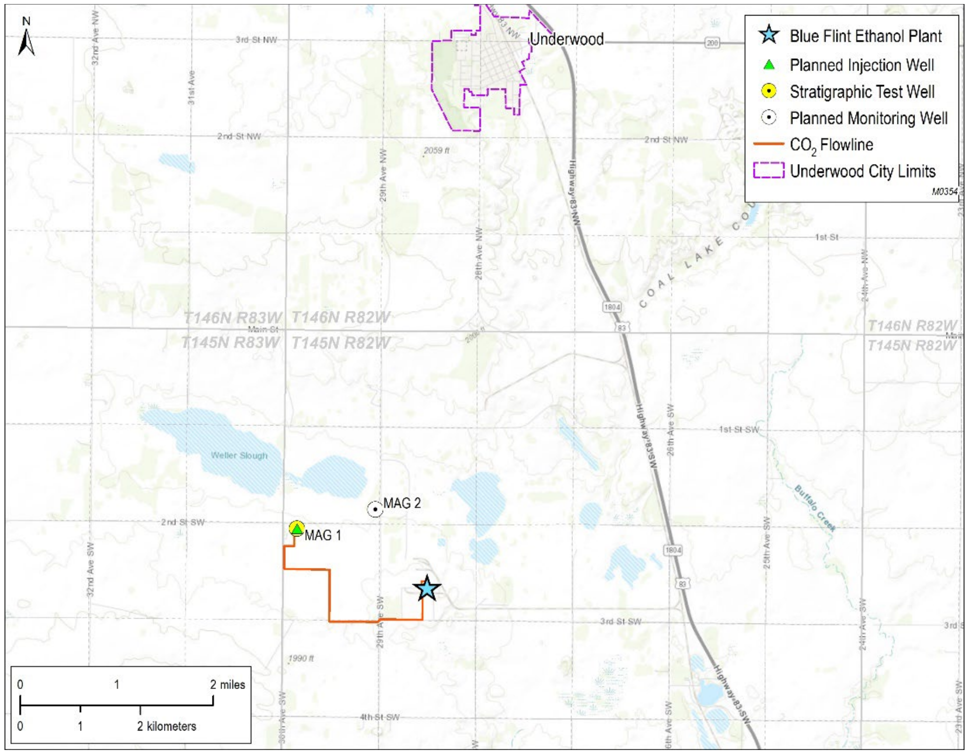



Figure PS-1. Location of the Blue Flint $CO_2$ storage project in relation to the city of Underwood, North Dakota.

# 1.0 PORE SPACE ACCESS

## 1.0 PORE SPACE ACCESS

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

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

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

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

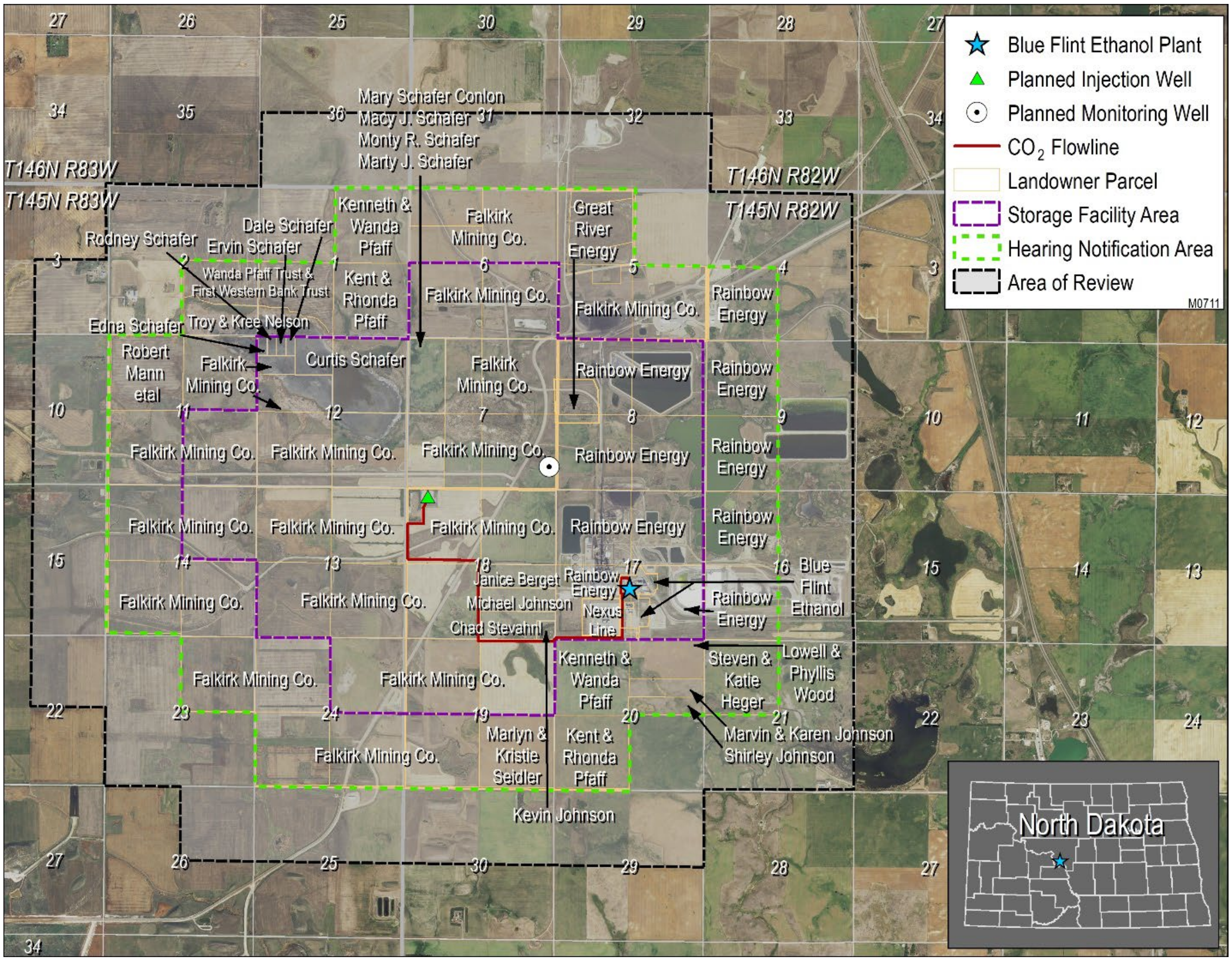



Figure 1-1. Storage facility area map showing pore space ownership.

Fredrikson

Fredrikson & Byron, P.A.
Attorneys and Advisors

1133 College Drive, Suite 1000
Bismarck, ND 58501-1215
Main: 701.221.8700
fredlaw.com

RECEIVED
DEC - 6 2022
N.D. INDUSTRIAL COMMISSION

December 6, 2022

***HAND DELIVERED***

Mr. Bruce Hicks
Assistant Director
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

**RE: NDIC CASE NO. ____________**
**CARBON DIOXIDE STORAGE FACILITY PERMIT APPLICATION OF BLUE FLINT SEQUESTER COMPANY, LLC**

Dear Mr. Hicks:

Enclosed herewith for filing in the above-captioned matter, please find the *Storage Agreement – Blue Flint Broom Creek – Secure Geologic Storage, McLean County North Dakota.*

Should you have any questions, please advise.

Sincerely,

LAWRENCE BENDER

LB/tjg
Enclosure(s)

cc: Blue Flint Sequester Company, LLC

RECEIVED

DEC - 6 2022

N.D. INDUSTRIAL COMMISSION

# STORAGE AGREEMENT
# BLUE FLINT BROOM CREEK – SECURE GEOLOGIC STORAGE
# MCLEAN COUNTY, NORTH DAKOTA

**STORAGE AGREEMENT**
**BLUE FLINT BROOM CREEK – SECURE GEOLOGIC STORAGE**
**MCLEAN COUNTY, NORTH DAKOTA**

**THIS AGREEMENT** ("Agreement") is entered into as of the ___ day of ________, 20__, by the parties who have signed the original of this instrument, a counterpart thereof, ratification and joinder or other instrument agreeing to become a Party hereto.

## RECITALS:

A. It is in the public interest to promote the geologic storage of carbon dioxide in a manner which will benefit the state and the global environment by reducing greenhouse gas emissions and in a manner which will help ensure the viability of the state's coal and power industries, to the economic benefit of North Dakota and its citizens;

B. To further geologic storage of carbon dioxide, a potentially valuable commodity, may allow for its ready availability if needed for commercial, industrial, or other uses, including enhanced recovery of oil, gas, and other minerals; and

C. For geologic storage, however, to be practical and effective requires cooperative use of surface and subsurface property interests and the collaboration of property owners, which may require procedures that promote, in a manner fair to all interests, cooperative management, thereby ensuring the maximum use of natural resources.

## AGREEMENT:

It is agreed as follows:

## ARTICLE 1
## DEFINITIONS

As used in this Agreement:

1.1 **Carbon Dioxide** means carbon dioxide in gaseous, liquid, or supercritical fluid state together with incidental associated substances derived from the source materials, capture process and any substances added or used to enable or improve the injection process.

1.2 **Commission** means the North Dakota Industrial Commission.

1.3 **Effective Date** is the time and date this Agreement becomes effective as provided in Article 14.

1.4 **Facility Area** is the land described by Tracts in Exhibit "B" and shown on Exhibit "A" containing 4953.71 acres, more or less.

1.5 **Party** is any individual, corporation, limited liability company, partnership, association, receiver, trustee, curator, executor, administrator, guardian, tutor, fiduciary, or other representative of any kind, any department, agency, or instrumentality of the state, or any governmental subdivision thereof, or any other entity capable of holding an interest in the Storage Reservoir.

1.6 **Pore Space** means a cavity or void, whether natural or artificially created, in any subsurface stratum.

1.7 **Pore Space Interest** is a right to or interest in the Pore Space in any Tract within the boundaries of the Facility Area.

1.8 **Pore Space Owner** is a Party hereto who owns Pore Space Interest.

1.9 **Storage Equipment** is any personal property, lease and well equipment, plants and other facilities and equipment for use in Storage Operations.

1.10 **Storage Expense** is all costs, expense or indebtedness incurred by the Storage Operator pursuant to this Agreement for or on account of Storage Operations.

1.11 **Storage Facility** is the unitized or amalgamated Storage Reservoir created pursuant to an order of the Commission.

1.12 **Storage Facility Participation** is the percentage shown on Exhibit "C" for allocating payments for use of the Pore Space under each Tract identified in Exhibit "B".

1.13 **Storage Operations** are all operations conducted by the Storage Operator pursuant to this Agreement or otherwise authorized by any lease covering any Pore Space Interest.

1.14 **Storage Operator** is the person or entity named in Section 4.1 of this Agreement.

1.15 **Storage Reservoir** consists of the Pore Space and confining subsurface strata underlying the Facility Area described as the lower Piper Picard and Spearfish(Upper Confining Zone), Broom Creek (Storage Reservoir/Injection Zone), and Amsden (Lower Confining Zone) Formation(s) and which are defined as identified by the well logging suite performed at the stratigraphic well, the MAG 1 well (File No. 37833). The log suites included caliper, spontaneous potential (SP), gamma ray (GR), density, porosity (neutron, density), dipole sonic, resistivity, and a full-bore formation microimager (FMI) log. Further, the logs were used to pick formation top depths and interpret lithology, petrophysical properties, and time-to-depth shifting of seismic data obtained from a 3D seismic survey covering an area totaling 9-mi$^2$ in and around the MAG 1 (located in Section 18, Township 145 North, Range 82 West) stratigraphic well located in Mclean County, North Dakota. Formation top depths were picked from the top of the lower Piper Picard Formation to the top of the Tyler Formation. These logs and data which encompass the stratigraphic interval from an average depth of 4,553 feet to an average depth of 5,053 feet within the limits of the Facility Area.

1.16 **Storage Rights** are the rights to explore, develop, and operate lands within the Facility Area for the storage of Storage Substances.

1.17 **Storage Substances** are Carbon Dioxide and incidental associated substances, fluids, and minerals.

1.18 **Tract** is the land described as such and given a Tract number in Exhibit "B."

## ARTICLE 2
## EXHIBITS

2.1 **Exhibits.** The following exhibits, which are attached hereto, are incorporated herein by reference:

2.1.1 Exhibit "A" is a map that shows the boundary lines of the Blue Flint Broom Creek Facility Area and the tracts therein;

2.1.2 Exhibit "B" is a schedule that describes the acres of each Tract in the Blue Flint Broom Creek Facility Area;

2.1.3 Exhibit "C" is a schedule that shows the Storage Facility Participation of each Tract; and

2.1.4 Exhibit "D" is a form of Pore Space Lease.

2.2 **Reference to Exhibits.** When reference is made to an exhibit, it is to the exhibit as originally attached or, if revised, to the last revision.

2.3 **Exhibits Considered Correct.** Exhibits "A," "B," "C" and "D" shall be considered to be correct until revised as herein provided.

2.4 **Correcting Errors.** The shapes and descriptions of the respective Tracts have been established by using the best information available. If it subsequently appears that any Tract, mechanical miscalculation or clerical error has been made, Storage Operator, with the approval of Pore Space Owners whose interest is affected, shall correct the mistake by revising the exhibits to conform to the facts. The revision shall not include any re-evaluation of engineering or geological interpretations used in determining Storage Facility Participation. Each such revision of an exhibit made prior to thirty (30) days after the Effective Date shall be effective as of the Effective Date. Each such revision thereafter made shall be effective at 7:00 a.m. on the first day of the calendar month next following the filing for record of the revised exhibit or on such other date as may be determined by Storage Operator and set forth in the revised exhibit.

2.5 **Filing Revised Exhibits.** If an exhibit is revised, Storage Operator shall execute an appropriate instrument with the revised exhibit attached and file the same for record in the county or counties in which this Agreement or memorandum of the same is recorded and shall also file the amended changes with the Commission.

## ARTICLE 3
## CREATION AND EFFECT OF STORAGE FACILITY

3.1 **Unleased Pore Space Interests.** Any Pore Space Owner in the Storage Facility who owns a Pore Space Interest in the Storage Reservoir that is not leased for the purposes of this Agreement and during the term hereof, shall be treated as if it were subject to the Pore Space Lease attached hereto as Exhibit "D".

3.2 **Amalgamation of Pore Space.** All Pore Space Interests in and to the Tracts are hereby amalgamated and combined insofar as the respective Pore Space Interests pertain to the Storage Reservoir, so that Storage Operations may be conducted with respect to said Storage Reservoir as if all of the Pore Space Interests in the Facility Area had been included in a single lease executed by all Pore Space Owners, as lessors, in favor of Storage Operator, as lessee and as if the lease contained all of the provisions of this Agreement.

3.3 **Amendment of Leases and Other Agreements.** The provisions of the various leases, agreements, or other instruments pertaining to the respective Tracts or the storage of the Storage Substances therein, including the Pore Space Lease attached hereto as Exhibit "D", are amended to the extent necessary to make them conform to the provisions of this Agreement, but otherwise shall remain in effect.

3.4 **Continuation of Leases and Term Interests.** Injection in to any part of the Storage Reservoir, or other Storage Operations, shall be considered as injection in to or upon each Tract within said Storage Reservoir, and such injection or operations shall continue in effect as to each lease as to all lands and formations covered thereby just as if such operations were conducted on and as if a well were injecting in each Tract within said Storage Reservoir.

3.5 **Titles Unaffected by Storage.** Nothing herein shall be construed to result in the transfer of title of the Pore Space Interest of any Party hereto to any other Party or to Storage Operator.

3.6 **Injection Rights.** Storage Operator is hereby granted the right to inject into the Storage Reservoir any Storage Substances in whatever amounts Storage Operator may deem expedient for Storage Operations, together with the right to drill, use, and maintain injection wells in the Facility Area, and to use for injection purposes.

3.7 **Transfer of Storage Substances from Storage Facility.** Storage Operator may transfer from the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, to any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North Dakota Century Code. The transfer of such Storage Substances out of the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.8 **Receipt of Storage Substances.** Storage Operator may accept and receive into the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, being stored in any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North Dakota Century Code. The receipt of such Storage Substances into the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.9 **Cooperative Agreements.** Storage Operator may enter into cooperative agreements with respect to lands adjacent to the Facility Area for the purpose of coordinating Storage Operations. Such cooperative agreements may include, but shall not be limited to, agreements regarding the transfer and receipt of Storage Substances pursuant to Sections 3.7 and 3.8 of this Agreement.

3.10 **Border Agreements.** Storage Operator may enter into an agreement or agreements with owners of adjacent lands with respect to operations which may enhance the injection of the Storage Substances in the Storage Reservoir in the Facility Area or which may otherwise be necessary for the conduct of Storage Operations.

## ARTICLE 4
## STORAGE OPERATIONS

4.1 **Storage Operator.** Blue Flint Sequester Company, LLC is hereby designated as the initial Storage Operator. Storage Operator shall have the exclusive right to conduct Storage Operations, which shall conform to the provisions of this Agreement and any lease covering a Pore Space Interest. If there is any conflict between such agreements, this Agreement shall govern.

4.2 **Successor Operators**. The initial Storage Operator and any subsequent operator may, at any time, transfer operatorship of the Storage Facility with and upon the approval of the Commission.

4.3 **Method of Operation.** Storage Operator shall engage in Storage Operations with diligence and in accordance with good engineering and injection practices.

4.4 **Change of Method of Operation.** As permitted by the Commission nothing herein shall prevent Storage Operator from discontinuing or changing in whole or in part any method of operation which, in its opinion, is no longer in accord with good engineering or injection practices. Other methods of operation may be conducted or changes may be made by Storage Operator from time to time if determined by it to be feasible, necessary or desirable to increase the injection or storage of Storage Substances.

## ARTICLE 5
## TRACT PARTICIPATIONS

5.1 **Tract Participations.** The Storage Facility Participation of each Tract is shown in Exhibit "C." The Storage Facility Participation of each Tract shall be based 100% upon the ratio of surface acres in each Tract to the total surface acres for all Tracts within the Facility Area.

5.2 **Relative Storage Facility Participations.** If the Facility Area is enlarged or reduced, the revised Storage Facility Participation of the Tracts remaining in the Facility Area and which were within the Facility Area prior to the enlargement or reduction shall remain in the same ratio to one another.

## ARTICLE 6
## ALLOCATION OF STORAGE SUBSTANCES

6.1 **Allocation of Tracts.** All Storage Substances injected shall be allocated to the several Tracts in accordance with the respective Storage Facility Participation effective during the period that the Storage Substances are injected. The amount of Storage Substances allocated to each tract, regardless of whether the amount is more or less than the actual injection of Storage Substances from the well or wells, if any, on such Tract, shall be deemed for all purposes to have been injected into such Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.1.

6.2 **Distribution within Tracts.** The Storage Substances injected and allocated to each Tract shall be distributed among, or accounted for to, the Pore Space Owners who own a Pore Space Interest in such Tract in accordance with each Pore Space Owner's Storage Facility Participation effective during the period that the Storage Substances were injected. If any Pore Space Interest in a Tract hereafter becomes divided and owned in severalty as to different parts of the Tract, the owners of the divided interests, in the absence of an agreement providing for a different division, shall be compensated for the storage of the Storage Substances in proportion to the surface acreage of their respective parts of the Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.2.

## ARTICLE 7
## TITLES

7.1 **Warranty and Indemnity.** Each Pore Space Owner who, by acceptance of revenue for the injection of Storage Substances into the Storage Reservoir, shall be deemed to have warranted title to its Pore Space Interest, and, upon receipt of the proceeds thereof to the credit of such interest, shall indemnify and hold harmless the Storage Operator and other Parties from any loss due to failure, in whole or in part, of its title to any such interest.

7.2 **Injection When Title Is in Dispute.** If the title or right of any Pore Space Owner claiming the right to receive all or any portion of the proceeds for the storage of any Storage Substances allocated to a Tract is in dispute, Storage Operator shall require that the Pore Space Owner to whom the proceeds thereof are paid furnish security for the proper accounting thereof to the rightful Pore Space Owner if the title or right of such Pore Space Owner fails in whole or in part.

7.3 **Payments of Taxes to Protect Title.** The owner of surface rights to lands within the Facility Area is responsible for the payment of any *ad valorem* taxes on all such rights, interests or property, unless such owner and the Storage Operator otherwise agree. If any *ad valorem* taxes are not paid by or for such owner when due, Storage Operator may at any time prior to tax sale or expiration of period of redemption after tax sale, pay the tax, redeem such rights, interests or property, and discharge the tax lien. Storage Operator shall, if possible, withhold from any proceeds derived from the storage of Storage Substances otherwise due any Pore Space Owner who is a delinquent taxpayer an amount sufficient to defray the costs of such payment or redemption, such withholding to be credited to the Storage Operator. Such withholding shall be without prejudice to any other remedy available to Storage Operator.

7.4 **Pore Space Interest Titles.** If title to a Pore Space Interest fails, but the tract to which it relates is not removed from the Facility Area, the Party whose title failed shall not be entitled to share under this Agreement with respect to that interest.

## ARTICLE 8
## EASEMENTS OR USE OF SURFACE

8.1 **Grant of Easement.** Storage Operator shall have the right to use as much of the surface of the land within the Facility Area as may be reasonably necessary for Storage Operations and the injection of Storage Substances.

8.2 **Use of Water.** Storage Operator shall have and is hereby granted free use of water from the Facility Area for Storage Operations, except water from any well, lake, pond or irrigation ditch of a Pore Space Owner; notwithstanding the foregoing, Storage Operator may access any well, lake, or pond as provided in Exhibit "D".

8.3 **Surface Damages.** Storage Operator shall pay surface owners for damage to growing crops, timber, fences, improvements and structures located on the Facility Area that result from Storage Operations.

8.4 **Surface and Sub-Surface Operating Rights.** Except to the extent modified in this Agreement, Storage Operator shall have the same rights to use the surface and sub-surface and use of water and any other rights granted to Storage Operator in any lease covering Pore Space Interests. Except to the extent expanded by this Agreement or the extent that such rights are common to the effected leases, the rights granted by a lease may be exercised only on the land covered by that lease. Storage Operator will to the extent possible minimize surface impacts.

## ARTICLE 9
## ENLARGEMENT OF STORAGE FACILITY

9.1 **Enlargement of Storage Facility.** The Storage Facility may be enlarged from time to time to include acreage and formations reasonably proven to be geologically capable of storing Storage Substances. Any expansion must be approved in accordance with the rules and regulations of the Commission.

9.2 **Determination of Tract Participation.** Storage Operator, subject to Section 5.2, shall determine the Storage Facility Participation of each Tract within the Storage Facility as enlarged, and shall revise Exhibits "A", "B" and "C" accordingly and in accordance with the rules, regulations and orders of the Commission.

9.3 **Effective Date.** The effective date of any enlargement of the Storage Facility shall be effective as determined by the Commission.

## ARTICLE 10
## TRANSFER OF TITLE PARTITION

10.1 **Transfer of Title.** Any conveyance of all or part of any interest owned by any Party hereto with respect to any Tract shall be made expressly subject to this Agreement. No change of title shall be binding upon Storage Operator, or any Party hereto other than the Party so transferring, until 7:00 a.m. on the first day of the calendar month following thirty (30) days from the date of receipt by Storage Operator of a photocopy, or a certified copy, of the recorded or filed instrument evidencing such a change in ownership.

10.2 **Waiver of Rights to Partition.** Each Party hereto agrees that, during the existence of this Agreement, it will not resort to any action to partition any Tract or parcel within the Facility Area or the facilities used in the development or operation thereof, and to that extent waives the benefits or laws authorizing such partition.

## ARTICLE 11
## RELATIONSHIP OF PARTIES

11.1 **No Partnership.** The duties, obligations and liabilities arising hereunder shall be several and not joint or collective. This Agreement is not intended to create, and shall not be construed to create, an association or trust, or to impose a partnership duty, obligation or liability with regard to any one or more of the Parties hereto. Each Party hereto shall be individually responsible for its own obligations as herein provided.

11.2 **No Joint Marketing.** This Agreement is not intended to provide, and shall not be construed to provide, directly or indirectly, for any joint marketing of Storage Substances.

11.3 **Pore Space Owners Free of Costs.** This Agreement is not intended to impose, and shall not be construed to impose, upon any Pore Space Owner any obligation to pay any Storage Expense unless such Pore Space Owner is otherwise so obligated.

11.4 **Information to Pore Space Owners.** Each Pore Space Owner shall be entitled to all information in possession of Storage Operator to which such Pore Space Owner is entitled by an existing lease or a lease imposed by this Agreement.

## ARTICLE 12
## LAWS AND REGULATIONS

12.1 **Laws and Regulations.** This Agreement shall be subject to all applicable federal, state and municipal laws, rules, regulations and orders.

## ARTICLE 13
## FORCE MAJEURE

13.1 **Force Majeure.** All obligations imposed by this Agreement on each Party, except for the payment of money, shall be suspended while compliance is prevented, in whole or in part, by a labor dispute, fire, war, civil disturbance, or act of God; by federal, state or municipal laws; by any rule, regulation or order of a governmental agency; by inability to secure materials; or by any other cause or causes, whether similar or dissimilar, beyond reasonable control of the Party. No Party shall be required against his will to adjust or settle any labor dispute. Neither this Agreement nor any lease or other instrument subject hereto shall be terminated by reason of suspension of Storage Operations due to any one or more of the causes set forth in this Article.

## ARTICLE 14
## EFFECTIVE DATE

14.1 **Effective Date.** This Agreement shall become effective as determined by the Commission.

14.2 **Ipso Facto Termination.** If the requirements of Section 14.1 are not accomplished on or before __________, 20__ this Agreement shall *ipso facto* terminate on that date (hereinafter called "termination date") and thereafter be of no further effect, unless prior thereto Pore Space Owners owning a combined Storage Facility Participation of at least thirty percent (30%) of the Facility Area have become Parties to this Agreement and have decided to extend the termination date for a period not to exceed six (6) months. If the termination date is so extended and the requirements of Section 14.1 are not accomplished on or before the extended termination date this Agreement shall *ipso facto* terminate on the extended termination date and thereafter be of no further effect.

14.3 **Certificate of Effectiveness.** Storage Operator shall file for record in the county or counties in which the land affected is located a certificate stating the Effective Date of this Agreement.

## ARTICLE 15
## TERM

15.1 **Term.** Unless sooner terminated in the manner hereinafter provided or by order of the Commission, this Agreement shall remain in full force and effect until the Commission has issued a certificate of project completion with respect to the Storage Facility in accordance with § 38-22-17 of the North Dakota Century Code.

15.2 **Termination by Storage Operator.** This Agreement may be terminated at any time by the Storage Operator with the approval of the Commission.

15.3 **Effect of Termination.** Upon termination of this Agreement all Storage Operations shall cease. Each lease and other agreement covering Pore Space within the Facility Area shall remain in force for ninety (90) days after the date on which this Agreement terminates, and for such further period as is provided by Exhibit "D" or other agreement.

15.4 **Salvaging Equipment Upon Termination.** If not otherwise granted by Exhibit "D" or other instruments affecting each Tract, Pore Space Owners hereby grant Storage Operator a period of six (6) months after the date of termination of this Agreement within which to salvage and remove Storage Equipment.

15.5 **Certificate of Termination.** Upon termination of this Agreement, Storage Operator shall file for record in the county or counties in which the land affected is located a certificate that this Agreement has terminated, stating its termination date.

## ARTICLE 16
## APPROVAL

16.1 **Original, Counterpart or Other Instrument.** A Pore Space Owner may approve this Agreement by signing the original of this instrument, a counterpart thereof, ratification or joinder or other instrument approving this instrument hereto. The signing of any such instrument shall have the same effect as if all Parties had signed the same instrument.

16.2 **Joinder in Dual Capacity.** Execution as herein provided by any Party as either a Pore Space Owner or the Storage Operator shall commit all interests owned or controlled by such Party and any additional interest thereafter acquired in the Facility Area.

16.3 **Approval by the North Dakota Industrial Commission.**
Notwithstanding anything in this Article to the contrary, all Tracts within the Facility Area shall be deemed to be qualified for participation if this Agreement is duly approved by order of the Commission.

## ARTICLE 17
## GENERAL

17.1 **Amendments Affecting Pore Space Owners.** Amendments hereto relating wholly to Pore Space Owners may be made with approval by the Commission.

17.4 **Construction.** This agreement shall be construed according to the laws of the State of North Dakota.

## ARTICLE 18
## SUCCESSORS AND ASSIGNS

18.1 **Successors and Assigns.** This Agreement shall extend to, be binding upon, and inure to the benefit of the Parties hereto and their respective heirs, devisees, legal representatives, successors and assigns and shall constitute a covenant running with the lands, leases and interests covered hereby.

[*Remainder of page intentionally left blank. Signature page follows.*]

Executed the date set opposite each name below but effective for all purposes as provided by Article 14.

Dated: ____________, 20__

**STORAGE OPERATOR**

BLUE FLINT SEQUESTER COMPANY, LLC

By:_________________________________
[Name]
Its: [Title]

77739768 v1

## **Exhibit A**

Tract Map

Attached to and made part of the Storage Agreement
Blue Flint Broom Creek – Secure Geological Storage
McLean County, North Dakota

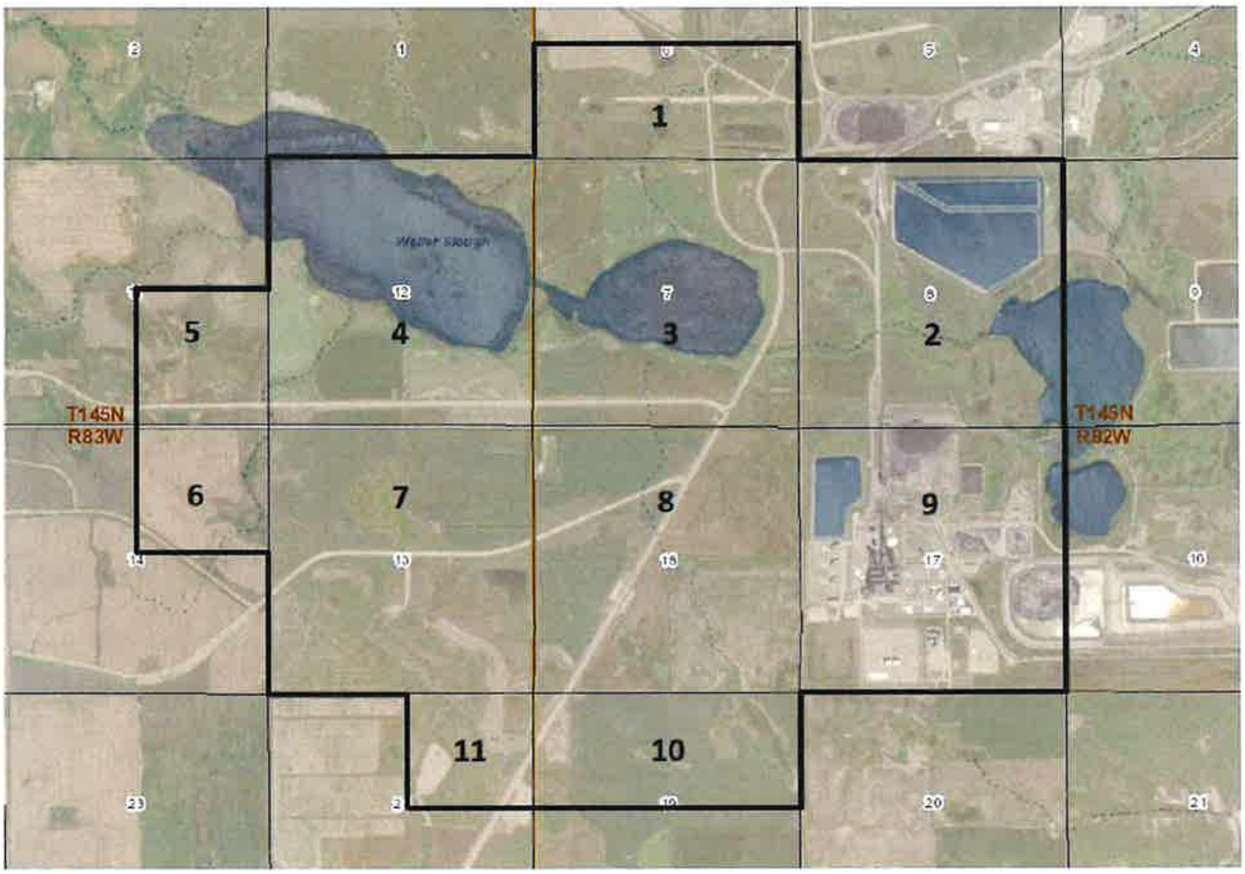


**Exhibit B**

Tract Summary

Attached to and made part of the Storage Agreement
Blue Flint Broom Creek – Secure Geological Storage
McLean County, North Dakota

| Tract No. | Land Description | Owner Name | Tract Net Acres | Tract Participation | Storage Facility Participation |
|---|---|---|---|---|---|
| | | | | | |
| 1 | Section 6-T145N-R82W | The Falkirk Mining Company | 318.770 | 100.00000000% | 6.43497500% |
| | | **Tract Total:** | **318.770** | **100.00000000%** | |
| | | | | | |
| 2 | Section 8-T145N-R82W | Rainbow Energy Center, LLC | 590.730 | 92.30156250% | 11.92500167% |
| | | Great River Energy | 49.270 | 7.69843750% | 0.99460808% |
| | | **Tract Total:** | **640.000** | **100.00000000%** | |
| | | | | | |
| 3 | Section 7-T145N-R82W | The Falkirk Mining Company | 558.760 | 87.56895687% | 11.27962678% |
| | | Mary Schafer Conlon | 19.830 | 3.10776078% | 0.40030603% |
| | | Macy J. Schafer | 19.830 | 3.10776078% | 0.40030603% |
| | | Monty R. Schafer | 19.830 | 3.10776078% | 0.40030603% |
| | | Marty J. Schafer | 19.830 | 3.10776078% | 0.40030603% |
| | | **Tract Total:** | **638.080** | **100.00000000%** | |

| Tract No. | Land Description | Owner Name | Tract Net Acres | Tract Participation | Storage Facility Participation |
|---|---|---|---|---|---|
| | | | | | |
| **4** | Section 12-T145N-R83W | The Falkirk Mining Company | 420.000 | 65.62500000% | 8.47849390% |
| | | Curtis Schafer | 200.000 | 31.25000000% | 4.03737805% |
| | | Estate of Edna B. Schafer | 5.000 | 0.78125000% | 0.10093445% |
| | | Rodney C. Schafer | 5.000 | 0.78125000% | 0.10093445% |
| | | Ervin R. Schafer Revocable Trust | 5.000 | 0.78125000% | 0.10093445% |
| | | Dale J. Schafer | 5.000 | 0.78125000% | 0.10093445% |
| | | **Tract Total:** | **640.000** | **100.00000000%** | |
| | | | | | |
| **5** | Section 11-T145N-R83W | The Falkirk Mining Company | 160.000 | 100.00000000% | 3.22990244% |
| | | **Tract Total:** | **160.000** | **100.00000000%** | |
| | | | | | |
| **6** | Section 14-T145N-R83W | The Falkirk Mining Company | 160.000 | 100.00000000% | 3.22990244% |
| | | **Tract Total:** | **160.000** | **100.00000000%** | |
| | | | | | |
| **7** | Section 13-T145N-R83W | The Falkirk Mining Company | 640.000 | 100.00000000% | 12.91960975% |
| | | **Tract Total:** | **640.000** | **100.00000000%** | |
| | | | | | |
| **8** | Section 18-T145N-R82W | The Falkirk Mining Company | 477.600 | 74.90589711% | 9.64125877% |
| | | Janice Berget | 40.000 | 6.27352572% | 0.80747561% |
| | | Michael Johnson | 60.000 | 9.41028858% | 1.21121341% |
| | | Chad Stevahn | 16.667 | 2.61396905% | 0.33644817% |
| | | Tammy Stevahn | 16.667 | 2.61396905% | 0.33644817% |
| | | Michelle Albrecht | 16.667 | 2.61396905% | 0.33644817% |
| | | Brandy Schmidt | 3.333 | 0.52279381% | 0.06728963% |
| | | Kevin L. Johnson | 3.333 | 0.52279381% | 0.06728963% |
| | | Keith Johnson | 3.333 | 0.52279381% | 0.06728963% |
| | | **Tract Total:** | **637.600** | **100.00000000%** | |

| Tract No. | Land Description | Owner Name | Tract Net Acres | Tract Participation | Storage Facility Participation |
|---|---|---|---|---|---|
| | | | | | |
| **9** | Section 17-T145N-R82W | Rainbow Energy Center, LLC | 552.000 | 86.25000000% | 11.14316341% |
| | | Blue Flint Ethanol LLC | 49.460 | 7.72812500% | 0.99844359% |
| | | Nexus Line, LLC | 38.540 | 6.02187500% | 0.77800275% |
| | | **Tract Total:** | **640.000** | **100.00000000%** | |
| | | | | | |
| **10** | Section 19-T145N-R82W | The Falkirk Mining Company | 319.260 | 100.00000000% | 6.44486657% |
| | | **Tract Total:** | **319.260** | **100.00000000%** | |
| | | | | | |
| **11** | Section 24-T145N-R83W | The Falkirk Mining Company | 160.000 | 100.00000000% | 3.22990244% |
| | | **Tract Total:** | **160.000** | **100.00000000%** | |
| | | | | | |
| | | **Total Acres:** | **4953.710** | **Total Participation:** | **100.00000000%** |

## Exhibit C

Tract Participation Factors

Attached to and made part of the Storage Agreement
Blue Flint Broom Creek – Secure Geological Storage
McLean County, North Dakota

| Tract No. | Acres | Tract Participation Factor |
|---|---|---|
| | | |
| 1 | 318.770 | 6.43497500% |
| 2 | 640.000 | 12.91960975% |
| 3 | 638.080 | 12.88085092% |
| 4 | 640.000 | 12.91960975% |
| 5 | 160.000 | 3.22990244% |
| 6 | 160.000 | 3.22990244% |
| 7 | 640.000 | 12.91960975% |
| 8 | 637.600 | 12.87116121% |
| 9 | 640.000 | 12.91960975% |
| 10 | 319.260 | 6.44486657% |
| 11 | 160.000 | 3.22990244% |
| | | |
| **Total:** | **4953.710** | **100.00000000%** |

**Exhibit D**

Form of Pore Space Lease

Attached to and made part of the Storage Agreement
Blue Flint Broom Creek – Secure Geological Storage
McLean County, North Dakota

## PORE SPACE LEASE

THIS PORE SPACE LEASE (this "Lease") is made effective as of the Effective Date (as defined below) by and between [________________________________], [husband and wife/a single person/a widow/a _________], whose address is [___________________________] (whether one or more, "Lessor"), and Blue Flint Sequester Company, LLC, a Delaware limited liability company, whose address is 2841 3rd Street SW, Underwood, ND 58576 ("Lessee"). Lessor and Lessee may be individually referred to herein as a "Party" and collectively as the "Parties".

1. Leased Premises. Lessor, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, does hereby grant, demise, lease and let unto Lessee for Lessee's geologic storage operations and other purposes set forth herein, the lands described in Exhibit A attached hereto and incorporated herein by reference (the "Leased Premises").

2. Term.

(a) Initial and Primary Term. This Lease shall commence on the date Lessee executes this Lease ("Effective Date") and continue for an initial term of twenty (20) years ("Initial Term") unless sooner terminated in accordance with the terms of this Lease. As consideration for the Initial Term, Lessee shall pay to Lessor [_____ AND __/100 DOLLARS ($__.__)] per acre as a single one-time bonus payment. Lessee may, at any time prior to the expiration of the Initial Term, elect to extend the Initial Term for up to an additional twenty (20) years by providing written notice to Lessor and payment of [_____ AND __/100 DOLLARS ($__.__)] per acre (the Initial Term, together with all extensions shall be referred to herein as the "Primary Term"). For the avoidance of doubt, Lessor's consent to any such extension will not be required provided that the foregoing payment is tendered to Lessor prior to the expiration of the Initial Term.

(b) Operational Term. This Lease shall continue beyond the Primary Term for so long as any portion of the Leased Premises or Lessee's storage facilities located in, on or under the Leased Premises (including without limitation, any Reservoirs) are subject to a permit issued by the North Dakota Industrial Commission (the "Commission") (a "Permit") or under the ownership or control of the State of North Dakota; *provided, however*, that all of Lessee's obligations under this Lease shall terminate upon issuance of a certificate of project completion pursuant to Chapter 38-22 of the North Dakota Century Code (the "Operational Term"). If the Primary Term expires and no portion of the Leased Premises or Lessee's storage facilities located in, on or under the Leased Premises is subject to a Permit, this Lease shall terminate, and Lessee shall execute a document evidencing termination of this Lease in recordable form and shall record it in the official records of the county in which the

Leased Premises is located. As consideration for the Operational Term, Lessee shall pay to Lessor the royalty set forth in Section 3, below.

3. Royalty. Lessee shall pay to Lessor its proportionate share of [_______ ($_.__)] per metric ton of carbon dioxide ($CO_2$) injected into the reservoirs and subsurface pore spaces (as used herein, such terms shall have the meanings set forth in Chapter 38-22 and Chapter 47-31 of the North Dakota Century Code), stratum or strata underlying the Leased Premises (collectively, "Reservoirs"), or reservoirs and subsurface pore spaces, stratum or strata unitized or amalgamated therewith. The quantity of $CO_2$ so injected shall be measured by meters installed by Lessee. Lessor's "proportionate share" shall be determined on a net acre basis and the Parties hereby stipulate that the acreage set forth in Exhibit A shall be used to calculate Lessor's proportionate share. The quantity of carbon dioxide injected into the Reservoirs or any reservoirs or subsurface pore spaces, stratum or strata unitized or amalgamated therewith shall be determined through the use of metering equipment installed and operated by Lessee at the injection site. All royalties due hereunder for carbon dioxide injected into the Reservoirs or any reservoirs or subsurface pore spaces, stratum or strata unitized or amalgamated therewith during any calendar month shall be paid to Lessor annually on or before March 1 for the prior year's injection volumes. Lessor and Lessee agree that this Lease shall continue as specified herein even in the absence of injection operations and the payment of royalties.

4. Right to Pore Space/Storage of Carbon Dioxide. Lessor grants to Lessee the exclusive right to inject and store carbon dioxide ($CO_2$) and other incidental gaseous substances into the Reservoirs, together with the right to construct, replace, inspect, repair, monitor, maintain, relocate, change the size of such surface or subsurface facilities on the Leased Premises that Lessee determines necessary or desirable for Lessee's storage operations, including, but not limited to fences, pipelines, tanks, reservoirs, electric and communication lines, roadways, underground facilities and equipment, surface facilities and equipment, buildings, structures and other such facilities and appurtenances. Lessor shall not grant any other person the right to inject or store $CO_2$ or any other incidental substances.

5. Facility Right of Ways/Compensation. Lessor grants Lessee the right of reasonable use of the surface of the Leased Premises, including without limitation, the rights of ingress and egress over the Leased Premises together with the right of way over, under and across the Leased Premises and the right from time to time to construct, replace, inspect, repair, monitor, maintain, relocate, change the size of such surface or subsurface facilities on the Leased Premises that Lessee determines necessary or desirable for Lessee's storage operations, including, but not limited to fences, pipelines, tanks, reservoirs, electric and communication lines, roadways, underground facilities and equipment, surface facilities and equipment, buildings, structures and other such facilities and appurtenances, (each a "Facility" and collectively the "Facilities"); *provided, however*, that (i) Lessee shall provide Lessor with notice of operations and an offer of damage, disruption and loss of production payments, as each may be applicable, prior to the installation of any such Facilities on the Leased Premises, and (ii) the agreed up terms, including the amount of damage payments to be paid to Lessor, shall be memorialized in an agreement separate from this Lease, such agreement to be consistent with the grant contained herein. Lessee shall be entitled to proceed with the installation of the Facilities while the separate agreement and amount of damage, disruption or loss is being agreed or determined. Lessee shall have the further right to fence the perimeter of any Facility on the Leased Premises and sufficiently illuminate the site for the safety and security of operations.

6. Amalgamation. Lessee, in its sole discretion, shall have the right and power, at any time and from time to time during the term of this Lease to pool, unitize, or amalgamate any reservoirs or subsurface pore spaces, stratum or strata underlying the Leased Premises with any other lands or interests into which such reservoirs or subsurface pore spaces extend and document such unit in accordance with applicable law or agency order. Amalgamated units shall be of such shape and dimensions as Lessee may elect and as are approved by the Commission. Amalgamated areas may include, but are not required to include, land upon which injection or extraction wells have been completed or upon which the injection and/or withdrawal of carbon dioxide and/or related gaseous substances has commenced prior to the effective date of amalgamation. In exercising its amalgamation rights under this Lease and if required by law, Lessee shall record or cause to be recorded a copy of the Commission's amalgamation order or other notice thereof in the county in which the amalgamated unit is located. Amalgamating in one or more instances shall, if approved by the Commission, not exhaust the rights of Lessee to amalgamate Reservoirs or portions of Reservoirs into other amalgamation areas, and Lessee shall have the recurring right to revise any amalgamated area formed under this Lease by expansion or contraction or both. Lessee may dissolve any amalgamated area at any time and document such dissolution by recording an instrument in accordance with applicable law or agency order. Lessee shall have the right to negotiate, on behalf of and as agent for Lessor, any unit, amalgamation, storage or operating agreements with respect to amalgamation of reservoir or pore space interests underlying the Leased Premises or the operation of any amalgamated areas formed under such agreements. To the extent any of the terms of such agreements conflict with the terms of this Lease, the terms of such agreements shall control, and the provisions of this Lease shall be deemed modified to conform to the terms, conditions, and provisions of any such agreements which are approved by the Commission.

7. Lessee Obligations. Lessee shall have no obligation, express or implied, to begin, prosecute or continue storage operations in, upon or under the Leased Premises, or store and/or sell or use all or any portion of the gaseous substances stored thereon. The timing, nature, manner and extent of Lessee's operations, if any, under this Lease shall be at the sole discretion of Lessee. All obligations of Lessee are expressed herein, and there shall be no covenants implied under this Lease, it being agreed that all amounts paid hereunder constitute full and adequate consideration for this Lease.

8. Ownership. Lessee shall at all times be the owner of (i) the carbon dioxide and other gaseous substances stored in the Reservoirs or any reservoirs or subsurface pore spaces, stratum or strata unitized or amalgamated therewith, and (ii) all equipment, buildings, structures, facilities and other property constructed or installed by Lessee on the Leased Premises. Lessee shall have the right, but not the obligation, at any time during this Lease to remove all or any portion of the property or fixtures placed by Lessee on the Lease Premises. Notwithstanding the foregoing, title to the storage facility and to the stored carbon dioxide or other gaseous substances shall be transferred to the State of North Dakota upon issuance of a certificate of project completion by the Commission in accordance with Chapter 38-22 of the North Dakota Century Code.

9. Minerals, Oil and Gas. This Lease is not intended to grant or convey, nor does it grant or convey, any right to or obligation for Lessee to explore for or produce minerals, including oil and gas, that may exist on or under the Leased Premises.

10. Surrender of Leased Premises. Lessee shall have the right, but not the obligation, at any time from time to time to execute and deliver to Lessor a surrender and/or release covering all or any part of the Leased Premises for which the Reservoirs are not being utilized for storage as set forth herein, and upon delivery of such surrender and/or release to Lessor this Lease shall terminate as to such lands, and Lessee shall be released from all further obligations and duties as to the lands so surrendered and/or released, including, without limitation, any obligation to make payments provided for herein, except obligations accrued as of the date of the surrender and/or release. Lessee shall be able to surrender the any and or all of the Leased Premises if not utilizing the Reservoirs located thereunder.

11. Hold Harmless and Indemnification. The Lessee agrees to defend, indemnify, and hold harmless Lessor from any claims by any person that are a direct result of the Lessee's use of the Leased Premises or Reservoirs. Notwithstanding the foregoing, such indemnity/hold harmless obligation excludes (i) any claim or cause of action, or alleged or threatened claim or cause of action, damage, judgment, interest, penalty or other loss arising or resulting from the negligence or intentional acts of Lessor or Lessor's agents, invitees, or licensees; or third parties, and (ii) any claim for exemplary, punitive, special or consequential damages claimed by Lessor. Lessee further accepts liability and indemnifies Lessor for reasonable costs, expenses and attorneys' fees incurred in establishing and litigating the indemnification coverage provided above. The legal defense provided by Lessee to the Lessor under this paragraph must be free of any conflicts of interest even if this requires Lessee to retain separate legal counsel for Lessor.

12. Hazardous Substances. Lessee shall have no liability for any regulated hazardous substances located on the Leased Premises prior to the Effective Date or placed in, on or about the Leased Premises by Lessor or any third-party on or after the Effective Date, and nothing in this Lease shall be construed to impose upon Lessee any obligation for the removal of such regulated hazardous substances. As used herein, "hazardous substances" shall have the meaning set forth in the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) and any amendments thereto, or any other local, state or federal statutes.

13. Termination. A material violation or default of any terms of this Lease by Lessee shall be grounds for termination of the Lease. Lessor shall give Lessee written notice of violation or default and Lessee shall have sixty (60) days after receipt of said notice to substantially cure such violations or defaults. If Lessee fails to substantially cure such violations or defaults within the 60-day cure period, Lessor may terminate the Lease; provided that if it is not possible to cure such violations or defaults within the 60-day cure period, Lessee shall have a reasonable longer period of time to cure such violations or defaults provided it commences cure within the initial 60-day cure period and thereafter diligently pursues such cure. Lessee may terminate the lease with thirty (30) days written notice to Lessor. Upon termination of this Lease, Lessee shall have one hundred eighty (180) days to remove all facilities and property of Lessee located on the Leased Premises. For the avoidance of doubt, Lessee shall not be required to remove any $CO_2$ or other incidental gaseous substances injected into the Reservoirs.

14. Taxes. Lessee shall pay all taxes, if any, levied against its personal property or on its improvements to the Leased Premises. Lessor shall pay for all real estate taxes and other assessments levied upon the Leased Premises. Lessee shall have the right to pay all taxes,

assessments and other fees on behalf of Lessor and to deduct the amount so paid from other payments due to Lessor hereunder.

15. Conduct of Operations. In conducting its operations hereunder, Lessee shall use its best efforts to comply with all applicable laws, rules and regulations and ordinances pertaining thereto. Lessee reserves and shall have the right to challenge and/or appeal any law, ruling, regulation, order or other determination and to carry on its operations in accordance with Lessee's interpretation of the same, pending final determination.

16. Force Majeure. Should Lessee be prevented from complying with any express or implied covenant of this Lease or from utilizing the Lease Premises for underground storage purposes by reason of scarcity of or an inability to obtain or to use equipment or material or failure or breakdown of equipment, or by operation of force majeure, any federal or state law or any order, rule or regulation of governmental authority, then while so prevented, Lessee's obligation to comply with such covenant shall be suspended and the primary term of this Lease shall be extended while and so long as Lessee is prevented by any such cause from utilizing the property for underground storage purposes and the time while Lessee is so prevented shall not be counted against Lessee, anything in this Lease to the contrary notwithstanding.

17. Surface Damage Compensation. The bonus and royalty amounts contemplated and paid to Lessor hereunder is compensation for, among other things, damages sustained by Lessor for lost land value, lost use of and access to Lessor's land and lost value of improvements, if any and to the extent applicable. Subject to Lessee's obligation to compensate Lessor for the installation of any Facilities on the Leased Premises pursuant to Section 5 of this Agreement, Lessor agrees that such compensation is just and adequate for any and all such damages and all other damages which Lessor may sustain as a result of Lessee's use of the property for its storage operations.

18. Warranty of Title and Quiet Enjoyment.

(a) Lessor represents and warrants to Lessee that Lessor is the owner of the surface of the Leased Premises and the pore space located thereunder. Lessor hereby warrants and agrees to defend title to the Leased Premises and the pore space located thereunder and Lessor hereby agrees that Lessee, at its option, shall have the right to discharge any tax, mortgage, or other lien upon the Leased Premises, and in the event Lessee does so, Lessee shall be subrogated to such lien with the right to enforce the same and apply royalty payments or any other payments due to Lessor toward satisfying the same.

(b) Lessor warrants that, except as disclosed to Lessee in writing, there are no liens, encumbrances, leases, mortgages, deeds of trust, options, or other exceptions to Lessor's fee title ownership of the Leased Premises (collectively, "Liens") which are not recorded in the public records of the County in which the Leased Premises is located. Lienholders (including tenants), whether or not their Liens are recorded, shall be Lessor's responsibility, and Lessor shall cooperate with Lessee to obtain a non-disturbance agreement from each party that holds a Lien (recorded or unrecorded) that might interfere with Lessee's rights under this Lease. A non-disturbance agreement is an agreement between Lessee and a lienholder which provides that the lienholder shall not disturb Lessee's possession or rights under the Lease or terminate this Lease so long as Lessor is not entitled to terminate this Lease under the provisions hereof.

(c) Lessor shall have the quiet use and enjoyment of the Leased Premises in accordance with the terms of this Lease. Lessor's activities and any grant of rights Lessor makes to any person or entity, whether located on the Leased Premises or elsewhere, shall not, currently or prospectively, materially interfere with activities permitted hereunder. If Lessor has any right to select, determine, prohibit or control the location of sites for drilling, exploitation, production and/or exploration of minerals, hydrocarbons, water, gravel, or any other similar resource in, to or under the Lease Premises, then Lessor shall exercise such right so as to minimize interference with any of the foregoing.

19. Environmental Incentives and Tax Credits. Lessee shall be the owner of (i) any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to Lessee's geologic storage operations, including any avoided emissions and the reporting rights related to these avoided emissions, such as 26 U.S.C. §45Q Tax Credits, and any other attributes of Lessee's ownership of the Facilities and Lessee's geologic storage operations ("Environmental Attributes"), and (ii) any and all credits, rebates, subsidies, payments or other incentives that relate to the use of technology incorporated into Lessee's geologic storage operations, environmental benefits of such operations, or other similar programs available from any regulated entity or any governmental authority ("Environmental Incentives"). Lessee is further entitled to the benefit of any and all (a) investment tax credits, (b) production tax credits, (c) credits under 26 U.S.C. §45Q credits, and (d) similar tax credits or grants under federal, state or local law relating to Lessee's geologic storage operations ("Tax Credits"). Lessor shall (i) cooperate with Lessee in obtaining, securing and transferring all Environmental Attributes and Environmental Incentives and the benefit of all Tax Credits, and (ii) shall allow Lessee to take any actions necessary to install additional equipment on the Facilities to comply with all monitoring and reporting obligations, and allow Lessee's personnel to enter the premises and collect any data Lessee requires to satisfy its obligations required in connection with obtaining Tax Credits and Environmental Attributes. Lessor shall not be obligated to incur any out-of-pocket costs or expenses in connection with such actions unless reimbursed by Lessee. If any Environmental Incentives are paid directly to Lessor, Lessor shall immediately pay such amounts over to Lessee.

20. Assignment. The rights of either Party hereto may be assigned in whole or part. The assigning party shall provide written notice of any assignment within sixty (60) days after such assignment has become effective; *provided, however,* that an assigning party's failure to deliver written notice of assignment within such 60-day period shall not be deemed a breach of this Lease unless such failure is willful and intentional. The Lessor's consent shall not be required for an assignment by the Lessee of this Lease, whether by way of a collateral assignment to its financiers or otherwise.

21. Change of Ownership. No change of ownership in the Leased Premises shall be binding on the Lessee for purpose of making payments to Lessor hereunder until the date Lessor, or Lessor's successors or assigns, furnishes Lessee the recorded original or a certified copy of the instrument evidencing the change in ownership. The Lessor's consent shall not be required for a change in the direct or indirect control of the Lessee.

22. Notices. All notices required to be given under this Lease shall be in writing and addressed to the respective Party at the addresses set forth at the beginning of this Lease unless otherwise directed by either Party.

23. No Waiver. The failure of either Party to insist in any one or more instances upon strict performance of any of the provisions of this Lease or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provision or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

24. Notice of Lease. This Lease shall not be recorded in the real property records. Lessee shall cause a memorandum of this Lease to be recorded in the real property records of the county in which the Leased Premises are situated.

25. Confidentiality. Lessor shall maintain in the strictest confidence, for the benefit of Lessee, all information pertaining to the compensation paid under this Lease, any information regarding Lessee and its business or operations on the Leased Premises or on any other lands, the capacity and suitability of any Reservoir or reservoirs and subsurface pore spaces, stratum or strata unitized or amalgamated therewith, and any other information that is deemed proprietary or that Lessee requests or identifies to be held confidential, in each such case whether disclosed by Lessee or discovered by Lessor.

26. Counterparts. This Lease may be executed in any number of counterparts, each of which, when executed and delivered, shall be an original, but all of which shall collectively constitute one and the same instrument.

27. Severability. If any provision of this Lease is found to be invalid, illegal or unenforceable in any respect, such provision shall be deemed to be severed from this Agreement, and the validity, legality and enforceability of the remaining provisions contained herein shall not in any way be affected or impaired thereby.

28. Governing Law. This Lease shall be governed by, construed and enforced in accordance with the laws of the State of North Dakota and the Parties hereby submit to the jurisdiction of the state or federal courts located in the State of North Dakota.

29. Further Assurances. Each Party will execute and deliver all documents, provide all information, and take or forbear from all actions as may be necessary or appropriate to achieve the purposes of this Lease, including without limitation executing a memorandum of this Lease and all documents required to obtain any necessary government approvals.

30. Entire Agreement. This Lease constitutes the entire agreement between the Parties and supersedes all prior negotiations, undertakings, notices, memoranda and agreement between the Parties, whether oral or written, with respect to the subject matter hereof. This Lease may only be amended or modified by a written agreement duly executed by Lessor and Lessee.

31. Cooperation with Financiers. The Lessor hereby acknowledges and consents that Lessee may grant a collateral assignment or leasehold mortgage of Lessee's rights under this Lease to Lessee's debt financiers, it being understood that such collateral assignment or leasehold mortgage would only encumber the leasehold interest created hereunder.

32. Electronic Signatures. This Lease, and any amendments hereto, to the extent signed and delivered by means of electronic transmission in portable document format (pdf) or by DocuSign or similar electronic signature process, shall be treated in all manner and respects as an original contract and shall be considered to have the same binding legal effect as if it were the original signed version thereof delivered in person.

IN WITNESS WHEREOF, the Parties have executed this Lease effective for all purposes as of the Effective Date.

**LESSOR:**

[____________________]

By: ____________________

Print: ____________________

Its: ____________________

**Effective Date:**____________

**LESSEE:**

BLUE FLINT SEQUESTER COMPANY, LLC

By: ____________________

Print: ____________________

Its: ____________________

# <u>EXHIBIT A</u>

**Leased Premises**

[Insert Legal Description and Net Surface Acres]

# 2.0 GEOLOGIC EXHIBITS

## 2.0 GEOLOGIC EXHIBITS

### 2.1 Overview of Project Area Geology

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

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

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

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

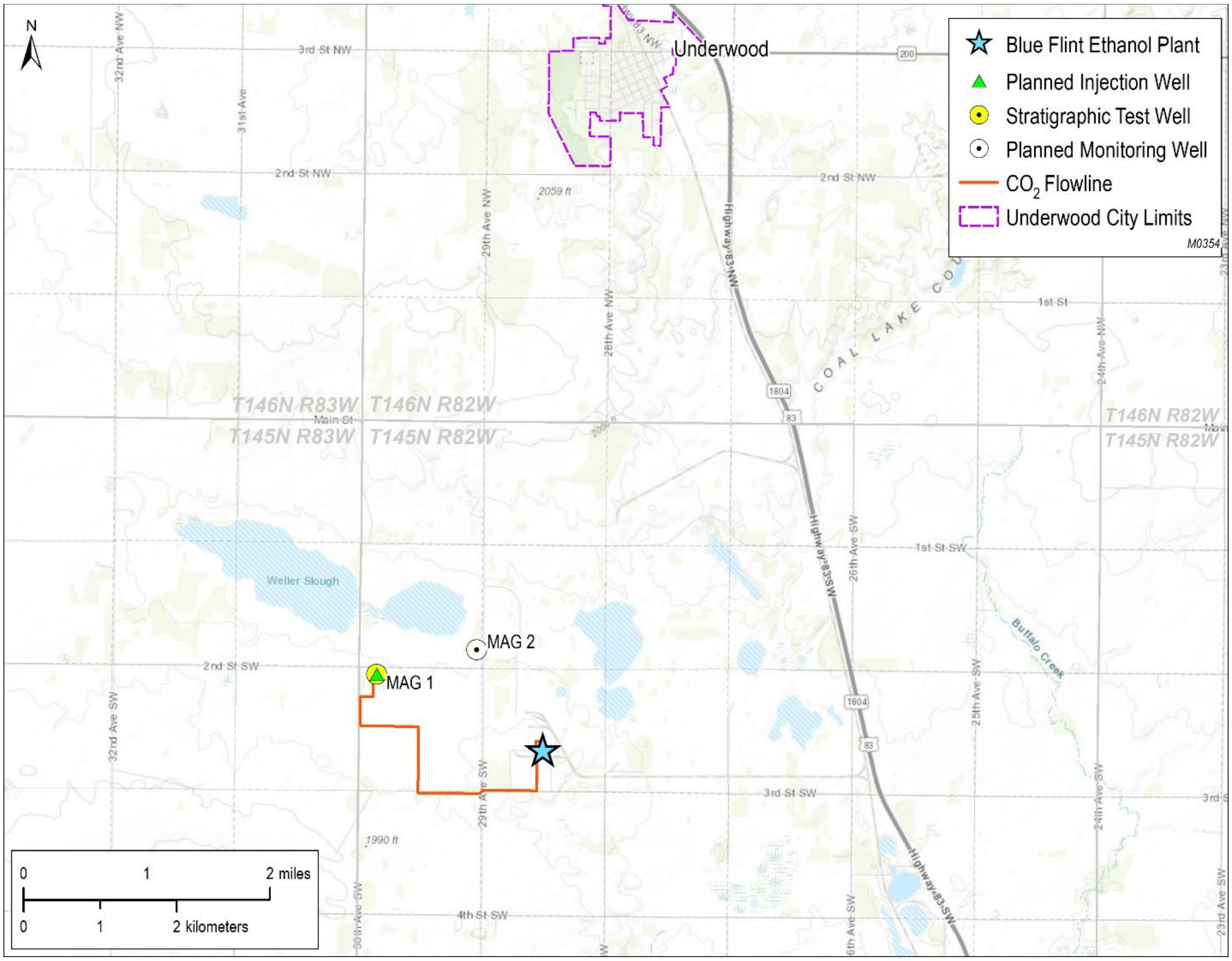



Figure 2-1. Topographic map of the project area showing the planned injection well, the planned monitoring well, and the BFE plant (blue star).

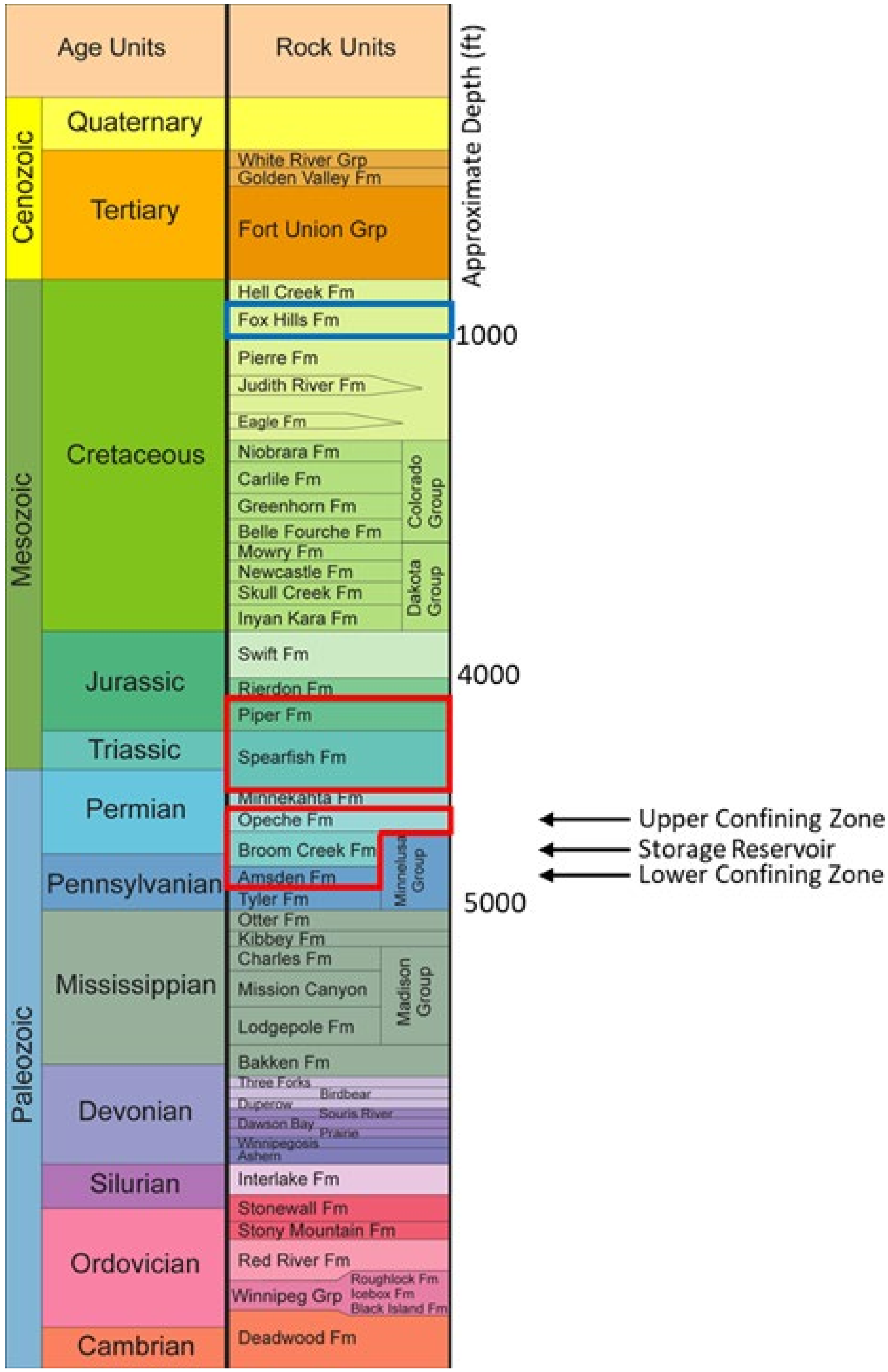



Figure 2-2. Stratigraphic column identifying the potential storage reservoirs and confining zones (outlined in red) and the lowest USDW (outlined in blue). The Minnekahta Formation is not present at this site.

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

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

* Measured depth.

## 2.2 Data and Information Sources

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

### *2.2.1 Existing Data*

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

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

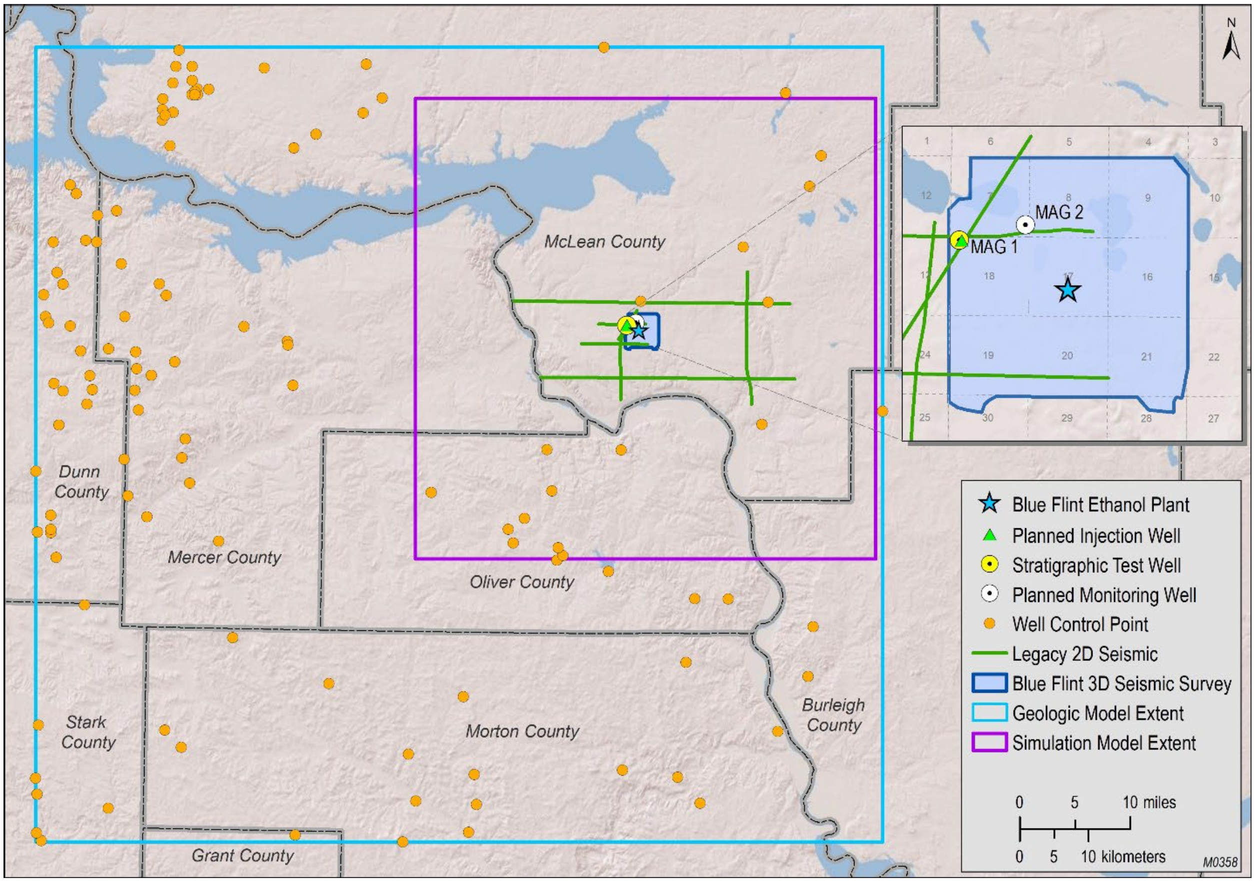



Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

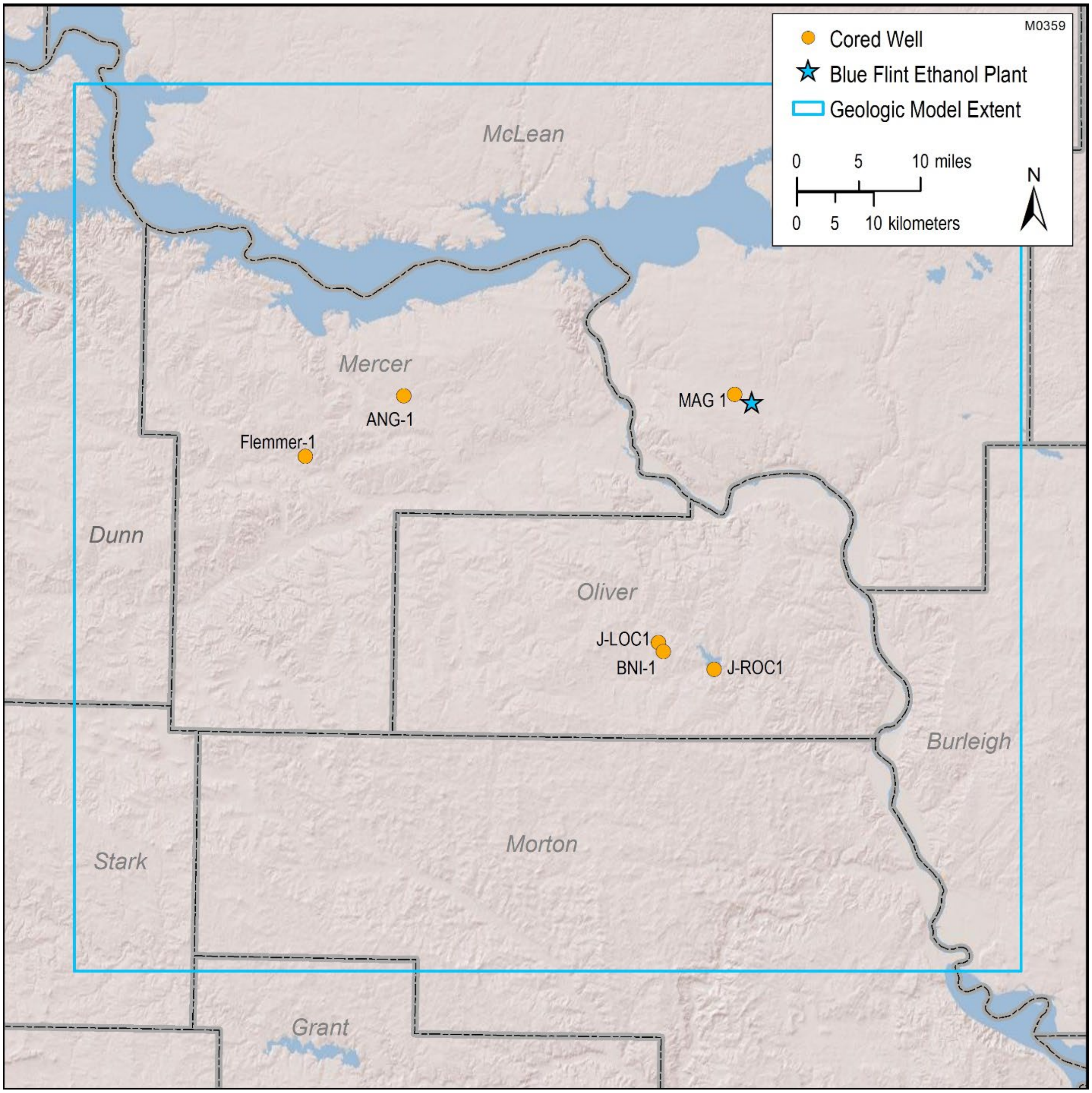



Figure 2-4. Map showing the spatial relationship between the Blue Flint project area and wells where the Broom Creek Formation core samples were collected. Wells with core data include the Flemmer-1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), ANG 1 (Well No. ND-UIC-101), J-LOC1(NDIC File No.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

### *2.2.2 Site-Specific Data*

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

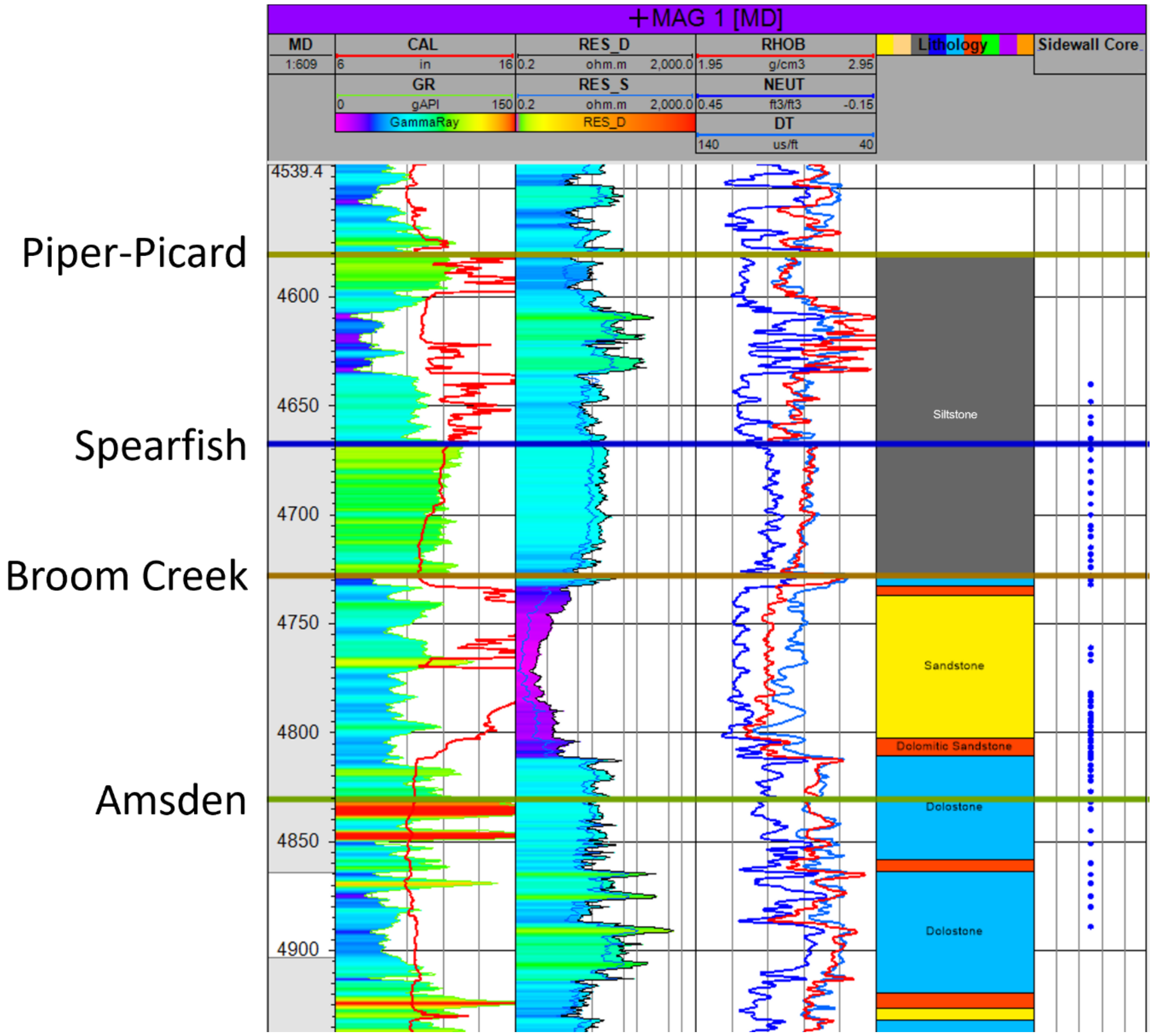



Figure 2-5. Well log display showing the vertical relationship of SW Core plugs taken from the Broom Creek Formation and confining zones. The 50 SW Core plugs are noted as blue circles on the far-right track. The Piper-Picard top denotes the top of the lower Piper Formation.

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

*2.2.2.1 Geophysical Well Logs*

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

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

*2.2.2.2 Core Sample Analyses*

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

*2.2.2.3 Formation Temperature and Pressure*

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

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

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

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

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

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

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

### *2.2.2.4 Fluid Samples*

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

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

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

### *2.2.2.5 Seismic Survey*

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

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

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

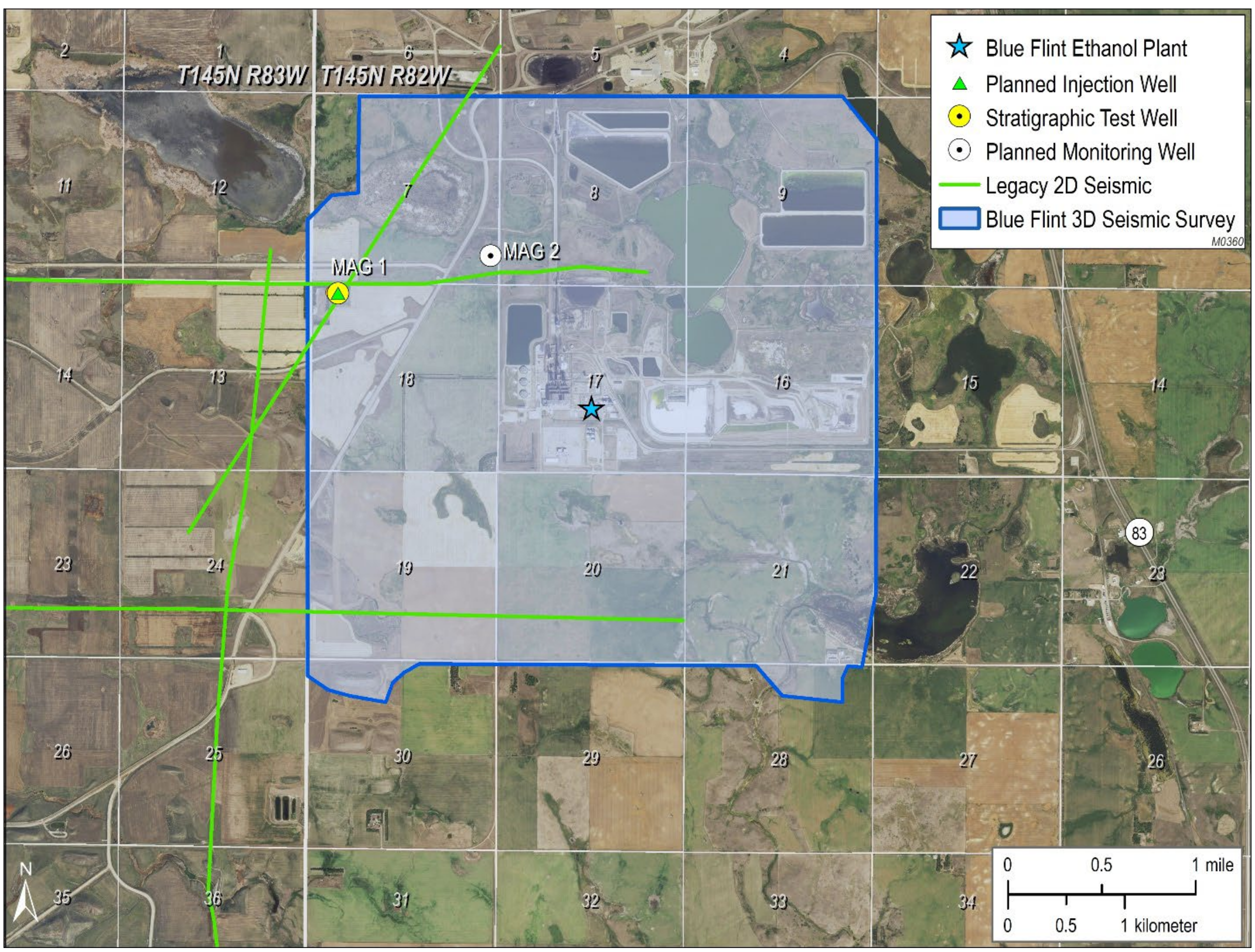



Figure 2-6. Map showing the 2D and 3D seismic surveys in the Blue Flint project area.

## 2.3 Storage Reservoir (injection zone)

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

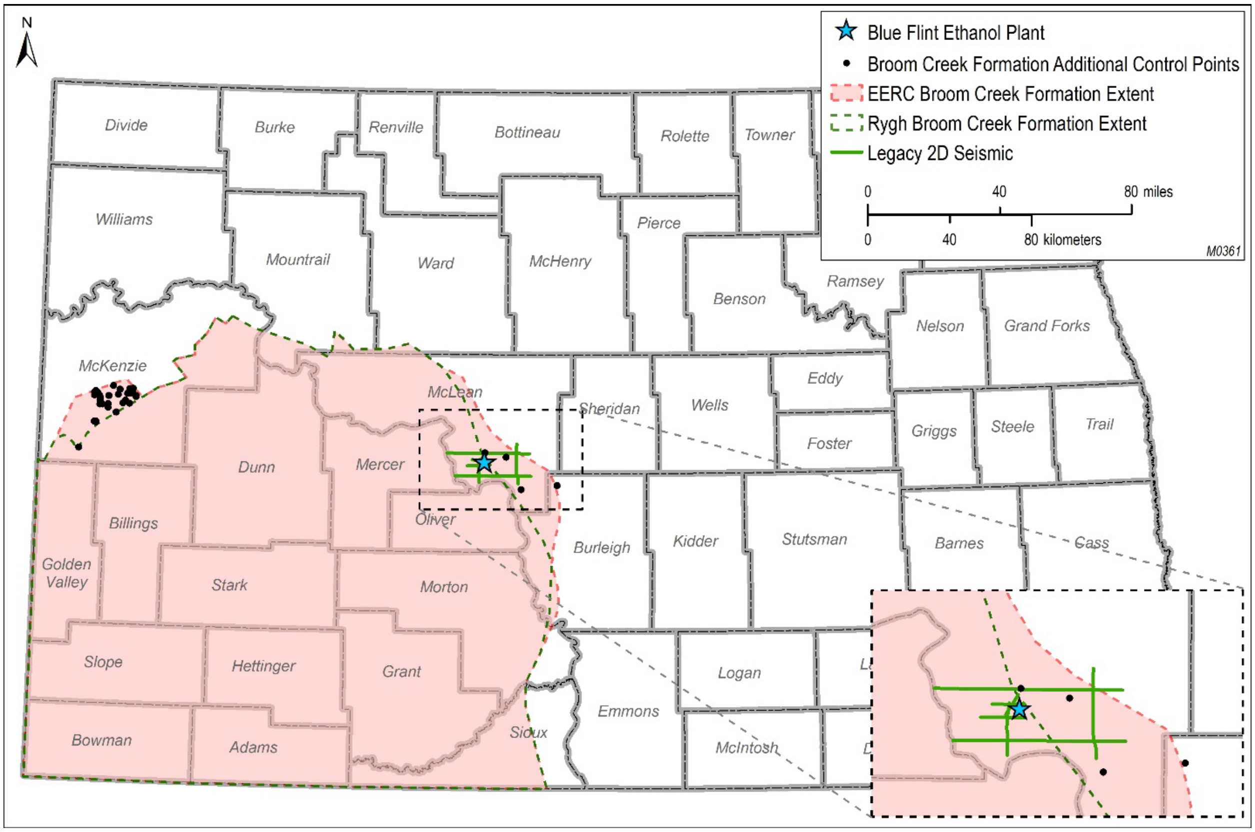



Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (red dashed line). This extent was modified from Rygh (1990) (green dashed line) based on new well control points shown outside of the green-dashed line. Legacy 2D seismic lines are depicted by green lines.

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

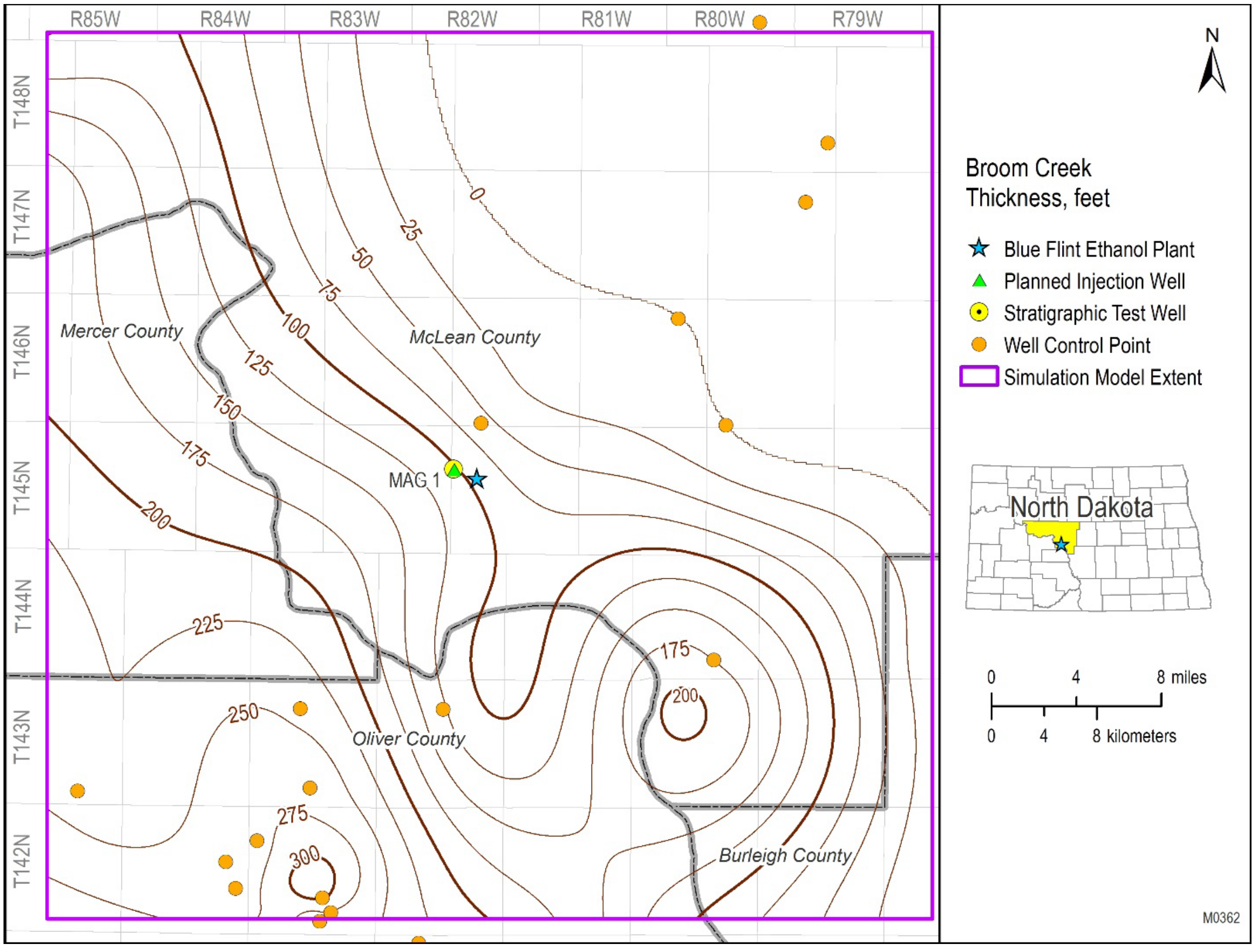



Figure 2-8. Isopach map of the Broom Creek Formation in the greater Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

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

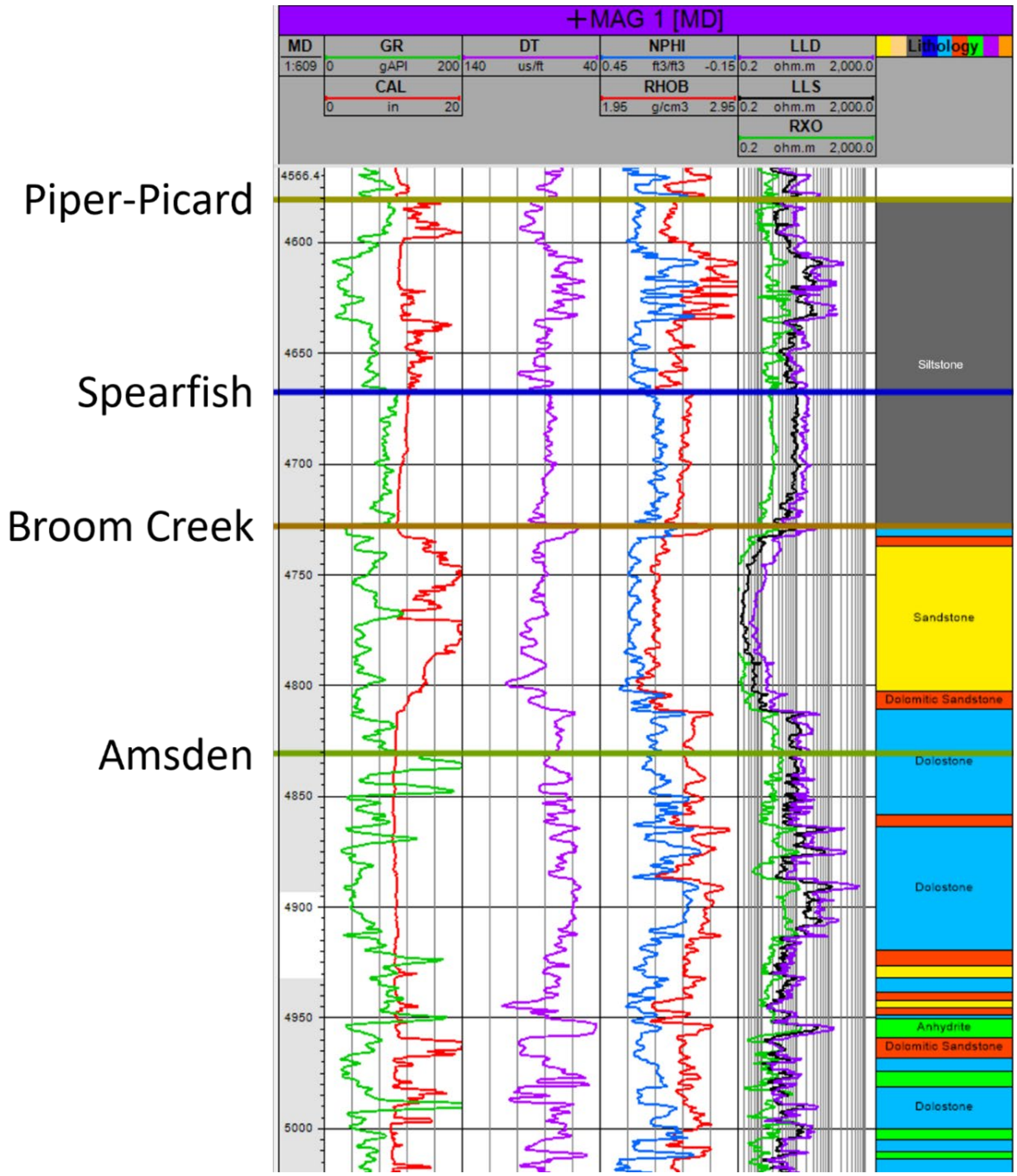



Figure 2-9. Well log display of the interpreted lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations in MAG 1.

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

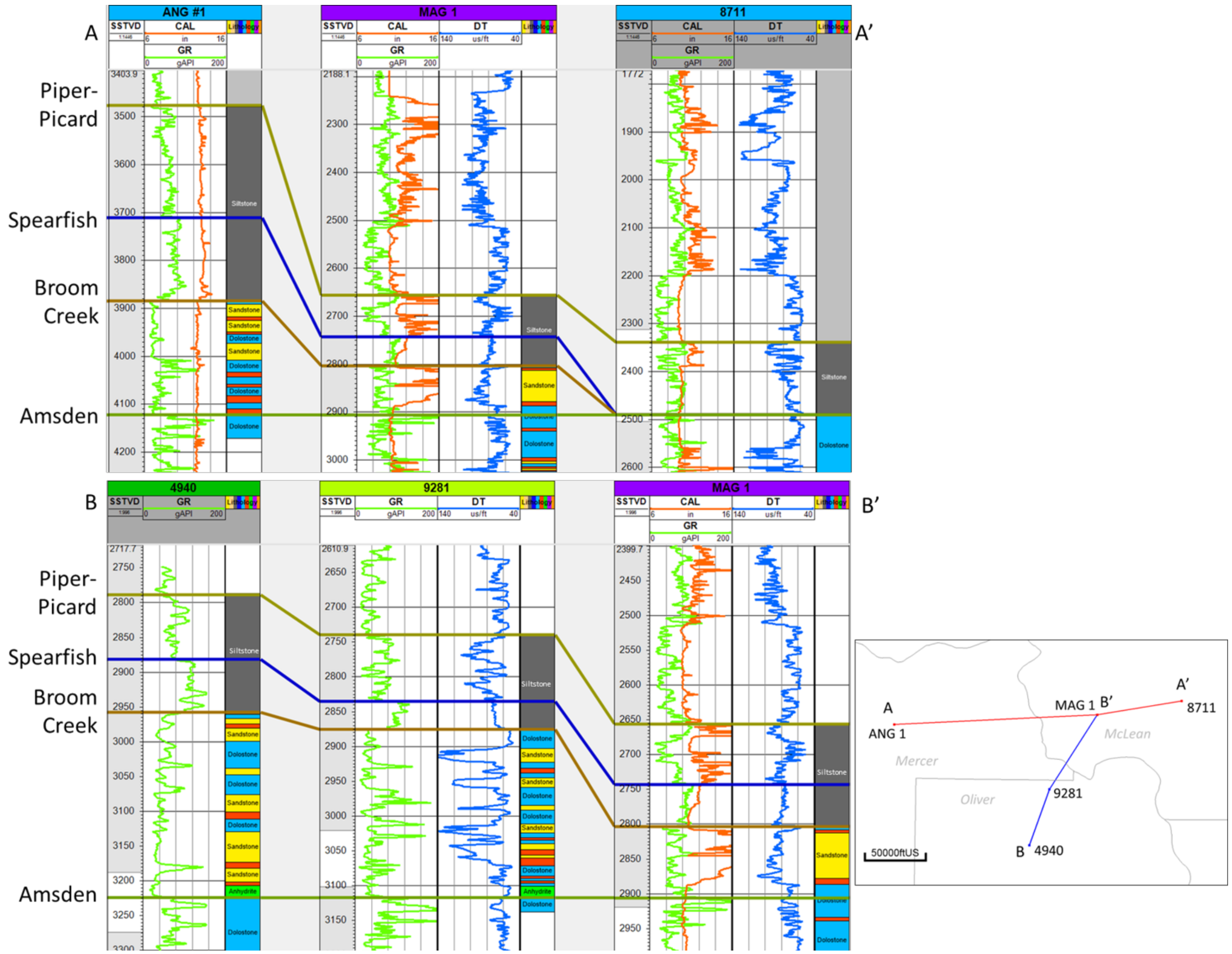



Figure 2-10. Regional well log stratigraphic cross sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) interpreted lithology log.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

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

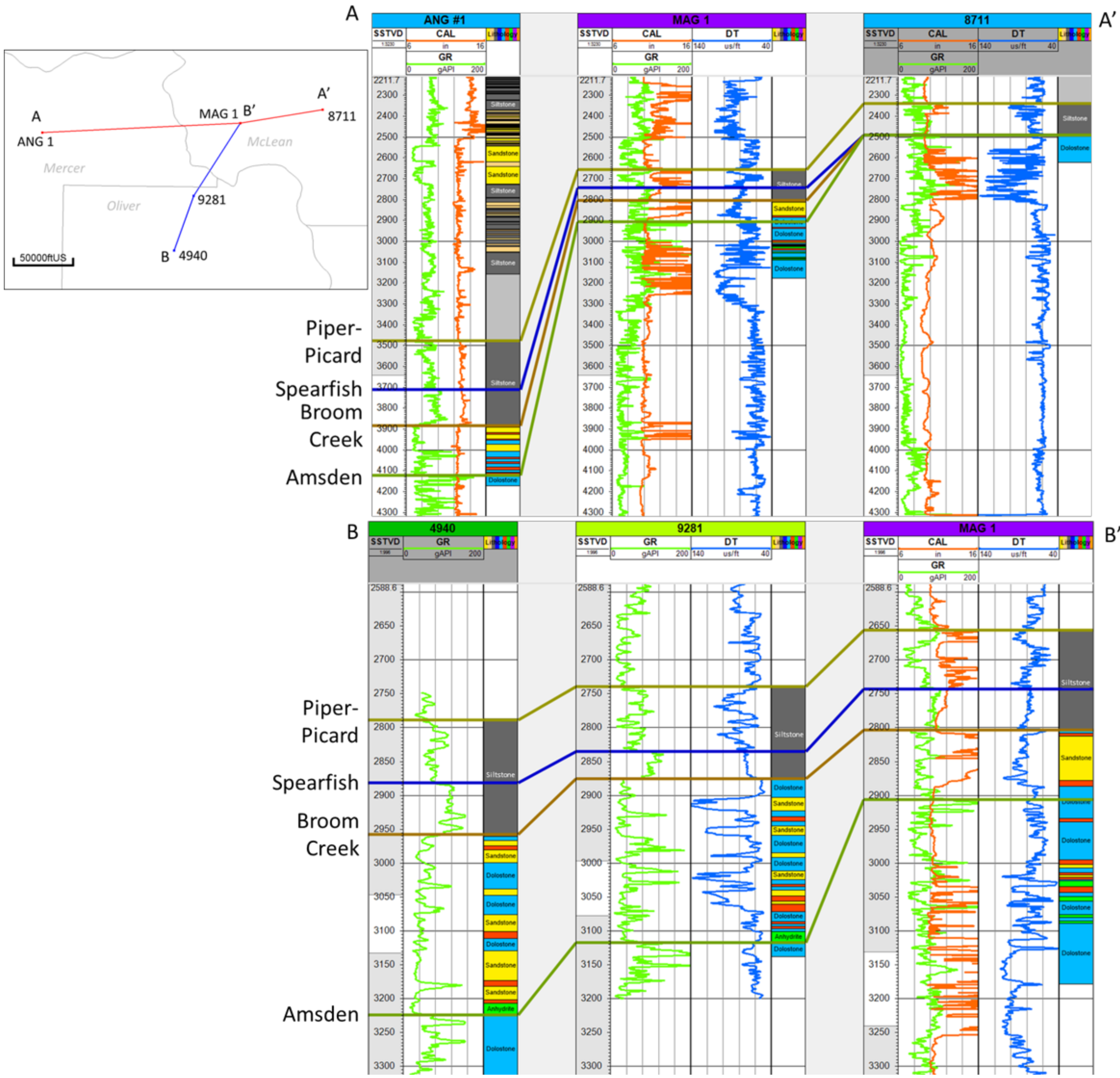



Figure 2-11. Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. Displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) interpreted lithology log. The different depth scales are used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

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

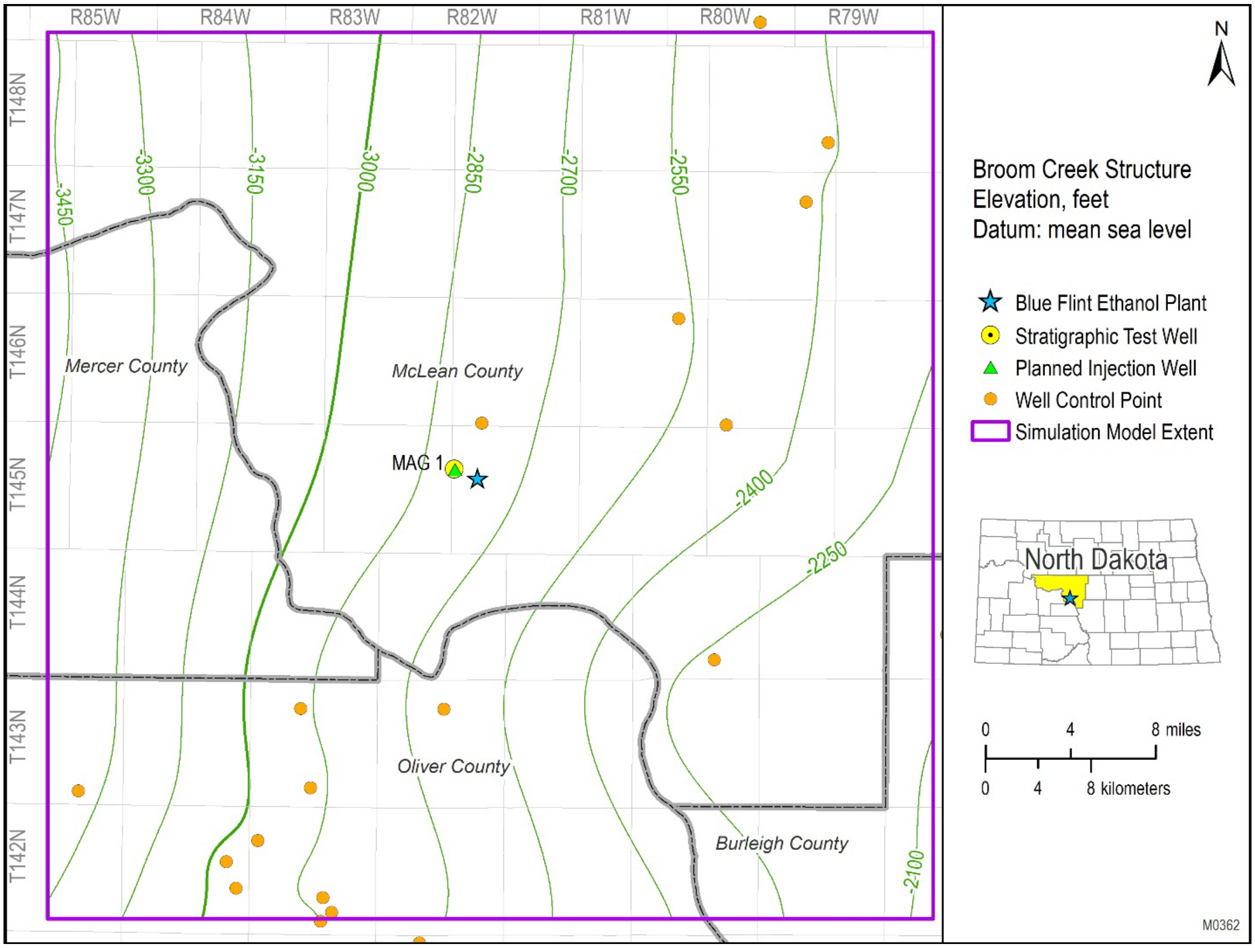



Figure 2-12. Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

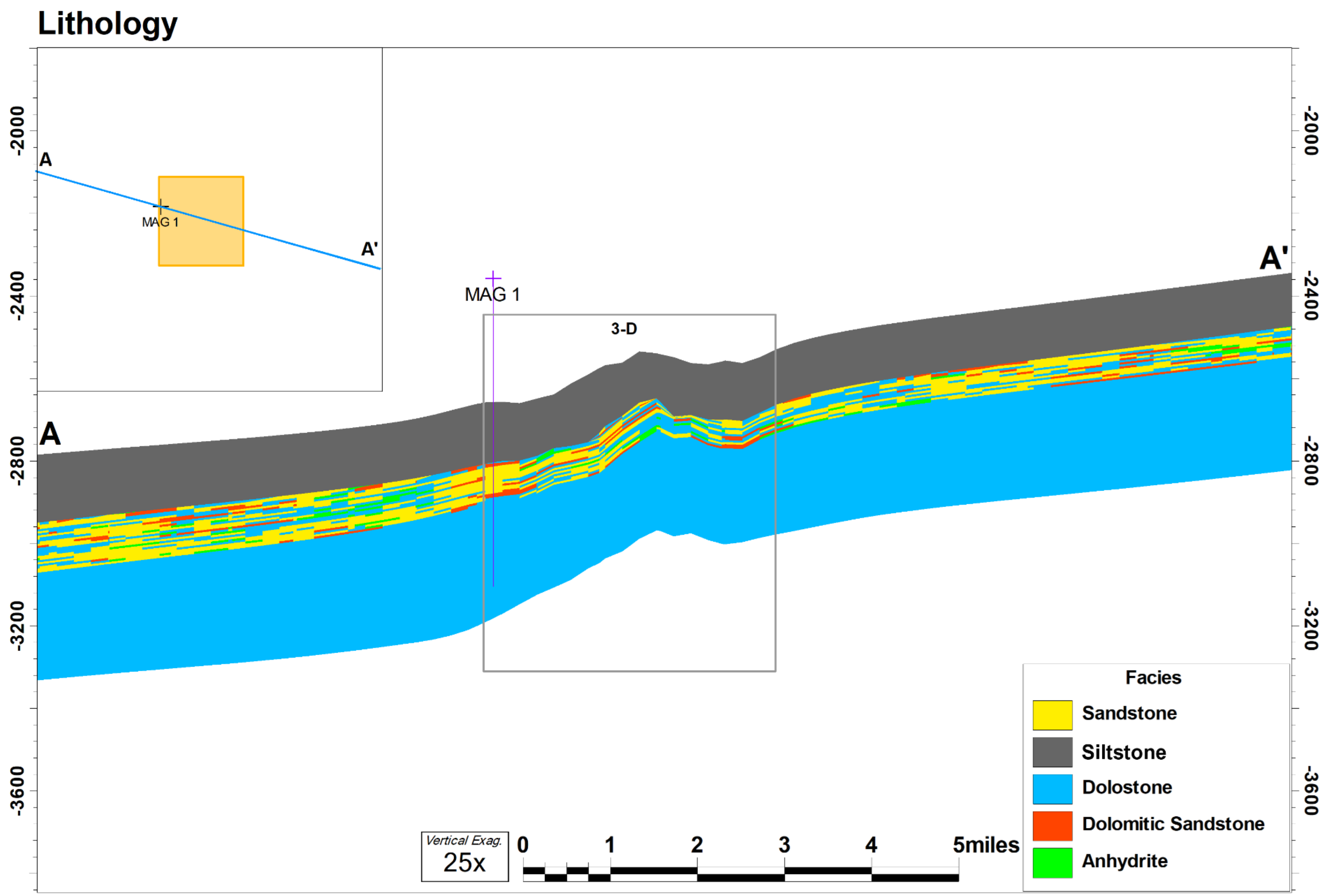



Figure 2-13. Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level.

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

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

**Geologic Properties**

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

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

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

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

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

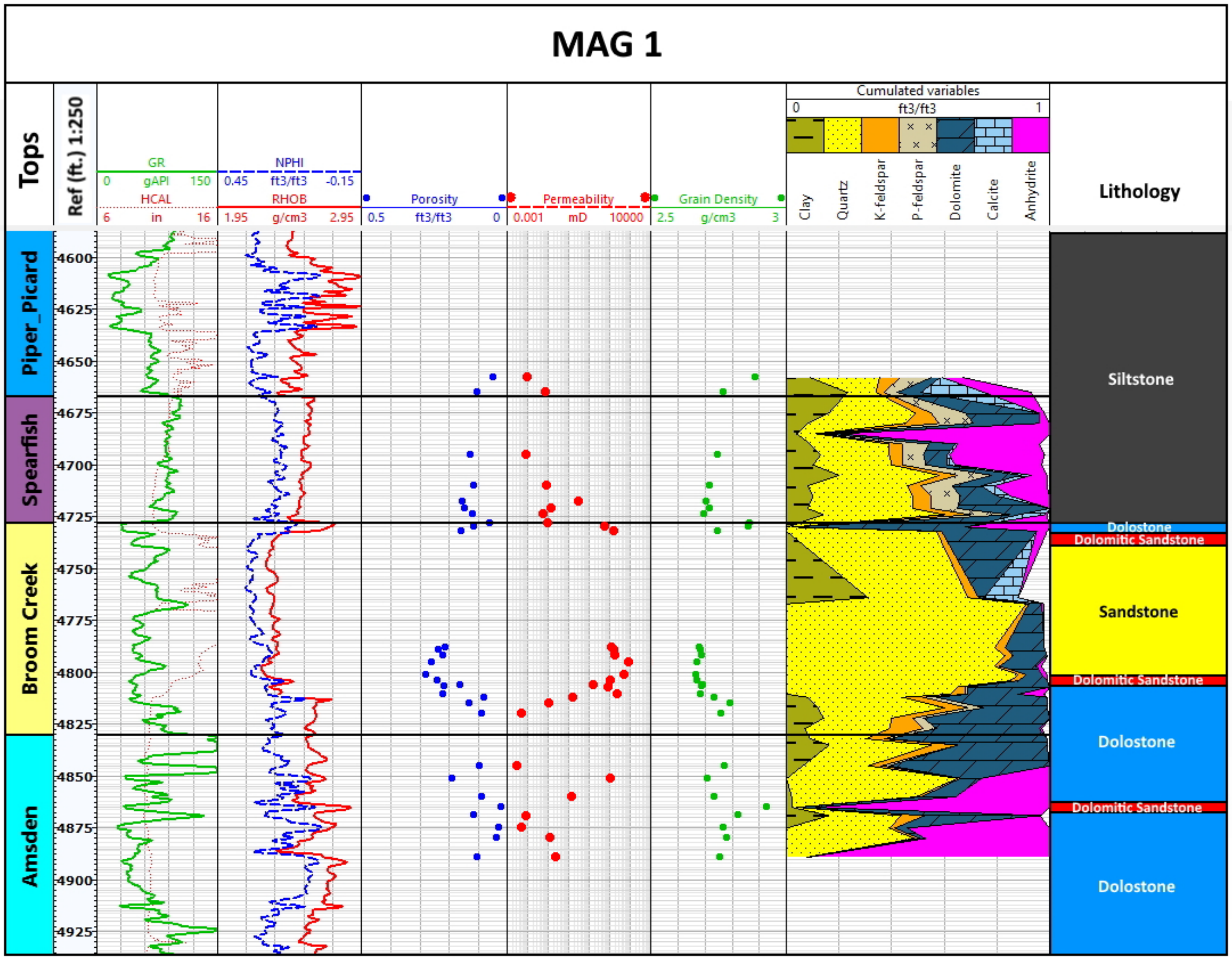



Figure 2-14. Vertical distribution of core-derived porosity and permeability values and the laboratory-derived mineralogic characteristics in the Blue Flint storage complex from MAG 1. Logs displayed in tracks from left to right are 1) formation designation, 2) measured depth track, 3) GR and caliper,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

### *2.3.1 Mineralogy*

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

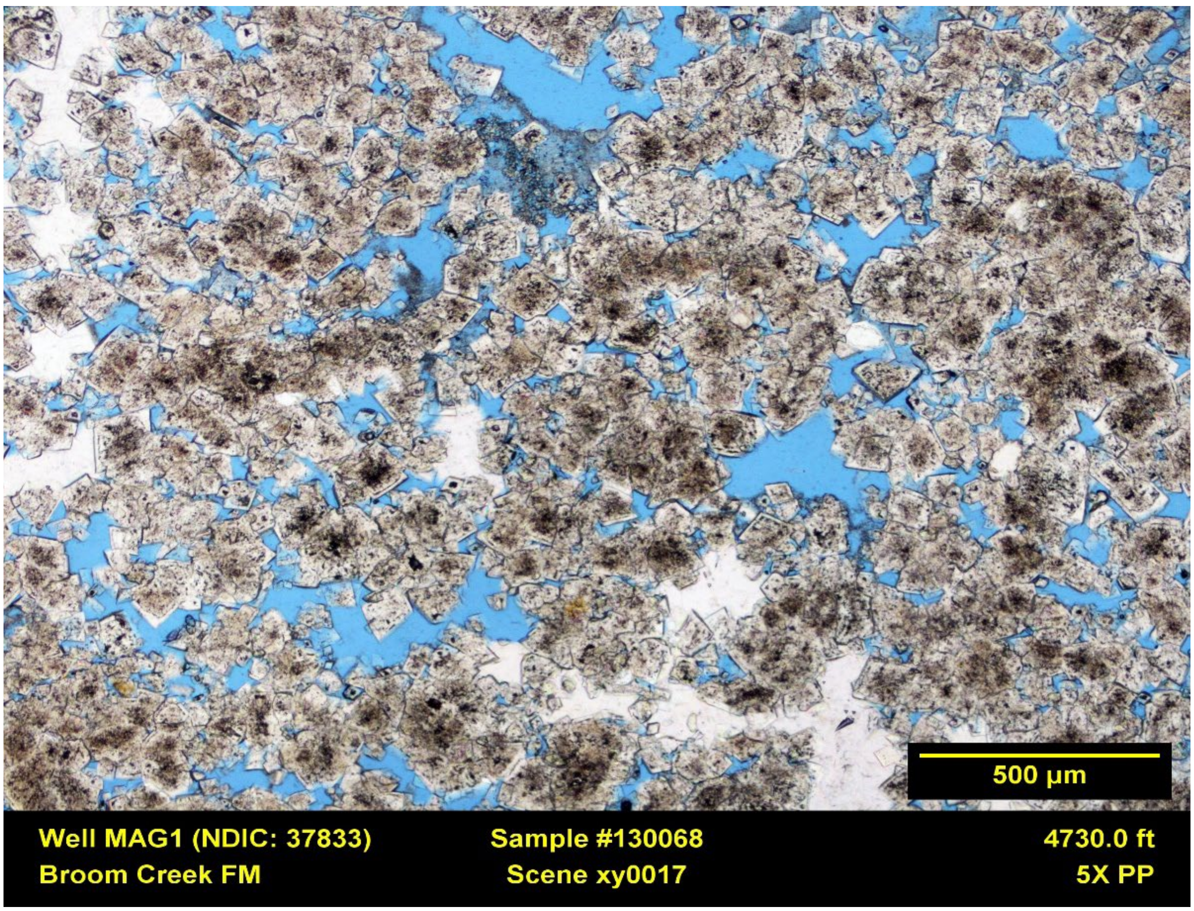



Figure 2-15. Thin section in upper Broom Creek Formation. This interval is primarily dolomite (gray) with anhydritic cement.

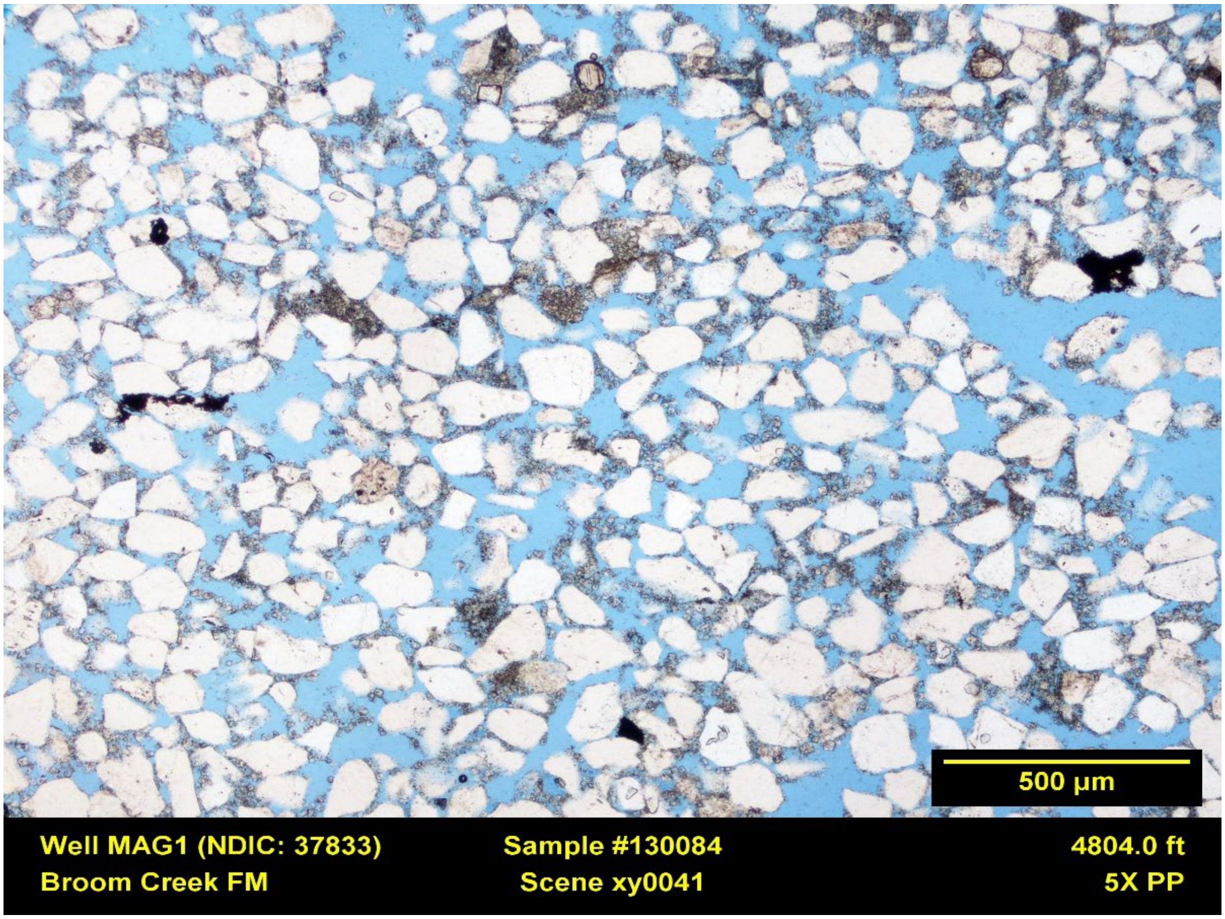



Figure 2-16. Thin section in middle Broom Creek Formation. This interval is dominated by fine-grained quartz and minor dolomite. Porosity is high in this interval.

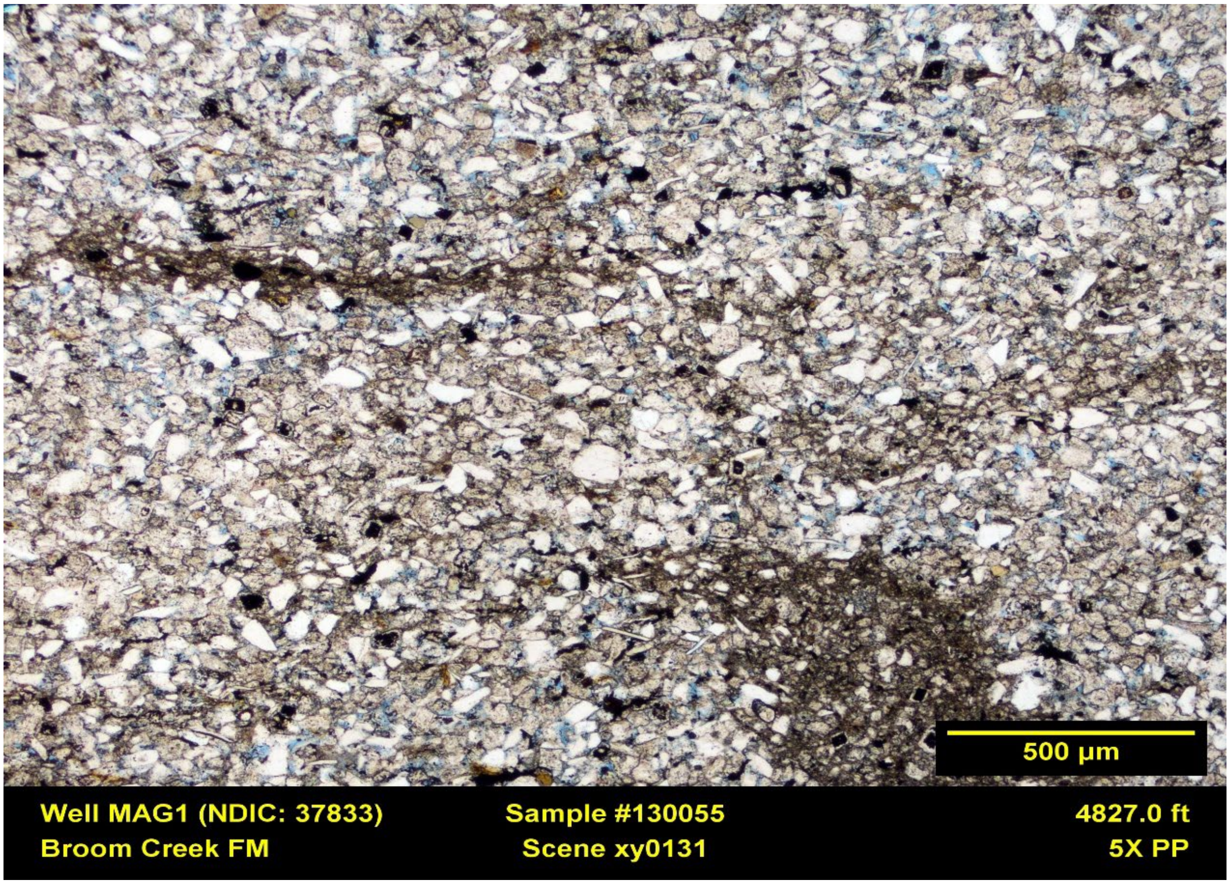



Figure 2-17. Thin section in lower Broom Creek Formation. This interval is a laminated silty mudstone. The matrix is dominated by clay and quartz.

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

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

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

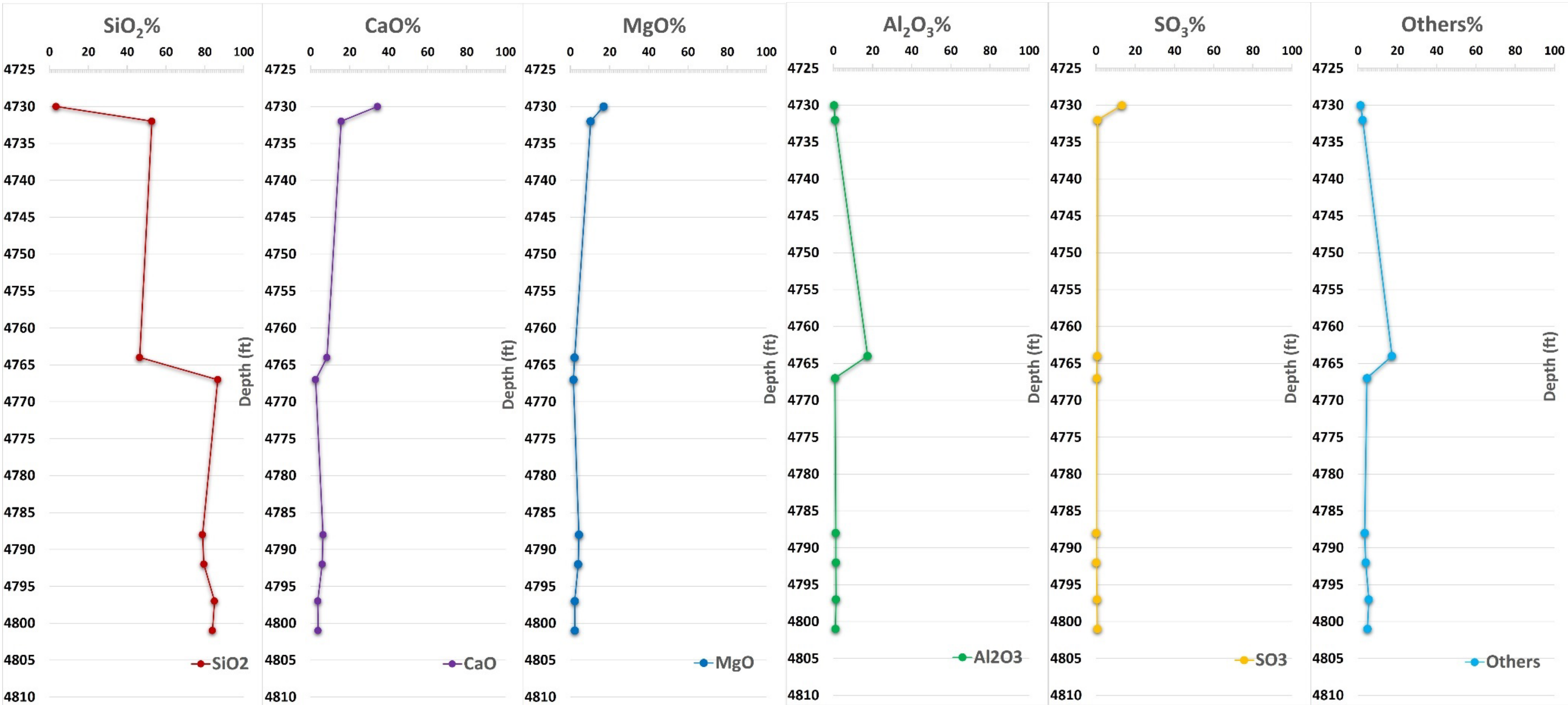



Figure 2-18. XRF analysis in Broom Creek Formation from MAG 1.

### *2.3.2 Mechanism of Geologic Confinement*

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

### *2.3.3 Geochemical Information of Injection Zone*

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

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

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

**Table 2-7. Injection Stream Composition**

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

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

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

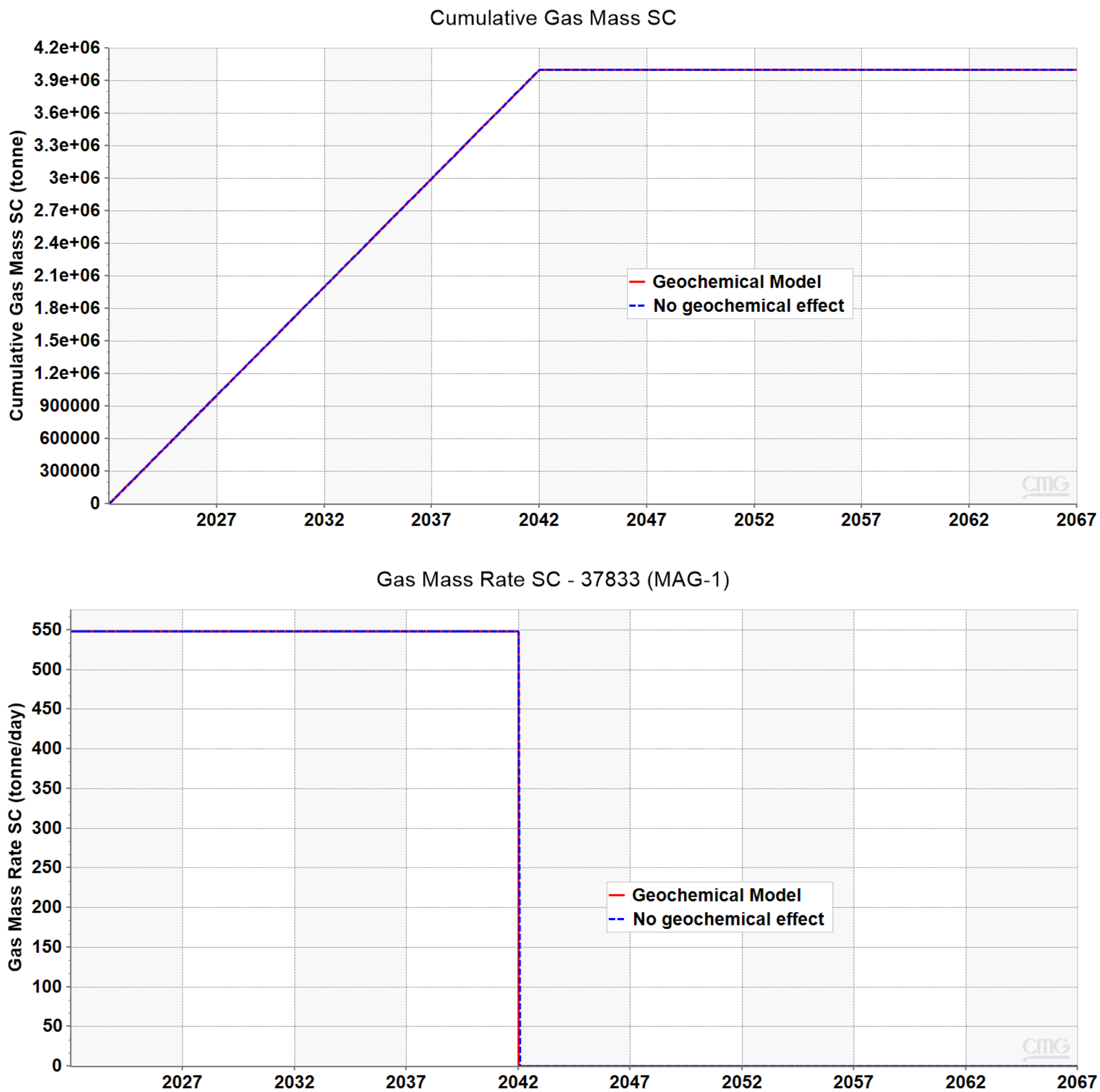
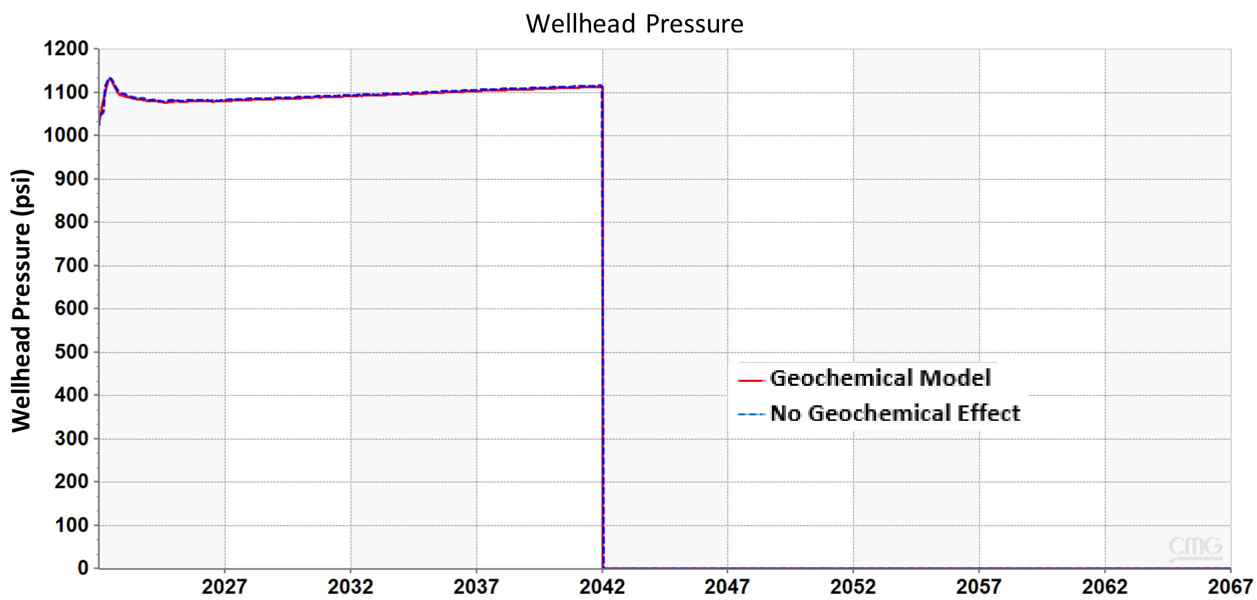



Figure 2-19. Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions.



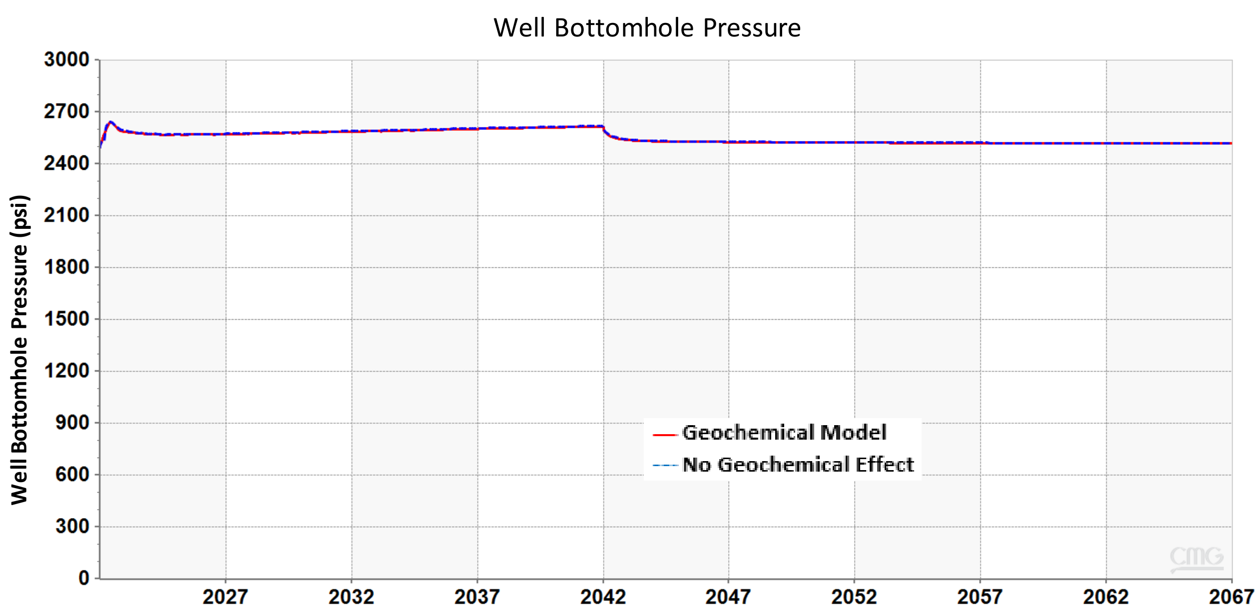




Figure 2-20. Upper graph shows wellhead pressure vs. time; the bottom figure shows the bottomhole pressure vs. time. There is no observable difference in pressures due to geochemical reactions.

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

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

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

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

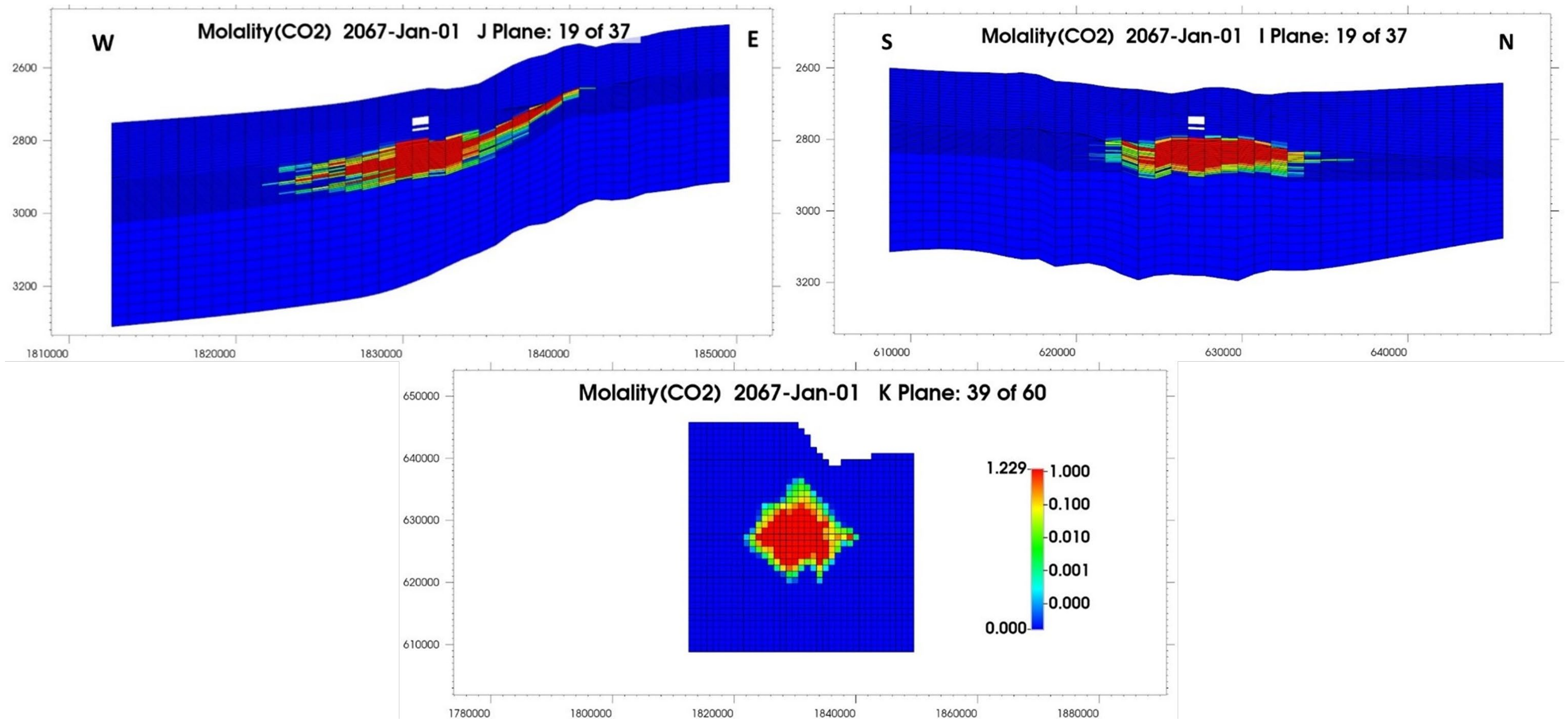



Figure 2-21. $CO_2$ molality for the geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of $CO_2$ molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of simulation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

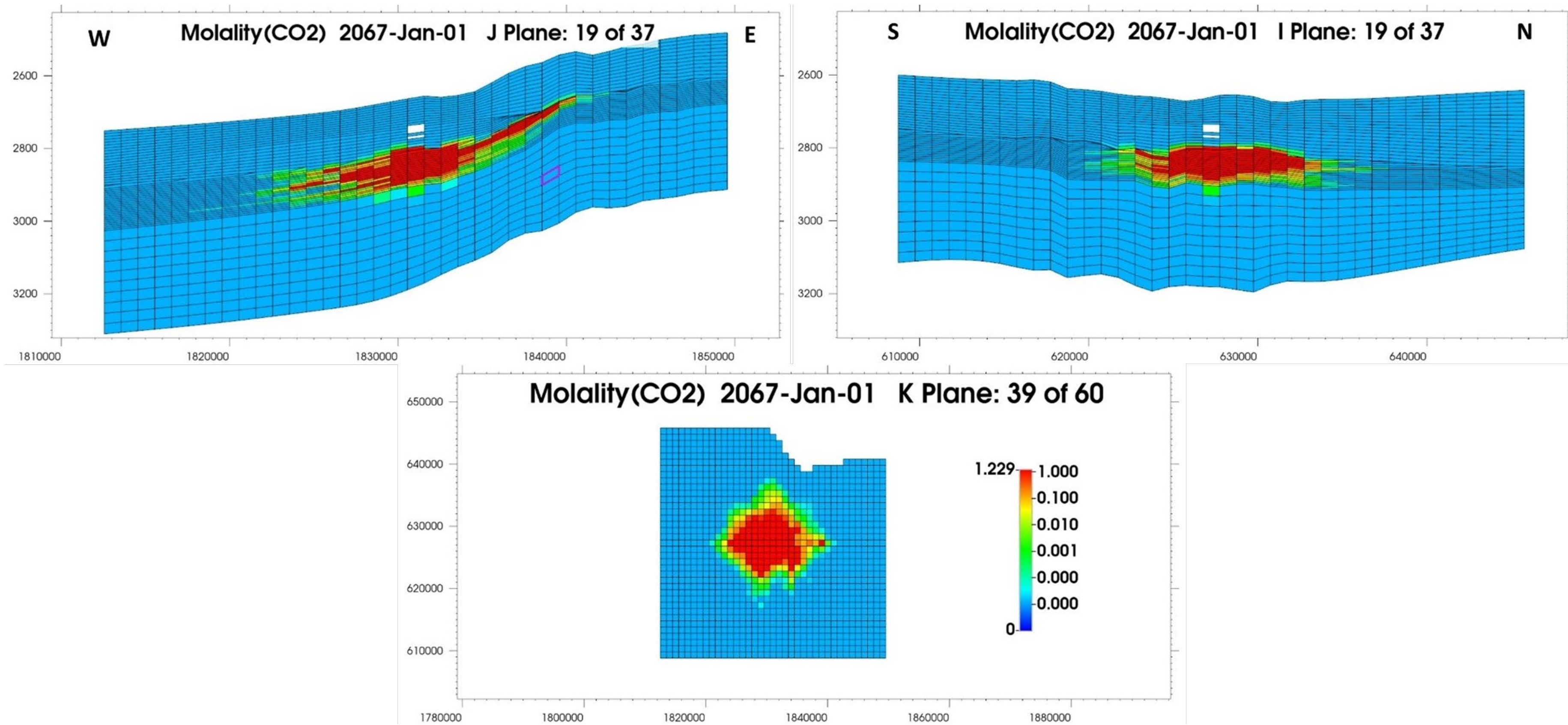



Figure 2-22. $CO_2$ molality for the non-geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of $CO_2$ molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of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

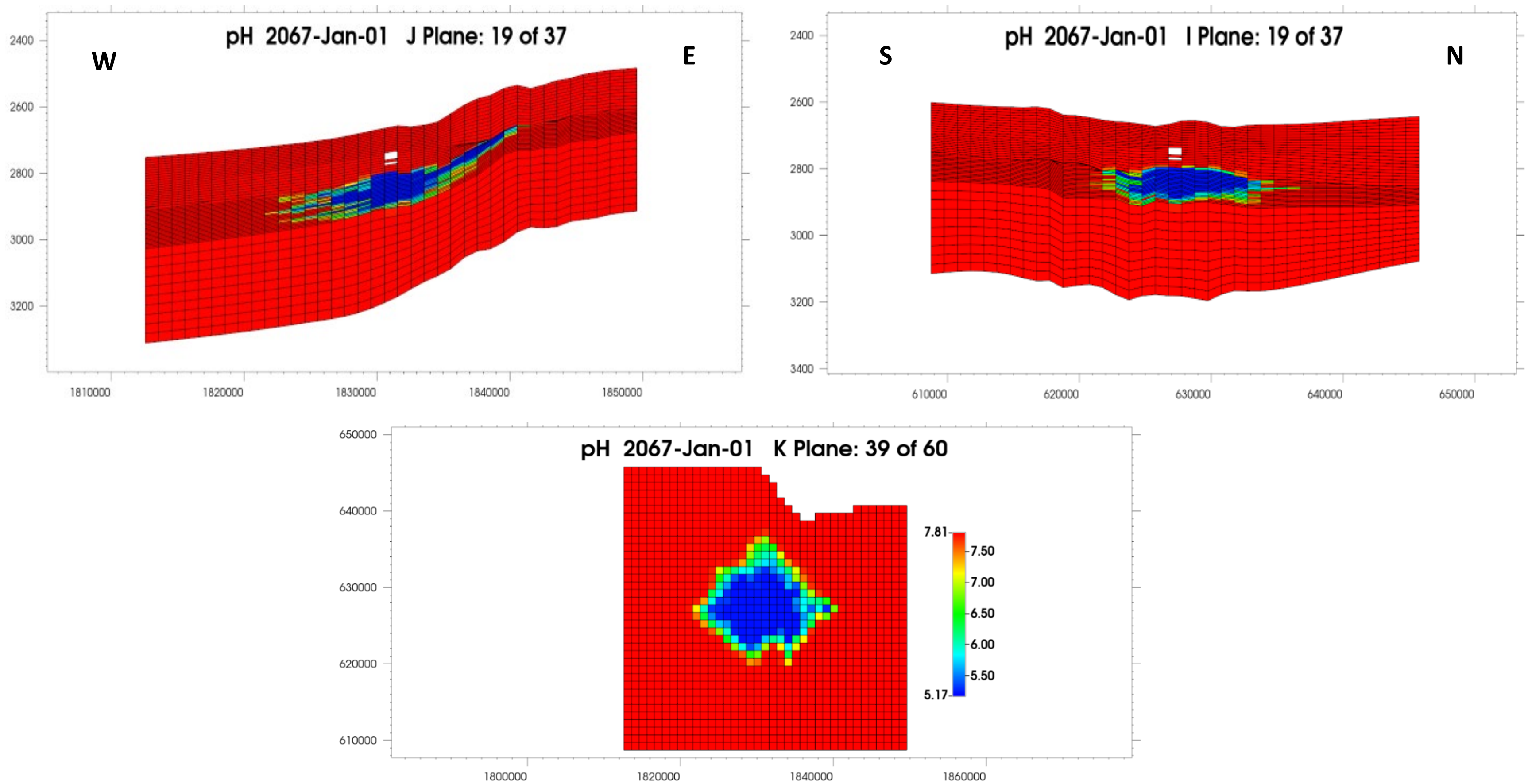



Figure 2-23. Geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

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

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

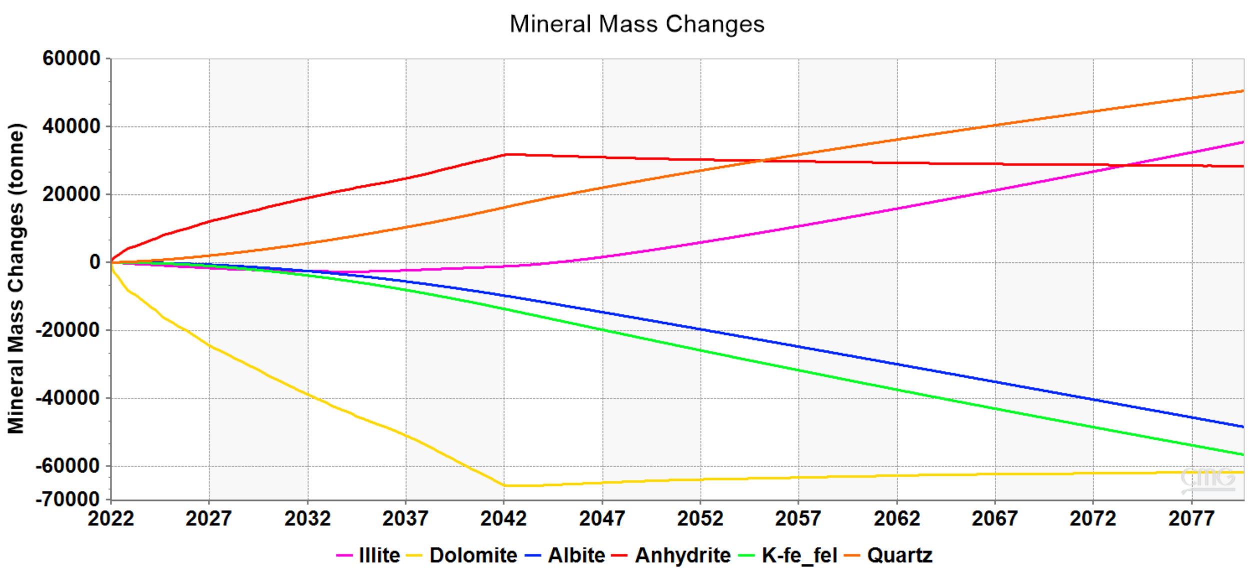



Figure 2-24. Dissolution and precipitation quantities of reservoir minerals because of $CO_2$ injection. Dissolution of albite, K-feldspar (K-fe_fel), and dolomite with precipitation of illite, quartz, and anhydrite was observed.

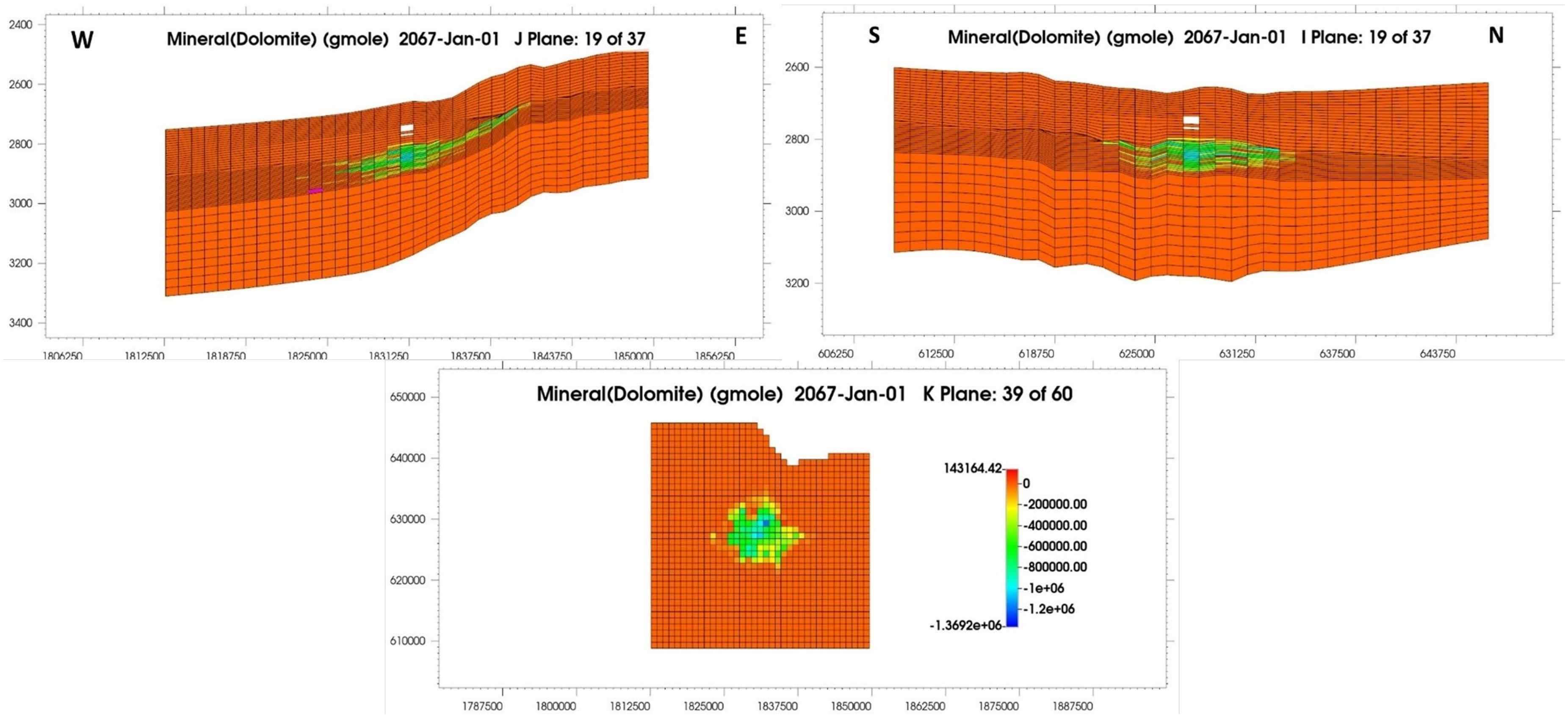



Figure 2-25. Change in molar distribution of dolomite, the most prominent dissolved mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

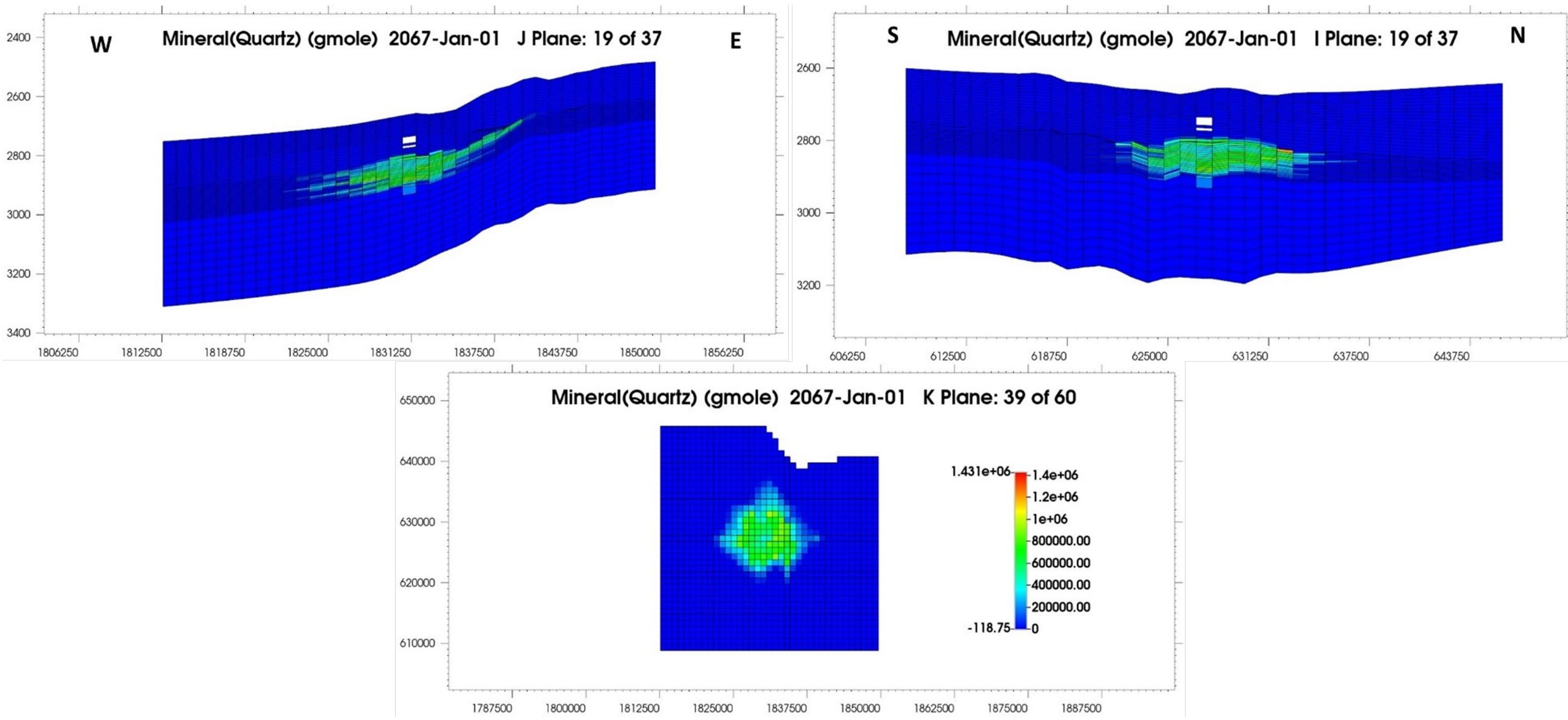



Figure 2-26. Change in molar distribution of quartz, the most prominent precipitated mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

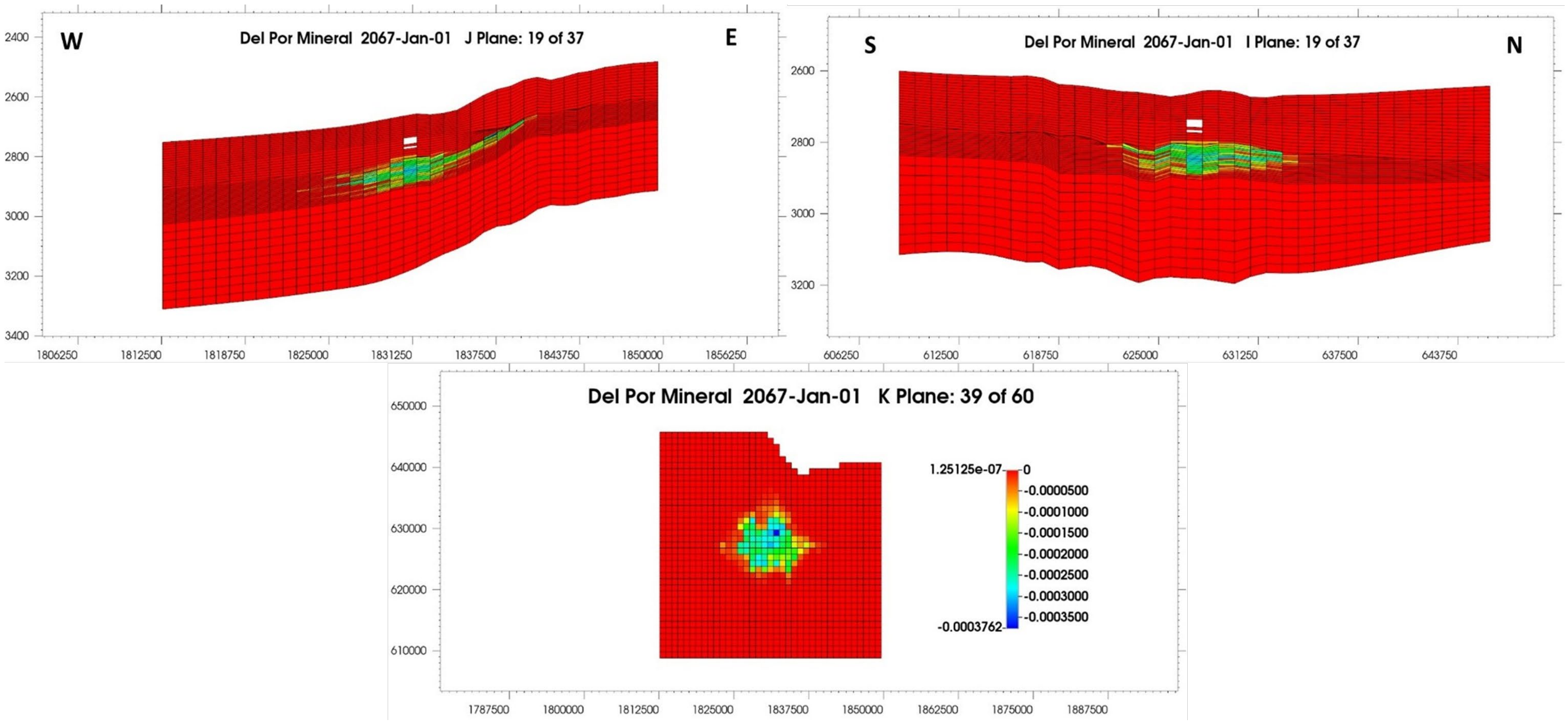



Figure 2-27. Change in porosity due to net geochemical dissolution at the end of the 20-year injection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero.

## 2.4 Confining Zones

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

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

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

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

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

### *2.4.1 Upper Confining Zone*

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

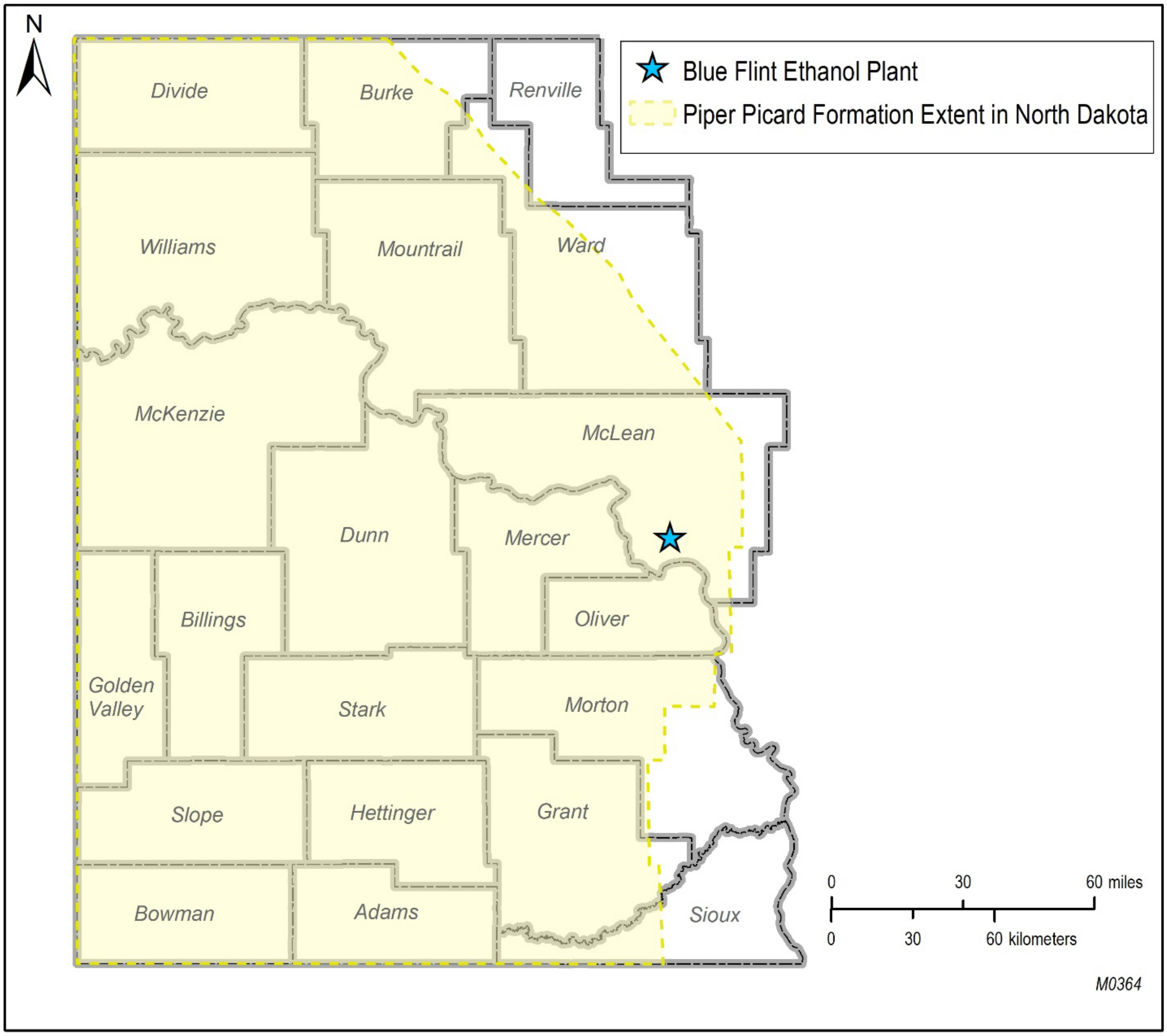



Figure 2-28. Areal extent of the lower Piper Formation in western North Dakota (modified from Carlson, 1993).

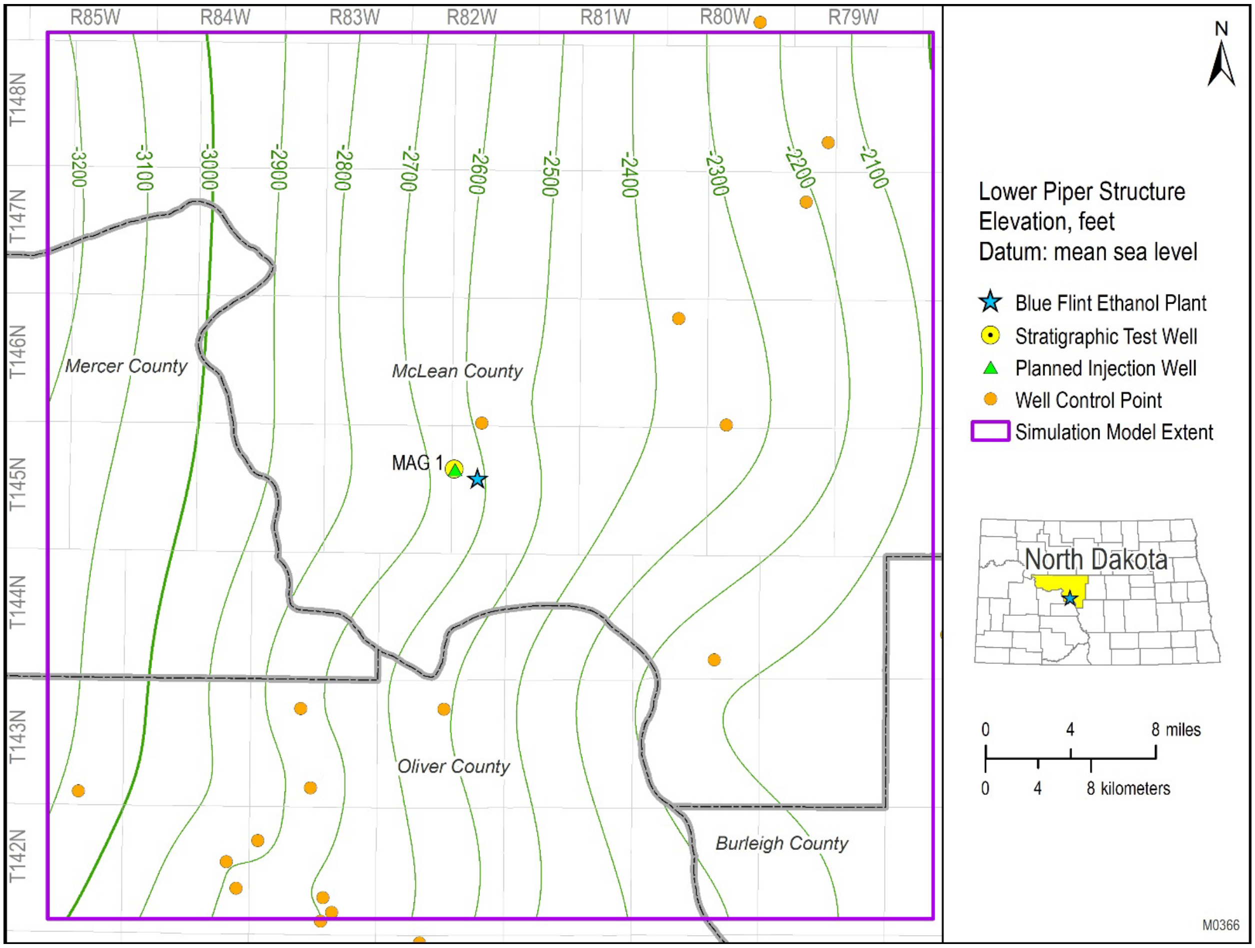



Figure 2-29. Structure map of the lower Piper Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

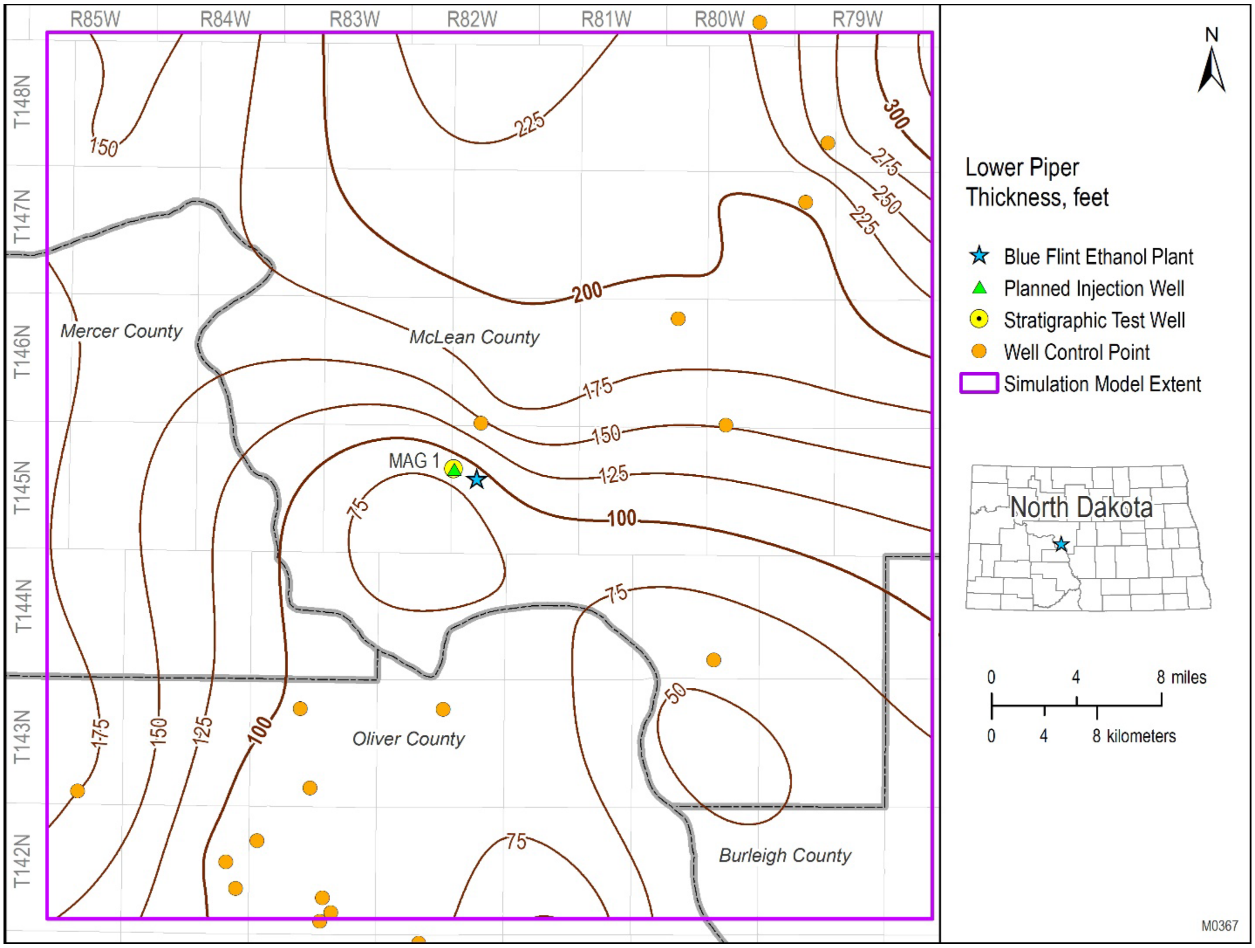



Figure 2-30. Isopach map of the lower Piper Formation in the greater Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

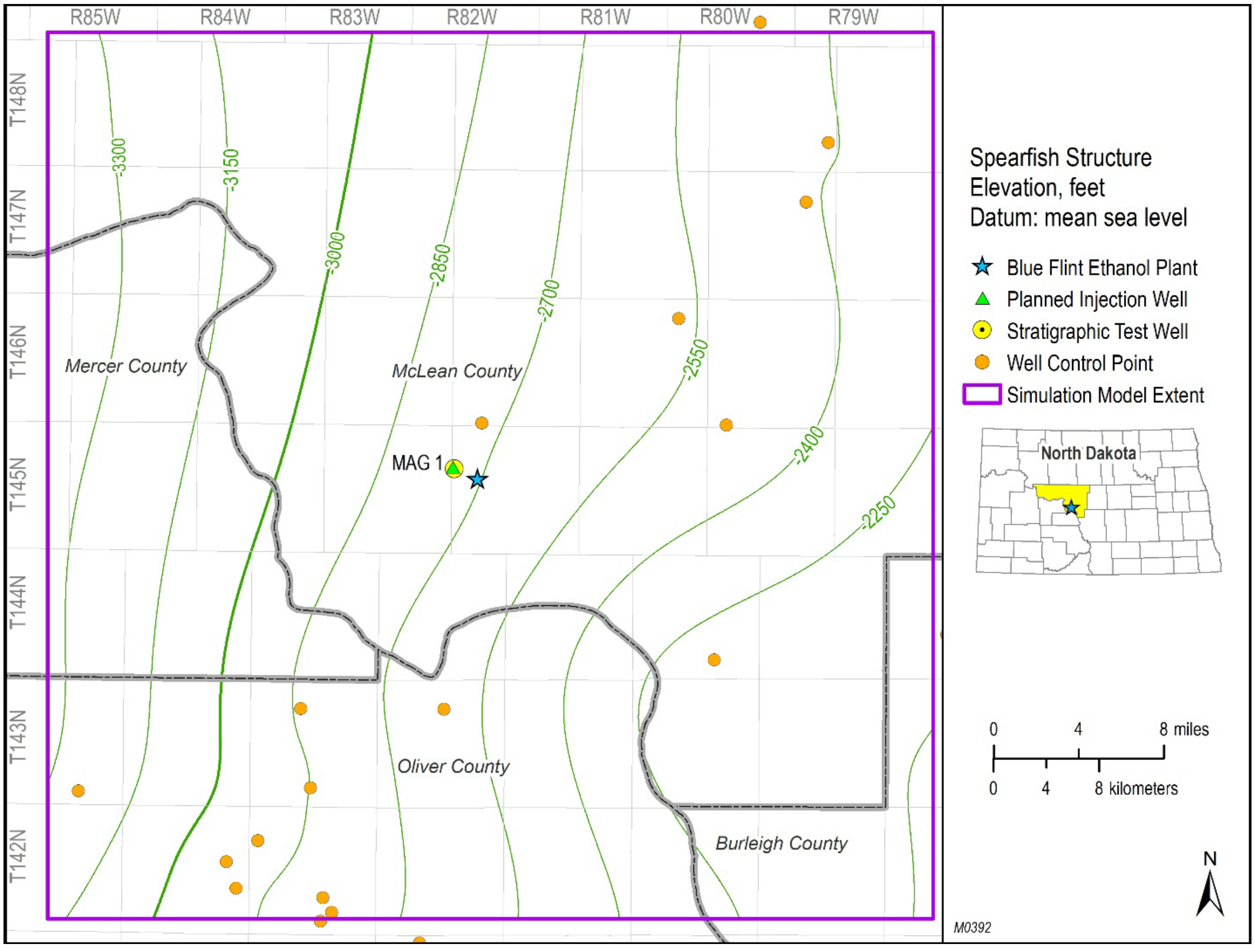



Figure 2-31. Structure map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

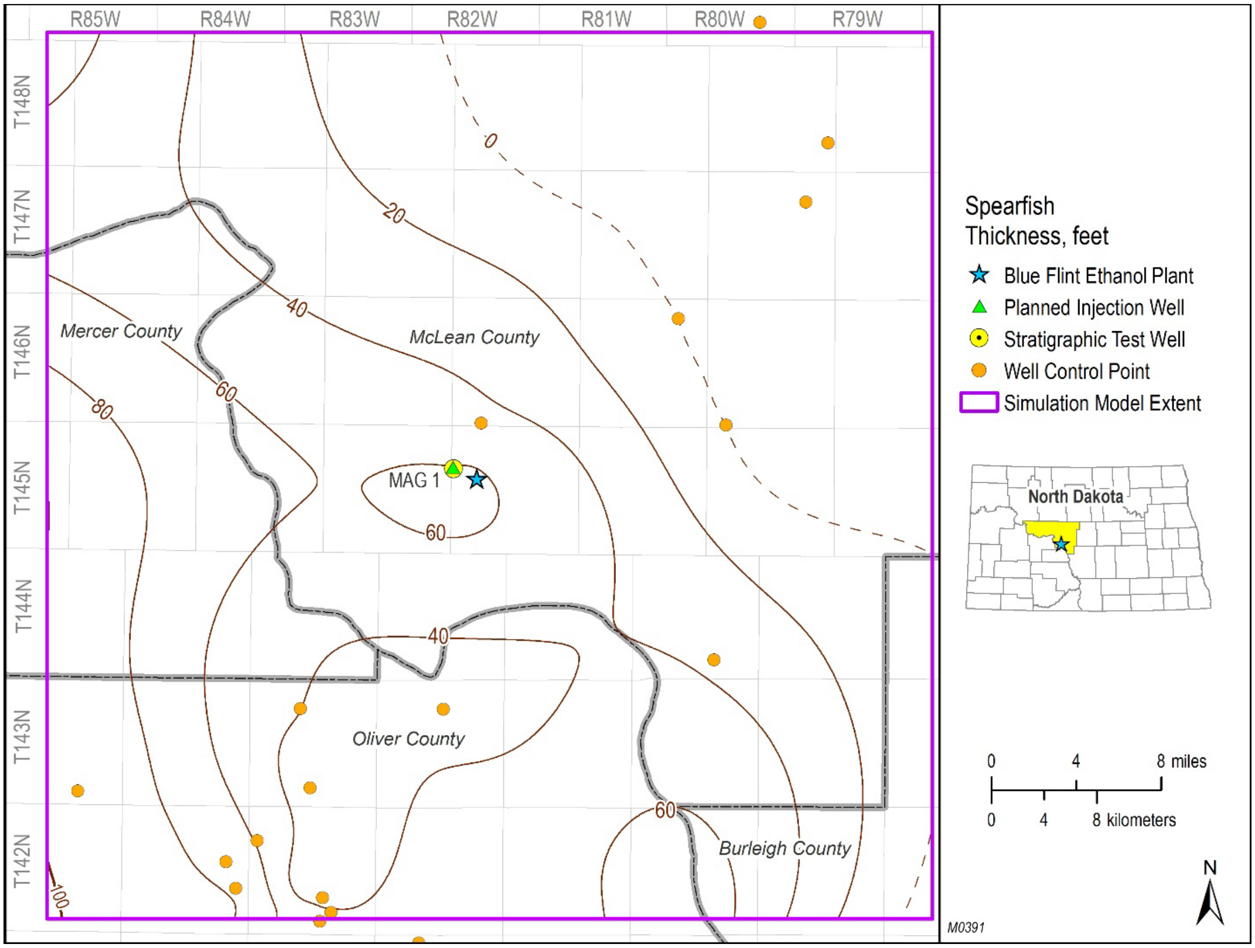



Figure 2-32. Isopach map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

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

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

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

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

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

*2.4.1.1 Mineralogy*

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

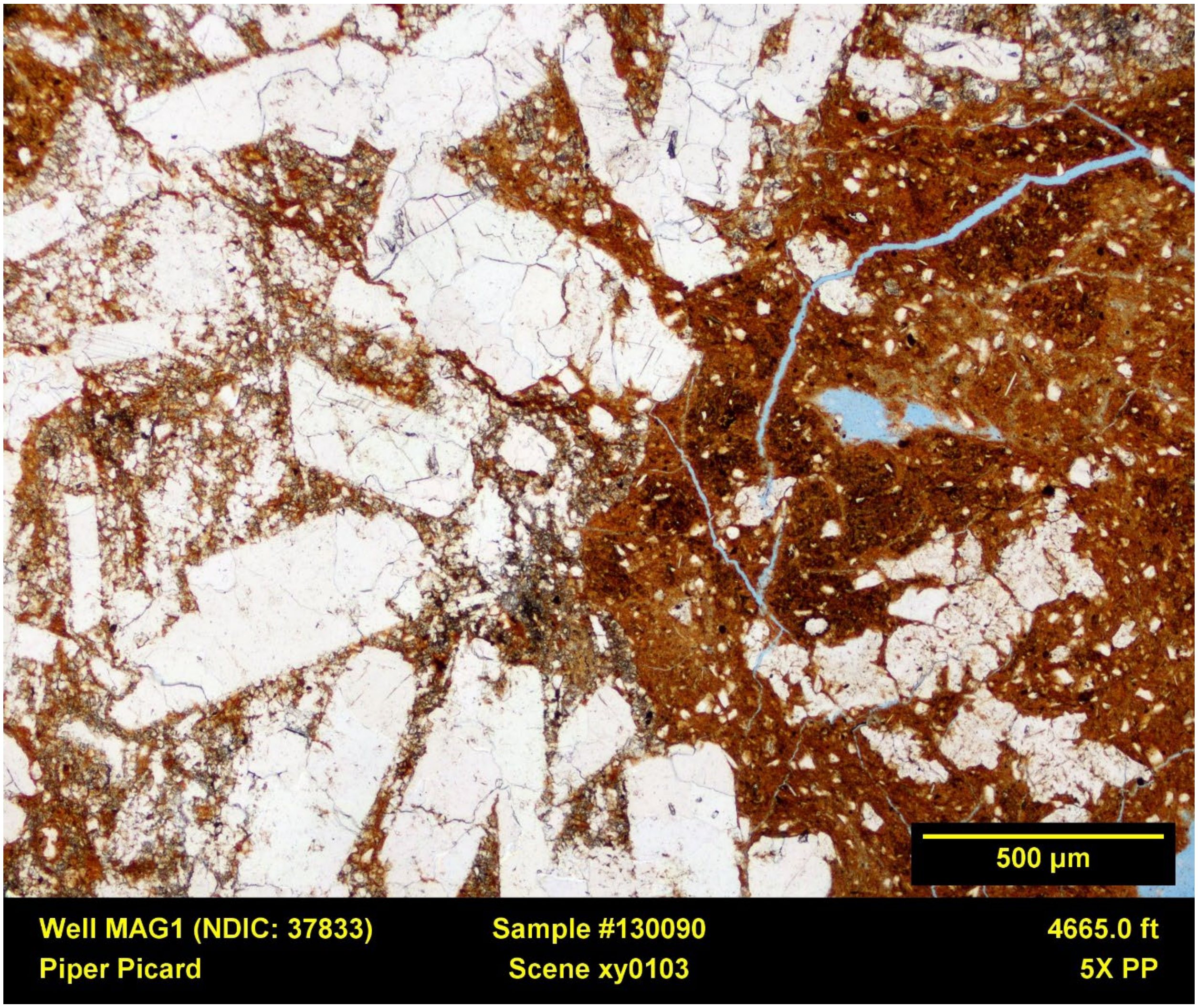



Figure 2-33. Thin section of Piper Formation. In this example, clay (brown) and anhydrite (white) dominate the depth interval. Minor porosity is observed (blue).

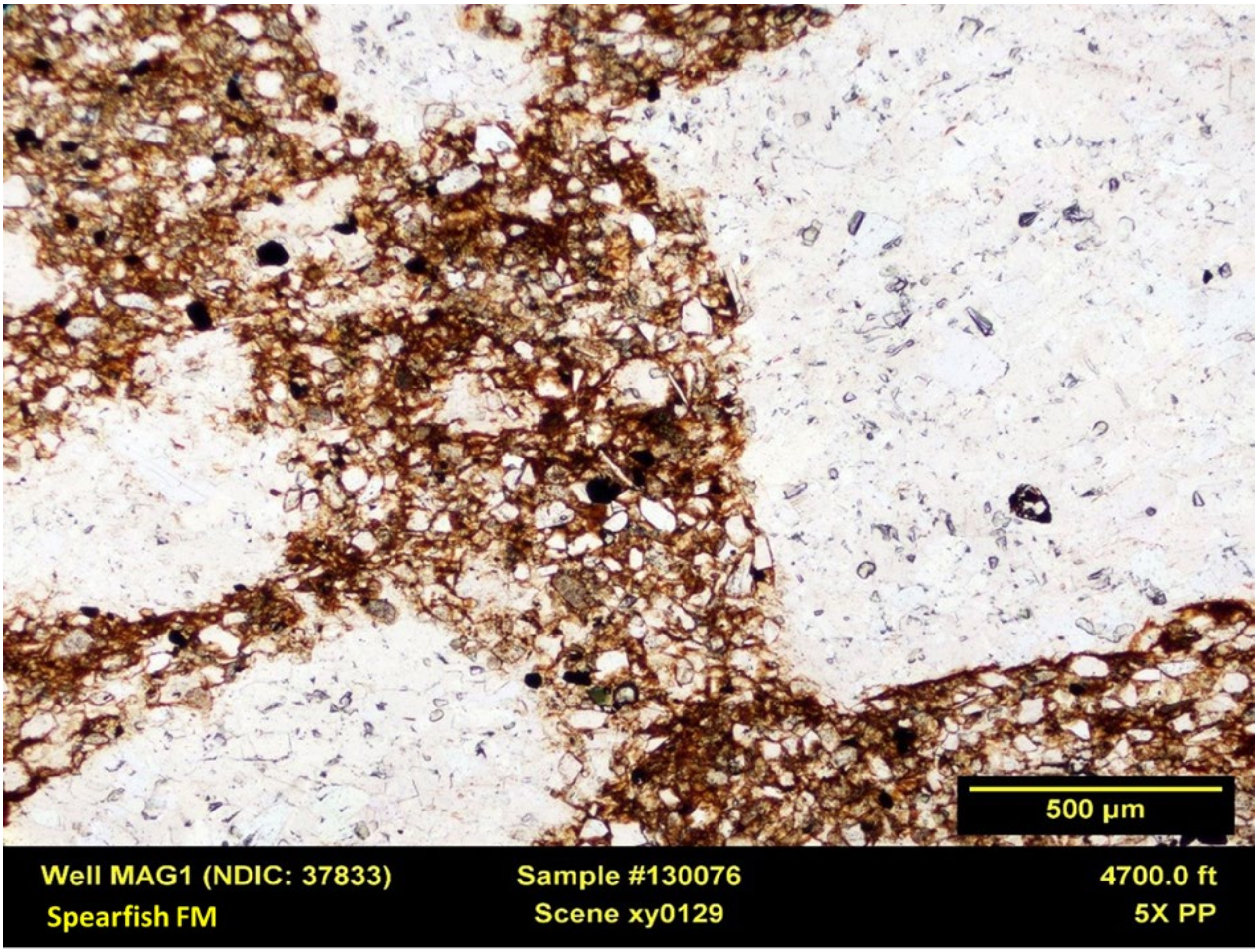



Figure 2-34. Thin section of Spearfish Formation. In this example, clay (brown), quartz (small white grains), anhydrite (large white grains), and iron oxides (black grains) dominate the depth interval. No porosity is observed.

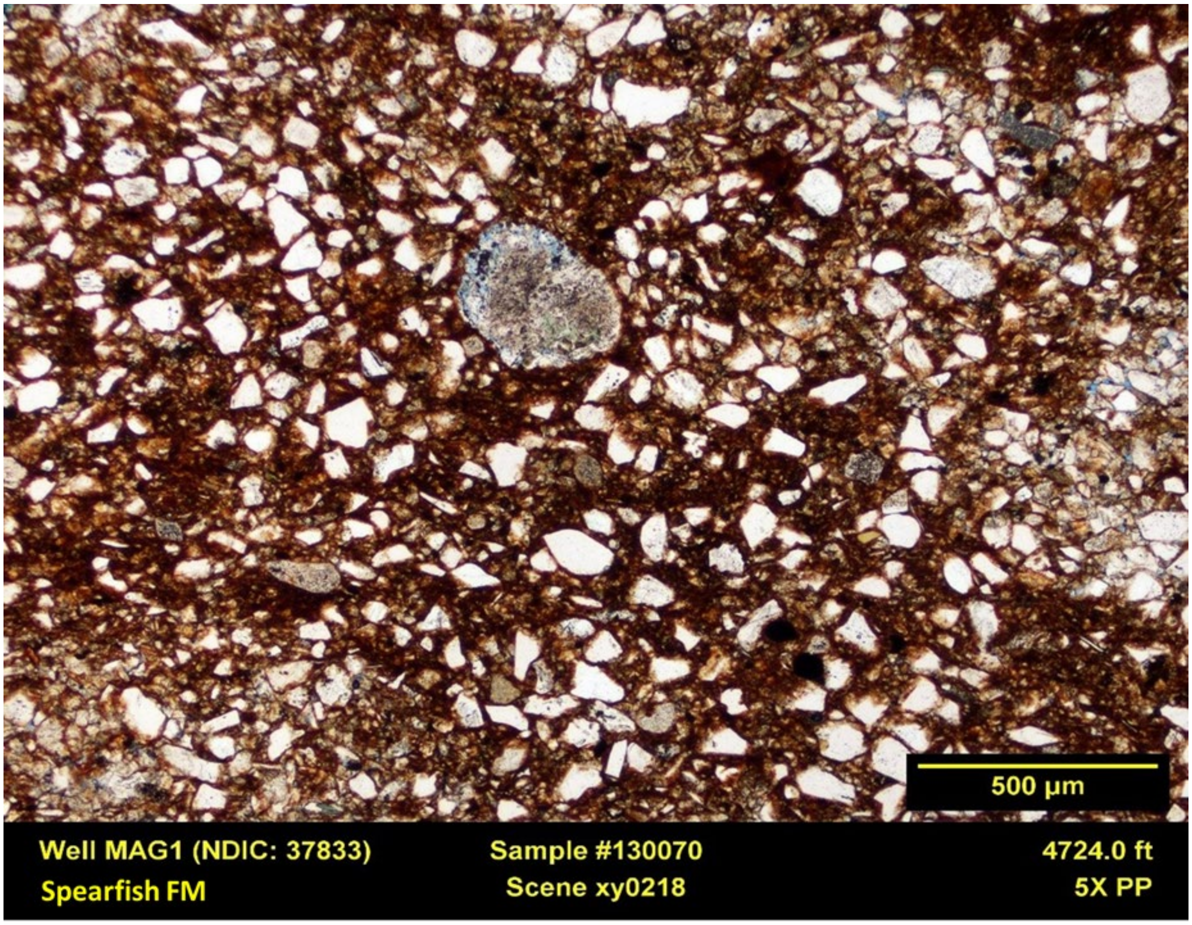



Figure 2-35. Thin section of Spearfish Formation. In this example, clay (brown) and quartz (white) dominate the depth interval. Minor intergranular and intragranular porosity are observed (blue).

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

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

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

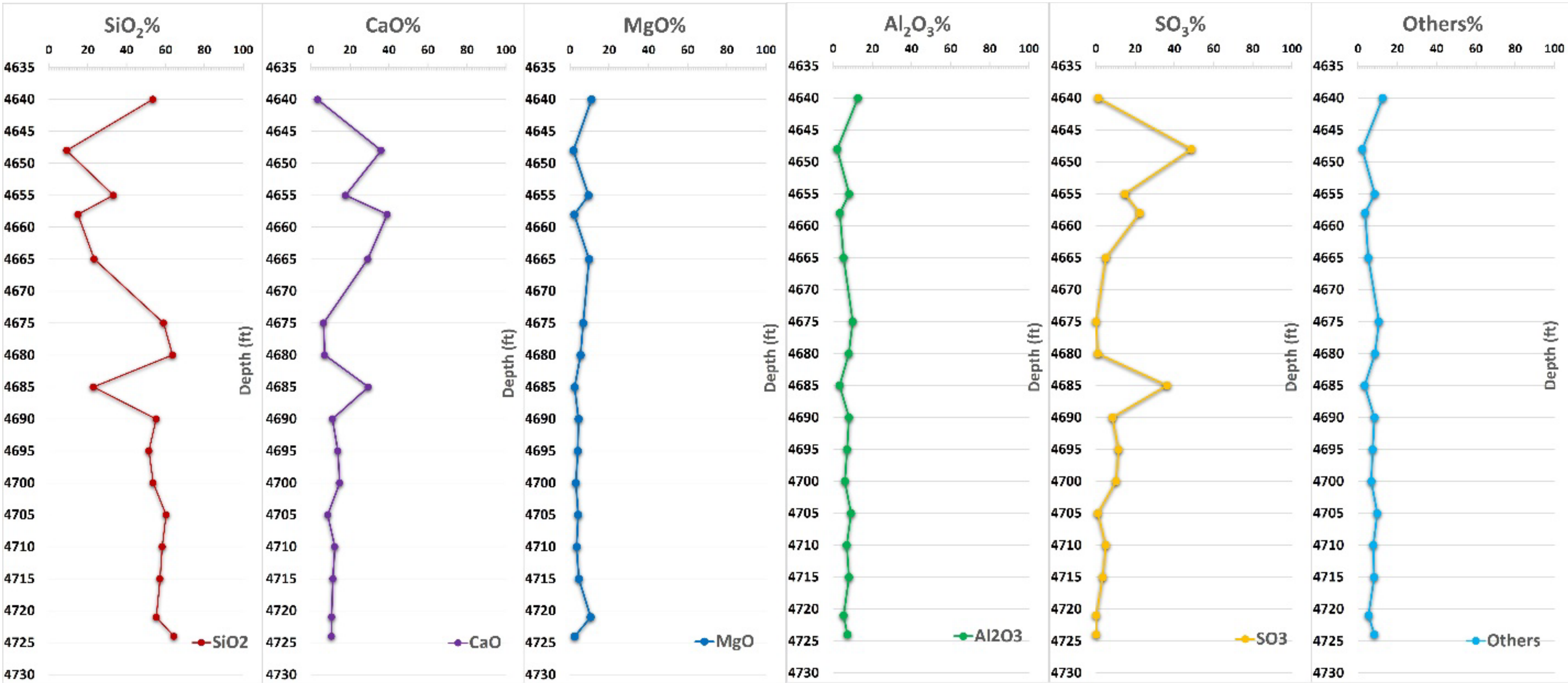



Figure 2-36. XRF analysis in the upper confining zone (Spearfish and lower Piper Formations) from MAG 1.

*2.4.1.2 Geochemical Interaction*

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

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

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

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

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

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

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

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

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

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

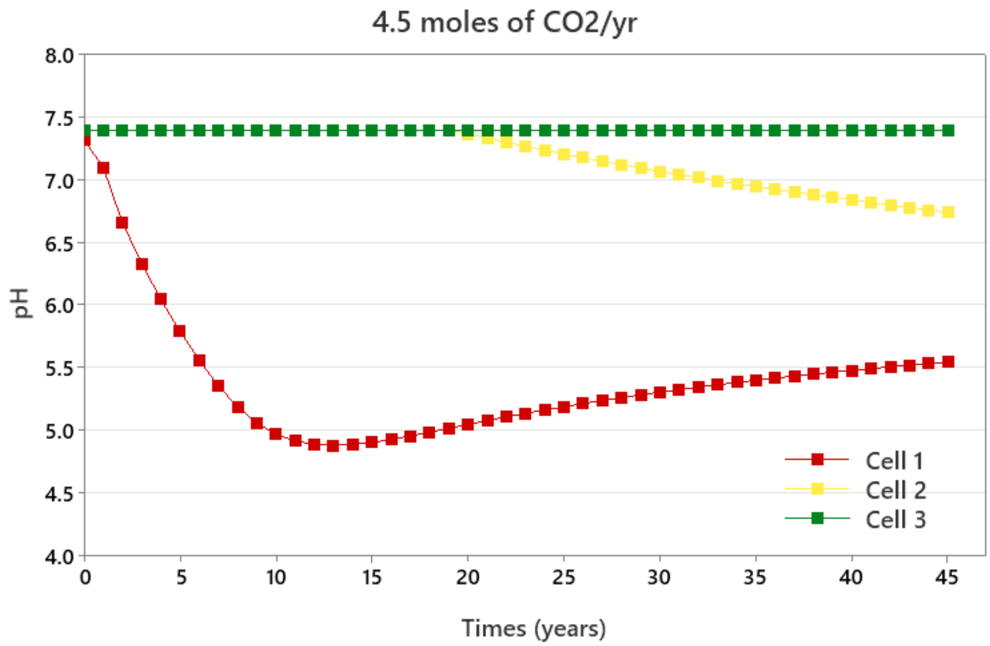



Figure 2-37. Change in fluid pH vs. time. Red line shows pH for the center of Cell C1, 0.5 meters above the Spearfish Formation cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to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

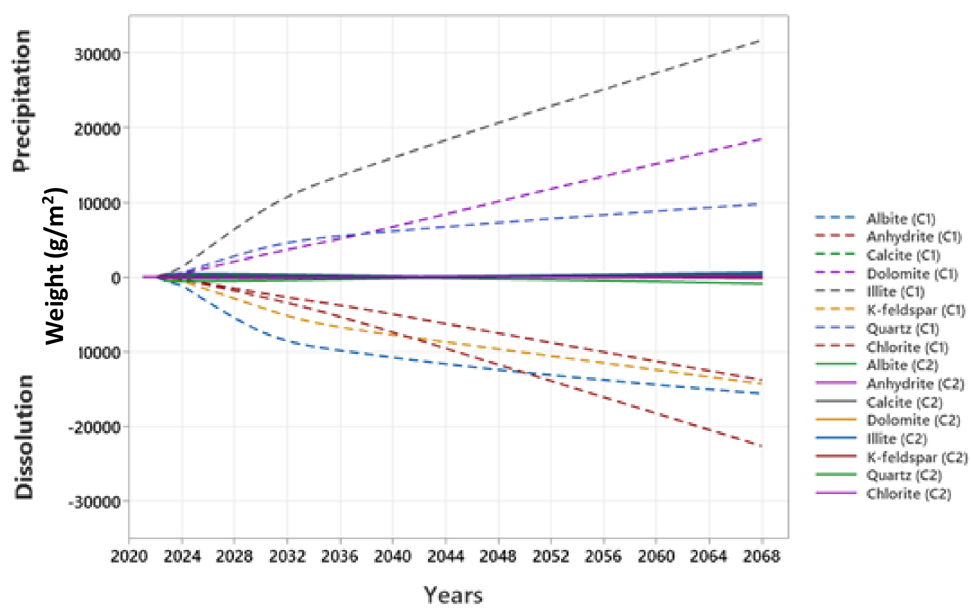



Figure 2-38. Dissolution and precipitation of minerals in the Spearfish Formation cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible. Results from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

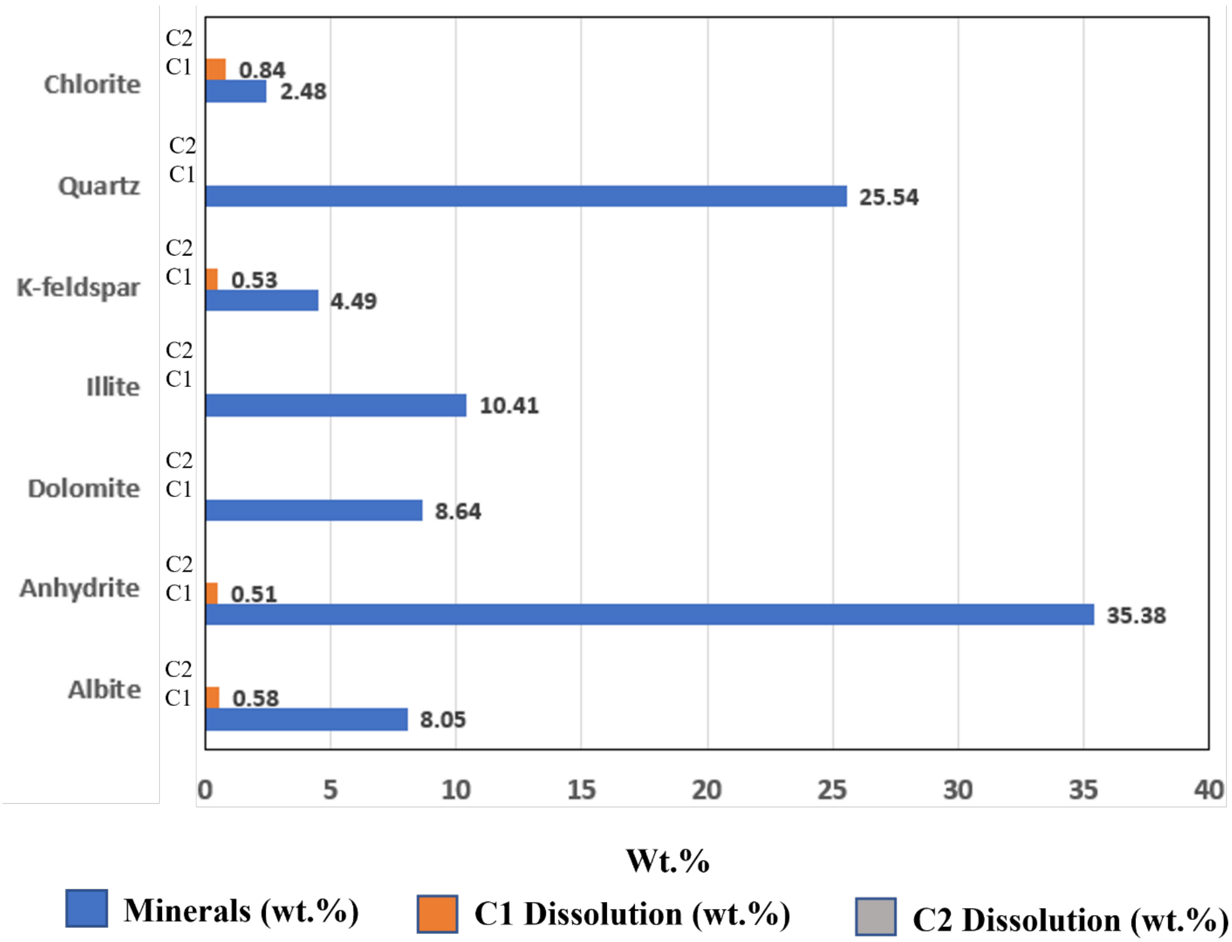



Figure 2-39. Weight percentage (wt%) of potentially reactive minerals present in the Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray, too small to see in the figure) after 20 years of injection plus 25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

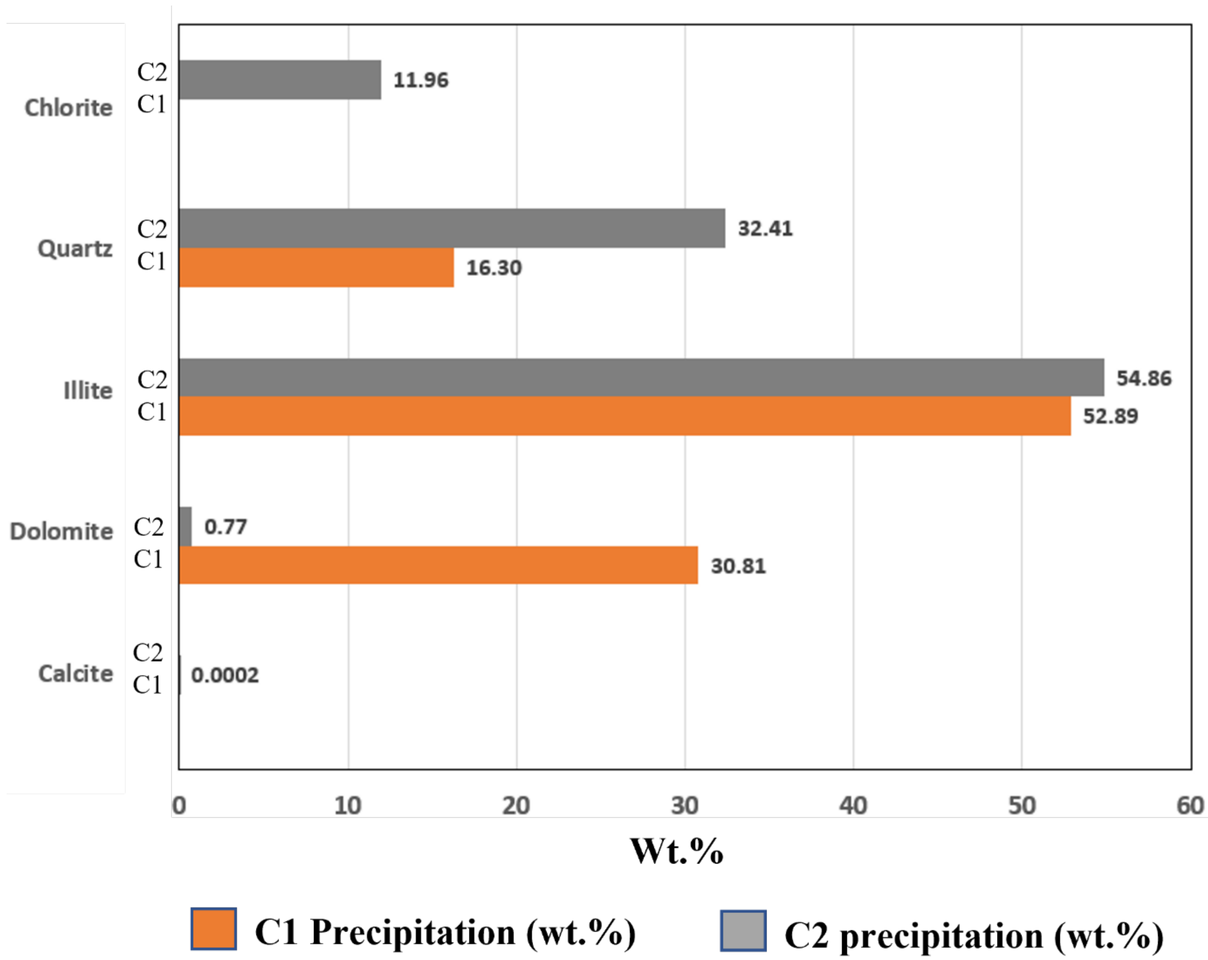



Figure 2-40. Weight percentage (wt%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time.

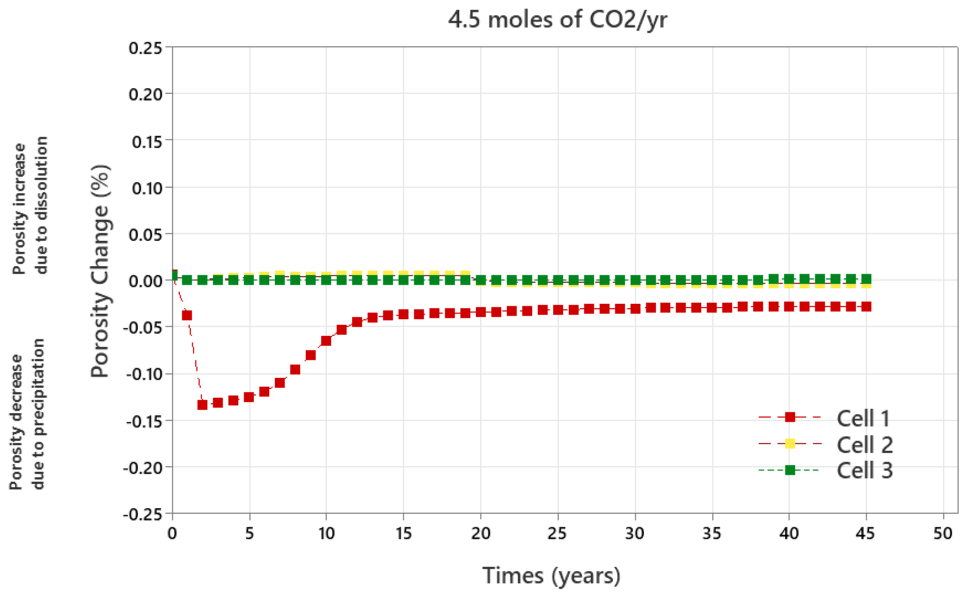



Figure 2-41. Change in percent porosity of the Spearfish cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change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

### *2.4.2 Additional Overlying Confining Zones*

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

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

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

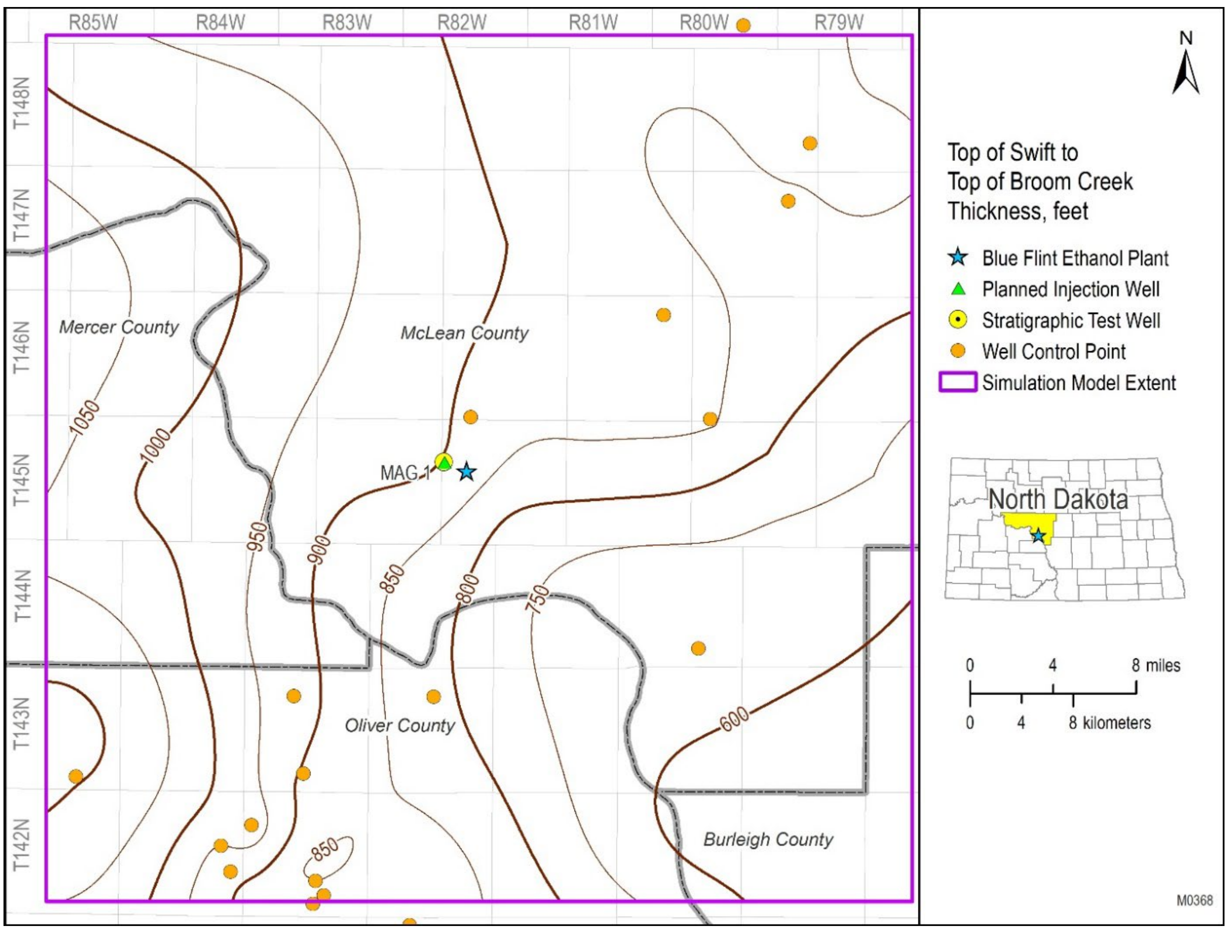



Figure 2-42. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

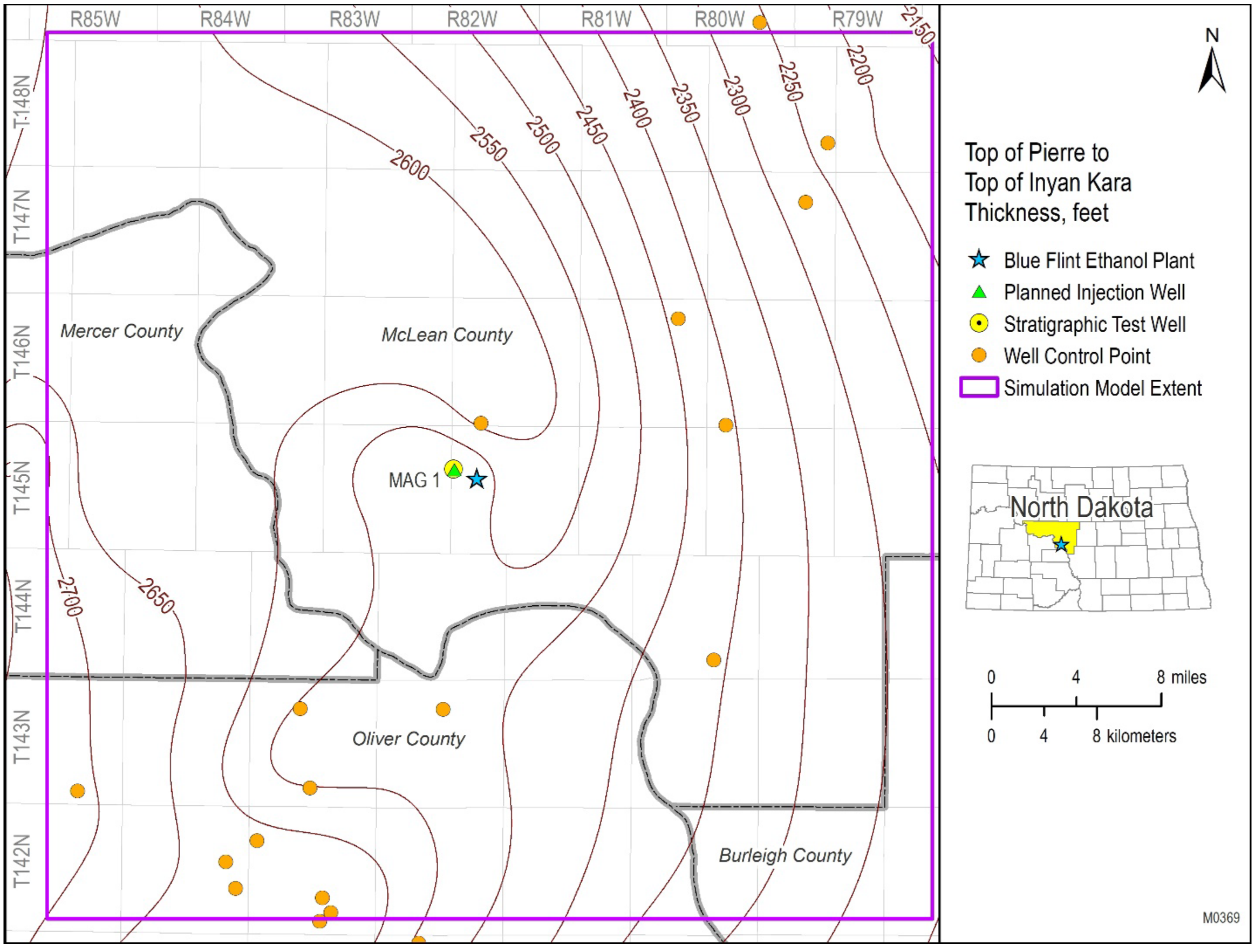



Figure 2-43. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

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

### *2.4.3 Lower Confining Zone*

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

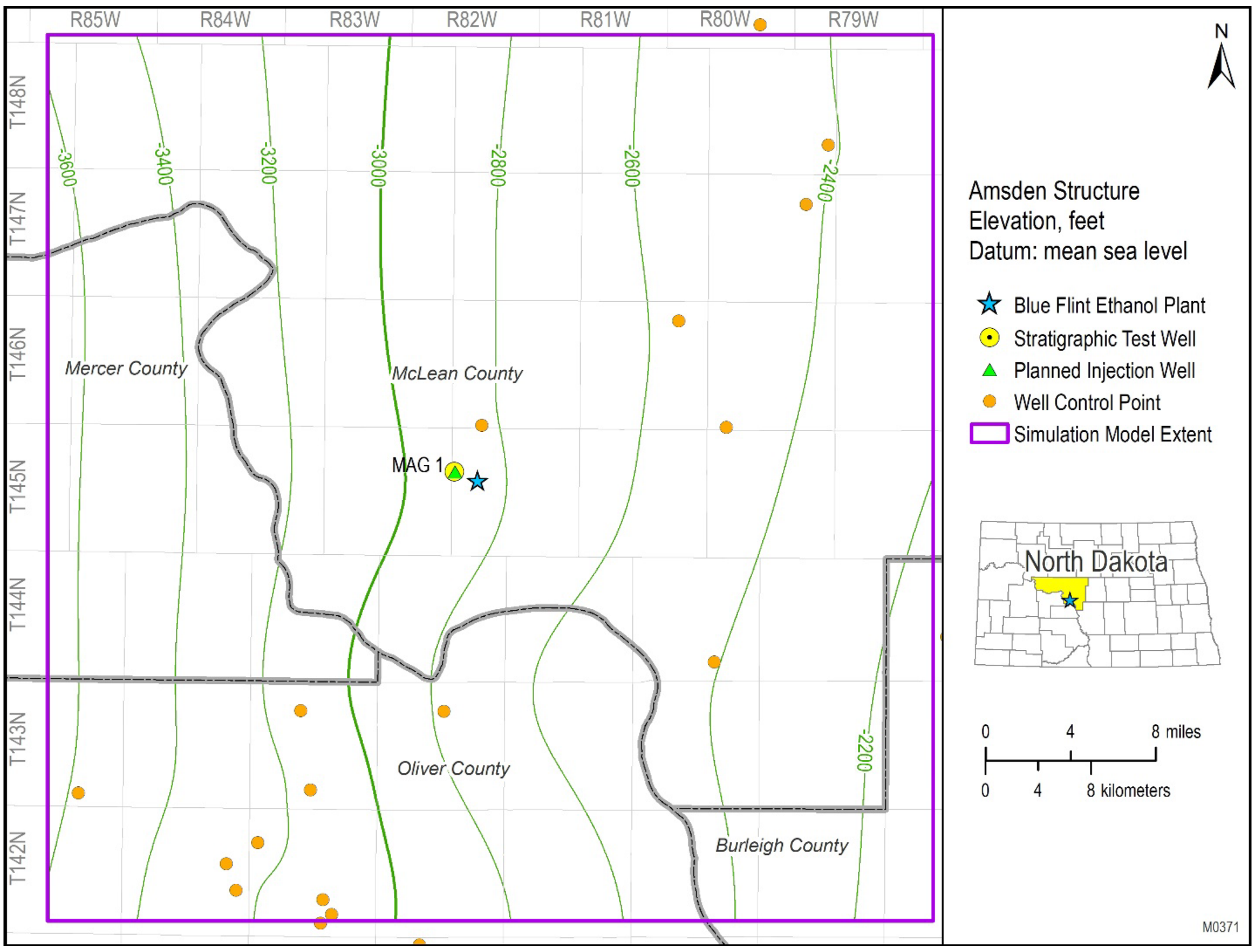



Figure 2-44. Structure map of the Amsden Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

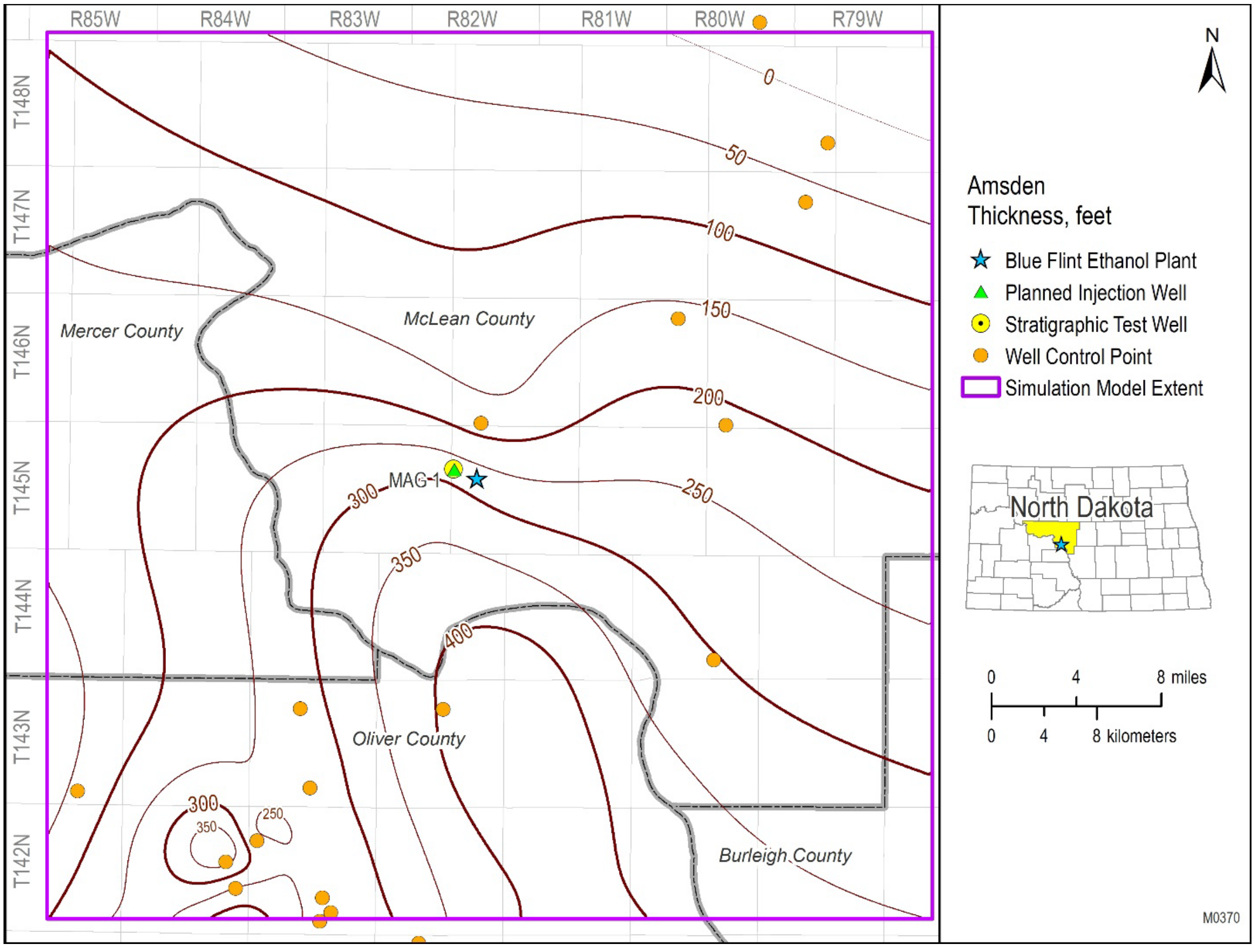



Figure 2-45. Isopach map of the Amsden Formation across the greater Blue Flint project area. The convergent interpolation gridding algorithm was used with well formation tops in creation of this map.

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

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

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

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

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

### *2.4.3.1 Mineralogy*

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

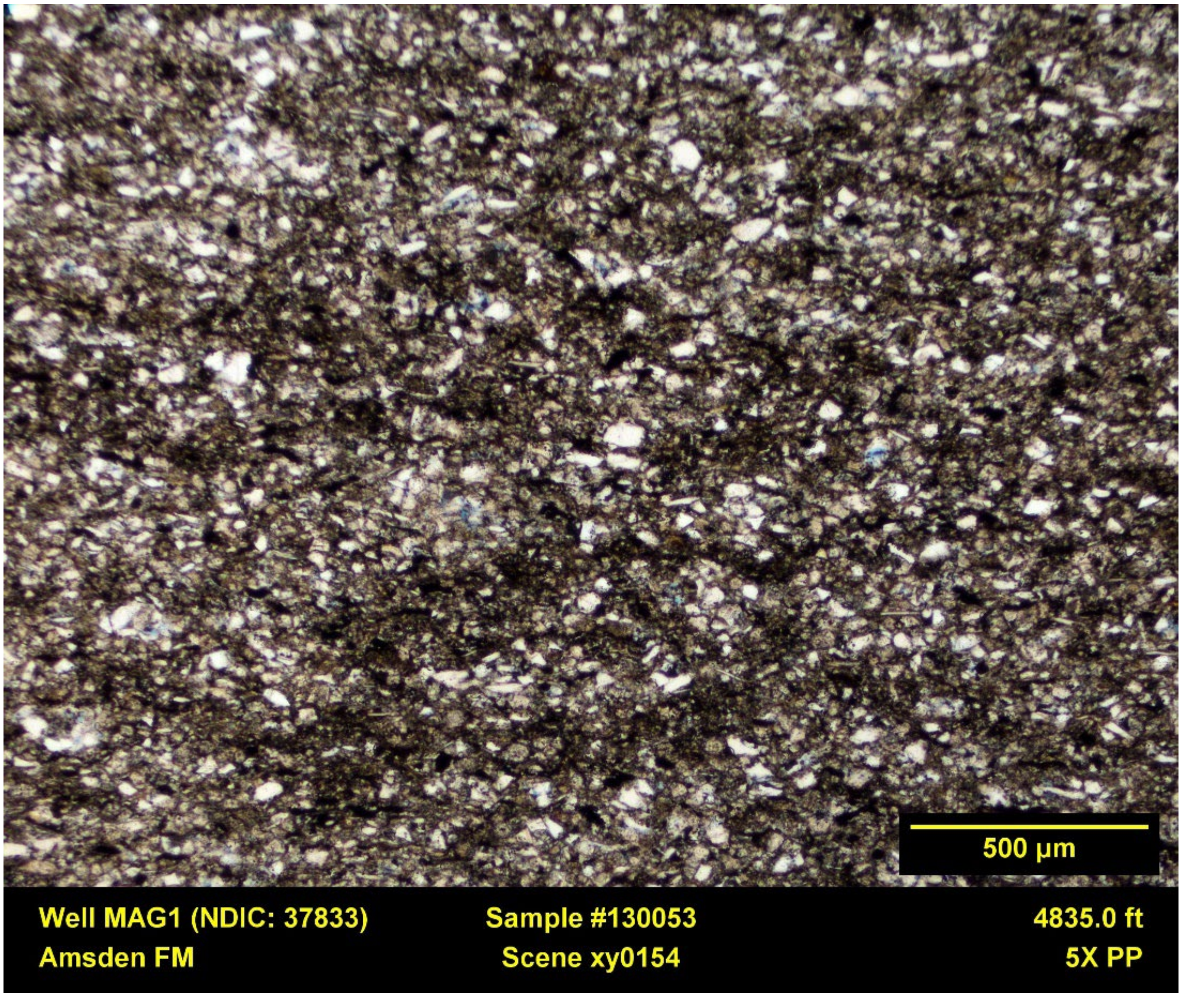



Figure 2-46. Thin section in the Amsden Formation. This example shows a dolomite matrix (gray/brown) with quartz grains distributed throughout. Minor porosity is observed.

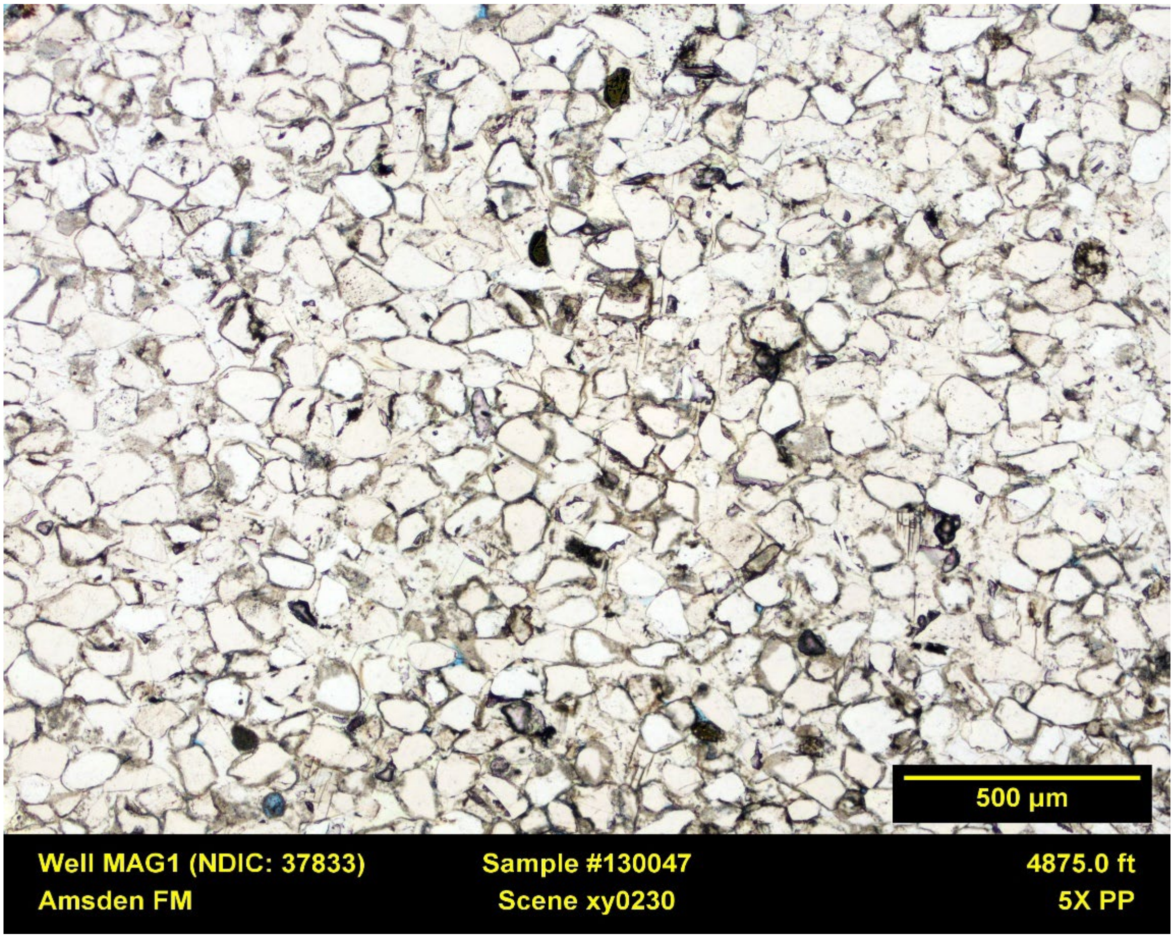



Figure 2-47. Thin section in the Amsden Formation. This interval is dominated by anhydrite and quartz. In this example, quartz grains are tightly cemented, and almost no porosity is observed.

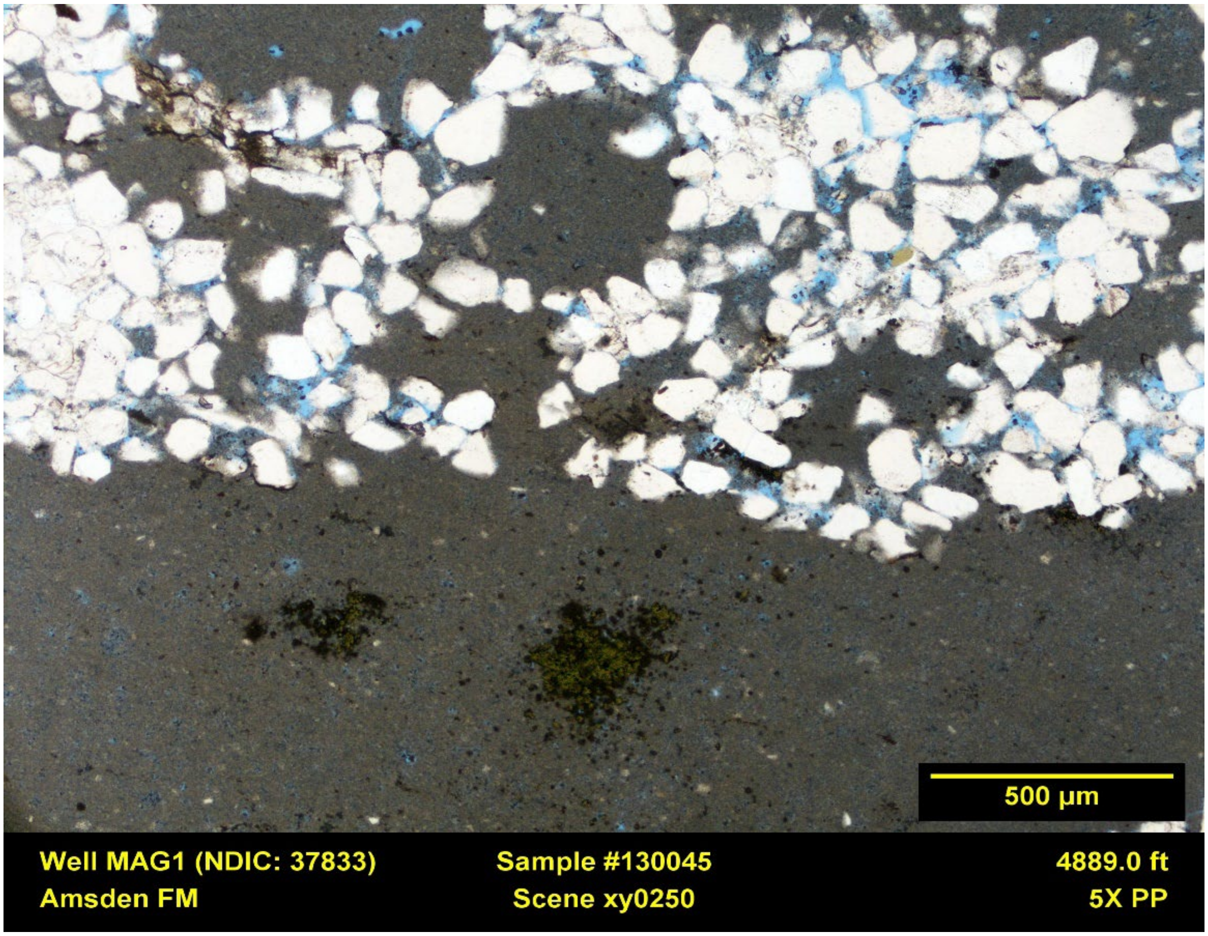



Figure 2-48. Thin section in the Amsden Formation. This interval shows a fine micritic dolomite with minor quartz grains. Porosity is generally low and found to be intergranular or due to the dissolution of dolomite in this example.

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

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

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

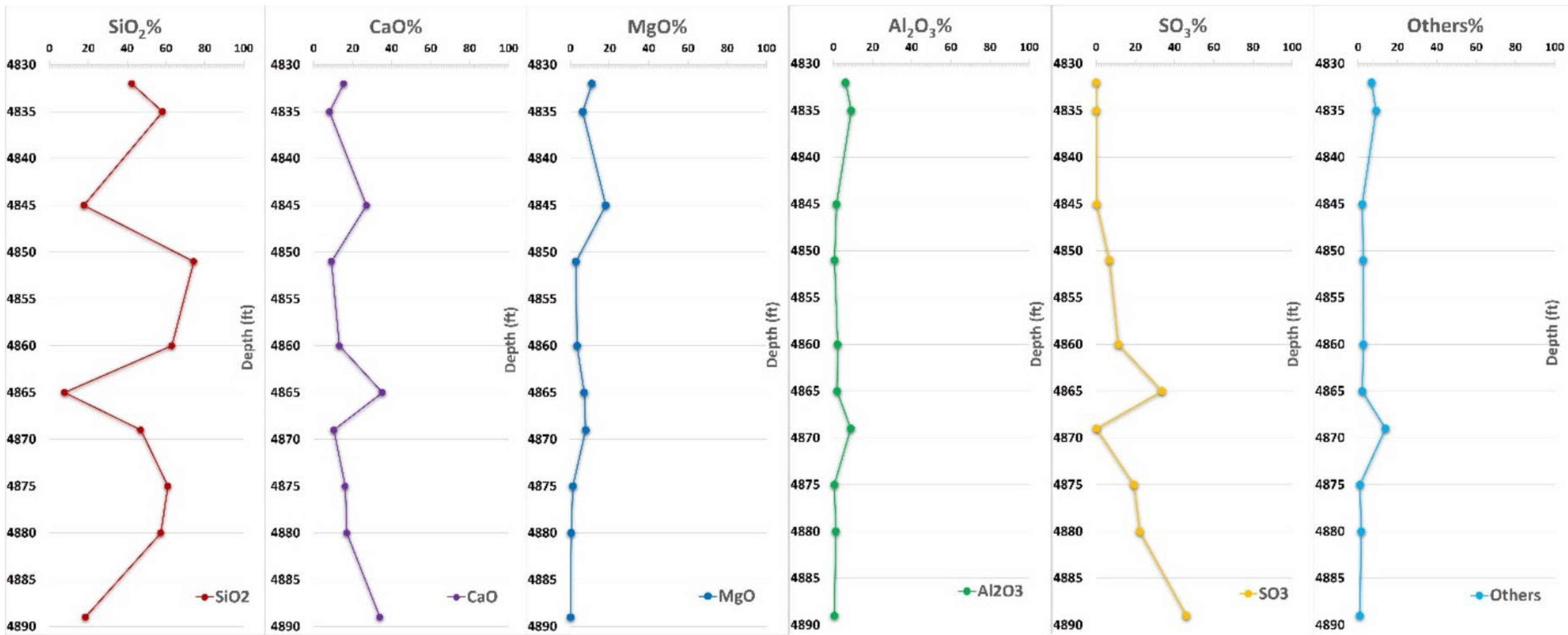



Figure 2-49. XRF analysis in the lower confining zone (Amsden Formation) from MAG 1.

### *2.4.3.2 Geochemical Interaction*

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

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

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

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

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

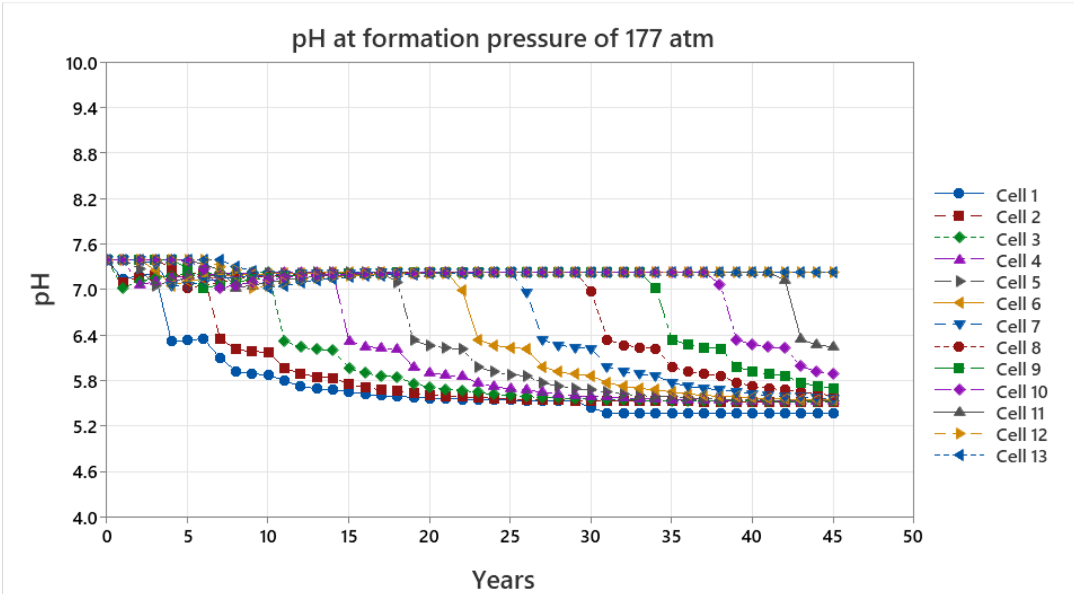



Figure 2-50. Change in fluid pH in the Amsden Formation underlying confining layer for Cells C1–C13.

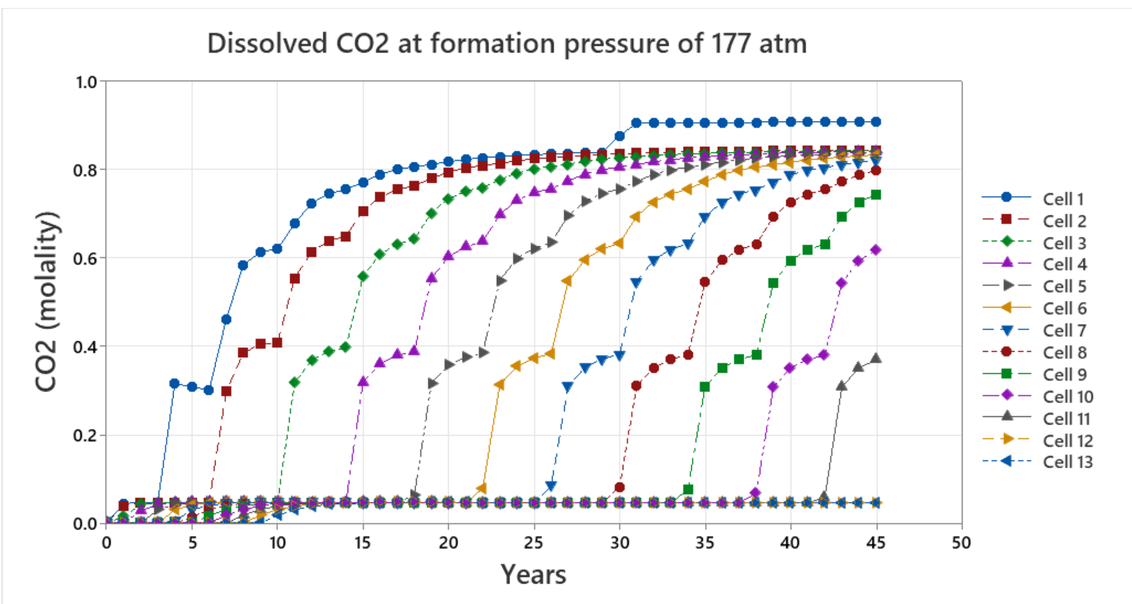



Figure 2-51. $CO_2$ concentration (molality) in the Amsden Formation underlying confining layer for Cells C1–C13.

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

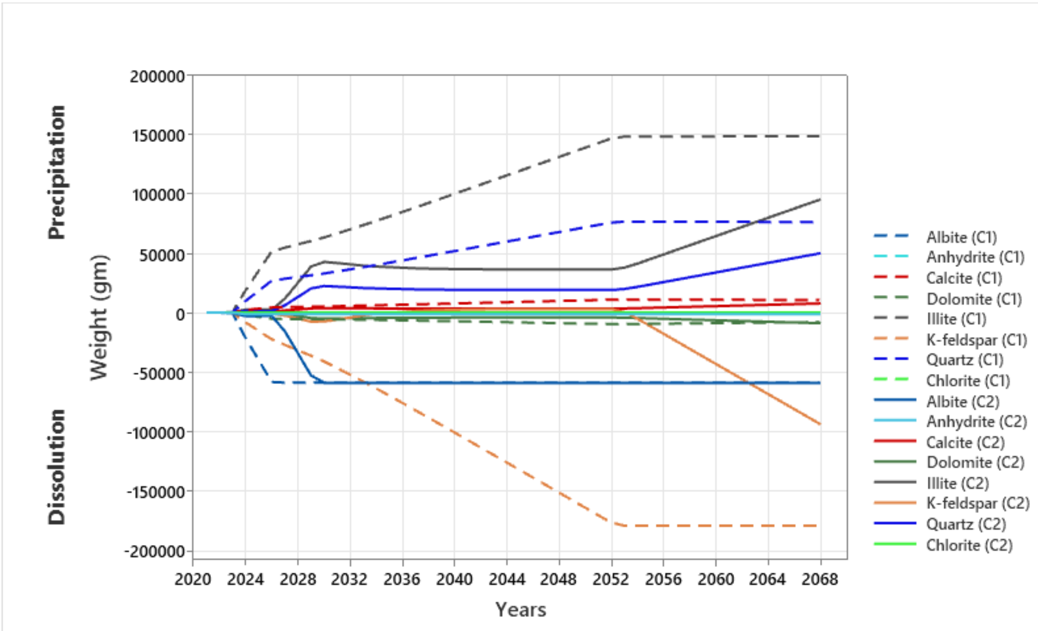



Figure 2-52. Dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for Cell C1, 0 to 1 meter below the Amsden top. Solid lines show results for Cell C2, 1 to 2 meters below the Amsden top.

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

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

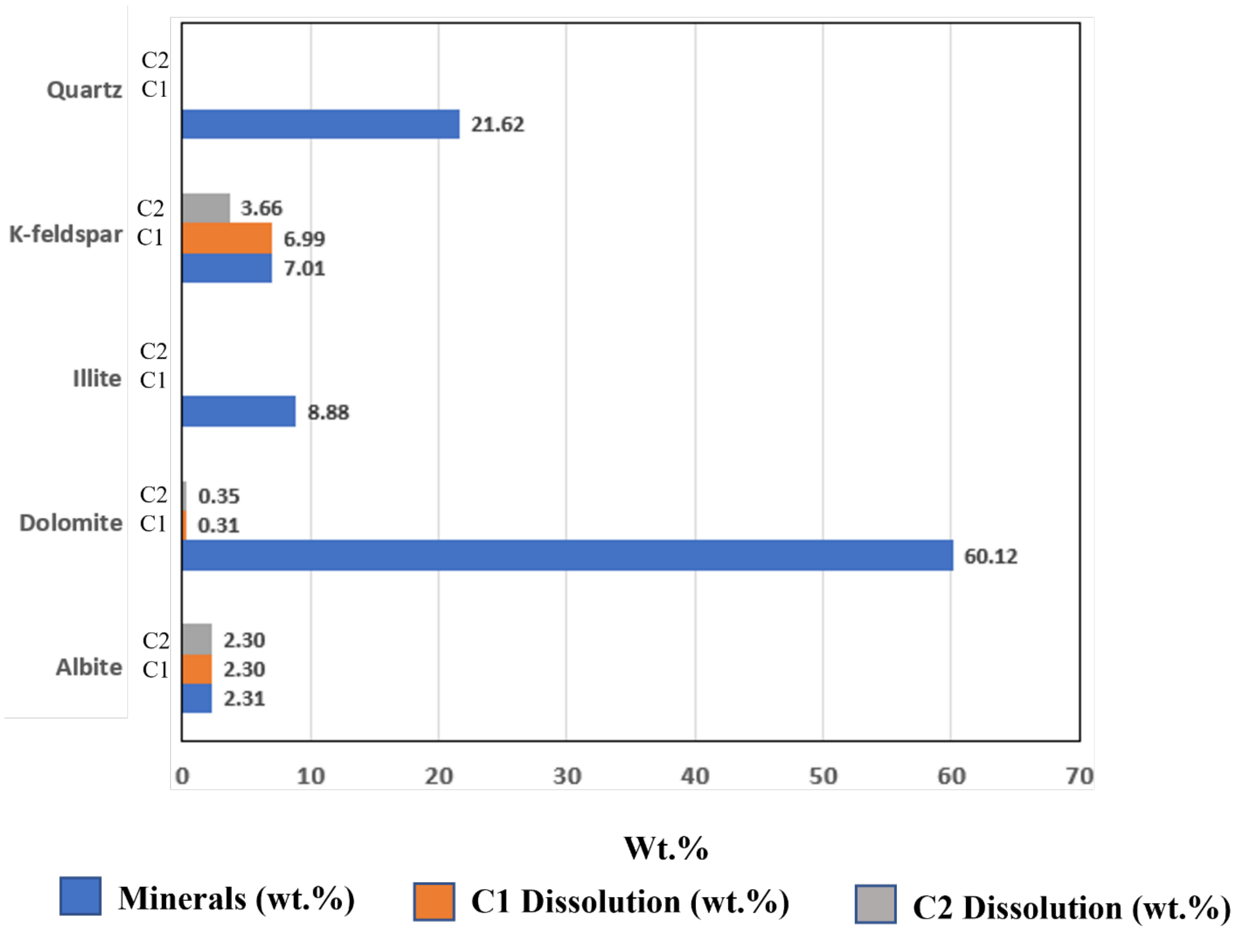



Figure 2-53. Weight percentage (wt%) of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time.

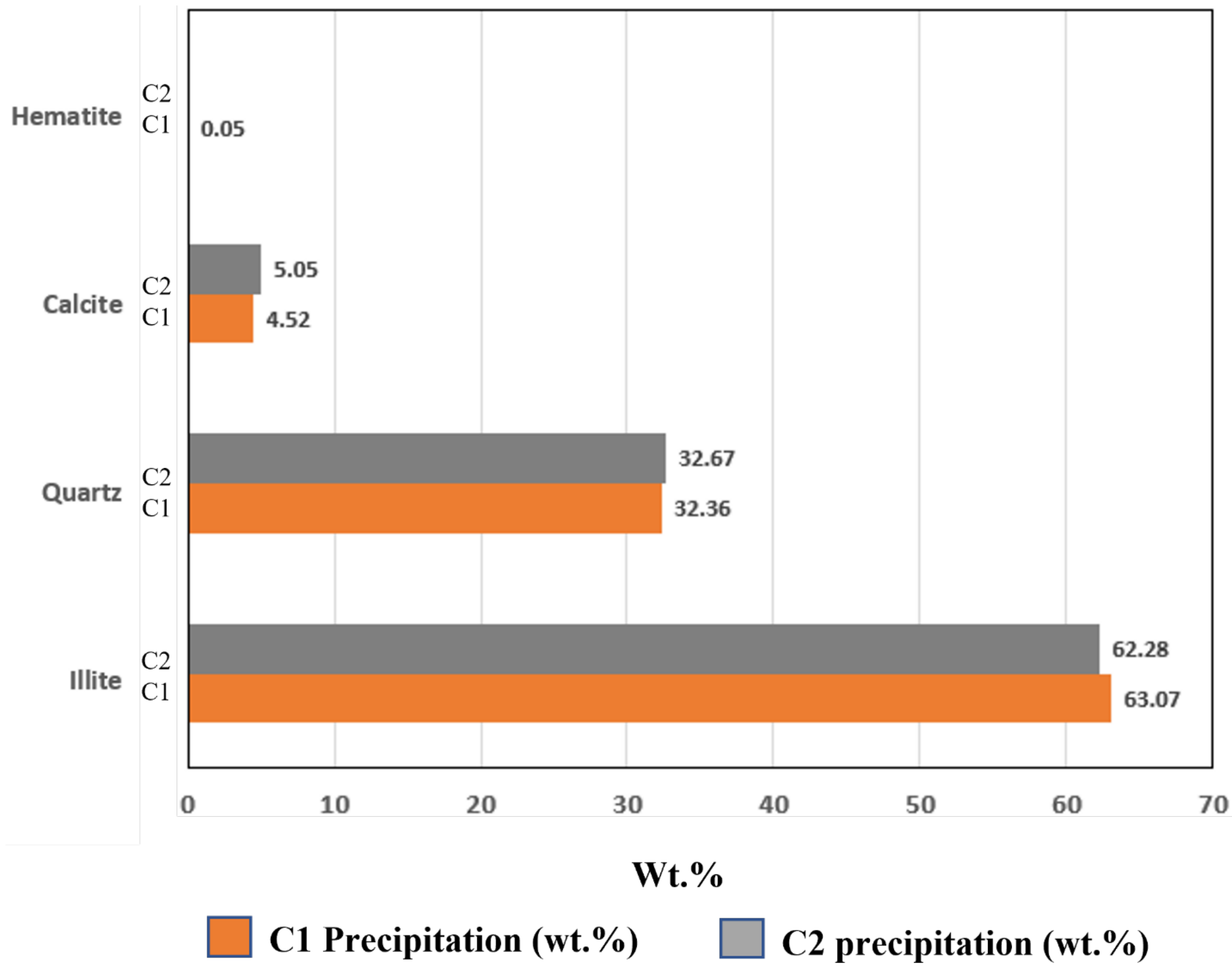



Figure 2-54. Weight percentage (wt%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time.

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

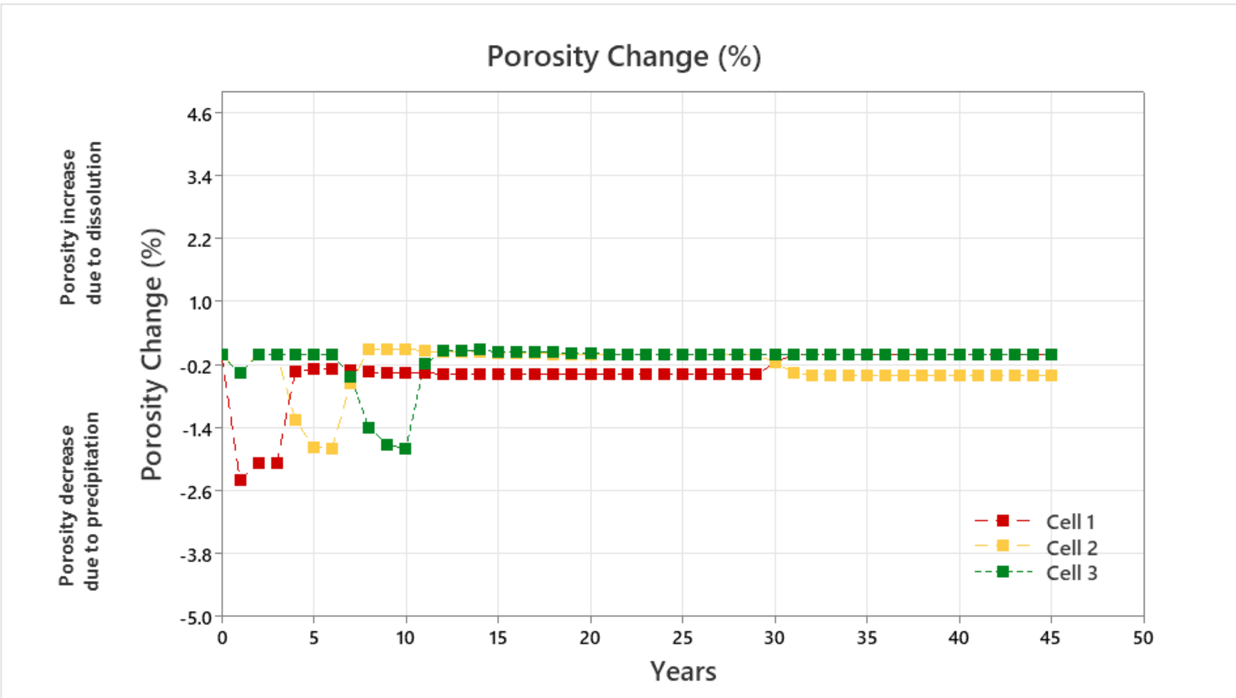



Figure 2-55. Change in percent porosity in the Amsden Formation underlying confining layer. Red line shows porosity change for Cell C1, 0 to 1 meter below the Amsden Formation top. Yellow line shows Cell C2, 1 to 2 meters below the Amsden Formation top. Green line shows Cell C3, 2 to 3 meters below the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

### *2.4.4 Geomechanical Information of Confining Zone*

#### *2.4.4.1 Borehole Image Fracture Analysis*

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

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

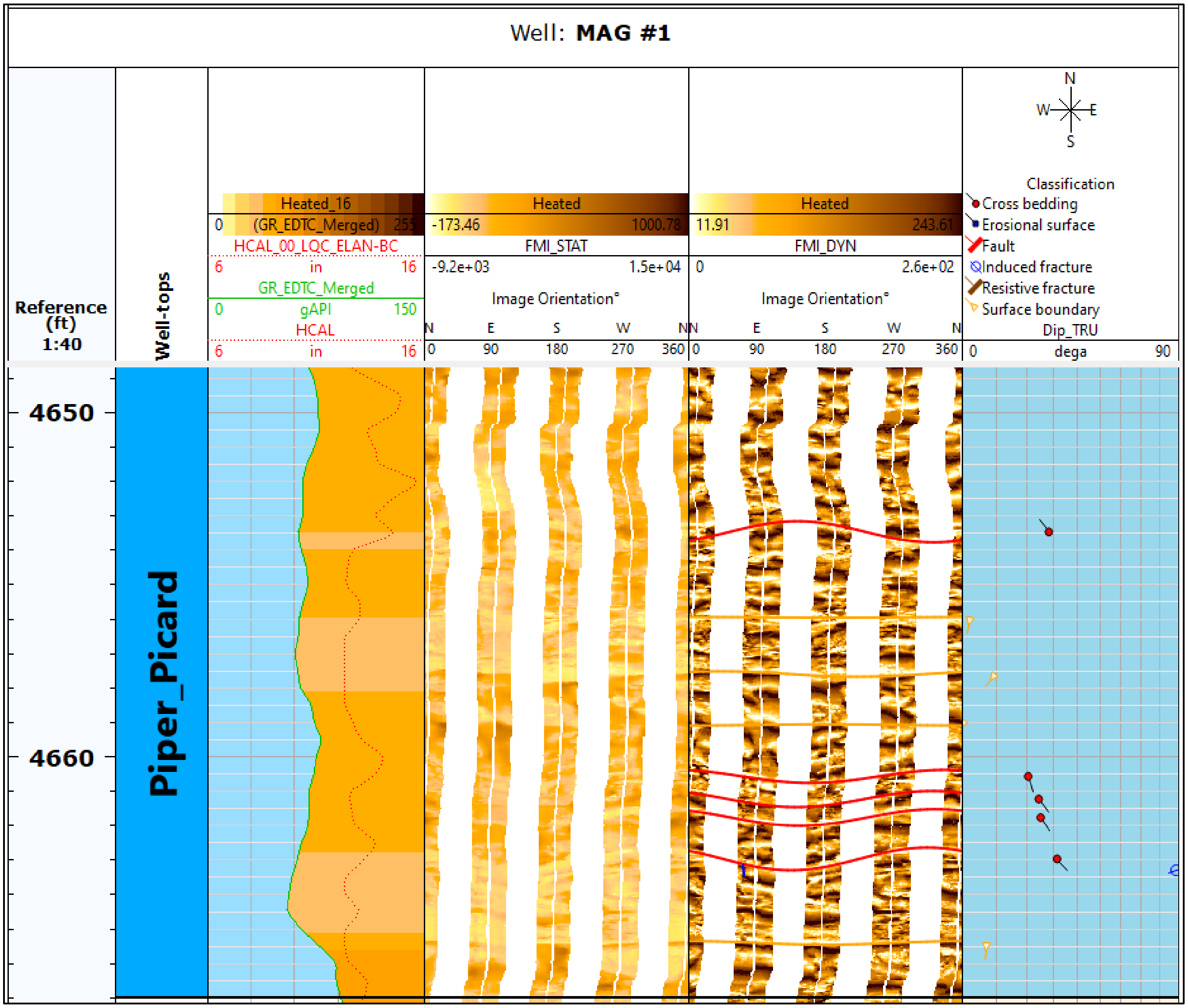



Figure 2-56a. Examples of the interpreted FMI log for the MAG 1 well showing one of the drilling induced fractures observed in the Piper Formation.

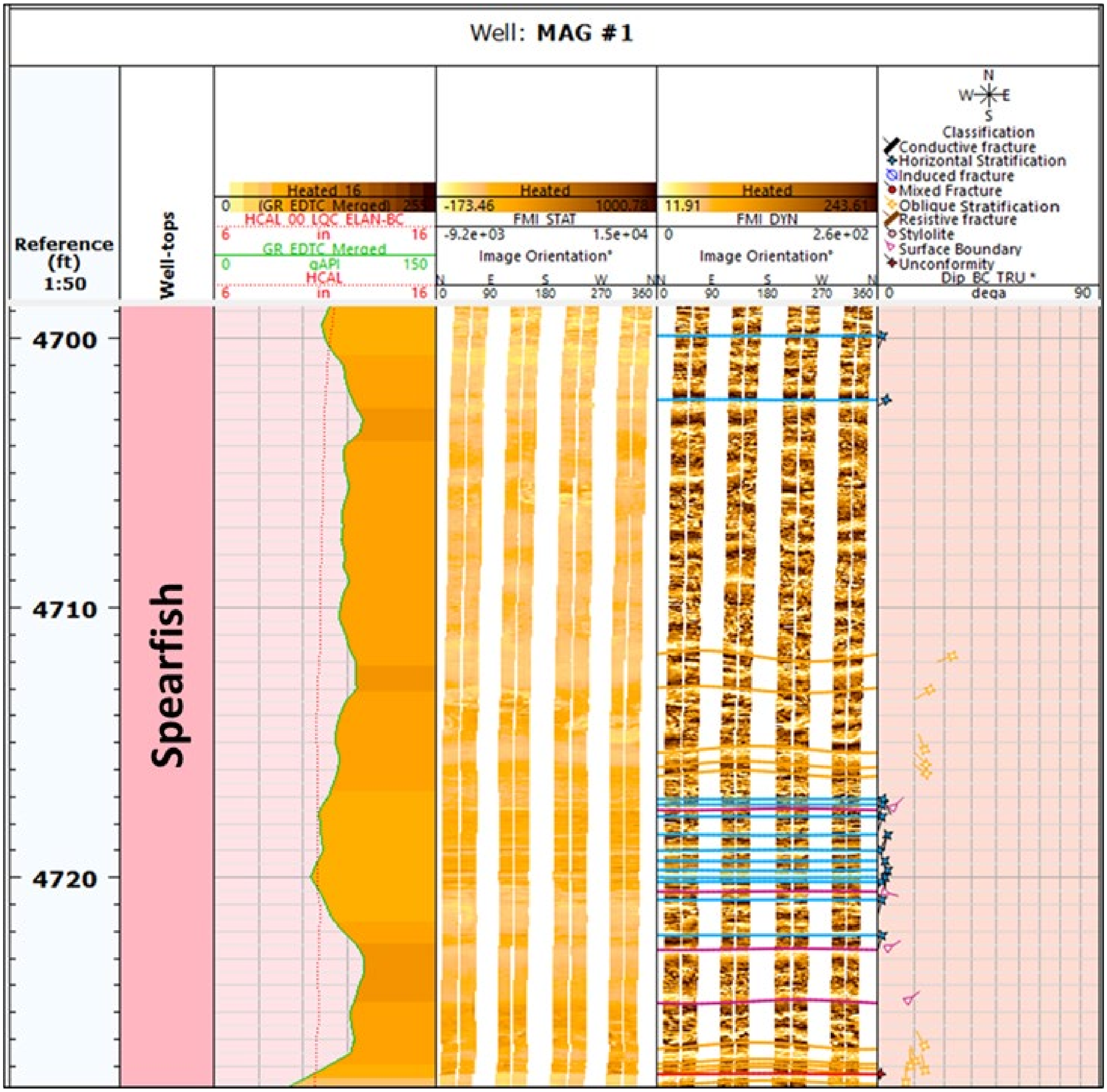



Figure 2-56b. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Spearfish Formation FMI image analysis.

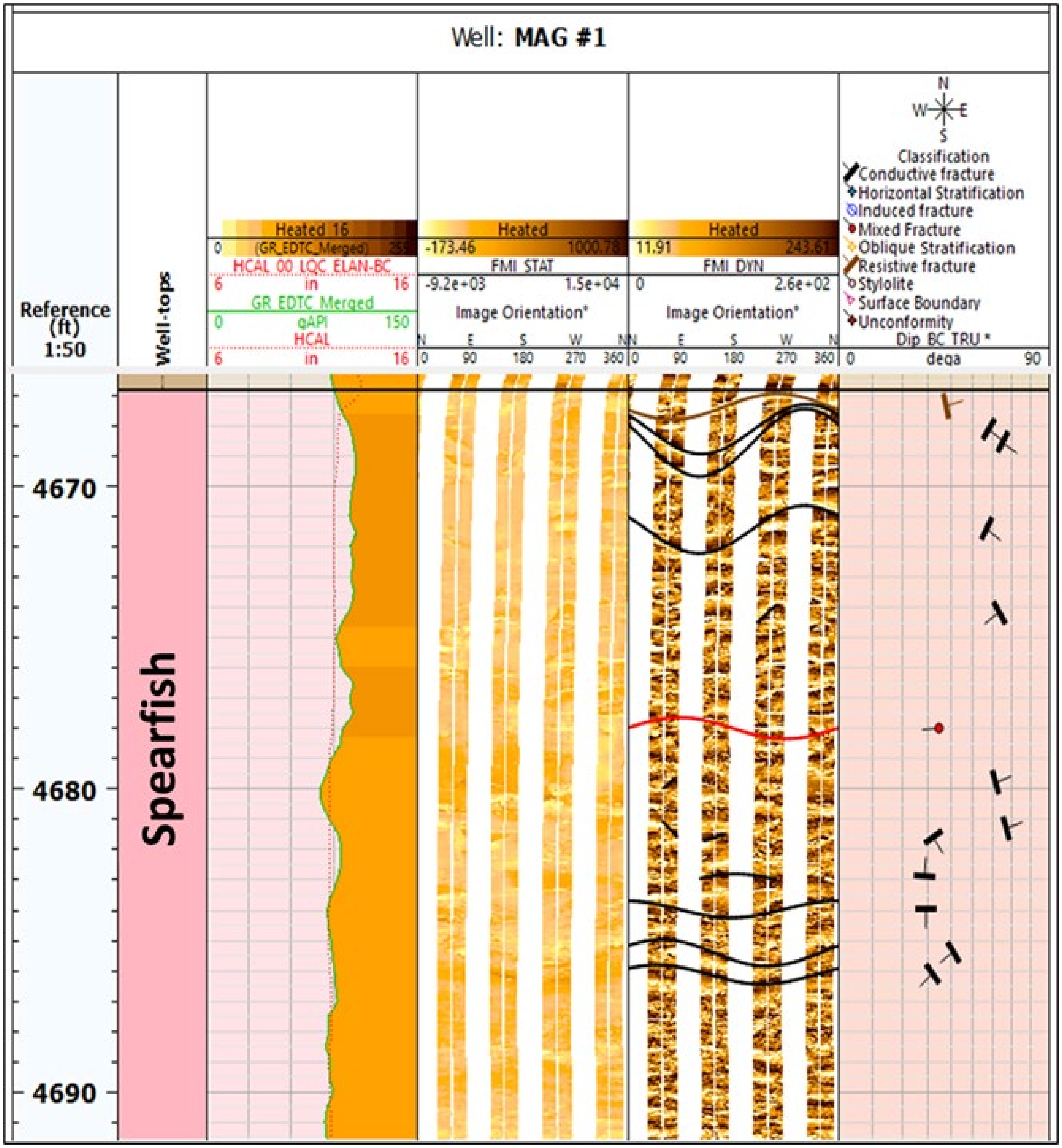



Figure 2-57. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, resistive fracture, mixed fracture, horizontal stratification, and oblique stratification) seen in Spearfish Formation FMI image analysis.

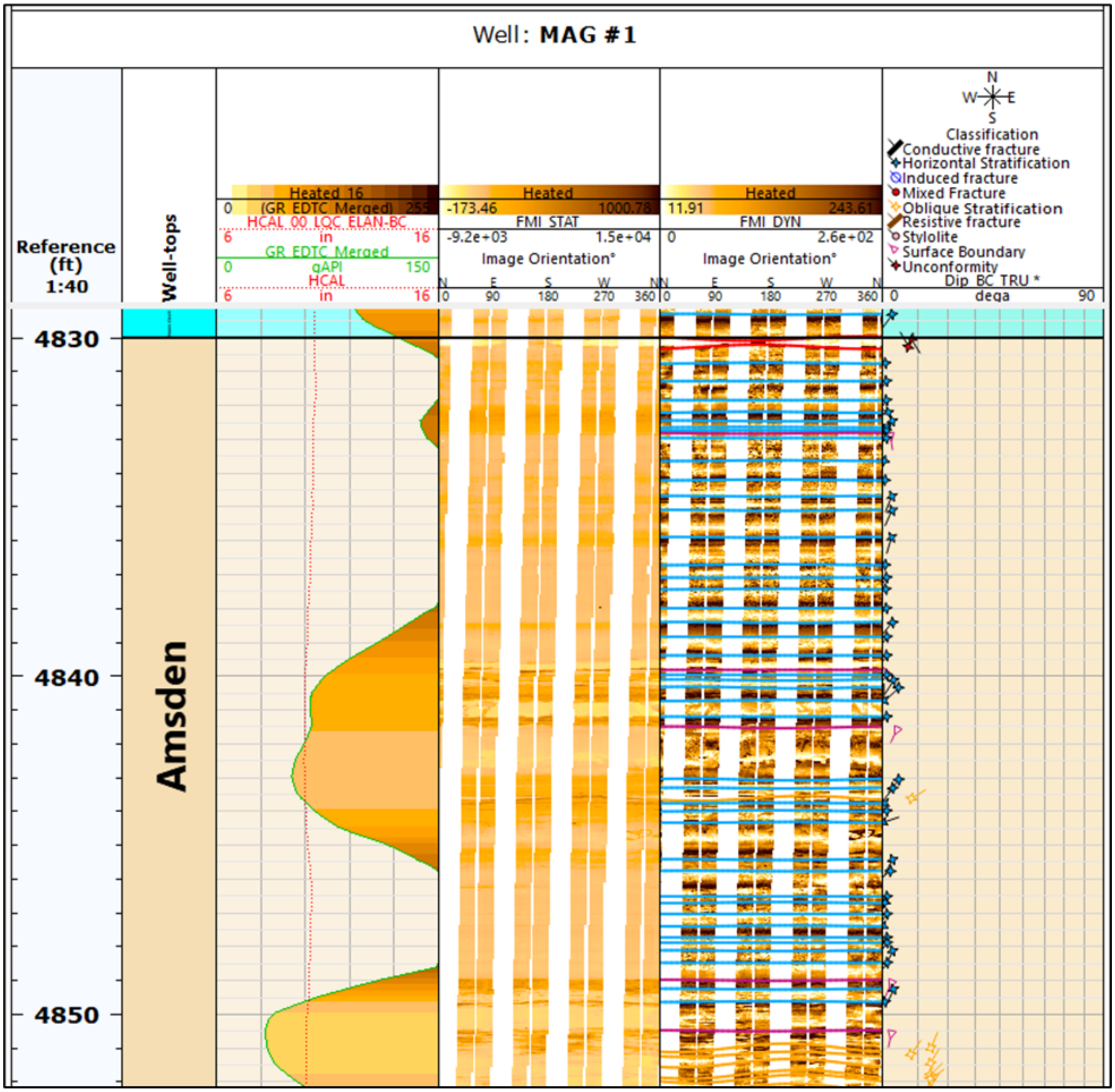



Figure 2-58. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis.

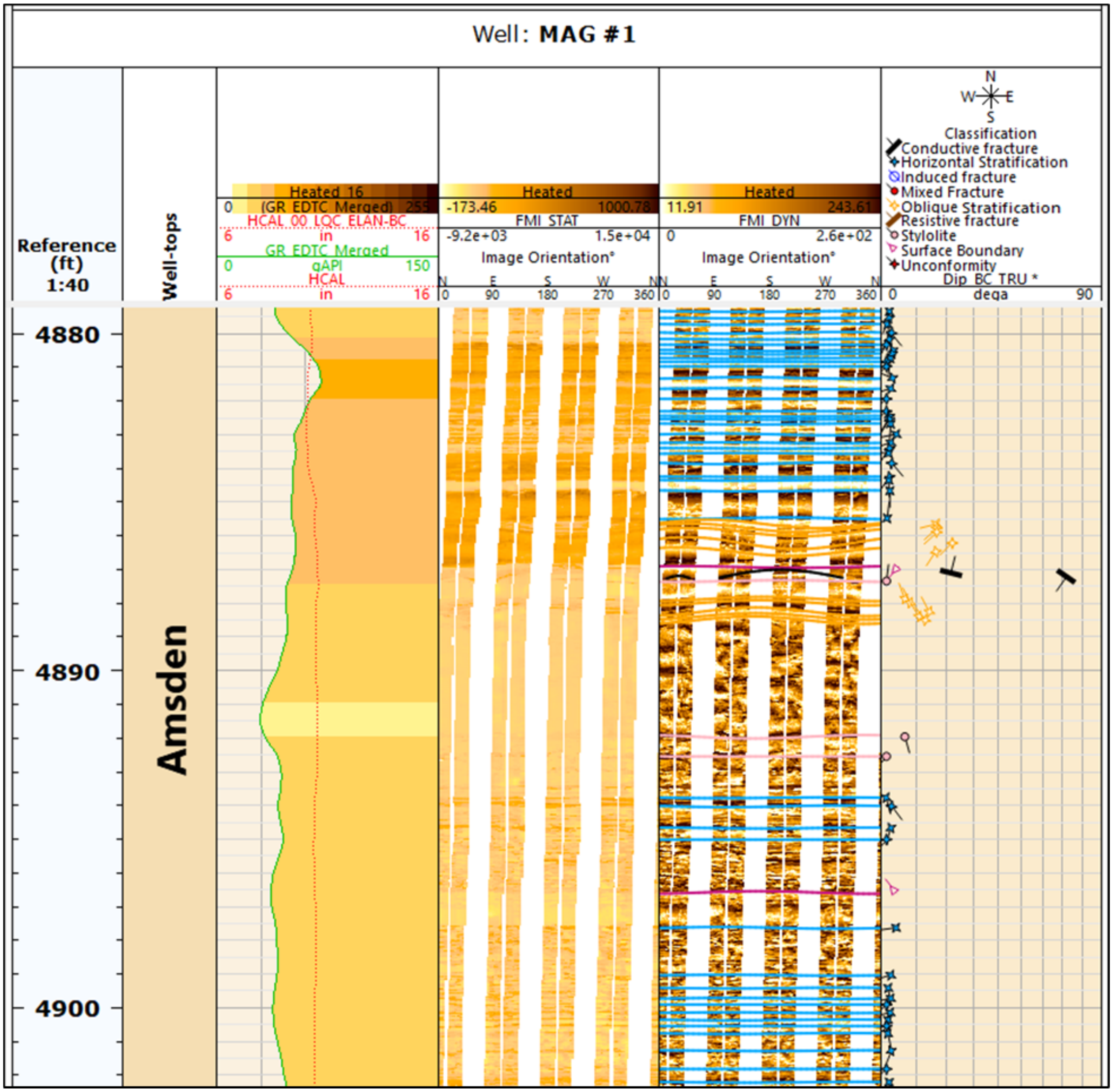



Figure 2-59. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, stylolites, horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis.

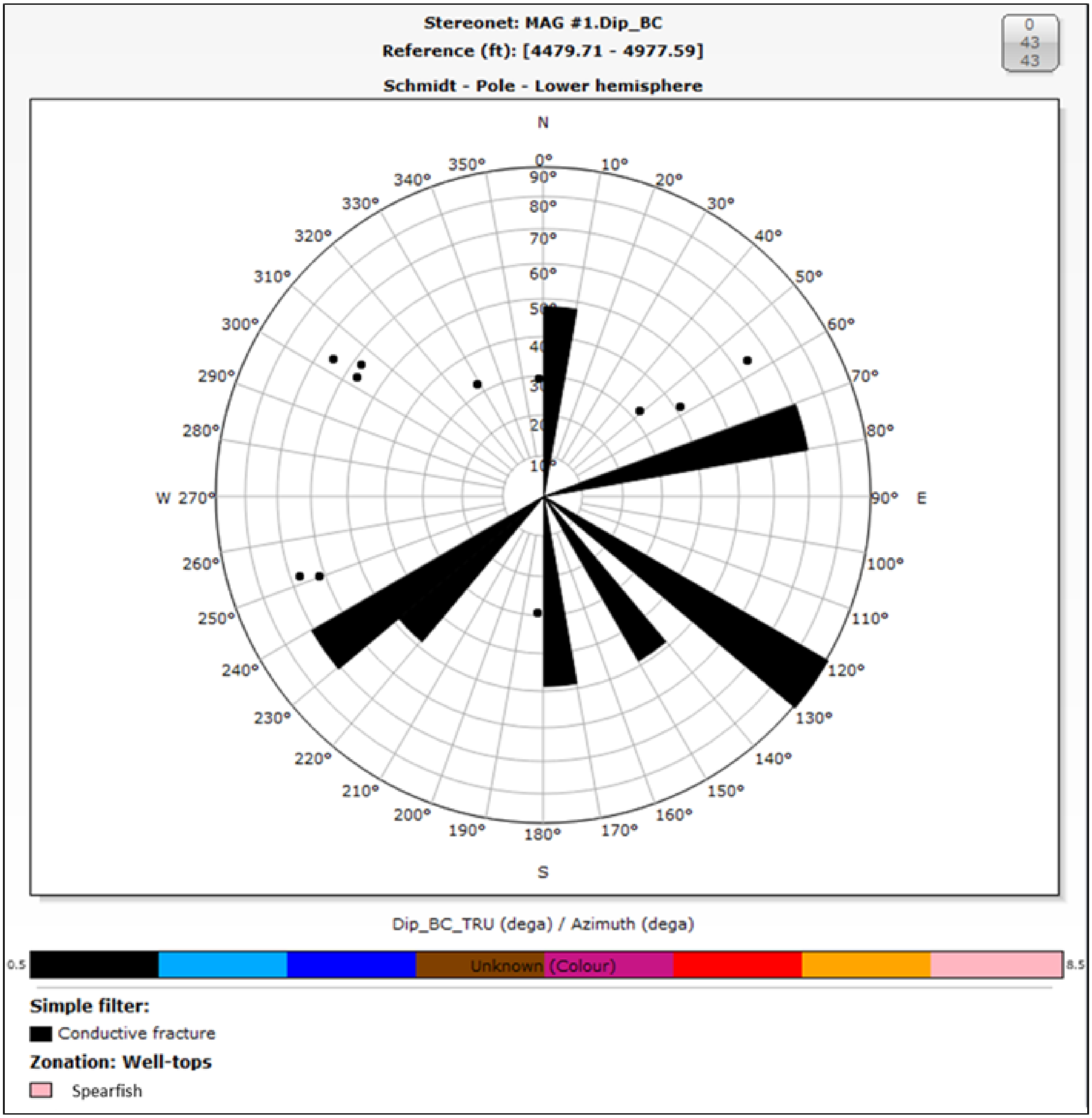



Figure 2-60. This example shows the dip azimuth and dip angle for conductive fractures seen in the Spearfish Formation.

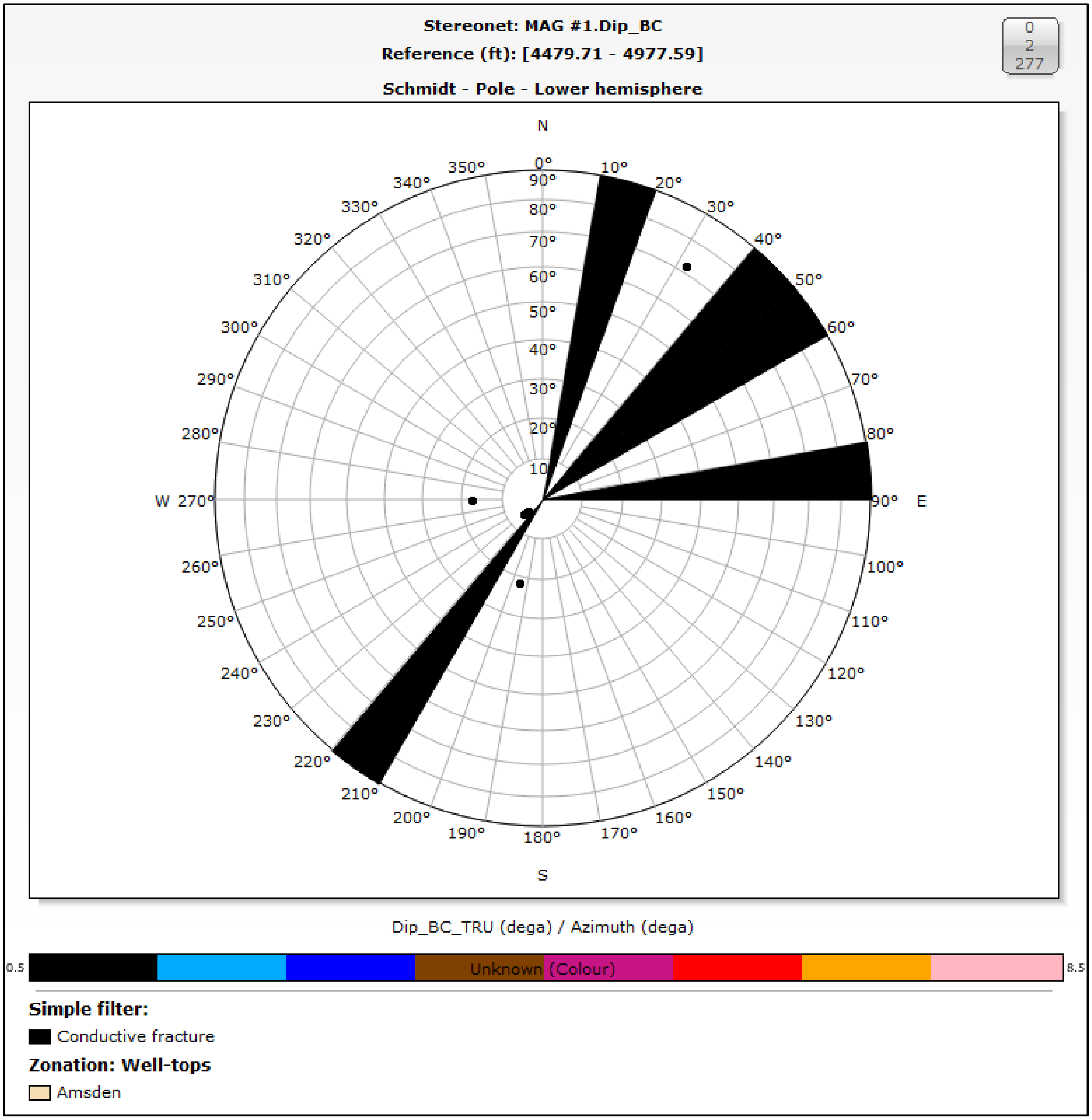



Figure 2-61. This example shows the dip azimuth and dip angle for conductive fractures seen in the Amsden Formation.

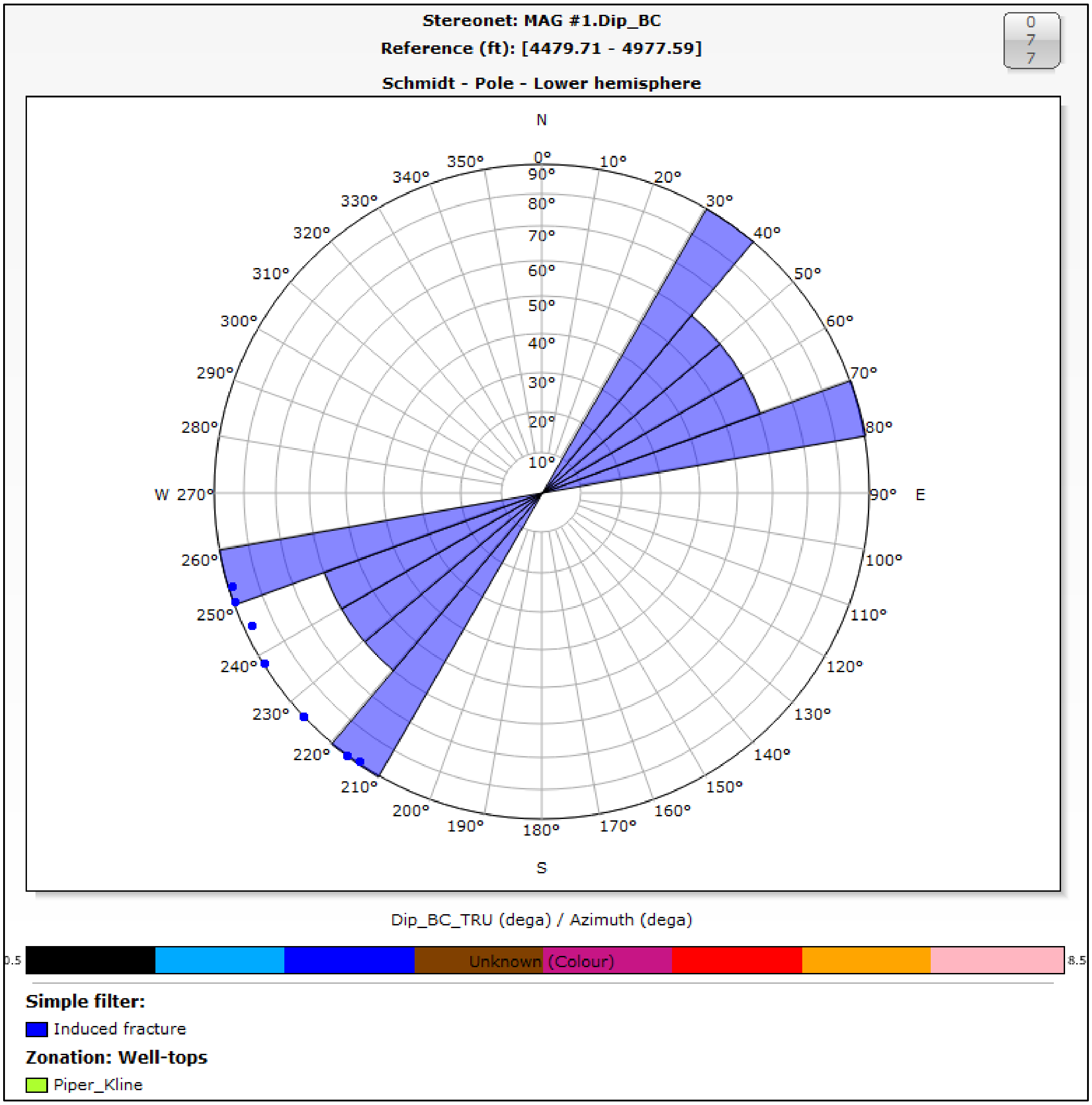



Figure 2-62. This example shows the orientation of drilled-induced fractures in the Piper Formation.

### *2.4.4.2 Stress, Ductility and Rock Strength*

A 1D MEM was derived using the log data from MAG 1 well. Logs were edited to account for washouts in the Broom Creek and Amsden Formation sections using multilinear regressions. Geomechanical parameters in the Spearfish, Broom Creek, and Amsden Formations were estimated using the 1D MEM. The 1D MEM was used to estimate the vertical stress, pore pressure, minimum and maximum horizontal stresses (Shmin, SHmax), Poisson's ratio, Young's modulus,

shear and bulk moduli, tensile, uniaxial compressive strength, and friction angle (Figure 2-63, Figure 2-64, and Figure 2-65). Table 2-19 shows the average and range of elastic and dynamic parameters, and stresses in the Spearfish, Broom Creek, and Amsden Formations.

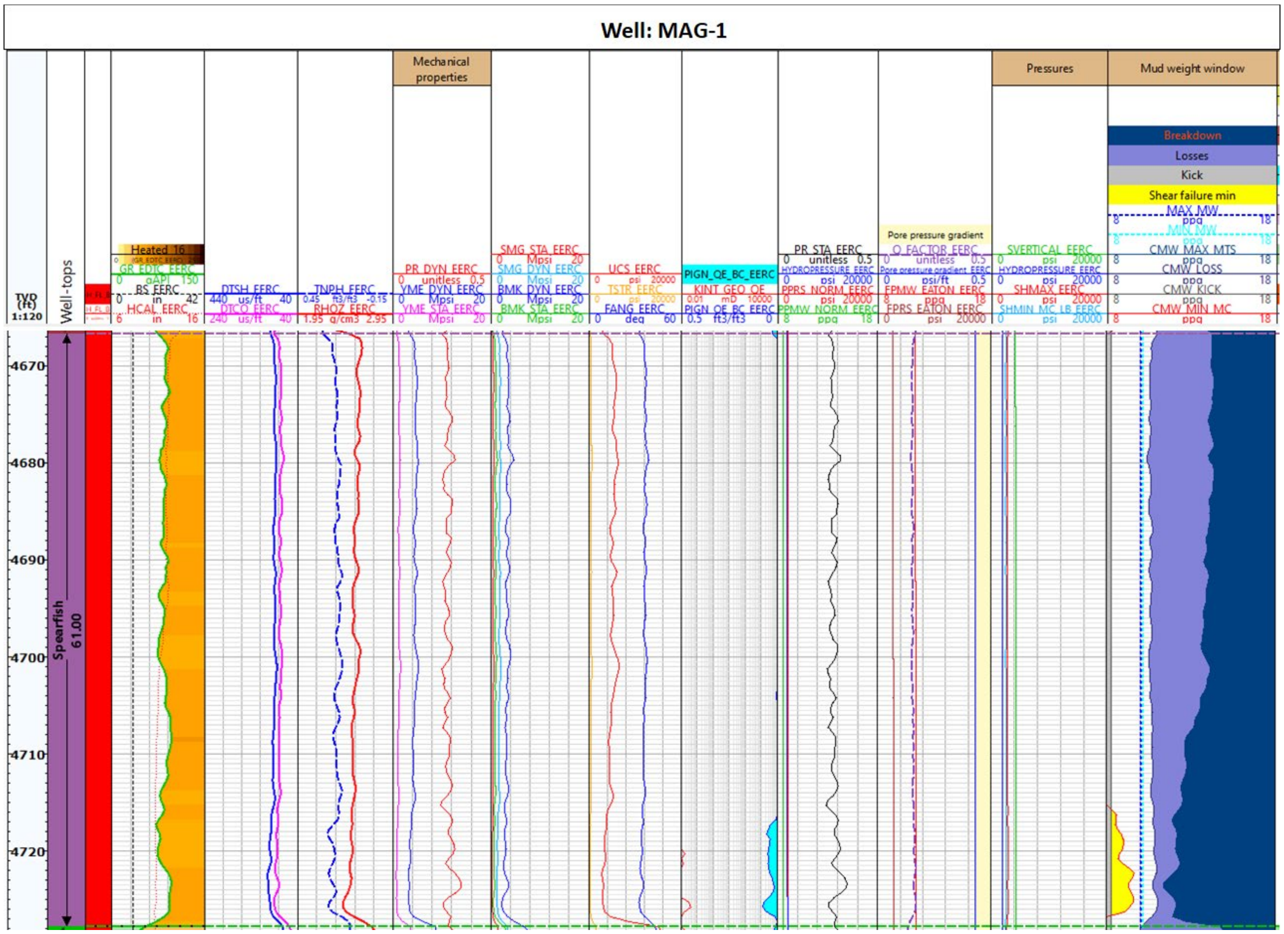



Figure 2-63. Geomechanical parameters in the Spearfish Formation. Track 1, bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, and dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static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

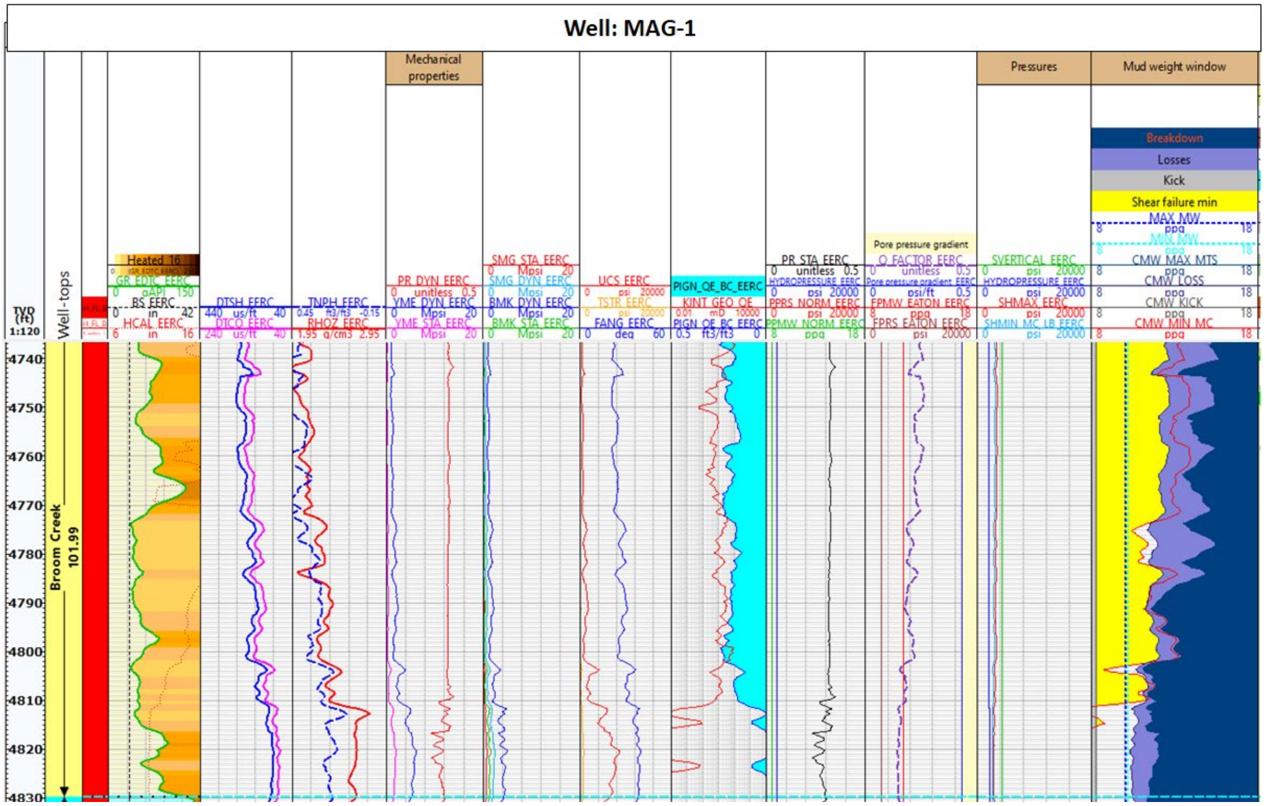



Figure 2-64. Geomechanical parameters in the Broom Creek Formation. Track 1, bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static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

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

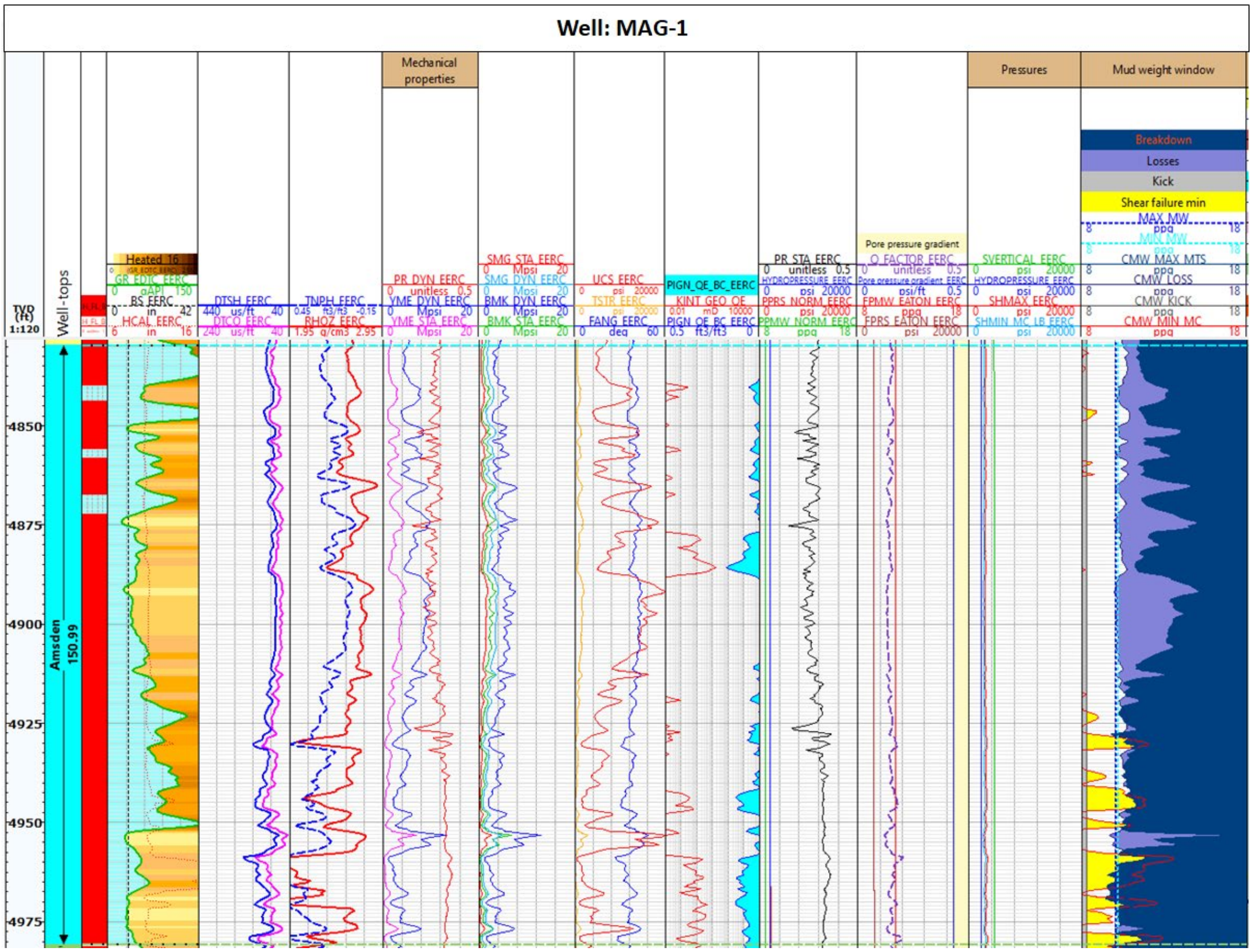



Figure 2-65. Geomechanical parameters in the Amsden Formation. Track 1, Bad hole. Track 2, total GR, bit size, and caliper. Track 3, DTSH, DTCO. Track 4, TNPH, RHOZ. Track 5, dynamic Poisson's ratio, dynamic and static Young's modulus. Track 6, dynamic and static shear modulus, dynamic and static bulk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

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

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

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

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

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

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

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

Where:

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

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

Where:

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

## 2.5 Faults, Fractures, and Seismic Activity

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

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

### *2.5.1 Stanton Fault*

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

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

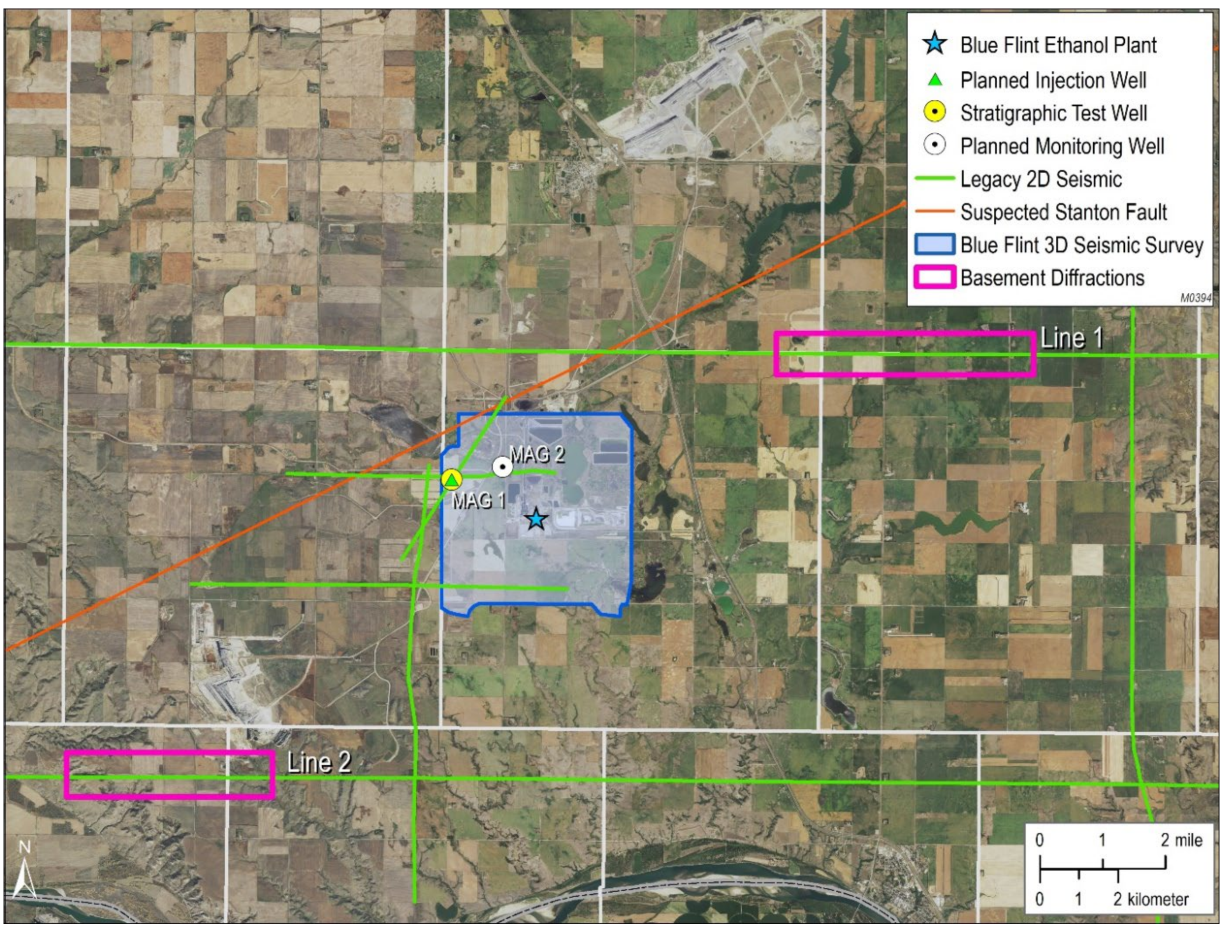



Figure 2-66. Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016).

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

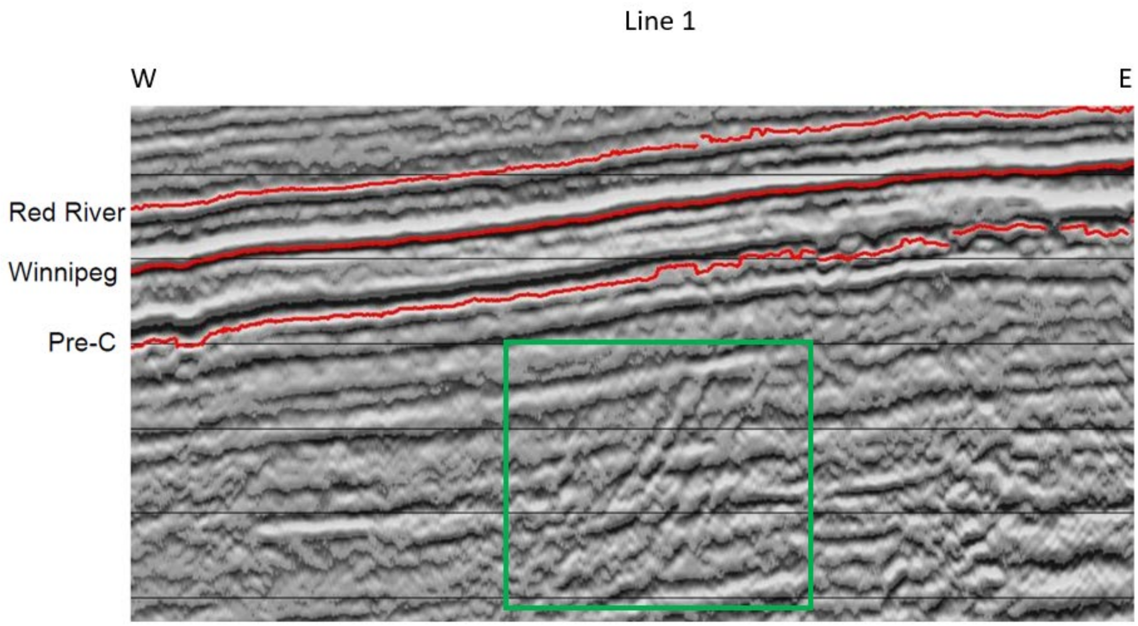



Figure 2-67. Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box).

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

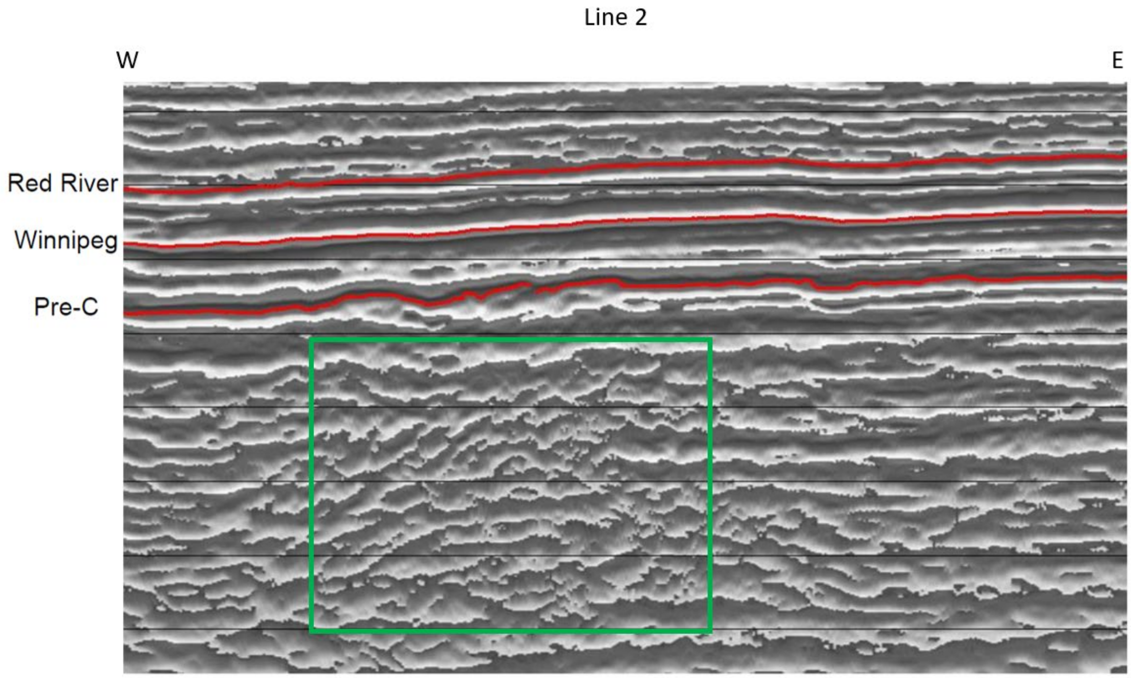



Figure 2-68. Cross section of Line 2 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box).

### *2.5.2 Seismic Activity*

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

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

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

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

* Estimated depth.

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

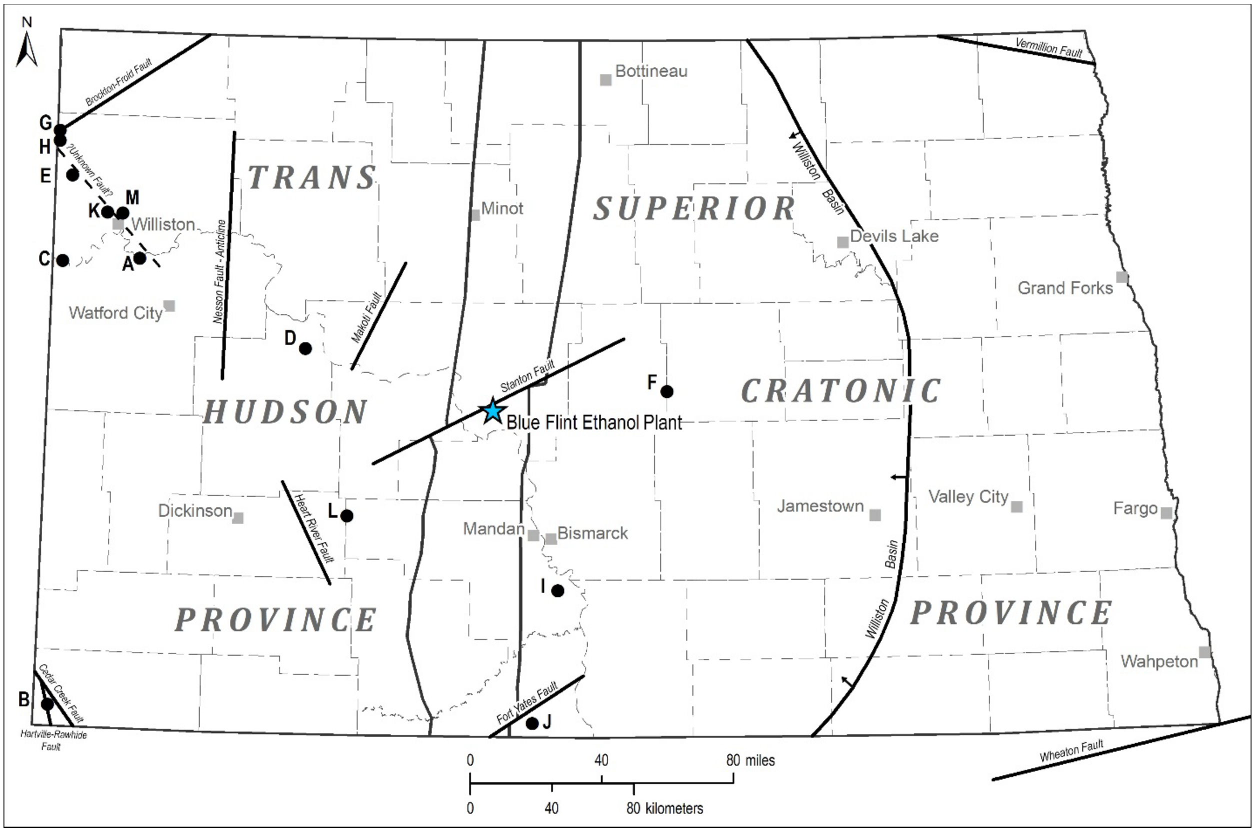



Figure 2-69. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-21.

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

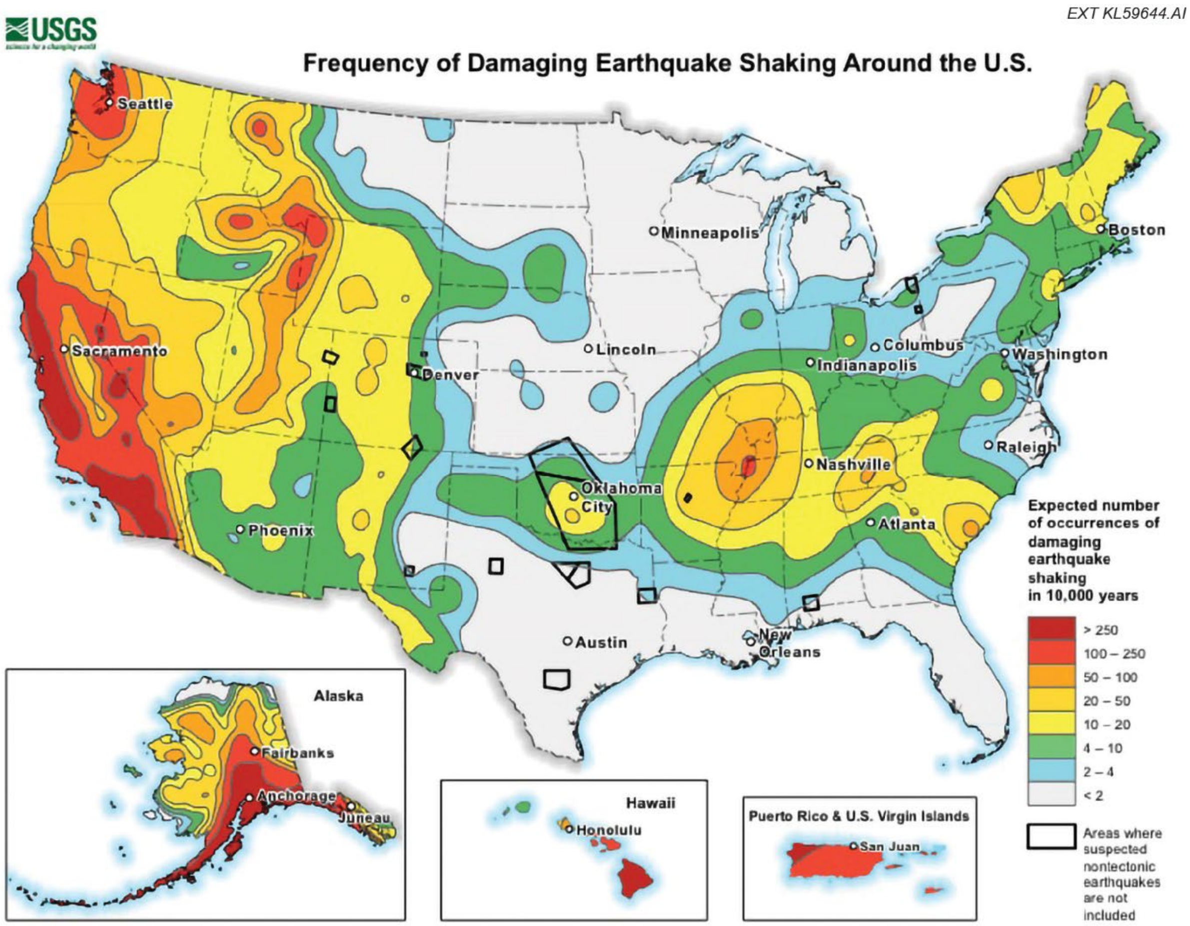



Figure 2-70. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

## 2.6 Potential Mineral Zones

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

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a horizontal well could be used to produce the hydrocarbon while avoiding drilling through the $CO_2$ plume, or a vertical well could be drilled using proper controls. Should operators decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation bottomhole pressure data will be available while the MAG 1 well is in operation, which will allow prospective operators to design an appropriate well control strategy via increased

drilling mud weight. Pressure increase in the Broom Creek caused by injection of $CO_2$ will relax postinjection as the area returns to its preinjection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the $CO_2$ should be designed to include an intermediate casing string placed across the storage reservoir, with $CO_2$-resistant cement used to anchor the casing in place.

Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC § 57-51-01(11)) define a shallow gas zone as gas produced from a zone that consists of "strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation [Jurassic], from which gas may be produced."

Lignite coal is currently mined at the Falkirk Mine, operated by the Falkirk Mining Company, a wholly owned subsidiary of North American Coal Corporation, which is located within the project area. The Falkirk Mine produces from the Hagel coal seam for power generation feedstock at Rainbow Energy's Coal Creek Station. The Hagel coal seam is the lowermost major lignite present in the area in the Sentinel Butte Formation (Figure 2-71).

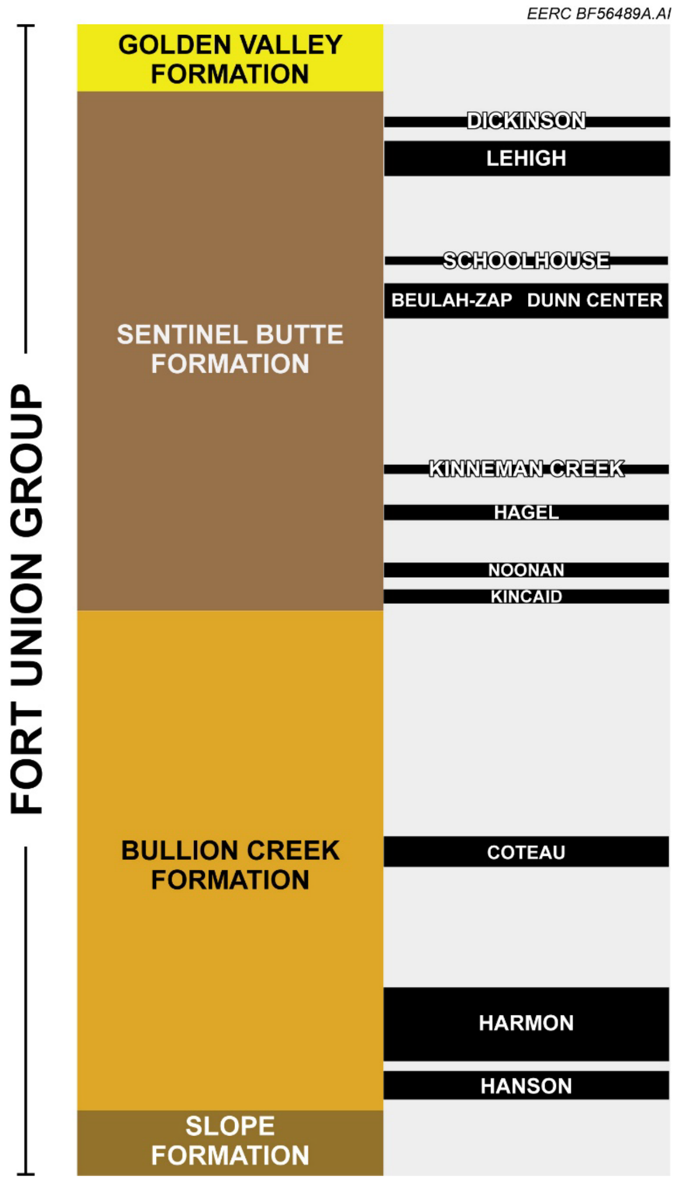



Figure 2-71. Coal beds of the Sentinel Butte and Bullion Creek (Tongue River) Formations showing the lignite coals in western North Dakota (Zygarlicke and others, 2019).

The Hagel coal seam is divided into two seams: the Hagel A and the Hagel B. The Hagel A lignite bed averages 5.7 ft thick with a range from 0.5 to 11.5 ft. The Hagel B bed has a mean thickness of approximately 1.8 ft, ranging in thickness from 0.5 to 6.3 ft. (Figure 2-72) (Zygarlicke and others, 2019). Coal seams in the Bullion Creek Formation exist in the area below the Hagel seam (Figure 2-71) but are too deep to be economically mined.

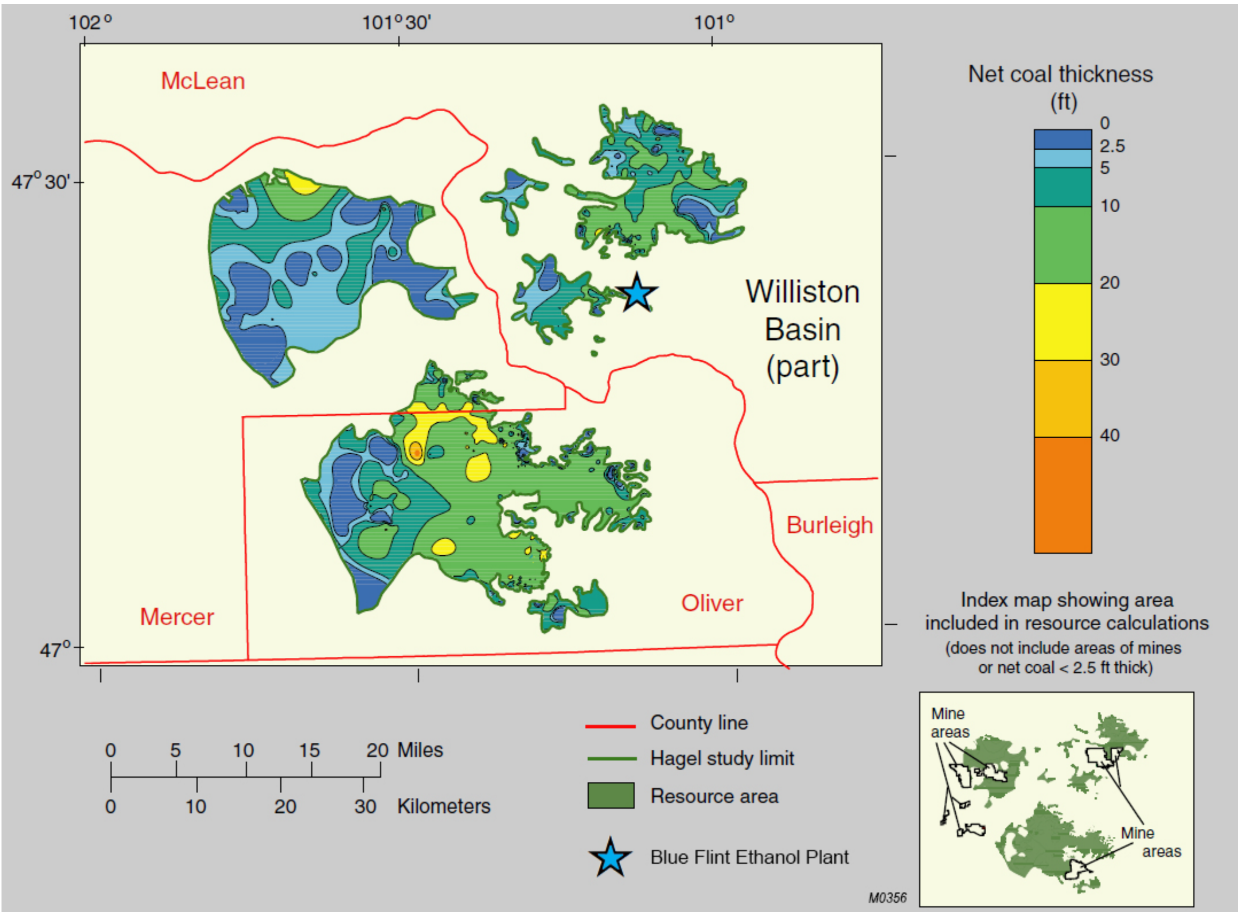



Figure 2-72. Hagel net coal isopach map (modified from Ellis and others, 1999).

## 2.7 References


Aadnoy, B.S., 1990, Inversion technique to determine the in-situ stress field from fracturing data: Journal of Petroleum Science and Engineering, v. 4, no. 2, p. 127–141.

Aadnoy, B.S., and Bell, J.S., 1998, Classification of drilling-induced fractures and their relationship to in-situ stress directions: The Log Analyst, v. 39, no. 6, p. 27–42.

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

Brudy, M., and Zoback, M.D, 1999, Drilling-induced tensile wall-fractures: implications for determination of in-situ stress orientation and magnitude: International Journal of Rock

Mechanics and Mining Sciences, v. 36, no. 2, p. 191–215. doi:10.1016/s0148-062(98)00182-x.

Carlson, C.G., 1993, Permian to Jurassic redbeds of the Williston Basin: North Dakota Geological Survey Miscellaneous Series 78, 21 p.

Downey, J.S., 1986, Geohydrology of bedrock aquifers in the northern Great Plains in parts of Montana, North Dakota, South Dakota and Wyoming: U.S. Geological Survey Professional Paper 1402-E, 87 p.

Downey, J.S., and Dinwiddie, G.A., 1988, The regional aquifer system underlying the northern Great Plains in parts of Montana, North Dakota, South Dakota, and Wyoming—summary: U.S. Geological Survey Professional Paper 1402-A.

Ellis, M.S., Gunther, G.L., Ochs, A.M., Keighin, C.W., Goven, G.E., Schuenemeyer, J.H., Power, H.C., Stricker, G.D., and Blake, D., 1999, Coal resources, Williston Basin: U.S. Geological Survey Professional Paper 1625-A, Chapter WN.

Espinoza, D.N., and Santamarina, J.C., 2017, $CO_2$ breakthrough—caprock sealing efficiency and integrity for carbon geological storage: International Journal of Greenhouse Gas Control, v. 66, p. 218–229.

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

Glazewski, K.A., Grove, M.M., Peck, W.D., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2015, Characterization of the PCOR Partnership Region: Plains $CO_2$ Reduction (PCOR) Partnership topical report for U.S. Department of Energy and multiclients, Grand Forks, North Dakota, Energy & Environmental Research Center, January.

Murphy, E.C., Nordeng, S.H., Juenker, B.J., and Hoganson, J.W., 2009, North Dakota stratigraphic column, E.C. Murphy and L.D. Helms, Eds., North Dakota Geological Survey, Bismarck, North Dakota.

North Dakota Industrial Commission, 2022, Overview of petroleum geology of the North Dakota Williston Basin: www.dmr.nd.gov/ndgs/resources/ (accessed July 2022).

North Dakota Industrial Commission, 2021a, NDIC Case No. 29029 – draft permit, fact sheet, and storage facility permit application: Minnkota Power Cooperative supplemental information, Grand Forks, North Dakota, www.dmr.nd.gov/oilgas/C29029.pdf (accessed July 2022).

North Dakota Industrial Commission, 2021b, NDIC Case No. 29032 – draft permit, fact sheet, and storage facility permit application: Minnkota Power Cooperative supplemental information, Grand Forks, North Dakota, www.dmr.nd.gov/oilgas/C29032.pdf (accessed July 2022).

North Dakota Industrial Commission, 2021c, NDIC Case No. 28848 – draft permit, fact sheet, and storage facility permit application: Red Trail Ethanol, LLC, supplemental information, www.dmr.nd.gov/oilgas/C28848.pdf (accessed July 2022).

Nowakowski, A., 2005, The static and dynamic elasticity constants of sandstones and shales from the hard coal mine "Jasmos" determined in the laboratory conditions, *in* Eurock 2005 – impact of human activity on the geologic environment: Konecy, Taylor & Francis Group, London, Eds.

Peck, W.D., Liu, G., Klenner, R.C.L., Grove, M.M., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2014, Storage capacity and regional implications for large-scale storage in the basal Cambrian system: Plains $CO_2$ Reduction (PCOR) Partnership Phase III Task 16 Deliverable D92 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2014-EERC-05-12, Grand Forks, North Dakota, Energy & Environmental Research Center, https://edx.netl.doe.gov/dataset/storage-capacity-and-regional-implications-for-large-scale-storage-in-the-basal-cambrian-system (accessed 2022).

Plumb, R.A., and Hickman, S.H., 1985, Stress-induced borehole elongation—a comparison between the four-arm dipmeter and the borehole televiewer in the Auburn Geothermal Well: Journal of Geophysical Research Atmospheres, v. 90, p. 5513–5521.

Rygh, M.E., 1990, The Broom Creek Formation (Permian), in southwestern North Dakota—depositional environments and nitrogen occurrence [Master's Thesis]: University of North Dakota, Grand Forks, North Dakota.

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

Tutuncu, A.N., and Sharma, M.M., 1992, Relating static and ultrasonic lab measurements to acoustic log measurements in tight gas sands: Presented at 67th SPE ATCE, Washington, D.C., October 1998. SPE-24689.

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

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

Yale, D.P., and Jamieson, W.H. Jr., 1994, Static and dynamic mechanical properties of carbonates, *in* Rock Mechanics – Models and Measurements Challenges from Industry: Nelson and Laubach, Eds., Balkema, Rotterdam.

Yale, D.P., and Walters, D.A., 2016, Integrated, logbased, anisotropic geomechanics analysis in unconventional reservoirs: Presented at SPE Unconventional Reservoir Fracturing Workshop, Muscat, Oman, February 2016.

Yale, D.P., Nieto, J.A., and Austin, S.P., 1995, The effect of cementation on the static and dynamic mechanical properties of the Rotliegendes sandstone, *in* Rock Mechanics – Proceedings of the 35th U.S. Symposium: Daemen and Schultz, Eds., Balkema, Rotterdam.

Zhang, J.J., and Bentley, L.R., 2005, Factors determining Poisson's ratio: CREWES Research Report, v. 17.

Zhang, J., and Yin. S.-X., 2017, Fracture gradient prediction—an overview and an improved method: Petroleum Science, v. 14, no. 4, p. 720–730. DOI 10.1007/s12182-017-0182-1.

Zhou, X.J., Zeng, Z., and Belobraydic, M., 2008, Geomechanical stability assessment of Williston Basin Formations for petroleum production and $CO_2$ sequestration: Presented at the 42nd U.S. Rock Mechanics Symposium and 2nd U.S.–Canada Rock Mechanics Symposium, San Francisco, California, June 29 – July 2, 2008.

Zygarlicke, C.J., Folkedahl, B.C., Nyberg, C.M., Feole, I.K., Kurz, B.A., Theakar, N.L., Benson, S.A., Hower, J., and Eble, C., 2019, Rare-earth elements (REEs) in U.S. coal-based resources—20 sampling, characterization, and round-robin interlaboratory study: Final Report for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0029007, EERC Publication 2019-EERC-09-08, Grand Forks, North Dakota, Energy & Environmental Research Center, September.

# 3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF $CO_2$ INJECTION

# 3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF $CO_2$ INJECTION

## 3.1 Introduction

Multiple sets of publicly available and newly acquired site-specific subsurface data were analyzed and interpreted (Section 2.2). The data and interpretations were used as inputs to Schlumberger's Petrel software (Schlumberger, 2020) to construct a geologic model of the injection zone: the Broom Creek Formation, the upper confining zone: the lower Piper and Spearfish Formations, and the lower confining zone: the Amsden Formation. The geologic model encompasses a 76-mile × 72-mile area around the proposed storage site to characterize the geologic extent, depth, and thickness of the subsurface geologic strata (Figure 2-3). Geologic properties were distributed within the 3D model, including lithofacies, porosity, and permeability.

The geologic model and properties served as inputs for numerical simulations of $CO_2$ injection using Computer Modelling Group Ltd.'s (CMG's) GEM software (Computer Modelling Group Ltd., 2019). Numerical simulations of $CO_2$ injection were conducted to assess potential $CO_2$ injection rate, disposition of injected $CO_2$, wellhead pressure (WHP), bottomhole pressure (BHP), and pressure changes in the storage reservoir throughout the expected injection time frame and postinjection period. Results of the numerical simulations were then used to determine the project's area of review (AOR) pursuant to North Dakota's geologic $CO_2$ storage regulations.

## 3.2 Overview of Simulation Activities

### *3.2.1 Modeling of the Injection Zone and Overlying and Underlying Seals*

A geologic model was constructed to characterize the injection zone and upper and lower confining zones. Activities included data aggregation, structural framework creation, data analysis, and property distribution. Major inputs for the geologic model included geophysical logs from nearby wells and core sample measurements, which acted as control points during the distribution of the geologic properties throughout the modeled area, and seismic survey data. The geologic properties distributed throughout the model include the effective porosity, permeability, and lithofacies.

Because of the uncertainty in sonic log values related to washouts in the Broom Creek Formation in the MAG 1 well, inversion results of the site-specific 3D seismic data were not used to inform property distribution in the geologic model. Instead, publicly available variograms reported in the Tundra SGS (secure geologic storage) facility permit were used to inform the distribution of the lithofacies and petrophysical properties in the geologic model. The variograms reported in the Tundra SGS (secure geologic storage) facility permit were selected as they provide a generalized representation of the property distributions expected within the Broom Creek Formation (North Dakota Industrial Commission, 2021).

### *3.2.2 Structural Framework Construction*

Schlumberger's Petrel software was used to interpolate structural surfaces for the lower Piper (Picard Member), Spearfish, Broom Creek, and Amsden Formations. Input data included formation top depths from the online North Dakota Industrial Commission (NDIC) database; core data collected from the MAG 1, Flemmer 1, ANG 1, J-LOC 1, and BNI-1 wells (Figure 2-4); and two 3D seismic surveys (Figure 2-3) conducted at the Flemmer 1 and MAG 1 wellsites. The interpolated data were used to constrain the model extent in 3D space.

### *3.2.3 Data Analysis and Property Distribution*

#### *3.2.3.1 Confining Zones (lower Piper, Spearfish, and Amsden Formations)*

The upper confining zone (lower Piper and Spearfish Formations), and the lower confining zone (Amsden Formation) were each assigned a single lithology, based on their primary lithology determined by well log analysis to be siltstone and dolostone, respectively. Porosity and permeability logs were upscaled from a well log scale to the scale of the geologic model grid to serve as control points for property distributions. The control points were used in combination with the publicly available variograms and Gaussian random function simulation algorithms to distribute the properties. A 3,000-ft-major and minor axis length variogram model in the lateral direction and a 6-ft vertical variogram length were used within the lower Piper Formation. The variogram used within the Spearfish Formation was the same as the one used for the lower Piper Formation, except the lateral variogram is a 4,000-ft-diameter circle. A major axis length of 6,000 ft and a minor axis length of 3,000 ft were used for the Amsden Formation along an azimuth of 155° with a vertical variogram of 5 ft.

#### *3.2.3.2 Injection Zone (Broom Creek Formation)*

Prior variogram assessments completed for use in a similar storage facility permit application, the Tundra SGS $CO_2$ storage project, were used to assign variogram ranges within the injection zone. Variogram mapping investigations, as noted in the Tundra SGS application, investigated the size and shape of variograms in several different azimuthal directions, which indicated that geobody structures with the following dimensions were present in the Broom Creek Formation: major axis range of 5,000 ft, minor axis range of 4,500 ft, and an azimuth of 155° (NDIC, 2021). Well logs recorded from the MAG 1 wellbore served as the basis for deriving a vertical variogram length of 7 ft. The variogram ranges were used to distribute lithofacies and petrophysical properties.

Lithofacies classifications were interpreted from well log data and correlated with descriptions of core taken from the MAG 1, BNI-1, J-LOC 1, Flemmer 1, and ANG 1 wells. Four lithofacies were identified within the Broom Creek Formation: 1) sandstone, 2) dolostone, 3) dolomitic sandstone, and 4) anhydrite. Lithofacies logs were generated from gamma ray, density, neutron porosity, and resistivity logs. The lithofacies logs were upscaled to the resolution of the 3D model to serve as control points for geostatistical distribution using sequential indicator simulation (Figure 2-13 and Figure 3-1).

Prior to distributing the porosity and permeability properties, total porosity (PHIT), effective porosity (PHIE), and permeability (KNIT) well logs were estimated and compared with core porosity and permeability measurements to ensure good agreement with the five wells: MAG 1, Flemmer 1, J-LOC 1, BNI-1and ANG 1.

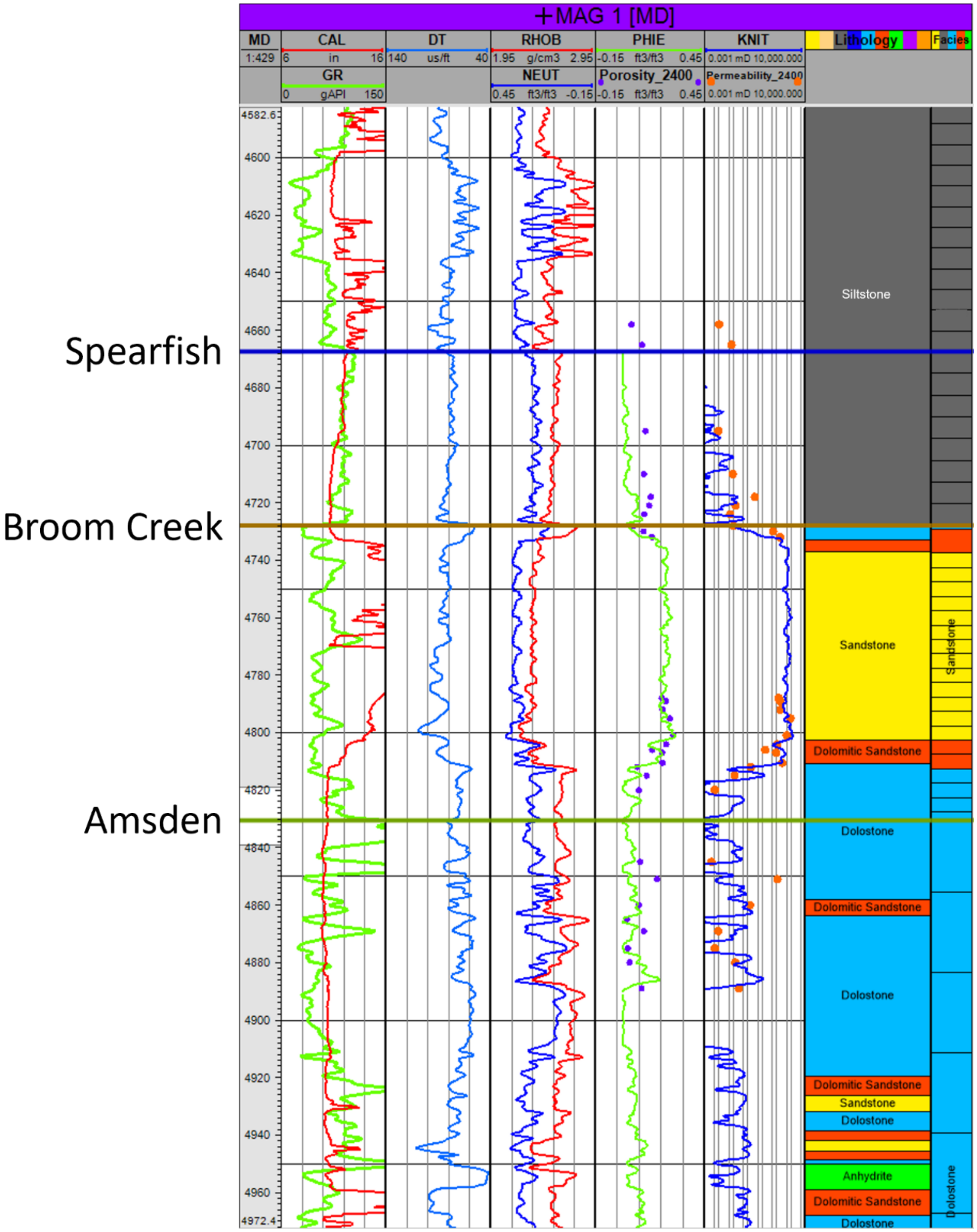



Figure 3-1. Lithofacies classification in MAG 1 well. Well logs displayed in tracks from left to right are 1) gamma ray (green) and caliper (red), 2) delta time (light blue), 3) neutron porosity (blue) and density (red), 4) effective porosity (green) and core sample porosity (purple dots), 5) predicted intrinsic permeability (blue) and core sample permeability (orange dots), 6) interpreted lithology, and 7) upscaled lithology.

A PHIE property (effective porosity; total porosity less occupied or isolated pore space) was distributed using calculated PHIE well logs, upscaled to the resolution of the 3D model as control points and variogram structures described previously with Gaussian random function simulation and conditioned to the distributed lithofacies. A permeability property was distributed using the same variables and algorithm but cokriged to the PHIE volume (Figures 3-2 and 3-3).

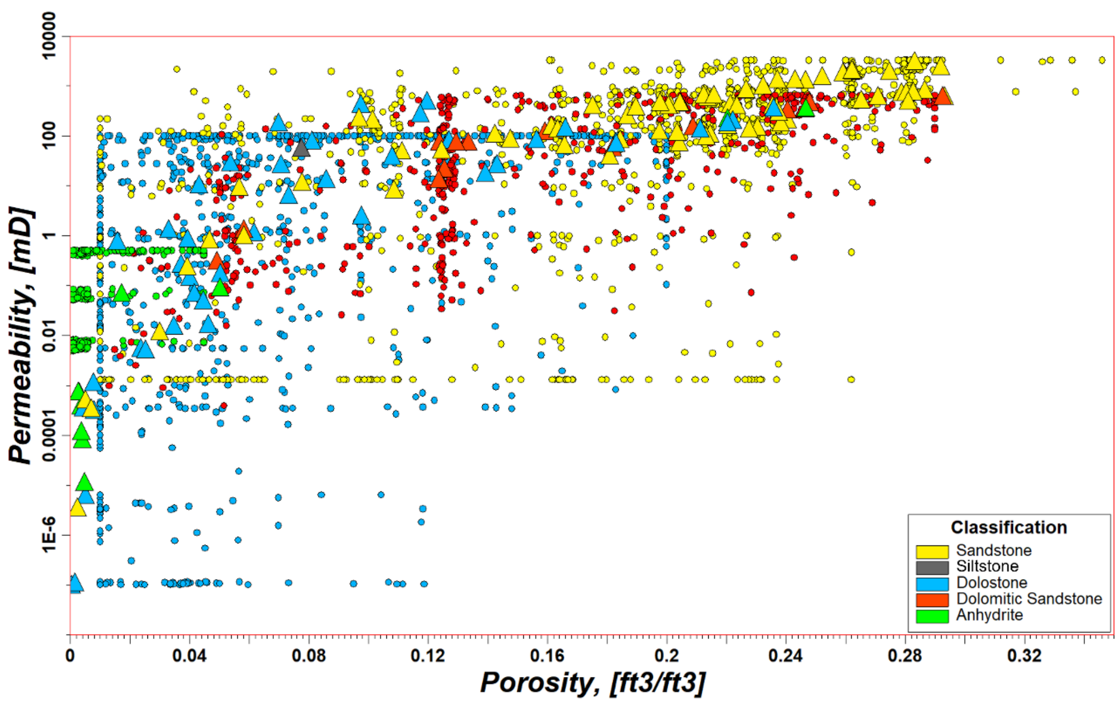



Figure 3-2. Illustration of the relationship between the modeled porosity and permeability. Upscaled well log values are represented by triangles, while circles represent distributed values. Values are colored according to lithofacies classification, as seen in Figure 3-3.

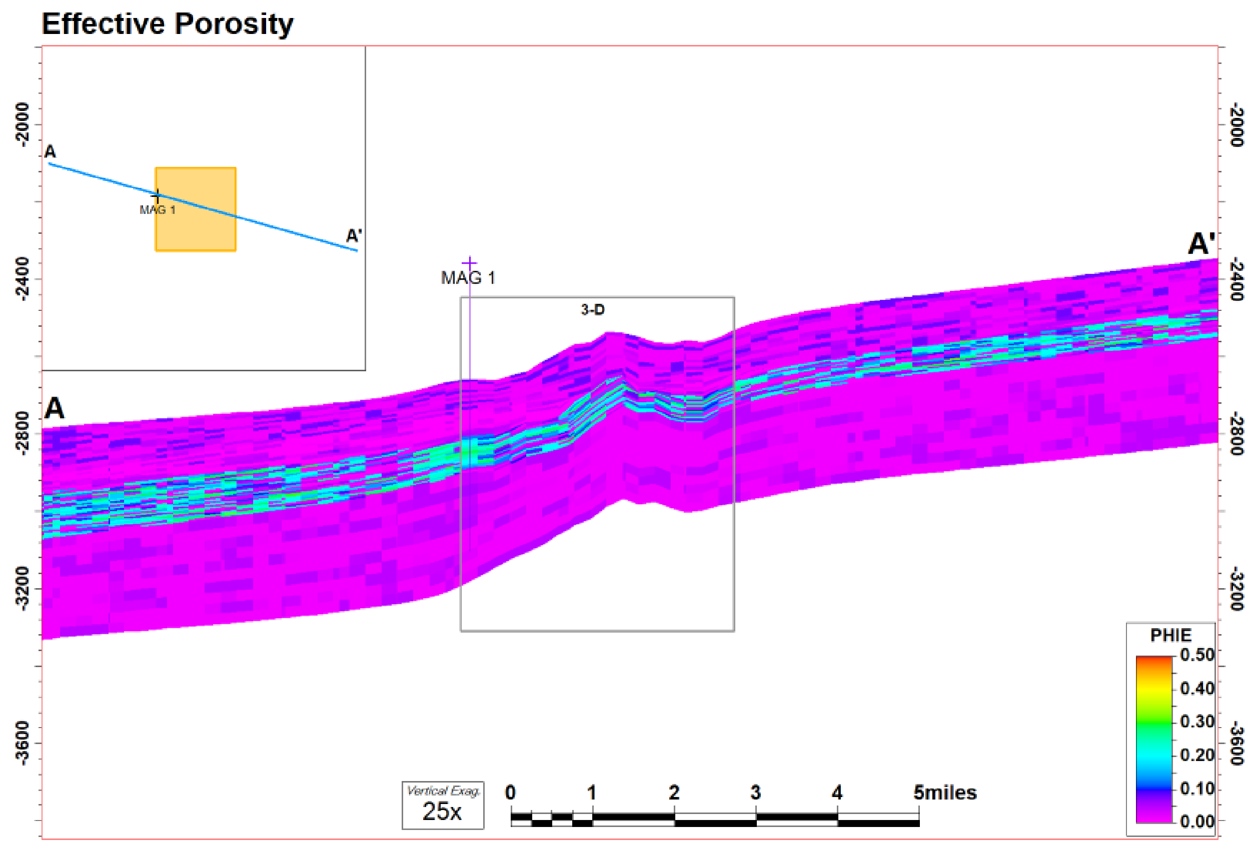



Figure 3-3. Distributed PHIE property along a northwest–southeast cross section. The distributed PHIE property was used to distribute permeability throughout the model. Units on the y-axis represent feet below mean sea level (25× vertical exaggeration shown).

## 3.3 Numerical Simulation of $CO_2$ Injection

### *3.3.1 Simulation Model Development*

Numerical simulations of $CO_2$ injection into the Broom Creek Formation were conducted using the geologic model described above. Simulations were carried out using CMG GEM, a compositional reservoir simulation module. Both measured temperature and pressure, along with the reference datum depth, were used to initialize the reservoir equilibrium conditions for performing numerical simulation. Figure 3-4 displays a 2D view of the simulation model with the permeability property and MAG 1 injection well.

The simulation model boundaries were assigned infinite-acting conditions along the western and southern boundaries and partially closed along the northern and eastern boundaries, as the Broom Creek Formation partially pinches out in the northern and eastern parts of the modeled area. The reservoir was assumed to be 100% brine-saturated with a measured initial formation salinity of 28,600 mg/L total dissolved solids (TDS) (Table 3-1).

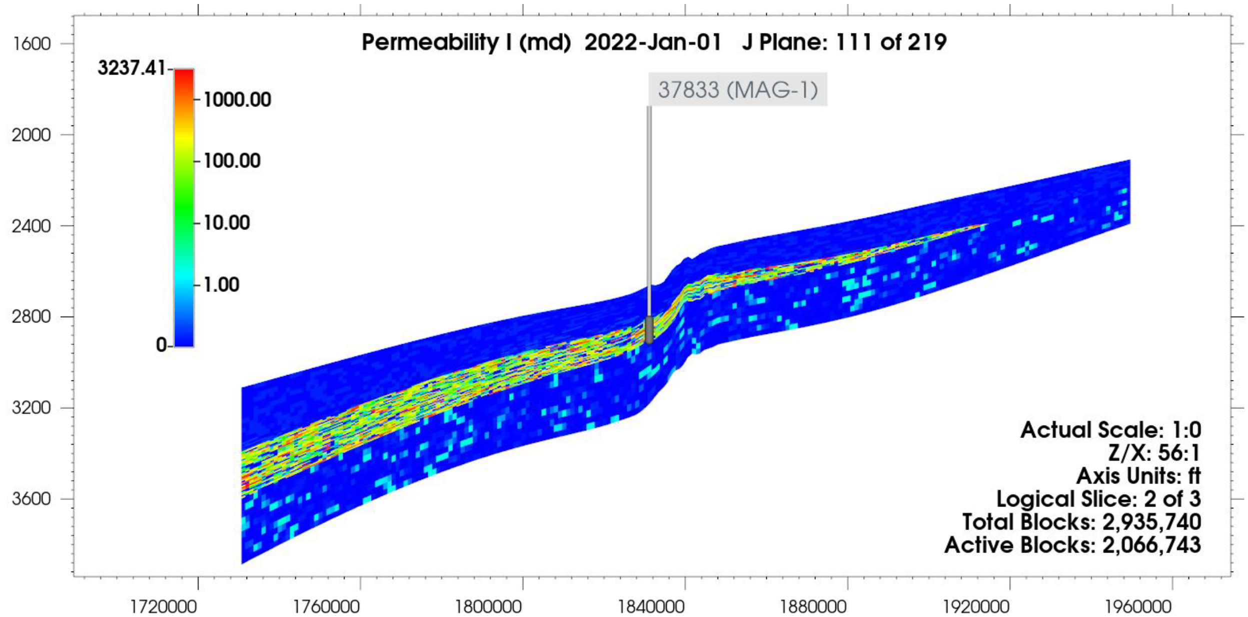



Figure 1-4. Cross-sectional view of the simulation model with the permeability property and injection well displayed. The low-permeability layers (blue) at the top and bottom of the figure should be noted. These layers represent the lower Piper and Spearfish Formations (upper confining zone) and the Amsden Formation (lower confining zone). The varied permeability of the Broom Creek Formation is shown between these layers.

**Table 3-1. Summary of Reservoir Properties in the Simulation Model**

| Formation | Average Permeability, mD | Average Porosity, % | Initial Pressure, $P_i$, psi | Salinity, mg/L | Boundary Condition |
|---|---|---|---|---|---|
| Spearfish | 0.068 | 5.1 | 2,448.8 (at 4,782.7 ft MD[1]) | 28,600 | Partially infinite |
| Broom Creek | 629.5 | 22.6 | | | |
| Amsden | 18.4 | 7.8 | | | |

[1] Measured depth.

Numerical simulations of $CO_2$ injection performed allowed $CO_2$ to dissolve into the native formation brine. Mercury injection capillary pressure (MICP) data for the Spearfish, Broom Creek, and Amsden Formations were used to generate relative permeability and the capillary curves for the five representative lithofacies in the simulation model (sandstone, siltstone, dolomite, dolomitic sands, and anhydrite) (Figures 3-6–3-8). Samples tested within the Spearfish, Broom Creek, and Amsden Formations included siltstone, sandstone, and dolomite lithologies. The siltstone (Spearfish) and dolomite (Amsden) values were assigned to anhydrite and dolomitic sandstone lithofacies, respectively, for both capillary entry pressure and relative permeability, as there were no available samples of these rock types from the MICP calculations. The main reason is both siltstone and anhydrite represent low perm facies. As for the dolomitic sandstone, the

dolomite relative permeability data was used because the dolomitic sandstones within the Broom Creek Formation are expected to be more similar to dolomite rather than to sandstone. Anhydrite and dolomitic sandstone facies intervals in the reservoir are sparse and very thin; therefore, these relative permeability assumptions are not expected to impact injectivity or $CO_2$ plume extent (Figure 3-5). Figure 3-5 shows the facies distribution in the simulation model. Please note the red and yellow colors represent the anhydrite (red) and dolomitic sandstone (yellow), respectively and these facies barely exist around the injection point.

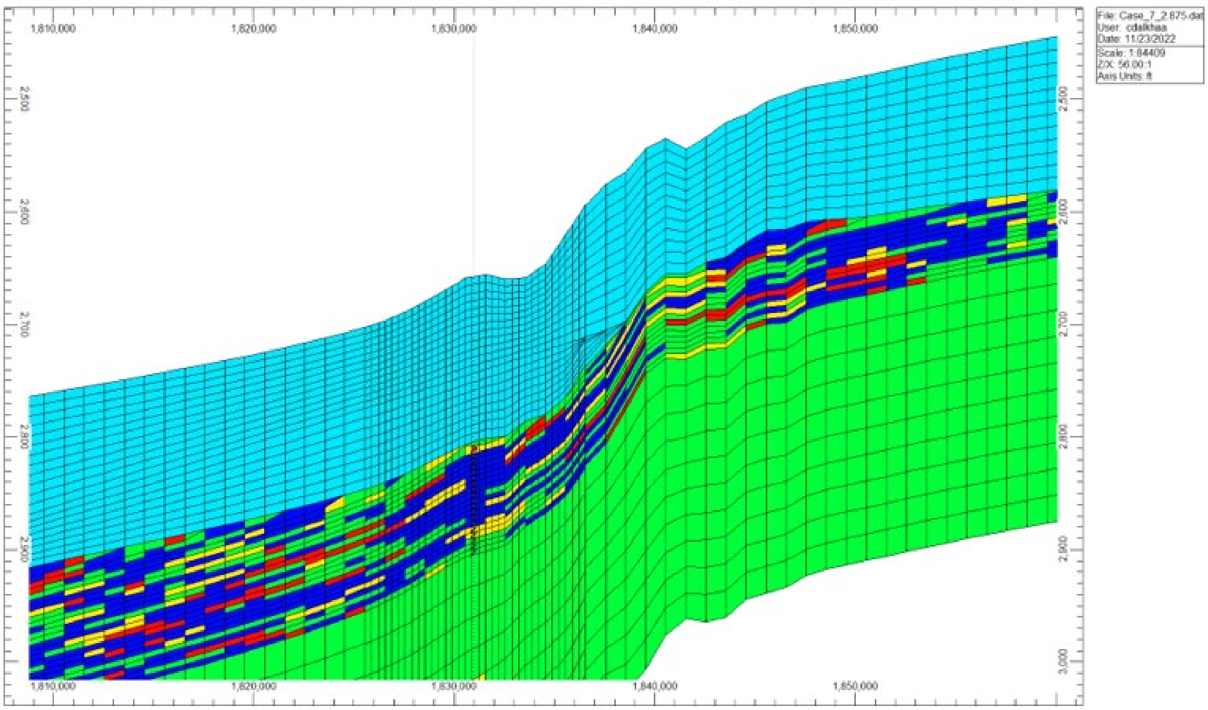
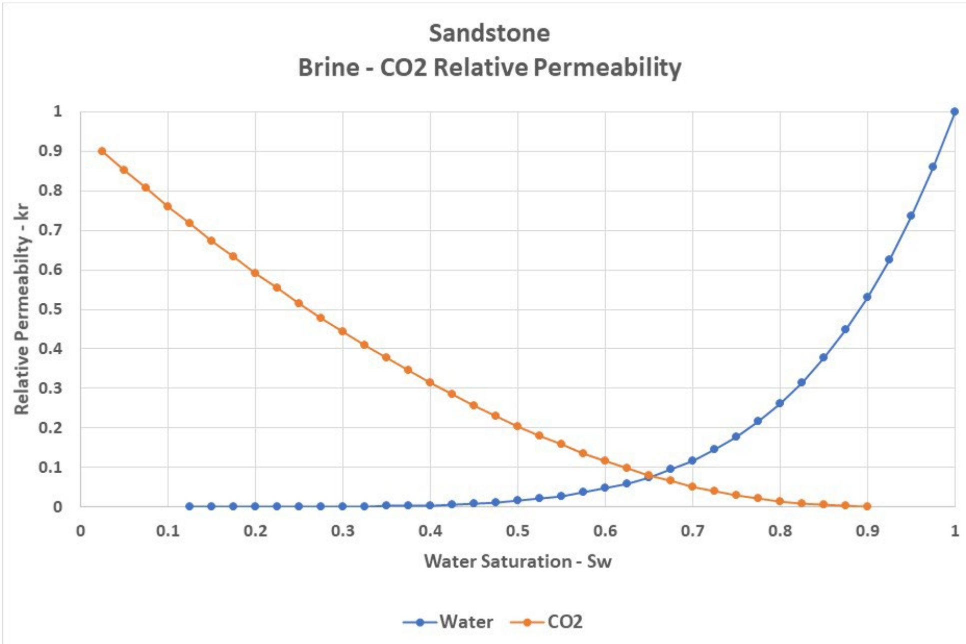



Figure 3-5. Facies distributions in the simulation model. Low permeability indicated by the color teal is siltstone. Other facies representations in the model are red representing anhydrite, yellow representing dolomitic sandstone, blue representing sandstone, and green representing dolomite.



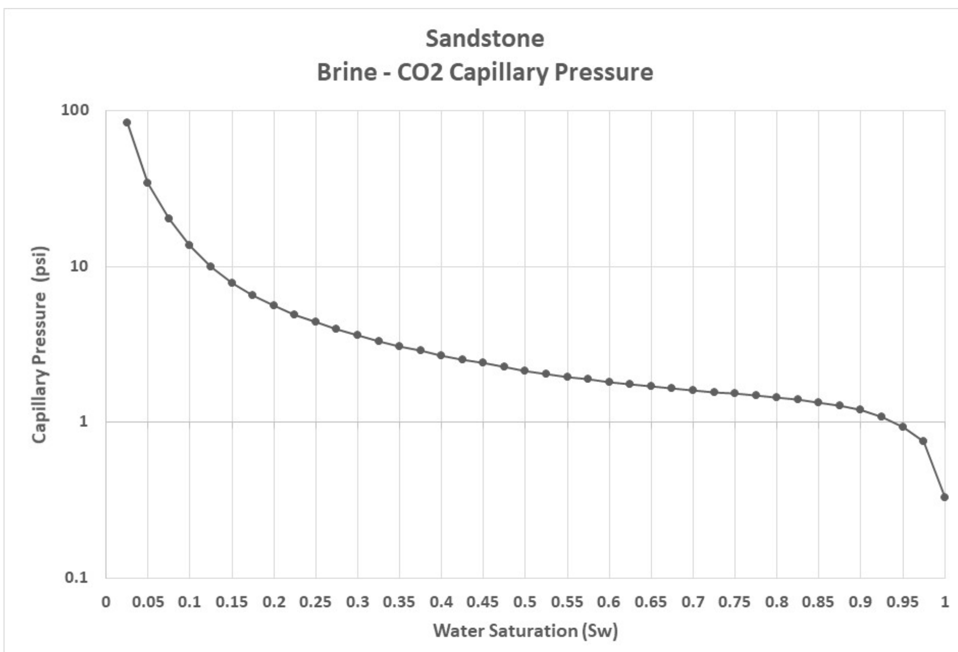
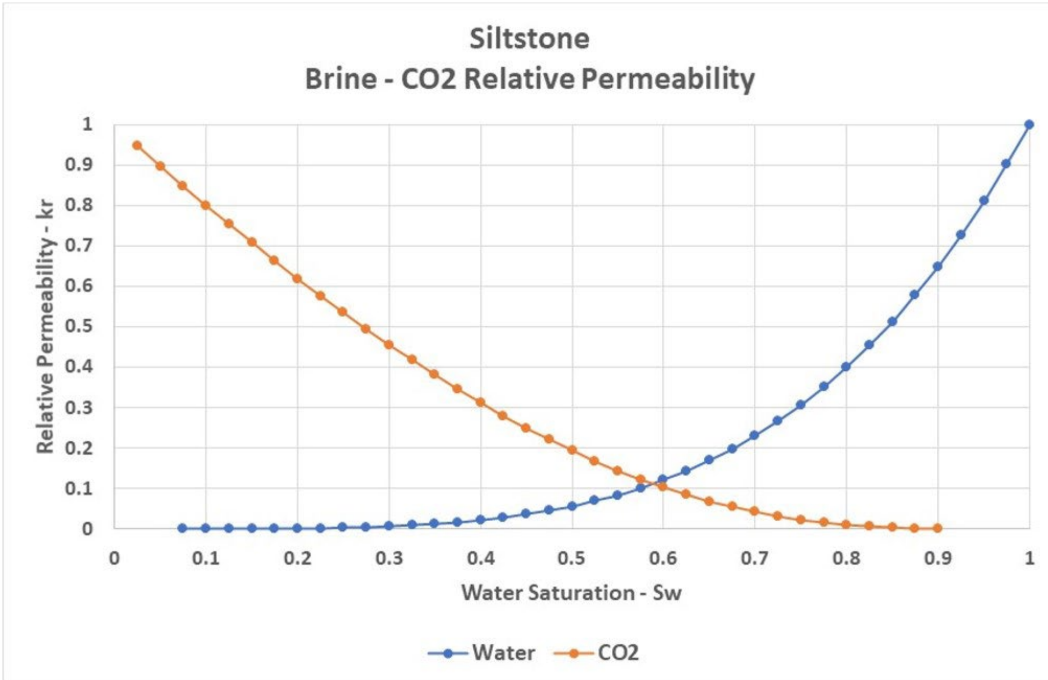




Figure 3-6. Relative permeability (top) and capillary pressure curves (bottom) for the sandstone rock type in the Broom Creek Formation.



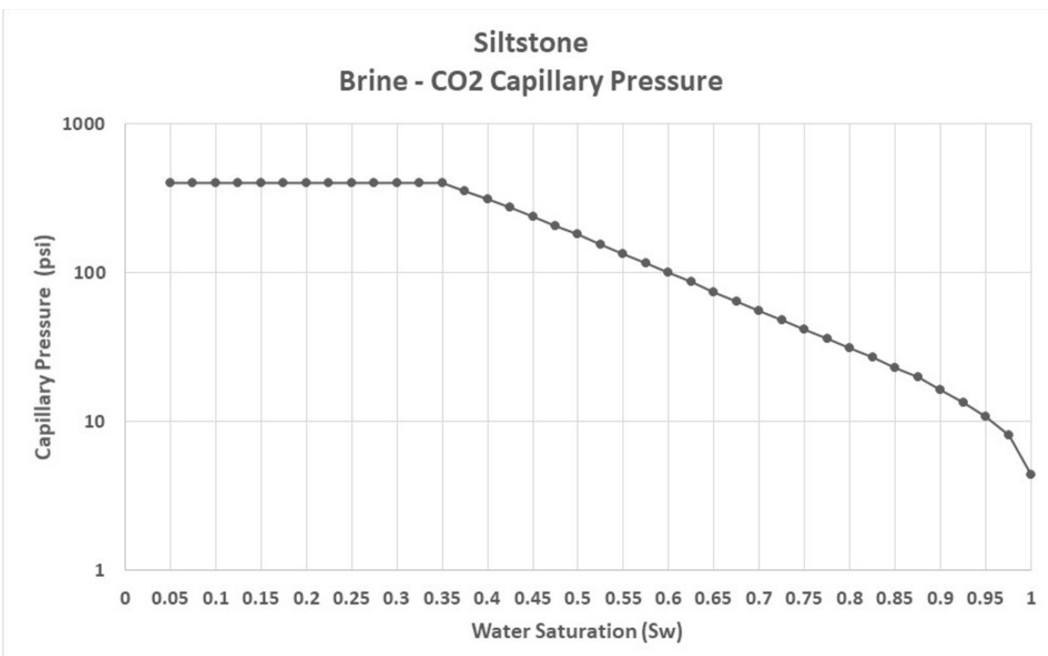
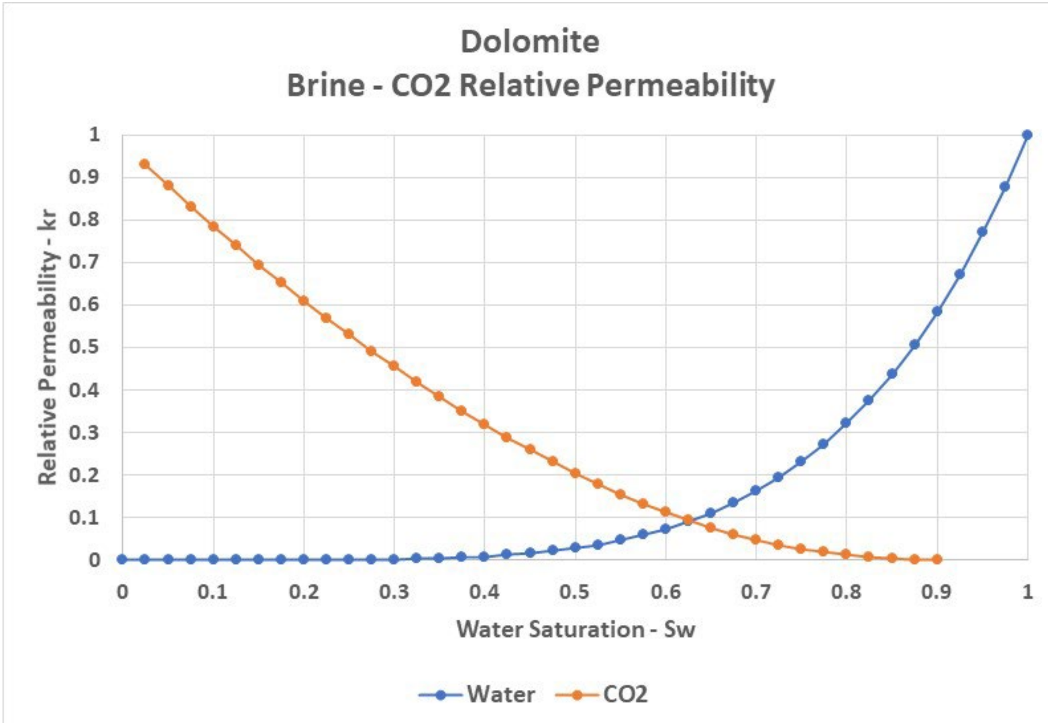




Figure 3-7. Relative permeability (top) and capillary pressure curves (bottom) for the siltstone rock type in the Spearfish Formation.



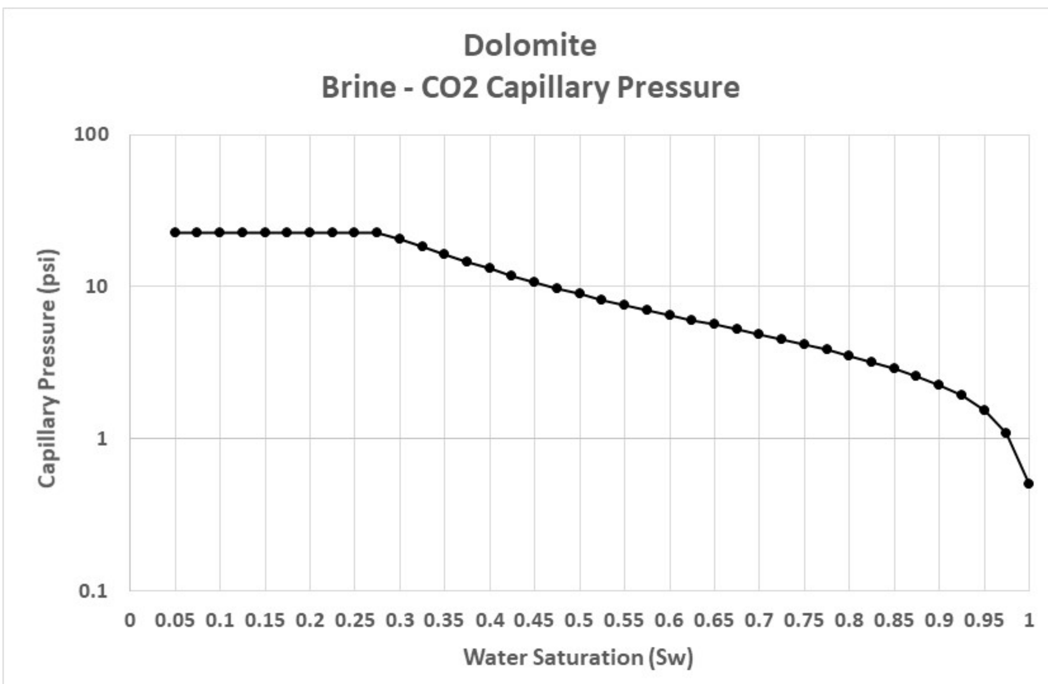




Figure 3-8. Relative permeability (top) and capillary pressure curves (bottom) for the dolomite rock type in the Amsden Formation.

Capillary pressure curves calculated from MICP data were modified to the model scale based on the permeability and porosity values of the simulation model and used in the numerical simulations. These modified capillary pressure curves are also shown in Figures 3-6–3-8. The capillary entry pressure values applied in the model were determined by deriving a ratio between the reservoir quality index of core samples and modeled properties to scale the capillary entry pressure value derived from core testing (Table 3-2).

Temperature and pressure data recorded in the MAG 1 wellbore were used to derive a temperature and pressure gradient to initialize the numerical simulation model for the proposed injection site. In combination with depth, a temperature gradient of 0.025°F/ft was used to calculate subsurface temperatures throughout the study area. A pressure reading recorded from the Broom Creek Formation was used to derive a pore pressure gradient of 0.512 psi/ft. The fracture gradient was obtained from a geomechanical analysis, resulting in an average of 0.69 psi/ft. The maximum allowable BHP of 2,970 psi was estimated to be 90% of the fracture gradient multiplied by the depth of the top perforation in the injection zone, the Broom Creek Formation, and used as the injection constraint in the numerical simulation of the expected injection scenario.

### *3.3.2 Sensitivity Analysis*

Because the availability of data for this study included well logs, core sample data, and rock–fluid properties, the need for typical sensitivity studies of influential reservoir parameters has been reduced. A preliminary sensitivity analysis made to the wellbore model parameters suggested, at the given injection volume rates and BHP conditions, the wellhead temperature played a prominent role in determining WHP response. Sensitivity simulations of different wellhead temperatures indicated that injection at a higher wellhead temperature would require a higher WHP. For evaluating the expected injection design, a wellhead temperature value of 60°F was chosen that most closely represents the expected operational temperature.

## 3.4 Simulation Results

The target injection rate of 200,000 tonnes per year (tpy) (548 tonnes per day) was consistently achievable over 20 years (Figure 3-9), translating to a cumulative 4 MMt of $CO_2$ injection (Figure 3-10). Simulations of $CO_2$ injection with the given well constraints, listed in Table 3-3, predicted the BHP would not reach the maximum BHP constraint of 2,970 psi (90% of the formation fracture pressure) as a result of injecting the target $CO_2$ volume of 200,000 tpy. The predicted maximum BHP and the average BHP during the 20 year injection period were 2,661 and 2,570 psi (Figure 3-11), respectively.

**Table 3-2. Core and Model Properties Showing the Multiplication Factor Used to Calculate Capillary Entry Pressure Used in the Simulation Model**

| | Core | | | | | Model | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Porosity (fraction) | Permeability, mD | Capillary Entry Pressure, A/Hg, psi | Capillary Entry Pressure B/$CO_2$, psi | Reservoir Quality Index | Porosity (fraction) | Permeability*, mD | Capillary Entry Pressure B/$CO_2$, psi | Reservoir Quality Index | Multiplication Factor |
| **Spearfish** | 0.125 | 0.028 | 58.3 | 12.245 | 0.015 | 0.051 | 0.068 | 5.018 | 0.036 | 0.410 |
| **Broom Creek** | 0.238 | 129 | 4.16 | 0.867 | 0.731 | 0.226 | 629.500 | 0.382 | 1.657 | 0.441 |
| **Amsden** | 0.096 | 0.011 | 126 | 26.134 | 0.011 | 0.078 | 18.400 | 0.576 | 0.482 | 0.022 |

* Pore volume weighted average.

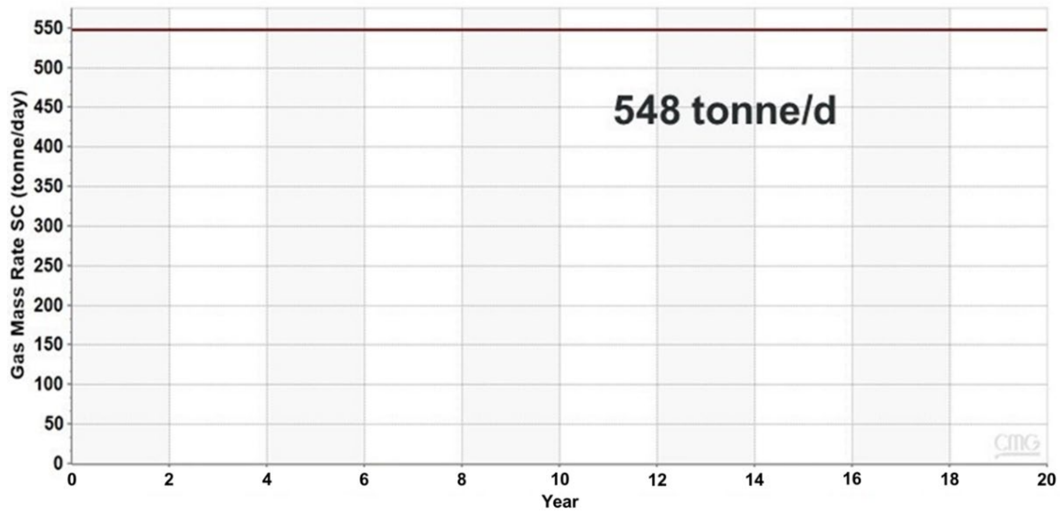



Figure 3-9. Mass injection rate over 20 years of injection with the expected injection rate.

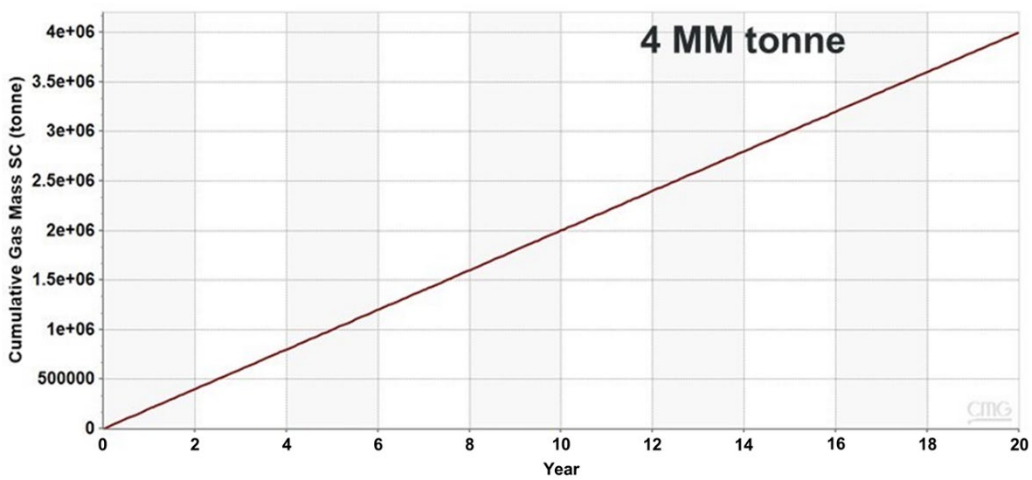



Figure 3-10. Cumulative injected gas mass over 20 years of injection with the expected injection rate.

**Table 3-3. Well Constraints and Wellbore Model in the Simulation Model**

| Injection rate | Well Constraint, maximum BHP | Tubing Size | Wellhead Temperature | Downhole Temperature |
|---|---|---|---|---|
| 200,000 tonnes/year for 20 years | 2,970 psi | 2.875 in. | 60°F | 119.6°F |

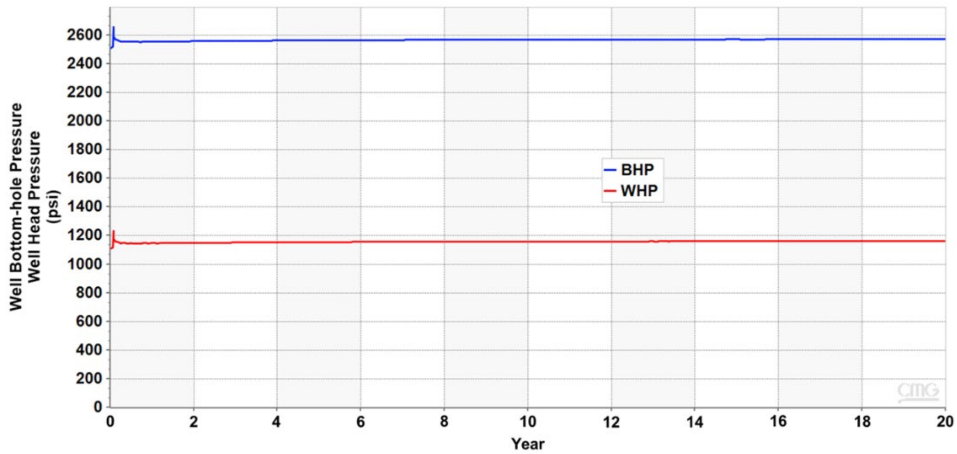



Figure 3-11. WHP and BHP response with the expected injection rate.

WHP depends on several factors, including injection rate, injection tubing parameters (tubing size and relative toughness), and surface injection temperature. For the designed injection rate and tubing size of 2.875 in., the predicted maximum WHP and average WHP during the 20 year injection period were 1,236 and 1,158 psi (Figure 3-11), respectively.

During and after injection, supercritical $CO_2$ (free-phase $CO_2$) accounts for the majority of $CO_2$ observed in the modeled pore space. Throughout the injection operation, a portion of the free-phase $CO_2$ is trapped in the pore space through a process known as residual trapping. Residual trapping can occur as a function of low $CO_2$ saturation and inability to flow under the effects of relative permeability. $CO_2$ also dissolves into the formation brine throughout injection operations (and continues afterward), although the rate of dissolution slows over time. The free-phase $CO_2$ transitions to either residually trapped or dissolved $CO_2$ during the postinjection period, resulting in a decline in the mass of free-phase $CO_2$. The relative portions of supercritical, trapped, and dissolved $CO_2$ can be tracked throughout the duration of the simulation (Figure 3-12).

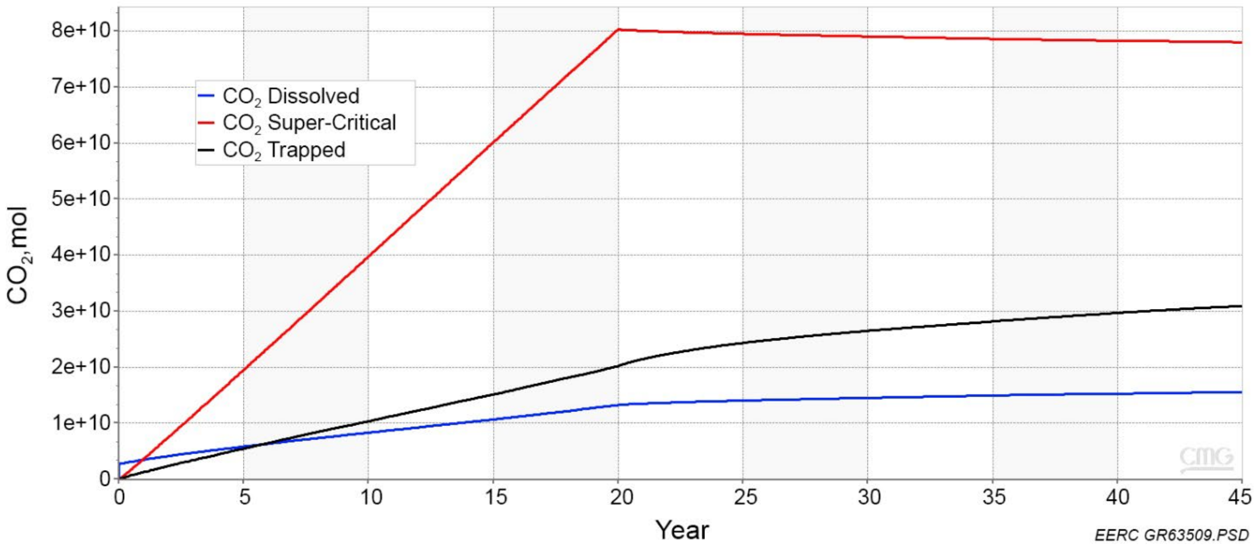



Figure 3-12. Simulated total super-critical free-phase $CO_2$, trapped $CO_2$, and dissolved $CO_2$ in brine.

The pressure front (Figure 3-13) shows the distribution of average pressure increase throughout the Broom Creek Formation after 1, 10, and 20 years of injection as well as 10 years postinjection (stabilization year). A maximum increase of 113.2 psi was estimated in the near-wellbore area at the end of the 20-year injection period.

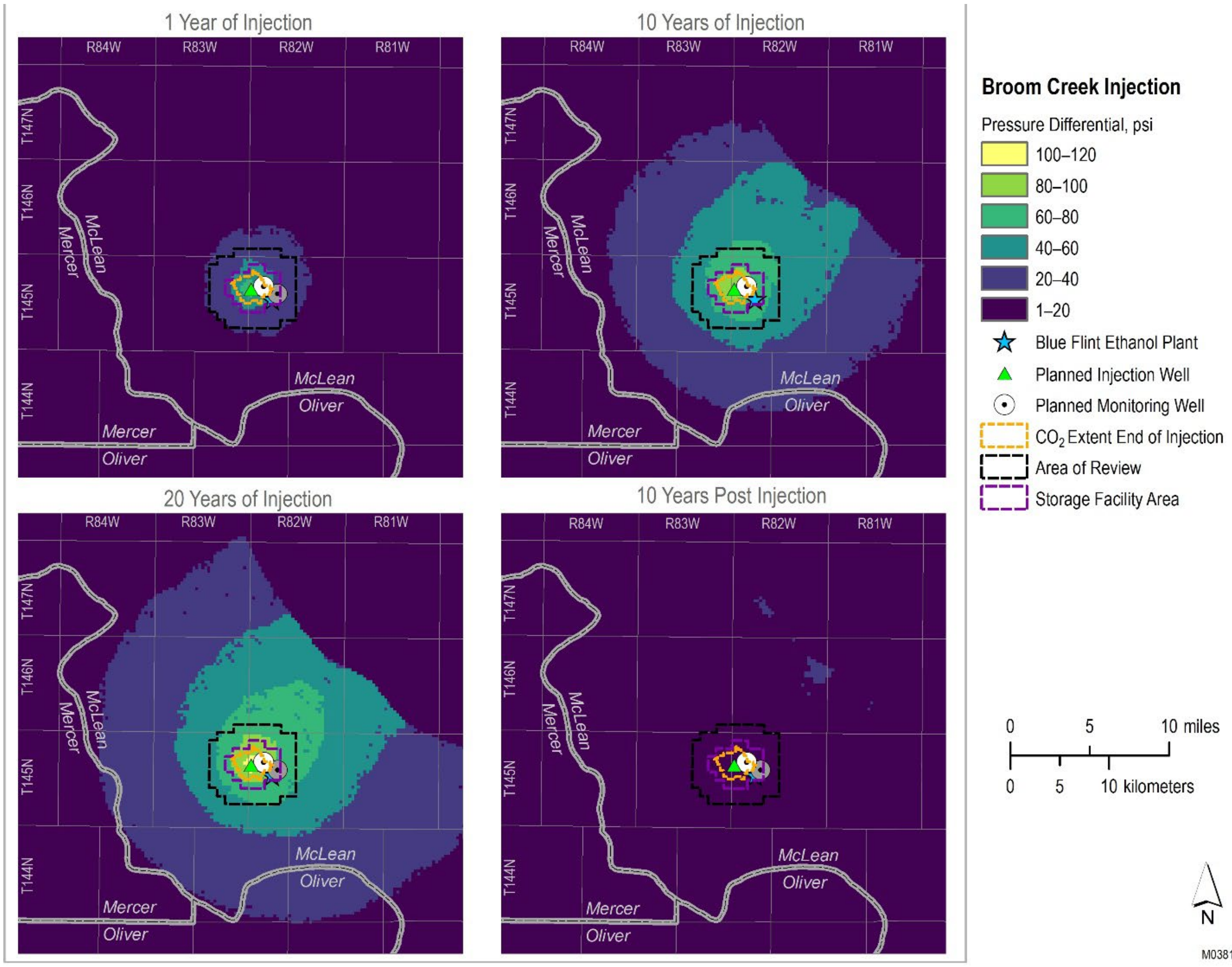



Figure 3-13. Top left, top right, and bottom left display average pressure increase within the Broom Creek Formation after 1, 10, and 20 years of simulated $CO_2$ injection operation. Bottom right displays pressure differential during 10 years of postinjection (plume stabilization year).

Long-term $CO_2$ migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase $CO_2$ injected into the formation rises to the bottom of the upper confining zone or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of $CO_2$ at the center which gradually spreads out toward the model edges where the $CO_2$ saturation is lower. Trapped $CO_2$ saturations, employed in the model to represent fractions of $CO_2$ trapped in small pores as immobile, tiny bubbles, ultimately immobilize the $CO_2$ plume and limit the plume's lateral migration and spreading. Figure 3-14 shows the $CO_2$ saturation at the injection well at the end of injection in north-to-south and east-to-west cross-sectional views.

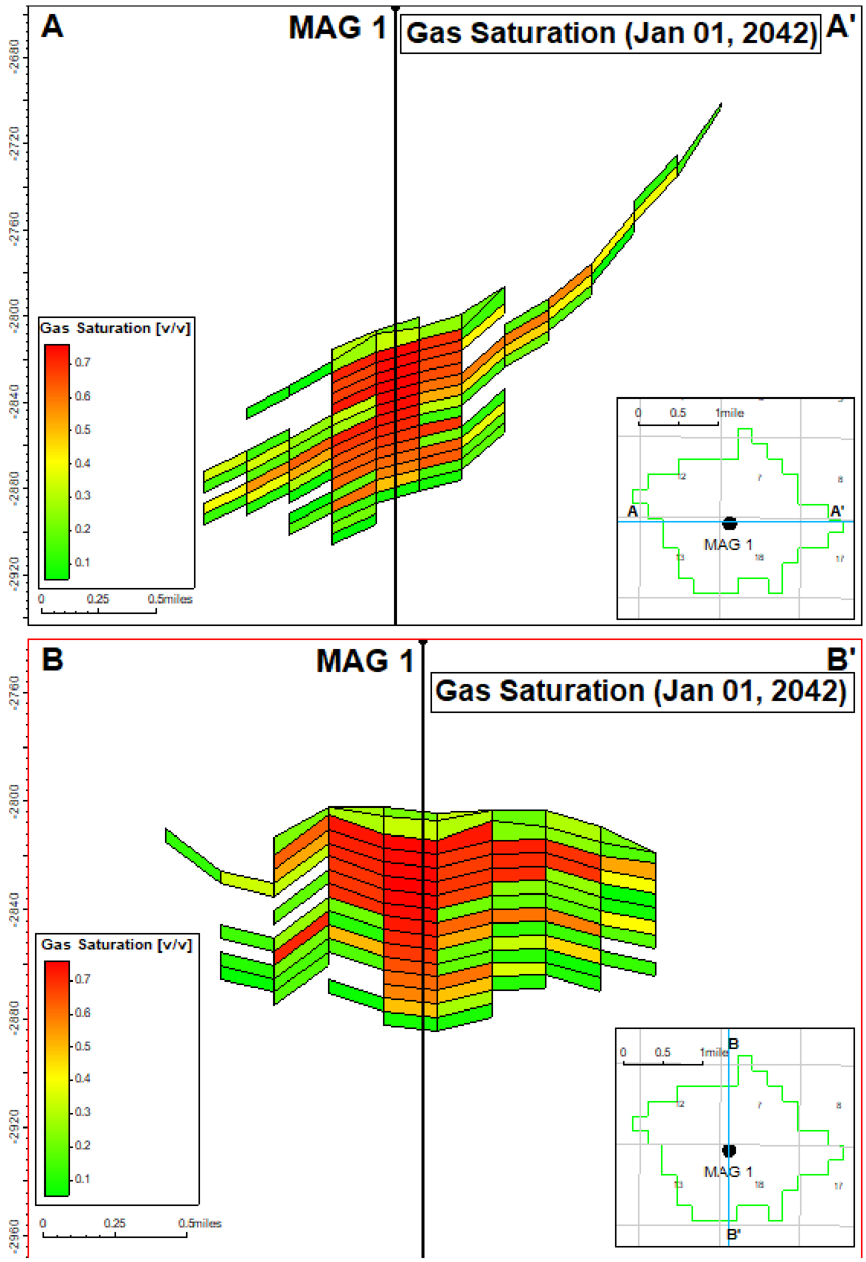



Figure 3-14. $CO_2$ plume cross section of MAG 1 at the end of injection displayed by a) west to east and b) north to south (50× vertical exaggeration shown). The inset map shows the location of the cross section and the stabilized plume boundary (shown as a green polygon).

### *3.4.1 Maximum Injection Pressures and Rates*

An additional case was run to determine the maximum storage potential if the well was only limited by the maximum calculated downhole pressure of 2,970 psi (90% of the formation fracture pressure). In this scenario, the MAG 1 well was able to inject at a daily average rate of 2,729 tonnes/day of $CO_2$ with a 2.875-in. diameter tubing, achieving a total injection volume of 19.9 MMt of $CO_2$. The predicted average WHP, using the designed injection tubing of 2.875 inches, was 4,300 psi (Figure 3-15).

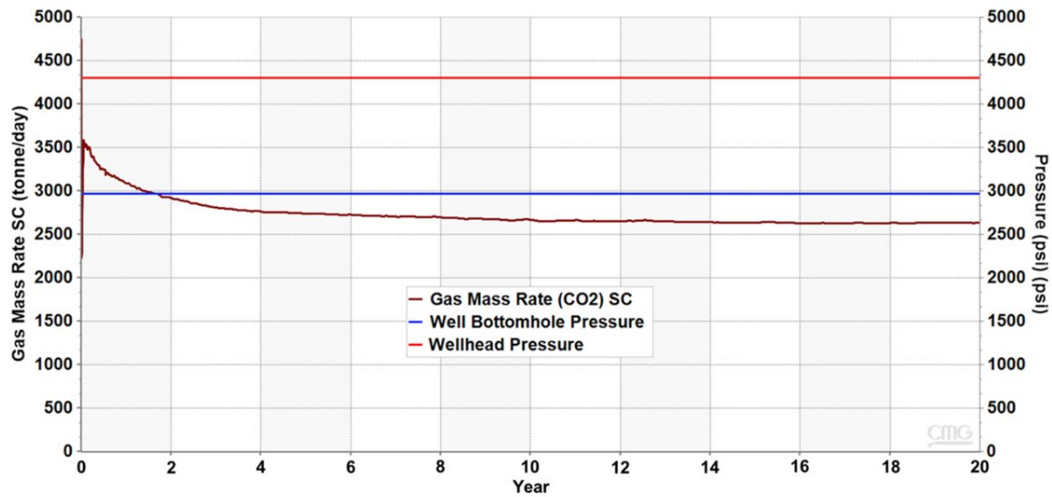



Figure 3-15. Maximum pressures and rate response when the well was operated without any injection rate limits.

### *3.4.2 Stabilized Plume and Storage Facility Area*

Movement of the injected $CO_2$ plume is driven by the potential energy found in the buoyant force of the injected $CO_2$. As the plume spreads out within the reservoir and $CO_2$ is trapped residually through the effects of relative permeability and dissolution, the potential energy of the buoyant $CO_2$ is gradually lost. Eventually, the buoyant force of the $CO_2$ is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the $CO_2$ plume ceases to move within the subsurface and becomes stabilized. The extent of the stabilized plume is important for determining the project's AOR and the corresponding scale and scope of the project's monitoring plans.

Plume stabilization can be visualized at the microscale as $CO_2$ being unable to exit its current pore space and enter the neighboring pore space, but at the macroscale, these interactions cannot be measured. Instead, plume stabilization may be estimated using the tools available to predict the $CO_2$ plume's extent.

For the Blue Flint project the $CO_2$ plume was simulated in 5-year time steps until the rate of total areal extent change slowed to less than 0.15 square miles per 5-year time step to define the stabilized plume extent boundary (Figure 3-13) and the associated buffers and boundaries. This estimate is anticipated to be regularly updated during the $CO_2$ storage operation as data collected from the site are used to update predictions made about the behavior of the injected $CO_2$.

## 3.5 Delineation of the Area of Review

The North Dakota Administrative Code (NDAC) defines AOR as the region surrounding the geologic storage project where underground sources of drinking water (USDWs) may be endangered by $CO_2$ injection activity (NDAC § 43-05-01-05). The primary endangerment risk is the potential for vertical migration of $CO_2$ and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the $CO_2$ plume within the storage reservoir.

However, the $CO_2$ plume has an associated pressure front where $CO_2$ injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the $CO_2$ plume. Therefore, the AOR encompasses both the areal extent of the $CO_2$ plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the $CO_2$ plume, AOR delineation focuses on the pressure front.

The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the underground injection control (UIC) program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure.

In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), "potential thief zone" refers to the Inyan Kara Formation, and "lowest USDW" refers to the Fox Hills Formation.

### *3.5.1 EPA Methods 1 and 2: AOR Delineation for Class VI Wells*

EPA guidance for AOR evaluation includes several computational methods for estimating the pressure buildup in the storage reservoir in response to $CO_2$ injection and the resultant areal extent of pressure buildup above a "critical threshold pressure" that could potentially drive higher-salinity formation fluids from the storage reservoir up an open conduit to the lowest USDW (U.S. Environmental Protection Agency, 2013). The following equations and analytical approach define the EPA methods used to delineate AOR. Each method can be applied both at a single location (e.g., the MAG 1 stratigraphic well) using site-specific data or for each vertical stack of grid cells in a geocellular model, considering the varying stratigraphic thickness between storage reservoir and lowest USDW.

EPA Method 1 (*pressure front based on bringing the injection zone and USDW to equivalent hydraulic heads*) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW (U.S. Environmental Protection Agency, 2013).

Under Method 1, the maximum pressure increase that may be sustained in the injection zone (critical threshold pressure increase) is given by Equation 1:

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_{\mathrm{I}} \qquad \text{[Eq. 1]}$$

Where:

$P_u$ is the initial fluid pressure in the USDW (Pa).
$\rho_i$ 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 ($\Delta P_c$), which is the fluid pressure increase sufficient to drive formation fluids into the lowermost USDW. This $\Delta P_c$ is determined using Equations 2 and 3, assuming 1) hydrostatic conditions, 2) initially linear densities in the borehole, and 3) constant density once the injection zone fluid Is lifted to the top of the borehole (i.e., uniform density approach):

$$\Delta P_C = \frac{1}{2}\, g\, \xi\, (Z_u - Z_i)^2 \qquad \text{[Eq. 2]}$$

Where $\xi$ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{Z_u - Z_i} \qquad \text{[Eq. 3]}$$

Where:

$\Delta P_c$ is the critical threshold pressure increase (Pa).
$g$ is the acceleration of gravity (m/s$^2$).
$z_u$ is the elevation of the base of the lowermost USDW (m amsl).
$z_i$ is the elevation of the top of the injections zone (m amsl).
$P_i$ is the fluid density in the injection zone (kg/m$^3$).
$P_u$ is the fluid density in the USDW (kg/m$^3$).

### *3.5.2 Risk-Based AOR Delineation*

The methods described by EPA (2013) for estimating the AOR under the Class VI rule (40 U.S. Code of Federal Regulations [CFR] 146.81 et seq.) were developed assuming that the storage

reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and potentially elsewhere around the United States, candidate storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW, even prior to the planned storage project. Consequently, applying EPA (2013) methods to these geologic situations essentially results in an infinite AOR, which makes regulatory compliance infeasible.

Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer and others (2014) described the unnecessary conservatism in EPA's definition of critical pressure, which could lead to a heavy burden on storage facility permit (SFP) applicants. As an alternative, Burton-Kelly and others (2021) proposed a risk-based reinterpretation of this framework that would allow for a reduction in the AOR while ensuring protection of drinking water resources.

A computational framework for estimating a risk-based AOR was proposed by Oldenburg and others (2014, 2016), who compared formation fluid leakage through a hypothetical open flow path in the baseline scenario (no $CO_2$ injection) to the incrementally larger leakage that would occur in the $CO_2$ injection case. The modeling for the risk-based AOR used semianalytical solutions to single-phase flow equations to model reservoir pressurization and vertical migration through leaky wells. These semianalytical solutions were extensions of earlier work for formation fluid leakage through abandoned wellbores by Raven and others (1990) and Avci (1994), which were creatively solved, coded, and compiled in FORTRAN under the name ASLMA (Analytical Solution for Leakage in Multilayered Aquifers) and extensively described by Cihan and others (2011, 2012) (hereafter "ASLMA Model").

Recently, White and others (2020) outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, NRAP-IAM-CS and the subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers.

Building a geologic model in a commercial-grade software platform (like Petrel; Schlumberger, 2020) and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform (like CMG's compositional simulator, GEM) provide the "gold standard" for estimating pressure buildup in response to $CO_2$ injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that are unwarranted given the amount of uncertainty that may be present if only a few nearby wells can be used for characterization activities. Earlier studies (e.g., Nicot and others, 2008; Birkholzer and others, 2009; Bandilla and others, 2012; Cihan and others, 2011, 2012) have shown that far-field fluid pressure changes outside of the $CO_2$ plume domain can be reasonably described by a single-phase flow calculation by representing $CO_2$ injection as an equivalent-volume injection of brine (Oldenburg and others, 2014).

The semianalytical solutions embedded within the ASLMA Model have been shown to compare with the numerical model, TOUGH2-ECO2-N, and provided accurate results for pressures beyond the $CO_2$ plume zone (Birkholzer and others, 2009; Cihan and others, 2011, 2012). Therefore, the proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and resultant effects of this buildup on the vertical migration of formation fluid via (single) hypothetical leaky wellbores located at progressively greater distances from the injection well (Figure 3-16).

An important distinction between EPA Methods 1 and 2, which both calculate a critical pressure threshold (either $\Delta P_{i,f}$ for Method 1 or $\Delta P_c$ for Method 2) and the risk-based AOR approach is that the risk-based approach 1) calculates and maps the potential incremental flow of

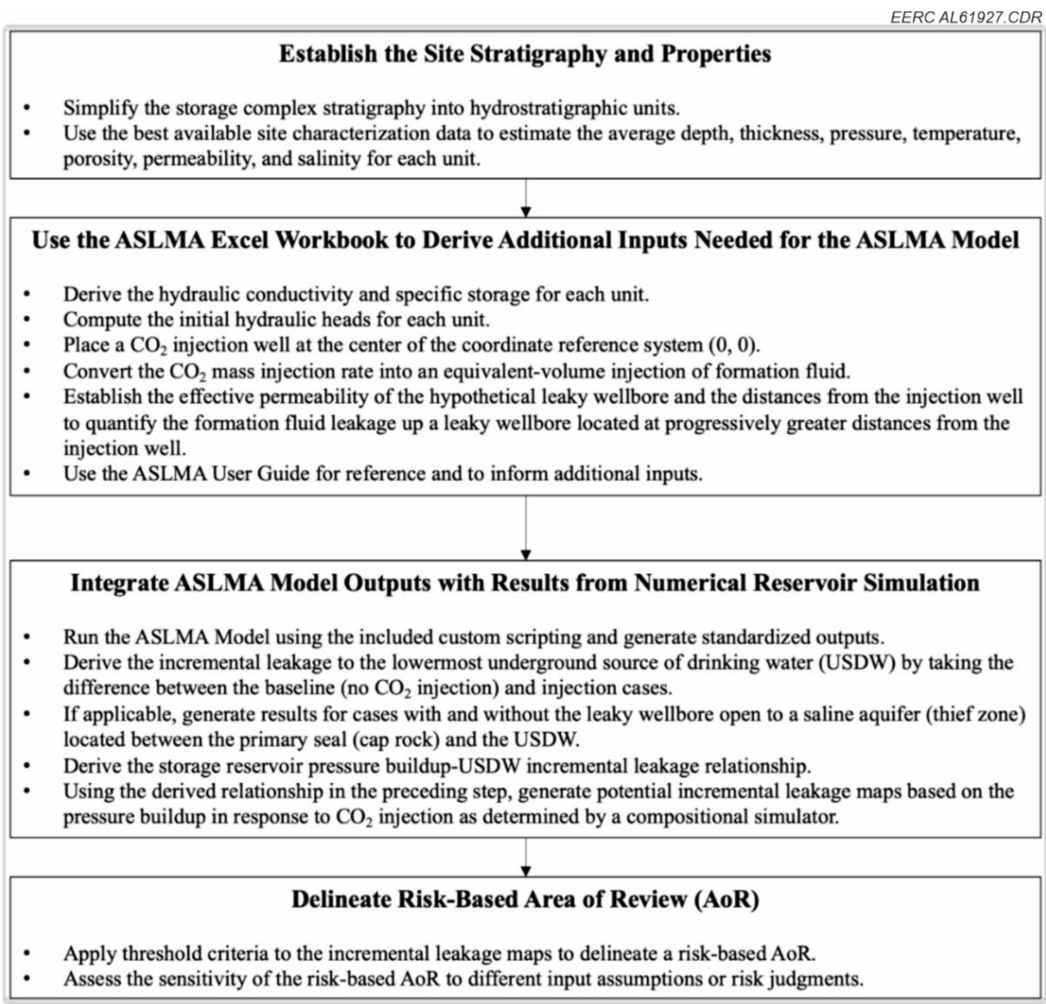



Figure 3-16. Workflow for delineating a risk-based AOR for a SFP (modified from Burton-Kelly and others, 2021).

formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR.

### *3.5.3 Critical Threshold Pressure Increase Estimation*

For the purposes of delineating AOR for the project study area, constant fluid densities for the lowermost USDW (Fox Hills Formation) and injection zone (Broom Creek Formation) were used in the calculations. Respective fluid densities were used to represent the injection zone fluids ($\rho_i$), which are estimated based on the in situ estimated brine salinity, temperature, and pressure at the MAG 1 stratigraphic test well.

Application of EPA Method 1 (Equation 1) using site-specific data from the MAG 1 well shows that the injection zone in the project area is overpressurized with respect to the lowest USDW (i.e., Method 1 $\Delta P_{i,f} < 0$). An example of the EPA Method 1 application showing negative $\Delta P_{i,f}$ (relative overpressure) is given in Table 3-4, with similar results when applied to each column of the grid cells in the Broom Creek Formation simulation model.

**Table 3-1. EPA Method 1 Critical Threshold Pressure Increase Calculated at the MAG 1 Wellbore Location Using Measured and Calculated Data Shown in Table 3-2**

| Depth,* | | $P_i$ Injection Zone Pressure, | $P_u$ USDW Base Pressure, | $\rho_i$ 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 |
| 4,731 | 1,442 | 16.41 | 3.15 | 1,006 | 276 | −855 | −2.11 | −306 |

* Ground surface elevation is 581 m above mean sea level. Depth provided is the reference depth used for the CMG simulation.

In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value across the project area and b) lack of evidence for hydrostatic equilibrium between the reservoir and the USDW (i.e., Method 2 does not apply) indicates that a risk-based approach to AOR delineation may be pursued.

### *3.5.4 Risk-Based AOR Calculations*

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). The inputs, assumptions, and results discussed here provide the necessary details for reproducing and verifying the results. A macro-enabled Microsoft Excel file was used to define the inputs and calculations that were employed in the method (hereafter "ASLMA Workbook").

#### *3.5.4.1 Initial Hydraulic Heads*

The original ASLMA Model (Cihan and others, 2011) initially assumed hydrostatic pressure distributions in the entire system. The current work uses a modified version of the ASLMA Model to simulate pressure perturbations and leakage rates when there are initial head differences in the aquifers (Oldenburg and others, 2014). The initial hydraulic heads are calculated assuming a total

head based on the unit-specific elevations and pressures. The total heads are entered into the ASLMA Model and establish the initial pressure conditions for the storage complex prior to $CO_2$ injection.

For example, the initial reference case total heads for the storage reservoir (Aquifer 1), potential thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-5 and illustrate the state of overpressure in the storage complex, as Aquifer 1 has a greater initial hydraulic head than Aquifers 2 and 3. Therefore, the storage complex requires different treatment than the default AOR calculations described by EPA (2013). Details on the calculations of initial hydraulic head are provided in Burton-Kelly and others (2021).

**Table 3-2. Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex**

| Hydrostratigraphic Unit | Depth to Top,* m | Thickness, m | Pressure, MPa | Temperature, °C | Salinity, ppm | Brine Density, $kg/m^3$ | Porosity, % | Permeability, mD | Permeability, $m^2$ | HCON, m/d | Specific Storage, $m^{-1}$ | Total Head, m |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Overlying Units to Ground Surface (not directly modeled) | 0 | 215 | | | | | | | | | | |
| Aquifer 3 (USDW – Fox Hills Fm) | 215 | 90 | 2.6 | 12.5 | 1,800 | 1,002 | 34.4 | 280 | 2.76E-13 | 1.92-01 | 5.56E-06 | 591 |
| Aquitard 2 (Pierre Fm–Inyan Kara Fm) | 305 | 788 | 7.0 | 25.3 | 16,300 | | 10 | 0.1 | 9.87E-17 | 9.30E-05 | 9.26E-06 | 585 |
| Aquifer 2 (Thief Zone – Inyan Kara Fm) | 1,093 | 69 | 11.3 | 37.8 | 16,300 | 1,008 | 22.4 | 42.1 | 4.16E-14 | 5.06E-02 | 5.25E-06 | 593 |
| Aquitard 1 (Swift–Broom Creek Fm) (primary upper seal) | 1,161 | 273 | 13.0 | 42.7 | 28,600 | | 10 | 0.1 | 9.87E-17 | 1.30E-04 | 9.31E-06 | 583 |
| Aquifer 1 (Storage Reservoir – Broom Creek Fm) | 1,435 | 32 | 16.5 | 68.3 | 28,600 | 1,003 | 18.2 | 121.3 | 1.20E-13 | 2.31E-01 | 5.15E-06 | 808 |

* Ground surface elevation 614 m amsl.

*3.5.4.2 $CO_2$ Injection Parameters*

The ASLMA Model for the project used a Broom Creek $CO_2$ injection rate that matched the simulation scenario. A single injector is placed at the center of the ASLMA Model grid at an x,y-location of (0,0) in the coordinate reference system. The ASLMA Model requires the $CO_2$ injection rate to be converted into an equivalent-volume injection of formation fluid in units of cubic meters per day. Microsoft Excel Visual Basic for Applications (VBA) functions were used to estimate the $CO_2$ density from the storage reservoir pressure and temperature, which resulted in an estimated density, shown in Table 3-6. The $CO_2$ mass injection rate and $CO_2$ density are then used to derive the daily equivalent-volume injection rate, shown in Table 3-6.

**Table 3-3. $CO_2$ Density and Injection Parameters Used for the ASLMA Model**

| $CO_2$ Density, Reservoir Conditions, kg/m$^3$ | Injection Period | Injection Rate, m$^3$ per day | Injection Period, years |
|---|---|---|---|
| 580 | 1 | 944 | 20 |

*3.5.4.3 Hypothetical Leaky Wellbore*

In the project area, few wellbores are known to exist that penetrate the primary seal of the Broom Creek storage reservoir. However, for heuristic, “what-if” scenario modeling, which is needed to generate the data for delineating a risk-based AOR, a single hypothetical leaky wellbore is inserted into the ASLMA Model at 1, 2, …, 100 km from the $CO_2$ injection well. The pressure buildup in the storage reservoir at each distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 12-year injection period, provides the data set needed to derive the risk-based AOR.

Published ranges for the effective permeability of a leaky wellbore (Figure 3-17) have included an “open wellbore” with an effective permeability as high as $10^{-5}$ m$^2$ ($10^{10}$ mD) to values more representative of leakage through a wellbore annulus of $10^{-12}$ to $10^{-10}$ m$^2$ ($10^3$ to $10^5$ mD) (Watson and Bachu, 2008, 2009; Celia and others, 2011). Carey (2017) provides probability distributions for the effective permeability of potentially leaking wells at $CO_2$ storage sites and estimated a wide range from $10^{-20}$ to $10^{-10}$ m$^2$ ($10^{-5}$ to $10^5$ mD). For the project Broom Creek ASLMA Model, the effective permeability of the leaky wellbore is set to $10^{-16}$ m$^2$ (0.1 mD), which is a conservative (highly permeable) value near the top of the published range for the effective permeability of potentially leaking wells at $CO_2$ storage sites (Figure 3-17).

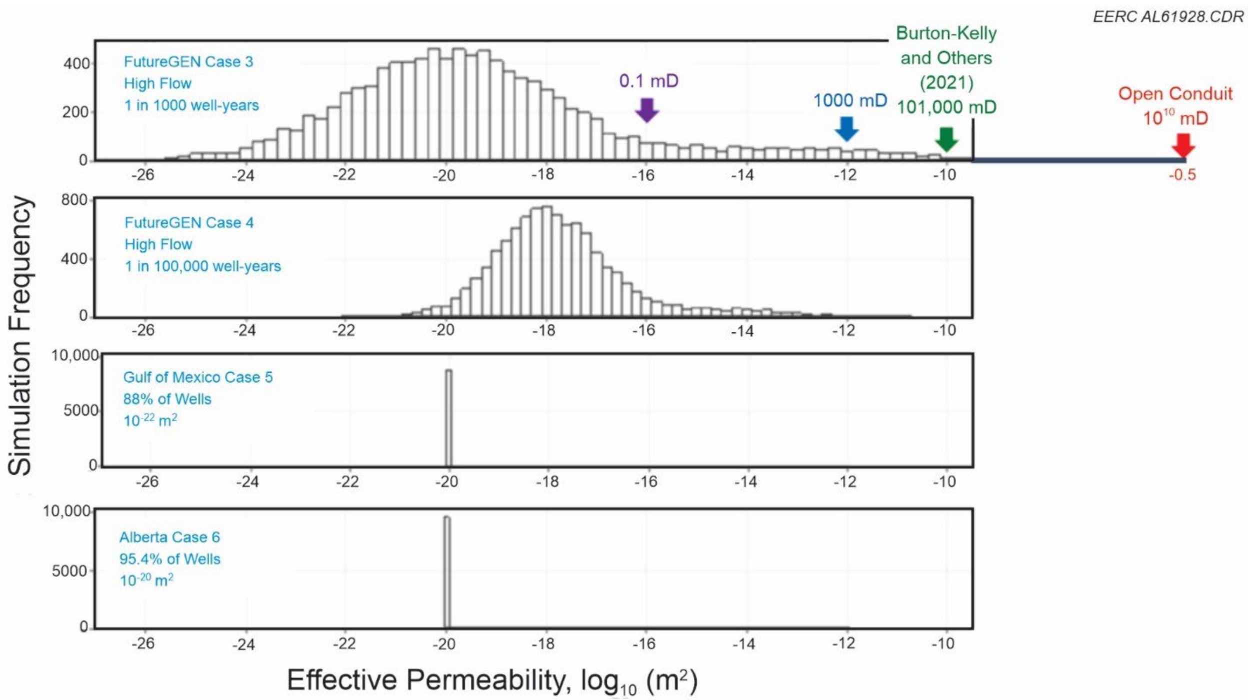



Figure 3-17. Histograms describing the expected frequency of leaky wellbore effective permeabilities under different scenarios. The ASLMA Model used for AOR delineation used a value of approximately 0.1 mD (constructed from data presented by Carey [2017]).

The current work uses the ASLMA Model Type 1 feature (focused leakage only) for the nominal model response, which makes the conservative assumption that the aquitards are impermeable. This assumption prevents the pressure from diffusing into the overlying aquitards, resulting in a greater pressure buildup in the storage reservoir and a commensurately greater amount of formation fluid vertically migrating from the storage reservoir through the leaky wellbore. The conservative assumption of Model Type 1 rather than Model Type 3 (coupled focused and diffuse leakage) provides an added level of protection to the delineation of a risk-based AOR by projecting a larger pressure buildup in the storage reservoir than a scenario in which pressure is allowed to dissipate through the upper seal and, therefore, a greater leakage of formation fluid up the leaky wellbore.

### *3.5.4.4 Saline Aquifer Thief Zone*

As shown in Table 3-5, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the primary seal above the storage reservoir and USDW (Aquifer 3, Fox Hills Formation). Formation fluid migrating up a leaky wellbore that is open to Aquifer 2 will preferentially flow into Aquifer 2, and the continued flow up the wellbore and into the USDW will be reduced. Therefore, the presence of Aquifer 2 may act as a thief zone and reduces the potential for formation fluid impacts to the groundwater.

The thief zone phenomenon was described by Nordbotten and others (2004) as an "elevator model" by analogy with an elevator full of people on the main floor, who then get off at various floors as the elevator moves up, such that only very few people ride all the way to the top floor. The term “thief zone” is also used in the oil and gas industry to describe a formation encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 (Inyan Kara Formation) were run and evaluated to quantify the effect of a thief zone on the risk-based AOR.

#### *3.5.4.5 Aquifer- and Aquitard-Derived Properties*

The ASLMA Model assumes homogeneous properties within each hydrostratigraphic unit (Table 3-5). For each unit shown in Table 3-5, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: hydraulic conductivity (HCON) and specific storage (SS). Average porosity and permeability values were derived as follows: Broom Creek, from distributed properties in the geologic model; Inyan Kara, from MAG 1 core data and regional well logs; and Fox Hills, from regional well log data. Porosity is represented as an arithmetic mean and permeability as a geometric mean value within each hydrostratigraphic unit (excluding nonsandstone rock types).

VBA functions included in the ASLMA Workbook are used to estimate the formation fluid density and viscosity from the aquifer or aquitard pressure, temperature, and salinity inputs, which are then used to estimate the HCON and SS. The estimated reference case HCON for the storage reservoir (Aquifer 1), thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-5. Details about the HCON and SS derivations are provided in supporting information for Burton-Kelly and others (2021).

### ***3.5.5 Risk-Based AOR Results***

#### *3.5.5.1 Relating Pressure Buildup to Incremental Leakage with ASLMA Model and Compositional Simulation*

Figure 3-18 shows the relationship between the maximum pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 (USDW) for scenarios with and without the leaky wellbore open to Aquifer 2 (thief zone). In the case where the leaky wellbore is closed to Aquifer 2, there is no incremental leakage to Aquifer 2. The curvilinear relationship between pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 is used to predict the incremental leakage from the pressure buildup map produced by the compositional simulation of the geocellular model. The average simulated pressure buildup in the reservoir is represented by a raster (grid) map of pressure buildup values. For each raster value (grid cell map location), the relationship between pressure buildup and incremental leakage (Figure 3-18) is used to predict incremental leakage using a linear interpolation between the points making up the curve. The estimated cumulative leakage potential from Aquifer 1 to Aquifer 3 along a hypothetical leaky wellbore without injection occurring (i.e., leakage due to natural overpressure) and no thief zone is shown in Table 3-7.

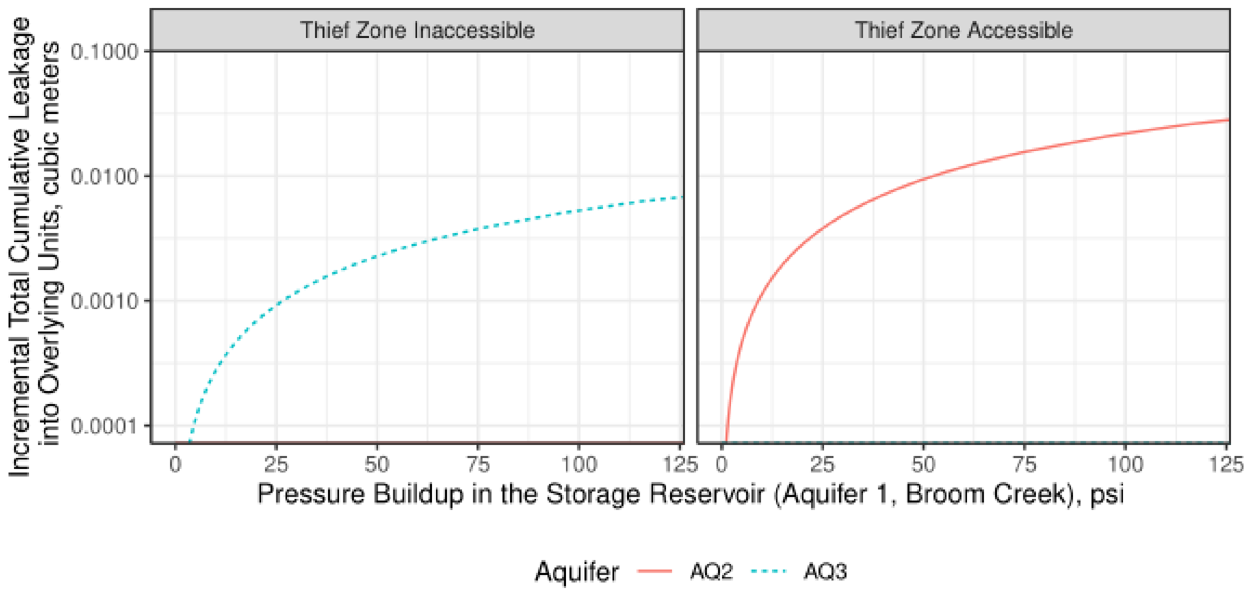



Figure 3-18. Relationship between pressure buildup (x-axis, psi) in the storage reservoir (Aquifer 1, Broom Creek) and incremental total cumulative leakage (y-axis, $m^3$) into Aquifer 2 (thief zone, Inyan Kara, red solid line) and Aquifer 3 (USDW, Fox Hills, dashed blue line). In the left-hand scenario, the leaky wellbore is closed to Aquifer 2 (Inyan Kara), so all flow is from the storage reservoir to the USDW. In the right-hand scenario, the leaky wellbore is open to Aquifer 2 (Inyan Kara), so the vast majority of flow is from the storage reservoir to the thief zone, and the curve showing flow into the USDW is not visible on this plot.

#### *3.5.5.2 Incremental Leakage Maps and AOR Delineation*

The pressure buildup–incremental leakage relationship, shown in Figure 3-18, results in the incremental leakage map, shown in Figure 3-19, which show the estimated total cumulative incremental leakage potential from a hypothetical leaky well into Aquifer 3 (USDW) over the entire injection period if the hypothetical leaky wellbore is not open to the thief zone.

The final step of the risk-based AOR workflow is to apply a threshold criterion to the incremental leakage maps to delineate a risk-based AOR. For the Broom Creek Formation injection at the project site, a threshold of 1 $m^3$ of potential incremental flow into the Fox Hills Formation USDW along a hypothetical leaky wellbore over the injection period is established. A value of 1 $m^3$ is the lowest meaningful value that can be produced by the ASLMA Model; although the model can return smaller values, they likely represent statistical noise. This potential incremental flow threshold is greater than all calculated potential incremental flow values described by the curve in Figure 3-18. The maximum vertically averaged change in pressure in the storage reservoir at the end of the simulated injection period and the corresponding flow over the injection period are shown in Table 3-7. This pressure is below the potential incremental flow threshold of 1 $m^3$. Therefore, the storage reservoir pressure buildup is not a deciding factor in determining the AOR extent.

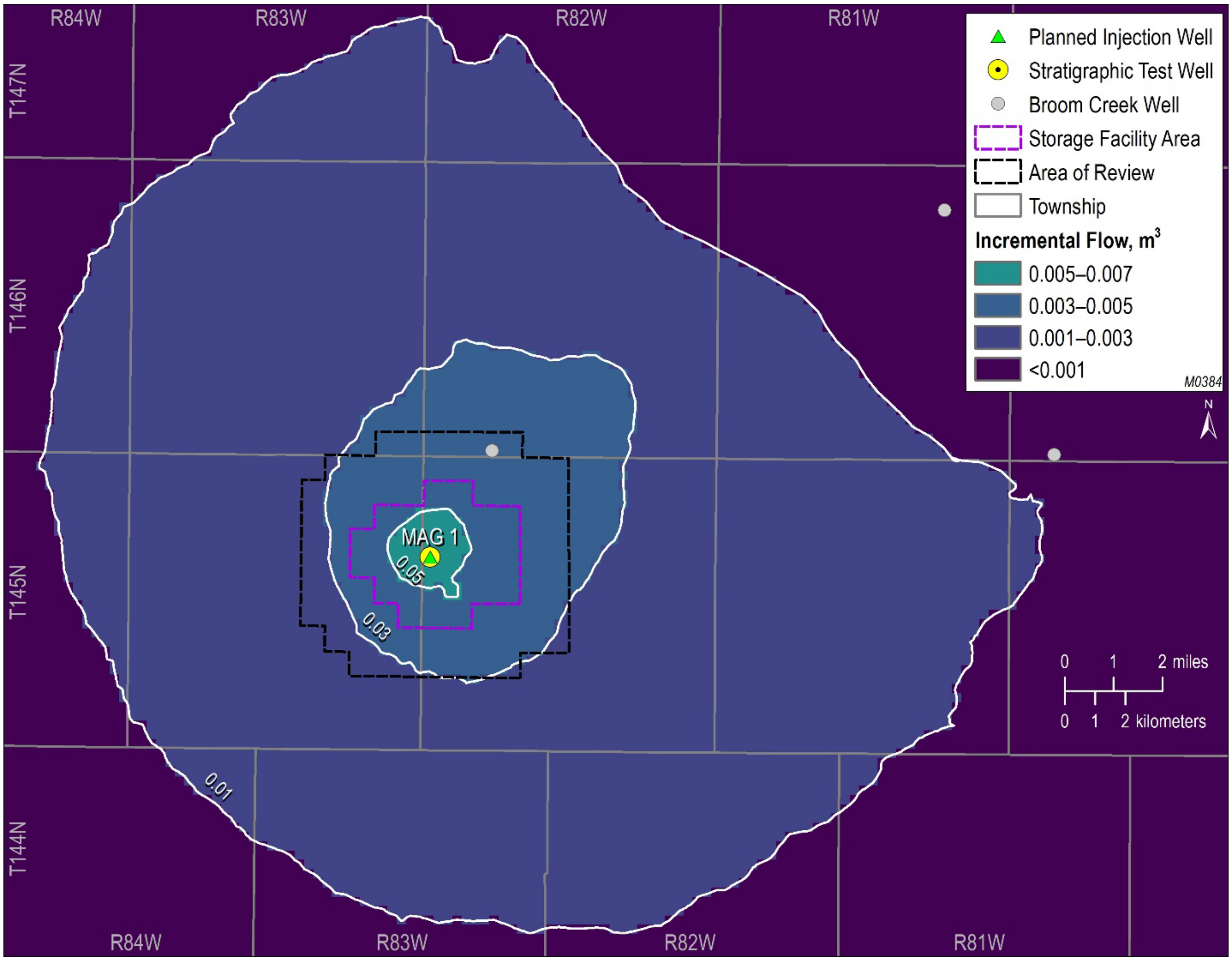



Figure 3-19. Map of potential incremental leakage into the USDW at the end of 20 years of $CO_2$ injection for the scenario where the hypothetical leaky wellbore is closed to Aquifer 2 (thief zone).

**Table 3-4. Summary Results from the Risk-Based AOR Method of Estimated Potential Cumulative Leakage after 20 years of Injection and No Thief Zone**

| | |
|---|---|
| Maximum Vertically Averaged Change in Reservoir Pressure, psi | 113.2 |
| Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Without* Injection, $m^3$ | 0.019 |
| Maximum Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Attributable to* Injection, $m^3$ | 0.005 |

The assumptions and calculations used to determine the risk-based AOR at the project site incorporate at least four safety factors for the protection of groundwater resources. If the ASLMA Model has resulted in an underestimation of the amount of potential leakage over the injection period, such underestimation is likely to be mitigated by:

- The statistical overestimation of hypothetical leaky wellbore permeability compared to known and estimated values in the literature—A more statistically likely hypothetical leaky wellbore permeability would be lower and allow less flow into the USDW.

- The lack of communication between the hypothetical leaky wellbore and Inyan Kara Formation, which would act as a thief zone—A real leaky wellbore would likely communicate with the Inyan Kara Formation, which would receive much, if not all, of the brine leaked from the storage reservoir.

- The low density of known legacy wellbores in the Blue Flint project area—$CO_2$ injection is proposed to occur in an area with few available leakage pathways.

- The continued overpressurized nature of the Broom Creek Formation with respect to overlying saline aquifers, over relatively short (e.g., 50-year) timescales, overpressurized aquifers with leakage pathways would demonstrate a change in upward flow rate and corresponding pressure (Oldenburg and others, 2016).

The risk-based method detailed above shows that storage reservoir pressure buildup is not necessary for determining AOR because the potential incremental flow into the USDW is below the identified threshold of 1 $m^3$. Therefore, the AOR is delineated as the storage facility area plus a 1-mile buffer (Figure 3-20). Figure 3-21 illustrates the land use within the AOR.

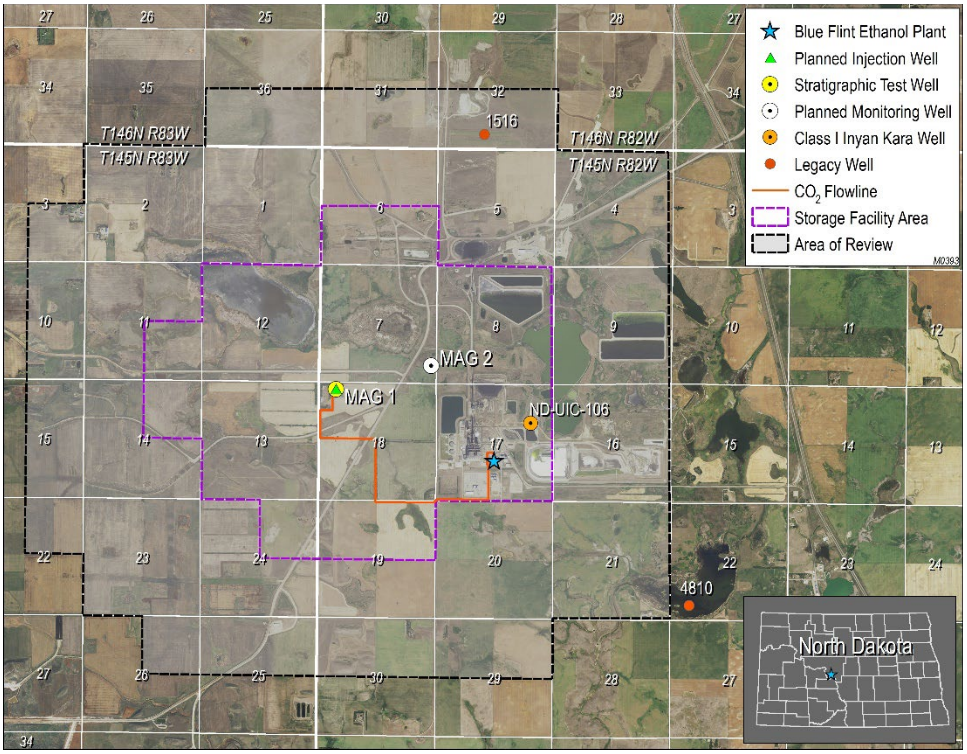



Figure 3-20. Final AOR estimations of the project storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple polygon) and AOR (black polygon). Orange circles represent legacy oil and gas wells near the storage facility area.

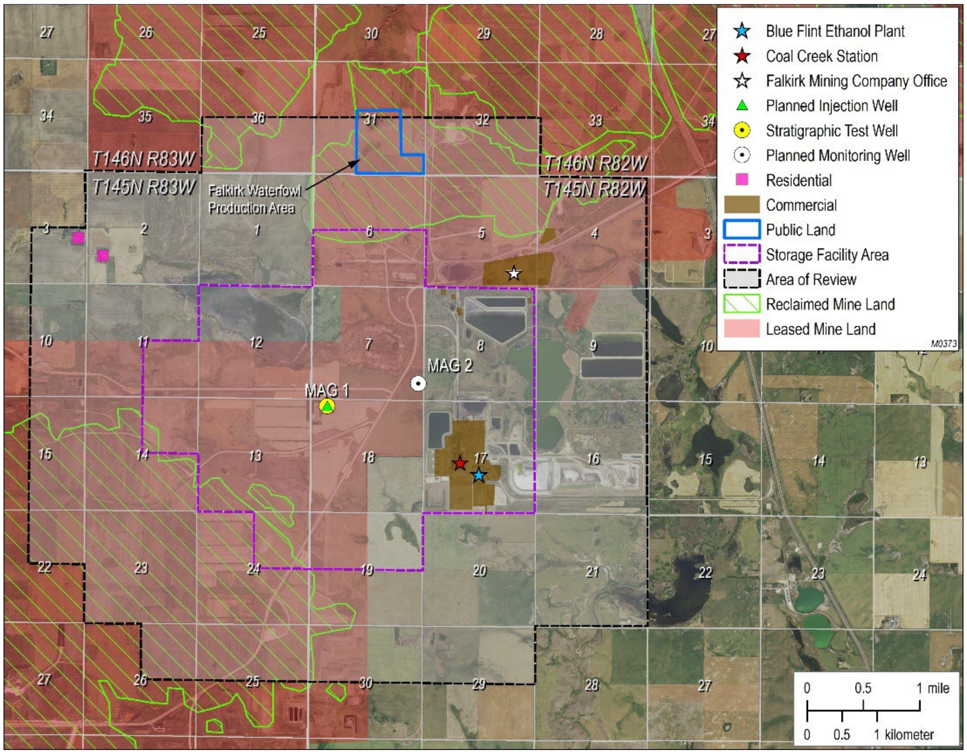



Figure 3-21. Land use in and around the AOR of the project storage facility.

## 3.6 References

Avci, C.B., 1994, Evaluation of flow leakage through abandoned wells and boreholes: Water Resour. Res., v. 9, p. 2565–2578.

Bandilla, K.W., Kraemer, S.R., and Birkholzer, J.T., 2012, Using semi-analytical solutions to approximate the area of potential impact for carbon dioxide injection: Int. J. Greenhouse Gas Control, v. 8, p. 196–204.

Birkholzer, J., Cihan, A., and Bandilla, K., 2014, A tiered area-of-review framework for geologic carbon sequestration (2013): Greenhouse Gases Sci. Technol. v. 4, no. 1, p. 20–35. https://doi.org/10.1002/ghg.1393.

Birkholzer, J.T., Zhou, Q., and Tsang, C.F., 2009, Large-scale impact of $CO_2$ storage in deep saline aquifers: a sensitivity study on pressure response in stratified systems: Int. J. Greenhouse Gas Control, v. 3, p. 181–194.

Bosshart, N.W., Pekot, L.J., Wildgust, N., Gorecki, C.D., Torres, J.A., Jin, L., Ge, J., Jiang, T., Heebink, L.V., Kurz, M.D., Dalkhaa, C., Peck, W.D., and Burnison, S.A., 2018, Best practices for modeling and simulation of $CO_2$ storage: Plains $CO_2$ Reduction (PCOR) Partnership Phase III, Task 9, Deliverable D69 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592.

Burton-Kelly, M.E., Azzolina, N.A., Connors, K.C., Peck, W.D., Nakles, D.V. and Jiang, T., 2021, Risk-based area of review estimation in overpressured reservoirs to support injection well storage facility permit requirements for $CO_2$ storage projects: Greenhouse Gas Sci Technol, v. 11, p. 887–906. https://doi.org/10.1002/ghg.2098.

Carey, J.W., 2017, Probability distributions for effective permeability of potentially leaking wells at $CO_2$ sequestration sites: NRAPTRS-III-021-2017, NRAP Technical Report Series, Morgantown, West Virginia, U.S. Department of Energy National Energy Technology Laboratory, p. 28.

Celia, M.A., Nordbotten, J.M., Court, B., Dobossy, M., and Bachu, S., 2011, Field-scale application of a semi-analytical model for estimation of $CO_2$ and brine leakage along old wells: Int. J. Greenhouse Gas Control, v. 5, no. 2, p. 257–269.

Cihan, A., Zhou, Q., and Birkholzer, J.T., 2011, Analytical solutions for pressure perturbation and fluid leakage through aquitards and wells in multilayered aquifer systems: Water Resour. Res., v. 47, p. W10504. doi:10.1029/2011WR010721.

Cihan, A., Birkholzer, J.T., and Zhou, Q., 2012, Pressure buildup and brine migration during $CO_2$ storage in multilayered aquifers: Ground Water. doi:10.1111/j.1745–6584.2012.00972.x.

Computer Modelling Group, 2019, GEM user guide.

Nicot, J.P., Oldenburg, C.M., Bryant, S.L., and Hovorka, S.D., 2008, Pressure perturbations from geologic carbon sequestration—area-of-review boundaries and borehole leakage driving forces: Proceedings of the 9th International Conference of Greenhouse Gas Control Technologies, Washington, USA, November.

Nordbotten, J., Celia, M., and Bachu, S., 2004, Analytical solutions for leakage rates through abandoned wells: Water Resour. Res., v. 40, p. W04204. doi:10.1029/2003WR002997.

North Dakota Industrial Commission, 2021, NDIC Case No. 29029 – draft permit, fact sheet, and storage facility permit application: Minnkota Power Cooperative supplemental information, Grand Forks, North Dakota, www.dmr.nd.gov/oilgas/GeoStorageofCO2.asp (accessed 2021).

Oldenburg, C.M., Cihan, A., Zhou, Q., Fairweather, S., and Spangler, L.J., 2014, Delineating area of review in a system with pre-injection relative overpressure: Energy Procedia, v. 63, p. 3715–3722.

Oldenburg, C.M., Cihan, A., and Zhou, Q., 2016, Geologic carbon sequestration injection wells in overpressured storage reservoirs—estimating area of review: Greenhouse Gases Sci. Technol., v. 6, no. 6. Raven, K.G., Lafleur, D.W., and Sweezey, R.A., 1990, Monitoring well into abandoned deep-well disposal formations at Sarnia, Ontario: Canadian Geotechnical J., v. 27, no. 1, p. 105–118. https://doi.org/10.1139/t90-010.

Schlumberger, 2020, Petrel 2019.5: Petrel E&P Software Platform.

U.S. Environmental Protection Agency, 2013, Geologic sequestration of carbon dioxide underground injection control (UIC) program Class VI well area of review evaluation and corrective action guidance: EPA 816-R-13-005, May.

Watson, T.L., and Bachu, S., 2008, Identification of wells with high $CO_2$-leakage potential in mature oil fields developed for $CO_2$-enhanced oil recovery, *in* SPE Improved Oil Recovery Symposium: Tulsa, Oklahoma, USA, 19–23 April, SPE 11294.

Watson, T.L., and Bachu, S., 2009, Evaluation of the potential for gas and $CO_2$ leakage along wellbores*:* SPE Drilling & Completion, v. 24, no. 1, p. 115–126.

White, S., Carroll, S., Chu, S., Bacon, D., Pawar, R., Cumming, L., Hawkins, J., Kelley, M., Demirkanli, I., Middletone, R., Sminchak, J., and Pasumarti, A., 2020, A risk-based approach to evaluating the area of review and leakage risks at $CO_2$ storage sites: Int. J. Greenhouse Gas Control, v. 93, p. 102884.

Wyllie, M.R.J., and Rose, W.D., 1950, Some theoretical considerations related to the quantitative evaluation of the physical characteristics of reservoir rock from electrical log data: J. Pet. Tech., v. 189.

# 4.0 AREA OF REVIEW

## 4.0 AREA OF REVIEW

## 4.1 Area of Review (AOR) Delineation

### *4.1.1 Written Description*

North Dakota geologic storage of $CO_2$ regulations require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water [USDW] may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of $CO_2$ and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase $CO_2$ plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the MAG 1 well (NDIC File No. 37833) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-5]).

NDAC § 43-05-01-05(1)(b)(3) requires "[a] review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate $CO_2$ injection activities and associated pressure front (Figure 4-1), the resulting AOR for the geologic storage project is delineated as being 1 mile from the SFP boundary. This extent ensures compliance with existing state regulations.

All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-20 and 4-2) by a professional engineer pursuant to NDAC § 43-05-01-05(1)(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected $CO_2$ from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 through 4-4, and Figure 4-3 through Figure 4-5).

An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC uncovered no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.

This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05(1)(a) and (b) and § 43-05-01-05.1(2), such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05(1)(a) and (b)(3) and § 43-05-01-05.1(2). Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1.

### *4.1.2 Supporting Maps*

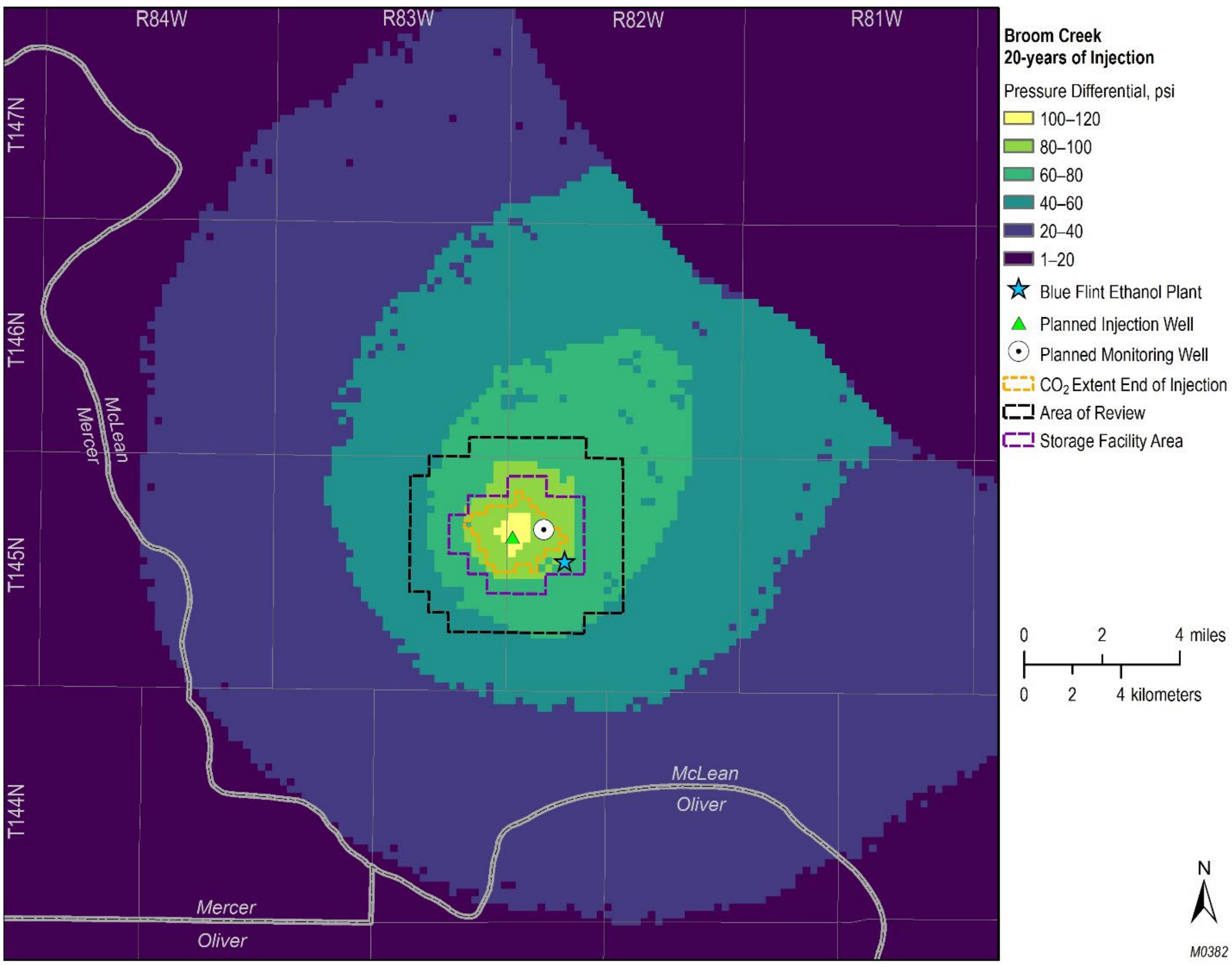



Figure 4-1. Pressure map showing the maximum subsurface pressure influence associated with $CO_2$ injection in the Broom Creek Formation. Shown is the $CO_2$ plume extent after end of injection, the storage facility area, and the 1-mile AOR boundary in relation to the maximum subsurface pressure influence.

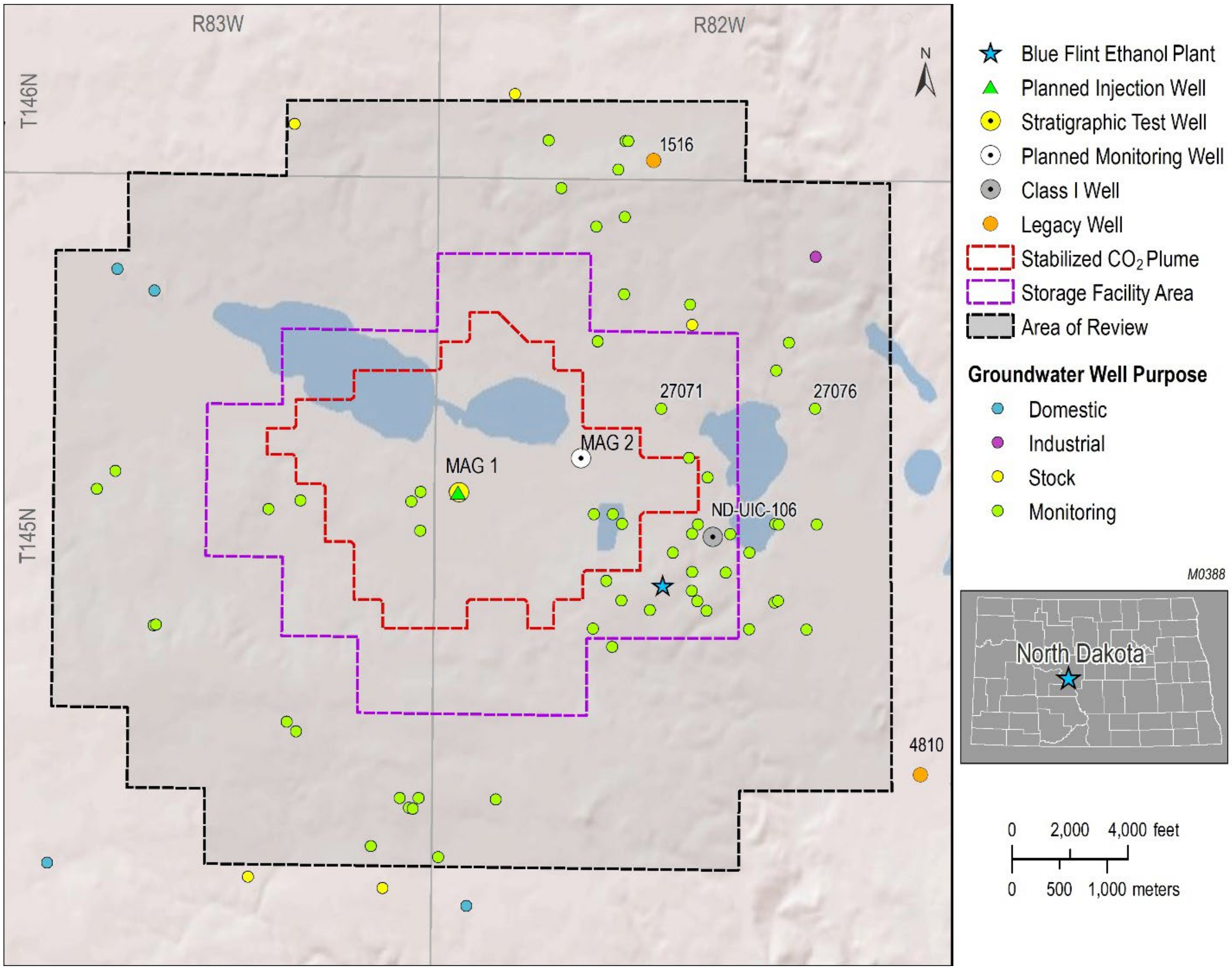



Figure 4-2. AOR map in relation to nearby groundwater wells. Shown are the stabilized $CO_2$ plume extent postinjection (dashed red boundary), storage facility area (dashed purple boundary), and 1-mile AOR (dashed black boundary). All groundwater wells in the AOR are identified above. All observation/monitoring wells shown are shallow groundwater wells associated with the mine activities. No springs are present in the AOR.

**Table 4-1. Investigated and Identified Surface and Subsurface Features (Figures 3-20, 4-1 and 4-2)**

| Surface and Subsurface Features | Investigated and Identified (Figures 4-1–4-5) | Investigated But Not Found in AOR |
|---|---|---|
| Producing (active) Wells | | X |
| Abandoned Wells | X | |
| Plugged Wells or Dry Holes | X | |
| Deep Stratigraphic Boreholes | X | |
| Subsurface Cleanup Sites | | X |
| Surface Bodies of Water | X | |
| Springs | | X |
| Water Wells | X | |
| Mines (surface and subsurface) | X | |
| Quarries | | X |
| Subsurface Structures (e.g., coal mines) | | X |
| Location of Proposed Wells | X | |
| *Location of Proposed Cathodic Protection Boreholes | | X |
| Any Existing Aboveground Facilities | X | |
| Roads | X | |
| State Boundary Lines | | X |
| County Boundary Lines | | X |
| Indian Boundary Lines | | X |
| Other Pertinent Surface Features | X | |

* There are no plans for cathodic protection for the injection well (MAG 1).

## 4.2 Corrective Action Evaluation

**Table 4-2. Wells in AOR Evaluated for Corrective Action***

| Well File No. | Operator | Well Name | Spud Date | Surface Casing o.d., inches | Surface Casing Seat, ft | Long-String Casing o.d., inches | Long-String Casing seat, inches | Hole Direction | TD, ft | TVD, ft | Status | Plug Date | TWN | RNG | Section | Qtr/Qtr | County | Corrective Action Needed |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1516** | H. Hanson Oil Syndicate | Ellen Samuelson 1 | 9/14/1957 | 10.75 | 462 | Openhole | | Vertical | 6,600 | 6,600 | P&A | 10/18/1957 | 146N | 82W | 32 | SE/SW | McLean | No |
| **ND-UIC-106**** | Great River Energy | Well #1 | 10/10/2014 | 11.75 | 1,232 | 7 | | 3531 | Vertical | 4,046 | 4,046 | NA | 145N | 82W | 17 | SE/NE | McLean | No |
| **4810** | W. H. HUNT TRUST ESTATE | Wallace O. Gradin 1 | 12/1/1969 | 8.625 | 233 | Openhole | | Vertical | 4240 | 4240 | P&A | 12/6/1969 | 145N | 82W | 22 | SW/SW | McLean | No |

* TD is total depth, and TVD is true vertical depth.
**ND-UIC-106 is classified as a Class I disposal well.

**Table 4-3. Ellen Samuelson 1 (NDIC File No. 1516) Well Evaluation**

Well Name: Ellen Samuelson 1 (NDIC File No. 1516)

| Cement Plugs | | | | |
|---|---|---|---|---|
| Number | Interval, ft | | Thickness, ft | Volume, sacks |
| 1 | 5,940 | | | 20 |
| 2 | 5,480 | | | 20 |
| 3 | 4,730 | | | 20 |
| 4 | 3,670 | | | 20 |
| 5 | Base of Surface | | | 25 |
| 6 | Top of Surface | | | 5 |

* Data and information are provided from well-plugging report found in NDIC database.

| Formation | | Cement Plug Class G* |
|---|---|---|
| Name | Estimated Top, ft | |
| 10¾" Casing Shoe | 462 | Cement Plug 5 isolates the 10¾" casing shoe. |
| Pierre | 1,055 | |
| Mowry | 3,355 | Top of Inyan Kara Formation is not covered by cement. However, Cement Plug 4 isolates Dakota Group. |
| Inyan Kara | 3,655 | |
| Swift | 3,912 | |
| Kibby Lime | 5,272 | Cement Plugs 3, 2, and 1 isolate the formations below the Broom Creek Formation. |
| | | |

Spud Date: 9/14/1957
Total Depth: 6,600 (Mission Canyon Formation)

Surface Casing: 10¾" casing set at 462, cement to surface with 200 sacks Class G cement.

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Ellen Samuelson 1 well (NDIC File No. 1516) will not be in contact with the $CO_2$ plume, and pressure increase in the Broom Creek Formation at this well location is predicted to be approximately 76 psi. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled and plugged.

* Cement Type is assumed to be Class G as no cement type was on file.

**Table 4-4. Well #1 (ND-UIC-106) Well Evaluation**

Well Name: Well #1 (ND-UIC-106)

| Formation | | Cement Plug Remarks |
|---|---|---|
| Name | Estimated Top, ft | |
| 11¾" Casing Shoe | 1,232 | Production Casing Cement isolates the 11¾" casing shoe. |
| Pierre | 1,110 | |
| Mowry | 3,190 | |
| Inyan Kara | 3,531 | |
| Production Casing | 3,531 | |

Spud Date: 10/10/2014
Total Depth: 4,046 (Inyan Kara Formation)

Surface Casing: 11¾" casing set at 1,232, cement to surface

Production Casing: 7" casing set at 3,531, cement to surface

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Well #1 well (ND-UIC-106) will not be in contact with the $CO_2$ plume, and the well does not penetrate the Broom Creek Formation. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled above the Broom Creek Formation.

Additional information: Well #1 is classified as a Class I disposal well for nonhazardous waste injection into the Inyan Kara.

**Table 4-5. Wallace O. Gradin 1 (NDIC File No. 4810) Well Evaluation**

Well Name: Wallace O. Gradin 1 (NDIC File No. 4810)

| Cement Plugs | | | | |
|---|---|---|---|---|
| Number | Interval, ft | | Thickness, ft | Volume, sacks |
| 1 | 3181 | 3249 | 68 | 20 |
| 2 | 1152 | 1220 | 68 | 20 |
| 3 | 204 | 270 | 66 | 20 |
| 4 | 0 | 16 | 16 | 5 |

*Data and information are provided from well-plugging report found in NDIC database.

| Formation | | Cement Plug Remarks |
|---|---|---|
| Name | Estimated Top, ft | |
| 8.625" Casing Shoe | 233 | 8-5/8" J-55, 20# casing. Set at 233'. Cemented w/ 135 sks 8-5/8", 20# casing capacity is 2.7328 lin ft per ft^3. Plug 1 at surface and plug 2 at surface casing shoe. |
| Pierre | 915 | Plug 3 is 200' into the Pierre Fm. Fox Hills Formation isolated by plug 2 and 3. |
| Mowry | 3195 | Cement Plug 3 isolates the uppermost Inyan Kara porosity. |
| Newcastle | 3249 | |
| Swift | 3745 | |
| Rierdon | 4083 | Well file reports TD in Piper Formation. |

Spud Date: 12/01/1969
Total Depth: 4083 ft

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Wallace O. Gradin 1 (NDIC File No. 4810) well will not be in contact with the $CO_2$ plume, and the well does not penetrate the Broom Creek Formation. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled above the Broom Creek Formation.

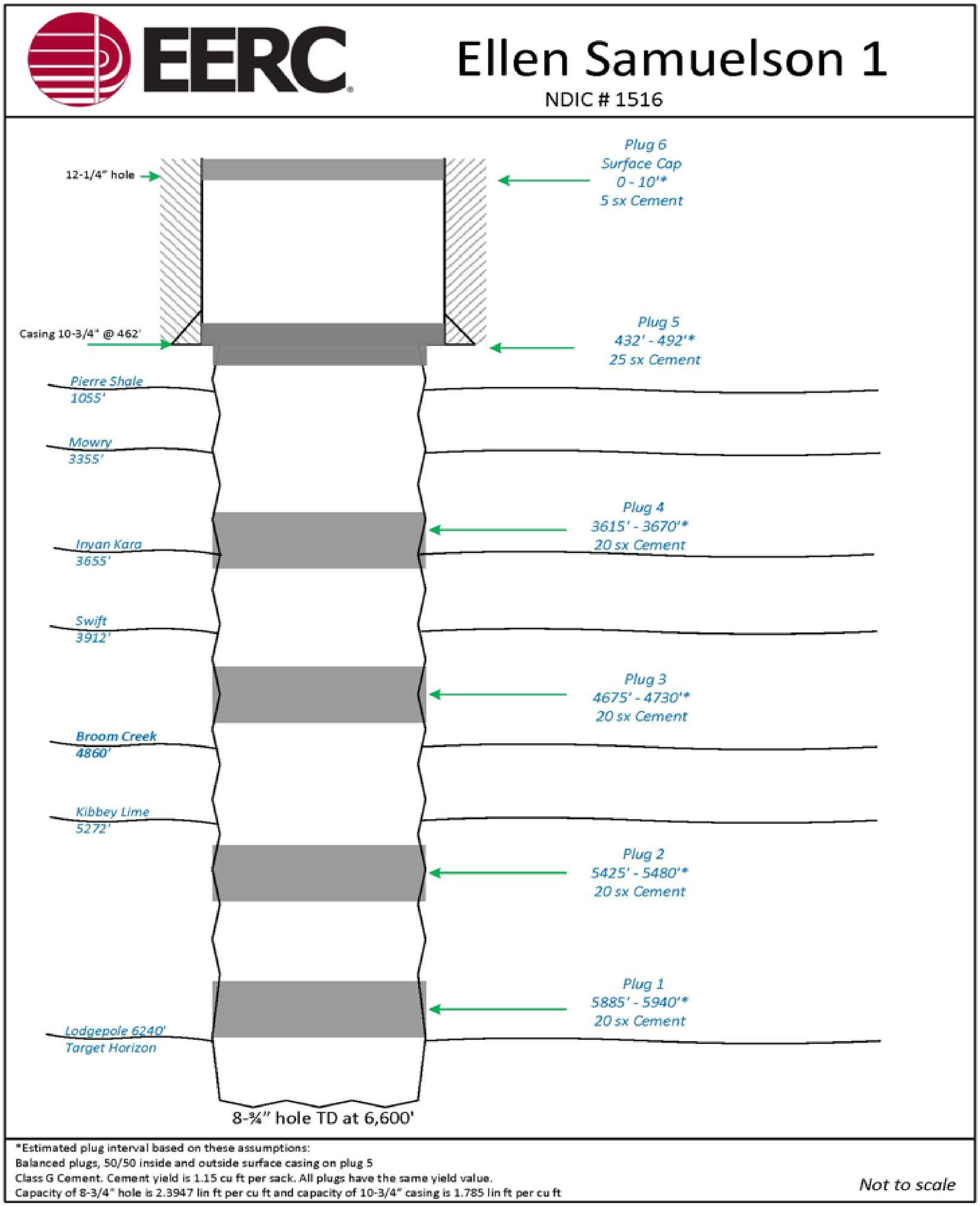



Figure 4-3. Ellen Samuelson 1 (NDIC File No. 1516) well schematic showing the location of cement plugs.

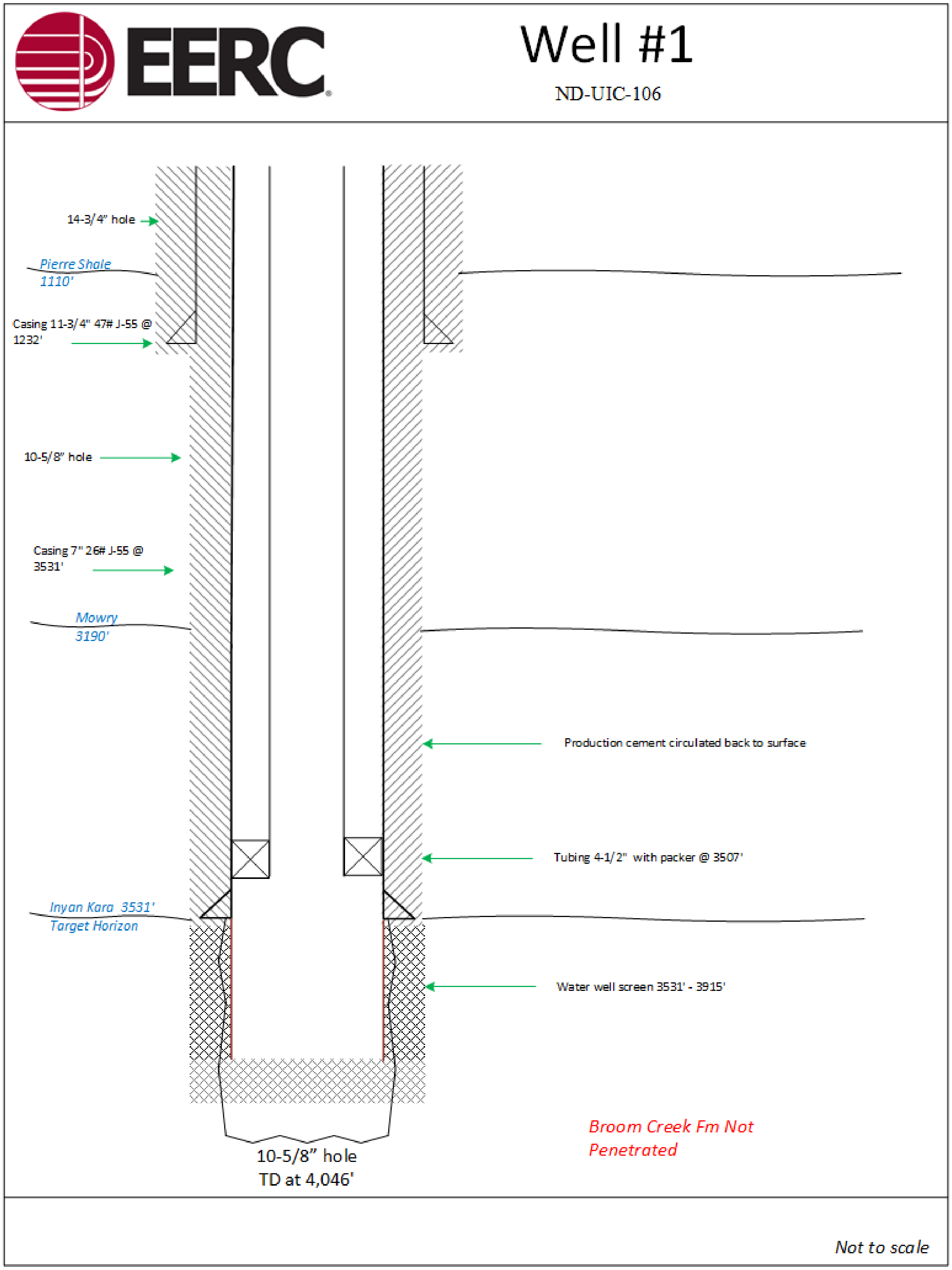



Figure 4-4. Well #1 (ND-UIC-106) well schematic.

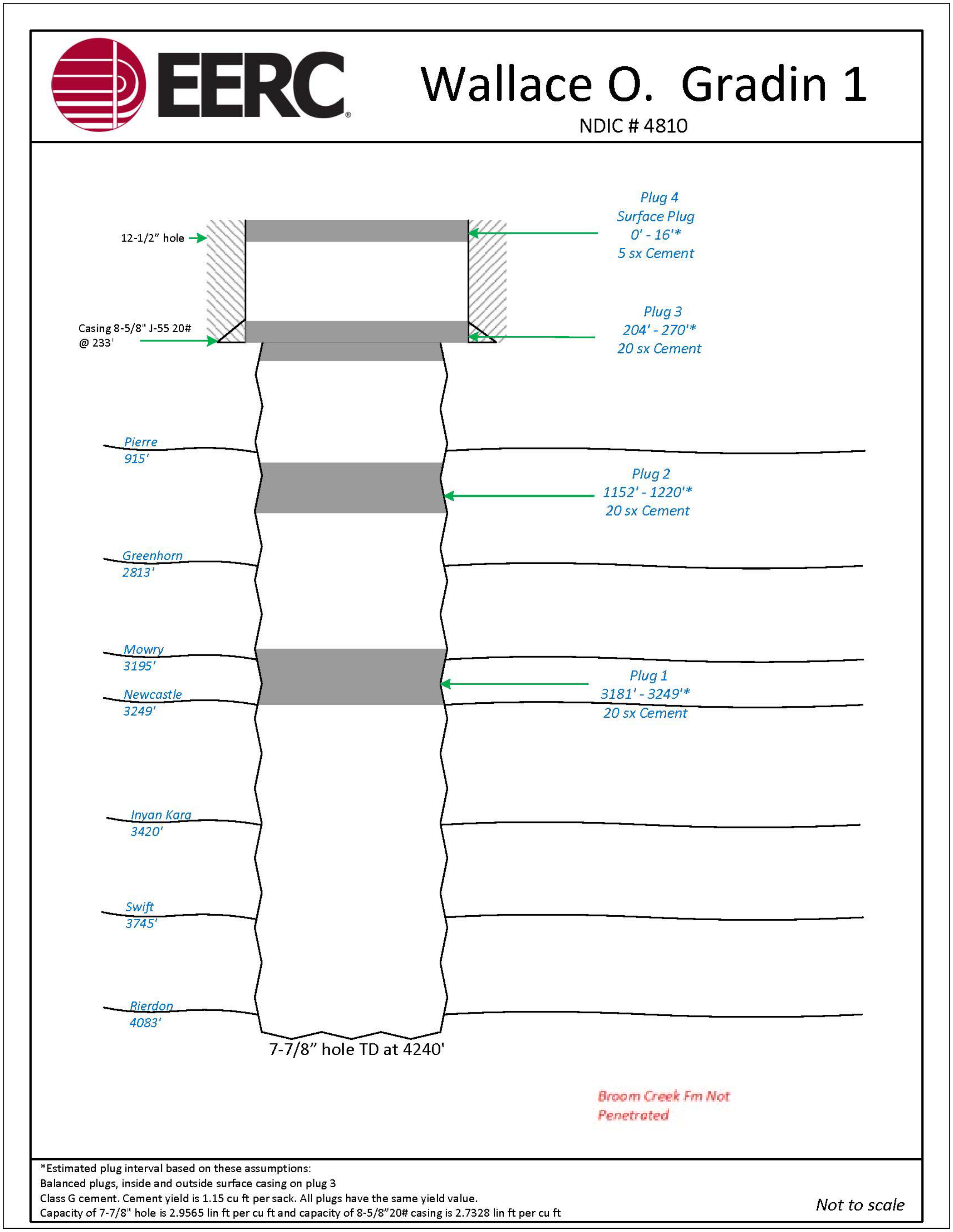



Figure 4-5. Wallace O. Gradin 1 (NDIC File No. 4810) well schematic showing the location of cement plugs.

## 4.3 Reevaluation of AOR and Corrective Action Plan

BFE will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place no later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following:

- Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date will be identified.
- Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and the computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and the operational data to be utilized as the basis for that update will be identified.
- The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.

## 4.4 Protection of USDWs (Broom Creek Formation)

### *4.4.1 Introduction of USDW Protection*

The primary confining zone and additional overlying confining zones geologically isolate the Fox Hills and Hell Creek Formations, the lowest USDW in the area of investigation from the underlying injection zone. The Spearfish Formation is the primary confining zone for the injection zone with additional confining layers above, geologically isolating all USDWs from the injection zone. The uppermost confining layer is the Pierre Formation, an impermeable shale in excess of 1,000 ft thick, providing an additional seal for all USDWs in the region.

### *4.4.2 Geology of USDW Formations*

The hydrogeology of western North Dakota is composed of several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 4-6). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1,000 and 1,500 ft thick (Thamke and others, 2014).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formation; the overlying Cannonball, Tongue River, and Sentinel Butte Formation of the Tertiary Fort Union Group; and the Tertiary Golden Valley Formation (Figure 4-7). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the area of investigation (Bluemle, 1971).

The lowest USDW in the area of investigation is the Fox Hills Formation, which together with the overlying Hell Creek Formation, is a confined aquifer system. The Hell Creek Formation is a poorly consolidated unit composed of interbedded sandstone, siltstone, and claystones with occasional carbonaceous beds, all fluvial origin. The underlying Fox Hills Formation is interpreted

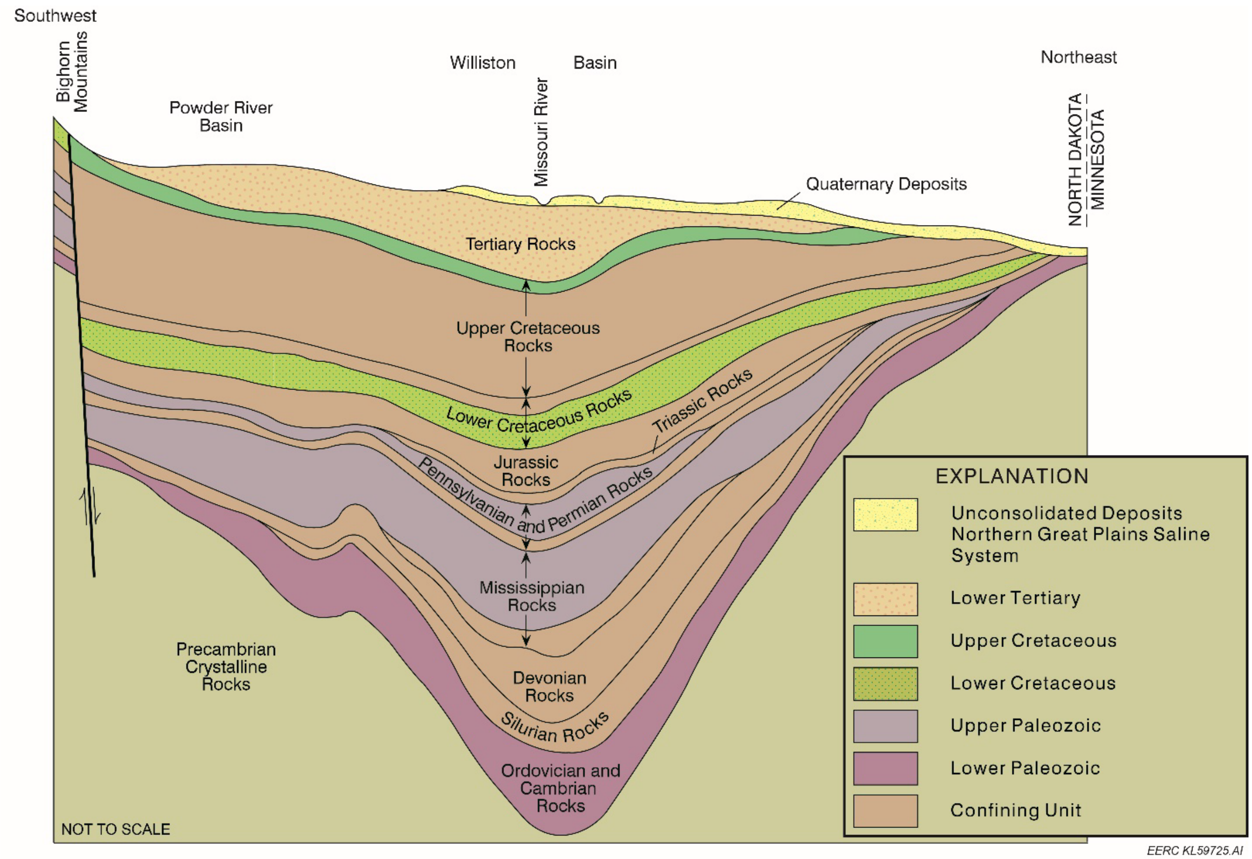



Figure 4-6. Major aquifer systems of the Williston Basin.

as interbedded nearshore marine deposits of sand, silt, and shale deposited as part of the final Western Interior Seaway retreat (Fischer, 2013). The Fox Hills Formation in the area of investigation is approximately 700 to 900 ft deep and 350–450 ft thick (Bluemle, 1971). The structure of the Fox Hills and Hell Creek Formations follows that of the Williston Basin, dipping gently toward the center of the basin to the northwest of the area of investigation (Figure 4-8).

The Pierre Shale is a thick, regionally extensive shale unit which forms the lower boundary of the Fox Hills–Hell Creek system, also isolating all overlying freshwater aquifers from the deeper saline aquifer systems. The Pierre Shale is a dark gray to black marine shale and is typically over 1,000 ft thick in the area of investigation (Thamke and others, 2014).

| Era | Period | Group | Formation | Freshwater Aquifer(s) Present |
|---|---|---|---|---|
| Cenozoic | Quaternary | | Glacial Drift | Yes |
| | Tertiary | | Golden Valley | Yes |
| | | Fort Union | Sentinel Butte | Yes |
| | | | Tongue River | Yes |
| | | | Cannonball | Yes |
| Mesozoic | Cretaceous | | Hell Creek | Yes |
| | | | Fox Hills | Yes |
| | | | Pierre | No |
| | | Colorado | Niobrara | No |
| | | | Carlile | No |
| | | | Greenhorn | No |
| | | | Belle Fourche | No |

Figure 4-7. Upper stratigraphy of McLean County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Bluemle, 1971).

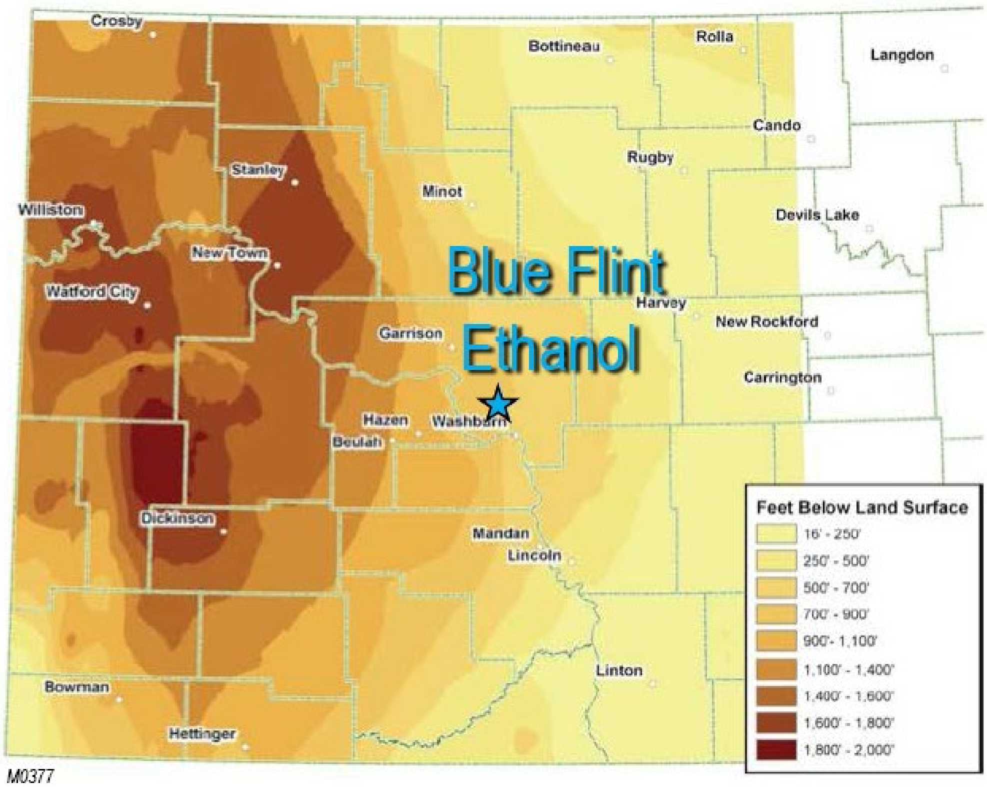



Figure 4-8. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

### *4.4.3 Hydrology of USDW Formations*

The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the northeast (Figure 4-9). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,500 ppm (Klausing, 1974). Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Honeyman, 2007). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering.

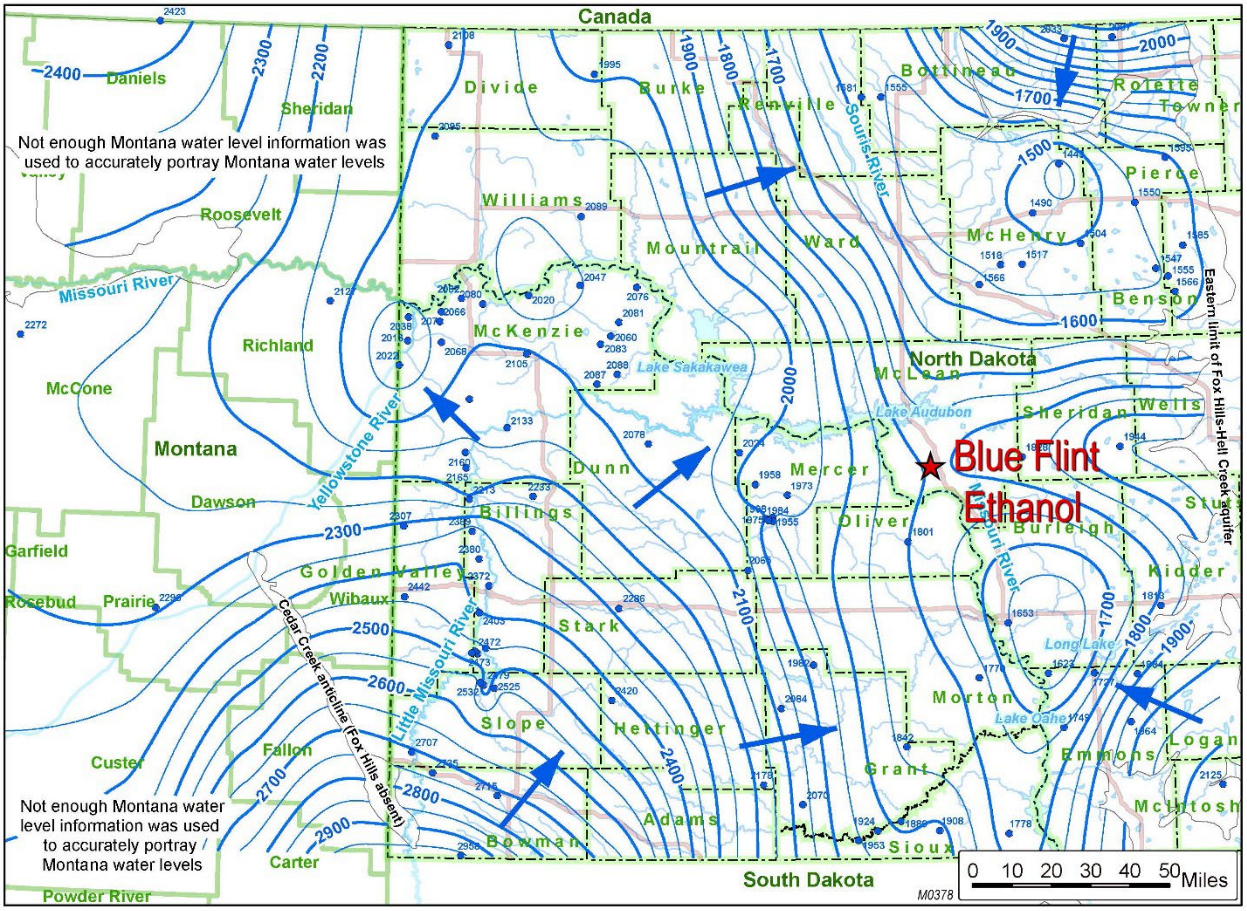



Figure 4-9. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central McLean County (modified from Fischer, 2013).

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the area of investigation. A cross section of these formations is presented in Figure 4-10. The upper formations are generally used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. The basal sandstone member of the Tongue River is persistent and a reliable source of groundwater in the region. The thickness of this basal sand ranges from approximately 50 to 200 ft and can be found at a depth of approximately 550 ft. Tongue River groundwaters are generally sodium bicarbonate with a TDS of approximately 1,000 ppm (Klausing, 1974).

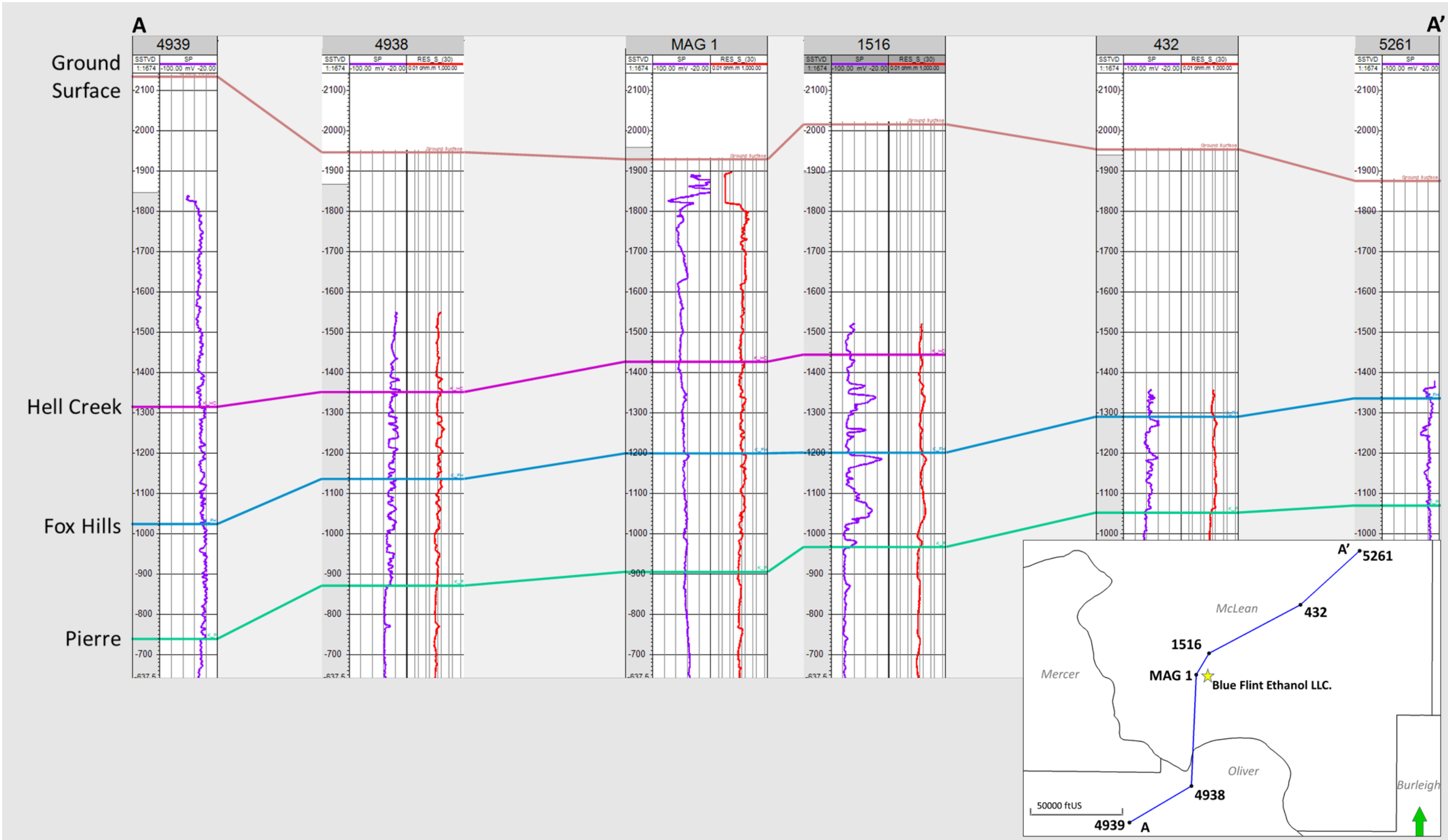



Figure 4-10. Southwest to northeast cross section of the major aquifer layers in McLean County. The black dots on the inset map represent the locations of the six wells used to create the cross section. The wells are labeled with their designation at the top of the cross section.

The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. The upper Sentinel Butte is approximately 150 ft thick in the area of investigation (Hemish, 1975). TDS concentrations in the Sentinel Butte Formation are approximately 1,000 ppm (Klausing, 1974). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers.

### *4.4.4 Protection for USDWs*

The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AOR. The injection zone (Broom Creek Formation) and the lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and siltstone formations (Figure 4-6). The primary seal of the injection zone is the Permian-aged Spearfish and the Jurassic-aged Piper, Rierdon, and Swift Formations, all of which overlie the Broom Creek Formation. These formations will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation.

Above the Swift is the confined saltwater aquifer system of the Inyan Kara Formation, which extends across much of the Williston Basin. The Inyan Kara will be monitored for temperature and pressure changes in the injection well (MAG 1) and the monitoring well (MAG 2). The Pierre Formation is the thickest shale formation in the area of investigation and the primary geologic barrier between the USDWs and the Inyan Kara. The geologic strata overlying the injection zone consist of multiple impermeable rock layers that are free of transmissive faults or fractures and provide adequate isolation of the USDWs from $CO_2$ injection activities in the area of investigation.

## 4.5 References


Bluemle, John P., 1971, Geology of McLean County, North Dakota: Theses and Dissertations.

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 No. 54.

Hemish, L., 1975, Stratigraphy of the upper part of the Fort Union Group in Southwestern Mclean County, North Dakota.

Honeyman, R.P., 2007, Pressure head fluctuations of the Fox Hills-Hell Creek Aquifer in the Knife River Basin, North Dakota.

Klausing, R., 1974, Ground-water resources of McLean County, North Dakota: U.S. Geological Survey, www.swc.nd.gov/info_edu/reports_and_publications/county_groundwater_studies/pdfs/Mclean_Part_III.pdf (accessed July 2022).

Thamke, J.N., LeCain, G.D., Ryter, D.W., Sando, R., and Long, A.J., 2014, Hydrogeologic framework of the uppermost principal aquifer systems in the Williston and Powder River structural basins, United States and Canada: U.S. Geological Survey Groundwater Resources Program Scientific Investigations Report 2014–5047.

# 5.0 TESTING AND MONITORING PLAN

## 5.0 TESTING AND MONITORING PLAN

This testing and monitoring plan includes 1) a plan for analyzing the injected $CO_2$ stream, 2) leak detection and corrosion-monitoring plans for surface facilities and well components of the $CO_2$ injection system, 3) a well-testing and logging plan, and 4) an environmental monitoring and verification plan to ensure $CO_2$ is stored safely and permanently in the storage reservoir. The combination of the foregoing monitoring efforts is used to verify that the geologic storage project is operating as permitted and is protecting all USDWs. Another goal of this testing and monitoring plan is to establish baseline conditions at the Blue Flint $CO_2$ storage project site, including but not limited to the injection and monitoring wellbores, soil gas, groundwaters from surface to lowest USDW (Fox Hills Aquifer[1]), and the storage reservoir complex. An overview of the testing and monitoring efforts is provided in Table 5-1.

Blue Flint will review this testing and monitoring plan at a minimum of every 5 years to ensure the monitoring and verification strategies remain appropriate for demonstrating containment of $CO_2$ in the storage reservoir and conformance with predictive modeling and simulations. If needed, amendments to this testing and monitoring plan (e.g., technologies applied, frequency of testing, etc.) will be submitted to the NDIC for approval. Results of pertinent analyses and data evaluations conducted as part of this testing and monitoring plan will be compiled and reported as required.

Details of the individual efforts for this testing and monitoring plan are provided in the remainder of this section and in Section 6 (Postinjection Site Care and Facility Closure Plan).

[1] The Fox Hills Aquifer underlying the Blue Flint $CO_2$ storage project site and western North Dakota is a confined aquifer system that does not receive measurable flow from overlying aquifers or the underlying Pierre Shale. The overlying confining layer in the Hell Creek Formation comprises impermeable clays, and the underlying Pierre Shale serves as the lower confining layer (Trapp and Croft, 1975). Recharge occurs hundreds of miles to the southwest in the Black Hills of South Dakota, where the corresponding geologic layers are exposed at the surface. Flow within the aquifer is to the east with a rate on the order of single feet per year. Groundwater in the Fox Hills Aquifer at the Blue Flint $CO_2$ storage project site is geochemically stable, as it is isolated from its source of recharge and does not receive other sources of recharge (Fischer, 2013). The aquifer itself is a quartz-rich sand and is not known to contain reactive mineralogy. Minimal geochemical variation can be expected to occur across the site, attributable to minor variations in the geologic composition of the aquifer sediments.

**Table 5-1. Overview of Blue Flint's Testing and Monitoring Plan**

| | Monitoring Type | Equipment/Testing | Target Area |
|---|---|---|---|
| Surface Monitoring | $CO_2$ Stream Analysis | Compositional and isotopic testing | $CO_2$ liquefaction outlet at the capture facility |
| | Surface Facilities Leak Detection | $CO_2$ detection stations on flowline risers and wellheads, pressure gauges, dual flowmeters, and SCADA* system | Flowline from capture facility to injection wellhead |
| | Flowline Corrosion Detection | Flow-through corrosion coupon system | Flowline from capture facility to injection wellhead |
| | Continuous Recording of Injection Pressure, Rate, and Volume | Surface pressure-temperature gauges and flowmeters installed at the capture facility and injection wellhead with shutoff alarms | Surface-to-reservoir ($CO_2$ injection well) |
| Wellbore Monitoring | External Mechanical Integrity Testing | Ultrasonic imaging tool (USIT) or electromagnetic casing inspection log and distributed temperature sensing (DTS) | Well infrastructure |
| | Internal Mechanical Integrity Testing | Tubing-conveyed pressure–temperature gauges, surface digital gauges, and annulus pressure testing | Well infrastructure |
| | Downhole Corrosion Detection | Flow-through corrosion coupon system | Well materials |
| Environmental Monitoring | Atmosphere | $CO_2$ detection stations outside injection wellhead enclosure and gas analyzer sample blanks at soil gas profile stations | Well pads |
| | Near Surface | Compositional and isotopic analysis of soil gas and shallow groundwater down to the Fox Hills | Vadose zone and lowest USDW |
| | Above-Zone Monitoring Interval | DTS and pulsed-neutron logs (PNLs) over the Inyan Kara and Spearfish intervals | Downhole tubing and casing strings |
| | Direct Reservoir | DTS, PNLs, tubing-conveyed bottomhole pressure-temperature-(BHP/T) gauges, and pressure falloff testing | Storage reservoir |
| | Indirect Reservoir | Time-lapse 2D seismic and surface seismometer stations | Entire storage complex |

* Supervisory control and data acquisition.

## 5.1 $CO_2$ Stream Analysis

Prior to injection, Blue Flint determined the chemical content of the captured $CO_2$ stream via laboratory testing performed by Salof, Ltd. The chemical content is 99.98% dry $CO_2$ (by volume) and 0.02% other chemical components, as specified in Table 5-2. The $CO_2$ stream will be sampled at the liquefaction outlet quarterly and analyzed using methods and standards generally accepted by industry to determine its chemical and physical characteristics, including composition, corrosiveness, temperature, and density.

| Table 5-2. Chemical Content of the captured $CO_2$ | |
|---|---|
| **Chemical Content** | **Volume %** |
| Carbon Dioxide | 99.98 |
| Water, Oxygen, Nitrogen, Hydrogen Sulfide, $C_2^+$, and Hydrocarbons | Trace amounts of each (0.02 total) |
| Total | 100.00 |

## 5.2 Surface Facilities Leak Detection Plan

The purpose of this leak detection plan is to monitor the surface facilities from the liquefaction outlet to the injection wellsite during the operational phase of the Blue Flint $CO_2$ storage project. Figure 5-1 is a map showing the surface facilities layout. Figure 5-2 illustrates a generalized flow diagram of surface connections from the liquefaction outlet to the MAG 1 injection wellsite.

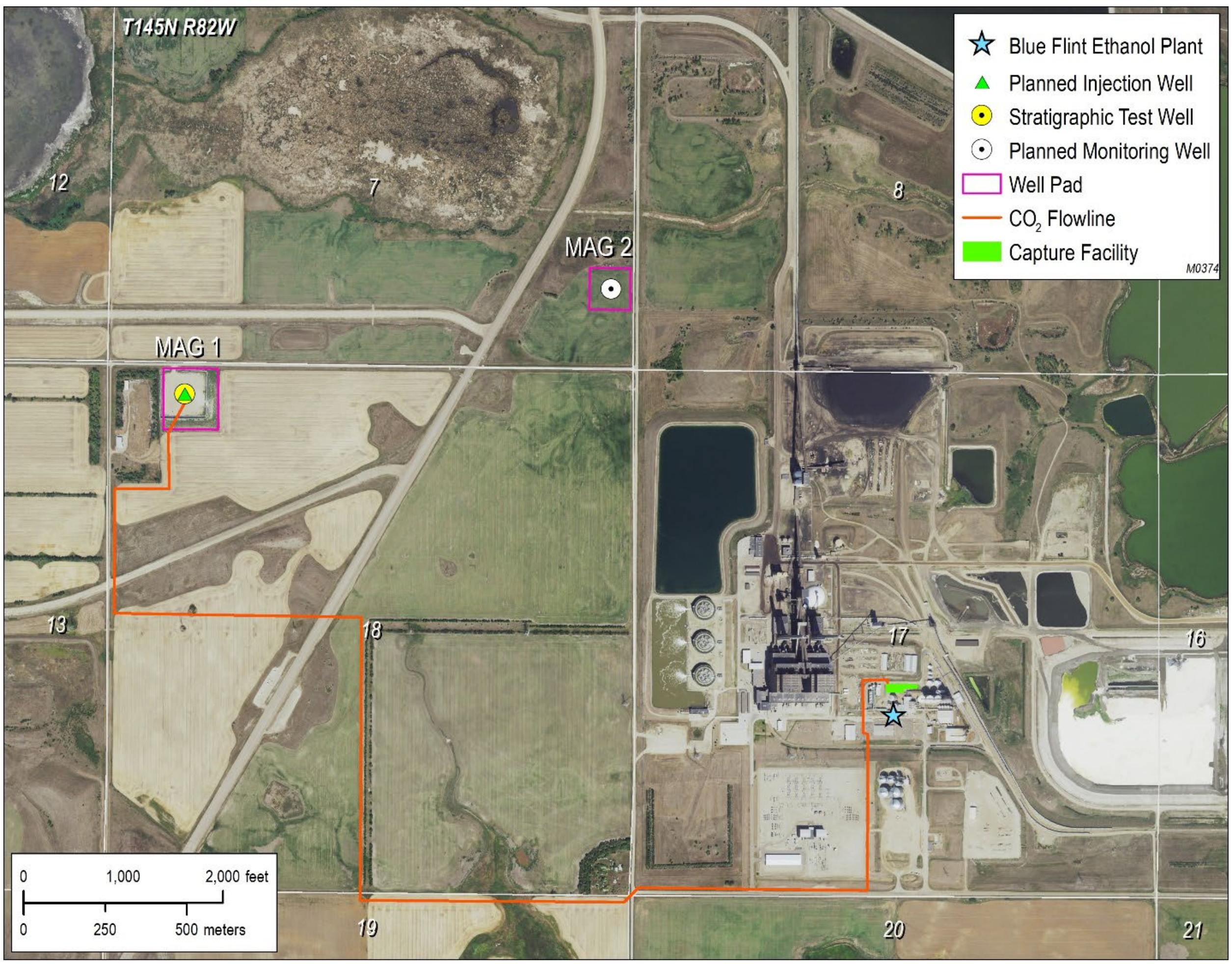



Figure 5-1. Site map showing the surface facilities layout for the Blue Flint $CO_2$ storage project.

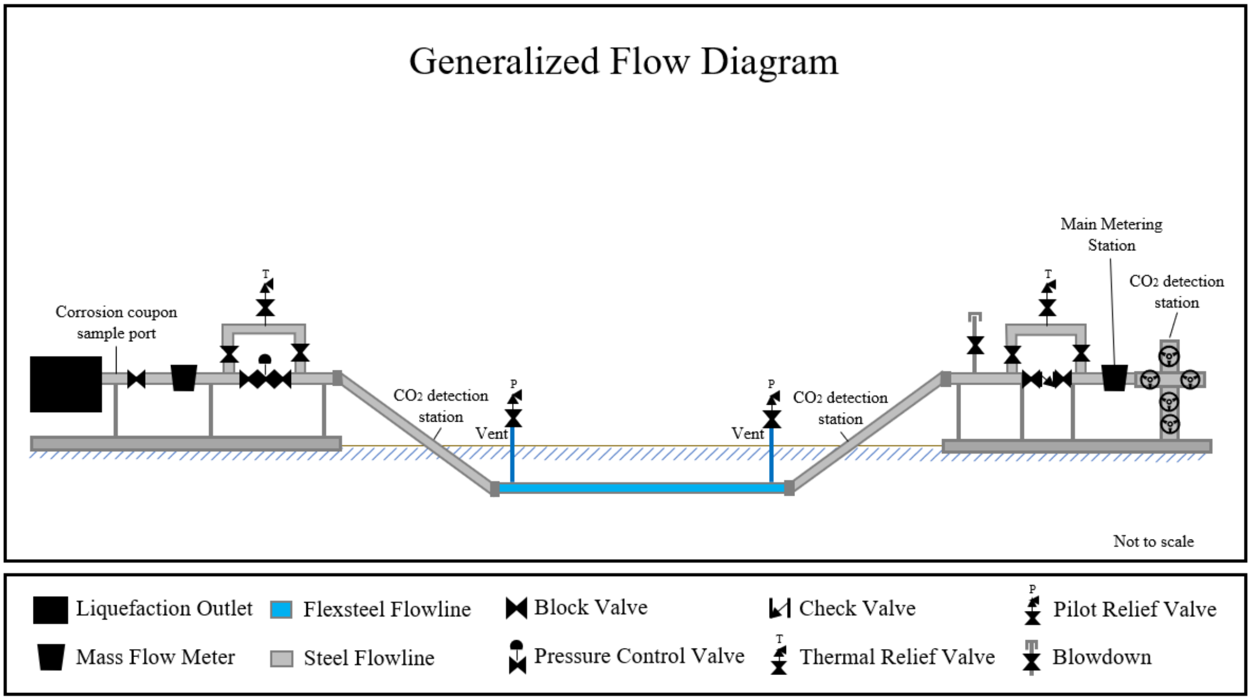



Figure 5-2. Diagram of surface connections and major components of the CCS system from the liquefaction outlet to the MAG 1 wellsite.

Surface components of the injection system, including the flowline and $CO_2$ injection wellhead, will be monitored with leak detection equipment. The flowline will be monitored continuously via dual flowmeters located at the liquefaction outlet and near the wellhead for performing mass balance calculations. The flowline will also be regularly inspected for any visual or auditory signs of equipment failure and monitored continuously with one pressure gauge at the capture facility outlet and one at the wellhead. $CO_2$ detection stations will be located on the flowline risers and the $CO_2$ injection wellhead. The leak detection equipment will be integrated with automated warning systems that notify Blue Flint's operations center, giving the operator the ability to remotely close the valves in the event of an anomalous reading.

Performance targets designed for the Blue Flint $CO_2$ storage project to detect potential leaks in the flowline are provided in Table 5-3. The performance targets are dependent upon the actual performance of instrumentation (e.g., pressure gauges) and the SCADA system (described further in Attachment A-1 of Appendix C), which uses software to track the status of the flowline in real time by comparing live pressure and flow rate data to a comprehensive predictive model. The performance targets assume a flow rate of approximately 550 metric tons of $CO_2$ per day. An alarm will trigger on the SCADA system if a volume deviation of more than 1% is registered.

**Table 5-3. Performance Targets for Detecting Leaks in Surface Equipment with SCADA**

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

* Thousand standard cubic feet per day.

$CO_2$ detection stations will be mounted on the inside of the wellhead enclosures to detect any potential indoor leaks. An additional $CO_2$ detection station will be mounted outside the injection wellhead enclosure to detect any potential atmospheric leaks at the wellsite. The stations can detect $CO_2$ concentrations as low as 2% by volume and have an integrated alarm system for increases of from 0% to 0.4% and 0.4% to 0.8% by volume. The stations are further described in Appendix C (Attachment A-2).

Field personnel will have multigas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multigas detectors will primarily monitor $CO_2$ levels in workspace atmospheres.

Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be made available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

### 5.3 Flowline Corrosion Prevention and Detection Plan

The purpose of this corrosion prevention and detection plan is to monitor the flowline and well materials during the operational phase of the project to ensure that all materials meet the minimum standards for material strength and performance.

#### *5.3.1 Corrosion Prevention*

The chemical composition of the $CO_2$ stream is highly pure and dry (Table 5-2), and the target moisture level for the $CO_2$ stream is estimated to be up to 12 ppm by volume. These factors help to prevent corrosion of the surface facilities. In addition, the flowline construction materials will be $CO_2$-resistant in accordance with API 17J (2017) requirements. The flowline will be constructed using FlexSteel, a 3-layer flexible steel pipe product. The inner and outer layers contain a $CO_2$-resistant polyethylene liner, and the middle layer comprises reinforcing steel. FlexSteel product specifications can be found in Appendix C (Attachment A-3).

#### *5.3.2 Corrosion Detection*

The flowline will use the corrosion coupon method to monitor for corrosion throughout the operational phase of the project, focusing on the loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. A coupon sample port will be located near the liquefaction outlet, and sampling will occur quarterly during the first year of injection and once a year thereafter. The process that will be used to conduct each coupon test is described in Appendix C under Section 1.3.

### 5.4 Wellbore Mechanical Integrity Testing

External mechanical integrity in the $CO_2$ injection well (MAG 1) and deep monitoring well (MAG 2) will be demonstrated with the following:

1) A USIT (described in Attachment A-4 of Appendix C), in combination with variable-density and cement bond logs will be used to establish the baseline external mechanical integrity behind the injection casing. The USIT log or another casing inspection logging (CIL) method will be run during well workovers but no less than once every 5 years.

2) DTS installed in the long-string casing will continuously monitor the temperature profile of the wellbore from the storage reservoir to surface.

3) A baseline temperature log will be run in case DTS fails and temperature log data are needed in the future.

Internal mechanical integrity in the MAG 1 and MAG 2 will be demonstrated with the following:

1) A tubing-casing annulus pressure test prior to injection and during well workovers but no less than once every 5 years. The tubing-casing annulus pressure will be continuously monitored with a surface digital pressure gauge at each wellhead.

2) The tubing pressure will be continuously monitored with tubing-conveyed BHP/T gauges and a digital surface pressure gauge.

3) USIT or another method may be used during well workovers but no less than once every 5 years.

Table 5-4 summarizes the foregoing mechanical integrity testing plan. Blue Flint will conduct an initial annulus pressure test to confirm the mechanical integrity of the tubing-casing annulus and confer with NDIC to confirm the annulus pressure test procedure satisfies all regulatory requirements prior to conducting the test.

**Table 5-4. Overview of Blue Flint's Mechanical Integrity Testing Plan**

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

* The baseline monitoring effort has been initiated as of the writing of this permit application.

## 5.5 Well Testing and Logging Plan

Table 5-5 describes the testing and logging plan developed for the MAG 1 wellbore (exclusive of any coring) to establish baseline conditions. Included in the table is a description of fluid sampling and pressure testing performed. The logging and testing plan for the MAG 2 wellbore will be the same as what is presented in Table 5-5, with the addition of a PNL but excluding dipole, elemental capture spectroscopy (ECS), fluid swab, and FMI. Table 5-4 and Table 5-6 (see Section 5.7) detail the frequency with which logging data will be acquired and in which wellbores throughout the operational period of the project.

Wellbore data collected from MAG 1 have been integrated with the geologic model and to inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations (Section 3). The simulated $CO_2$ plume extents informed the timing and frequency of the application of the direct and indirect monitoring methods of the testing and monitoring plan.

**Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore**

| OH/CH* Depth, ft | Logging/Testing | Justification | NDAC § 43-05-01 |
|---|---|---|---|
| **Surface Section** | | | |
| OH 1340-0 | Triple combo (resistivity, bulk density, density and neutron porosity, GR, caliper, and spontaneous potential [SP]) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. | 11.2(1)(b)(1) |
| CH 1260-0 | Ultrasonic, casing collar locator (CCL), variable-density log (VDL), GR, and temperature log | Identified cement bond quality radially. Interpreted minor cement channeling throughout several isolated intervals and determined good azimuthal cement coverage and zonal isolation. | 11.2(1)(b)(2) |
| **Intermediate Section** | | | |
| OH 4170-1334 | Triple Combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for enhanced geomodeling and predictive simulation of $CO_2$ injection into the interest zones to improve test design and interpretations. Generated core-log correlations. | 11.2(1)(c)(1) |
| OH 4170-1334 | Dipole sonic | Identified mechanical properties in intermediate section. | 11.2(1)(c)(1) |
| OH 4170-3070 | Dielectric scanner | Quantified petrophysical properties and salinity calculations within the intermediate zones (Inyan Kara Formation). Provided information on rock properties and fluid distribution as inputs for reservoir evaluation and management. | 11.2(4) |
| CH 4070-30 | Ultrasonic, CCL, VDL, GR, and temperature log | Identified cement bond quality radially. Interpreted good azimuthal cement coverage and casing condition. Evaluated the cement top and zonal isolation. | 11.2(1)(c)(2) |
| **Long-string Section** | | | |
| OH 7068-4163 | Triple combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. | 11.2(1)(c)(1) |
| OH 7556-4163 | Dipole sonic | Identified mechanical properties of the rock including stress anisotropy. Provided compression and shear waves for seismic tie in and quantitative analysis of seismic data. | 11.2(1)(c)(1) |
| OH 5250-4250 | Fullbore FMI | Verified no fracture networks exist in the Broom Creek Formation or confining layers to ensure safe storage of $CO_2$. | 11.2(1)(c)(1) |
| OH 4741 and 4735 | BHP/T survey | Measured Broom Creek Formation pressure and temperature in the wellbore. | 11.2(2) |
| OH 4740-4733 | Fluid swab | Collected fluid sample from the Broom Creek Formation for analysis. | 11.2(2) |
| CH** TBD | Ultrasonic, CCL, VDL, and GR | Will identify cement bond quality radially and determine azimuthal cement coverage. Will evaluate the cement top and zonal isolation. | 11.2(1)(b)(2) |

* OH/CH – openhole/cased-hole
** Planned activity at the time of writing this permit to be completed prior to injection.

## 5.6 Wellbore Corrosion Prevention and Detection Plan

To prevent corrosion of the well materials, the following preemptive measures will be implemented in the MAG 1 and MAG 2 wellbores: 1) cement in the injection well opposite the injection interval and extending 1850 feet uphole will be $CO_2$-resistant; 2) the well casing will also be $CO_2$-resistant from the bottomhole to a depth just above the Spearfish Formation (upper confining zone); 3) the well tubing (poly-lined) will be $CO_2$-resistant from the injection interval to surface; 4) the packer (Ni-Plated) will be $CO_2$-resistant; and 5) the packer fluid will be an industry standard corrosion inhibitor.

To detect possible signs of corrosion in the MAG 1 and MAG 2, corrosion coupon samples will be used which will be constructed from the well materials. The corrosion coupon method is described in Section 5.3.2 of this testing and monitoring plan. In addition, the USIT or an equivalent wall thickness or imaging tool (e.g., EM CIL) may also be considered for detecting corrosion in the MAG 1 and MAG 2 wellbores. The USIT (or equivalent tool) may be used during workovers but no less than every 5 years.

## 5.7 Environmental Monitoring Plan

To verify the injected $CO_2$ is contained in the storage reservoir and to protect all USDWs, multiple environments will be monitored.

The surface atmosphere environment will be monitored via air sampling at soil gas profile stations installed near the MAG 1 and MAG 2 and a $CO_2$ detection station installed outside the injection wellhead enclosure.

The near-surface environment will be monitored via soil gas profile stations, shallow groundwater wells, and one dedicated Fox Hills Formation (lowest USDW) monitoring well.

The deep subsurface environment, defined as the region from below the lowest USDW to the base of the storage reservoir, will be monitored with multiple methods, starting with the above-zone monitoring interval (AZMI) or the geologic interval from the Spearfish Formation to the Inyan Kara Formation. The AZMI will be monitored with DTS in the MAG 1 and MAG 2 as well as PNLs in the MAG 2 (further described in Attachment A-5 of Appendix C).

The storage reservoir will be monitored with both direct and indirect methods. Direct methods include DTS and BHP/T measurements in the MAG 1 and MAG 2, as well as PNLs in the MAG 2. Indirect methods include time-lapse seismic and passive seismicity. During injection operations, pressure falloff testing to demonstrate storage reservoir injectivity in the MAG 1 wellbore will be carried out at least once every 5 years. These efforts will provide additional assurance that surface and near-surface environments are protected and that the injected $CO_2$ is safely and permanently stored in the storage reservoir.

Table 5-6 summarizes the environmental baseline and operational monitoring plans for the Blue Flint $CO_2$ storage project. Further details regarding these efforts are provided in the remainder of this section of the testing and monitoring plan.

**Table 5-6. Summary of Environmental Baseline and Operational Monitoring**

| Activity | Baseline Frequency* | Operational Frequency (20-year period) |
|---|---|---|
| **Atmosphere** | | |
| Wellsite (workplace) Atmosphere Sampling (Figures 5-3 and 5-4) | At start-up, install $CO_2$ detection stations placed outside well enclosures at the MAG 1 location. | Stations provide continuous monitoring of $CO_2$ conditions at the well pad. |
| Ambient Atmosphere Sampling (Figure 5-4) | Sample 3–4 events at each soil gas probe location (SG-1 through SG-5) prior to injection. | Sample 3–4 events per year at each soil gas profile station (SGPS 1 and SGPS 2).<br><br>Sampling will piggyback on the planned soil gas monitoring plan (described below). |
| **Soil Gas Monitoring** | | |
| Soil Gas Sampling (Figures 5-3 through 5-5) | Sample 3–4 events per probe location (i.e., SG-1 through SG-5) prior to injection.<br><br>Perform concentration and isotopic testing on all samples. | Sample 3–4 events per year at each soil gas profile station (i.e., SGPS 1 and SGPS 2).<br><br>Perform concentration and periodic isotopic testing on all samples. |
| **Shallow Groundwater** | | |
| Up to 5 Stock Wells (3 Operated by Falkirk Mining Company) (Figure 5-5) | Sample 3-4 events per well prior to injection.<br><br>Perform water quality and isotopic testing on all samples. | Shift sampling program to the dedicated Fox Hills monitoring well near the MAG 1 well. |
| **Lowest USDW** | | |
| Dedicated Fox Hills Monitoring Well Sampling at MAG 1 (Figure 5-5) | Sample 3–4 events per well.<br><br>Perform water quality and isotopic testing on all samples | Sample 3–4 events per well annually.<br><br>Perform water quality and periodic isotopic testing on all samples. |
| **AZMI** | | |
| DTS | Install during completion of MAG 1 and MAG 2. | Monitor temperature changes continuously in the MAG 1 and MAG 2. |
| PNL | Perform in MAG 2 prior to injection.<br><br>Run log from the Spearfish Formation through the Inyan Kara Formation to establish baseline conditions. | Collect PNL in MAG 2 at Year 4 and every 5 years thereafter until end of injection.<br><br>Run log from the Spearfish Formation through the Inyan Kara Formation to confirm containment in the storage reservoir. |
| **Storage Reservoir (direct)** | | |
| DTS | Install during completion of the MAG 1 and MAG 2. | Monitor temperature changes continuously in the MAG 1 and MAG 2. |
| PNL | Perform in MAG 2 prior to injection.<br><br>Run log from the Amsden Formation through the Spearfish Formation to establish baseline conditions. | Collect PNL in MAG 2 at Year 4 and every 5 years thereafter until end of injection.<br><br>Run log from the Amsden Formation through the Spearfish Formation to determine the Broom Creek Formation's saturation profile. |
| BHP/T Readings | Install BHP/T gauges over the storage reservoir in MAG 1 and MAG 2 prior to injection. | Collect BHP/T readings continuously from the storage reservoir in MAG 1 and MAG 2. |
| Pressure Falloff Testing | Conduct once prior to injection. | Perform at least once every five years. |

* The baseline (preinjection) monitoring effort has not yet begun as of the writing of this permit application.

Continued…

**Table 5-6. Summary of Environmental Baseline and Operational Monitoring (continued)**

| Activity | Baseline Frequency | Operational Frequency (20-year period) |
|---|---|---|
| **Storage Reservoir (indirect)** | | |
| Time-Lapse 2D Seismic Surveys (Figure 5-5) | Collect baseline fence 2D seismic survey. | Repeat 2D seismic survey in Year 1 and Year 4. At Year 4 following the start of injection, reevaluate frequency based on plume growth and seismic results. |
| Passive Seismicity Monitoring (Figure 5-7) | Utilize existing U.S. Geological Survey's network. | Utilize existing U.S. Geological Survey's network and supplement with additional equipment as necessary. |

### *5.7.1 Atmospheric Monitoring*

Figures 5-3 and 5-4 illustrate the planned well pad design at MAG 1 and MAG 2 and the locations of the $CO_2$ detection stations that will be used to monitor workspace atmospheres to ensure a safe work environment. As mentioned in Section 5.2 of this testing and monitoring plan, field personnel will be equipped with multigas detectors with them for wellsite visits or flowline inspections to detect potential leaks as an added safety precaution.

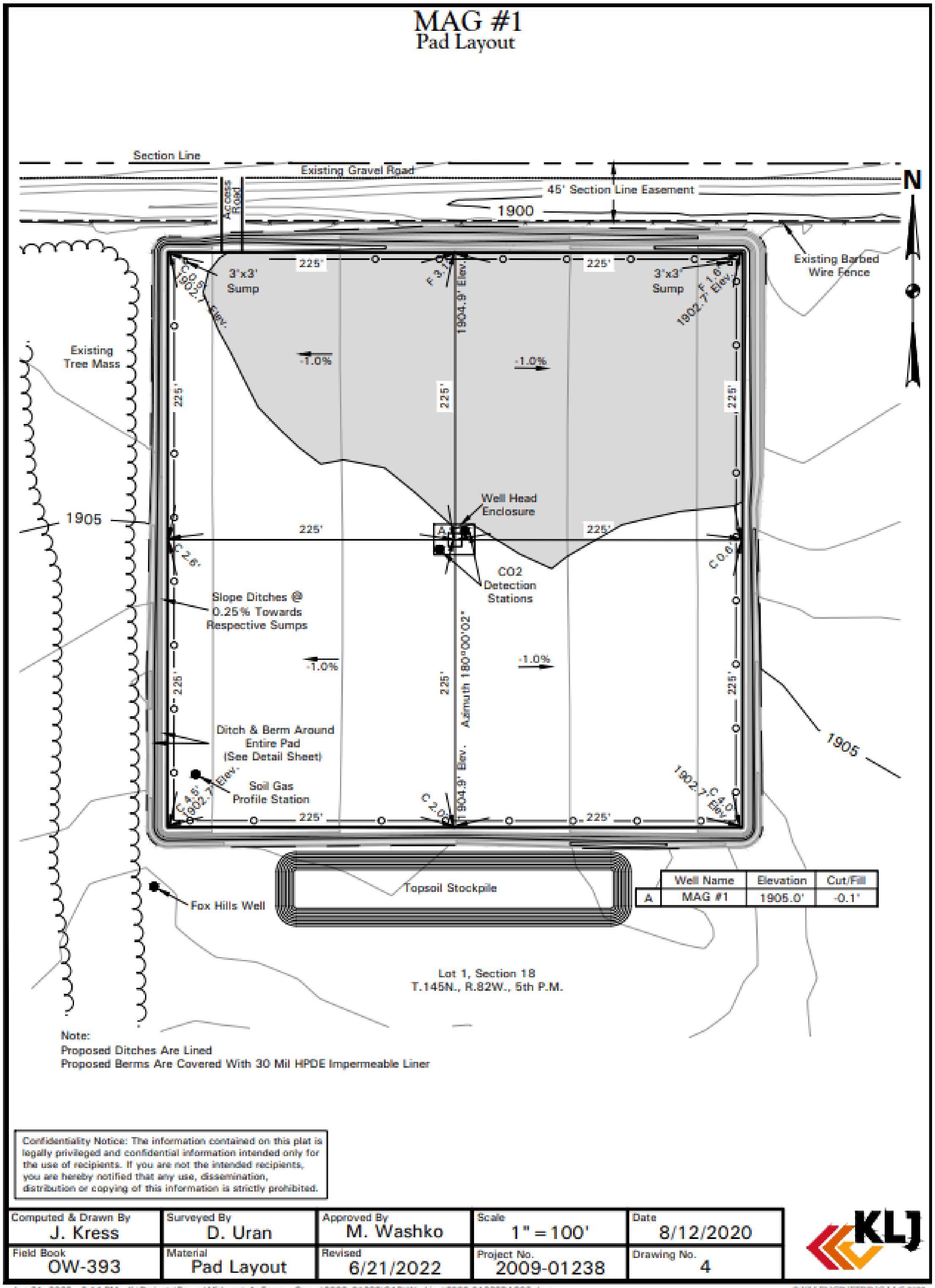



Figure 5-3. Well pad design for the MAG 1 $CO_2$-injection well. Indicated on the drawing are the locations of the $CO_2$ detection stations for atmospheric monitoring at the wellsite, the locations of the soil gas profile stations, and the Fox Hills Formation monitoring well.

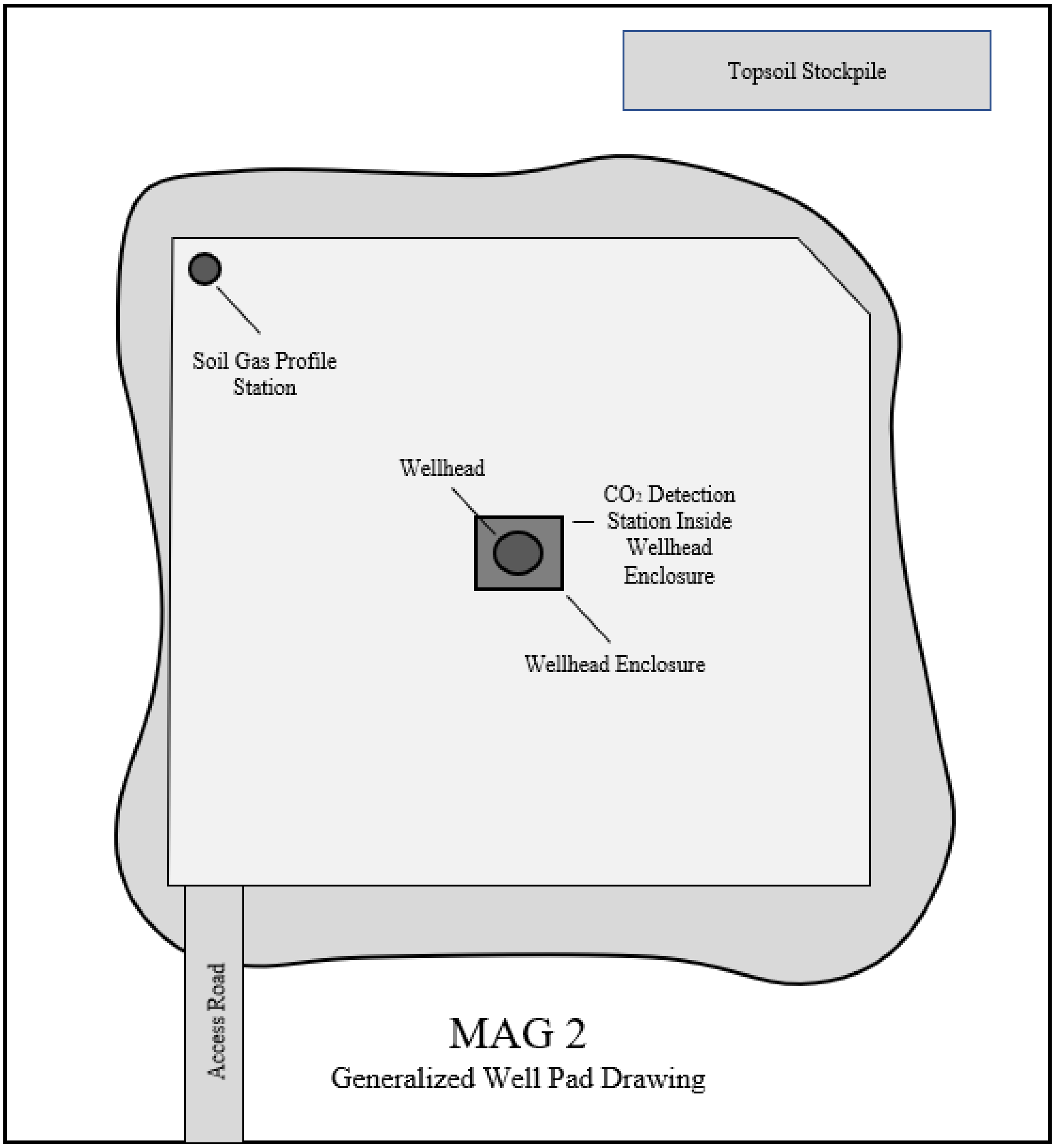



Figure 5-4. Well pad design for the MAG 2 deep monitoring well. Indicated on the drawing are the location of the $CO_2$ detection station as well as the location of the soil gas profile station.

Ambient atmospheric samples will be obtained quarterly at each of the soil gas profile stations (later described in Section 5.6.2). Field personnel collecting the soil gas samples will use a handheld soil gas analyzer to obtain an atmospheric sample to calibrate the instrument before obtaining soil gas measurements, and measurements of ambient $N_2$, $CO_2$, and $O_2$ will be recorded. QA/QC (quality assurance/quality control) methods regarding ambient air sampling are provided in Appendix C.

### *5.7.2 Soil Gas and Groundwater Monitoring*

Blue Flint plans to initiate soil gas sampling (Figure 5-5) in September 2022 to establish baseline conditions at the Blue Flint $CO_2$ storage project site and anticipates completing the sampling program by July 2023. Soil gas will be sampled via semi-permanent probe stations at five locations (SG-1 through SG-5) within the predicted 20-year $CO_2$ plume boundary 3-4 times prior to injection. Once injection begins, the soil gas sampling frequency will remain the same but shift to two soil gas profile stations to be installed: one soil gas profile station near the MAG 1 (SGPS 1); one soil gas profile station near the MAG 2 (SGPS 2).

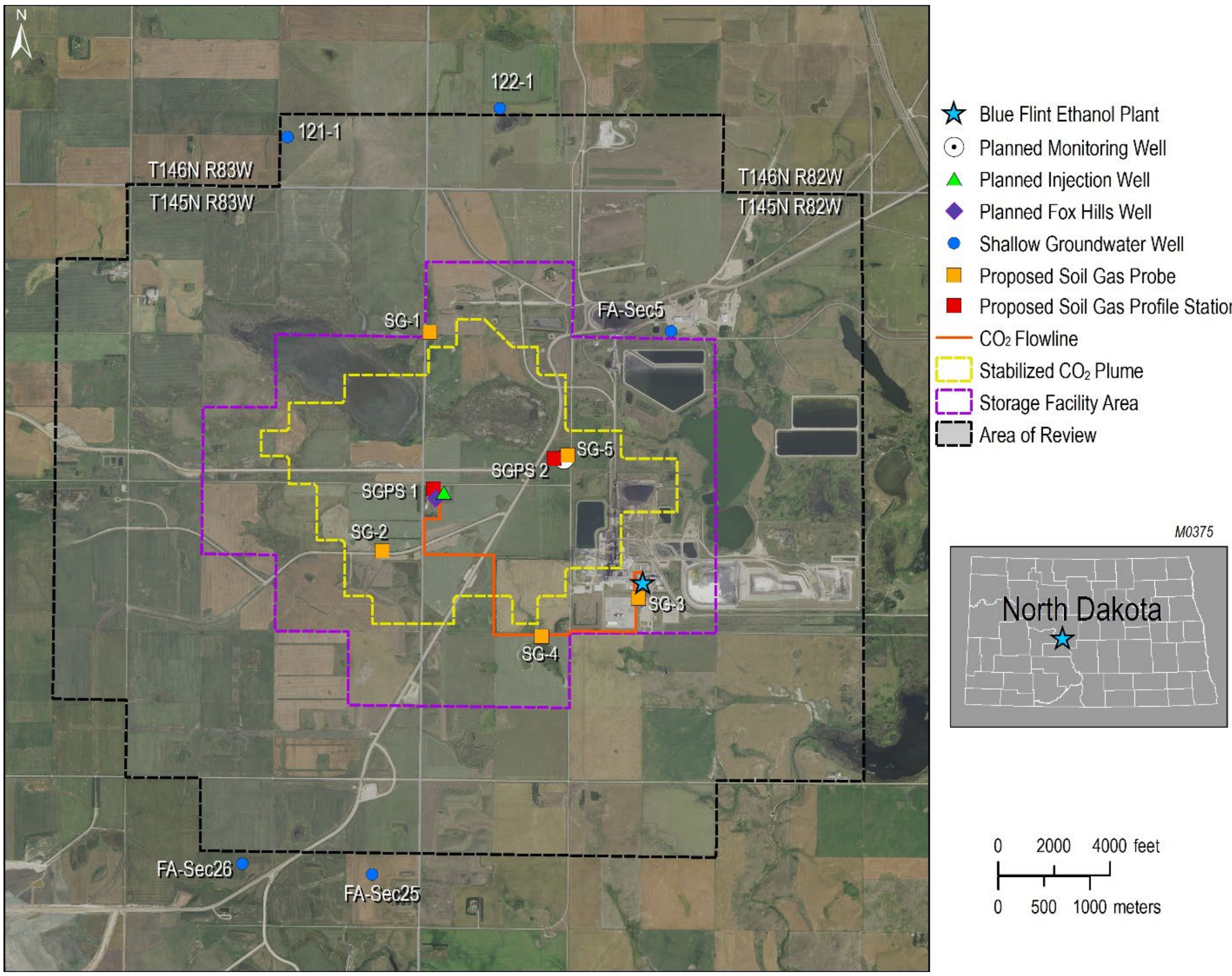



Figure 5-5. Blue Flint's planned baseline and monitoring program for soil gas, shallow groundwater aquifers, and the Fox Hills Aquifer.

Soil gas analytes will include concentrations of $CO_2$, $O_2$, and $N_2$ as well as isotopic ratios for $^{13}CO_2$, $^{14}CO_2$, $\delta^{13}C_1$, and $\delta D_{C_1}$ (further described in Appendix C). The results of the soil gas sampling program will be provided to NDIC prior to injection.

Blue Flint also plans to initiate a baseline groundwater sampling program in up to five existing shallow groundwater (stock) wells within 1 mile of the AOR, collecting 3-4 samples from each well prior to injection. In addition, Blue Flint will drill one dedicated Fox Hills Formation (lowest USDW) monitoring well near the MAG 1 well and acquire samples at the same frequency (Figure 5-5). Once injection begins, groundwater sampling will only occur at the dedicated Fox Hills monitoring well, collecting samples 3-4 times annually. Sample frequencies are further described in Table 5-6, and water analytes will include pH, conductivity, total dissolved solids, and alkalinity as well as major cations/anions and trace metals (further described in Appendix C). A state-certified laboratory analysis will be provided to NDIC prior to injection for all groundwater testing.

Water chemistry reports from active groundwater monitoring sites that are within or near the AOR and operated by the Falkirk Mining Company are provided in Appendix B.

### *5.7.3 Deep Subsurface Monitoring*

Blue Flint will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase $CO_2$ plume and associated pressure relative to the permitted storage reservoir. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and postoperational periods.[2] The methods described in Table 5-6 will be used to characterize the $CO_2$ plume's saturation and pressure within the AOR.

Blue Flint will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan (Ayash and others, 2017) at least once every 5 years. During each review, monitoring and operational data will be analyzed, and the AOR will be reevaluated. Based on this reevaluation, it will either be demonstrated that 1) no amendment to the testing and monitoring program is needed or 2) modifications are necessary to ensure proper monitoring of storage performance is achieved moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the $CO_2$ plume and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will, in turn, be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected $CO_2$ within the permitted geologic storage facility.

[2] Monitoring efforts for the postinjection period are described in Section 6: "Postinjection Site Care and Facility Closure Plan."

#### *5.7.3.1 AZMI Monitoring*

Prior to injection, Blue Flint will acquire PNL data in the MAG 2 well from the storage reservoir (Broom Creek Formation) up through the Spearfish Formation (upper confining zone) and Inyan Kara Formation (upper dissipation interval) (see Figure 2-2 for stratigraphic reference). PNLs will be run in MAG 2 at Year 4 and then every five years thereafter until the end of injection. These time-lapse saturation data will be used to monitor for $CO_2$ saturation in the AZMI (i.e., first few formations above the storage reservoir) as an assurance-monitoring technique to monitor the performance of the storage reservoir complex. Monitoring of the overlying interval can provide an early warning of out-of-zone migration of fluids, providing sufficient time for the development and implementation of mitigation strategies to ensure these migrating fluids do not impact a USDW or reach the surface.

#### *5.7.3.2 Direct Reservoir Monitoring*

DTS fiber installed in the MAG 1 and MAG 2 will directly monitor the temperature in the storage reservoir continuously. BHP/T readings will also be continuously recorded in the MAG 1 and MAG 2 wellbores via tubing-conveyed gauges. To track the migration of the $CO_2$ plume in the subsurface, PNLs will be performed in the MAG 2 at Year 4 and every five years thereafter until the end of $CO_2$ injection. The temperature and saturation profiles collected over the storage reservoir will provide information about the uniformity of $CO_2$ injectivity within the injection interval. The pressure data will be used primarily to ensure the pressure differential in the Broom Creek Formation conforms to numerical simulations.

#### *5.7.3.3 Indirect Reservoir Monitoring*

Indirect monitoring at the Blue Flint $CO_2$ storage project will include time-lapse 2D seismic surveys and passive seismicity monitoring. These indirect monitoring methods are described below and presented in Table 5-6.

To track the extent of the $CO_2$ plume within the storage reservoir over time, a 2D seismic survey was selected. The fence design was preferred over an alternative geometry (e.g., radial lines extending in all directions from the MAG 1 well location) or a 3D seismic acquisition for managing field logistics because of nearby active mining activities. Figure 5-6 illustrates the proposed 2D seismic survey that will be acquired prior to injection, in Year 1 of injection, and then in Year 4 of injection. At Year 4 of injection, the seismic survey design and frequency will be reevaluated. If necessary, the time-lapse seismic monitoring plan will be adapted based on updated simulations of the predicted extents of the $CO_2$ plume, including extending the 2D lines to capture additional data as the $CO_2$ plume expands. Repeat 2D seismic surveys will demonstrate conformance between the reservoir model simulation and site performance and monitor the evolution of the $CO_2$ plume. Because the fiber installed in the MAG 1 and MAG 2 wellbores will be capable of collecting distributed acoustic sensing (DAS) information (Figures 9-1 and 9-3), Blue Flint may also evaluate the feasibility of performing vertical seismic profiles (VSPs) to track the migration of the free-phase $CO_2$ plume in the storage reservoir.

Blue Flint plans to utilize the U.S. Geological Survey (USGS) existing seismicity network to monitor for seismic events larger than magnitude 2.7 in or near the AOR to inform the ERRP (emergency and remedial response plan) (Section 7) as an added safety precaution. Figure 5-7 provides the locations of existing USGS seismicity stations in North Dakota and the surrounding region.

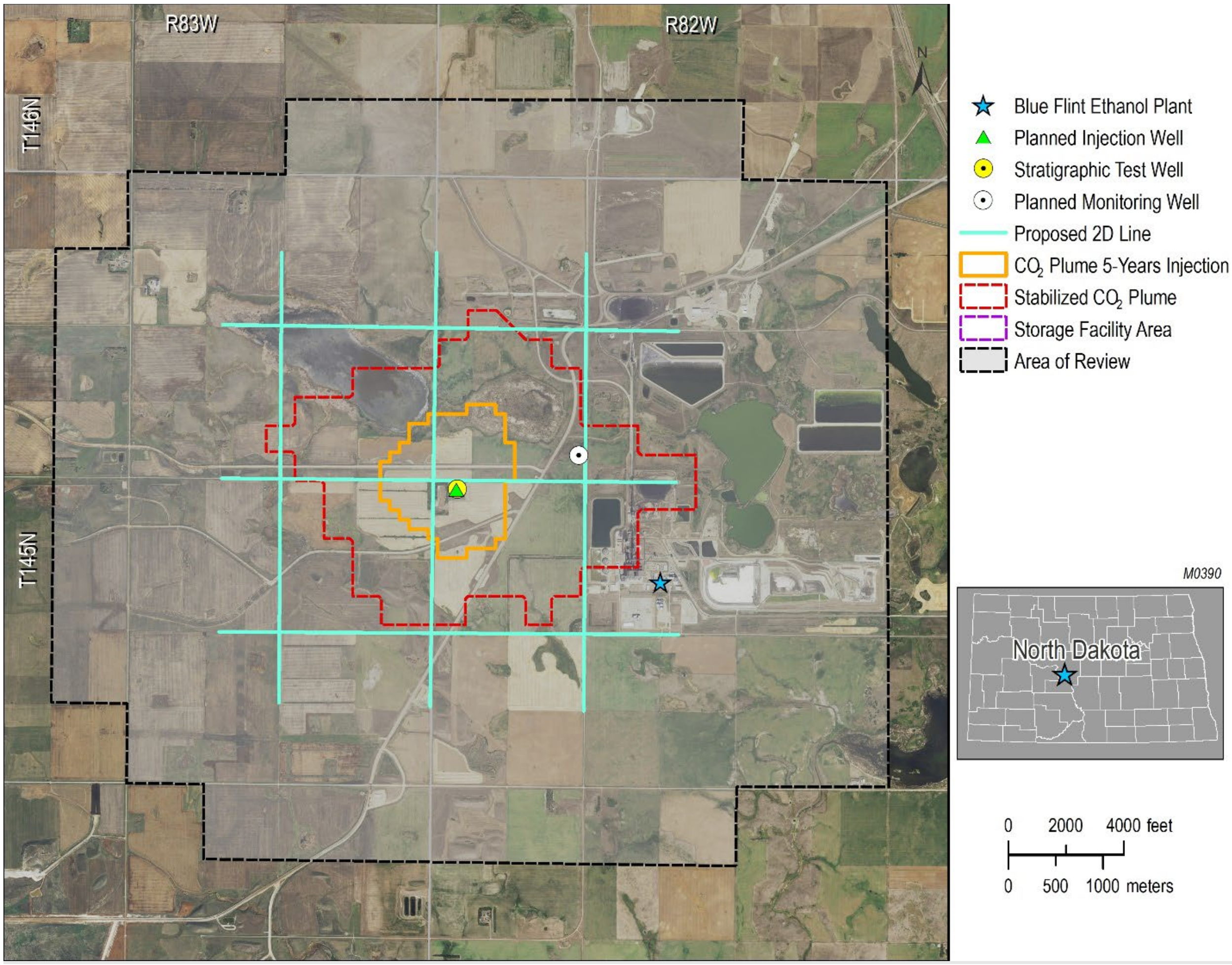



Figure 5-6. Locations of the proposed 2D seismic lines for the fence design near the MAG 1 well to establish a baseline and monitoring for the Blue Flint $CO_2$ storage project during Years 1–4 of injection.

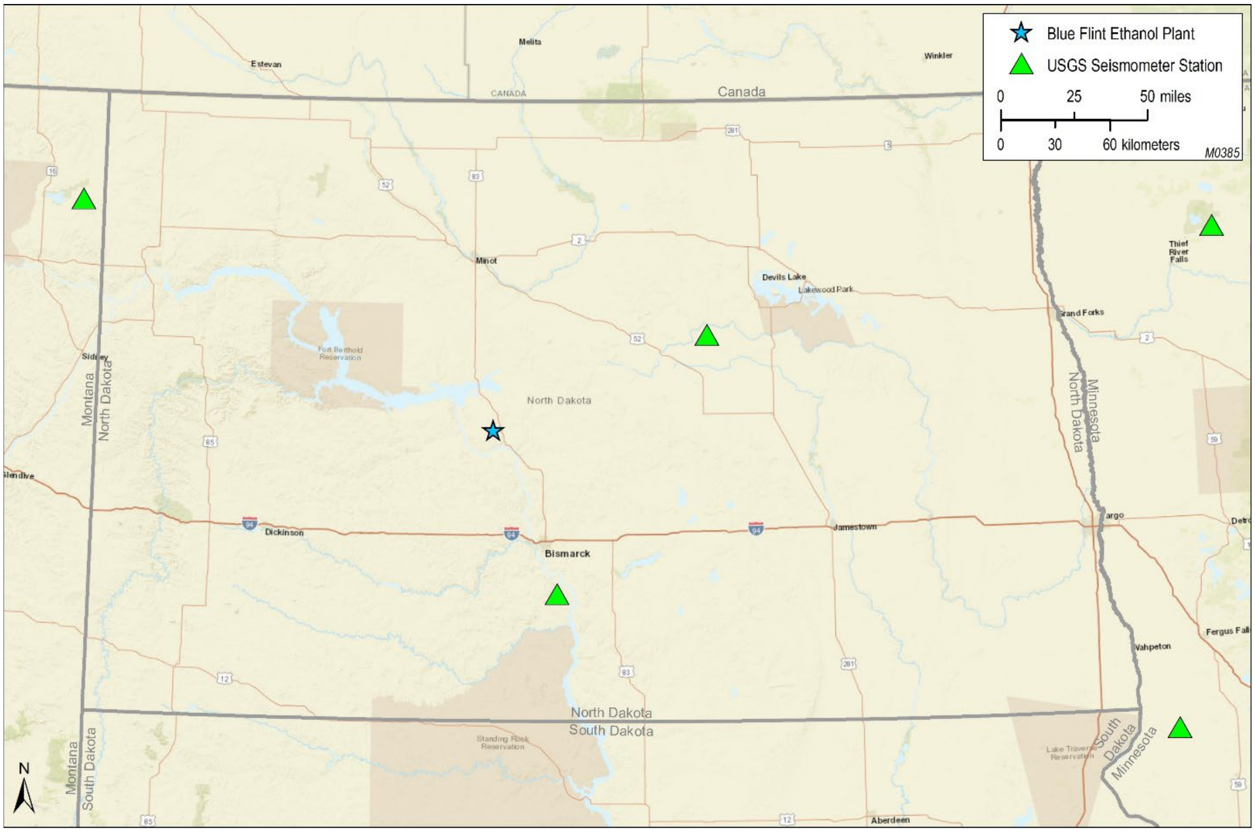



Figure 5-7. Locations of USGS seismometer stations in North Dakota and the surrounding region.

## 5.8 References


API SPEC 17J (R2021), 2017, Specification for unbonded flexible pipe: American Petroleum Institute, 2014, STANDARD 05/01/2014, Fourth Edition, Includes Errata 1 (September 2016), Errata 2 (May 2017), and Addendum 1 (2017).

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.

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.

# 6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

## 6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

This postinjection site care (PISC) and facility closure plan describes the activities that Blue Flint will perform following the cessation of $CO_2$ injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected $CO_2$ plume is stable (i.e., $CO_2$ migration will be unlikely to move beyond the boundary of the storage facility area). Based on simulations of the predicted $CO_2$ plume movement following the cessation of $CO_2$ injection, it is projected that the $CO_2$ plume will stabilize within the storage facility area boundary (Section 3.0). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the $CO_2$ plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable $CO_2$ plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval.

In addition to Blue Flint executing this postinjection monitoring plan, the $CO_2$ injection well will be plugged as described in the plugging plan of this permit application (Section 10.0). All surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site for submission as part of a site-closure report.

### 6.1 Predicted Postinjection Subsurface Conditions

#### *6.1.1 Pre- and Postinjection Pressure Differential*

Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of $CO_2$ injection. The simulations were conducted for 20 years of $CO_2$ injection at a rate of 200,000 metric tons per year, followed by a PISC period of 10 years.

Figure 6-1 illustrates the predicted pressure differential at the conclusion of $CO_2$ injection. At the time that $CO_2$ injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of up to 120 psi at the location of the $CO_2$ injection well. There is insufficient pressure increase caused by $CO_2$ injection to move more than 1 cubic meter of formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the AOR delineation of this permit application (Section 3.0).

Figure 6-2 illustrates the predicted gradual pressure decrease following the cessation of $CO_2$ injection, with the pressure at the injection well at the end of the PISC period anticipated to decrease 80 to 100 psi as compared to the pressure at the time $CO_2$ injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions.

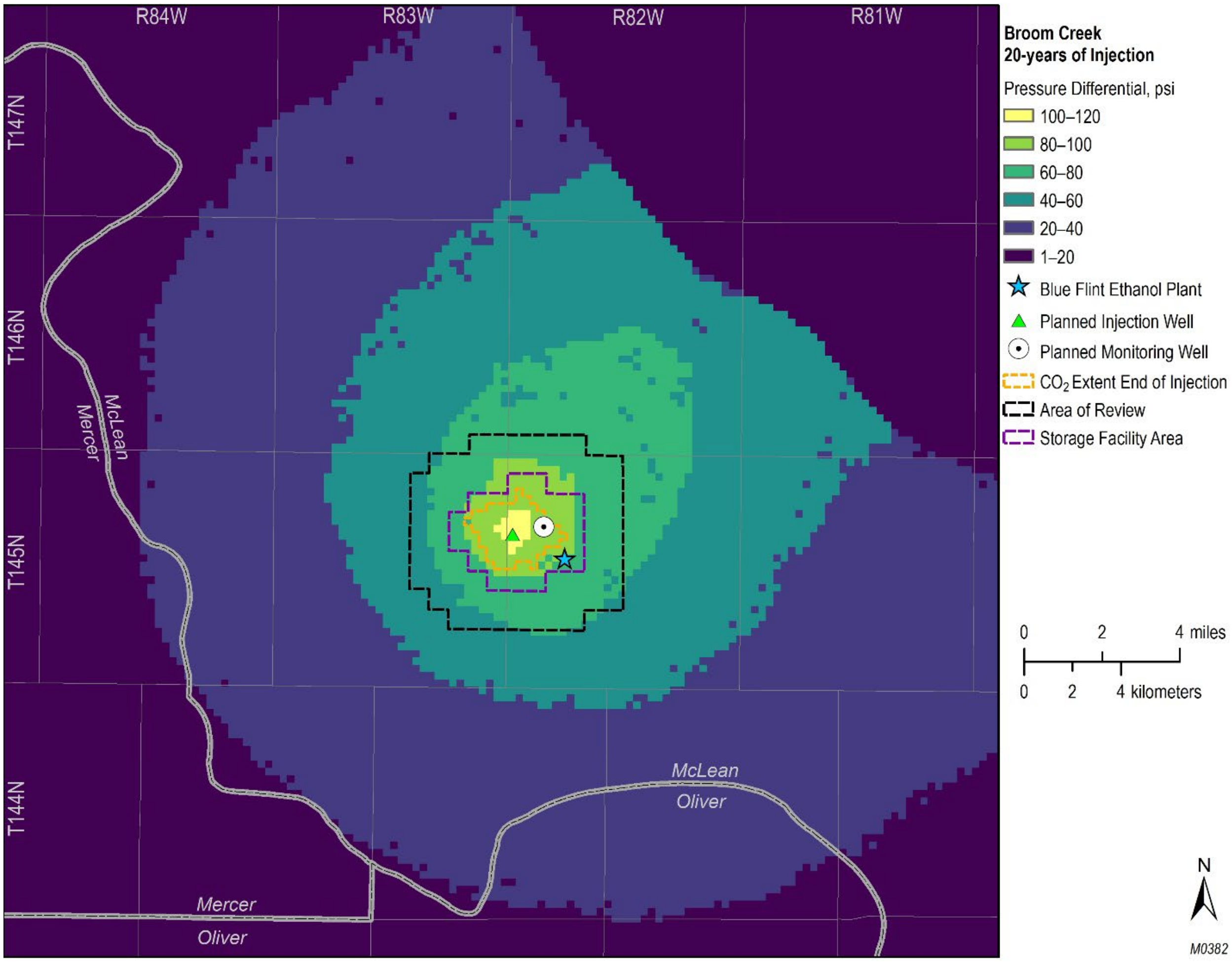



Figure 6-1. Predicted pressure increase in storage reservoir following 20 years of $CO_2$ injection at a rate of 200,000 metric tons per year.

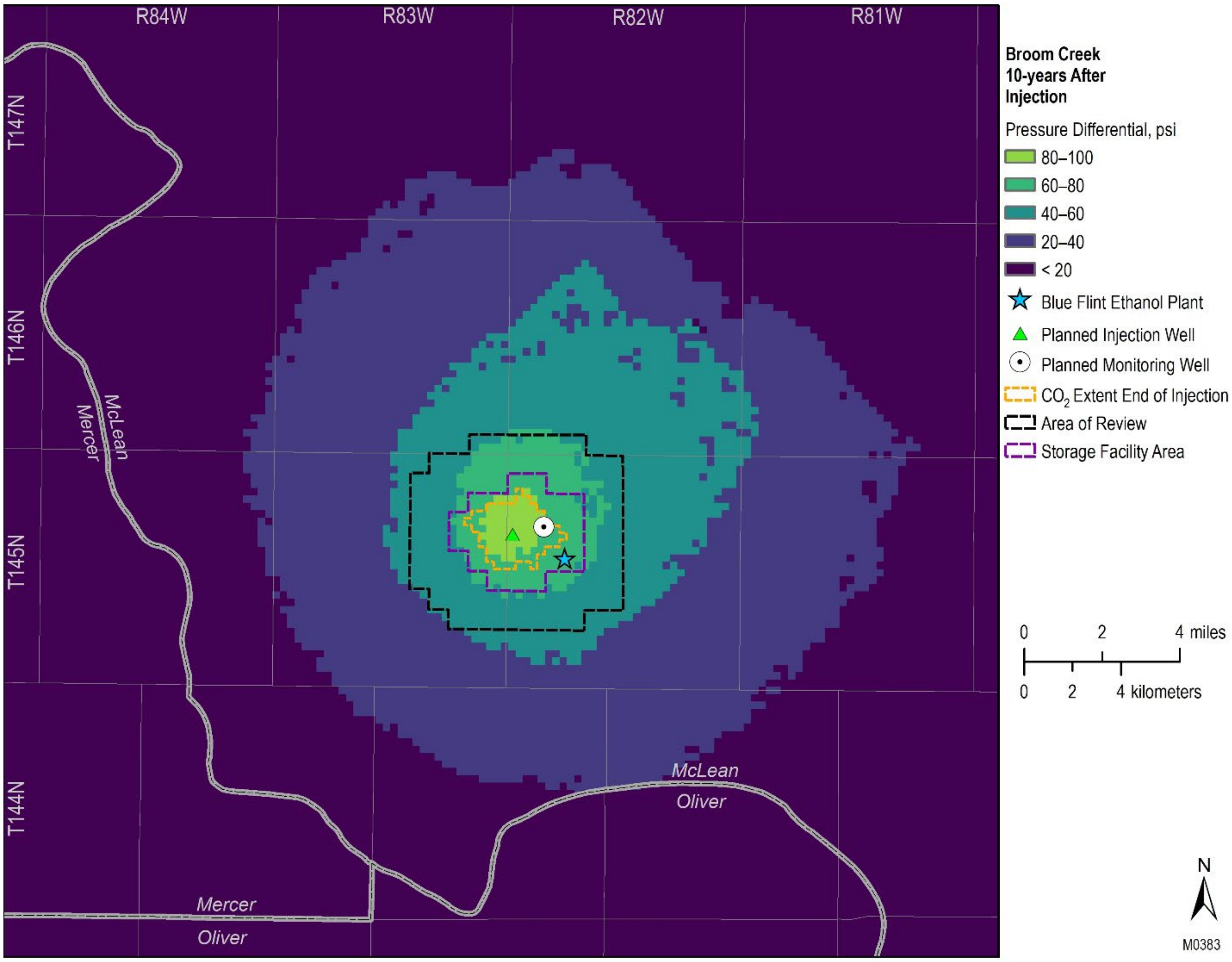



Figure 6-2. Predicted pressure decrease in the storage reservoir over a 10-year period following the cessation of $CO_2$ injection.

### *6.1.2 Predicted Extent of $CO_2$ Plume*

Figure 6-2 illustrates the extent of the $CO_2$ plume following the planned 10-year PISC period (also called the stabilized plume), which is based on numerical simulation predictions. The results of these simulations predict that 99% of the separate-phase $CO_2$ mass would be contained within an area of 2.96 $mi^2$ at the end of $CO_2$ injection. As shown in Figure 6-2, the areal extent of the $CO_2$ plume is not predicted to change substantially over the planned PISC period.

Additional simulations beyond the 10-year PISC period were also performed and predict that at no time will the boundary of the stabilized plume at the site, which is shown in Figure 6-2, extend beyond the boundary of the storage facility area. If such a determination can be made following the planned 10-year PISC period, the $CO_2$ plume will meet the definition of stabilization as presented in NDCC § 38-22-17(5)(d) and qualify the geologic storage site for receipt of a certificate of project completion.

## 6.2 Postinjection Testing and Monitoring Plan

A summary of the postinjection testing and monitoring plan that will be implemented during the 10-year postinjection period is provided in Tables 6-1 and 6-2. Table 6-1 includes a plan to monitor wellbore stability (mechanical integrity and corrosion monitoring plans) and assumes the MAG 1 wellbore will be plugged after injection ceases and that the MAG 2 wellbore will monitor the storage reservoir until site closure. Table 6-2 summarizes environmental monitoring efforts to track the $CO_2$ plume in the storage reservoir and protect USDWs.

**Table 6-1. Overview of Blue Flint's PISC MAG 2 Mechanical Integrity Testing and Corrosion Monitoring Plan**

| Activity | Postinjection Frequency (10-year period) |
|---|---|
| **External Mechanical Integrity Testing** | |
| DTS | Continuous monitoring. |
| USIT or Electromagnetic Casing Inspection Log | Perform during well workovers but no less than once every 5 years. |
| **Internal Mechanical Integrity Testing** | |
| Tubing–Casing Pressure Testing | Perform during well workovers but not more frequently than once every 5 years.<br><br>Digital surface gauges will monitor tubing and annulus pressures continuously. |
| Surface and Tubing-Conveyed BHP/T Gauges | Gauges will monitor temperatures and pressures in the tubing continuously. |
| **Corrosion Monitoring** | |
| USIT or Electromagnetic Casing Inspection Log | Perform during well workovers but no less than once every 5 years. |

### *6.2.1 Soil Gas and Groundwater Monitoring*

Six soil gas-monitoring locations (i.e., two SGPSs and four soil probe locations) will be sampled during the proposed PISC period. Additionally, one dedicated monitoring well in the Fox Hills Formation (i.e., lowest USDW) near the MAG 1 well will be sampled. Figure 6-3 identifies the locations of the soil gas-monitoring locations and the dedicated Fox Hills Formation monitoring well. All samples will likely be analyzed for the same list of parameters as described in the testing and monitoring plan (Section 5.0); however, the final target list of analytical parameters may be reduced for the PISC period based on an evaluation of the monitoring results that are generated during the 20-year injection period of the storage operations. Additional sampling of groundwater in the PISC period may occur on active and accessible shallow groundwater wells within the AOR.

**Table 6-2. Overview of Blue Flint's PISC Monitoring Plan**

| Activity | Postinjection Frequency (10-year period) |
|---|---|
| **Soil Gas** | |
| SGPSs (SGPS01 and SGPS02) (Figure 6-3) | Sample SGPS01 prior to MAG 1 reclamation. Sample SGPS02 annually until site closure. |
| Soil Gas Probe Locations (SG01 to SG04) (Figure 6-3) | Sample soil gas probe locations at the start of the PISC period and prior to site closure. |
| **Shallow Groundwater** | |
| Shallow Groundwater Wells | Sampling may be performed on active and accessible shallow groundwater wells in the AOR prior to site closure. |
| **Lowest USDW** | |
| Dedicated Fox Hills Monitoring Well near the MAG 1 (Figure 6-3) | Sample the dedicated Fox Hills monitoring well annually until site closure. |
| **Above-Zone Monitoring Interval (AZMI) Monitoring** | |
| DTS | Continuous monitoring |
| PNL | Perform PNL in the MAG 2 well annually from the Spearfish up through the Inyan Kara until the near-wellbore environment reaches full $CO_2$ saturation (anticipated during the injection stage). Reduce frequency to every 4 years thereafter. |
| **Storage Reservoir (direct)** | |
| DTS | Continuous monitoring |
| PNL | Perform PNL in the MAG 2 well annually until the near-wellbore environment reaches full $CO_2$ saturation (anticipated during the injection stage). Reduce frequency to every 4 years thereafter. |
| **Storage Reservoir (indirect)** | |
| 2D Time-Lapse Seismic (Figure 6-4) | Actual design and frequency to be determined based on reevaluations of the testing and monitoring plan (Section 5.0) and migration of the $CO_2$ plume over time. |
| Passive Seismicity | USGS seismic network, supplemented with additional stations as needed. |

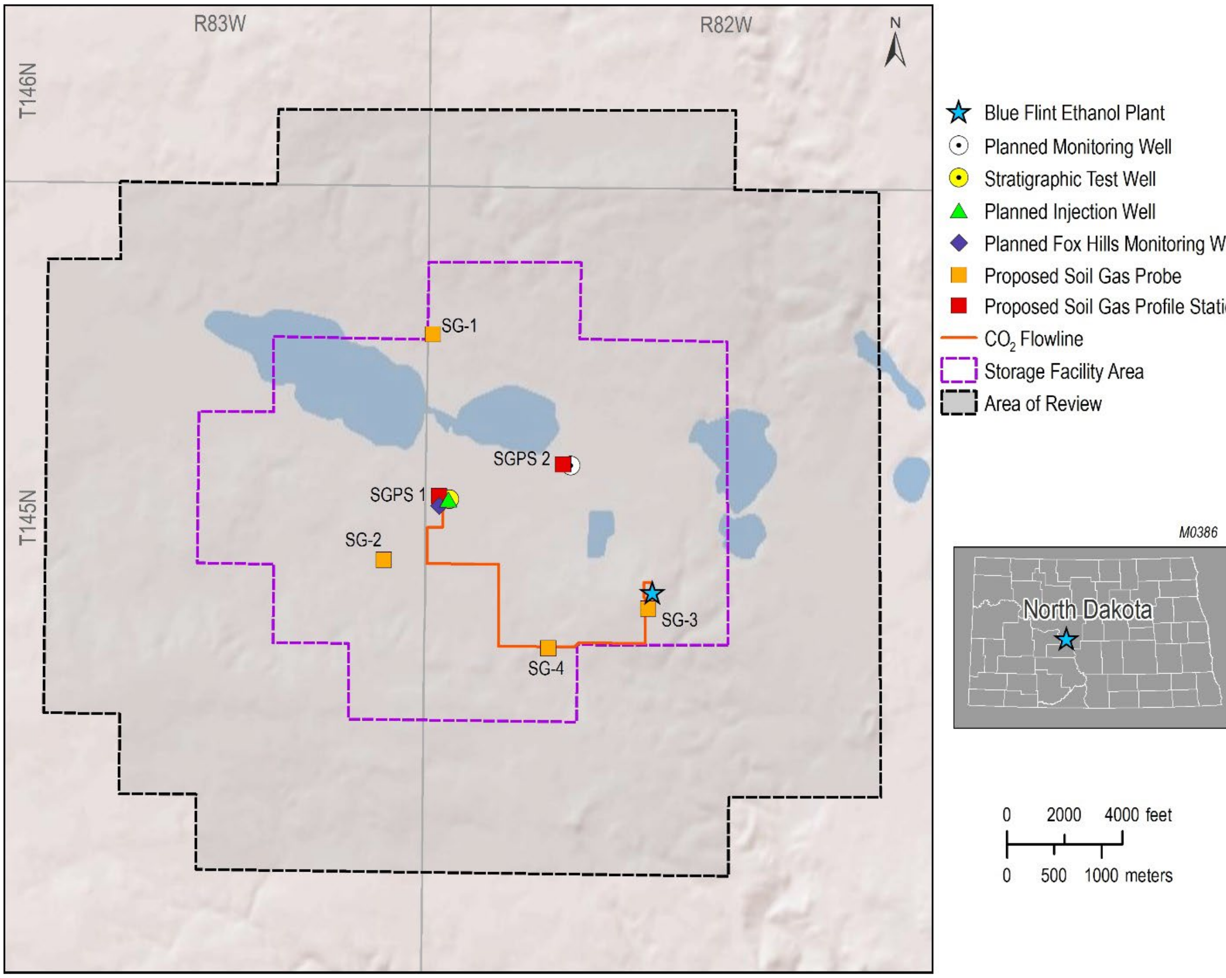



Figure 6-3. Soil gas- and groundwater well-sampling locations included in the PISC monitoring program.

### *6.2.2 $CO_2$ Plume Monitoring*

The design and frequency of the 2D time-lapse seismic survey will depend on how the $CO_2$ plume is migrating and the results of the adaptive management approach (Section 5.6.3). As stated in Table 5-6 and Section 5.6.3.3 of the testing and monitoring plan, the 2D seismic survey design and frequency will be repeatedly reevaluated and updated as necessary starting in Year 4 of injection.

Existing seismicity stations and the network maintained by the USGS (Figure 5-7) will be used to monitor for any seismic events that may occur during the postinjection period of the Blue Flint $CO_2$ storage project.

## 6.3 Schedule for Submitting Postinjection Monitoring Results

All PISC-monitoring data and monitoring results will be submitted to NDIC in annual reports. These reports will be submitted within 60 days of the anniversary date on which the $CO_2$ injection ceased.

The annual reports will contain information and data generated during the reporting period, including seismic data acquisition, formation monitoring data, soil gas and groundwater sample analytical results, and simulation results from updated site models and numerical simulations.

### *6.3.1 PISC Plan*

Blue Flint will submit a final site closure plan and notify NDIC at least 90 days prior to its intent to close the site. The site closure plan will describe a set of closure activities that will be performed, following approval by NDIC, at the end of the PISC period. Site closure activities will include the plugging of all wells that are not planned for continued use in monitoring the closed site; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring; the reclaiming of the surface land of the site to as close as is practical to its original condition; and abandonment of flowlines pursuant to NDAC Section 43-02-03-34.1.

Any flowlines buried less than 3 feet below final contour will be removed (e.g., the planned flowline segment at the capture facility on Blue Flint Ethanol property and the above-ground portion of the flowline at the injection wellsite). Associated costs during the PISC period are outlined in Section 12, which include the type and frequency of monitoring as well as equipment costs, plugging of the injection well, and site reclamation.

As part of the PISC monitoring and closure plan and in accordance with NDAC 43-05-01-19(5), the MAG 1 injection well will be plugged and abandoned and the injection well pad will be reclaimed. Reclamation of the MAG 1 well and the injection pad includes wellhead removal, sump removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, reclamation of the flowline at the injection pad, and the P&A of SGPS01.

The dedicated Fox Hills monitoring well adjacent to the MAG 1 injection wellsite will remain, at a minimum, until site closure. At the time of site closure, NDIC and Blue Flint will decide if the Fox Hills well adjacent to the MAG 1 wellsite will be plugged and abandoned with the site location reclaimed or if the ownership of the Fox Hills well will transfer to the State.

### *6.3.2 Site Closure Plan*

To comply with NDAC 43-05-01-19(2), the MAG 2 well will be used for deep subsurface monitoring during the PISC period and will be plugged and abandoned as part of site closure activities. Reclamation of the MAG 2 well and well pad at site closure includes wellhead removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, and the P&A of SGPS02.

As part of the final assessment, Blue Flint will work with NDIC to determine which wells and monitoring equipment will remain and transfer to the State for continued postclosure monitoring. The dedicated Fox Hills monitoring well drilled adjacent to the MAG 1 injection well

and soil gas profile stations may transfer ownership to the State or a third party, pending NDIC review and approval of the PISC plan and final assessment pursuant to 43-05-01-19. Cost estimates for the PISC and closure periods can be found in Section 12 in the scenario that transfer to the State or a third party does not occur.

### *6.3.3 Submission of Site Closure Report, Survey, and Deed*

A site closure report will be prepared and submitted to NDIC within 90 days of the execution of the PISC and facility closure plan. This report will provide NDIC with a final assessment that documents the location of the stored $CO_2$ in the reservoir, describes its characteristics, and demonstrates the stability of the $CO_2$ plume in the reservoir over time. The site closure report will also document the following:

- Plugging records of the injection well and monitoring well.
- Location of the sealed injection well and monitoring well on a plat survey that has been submitted to the local zoning authority.
- Notifications to state and local authorities as required by NDAC § 43-05-01-19.
- Records regarding the nature, composition, and volume of the injected $CO_2$.
- Postinjection monitoring records.

At the same time, Blue Flint will also provide NDIC with a copy of an accurate plat certified by a registered surveyor that has been submitted to the county recorder's office designated by NDIC. The plat will indicate the location of the injection well and monitoring well relative to permanently surveyed benchmarks pursuant to NDAC § 43-05-01-19.

Lastly, Blue Flint will record a notation on the deed (or any other title search document) to the property on which the injection well and monitoring well were located pursuant to NDAC § 43-05-01-19.

# 7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

## 7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

Blue Flint Sequester Company LLC (Blue Flint) and Blue Flint Ethanol LLC, operator of the Blue Flint Ethanol (BFE) facility, will enter into an agreement whereby Blue Flint employees, contractors and agents are required to follow the BFE facility emergency action plans, including, but not limited to, the BFE facility response plan. This emergency and remedial response plan (ERRP) for the geologic storage project 1) describes the local resources and infrastructure in proximity to the project site; 2) identifies events that have the potential to endanger USDWs during the construction, operation, and postinjection site care periods of the geologic storage project, building upon the screening-level risk assessment (SLRA); and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing BFE facility response plan and risk management plan (and incorporated into the BFE Integrated Contingency Plan [ICP]) is described, emphasizing the facility response team and command structure, facility evacuation plans, HazMat (hazardous materials) capabilities, and emergency communication plans. Lastly, procedures are presented for regularly conducting an evaluation of the adequacy of the ERRP and updating it, if warranted, over the lifetime of the geologic storage project. Copies of this ERRP are available at the Blue Flint's office and the BFE facility.

### 7.1 Background

$CO_2$ produced at the BFE facility will be captured and geologically stored in close proximity to the plant location (see Table 7-1 for a listing of relevant BFE environmental permits). The projected composition of the captured gas is 99.98% dry $CO_2$ (by volume), with trace quantities (0.02% by volume) of water, nitrogen, oxygen, hydrogen sulfide, $C_2^+$ and hydrocarbons. Figure 5-1 identifies the BFE facility location, as well as the planned capture facility, the $CO_2$ flowline, and the $CO_2$ injection well (MAG 1) and monitoring well (MAG 2). The well locations, including latitudes and longitudes, are provided below (Table 7-2).

**Table 7-1. Environmental Permits Issued to BFE**

| Permit | Permit Number | Issuing Agency |
|---|---|---|
| Risk Management Plan | 10000098136 | EPA |
| Facility Response Plan | FRP08D0017 | EPA |
| Air Permit to Operate – Title V | AOP-28450 V2.0 | NDDEQ |
| Industrial Storm Water Permit | NDR05-0000 | NDDEQ |
| Alcohol Fuel Producer Permit | AFP-ND-15003 | ATF |

**Table 7-2. Well Name and Location Information for the $CO_2$ Injection Well (MAG 1) and Monitoring Well (MAG 2) of the Geologic Storage Operations**

| Well Name | Purpose | NDIC File No. | Quarter/Quarter | Section | Township | Range | Latitude | Longitude |
|---|---|---|---|---|---|---|---|---|
| MAG 1 | $CO_2$ Injection Well | 37833 | Lot 1 | 18 | 145N | 82W | 47.385185 | 101.182135 |
| MAG 2 | Monitoring Well | TBD* | SE4 | 19 | 145N | 82W | TBD | TBD |

* TBD = to be determined

The primary Blue Flint contacts for the geologic storage project and their contact information are listed in Table 7-3.

**Table 7-3. Primary Blue Flint Project Contacts**

| Individual | Title | Contact Information<br>Office Phone Number |
|---|---|---|
| Jeff Zueger | CEO | (701) 442-7501 |
| Adam Dunlop | Director – Regulatory & Technical Services | (701) 442-7503 |
| Travis Strickland | Plant Manager | (701) 442-7502 |
| Jeff Martian | Process Engineer | (701) 442-7512 |

Contact names and information for the complete facility response team (Table 7-6) as well as key local emergency organizations/agencies (Table 7-8) and specific contractors and equipment vendors able to respond to potential leaks or loss of containment (Table 7-9) are provided in a separate section of this ERRP (Section 7.6, Emergency Communications Plan).

## 7.2 Local Resources and Infrastructure

Local resources in the vicinity of the geologic storage project that may be impacted as a result of an emergency event include: 1) the holding ponds associated with the Coal Creek Station (owned by Rainbow Energy Center); 2) the Weller Slough and Turtle Lake Aquifers; and 3) the Falkirk Mining Company leased mine land, including reclaimed mine land.

The infrastructure in the vicinity of the project that may be impacted as a result of an emergency event is shown in Figure 5-1, and includes: 1) BFE facility; 2) the $CO_2$ injection wellhead (MAG 1) and the monitoring wellhead (MAG 2); 3) nearby commercial and residential structures; and 4) the $CO_2$ flowline. Figure 3-20 shows land use within the area of review (AOR), including commercial, residential, and public lands, if any, as required in NDAC § 43-05-01-13.

## 7.3 Identification of Potential Emergency Events

### *7.3.1 Definition of an Emergency Event*

An emergency event is an event that poses an immediate, or acute, risk to human health, resources, or infrastructure and requires a rapid, immediate response. This ERRP focuses on emergency events that have the potential to move injection fluid or formation fluid in a manner that may endanger USDWs or lead to an accidental release of $CO_2$ to the atmosphere during the construction, operation or postinjection site care project periods.

### *7.3.2 Potential Project Emergency Events and Their Detection*

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

1. Injectivity
2. Storage capacity
3. Containment – lateral migration of $CO_2$

4. Containment – pressure propagation
5. Containment – vertical migration of $CO_2$ or formation water brine via injection wells, other wells, or inadequate confining zones
6. Natural Disasters (induced seismicity)

Based on a review of these technical risk categories, a list of the geologic storage project events that could potentially result in the movement of injection fluid or formation fluid in a manner that may endanger a USDW and require an emergency response was developed for inclusion in this ERRP. These events and means for their detection are provided in Table 7-4.

In addition to the foregoing technical project risks, the occurrence of a natural disaster (e.g., naturally occurring earthquake, tornado, lightning strike, etc.) also represents an event for which an emergency response action may be warranted. For example, an earthquake or weather-related disaster (e.g., tornado or lightning strike) has the potential to result in injection well problems (integrity loss, leakage, or malfunction) and may also disrupt surface and subsurface storage operations. These events are addressed in the BFE emergency response plans and will be extended to the geologic storage operations.

## 7.4 Emergency Response Actions

The response actions that will be taken to address the events listed in Table 7-4, as well as potential natural disasters, will follow the same protocol. This protocol consists of the following actions:

- The facility response plan qualified individual (QI) (see Section 7.6, Emergency Communications Plan) will be notified immediately and, as soon as practical and within 24 hours, of that notification, make an initial assessment of the severity of the event (i.e., does it represent an emergency event?) to ensure all necessary steps have been taken to identify and characterize any release pursuant to NDAC Section 43-05-01-13(2)(b).
- If determined to be an emergency event, the QI or designee shall notify the NDIC Department of Mineral Resources (DMR) Underground Injection Control (UIC) program director (see Section 7.6, Emergency Communications Plan, Table 7-7) within 24 hours of the emergency event determination (pursuant to NDAC § 43-05-01-13) and implement the emergency communications plan.
- Following these actions, the geologic storage project operator will:
    1. Initiate a project shutdown plan and immediately cease $CO_2$ injection. (However, in some circumstances, the operator may, in consultation with the NDIC DMR UIC Program director, determine whether gradual or temporary cessation of injection is more appropriate).
    2. Shut in the $CO_2$ injection well (close flow valve).
    3. Vent $CO_2$ from surface facilities.
    4. Limit access to the wellhead to authorized personnel only, equipped with appropriate personal protection equipment (PPE).

**Table 7-4. Potential Project Emergency Events and Their Detection**

| Potential Emergency Events | Detection of Emergency Events |
|---|---|
| Failure of $CO_2$ Flowline from Capture System to $CO_2$ Injection Wellhead | • Computational flowline continuous monitoring and leak detection system (LDS). Instrumentation at both ends of the flowline for each injection well collects pressure, temperature, and flow data. The LDS software uses the pressure readings and flow rates in and out of the line to produce a real-time model and predictive model. By monitoring deviations between the real-time model and the predictive model, the software detects flowline leaks.<br>• Frozen ground at leak site may be observed.<br>• $CO_2$ monitors located on the flowline risers detect a release of $CO_2$ from the flowline connection and/or wellhead. |
| Integrity Failure of Injection or Monitoring Well | • Pressure monitoring reveals wellhead pressure exceeds the shutdown pressure specified in the permit.<br>• Annulus pressure indicates a loss of external or internal well containment.<br>• Mechanical integrity test results identify a loss of mechanical integrity.<br>• $CO_2$ monitors located inside and outside the enclosed wellhead building detect a release of $CO_2$ from the wellhead. |
| Monitoring Equipment Failure of Injection Well | Failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure is detected. |
| Storage Reservoir Unable to Contain the Formation Fluid or Stored $CO_2$ | Elevated concentrations of indicator parameter(s) in soil gas, groundwater, and/or surface water sample(s) are detected. |

5. If warranted, initiate the evacuation of the BFE plant and associated geologic storage project facilities in accordance with the facility response plan and communicate with local emergency authorities to initiate evacuation plans of nearby residents.
6. Perform the necessary actions to determine the cause of the event and, in consultation with the NDIC DMR UIC program director, identify and implement appropriate emergency response actions (see Table 7-5, for details regarding the specific actions that will be taken to determine the cause and, if required, mitigation of each of the events listed in Table 7-4).

**Table 7-5. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions**

| | |
|---|---|
| Failure of $CO_2$ Flowline from the $CO_2$ Capture System to $CO_2$ Injection Wellhead | • The $CO_2$ release and its location will be detected by the LDS and/or $CO_2$ wellhead monitors, which will trigger a BFE alarm, alerting plant system operators to take necessary action.<br>• If warranted, initiate an evacuation plan in tandem with an appropriate workspace and/or ambient air-monitoring program near the location of failure to monitor the presence of $CO_2$ and its natural dispersion following the shutdown of the flowline using practices similar to those used to develop the risk management plan.<br>• The flowline failure will be inspected to determine the root cause of the flowline failure.<br>• Repair/replace the damaged flowline, and if warranted, put in place the measures necessary to eliminate such events in the future. |
| Integrity Failure of Injection or Monitoring Well | • Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure.<br>• Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the NDIC DMR UIC program director).<br>• If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts.<br>• If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director). |
| Monitoring Equipment Failure of Injection Well | • Monitor well pressure, temperature, and annulus pressure (manually, if necessary) to determine the cause and extent of failure.<br>• Identify and, if necessary, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director). |

Continued . . .

**Table 7-5. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)**

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

- Collect a confirmation sample(s) of groundwater from the Fox Hills monitoring well, and soil gas profile station, and analyze the samples for indicator parameters (see Testing and Monitoring Plan in Section 5.0 of the SFP application).
- If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC program director) a case-specific work plan to:
  1. Install additional monitoring points near the impacted area to delineate the extent of impact:
     a. If a USDW is impacted above drinking water standards, arrange for an alternate potable water supply for all users of that USDW.
     b. If a surface release of $CO_2$ to the atmosphere is confirmed, initiate an evacuation plan, if warranted, in tandem with an appropriate workspace and/or ambient air-monitoring program at the appropriate incident boundary to monitor the presence of $CO_2$ and its natural dispersion following the termination of $CO_2$ injection following practices similar to those used to develop the risk management plan.
     c. If surface release of $CO_2$ to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are exceeded.
  2. Proceed with efforts, if necessary, to a) remediate the USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or $CO_2$ or “pump and treat” the impacted drinking water to mitigate $CO_2$/brine impacts) and/or b) manage surface waters using natural attenuation (i.e., natural processes, e.g., biological degradation, active in the environment that can reduce contaminant concentrations) or active treatment to achieve compliance with applicable water quality standards.
- Continue all remediation and monitoring at an appropriate frequency (as determined by BFE management designee and the NDIC DMR UIC program director) until unacceptable adverse impacts have been fully addressed.

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

Continued . . .

**Table 7-5. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)**

| | |
|---|---|
| Natural Disasters (seismicity) | • Identify when the event occurred and the epicenter and magnitude of the event.<br>• If magnitude is greater than 2.7:<br>1. Determine whether there is a connection with injection activities.<br>2. Demonstrate all project wells have maintained mechanical integrity.<br>3. If a loss of $CO_2$ containment is determined, proceed as described above to evaluate, and if warranted, mitigate the loss of containment. |
| Natural Disasters | • Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure.<br>• If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts.<br>• If impacts or endangerment are detected, identify and implement appropriate response actions in accordance with the facility response plan (in consultation with the NDIC DMR UIC program director). |

## 7.5 Response Personnel/Equipment and Training

### *7.5.1 Response Personnel and Equipment*

All BFE plant and geologic storage project personnel will have undergone hazardous waste operations and emergency response (HAZWOPER) training in accordance with guidelines produced and maintained by the Occupational Safety and Health Administration (OSHA) (OSHA 29 Code of Federal Regulations [CFR] § 1910.120). In addition, assistance has been secured from local (Washburn and Underwood, North Dakota) and McLean County emergency services to implement this ERRP (see Table 7-6).

Equipment (including appropriate PPE) needed in the event of an emergency and remedial response will vary, depending on the emergency event. Response actions (e.g., cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. However, when specialized equipment (such as a drilling rig or logging equipment or potable water hauling, etc.) is required, the Director – Regulatory & Technical Services (see Table 7-3) shall be responsible for its procurement, including maintenance of the list of contractors and equipment vendors (see Section 7.6, Emergency Communications Plan).

### *7.5.2 Staff Training and Exercise Procedures*

BFE will integrate the training of the emergency response personnel of the geologic storage project into the standard operating procedures and plant operations training programs, which are described in the ICP. Periodic training will be provided, not less than annually, to protect all necessary plant and project personnel. The training efforts will be documented in accordance with the requirements of the BFE plans which, at a minimum, will include a record of the trainee name, date of training, type of training (e.g., initial or refresher), and instructor name. BFE will also work with local emergency response personnel to perform coordinated training exercises associated with potential emergency events such as a significant release of $CO_2$ to the atmosphere.

## 7.6 Emergency Communications Plan

An incident command system is identified in the facility response plan that specifies the organization of a facility response team and team member roles and responsibilities in the event of an emergency. The organizational structure of this system is provided below, along with the identification and contact information of each member of the facility response team (see Table 7-6).

The following table contains the contact information for designated QIs.

**Table 7-6. Internal Emergency Notification Phone List**

| Team Member | Phone Number | Response Time (hours) | Emergency Responsibility | Level of Training |
|---|---|---|---|---|
| Travis Strickland Plant Manager | H: 701-462-3937 C: 701-202-7107 | 24 | QI | Initial Facility Response Plan, Training Elements for Oil Spill Response and National Preparedness for Response Exercise Program (PREP) |
| Adam Dunlop, Director – Regulatory & Technical Services | H: 701-250-4893 C: 701-527-5198 | 24 | QI | Initial Facility Response Plan, Training Elements for Oil Spill Response and National Preparedness for Response Exercise Program (PREP) |
| Jeff Martian Process Engineer | W:701-442-7512 C: 605-201-1587 | 24 | | BFE Employee spill response training |
| Cory Gullickson Maintenance Manager | W: 701-442-7506 C: 701-391-2306 | 24 | Assistant QI | BFE Employee spill response training |
| Alyssa Hollinshead HSE Coordinator | W:701-442-7519 C: 970-581-0510 | 24 | | BFE Employee spill response training |
| Shift Lead | W: 701-442-7520 | 24 | Assistant QI | BFE Employee spill response training |

**Table 7-7. NDIC DMR UIC Contact**

| Company | Service | Location | Phone |
| --- | --- | --- | --- |
| NDIC DMR | Class VI/CCUS Supervisor | Bismarck, ND | 701.328.8020 |

The QI or designee is responsible for establishing and maintaining communications with appropriate off-site persons and/or agencies, including, but not limited to, the following:

**Table 7-8. Off-site Emergency Notification Phone List**

| | |
| --- | --- |
| Mclean Sheriff Department* | 701.462.8103 |
| Washburn Fire Department (Primary)* | 701.462.8558 |
| Underwood Fire Department (Secondary)* | 701.442.5224 |
| Washburn Ambulance | 701.462.8431 |
| REC CCS Ambulance | 701.442.5696 |
| Falkirk Mine Ambulance/Fire Fighters | 701.442.5751 |
| McLean County Sheriff's Office | 701.462.8103 |
| North Dakota Highway Patrol | 701.327.2447 |
| North Dakota Highway Department | 701.327.2447 |
| North Dakota Poison Control | 800.222.1222 |
| Washburn Medical Clinic | 701.462.3389 |
| Turtle Lake Hospital | 701.448.2331 |
| Bismarck St. Alexius Hospital | 701.530.7000 |
| Bismarck Sanford Hospital | 701.323.6000 |
| Mclean County Emergency Management* | 701.462.8541 |
| State Emergency Response Commission* | 833.997.7455 |

* Those persons/agencies above marked with an asterisk have received a copy of the BFE emergency response action plan.

**Table 7-9. Potential Contractor and Services Providers**

| Company | Service | Phone |
| --- | --- | --- |
| Clean Harbors | Oil spill Removal Organization (OSRO), Collection, & Storage | 701.774.2201 |
| Garner Environmental Services | OSRO & Spill Cleanup Services | 855.774.1200 |

Lastly, the facility response plan contact list also includes addresses and contact information for the neighboring facilities and occupied residences located within a 1-mile radius of geologic storage project. Because indicated local and regional emergency agencies (Table 7-8) are provided a copy of the facility response plan, the QI or designee may rely upon emergency agency assistance when it is necessary and appropriate to alert the applicable neighboring facilities and residents in order to allow the operator to focus time and resources on response measures (see also Section 7.4 [5]).

### 7.7 ERRP Review and Updates

This ERRP shall be reviewed:

- At least annually following its approval by NDIC.
- Within 1 year of AOR reevaluation.
- Within a prescribed period (to be determined by NDIC) following any significant changes to the project, e.g., injection process, the injection rate, etc.
- As required by NDIC DMR.

If the review indicates that no amendments to the ERRP are necessary, BFE will provide the documentation supporting the "no amendment necessary" determination to the UIC program director.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to NDIC as soon as reasonably practicable, but in no event later than 1 year following the commencement of a review.

# 8.0 WORKER SAFETY PLAN

## 8.0 WORKER SAFETY PLAN

Blue Flint Sequester Company LLC (Blue Flint) and Blue Flint Ethanol LLC, operator of the Blue Flint Ethanol (BFE) facility, will enter into an agreement whereby Blue Flint employees, contractors and agents are required to follow the BFE facility worker safety plans. BFE facility maintains and implements a plantwide safety program that meets all state and federal requirements for worker safety protections, including OSHA and the National Fire Protection Association (NFPA). This program is described in the BFE safety plan, which includes a list of training programs that are currently in place and the frequency with which they will be reviewed and, if necessary, updated.

The $CO_2$ safety training program of BFE facility identifies the dangers of $CO_2$ and requires all employees and visitors to wear the proper PPE and to perform their duties in ways that prevent the discharge of $CO_2$. Project personnel will participate in annual safety training to include familiarization with operating procedures and equipment configurations that are appropriate to their job assignment as well as ERRP procedures, equipment, and instrumentation. New personnel, if appropriate, will receive similar instruction prior to beginning their work. Lastly, contractors and visitors will undergo an orientation that ensures all persons on-site are trained and aware of the dangers of $CO_2$. Initial training will be conducted by, or under the supervision of, the safety director or his designated representative, and all trainers will be thoroughly familiar with the project operations plan and ERRP.

Refresher training will be conducted at least annually for all project personnel. Monthly briefings will be provided to operations personnel according to their respective responsibilities and will highlight recent operating incidents, lessons learned based on actual experience in operating the equipment, and recent storage reservoir-monitoring information.

Only personnel who have been properly trained will participate in the project activities of drilling, construction, operations, and equipment repair. A record including the person's name, date and type of training, and the signatures of the trainee and instructor will be maintained.

# 9.0 WELL CASING AND CEMENTING PROGRAM

## 9.0 WELL CASING AND CEMENTING PROGRAM

Blue Flint plans to reenter and convert MAG 1 (API 3305500196, File No. 37833) into a $CO_2$ injection well, complying with NDIC Class VI underground injection control (UIC) injection well construction requirements. The targeted injection horizon is the Broom Creek Formation. The project includes the installation of a monitoring well, MAG 2, to monitor and record real-time pressure and temperature data and monitor $CO_2$ saturations as well as utilize the data for history matching in the modeling and simulations, as required in the testing and monitoring plan.

### 9.1 $CO_2$ Injection Well – MAG 1 Well Casing and Cementing Programs

The MAG 1 well was permitted and drilled as a stratigraphic test well on October 11, 2020, under NDIC governance. The original well design was to drill the entire stratigraphic column from surface to the Precambrian formation to characterize potential storage reservoirs and seals for $CO_2$ geological sequestration.

The surface and intermediate wellbore sections were drilled, logged, cased, and cemented without major operational issues. The 13.375-in. surface casing was set at 1,330 ft, with a 10.75-in. intermediate casing set at 4,163 ft. While drilling the 9.5-in. long-string interval, severe lost circulation events were encountered at the Interlake (8,120 ft) and Red River (8,708 ft) Formations. The drilling reached a depth of 9,213 ft when a lost circulation event caused the drill pipe and bottomhole assembly (BHA) to get stuck. Unsuccessful fishing operations were performed, resulting in a section of drill pipe and the BHA, the "fish," in the wellbore from 7,575 to 9,072 ft.

The well was conditioned from the base of the intermediate casing to the top of the fish, and the sidewall cores and electronic logs were conducted for characterization of the Broom Creek Formation as well as the associated confining formations. Upon completion of the coring and logging, the wellbore was temporarily plugged and abandoned. Because of the inability to reach total depth, cement plugs were set across the following intervals: 1) a $CO_2$-resistant cement plug from 7,566 to 6,531 ft, 2) a conventional cement plug from 4,729 to 4,374 ft, and 3) a cast iron bridge plug (CIBP) set in the 10.75-in. intermediate casing at 4,090 ft and topped with five sacks of conventional cement.

On May 13, 2022, the well was reentered by drilling out the CIBP and the upper cement plug at 4,729 ft. A new $CO_2$-resistant cement plug was set from 4,815 to 5,480 ft to isolate the Madison Formation group in order to collect representative fluid samples and measure the reservoir pressure in the Broom Creek Formation. The reservoir pressure and temperature values were captured, and fluid samples were collected by swabbing the well. The well was temporarily abandoned on June 7, 2022, with a CIBP set at 4,080 ft and topped with ten sacks of conventional cement, as shown in Figure 9-1, for a current, as-constructed wellbore schematic of the MAG 1 well.

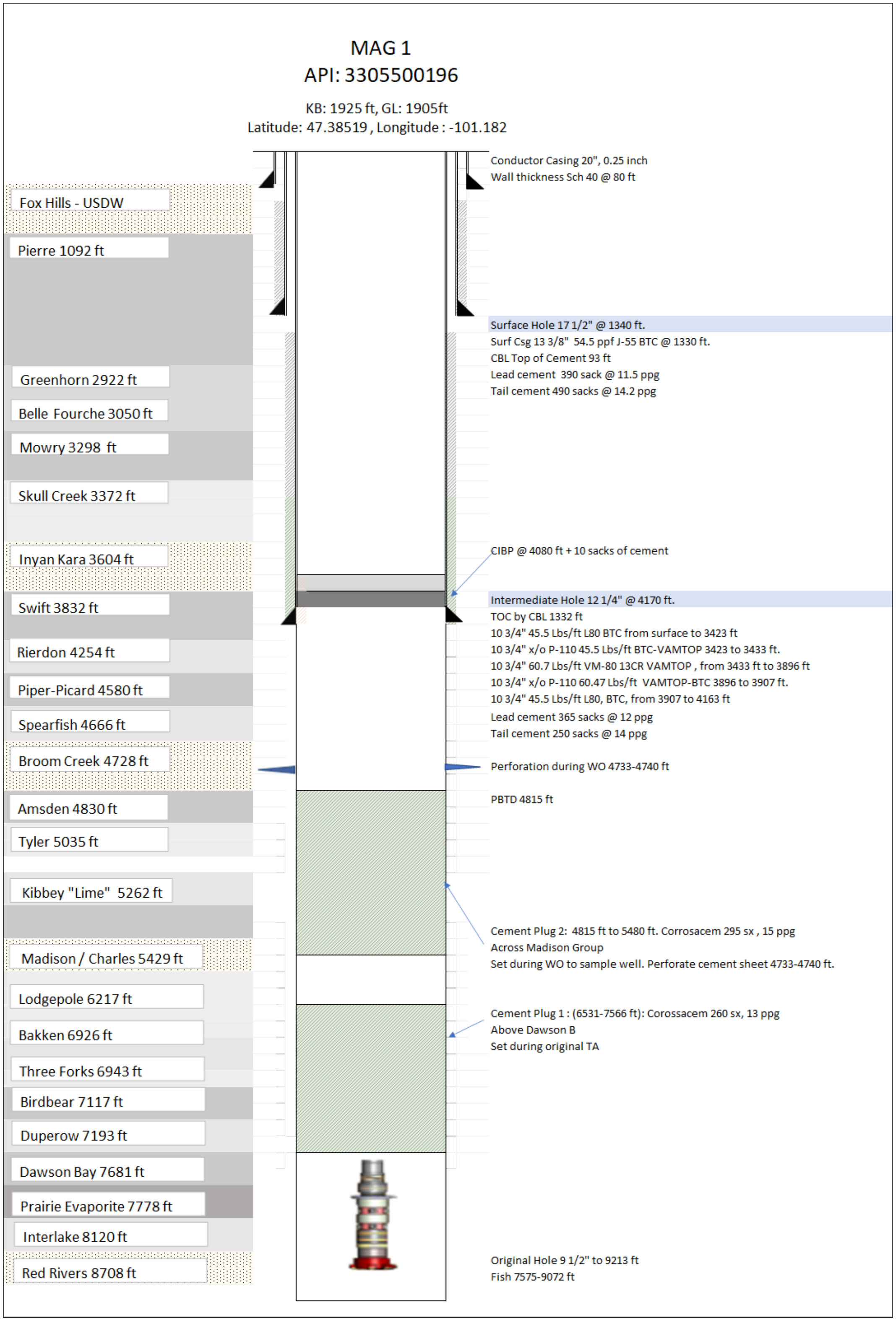



Figure 9-1. MAG 1 as-constructed wellbore schematic.
Note: top of cement (TOC), workover (WO).

To convert the existing stratigraphic wellbore into a $CO_2$ injection well, Blue Flint plans to reenter the MAG 1 well, drill out the CIBP and Cement Plug 2 from 4,815 to 5,150 ft, condition the open hole, install and cement 7-in. long-string casing from surface to 5,150 ft. The Broom Creek Formation will be perforated, and injection will be performed by setting injection tubing and packer above the Broom Creek perforations, as shown in Figure 9-2, the proposed design for the conversion of MAG 1 to a $CO_2$ injection well.

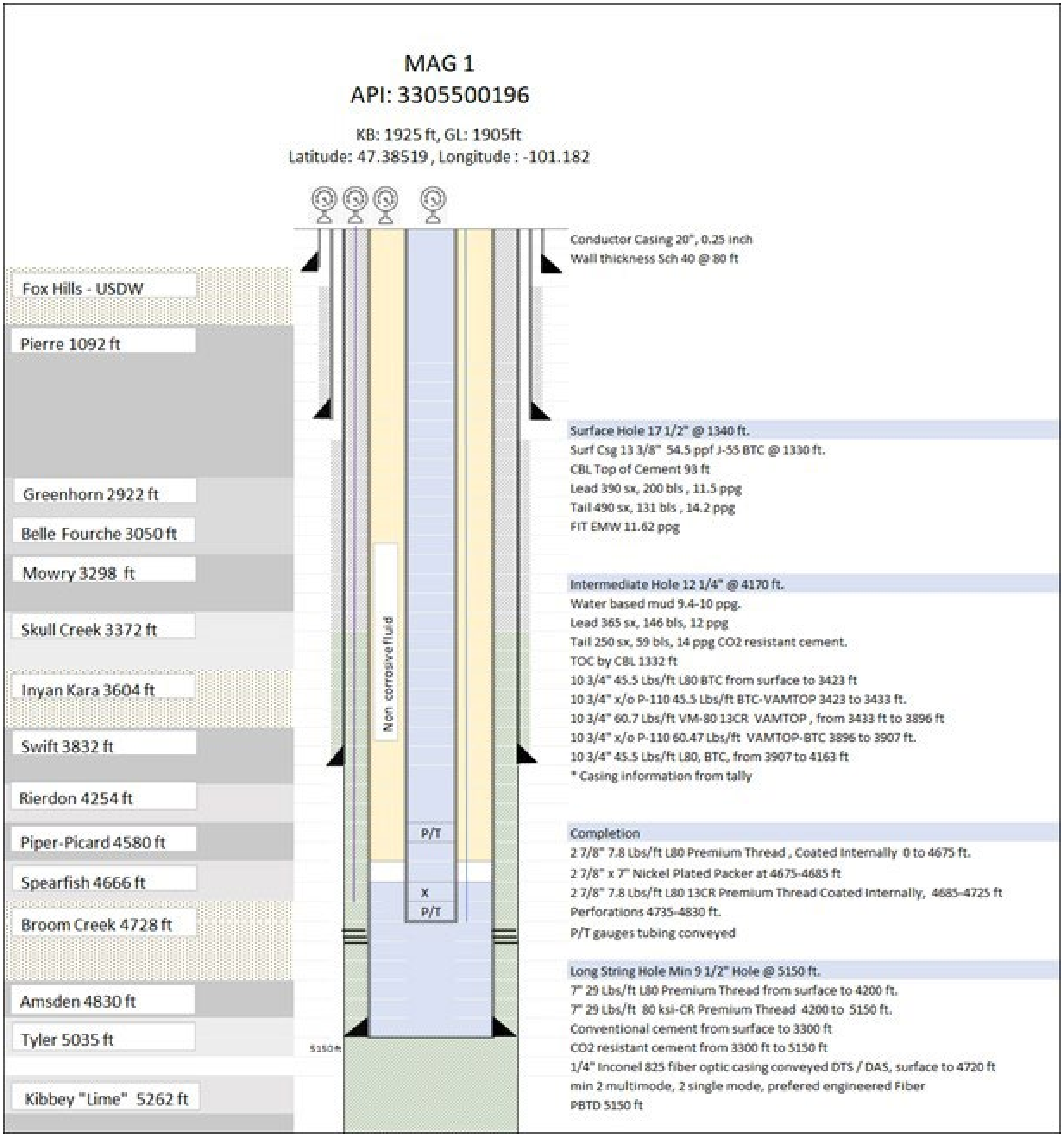



Figure 9-2. MAG 1 Proposed wellbore schematic as a $CO_2$ injection well. Casing-conveyed fiber-optic cable shown in purple from surface to the Broom Creek Formation.

Tables 9-1 through 9-4 provide the casing and cement programs for the MAG 1 drilling program as of October 11, 2020, which demonstrate compliance of the executed well construction program with NDAC § 43-05-01-09 and § 43-05-01-09(2) for conversion into a $CO_2$ storage injection well.

**Table 9-1. $CO_2$ Injection Well MAG 1 – Well Information**

| **Well Name:** | **MAG 1** | **NDIC No.:** | | **API No.:** | **3305500196** |
|---|---|---|---|---|---|
| **County:** | McLean | **State:** | ND | **Operator:** | Midwest AgEnergy Group, LLC |
| **Location:** | Sect. 18, T145N R82W | **Footages:** | 295 FNL<br>740 FWL | **Total Depth:** | 9,213 ft |

FNL: From the north line.
FWL: From the west line.

**Table 9-2. $CO_2$ Injection Well MAG 1 – Casing Program**

| Section | Hole Size, in. | Casing o.d., in. | Weight, lb/ft | Grade | Connection* | Top Depth, ft | Bottom Depth, ft | Objective |
|---|---|---|---|---|---|---|---|---|
| Surface | 17½ | 13⅜ | 54.5 | J55 | BTC | 0 | 1,330 | Isolate Fox Hills |
| Intermediate | 12¼ | 10¾ | 45.5 | L80 | BTC | 0 | 3,433 | Isolate Inyan Kara |
| Intermediate | 12¼ | 10¾ | 60.7 | VM-80 13CR | VAM TOP | 3,433 | 3,907 | Isolate Inyan Kara |
| Intermediate | 12¼ | 10¾ | 45.5 | L80 | BTC | 3,907 | 4,163 | Isolate Inyan Kara |
| Long String | 9½ | 7 | 29 | L80 | Premium | 0 | 4,200 | |
| Long String | 9½ | 7 | 29 | L80 CR13 | Premium | 4,200 | 5,150 | Injection target |

BTC: Buttress.

**Table 9-3. $CO_2$ Injection Well MAG 1 – Casing Properties**

| o.d., in. | Grade | Weight, lb/ft | Con-nect. | i.d., in. | Drift, in. | Burst, psi | Collapse, psi | Yield Strength, Klb | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Body | Conn. |
| 13⅜ | J55 | 54.5 | BTC | 12.615 | 12.459 | 2,730 | 1,130 | 853 | 909 |
| 10¾ | L80 | 45.5 | BTC | 9.95 | 9.875 | 5,210 | 2,470 | 1,040 | 1,062 |
| 10¾ | VM-80 13CR | 60.7 | VAM TOP | 9.66 | 9.504 | 7,100 | 5,170 | 1,398 | 1,398 |
| 7 | L80 | 29 | M-M | 6.184 | 6.059 | 8,160 | 7,030 | 676 | 676 |
| 7 | L80 CR13 | 29 | M-M | 6.184 | 6.059 | 8,390 | 7,030 | 676 | 676 |

M-M: Premium metal to metal connection.

**Table 9-4. $CO_2$ Injection Well MAG 1 – Cement Program**

| Casing, in. | Tail | | Lead | | Excess, % | Volume, sacks |
|---|---|---|---|---|---|---|
| | Slurry | Interval, ft | Slurry | Interval, ft | | |
| 13⅜ | Varicem*, 14.2 ppg | 800–1,330 | Varicem*, 11.5 ppg | 93–800** | 50–100 | 880 |
| 10¾ | Corrosacem*** 14 ppg | 2,750–4,163 | Neo Cement* 12 ppg | 1,332–2,750** | 50–100 | 616 |
| 7 | $CO_2$-resistant Slurry 14.5 ppg | 3,300–5,150 | Portland cement + additive 11.5–12.5 ppg | 0–3,300 | 50 | 1,034 |

* Varicem and Neo cement are conventional portland cement slurry plus additives.
** The cement top was obtained from the CBL–USIT log.
*** Corrosacem is an enhanced portland cement blend to resist the degradation by $CO_2$ reaction.

Evaluation of the need for a two-stage cementing job for the long-string section will be conducted considering the wellbore condition and hydraulic pressure simulation of the cementing operation. Communication for approval from the North Dakota Department of Mineral Resources (DMR) will occur prior to installation.

## 9.2 Monitoring Well MAG 2 – Well Casing and Cementing Programs

To meet testing and monitoring requirements, a monitor well, MAG 2, will be drilled through the Broom Creek reservoir into the Amsden/Tyler lower confining seals, as shown in Figure 9-3, MAG 2 proposed wellbore design.

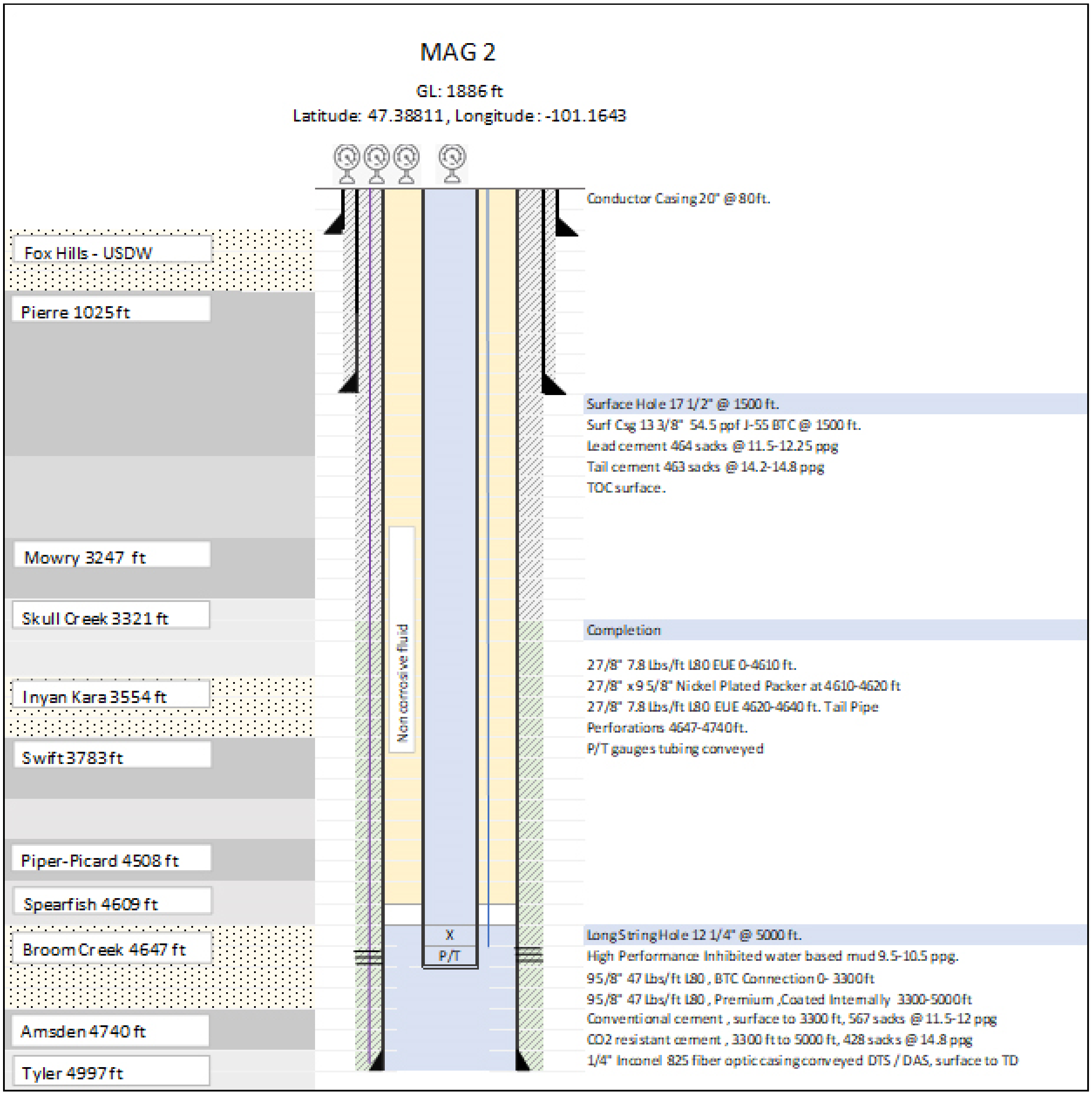



Figure 9-3. Monitor Well MAG 2 proposed wellbore schematic. Casing-conveyed fiber-optic cable shown in purple from surface to the Broom Creek Formation.

Tables 9-5 through 9-8 provide the proposed casing and cement programs for MAG 2, which demonstrate compliance for the well construction program with NDAC § 43-05-01-09 and § 43-05-01-09(2) for a $CO_2$ monitoring well.

**Table 9-5. Monitor Well MAG 2 – Well Information**

| | | | | | |
|---|---|---|---|---|---|
| **Well Name:** | **MAG 2** | | | | |
| **County:** | McLean | **State:** | ND | | |
| **Location:** | Sect. 7, T145N R82W | **Footages*:** | 820 FSL 165 FEL | **Total Depth:** | 5,000 ft |

* Estimates; location has not been surveyed

**Table 9-6. Monitor Well MAG 2 – Casing Program**

| Section | Hole Size, in. | Casing o.d., in. | Weight, lb/ft | Grade | Conn. | Top Depth, ft | Bottom Depth, ft | Objective |
|---|---|---|---|---|---|---|---|---|
| Surface | 17½ | 13⅜ | 54.5 | J55 | BTC | 0 | 1,500 | Isolate Fox Hills |
| Long String | 12¼ | 9⅝ | 47 | L80 | BTC | 0 | 3,300 | |
| Long String | 12¼ | 9⅝ | 47 | L80 Coated | Premium* | 3,300 | 5,000 | Monitoring zone |

**Table 9-7. Monitor Well MAG 2 – Casing Properties**

| o.d., in. | Grade | Weight, lb/ft | Connection | i.d., in. | Drift, in. | Burst, psi | Collapse, psi | Yield Strength, Klb | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Body | Connection |
| 13 ⅜ | J55 | 54.5 | BTC | 12.615 | 12.459 | 2,730 | 1,130 | 853 | 909 |
| 9 ⅝ | L80 | 47 | BTC | 8.681 | 8.525 | 6,870 | 4,750 | 1,086 | 1,122 |
| 9 ⅝ | L80 | 47 | Premium* | 8.681 | 8.525 | 6,870 | 4,750 | 1,086 | 1,086 |

* Connection will be compatible with the internal coating requirements.

**Table 9-8. Monitor Well MAG 2 – Cement Program**

| Casing, in. | Tail | | Lead | | Excess, % | Volume, sacks |
|---|---|---|---|---|---|---|
| | Slurry | Interval, ft | Slurry | Interval, ft | | |
| 13⅜ | Portland cement + additives, 14.2–14.8 ppg | 1,000–1,500 | Portland cement + additives, 11.5–12.5 ppg | 0–1,000 | 100 | 927 |
| 9⅝ | $CO_2$-resistant cement, 14.8 ppg | 3,300–5,000 | Portland cement + additives, 11.5–12 ppg | 0–3,300 | 50 | 996 |

Evaluation of the need for a two-stage cementing job for the long-string section will be conducted considering the wellbore condition and hydraulic pressure simulation of the cementing operation. Communication for approval from the North Dakota DMR will occur prior to installation.

# 10.0 PLUGGING PLAN

## 10.0 PLUGGING PLAN

The proposed plug and abandonment (P&A) procedure for the MAG 1 well is intended to be interpreted as proposed conditions and does not reflect the current as-constructed state for the MAG 1 well. Also, the plugging operations are likely to occur at different times in the life cycle of the injector well, MAG 1, and the monitor well, MAG 2. The MAG 1 well is planned for P&A once the $CO_2$ injection operation ceases. The $CO_2$ monitor well, MAG 2, is planned for P&A after verification and approval that the $CO_2$ plume has stabilization.

A proposed P&A procedure will be provided to the NDIC. After approval, ample notification will be given to allow an NDIC representative to be present during the plugging operations. The P&A events will be documented by a workover supervisor during P&A execution. The records of the P&A events shall demonstrate the utilization of $CO_2$-compatible materials used and complete isolation of the injection zone.

### 10.1 MAG 1: P&A Program

The proposed MAG 1 $CO_2$ injection well schematic is provided in Figure 10-1.

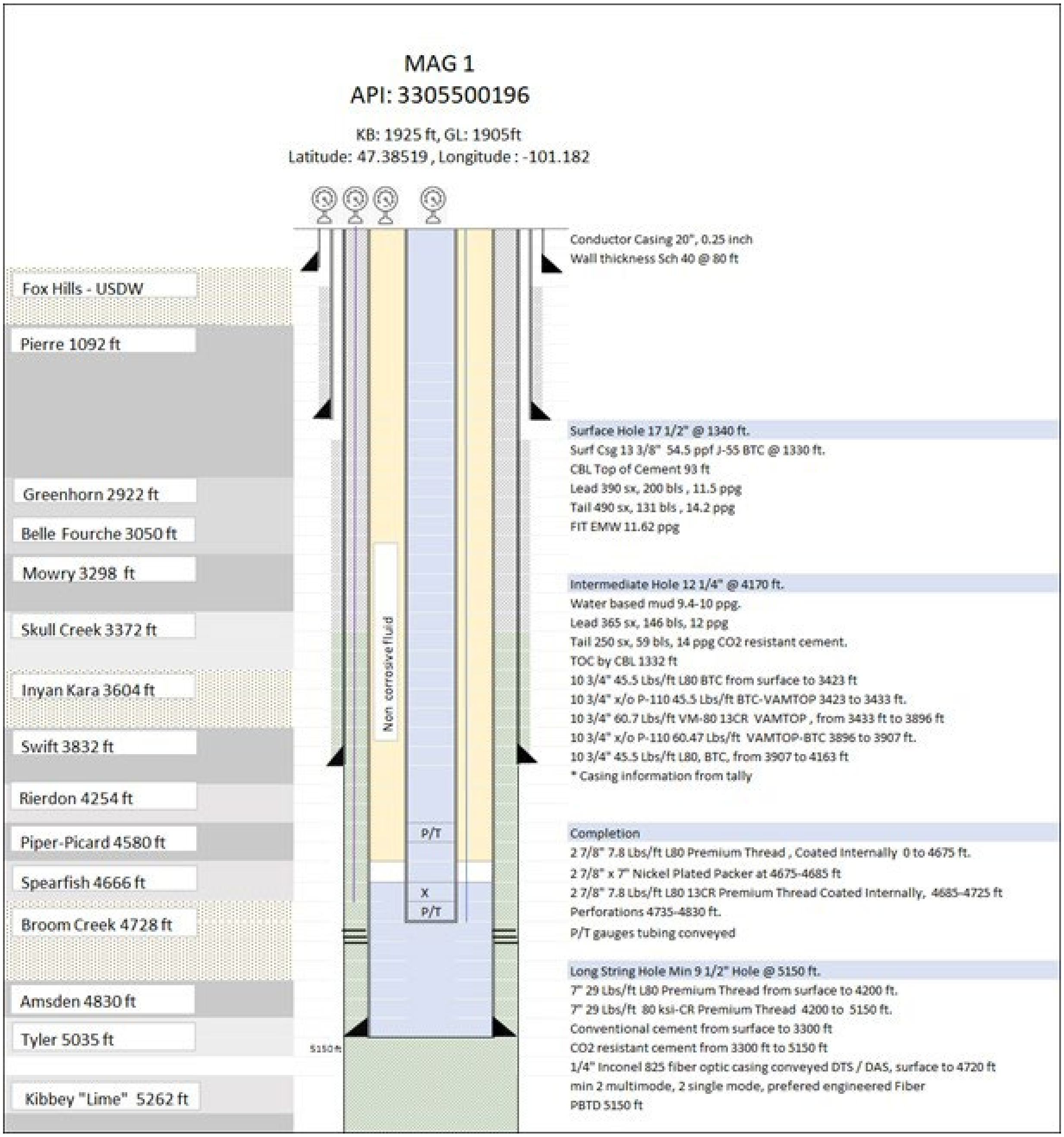



Figure 10-1. Proposed $CO_2$ injection well schematic for MAG 1.

The NDIC will be contacted and an intent to plug and abandon form for MAG 1 will be filed for approval. Final adjustments to the proposed P&A procedure will be made based on current wellbore conditions and NDIC field inspector recommendations. Currently, the proposed P&A procedure for the well is as follows.

Proposed P&A Procedure:

1. After injection operations have been terminated, the well will be flushed with a kill fluid with a calculated fluid weight for proper execution. A minimum of three tubing volumes will be pumped, remaining below the fracture pressure and ensuring control of the well.

2. Move-in (MI) and rig up (RU) workover rig onto the MAG 1 well. All $CO_2$ flowlines and valves will be marked and noted by the rig supervisor prior to MI and RU.

3. Conduct and document a safety meeting.

4. Record bottomhole pressure (BHP) from downhole gauges and calculate kill fluid density. BHP measurements will be taken by using the installed tubing-conveyed downhole pressure gauges. In case the gauges are not functional, the operator may use surface tubing pressure gauges to calculate kill mud density.

5. Test the pump and line to 5,000 psi or 90% of maximum pump pressure. Fill tubing with kill fluid. Bleeding off occasionally may be necessary to remove all air from the system. Wait for well to stabilize. Shut in tubing. Monitor tubing pressure.

6. Test casing annulus to 1,500 psi and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

   Note: If failure in long-string casing is identified, the operator will prepare a plan to repair the well prior to P&A.

7. If both casing and tubing are dead, then nipple up blowout preventers (NU BOPs).

   Contingency: If the well is not dead or the pressure cannot be bled off via tubing, RU wireline and set plug in lower-profile nipple below packer. Unlatch tubing from the packer and circulate tubing and annulus with kill weight fluid until the well is on control. After casing and tubing pressure are zero, nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string in case the packer needs to be unlatched.

8. Pull out of hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packer, RU electric line and make a cut on the tubing string just above the packer. The cut must be made above the packer at least 5 to 10 ft MD. Pull the tubing string out of hole and proceed to the next step. If problems are noted, update the cement remediation plan. A cement retainer might be used to force cement through the packer if it cannot be removed.

9. Pick up work string and trip in hole (TIH) with bit to condition wellbore.

10. Pull out of hole and RU logging unit. Confirm external mechanical integrity by running one of the tests listed below as options. Rig down logging truck.

    - Activated neutron log
    - Noise log
    - Production logging tool (PLT)
    - Tracers
    - Temperature log
    - DTS (distributed-temperature sensing) survey (no required logging unit)

11. TIH with work string and cement retainer to the top of Plug 1. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

12. Mix and pump $CO_2$-resistant slurry to cover the Broom Creek Formation and isolate from the Dakota Group in accordance with program. Under displaced two barrels of cement. Disconnect from retainer and finish displacing the last two barrels on top of the cement retainer. Check for flow. Pull work string 150 ft and circulate.

13. Pull up hole, set a balanced plug with $CO_2$-resistant cement, 15.8 ppg, across Dakota Group and isolate it from the Fox Hills USDW. Pull out above plug and circulate. Wait on setting time and tag top of the plug.

14. Pull up hole, set balanced plug with Class G cement + additive, 15.8 ppg, to cover the shoe of the surface casing. Pull out above the plug and circulate. Wait on setting time and tag top of the plug.

15. Pull up hole, set surface plug with Class G cement + additive, 15.8 ppg, to isolate the top of surface casing.

16. Lay down all work string. Rig down all equipment and move out.

17. Dig out wellhead and cut off casing 5 ft below ground level (GL). Weld ½-in. steel cap on casing with well name, date inscribed, and information that it was used for $CO_2$ injection.

18. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

19. Within 60 days, submit Form 7 plugging report after plugging operations are complete – NDAC § 43-05-01-11.5(4).

20. Submit notice of intent to reclaim to NDIC 30 days in advance prior to reclamation – NDAC § 43-05-01-18(10d).

The proposed P&A plan for MAG 1 is summarized in Table 10-1 and provided in Figure 10-2.

**Table 10-1. Summary of P&A Plan for MAG 1**

| Cement Plug Number | Interval Range, ft | Thickness, ft | Volume, sacks | Notes |
|---|---|---|---|---|
| 1 | 4,550–5,150 | 600 | 225 | $CO_2$-resistant slurry, 15.8 ppg, 1.11 $ft^3$/sx<br>Squeezed cement job to isolate perforations |
| 2 | 3,350–3,850 | 500 | 103 | $CO_2$-resistant slurry, 15.8 ppg, 1.11 $ft^3$/sx<br>Balanced plug |
| 3 | 1,000–1,500 | 500 | 99 | Conventional cement, 15.8 ppg, 1.16 $ft^3$/sx<br>Balanced plug |
| 4 | 0–80 | 80 | 16 | Conventional cement, 15.8 ppg, 1.16 $ft^3$/sx<br>Balanced plug |

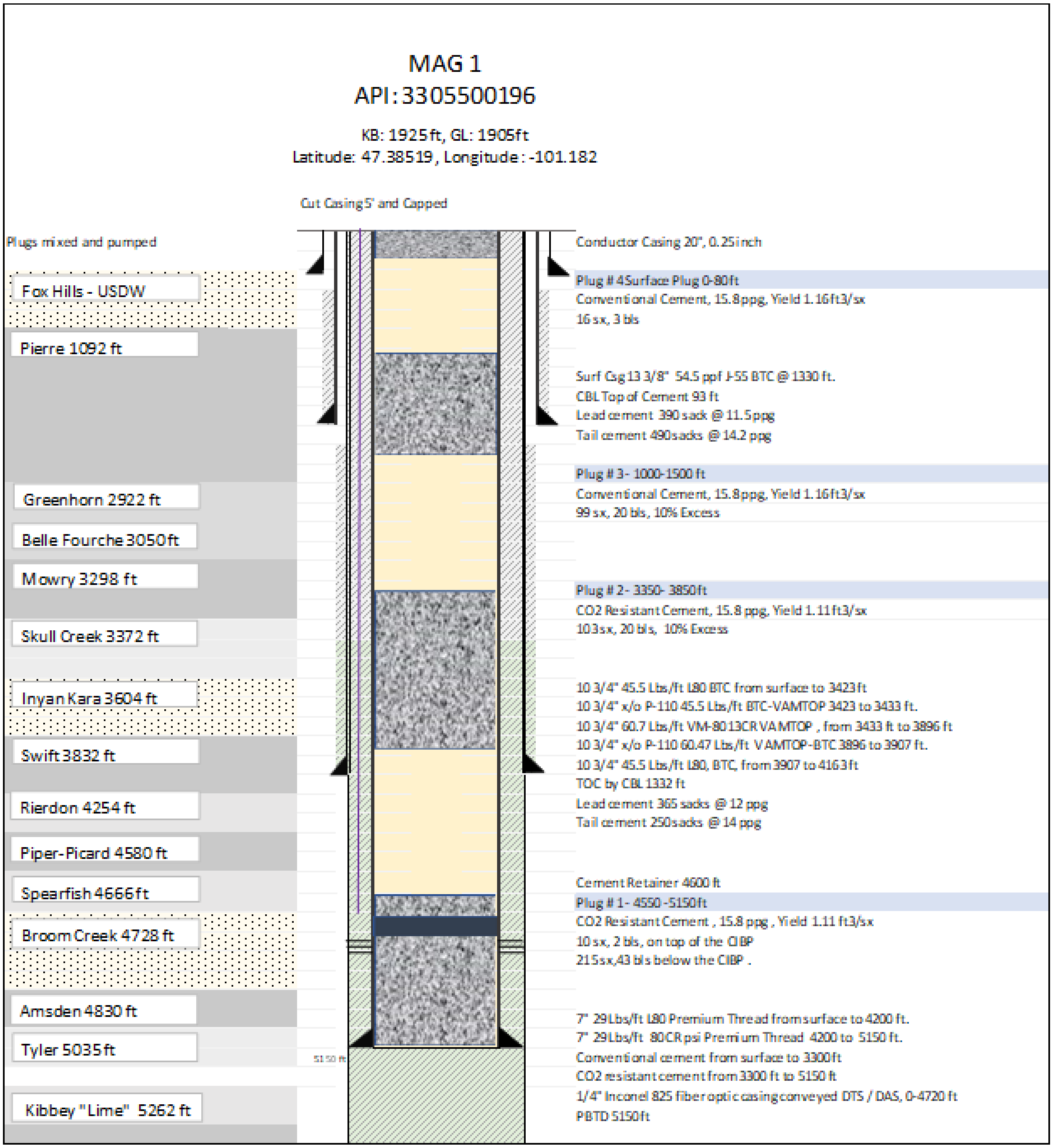



Figure 10-2. Schematic of proposed P&A plan for MAG 1.

## 10.2 MAG 2 P&A Program

The MAG 2 wellbore is to be plugged and abandoned when the $CO_2$ plume has stabilized and monitoring of the plume extent is no longer necessary.

A proposed $CO_2$-monitoring well schematic of MAG 2 is provided in Figure 10-3.

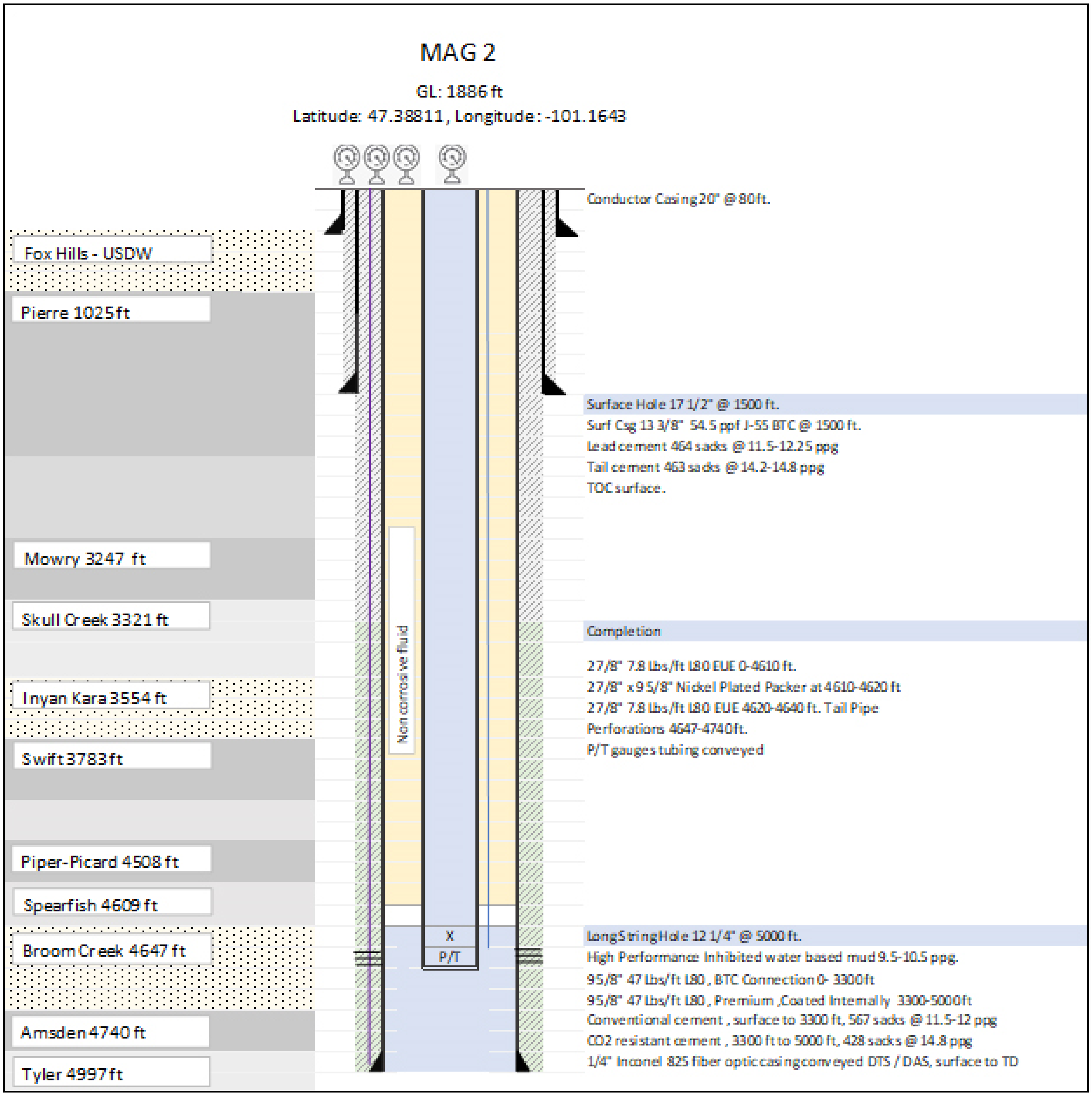



Figure 10-3. Proposed monitoring wellbore schematic for MAG 2.

The proposed procedure for P&A of the MAG 2 wellbore will be performed as follows.

1. MI rig onto MAG 2 and RU.

2. Conduct and document a safety meeting.

3. Test the pump and line to 5,000 psi or 90% of maximum pump pressure. Fill tubing with kill fluid. Bleeding off occasionally may be necessary to remove all air from the system. Monitor tubing and annulus pressure.

4. Test casing annulus to 1,500 psi and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

   Note: If failure in long-string casing is identified, the operator will prepare a plan to repair the well prior to P&A.

5. If both casing and tubing are dead, then NU BOPs.

   Contingency: If the well is not dead or the pressure cannot be bled off via tubing, RU wireline and set plug in lower-profile nipple below packer. Unlatch the tubing from the packer and circulate tubing and annulus with kill weight fluid until the well is on control. After casing and tubing pressure are zero, nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string in case the packer needs to be unlatched.

6. Pull out of hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packer, RU electric line and make cut on tubing string just above packer. A cut must be made above the packer at least 5 to 10 ft MD. Pull the work string out of hole and proceed to next step. If problems are noted, update the cement remediation plan. A cement retainer might be used to force cement through the packer if it cannot be removed.

7. Pick up work string and TIH with bit to condition wellbore.

8. Pull out of the hole and RU logging unit. Confirm external mechanical integrity by running one or a combination of the tests listed below as options. Rig down logging truck.

   - Activated neutron log
   - Noise log
   - PLT
   - Tracers
   - Temperature log
   - CBL–USIT
   - DTS survey (no required logging unit)

9. TIH work string with cement retainer to the top of Plug 1. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

10. Mix and pump $CO_2$-resistant slurry to cover the Broom Creek Formation and isolate from the Dakota Group in accordance with program. Under displaced four barrels of cement. Disconnect from retainer and finish displacing the last four barrels on top of the cement retainer. Check for flow. Pull work string 150 ft and circulate.

11. Pull up hole, set balanced plug with $CO_2$-resistant cement, 15.8 ppg, to cover Dakota Group and isolate it from the Fox Hills USDW. Pull out above the plug and circulate. Wait on setting time and tag top of the plug.

12. Pull up hole, set balanced plug with Class G cement + additive, 15.8 ppg, to cover the shoe of the surface casing. Pull out above the plug and circulate. Wait on setting time and tag top of the plug.

13. Pull up hole, set surface plug with Class G cement + additive, 15.8 ppg, to isolate the top of surface casing.

14. Lay down all work string. Rig down all equipment and move out.

15. Dig out wellhead and cut off casing 5 ft below GL. Clean cellar to where a plate can be welded with well information.

16. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

17. Within 60 days, submit Form 7 plugging report after plugging operations are complete – NDAC § 43-05-01-11.5(4).

18. Submit notice of intent to reclaim to NDIC 30 days in advance prior to reclamation – NDAC § 43-05-01-18(10d).

The proposed P&A plan for MAG 2 is summarized in Table 10-2 and provided in Figure 10-4.

**Table 10-2. Summary of P&A Plan for MAG 2**

| Cement Plug Number | Interval Range, ft | Thickness, ft | Volume, sacks | Note |
|---|---|---|---|---|
| 1 | 4,550–5,000 | 450 | 333 | $CO_2$-resistant slurry, 15.8 ppg, 1.11 $ft^3$/sx<br>Squeezed cement job to isolate perforations |
| 2 | 3,300–3,800 | 500 | 203 | $CO_2$-resistant slurry, 15.8 ppg, 1.11 $ft^3$/sx<br>Balanced plug |
| 3 | 1,300–1,800 | 500 | 195 | Conventional cement, 15.8 ppg, 1.16 $ft^3$/sx<br>Balanced plug |
| 4 | 0–80 | 80 | 31 | Conventional cement, 15.8 ppg, 1.16 $ft^3$/sx<br>Balanced plug |

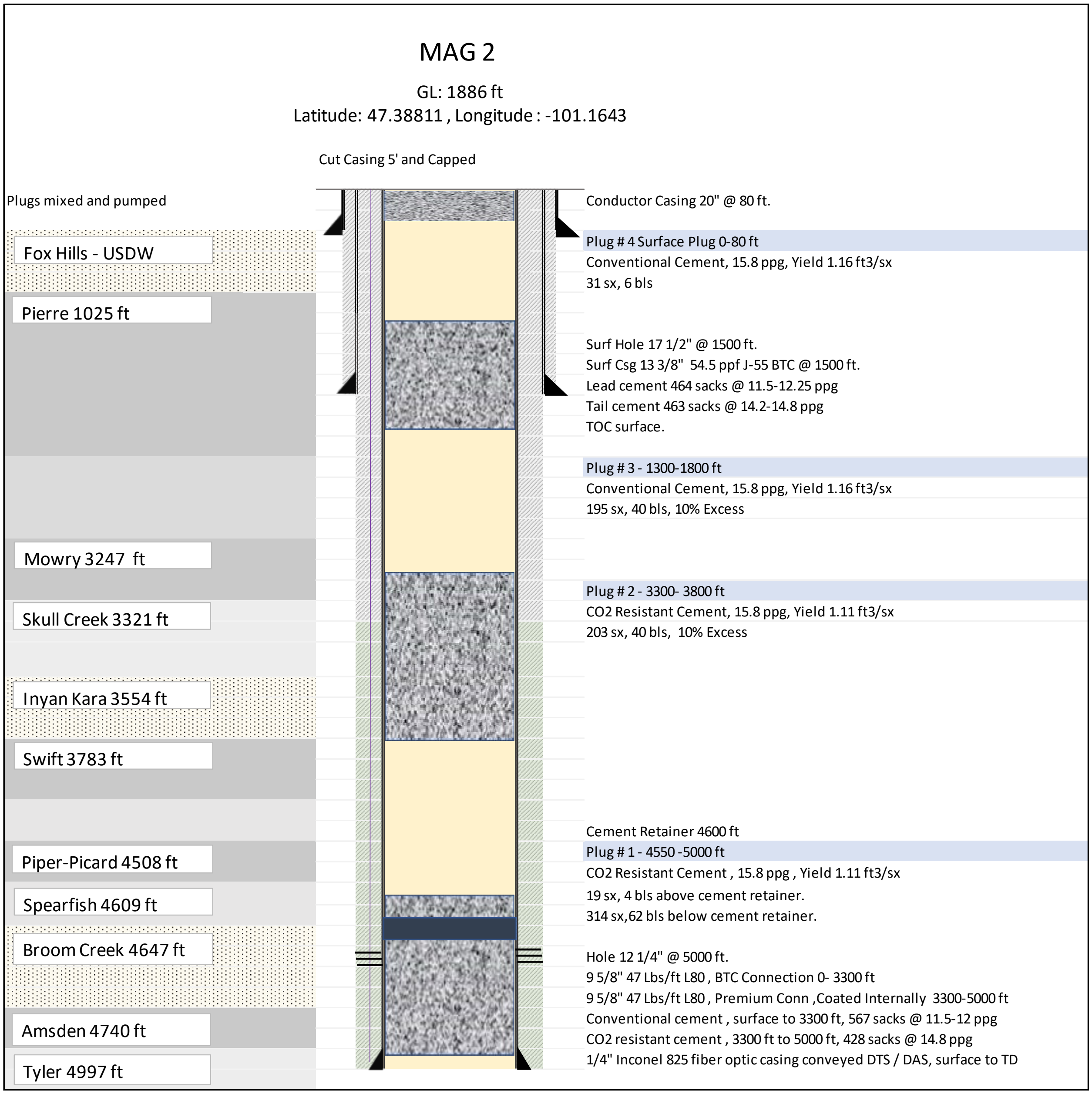



Figure 10-4. Schematic of proposed abandonment plan for monitoring well MAG 2.

# 11.0 INJECTION WELL AND STORAGE OPERATIONS

## 11.0 INJECTION WELL AND STORAGE OPERATIONS

This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.

**Table 11-1. MAG 1 Proposed Injection Well Operating Parameters**

| Item | Values | Description/Comments |
|---|---|---|
| **Injected Volume** | | |
| Total Injected Volume | 4,000,000 tonnes | Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day |
| **Injection Rates** | | |
| Average Injection Rate | 548 tonnes/day (10.35 MMscf/day) | Based on 200,000 tonnes/year for 20 years of injection (using 365 operating days per year) |
| Average Maximum Daily Injection Rate | 2,729 tonnes/day (51.56 MMscf/day) | Based on maximum bottomhole injection pressure (2,970 psi) |
| **Pressures** | | |
| Formation Fracture Pressure at Top Perforation | 3,300 psi | Based on geomechanical analysis of formation fracture gradient as 0.69 psi/ft (see Section 2.0) |
| Average Surface Injection Pressure | 1,158 psi | Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day) using the designed 2.875-inch tubing |
| Surface Maximum Injection Pressure | 4,300 psi | Based on maximum bottomhole injection pressure (2,970 psi) using the designed 2.875-inch tubing |
| Average Bottomhole Pressure (BHP) | 2,570 psi | Based on average daily injection rate of 548 tonnes/day |
| Calculated Maximum BHP | 2,970 psi | Based on 90% of the formation fracture pressure of 3,300 psi |

### 11.1 MAG 1 Well – Proposed Completion Procedure to Conduct Injection Operations

As described in Section 9.1, the MAG 1 well will be reentered and completed as a $CO_2$ injector (Figures 11-1 and 11-2 and Tables 11-2 through 11-4). The following proposed completion procedure outlines the steps necessary to complete and test the well.

1. Rig up workover (WO) rig and equipment, check pressure in the casing, and release pressure if any.

2. Remove night cap and nipple up blowout preventer (BOP).

3. Test BOP to maximum anticipated surface pressure (MASP).

4. Pick up work string, scraper, and bit to clean out residual cement.

5. Run in the hole and tag plug back total depth (PBTD). Condition casing if needed.

6. Circulate the wellbore with brine, compatible with the formation, estimated at 10 ppg, with a reservoir pressure gradient of 0.512 psi/ft.

7. Trip out of hole (TOOH) work string with bit and scraper.

8. Test casing for 30 minutes to 1,500 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the operator will be required to assess the root cause and correct it.

9. Conduct safety meeting to discuss logging and perforating operations.

10. Rig up logging truck.

11. Install and test lubricator.

12. Run cementing evaluation logs by program.
    Note: run cement bond logs without pressure as a first pass and repeat pass with 1,000 psi pressure. If cementing logs show poor bonding or a low top of cement, the results will be communicated to the NDIC and an action plan will be prepared.

13. Round trip a magnetic tool and casing collar locator (CCL) to identify location of the fiber-optic cable.
    Note: DTS/DAS (distributed temperature sensing/distributed acoustic sensing) fiber-optic cable will be run along the exterior of the long-string casing. Special clamps, bands, and centralizers are installed to protect the fiber and provide a marker for wireline operations.

14. Perforate the Broom Creek Formation, minimum of 6 spf (shots per foot), 36.7-inch-deep penetration, 0.37-inch diameter, and 60° phase (ensure shots do not penetrate fiber-optic cable). Actual perforation depths and design will be determined by designated geologist and engineers, and based on the log analysis review, as well as selected contractor.

15. TOOH with perforating guns.

16. Rig down logging truck and lubricator.

17. Pick up retrievable testing packer with downhole gauges and run in the hole with work string to the top of the perforations.

18. Set packer above perforations to isolation and test the annulus to ensure seal and no communication with backside.

19. Perform an injectivity test/step rate test (SRT) with clean brine compatible with formation.

20. If the well shows poor injectivity, perform a near-wellbore/perforation cleanout using a designed concentration of acid. Adjust acid formulation and volumes with water samples and compatibility test. Maximum injection pressure is not to exceed formation fracture pressure as determined in SRT.

21. Unset packer and circulate hole if acid cleanout is performed.

22. TOOH and lay down temporary packer and work string.

23. Rig up spooler and prepare rig floor to install completion injection assembly (injection tubing and packer).

24. Pick up and run completion assembly in accordance with program.

25. Displace the well with inhibited packer fluid.

26. Set injection packer within 50 ft above the top perforations, according to manufacturer recommendations and NDIC requirements. Test backside/annulus of tubing/casing to designated pressure during operations.

27. Install tubing hanger and cable connectors.

28. Nipple down BOP.

29. Install injection tree.

30. Rig down WO rig and equipment.

31. Move in wireline unit and perform through-tubing cased-hole logging in accordance with program (rigless).

**Table 11-2. MAG 1 Proposed Upper Completion**

| Description | o.d., in. | Depth, ft | Grade | Weight, lb/ft | Connection | i.d., in. | Drift i.d., in. |
|---|---|---|---|---|---|---|---|
| Tubing | 2⅞ | 0–4,675 | L80 | 7.8 | Premium | 2.323 | 2.229 |
| 2⅞-in. × 7-in. Nickel-Plated Packer + Pressure/Temperature (P/T) Gauge | | | | | | | |
| Tubing | 2⅞ | 4,685–4,425 | L80 13 CR | 7.8 | Premium | 2.323 | 2.229 |
| P/T Gauge | | | | | | | |

**Table 11-3. MAG 1 Tubing Properties**

| o.d., in. | Grade | Weight, lb/ft | Connection | i.d., in. | Drift i.d., in. | Collapse, psi | Burst, psi | Tension, Klb |
|---|---|---|---|---|---|---|---|---|
| 2⅞ | L80 | 7.8 | Premium | 2.323 | 2.229 | 13,890 | 13,440 | 180 |
| 2⅞ | L80 13 CR | 7.8 | Premium | 2.323 | 2.229 | 13,890 | 13,440 | 180 |

**Table 11-4. MAG 1 Cased-Hole Logging**

| Description | Depth, ft | Comments |
|---|---|---|
| CBL (cement bond log)–VDL (variable density log)–CCL–USIT (ultrasonic imaging tool) | 0–5,120* | Cement/casing log; 30-ft shoe track |
| CIL (casing inspection log) | 0–4,685* | Baseline; run through tubing |
| Temperature Log | 0–4,685* | Baseline; run through tubing |
| Pulsed Activated Neutron | 0–4,685* | Baseline; run through tubing |

* Estimated, will be adjusted with actual tally.

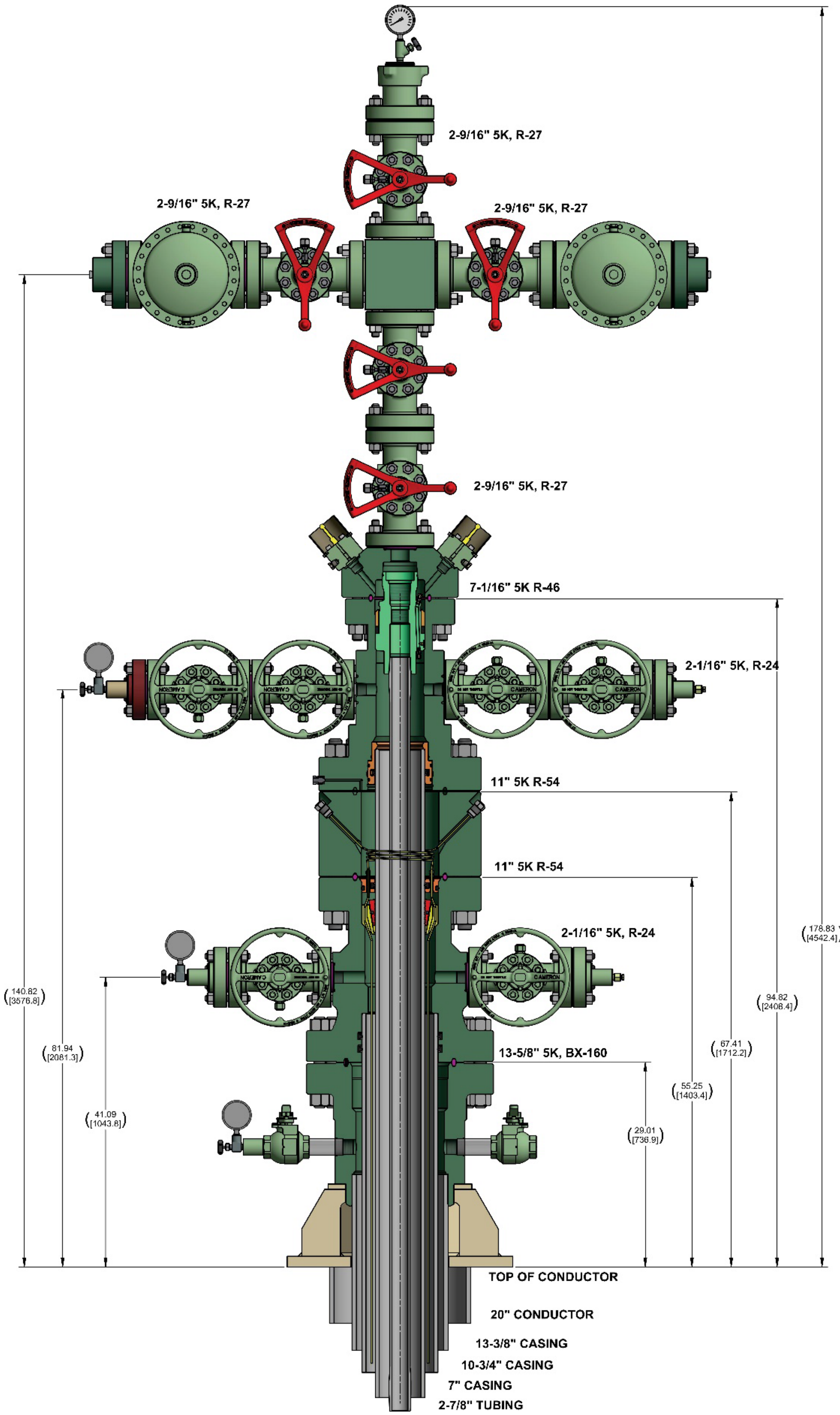



Figure 11-1. MAG 1 proposed $CO_2$-resistant wellhead schematic.

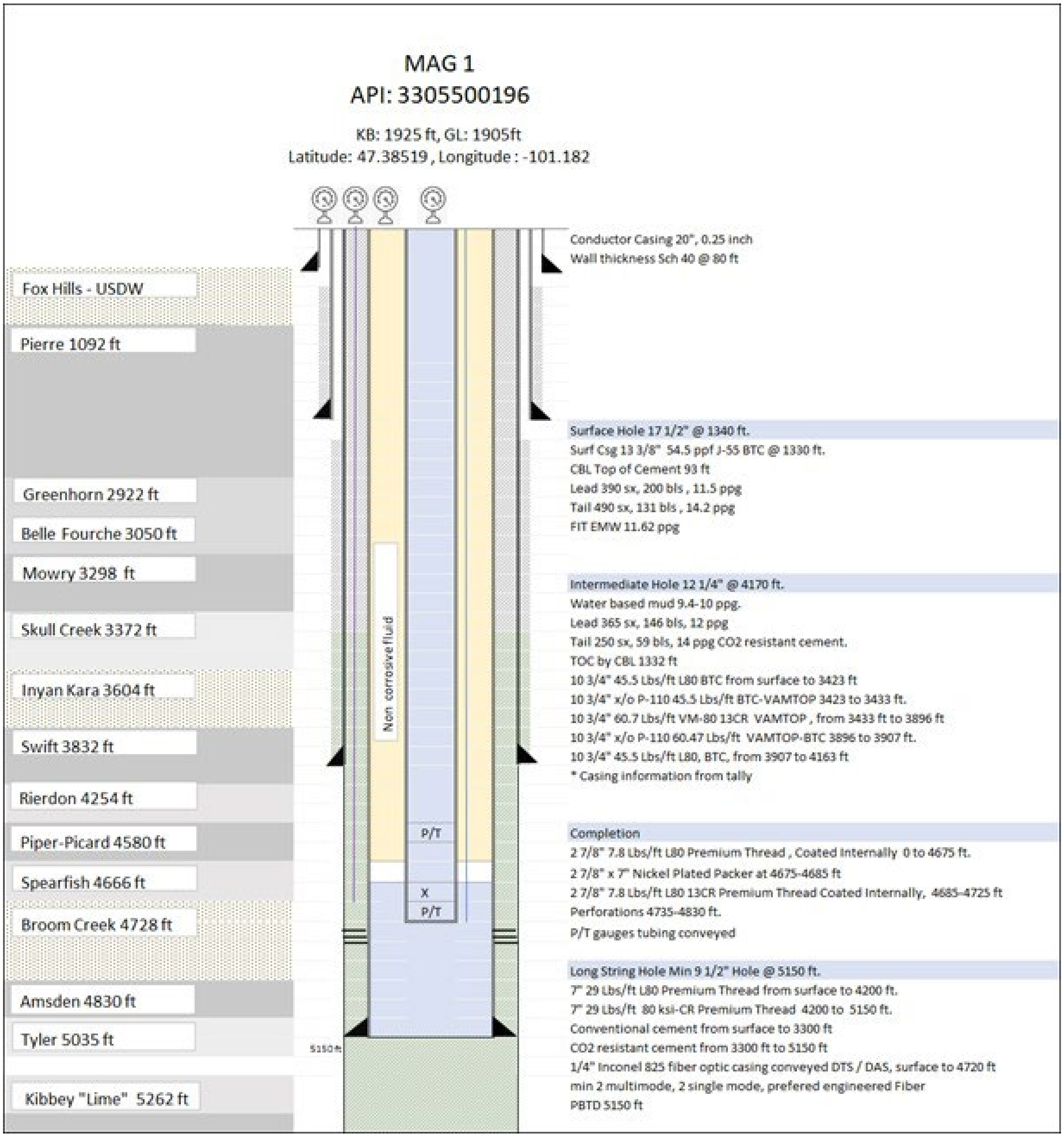



Figure 11-2. MAG 1 proposed completed wellbore schematic.

### 11.2 MAG 2 Well – Proposed Procedure for Monitoring Well Operations

MAG 2 will be constructed as a $CO_2$-monitoring well (Figures 11-3 and 11-4 and Tables 11-5 through 11-7) to support deep subsurface monitoring of MAG 1, the $CO_2$ stream injection well. Monitoring of the $CO_2$ plume extent and the storage reservoir pressure will be conducted continuously through the use of the casing-conveyed fiber-optic cable installed on the outside the long string and pressure/temperature gauges deployed along the outside of the tubing. Monitoring will be conducted during injection operations as well as during the postinjection site closure (PISC) which are also discussed in more detail in the Testing and Monitoring section of this permit application. Monitoring methods will include a combination of formation-monitoring methods (e.g., downhole pressure, downhole temperature, and pulsed-neutron capture/reservoir saturation tool logs) to verify casing mechanical integrity and support $CO_2$ plume stabilization evaluations.

The following proposed completion procedure outlines the steps necessary to complete and test the well.

1. Rig up WO rig and equipment, check pressure in the casing, and release pressure if any.

2. Remove night cap and nipple up BOP.

3. Test BOP to MASP.

4. Pick up work string, scraper, and bit to clean out residual cement.

5. Run in the hole and tag PBTD and condition casing if needed.

6. TOOH work string with bit and scraper.

7. Displace the well with formation-compatible brine, estimated at 10 ppg, with a reservoir pressure gradient of 0.512 psi/ft.

8. Test casing for 30 minutes with 1,500 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the operator will be required to assess the root cause and correct it.

9. Conduct safety meeting to discuss logging and perforating operations.

10. Rig up logging truck.

11. Install and test lubricator.

12. Run cased-hole logs by program.
    Note: run CBL/VDL and USIT logs without pressure as a first pass and repeat run with 1,000 psi of pressure as a second pass.
    Note: If CBLs show poor bonding, the results will be communicated to NDIC and an action plan will be prepared.

13. Run magnetic survey to identify fiber-optic orientation and complement with oriented perforating guns. An oriented gun should be used to avoid any damage to the external fiber optic.

14. Perforate the Broom Creek Formation, minimum 4 spf (shots per foot). Actual perforation depths, design, and phasing will be determined by designated geologist and engineers based on the log analysis review.
Note: DTS/DAS fiber-optic cable will be run along the exterior of the long-string casing. Special clamps, bands, and centralizers are installed to protect the fiber and provide a marker for wireline operations.

15. Pull guns out of the hole.

16. Rig down logging truck.

17. Rig up spooler and prepare rig floor to run upper completion assembly (tubing and packer).

18. Run completion assembly in accordance with program.

19. Circulate well with inhibited packer fluid.

20. Set packer within 50 ft above the top perforations, according to manufacturer recommendations and NDIC requirements. Test backside/annulus of tubing/casing to designated pressure.

21. Install tubing hanger and cable connectors.

22. Nipple down BOP.

23. Install tree.

24. Rig down WO rig and equipment.

25. Move in wireline unit and perform through-tubing cased-hole logging in accordance with program (rigless).

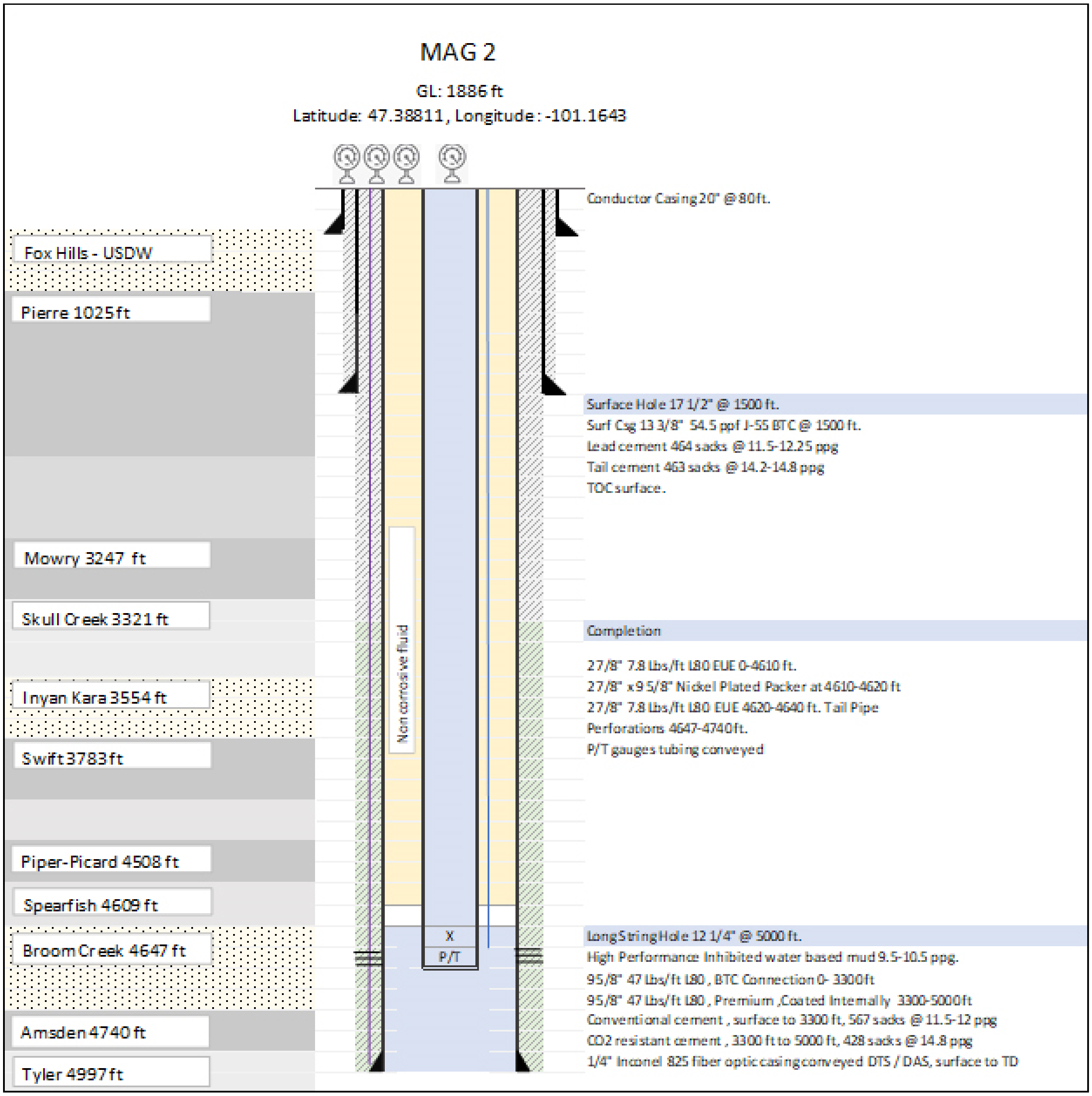



Figure 11-3. MAG 2 proposed completed wellbore schematic.

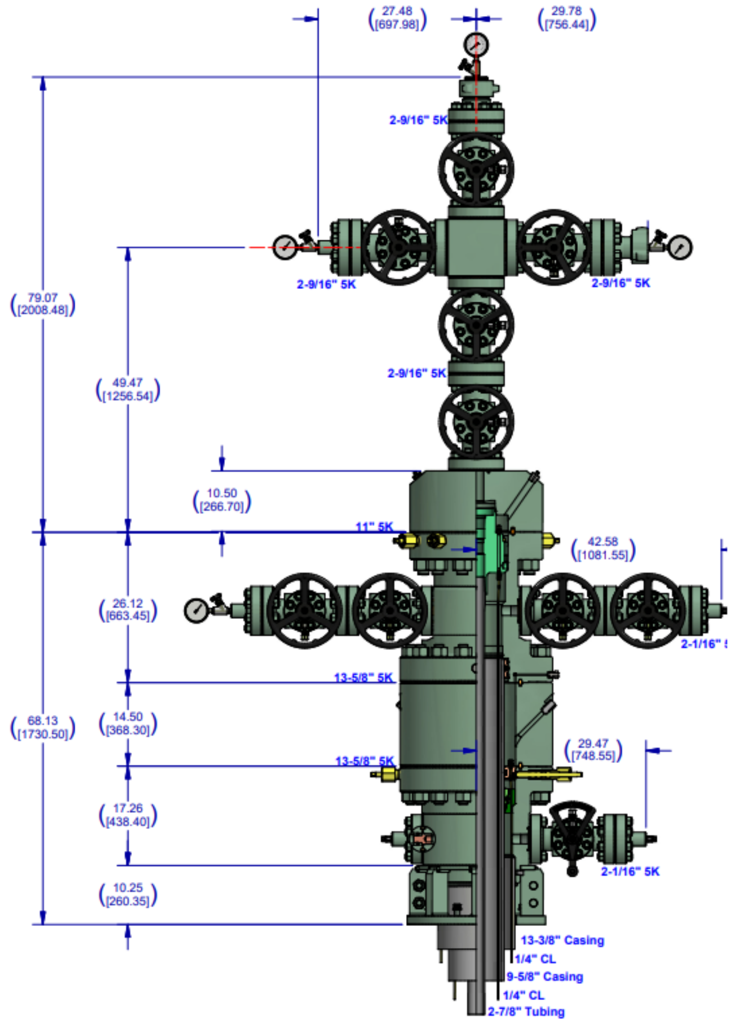



Figure 11-4. MAG 2 proposed wellhead schematic.

**Table 11-5. MAG 2 Proposed Upper Completion**

| Description | o.d., in. | Depth, ft | Grade | Weight, lb/ft | Connection | i.d., in. | Drift i.d., in. |
|---|---|---|---|---|---|---|---|
| Tubing | 2⅞ | 0–4,610 | L80 | 7.8 | EUE (external upset end) | 2.323 | 2.229 |
| 2⅞-in. × 9⅝-in. Nickel-Plated Packer | | | | | | | |
| Tubing (tail pipe) | 2⅞ | 4,620–4,640 | L80 | 7.8 | EUE | 2.323 | 2.229 |

**Table 11-6. MAG 2 Tubing Properties**

| o.d., in. | Grade | Weight, lb/ft | Connection | i.d., in. | Drift i.d., in. | Collapse, psi | Burst, psi | Tension, Klb |
|---|---|---|---|---|---|---|---|---|
| 2⅞ | L80 | 7.8 | Premium | 2.323 | 2.229 | 13,890 | 13,440 | 180 |

**Table 11-7. MAG 2 Cased-Hole Logging**

| Description | Depth, ft | Comments |
|---|---|---|
| CBL–VDL–CCL–USIT | 0–4,970* | Cement/Casing Log; 30-ft shoe track |
| CIL | 0–4,640* | Baseline; run through tubing |
| Temperature Log | 0–4,640* | Baseline; run through tubing |
| Pulsed Activated Neutron | 0–4,640* | Baseline; run through tubing |

* Estimated; will be adjusted with actual tally.

# 12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

## 12.0 FINANCIAL ASSURANCE AND DEMONSTRATION PLAN

This financial assurance and demonstration plan (FADP) is provided to meet the regulatory requirements for the geologic storage of $CO_2$ as prescribed by the state of North Dakota in North Dakota Administrative Code (NDAC) § 43-05-01-09.1. The storage facility permit (SFP) application must demonstrate that a financial instrument is in place that is sufficient to cover the costs associated with the following actions:

- Pursuant to NDAC § 43-05-01-05.1, corrective action on all active and abandoned wells, which are within the AOR (area of review) and penetrate the confining zone, and have the potential to endanger USDWs (underground sources of drinking water) through the subsurface movement of the injected $CO_2$ or other fluids.
- Pursuant to NDAC § 43-05-01-11.5, plugging of injection wells.
- Pursuant to NDAC § 43-05-01-19, implementation of postinjection site care (PISC) and facility closure activities, which includes the 10-year PISC monitoring program.
- Pursuant to NDAC § 43-05-01-13, implementation of ERRP (emergency and remedial response plan) actions.

This FADP identifies the financial instruments that will be established (Section 12.2) and provides cost estimates for each of the above actions (Section 12.3) based on the information that is provided in the SFP application.

### 12.1 Facility Information

The facility name, facility contact, and injection well locations are provided below:

| | |
|---|---|
| Facility Name: | Blue Flint Sequester Company, LLC |
| Facility Contact: | Adam Dunlop |
| Injection Well Locations: | MAG 1 (NDIC File No. 37833) NW/NW of Section 18 T145N, R82. |

### 12.2 Financial Instruments

Blue Flint is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments:

- Blue Flint will plan to increase existing well bonding or secure other financial instrument to cover costs of plugging the injection well in accordance with NDAC § 43-05-01-11.5.
- No corrective action estimates have been provided as there are no legacy wellbores within the AOR; thus no action is necessary.
- Blue Flint will establish a bond, escrow account, third-party insurance policy, or other financial instrument to ensure funds are available for PISC and facility closure activities in accordance with NDAC § 43-05-01-19.

- A third-party pollution liability insurance policy with an aggregate limit of $9 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13.

The estimated total costs of these activities are presented in Table 12-1. Section 12.3 of this FADP provides additional details of the financial responsibility cost estimates for each activity.

**Table 12-1. Cost Estimates for Activities to Be Covered**

| Activity | Estimated Total Cost |
|---|---|
| Corrective Action on Wells in the AOR | $0 |
| Plugging of Injection Well | $100,000 |
| PISC and Facility Closure | $2,467,550 |
| Emergency and Remedial Response (including endangerment to USDWs) | $9,000,000 |
| Total | $11,567,550 |

The company providing insurance will meet all the following criteria:

1. The company is authorized to transact business in North Dakota.

2. The company has either passed the specified financial strength requirements based on credit ratings or has met a minimum rating, minimum capitalization, and ability to pass the rating, when applicable.

3. The third-party insurance can be maintained until such time that the North Dakota Industrial Commission (NDIC) determines that the storage operator has fulfilled its financial obligations.

The third-party insurance, which identifies Blue Flint as the covered party, will be provided by one or a combination of the companies shown below: The Applicant has procured indicated terms for commercial Environmental Impairment Liability (‘EIL’) insurance coverage to fund covered emergency and remedial response actions to protect underground sources of drinking water arising out of sequestration operations. Coverage terms are of an indicative/estimated nature only at this time, as firm and bindable terms are not possible this far in advance of commencement of sequestration operations; however, at this time a coverage limit of $9 million per occurrence/aggregate is contemplated and likely expected to be provided by one or a combination of the following insurers:

- Ascot Insurance Group – AM Best Rated ‘A’ (Excellent)
- Aspen Insurance Group – AM Best Rated ‘A’ (Excellent)
- W.R. Berkley Insurance Group – AM Best Rated ‘A+’ (Superior)
- Ironshore Insurance Company (Liberty Mutual Group) – AM Best Rated ‘A’ (Excellent)

Final coverage terms and costs will be determined upon full underwriting and firm/bindable quotations to be issued by insurers 30–60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations.

The third-party insurance companies listed above meet both of the following criteria, as specified in NDAC §43-05-01-09.1(1)(g):

1. The companies satisfy financial strength requirements based on credit ratings in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa).

2. The companies meet a minimum rating (minimum rating based on an issuer, credit, securities, or financial strength rating as a demonstration of financial stability) and minimum capitalization (i.e., demonstration that minimum thresholds are met for the following financial ratios: debt–equity, assets–liabilities, cash return on liabilities, liquidity, and net profit) and are able to pass bond rating in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa), when applicable.

## 12.3 Financial Responsibility Cost Estimates

### *12.3.1 Corrective Action*

Blue Flint implemented the following workflow to estimate costs associated with corrective action activities: 1) delineate the AOR and 2) identify and evaluate active and abandoned legacy wells within the AOR (i.e., MAG 1) to ensure they meet the minimum completion standards for geologic storage of $CO_2$ and need no corrective action. Based on the results of the well evaluations, no correction action was needed.

### *12.3.2 Plugging of Injection Wells*

Blue Flint implemented the following approach to estimate costs associated with the plugging of the injection well: assume plugging of one Class VI injection well at a total cost of $100,000 per well, the MAG 1 well.

### *12.3.3 Implementation of PISC and Facility Closure Activities*

The breakdown of estimated costs totaling $2.272 million for implementing the PISC as described in the PISC and facility closure plan is provided in Table 12-2a, which includes the following monitoring activities: a) formation monitoring (i.e., downhole pressure and temperature surveys, pulsed-neutron logs), b) near-surface monitoring (i.e., soil gas and Fox Hills Formation testing) and mechanical integrity well tests (i.e., injection well annulus pressure, ultrasonic logs), and c) coordinated repeat 2D seismic surveys. Table 12-2a covers the estimated costs in the time period between cessation of injection activities and issuance of the certificate of project completion. The MAG 1 wellbore will be plugged upon cessation of injection, with plugging cost estimates provided in Table 12-1. As part of PISC monitoring activities, the deep subsurface monitoring well, MAG 2, and the Fox Hills monitoring well will remain until site closure. The MAG 2 wellbore will monitor the storage reservoir until site closure, with cost estimates for plugging and site closure activities provided in Table 12-2b.

**Table 12-2a Cost Estimate[1] for PISC Activities for the Blue Flint $CO_2$ Storage Project. The Cost Estimate Assumes a 10-year PISC Period.**

| Activity | Frequency | Unit Cost | Total |
|---|---|---|---|
| **Injection Pad Reclamation (MAG 1)** | | | |
| Reclamation Costs of the Injection Pad of MAG 1 | Prior to closure | $50,000 | $50,000 |
| Flowline Abandonment and Closure | Once | $21,000 | $21,000 |
| SGPS01 P&A[3] | Prior to closure | $10,000 | $10,000 |
| **Flowline Reclamation at the Capture Facility** | | | |
| Flowline Abandonment and Closure | Once | $21,000 | $21,000 |
| **Wellbore Monitoring (MAG 2)** | | | |
| Pulsed-Neutron Logging (saturation monitoring, reservoir, and AZMI[2]) | Annually until full $CO_2$ saturation occurs within storage reservoir; reduce to once every 4 years thereafter. | $45,000 | $180,000 |
| Temperature Logging (external mechanical integrity) | Annually (if needed) | $10,000 | $100,000 |
| USIT Logging (corrosion monitoring) | Once every 5 years | $55,000 | $110,000 |
| Annulus Pressure Testing (internal mechanical integrity) | Once every 5 years | $8,000 | $16,000 |
| **Near-Surface Monitoring** | | | |
| SGPS01 – Sampling and Analysis | Once | $4,450 | $4,450 |
| SGPS02 – Sampling and Analysis | Annually | $4,450 | $44,500 |
| SG01-SG04 – Sampling and Analysis | Once at start of PISC and once prior to closure | $4,450 | $35,600 |
| Up to Five Groundwater Wells – Sampling and Analysis | Once prior to closure | $2,000 | $10,000 |
| One Dedicated Fox Hills Well – Sampling and Analysis | Annually | $2,000 | $20,000 |
| **Storage Complex Monitoring** | | | |
| Time-Lapse 2D Fence Seismic Survey Acquisition and Processing | Once every 5 years | $825,000 | $1,650,000 |

**Table 12-2b Cost Estimate[1] for Site Closure and Remediation Activities for the Blue Flint $CO_2$ Storage Project**

| Activity | Timing | Description | Total |
|---|---|---|---|
| **Closure and Reclamation Costs** | | | |
| Plugging of the MAG 2 Monitoring Well | Prior to closure | Plugging activities described in Section 10 Plugging Plan | $100,000 |
| Reclamation Costs of the Monitoring Pad of MAG 2 | Prior to closure | Wellhead removal, sump removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, general labor | $50,000 |
| Fox Hills Monitoring Well P&A[2] | Prior to closure | Pipe removal, pad reclamation (rock removal and soil coverage), reseeding, general labor | $35,000 |
| SGPS02 P&A[2] | Prior to closure | Plugging and abandonment of SGPS01 and SGPS02 | $10,000 |
| Total for Closure Activities | | | $195,000 |

[1] Does not include interpretation and reporting. Costs are based on today's pricing and do not account for inflation.
[2] Plugging and abandonment assumed unless NDIC requests transfer of ownership.

Table 12-2b lists the costs for the closure of the site and activities related to injection and monitoring of CCS activities which demonstrate a total of $195 thousand. As listed in Section 6.0 PISC, Subsection 6.3.1 PISC Plan, Blue Flint plans to initiate site closure activities that will include the plugging of all wells that are not planned for continued use in monitoring the closed site; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring; and the reclaiming of the surface land of the site to as close as is practical to its original condition.

As described in 6.3.2 Site Closure Plan, the Fox Hills monitoring well and the two soil gas profile stations are available for transfer of ownership to the state. Table 12-2b demonstrates the costs for the plugging and abandonment of one of two soil gas profile stations (SGPS02) and the Fox Hills monitoring well in the case the state does not request transfer of ownership. SGPS01's plugging and abandonment cost is shown in Table 12-2a in the case it is not transferred to the state. The five groundwater sampling wells listed in Table 12-2a do not require remediation and were not incorporated into cost estimates as the wells were not constructed as part of the project and are privately owned by third parties. This brings the total for PISC and closure activities to $2.467 million.

### *12.3.4 Implementation of Emergency and Remedial Response Actions*

*12.3.4.1 Emergency Response Actions*

A review of the technical risk categories for Blue Flint identified a list of events that could potentially result in the movement of injected $CO_2$ or formation fluids in a manner that may endanger a USDW and require an emergency response. These events are as follows:

- Injectivity
- Storage capacity
- Containment – lateral migration of $CO_2$
- Containment – pressure propagation
- Containment – vertical migration of $CO_2$ or formation water brine via injection wells, other wells, or inadequate confining zones
- Natural disasters (induced seismicity)

If it is determined that one or more of these events have occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7). These response actions are summarized in Tables 7-3 and 7-4.

*12.3.4.2 Estimation of Costs of Emergency Response Actions*

Estimating the costs of implementing the emergency response actions in Tables 7-3 and 7-4 is challenging since remediation measures specifically dedicated to $CO_2$ storage impacts are poorly documented, with one of the more important data gaps being the lack of precise knowledge of the leakage mechanisms and associated impacts (Manceau and others, 2014). Without this knowledge, it is not possible to design appropriate remedial measures. Furthermore, to date, no remediation action following $CO_2$ leakage after geologic storage has ever been implemented mainly because of the absence of established impacts (Manceau and others, 2014). Consequently, the degree of maturity of remediation measures in the carbon capture and storage (CCS) field is low, making it necessary to rely on literature that is primarily based on modeling or analogies with other pollutants, e.g., the analogy between $CO_2$ and volatile organic compounds, the latter having been addressed extensively in the literature. Additionally, for the remedial measures, costs and time for adequate removal are generally site-dependent, and no information is specifically available in this area in the CCS field.

Based on this current situation, two key technical manuscripts were relied upon to identify and estimate the costs of mitigation/remediation technologies to address undesired migration of $CO_2$ from a geological storage unit (Manceau and others, 2014; Bielicki and others, 2014).

12.3.4.2.1 Identification of Remediation Technologies

Manceau and others (2014) identified several remediation technologies/strategies that are available to address the potential impacted media that may result from an emergency event. These impacted media and remediation measures are listed in Table 12-3. The impacted media in Table 12-3 include surface and groundwater/USDWs, vadose zone, indoor settings, and atmosphere; the

**Table 12-3. Proposed Technologies/Strategies for Remediation of Potential Impacted Media**

| Impacted Media | Potential Remedial Measures |
|---|---|
| Groundwater/USDW | Monitored natural attenuation |
| | Pump-and-treat |
| | Air sparging |
| | Permeable reactive barrier |
| | Extraction/injection |
| | Biological remediation |
| Vadose Zone | Monitored natural attenuation |
| | Soil vapor extraction |
| | pH adjustment (via spreading of alkaline supplements, irrigation, and drainage) |
| Surface Water | Passive systems, e.g., natural attenuation |
| | Active treatment systems |
| Atmosphere | Passive systems, e.g., natural mixing, dispersion |
| Indoor/Workplace Settings | Sealing of leak points |
| | Depressurization |
| | Ventilation |

remedial measures include a combination of active (e.g., air sparging) and passive (e.g., dispersion, natural attenuation) systems. However, it is important to note that, at this time, there is no widely accepted methodology for designing intervention and remediation plans for $CO_2$ geologic storage projects. Consequently, there remains a need for establishing the best field-applied and test practices for mitigating an undesired $CO_2$ migration. This effort will be based on a combination of available literature and experience that is gained over time in existing $CO_2$ storage projects.

12.3.4.2.2 Estimation of Costs for Implementing Emergency Event Responses

Given the lack of a site-specific estimate of implementing the emergency event responses at the $CO_2$ geologic storage site of Blue Flint, cost estimates developed by Bielicki and others (2014) were used to derive a cost range for the project related to the undesired migration of $CO_2$ from a geologic storage unit. Extrapolating these literature costs, which were based on a case study site in the Michigan Sedimentary Basin, to Blue Flint only provides an order-of-magnitude estimate of the potential costs because of the significant site-specific differences in the storage projects; however, the range of costs estimated in this manner are believed to be conservatively high in nature, making them more than sufficient for informing the value of the financial instrument that must be secured for the project, as described in the financial responsibility demonstration plan.

Case Study Description

Bielicki and others (2014) examined the costs associated with remediating undesired migration of $CO_2$ from a geologic storage unit as part of a case study of an extreme leakage situation. The case study involved the continuous annual injection of 9.5 Mt (9,500,000 metric tons) of $CO_2$ into the Mt. Simon sandstone of the Michigan Sedimentary Basin over a period of 30 years. It assumed every well in the basin was a potential leakage pathway and that no action was taken to mitigate any of these leakage pathways. In addition, eight UIC (underground injection control) Class I injection wells, which were located within approximately 1 mile of the $CO_2$ injection well, were also identified as leakage pathways. Four hundred probabilistic simulations of the $CO_2$ injection were performed and produced estimates of the area of the $CO_2$ plume as well as leakage rates of $CO_2$ from the storage reservoir to four aquifers as well as to the surface.

Cost Estimates

Story lines were developed for the site based on 1) risk assessments for the geologic storage of $CO_2$; 2) consequences of leakage; 3) lay and expert opinion of leakage risk; 4) modeling of $CO_2$ injection and leakage for the case study; and 5) input from local experts, oil and gas engineers, academics, attorneys, and other environmental professionals familiar with the Michigan Sedimentary Basin. Cost estimates for managing leakage events were then generated for first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) projects based on a low-cost and high-cost story line. These cost estimates provided a breakdown of the costs into the following categories:

- Find and fix a leak
- Environmental remediation
- Injection interruption
- Technical remedies for damages
- Legal costs
- Business disruption to others, e.g., natural gas storage
- Labor burden to others

Of interest for the financial responsibility demonstration plan is the environmental remediation cost estimate, which was provided for a leak scenario where there was interference with groundwater as well as a scenario where there was groundwater interference combined with $CO_2$ migration to the surface.

Environmental Remediation – Low-Cost and High-Cost Story Line

The low-cost and high-cost story lines for the two components of environmental remediation, groundwater interference and migration to the surface, are summarized in Table 12-4. As shown in Table 12-4, the low-cost story lines are characterized by independent leak scenarios that either result in interference with groundwater or $CO_2$ migration to the surface. On the other hand, the high-cost story lines are interrelated, where it is assumed that the high-cost story line for $CO_2$ migration to the surface is conditional upon the existence of the high-cost story line for groundwater interference.

Estimated Environmental Remediation Costs – FOAK and NOAK Projects

Based on the above story lines, the estimated environmental remediation costs for the high-cost story lines are basically the same for both FOAK and NOAK projects:

- High-cost story line – Groundwater interference alone: ~ $13M
- High-cost story line – Groundwater interference with $CO_2$ migration to the surface: $15M to $16M

**Table 12-4. Low-Cost and High-Cost Story Line for Environmental Remediation**

| | |
|---|---|
| **Low-Cost Story Line** | |
| Groundwater Interference | • A small amount of $CO_2$ migrates into a deep formation that has a total dissolved solids concentration of ~9000 ppm. By definition, this unit is a USDW, but the state has abundant water resources, and there are no foreseeable uses for water from this unit.<br>• 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.<br>• Injection is halted from the time that the leak is discovered until monitoring confirms that containment is effective (9 months).<br>• 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.<br>• Neither $CO_2$ nor brine leaks into the subsurface formation outside the injection formation in significant quantities.<br>• 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.<br>• A new water supply well is installed to serve the community, and the former water supply wells are plugged and capped.<br>• Potable water is provided to the affected households during the 6 months required to drill the new water supply wells.<br>• Groundwater regulators take legal action on the geologic storage operator to force remediation of the affected USDW using pump-and-treat technology.<br>• 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.<br>• $CO_2$ 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.<br>• A hyperspectral survey completed during the diagnostic monitoring program identifies surface leakage in a sparsely populated area.<br>• Elevated $CO_2$ concentrations are detected by a soil gas survey and by indoor air quality sampling in the basements of several residences.<br>• Affected residents are housed in a local hotel for several nights while venting systems are installed in their basements.<br>• A soil-venting system is installed at the site.<br>• $CO_2$ injection is halted for a year during these remediation activities. |

12.3.4.2.3 Input for the Financial Responsibility Demonstration Plan

The estimated costs for the environmental remediation of the high-cost story line for the case study, $15M to $16M, likely represents a high estimate of similar costs for Blue Flint. This statement is based primarily on the fact that the quantity of $CO_2$ injection of the case study (9,500,000 metric tons of $CO_2$ per year) is significantly larger than the planned injection quantity of Blue Flint (from 200,000 metric tons of $CO_2$ per year). Furthermore, the case study site had 450,000 active and abandoned wells, 400,000 of which penetrate the shallow subsurface to provide for drinking water, irrigation, and industrial uses. In contrast, there is one proposed $CO_2$ injection well (MAG 1) and one monitoring well (MAG 2) located in the area of Blue Flint. As such, the extreme leakage scenario of the case study represents a more extensive leakage scenario than could exist at the Blue Flint site. Accordingly, even though the same remedial technologies and strategies may be used at both sites to address $CO_2$ migration, it is assumed that the cost estimates provided for the case study represent a high cost that is unlikely to be incurred for the Blue Flint project. It is on this basis that the value of \$9M has been used for the emergency and remedial response portion of the financial instrument that will be put in place for Blue Flint.

To provide additional perspective for this \$9M cost estimate for environmental remediation, two other cost estimates for the remediation of potential environmental impacts associated with the geologic storage of $CO_2$ were found in the literature. These costs ranged from \$9M to \$34M. The source of the lower limit (\$9M) was a 2012 study (Trabucchi and others, 2012) which estimated the damages, i.e., dollars necessary to remediate or compensate for harm should a release occur at a commercial storage site (i.e., FutureGen 1.0 located in Jewett, Texas) that planned to inject 1,000,000 metric tons of $CO_2$ per year. This study estimated the “most likely” (50th percentile) total damages to be approximately \$8.7M and the “upper end” (95th and 99th percentiles) of the total damages to be approximately \$20.1M and \$26.2M, respectively (all estimates in 2020 dollars). Given that that the quantity of $CO_2$ injection of this case study (1,000,000 metric tons of $CO_2$ per year) is significantly larger than the planned injection quantity of Blue Flint (from 200,000 metric tons of $CO_2$ per year) the lower limit of \$9M is a conservatively high estimate for Blue Flint.

The upper limit of the range (\$34M) came from a Class VI UIC permit, which was issued to Archer Daniels Midland (ADM) by the U.S. Environmental Protection Agency (Underground Injection Control Permit – Class VI, Permit No. IL-115-6A-0001). As part of the financial responsibility demonstration plan of the ADM permit, a cost estimate of \$33.8M was provided for the cost element, emergency, and remedial response, which is slightly higher than the 99th percentile cost estimate of \$26.2M for the FutureGen 1.0 site. The planned injection rate for the ADM geologic storage project was ~1,200,000 metric tons per year.[1]

### 12.4 References

Bielicki, J.M., Pollak, M.F., Fitts, J.P., Peters, C.A., and Wilson, E.J., 2013, Causes and financial consequences of geologic $CO_2$ storage reservoir leakage and interference with other subsurface resources: International Journal of Greenhouse Gas Control, v. 20, p. 272–284.

Manceau, J.C., Hatzignatiou, D.G., Latour, L.L, Jensen, N.B., and Réveillére, A., 2014, Mitigation and remediation technologies and practices in case of undesired migration of $CO_2$ from a geological storage unit—current status: International Journal of Greenhouse Gas Control, v. 22, p. 272–290.

[1] It should be noted that both of these examples are injecting $CO_2$ at a rate 5–6 times higher than the planned injection at the Blue Flint facility, which suggests that these cost estimates are likely higher than the costs that will be required for Blue Flint Sequester Company, LLC.

Trabucchi, C., Donlan, M., Huguenin, M, Konopka, M., and Bolthrunis, S., 2012, Valuation of potential risks arising from a model, commercial-scale CCS project site: Prepared for CCS Valuation Sponsor Group, June 1, 2012.

# APPENDIX A

# MAG 1 FORMATION FLUID SAMPLING

MVTL

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL





Report Date: 12 Nov 20
Lab Number: 20-W4389
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:45
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

PO #: CC#990-81100-002

Temp at Receipt: 5.5C ROI

Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Project Name: MAG1

Sample Description: Inyan Kara Upper

| | As Received Result | | Method RL | Method Reference | Date Analyzed | Analyst |
|---|---|---|---|---|---|---|
| Metal Digestion | | | | EPA 200.2 | 3 Nov 20 | HT |
| pH | * 7.7 | units | N/A | SM4500-H+-B-11 | 3 Nov 20 17:00 | HT |
| Conductivity (EC) | 24500 | umhos/cm | N/A | SM2510B-11 | 3 Nov 20 17:00 | HT |
| pH - Field | 7.87 | units | NA | SM 4500 H+ B | 2 Nov 20 13:45 | DJN |
| Temperature - Field | 19.7 | Degrees C | NA | SM 2550B | 2 Nov 20 13:45 | DJN |
| Total Alkalinity | 428 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Phenolphthalein Alk | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Bicarbonate | 428 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Carbonate | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Hydroxide | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Conductivity - Field | 26360 | umhos/cm | 1 | EPA 120.1 | 2 Nov 20 13:45 | DJN |
| Total Organic Carbon | 746 | mg/l | 0.5 | SM5310C-11 | 11 Nov 20 23:56 | NAS |
| Sulfate | 1100 | mg/l | 5.00 | ASTM D516-11 | 6 Nov 20 10:02 | SD |
| Chloride | 11500 | mg/l | 2.0 | SM4500-Cl-E-11 | 4 Nov 20 8:37 | EV |
| Nitrate-Nitrite as N | < 1 @ | mg/l | 0.20 | EPA 353.2 | 5 Nov 20 10:12 | EV |
| Ammonia-Nitrogen as N | 36.2 | mg/l | 0.20 | EPA 350.1 | 10 Nov 20 11:46 | SD |
| Mercury - Dissolved | < 0.0002 | mg/l | 0.0002 | EPA 245.1 | 6 Nov 20 13:06 | MDE |
| Total Dissolved Solids | 17000 | mg/l | 10 | USGS I1750-85 | 4 Nov 20 9:30 | HT |
| Calcium - Total | 581 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Magnesium - Total | 38.8 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Sodium - Total | 5600 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Potassium - Total | 139 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Iron - Total | 0.74 | mg/l | 0.10 | 6010D | 11 Nov 20 10:12 | MDE |
| Manganese - Total | 0.25 | mg/l | 0.05 | 6010D | 11 Nov 20 10:12 | MDE |

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
# = Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

*MINNESOTA VALLEY TESTING LABORATORIES, INC.*

MVTL

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL





Report Date: 12 Nov 20
Lab Number: 20-W4389
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:45
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Project Name: MAG1

PO #: CC#990-81100-002

Sample Description: Inyan Kara Upper

Temp at Receipt: 5.5C ROI

| | As Received Result | | Method RL | Method Reference | Date Analyzed | Analyst |
|---|---|---|---|---|---|---|
| Strontium - Dissolved | 23.4 | mg/l | 0.10 | 6010D | 9 Nov 20 12:31 | MDE |
| Arsenic - Dissolved | < 0.004 + | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Barium - Dissolved | 0.4902 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Cadmium - Dissolved | < 0.002 + | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |
| Chromium - Dissolved | < 0.004 + | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Copper - Dissolved | < 0.004 + | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Lead - Dissolved | < 0.0005 | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |
| Molybdenum - Dissolved | 0.0353 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Selenium - Dissolved | < 0.02 + | mg/l | 0.0050 | 6020B | 9 Nov 20 11:20 | MDE |
| Silver - Dissolved | < 0.002 + | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |

* Holding time exceeded

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix  # = Due to concentration of other analytes
! = Due to sample quantity  + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL

*MINNESOTA VALLEY TESTING LABORATORIES, INC.*

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL





Report Date: 12 Nov 20
Lab Number: 20-W4390
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:52
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Project Name: MAG1

PO #: CC#990-81100-002

Sample Description: Inyan Kara Lower

Temp at Receipt: 5.5C ROI

| | As Received Result | | Method RL | Method Reference | Date Analyzed | Analyst |
|---|---|---|---|---|---|---|
| Metal Digestion | | | | EPA 200.2 | 3 Nov 20 | HT |
| pH | * 8.1 | units | N/A | SM4500-H+-B-11 | 3 Nov 20 17:00 | HT |
| Conductivity (EC) | 22524 | umhos/cm | N/A | SM2510B-11 | 3 Nov 20 17:00 | HT |
| pH - Field | 8.35 | units | NA | SM 4500 H+ B | 2 Nov 20 13:52 | DJN |
| Temperature - Field | 19.0 | Degrees C | NA | SM 2550B | 2 Nov 20 13:52 | DJN |
| Total Alkalinity | 393 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Phenolphthalein Alk | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Bicarbonate | 393 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Carbonate | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Hydroxide | < 20 | mg/l CaCO3 | 20 | SM2320B-11 | 3 Nov 20 17:00 | HT |
| Conductivity - Field | 24178 | umhos/cm | 1 | EPA 120.1 | 2 Nov 20 13:52 | DJN |
| Total Organic Carbon | 889 | mg/l | 0.5 | SM5310C-11 | 11 Nov 20 23:56 | NAS |
| Sulfate | 1110 | mg/l | 5.00 | ASTM D516-11 | 6 Nov 20 10:02 | SD |
| Chloride | 9520 | mg/l | 2.0 | SM4500-Cl-E-11 | 4 Nov 20 8:37 | EV |
| Nitrate-Nitrite as N | < 1 @ | mg/l | 0.20 | EPA 353.2 | 5 Nov 20 10:12 | EV |
| Ammonia-Nitrogen as N | 37.1 | mg/l | 0.20 | EPA 350.1 | 10 Nov 20 11:46 | SD |
| Mercury - Dissolved | < 0.0002 | mg/l | 0.0002 | EPA 245.1 | 6 Nov 20 13:06 | MDE |
| Total Dissolved Solids | 15600 | mg/l | 10 | USGS I1750-85 | 4 Nov 20 9:30 | HT |
| Calcium - Total | 516 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Magnesium - Total | 34.6 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Sodium - Total | 5130 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Potassium - Total | 140 | mg/l | 1.0 | 6010D | 5 Nov 20 11:27 | MDE |
| Iron - Total | < 0.5 @ | mg/l | 0.10 | 6010D | 11 Nov 20 10:12 | MDE |
| Manganese - Total | < 0.25 @ | mg/l | 0.05 | 6010D | 11 Nov 20 10:12 | MDE |

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix    # = Due to concentration of other analytes
! = Due to sample quantity    + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL





Report Date: 12 Nov 20
Lab Number: 20-W4390
Work Order #:82-3067
Account #: 021017
Date Sampled: 2 Nov 20 13:52
Date Received: 2 Nov 20 15:15
Sampled By: MVTL Field Services

Adam Dunlop
Midwest Ag Energy - Blue Flint
2841 3rd St SW
Underwood ND 58576

Project Name: MAG1

PO #: CC#990-81100-002

Sample Description: Inyan Kara Lower

Temp at Receipt: 5.5C ROI

| | As Received Result | | Method RL | Method Reference | Date Analyzed | Analyst |
|---|---|---|---|---|---|---|
| Strontium - Dissolved | 21.4 | mg/l | 0.10 | 6010D | 9 Nov 20 12:31 | MDE |
| Arsenic - Dissolved | < 0.002 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Barium - Dissolved | 0.2619 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Cadmium - Dissolved | < 0.0005 | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |
| Chromium - Dissolved | 0.0020 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Copper - Dissolved | 0.0041 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Lead - Dissolved | < 0.0005 | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |
| Molybdenum - Dissolved | 0.0523 | mg/l | 0.0020 | 6020B | 9 Nov 20 11:20 | MDE |
| Selenium - Dissolved | < 0.01 ^ | mg/l | 0.0050 | 6020B | 9 Nov 20 11:20 | MDE |
| Silver - Dissolved | < 0.0005 | mg/l | 0.0005 | 6020B | 9 Nov 20 11:20 | MDE |

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix    # = Due to concentration of other analytes
! = Due to sample quantity    + = Due to internal standard response

CERTIFICATION: ND # ND-00016

EERC
Energy & Environmental Research Center®

UNIVERSITY OF NORTH DAKOTA

15 North 23rd Street -- Stop 9018 / Grand Forks, ND 58202-9018 / Phone: (701) 777-5000 Fax: 777-5181
Web Site: www.undeerc.org

## ANALYTICAL RESEARCH LAB - Final Results

*July 20, 2022*

**Set Number:** 55028
**Fund#:** 27026
**PI:** Ian Feole
**Contact Person:** Ian Feole

**Request Date:** Tuesday, June 7, 2022
**Due Date:** Tuesday, June 21, 2022
**Set Description:** Midwest AgEnergy - MAG-1 Broom Creek Formation Water

| Sample | Parameter | Result | |
|---|---|---|---|
| **55028-01** | **MAG-1 Broom Creek 6/4/22** | | |
| | Alkalinity, as Bicarbonate ($HCO_3^-$) | 249 | mg/L |
| | Alkalinity, as Carbonate ($CO_3^{=}$) | 0 | mg/L |
| | Alkalinity, as Hydroxide ($OH^-$) | 0 | mg/L |
| | Alkalinity, Total as $CaCO_3$ | 204 | mg/L |
| | Bromide | 21.8 | mg/L |
| | Calcium | 823 | mg/L |
| | Chloride | 11600 | mg/L |
| | Conductivity at 25°C | 39900 | µS/cm |
| | Density | 1.02 | g/mL |
| | Magnesium | 187 | mg/L |
| | pH | 7.48 | |
| | Potassium | 90.9 | mg/L |
| | Sodium | 9020 | mg/L |
| | Strontium | 18.4 | mg/L |
| | Sulfate | 7350 | mg/L |
| | Total Dissolved Solids | 28600 | mg/L |

Distribution ______________________ Date __________

1 of 1

**MINNESOTA VALLEY TESTING LABORATORIES, INC.**
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

**Account #:** 74217 **Client:** Neset Consulting
**Workorder:** Mag #1 (1427)

Jean Datahan
Neset Consulting
6844 Hwy 40
Tioga, ND 58852

**Certificate of Analysis**

## Approval

**All data reported has been reviewed and approved by:**

C. Carroll

Claudette Carroll, Lab Manager Bismarck, ND

Analyses performed under Minnesota Department of Health Accreditation conforms to the current TNI standards.

NEW ULM LAB CERTIFICATIONS:
MN LAB # 027-015-125 ND WW/DW # R-040

BISMARCK LAB CERTIFICATIONS:
MN LAB # 038-999-267 ND W/DW # ND-016 SD SDWA

**Account #:** 74217 **Client:** Neset Consulting

## Workorder Summary

### Workorder Comments

All analytes with dilution factors greater than 1 (displayed in DF column) required dilution due to matrix or high concentration of target analyte unless otherwise noted and reporting limits (RDL column) have been adjusted accordingly.

Workorder amended (project name). 14 Jul 22

### Sample Comments

***1427001 (Broom Creek) - Sample***

Temperature received outside of the 0 - 6 °C range specified by EPA requirements. Client has authorized MVTL to proceed with analysis through direct communication or authorization letter retained on file with customer service.

### Task Comments

***1427001 - 618013 - GENb/346***

Sample required dilution due to matrix. Reporting limit has been raised.

### Analysis Results Comments

***1427001 (Broom Creek)***

The reporting limit for this analyte has been raised to account for the reporting limit verification standard.
(Copper, Dissolved)

***1427001 (Broom Creek)***

Sample required dilution due to matrix. Reporting limit has been raised.
(Nitrate + Nitrite as N)

***1427001 (Broom Creek)***

Sample analyzed beyond holding time.(pH)

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.MVTL.com

Member ACIL

Account #: 74217 Client: Neset Consulting

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 1427001 | **Date Collected:** | 06/04/2022 13:40 | **Matrix:** | Groundwater |
| **Sample ID:** | Broom Creek | **Date Received:** | 06/06/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 26.6 | **Received on Ice:** | Yes | | |

### Calculated

**Method: SM1030F**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Cation Summation | **463** | meq/L | | 1 | 07/14/2022 15:43 | 07/14/2022 15:43 | CW | | |
| Anion Summation | **557** | meq/L | | 1 | 07/14/2022 15:43 | 07/14/2022 15:43 | CW | | |
| Percent Difference | **-9.20** | % | | 1 | 07/14/2022 15:43 | 07/14/2022 15:43 | CW | | |

### Inorganic Chemistry

**Method: ASTM D516-11**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Sulfate | **7940** | mg/L | 250 | 50 | 06/10/2022 11:25 | 06/10/2022 11:25 | EJV | MA,NDA | |

**Method: EPA 350.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Ammonia as N | **14.5** | mg/L | 0.2 | 2 | 06/07/2022 15:37 | 06/07/2022 15:37 | EMS | | |

**Method: EPA 353.2**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Nitrate + Nitrite as N | <2 | mg/L | 2 | 10 | 06/09/2022 09:27 | 06/09/2022 09:27 | EJV | MA,NDA | * |

**Method: SM 5310C-2014**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Total Organic Carbon | **89.8** | mg/L | 0.5 | 500 | 06/14/2022 08:48 | 06/14/2022 08:48 | NS | MA,NDA | |

**Method: SM2320 B-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Alkalinity, Total | **176** | mg/L as CaCO3 | 20.5 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | MA,NDA | |
| Alkalinity, Phenolphthalein | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | | |
| Carbonate | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | | |
| Bicarbonate | **176** | mg/L as CaCO3 | 20.5 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | | |
| Hydroxide | <20.5 | mg/L as CaCO3 | 20.5 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | | |

**Account #:** 74217 **Client:** Neset Consulting

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 1427001 | **Date Collected:** | 06/04/2022 13:40 | **Matrix:** | Groundwater |
| **Sample ID:** | Broom Creek | **Date Received:** | 06/06/2022 08:00 | **Collector:** | MVTL Field Service |
| **Temp @ Receipt (C):** | 26.6 | **Received on Ice:** | Yes | | |

### Inorganic Chemistry

**Method: SM2510 B-2011 EC**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Specific Conductance | **34490** | umhos/cm | 1 | 1 | 06/06/2022 18:31 | 06/06/2022 18:31 | AMC | MA,NDA | |

**Method: SM4500 H+ B-2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| pH | **7.6** | units | 0.1 | 1 | 06/08/2022 15:21 | 06/08/2022 15:21 | RAA | MA,NDA | * |

**Method: SM4500-Cl-E 2011**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Chloride | **13800** | mg/L | 200 | 100 | 06/09/2022 17:05 | 06/09/2022 17:05 | EJV | MA,NDA | |

**Method: USGS I-1750-85**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Total Dissolved Solids | **28700** | mg/L | 10 | 1 | 06/07/2022 15:49 | 06/07/2022 15:49 | AMC | MA,NDA | |

### Metals

**Method: EPA 245.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Mercury, Dissolved | <0.0002 | mg/L | 0.0002 | 1 | 06/24/2022 11:00 | 06/28/2022 09:00 | MDE | MA,NDA | |

**Method: EPA 6010D**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Calcium | **937** | mg/L | 10 | 10 | 06/06/2022 17:20 | 06/23/2022 12:06 | SLZ | MA,NDA | |
| Magnesium | **197** | mg/L | 10 | 10 | 06/06/2022 17:20 | 06/23/2022 12:06 | SLZ | MA,NDA | |
| Sodium | **9080** | mg/L | 50 | 50 | 06/06/2022 17:20 | 06/23/2022 12:13 | SLZ | MA,NDA | |
| Potassium | **110** | mg/L | 10 | 10 | 06/06/2022 17:20 | 06/23/2022 12:06 | SLZ | MA,NDA | |
| Iron | **33.8** | mg/L | 1 | 10 | 06/06/2022 17:20 | 06/09/2022 14:46 | SLZ | MA,NDA | |
| Manganese | <0.5 | mg/L | 0.5 | 10 | 06/06/2022 17:20 | 06/09/2022 14:46 | SLZ | MA,NDA | |
| Barium, Dissolved | <1 | mg/L | 1 | 10 | 06/06/2022 17:20 | 06/09/2022 14:44 | SLZ | MA,NDA | |
| Strontium, Dissolved | **17.0** | mg/L | 1 | 10 | 06/06/2022 17:20 | 06/09/2022 14:44 | SLZ | MA,NDA | |

Account #: 74217 Client: Neset Consulting

## Analytical Results

| | | | | | |
|---|---|---|---|---|---|
| **Lab ID:** | 1427001 | **Date Collected:** | 06/04/2022 13:40 | **Matrix:** | Groundwater |
| **Sample ID:** | Broom Creek | **Date Received:** | 06/06/2022 08:00 | **Collector:** | MVTL Field Service |

**Temp @ Receipt (C):** 26.6 **Received on Ice:** Yes

### Metals

**Method: EPA 6020B**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Arsenic, Dissolved | <0.008 | mg/L | 0.008 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Chromium, Dissolved | **0.0085** | mg/L | 0.008 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Lead, Dissolved | <0.002 | mg/L | 0.002 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Selenium, Dissolved | <0.02 | mg/L | 0.02 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Silver, Dissolved | <0.002 | mg/L | 0.002 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Cadmium, Dissolved | <0.002 | mg/L | 0.002 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Molybdenum, Dissolved | **1.010** | mg/L | 0.008 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | |
| Copper, Dissolved | <0.008 | mg/L | 0.008 | 20 | 06/06/2022 17:20 | 07/06/2022 13:59 | MDE | MA,NDA | * |

### Sampling Information

**Method: 120.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Specific Conductance - Field | **35976** | umhos/cm | 1 | 1 | 06/04/2022 13:40 | 06/04/2022 13:40 | JSM | | |

**Method: 150.2**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| pH - Field | **7.36** | units | 0.01 | 1 | 06/04/2022 13:40 | 06/04/2022 13:40 | JSM | | |

**Method: 170.1**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Temperature - Field C | **31.21** | degrees C | | 1 | 06/04/2022 13:40 | 06/04/2022 13:40 | JSM | | |

**Method: SM2110**

| Parameter | Results | Units | RDL | DF | Prepared | Analyzed | By | Cert | Qual |
|---|---|---|---|---|---|---|---|---|---|
| Appearance - Field | Slightly Turbid | | | 1 | 06/04/2022 13:40 | 06/04/2022 13:40 | JSM | | |

Minnesota Valley Testing Laboratories
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Neset Consulting
W0: 1427

# Chain of Custody Record

| | | | |
|---|---|---|---|
| Report To: | Neset Consulting | CC: | Project Name: Mag #1 |
| Attn: | Jean Datahan | | Event: |
| Address: | 6844 Hwy 40<br>Tioga, ND 58852 | | Sampled By: |
| Phone: | 701-664-1492 | | |
| Email: | jeandatahan@nestconsulting.com | | |

| | Sample Information | | | | Sample Containers | | | | | | | | | | | Field Readings | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Lab Number | Sample ID | Date | Time | Sample Type | 1 Liter Raw | 500 mL HNO3 | 500 mL HNO3 (filtered) | 250 mL H2SO4 | | TOC (set of 3) | | | | | Temp (°C) | Spec. Cond. | pH | Appearance | Analysis Required |
| 001 | Broom Creek | 4 Jun 22 | 1340 | GW | ~~X~~ | X | X | X | | X | | | | | 31.21 | 35,976 | 7.36 | ST | Neset GW well List |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | |

Comments:

ST = Slightly Turbid

| Relinquished By | | Sample Condition | | Received By | |
|---|---|---|---|---|---|
| Name | Date/Time | Location | Temp (°C) | Name | Date/Time |
| 1 | 4 June 22<br>1520 | Log In<br>Walk In #2 | ROI 26.6<br>TM562 / TM805 | | 6 Jun 22<br>0800 |
| 2 | | | | | |

# APPENDIX B

# HISTORIC FRESHWATER WELL FLUID SAMPLING

## HISTORIC FRESHWATER WELL FLUID SAMPLING

The Falkirk Mining Company (FMC), a wholly owned subsidiary of North American Coal Corporation, has implemented a shallow groundwater monitoring program since the 1970s as part of its operations at the Falkirk Mine. The shallow groundwater monitoring program has established baselines of water quality for many of the freshwater aquifer systems within the Blue Flint $CO_2$ storage project AOR.

Hundreds of shallow groundwater wells (monitoring sites) have been drilled to date over the >50,000 acres leased to FMC. Each of the monitoring sites is tested annually to assess groundwater quality in the area. The monitoring sites sample from either surficial glacial aquifers of the Coleharbor Group (Pleistocene) or water-bearing coalbed (lignite) horizons of the Sentinel Butte and Bullion Creek Formations of the Fort Union Group (Paleocene) (U.S. Bureau of Land Management, 2017). Figure B-1 summarizes the stratigraphy and identifies which freshwater aquifers are present and under surveillance in the Underwood area.

| ERATHEM | SYSTEM | | SERIES | ROCK UNIT: GROUP | ROCK UNIT: FORMATION | | FRESHWATER AQUIFER(S) PRESENT | FRESHWATER AQUIFER NAMES |
|---|---|---|---|---|---|---|---|---|
| CENOZOIC | Quaternary | | Holocene | | Oahe | | No | |
| | | | Pleistocene | Coleharbor | "Glacial Drift" | | Yes | Weller Slough and Turtle Lake |
| | Tertiary | Paleogene | Eocene | | Golden Valley | | No | |
| | | | Paleocene | Fort Union | Sentinel Butte | | Yes | Hagel A and B coal beds and C sand |
| | | | | | Tongue River | Bullion Creek | Yes | Tavis Creek and Coal Lake Coulee coal beds and Hensler sand |
| | | | | | | Slope | No | |
| | | | | | Cannonball | | Yes | |
| | | | | | Ludlow | | Yes | |
| MESOZOIC | Cretaceous | | Upper | Montana | Hell Creek | | Yes | |
| | | | | | Fox Hills | | Yes | |
| | | | | | Pierre | | No | |

Figure B-1. Stratigraphic column showing the shallow subsurface geologic units and freshwater aquifer systems for the region in and around Underwood, North Dakota. Major freshwater aquifer systems under FMC's surveillance are indicated at far right (modified from Murphy and others [2009]).

Table B-1 summarizes the ranges of pH, electrical conductivity (EC), total dissolved solids (TDS), and total alkalinity measured from 15 active monitoring sites within the AOR. Figure B-2 is a map showing the locations of the selected monitoring sites. Monitoring sites were selected to establish baseline conditions for the Blue Flint $CO_2$ storage project if the wells 1) are operated by FMC, 2) have multiple years of recent (i.e., 2015 or later) geochemical results available, 3) and fall within a mile of the AOR.

The groundwater wells were drilled no more than 150 ft below ground surface and were perforated or screened along a 5–20-ft zone for sampling the horizons of interest. Groundwater wells represented in Table B-1 each have a minimum of four water chemistry samples collected and a maximum of seven. All water chemistries were determined by MVTL.

**Table B-1. Summary of Water Chemistries at 15 Monitoring Sites in the AOR**

| Number of Wells | Water Samples | Data Vintage | Sampling Horizon | pH | EC, mS/cm | TDS, mg/L | Total Alkalinity, mg/L $CaCO_3$ |
|---|---|---|---|---|---|---|---|
| 3 | 19 | 2015–2021 | Spoils | 7.0–8.3 | 1,958–3,632 | 1,290–2,610 | 549–1,370 |
| 2 | 13 | 2015–2021 | Sheet Sand | 6.1–6.9 | 1,458–2,628 | 991–1,960 | 282–887 |
| 2 | 11 | 2015–2021 | Coleharbor | 6.7–7.6 | 1,673–2,210 | 1,130–1,670 | 399–496 |
| 1 | 7 | 2015–2021 | Hagel A | 6.4–6.8 | 1,496–1,819 | 1,010–1,400 | 360–388 |
| 1 | 7 | 2015–2021 | Hagel A&B | 5.9–6.2 | 2,538–3,560 | 2,040–3,070 | 261–278 |
| 3 | 21 | 2015–2021 | Hagel B | 6.2–7.5 | 1,329–2,013 | 830–1,450 | 270–443 |
| 1 | 5 | 2017–2021 | C Sand | 8.2–8.4 | 2,323–2,362 | 1,440–1,950 | 999–1,240 |
| 2 | 14 | 2015–2021 | Tavis Creek | 7.0–8.4 | 2,215–2,367 | 1,330–2,020 | 524–1,260 |

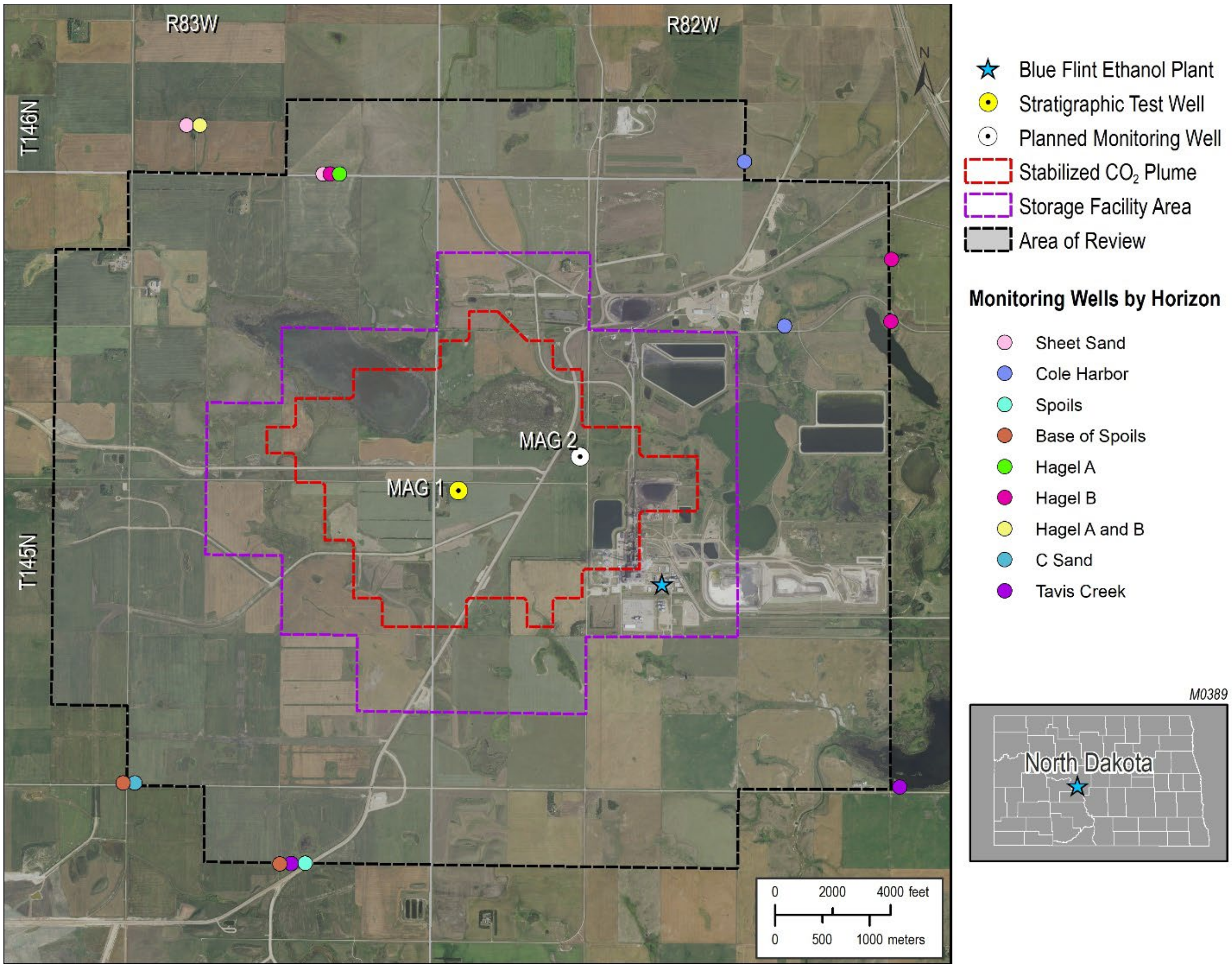



Figure B-2. Locations of the 15 monitoring sites operated by FMC with multiple years of recent (i.e., 2015 or later) water chemistry results available.

**REFERENCES**

Murphy, E.C., Nordeng, S.H., Juenker, B.J., and Hoganson, J.W., 2009, North Dakota stratigraphic column: North Dakota Geological Survey Miscellaneous Series 91.

U.S. Department of the Interior Bureau of Land Management, 2017, Environmental assessment DOI-BLM-MT-C030-2016-0020-EA: The Falkirk Mining Company Federal Coal Lease by Application, Dickinson, North Dakota, 121 p.

# APPENDIX C

# QUALITY ASSURANCE SURVEILLANCE PLAN

# C1.0 QUALITY ASSURANCE AND SURVEILLANCE PLAN

The primary goal of the testing and monitoring plan (Section 5) of this storage facility permit application is to ensure that the geologic storage project is operating as permitted and is not endangering USDWs. In compliance with NDAC § 43-05-01-11.4 (Testing and Monitoring Requirements), this quality assurance and surveillance plan (QASP) was developed and is provided as part of the testing and monitoring plan.

## C1.1 $CO_2$ Stream Analysis

NDAC § 43-05-01-11.4(1)(a) requires analysis of the $CO_2$ stream in compliance with applicable analytical methods and standards generally accepted by industry and with sufficient frequency to yield data representative of its chemical and physical characteristics. Blue Flint will collect samples of the injected $CO_2$ stream quarterly at the liquefaction outlet and analyze the $CO_2$ stream to determine the concentrations of $CO_2$, nitrogen, oxygen, hydrogen, water, hydrogen sulfide, carbon monoxide, and a suite of hydrocarbons (e.g., ethane, propane, n-butane, and methane) via a third party. Selected stable isotopes (i.e., isotopes of carbon dioxide [$^{12}C$ and $^{13}C$], methane [$^{12}C$ and $^{13}C$], and deuterium [$^{2}H$]) will also be sampled in the first year to establish a baseline. The isotopic analyses will be outsourced to commercial laboratories that will employ standard analytical QA/QC protocols used in the industry.

## C1.2 Surface Facilities Leak Detection Plan

The surface leak detection and monitoring plan is outlined in Section 5.2. The SCADA system (described in Attachment A-1) will continuously monitor surface facilities operations in real time and be equipped with automated alarms that will notify the Blue Flint operations center in the event of an anomalous reading. A generalized specification sheet for the $CO_2$ detection stations (see Attachment A-2) will monitor $CO_2$ levels at each wellsite to ensure workspace atmospheres are safe.

## C1.3 Corrosion Monitoring and Prevention Plan

### *C1.3.1 Corrosion Monitoring*

The flow line will use the corrosion coupon method to monitor for corrosion in the flow line and injection wellbore throughout the operational phase of the project, focusing on loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. The coupon sample port will be located near the liquefaction outlet, and sampling will occur quarterly during the first year of injection and once a year thereafter.

The process that will be used to conduct each coupon test is described below.

#### *C1.3.1.1 Sample Description*

Corrosion coupons that are representative of the construction materials of the flowline and injection well that contact the $CO_2$ stream will be tested. Materials from these process components and/or conventional corrosion coupons of similar composition and specifications will be weighed, measured, and photographed prior to initial exposure.

*C1.3.1.2 Sample Exposure*

Each sample will be suspended in a flow-through apparatus, which will be located downstream of all processes (i.e., at the liquefaction outlet which connects to the start of the flowline). A parallel stream of high-pressure $CO_2$ will be withdrawn from the flowline, passed through the flow-through apparatus, and then routed back into a lower-pressure point upstream in the compression system. This loop will operate any time injection is occurring. The operation of this system will provide exposure of the samples to $CO_2$ representative of the composition, temperature, and pressures that will be present along the flowline, at the wellhead, and in the injection tubing.

*C1.3.1.3 Sample Handling and Monitoring*

The exposed materials/coupons will be handled and assessed for corrosion in accordance with either National Association of Colleges and Employers (NACE) Standard SP0775—Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations—(2018) or American Society for Testing Materials (ASTM) International Method G1-03—Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens—(2017) to determine and document corrosion rates based on mass loss. The coupons will be photographed, visually inspected for cracking and pitting with a minimum of 10× power, dimensionally measured (to within 25.4 micrometers), and weighed (to within 0.0001 gram).

#### *C1.3.2 Corrosion Prevention*

The corrosion prevention plan for the surface facilities and the wellbores is outlined in Sections 5.3.1 and 5.6, respectively. Attachment A-3 describes the specifications of the FlexSteel flowline. The wellbore designs, which show what corrosion-resistant materials will be used in the MAG 1 and MAG 2 wells, are shown in Section 9, Figures 9-1 and 9-3, respectively.

### C1.4 Wellbore Mechanical Integrity Testing Plan

The plan for mechanical integrity testing of the $CO_2$ injection well and deep monitoring well can be found in Section 5.4 of this application. The specification sheet for the USIT is provided in Attachment A-4. Blue Flint will select third parties to perform logging and testing specified in the testing and monitoring plan. Blue Flint will also ensure that third parties apply proper QA/QC protocols to the tools to ensure their effectiveness and functionality and that all well testing procedures follow industry standards.

### C1.5 Near-Surface Soil Gas and Groundwater Monitoring

Near-surface sampling discussed herein comprises 1) sampling of soil gas in the shallow vadose zone and 2) sampling groundwater aquifers (to the lowest USDW). Sampling and chemical analysis of these zones will provide concentrations of chemical constituents, including stable and radiogenic carbon isotopes to detect movement of the $CO_2$ out of the reservoir. These monitoring efforts will provide data to confirm that near-surface environments are not adversely impacted by $CO_2$ injection and storage operations.

#### *C1.5.1 Soil Gas*

Vadose zone soil gas monitoring directly measures the characteristics of the air space between soil components and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of five semi-permanent soil gas locations will be sampled in the

SFA (as shown in Figure 5-5) to establish baseline conditions. Figure C-1 illustrates the schematic for the semi-permanent soil gas probes that will be used to collect baseline data.

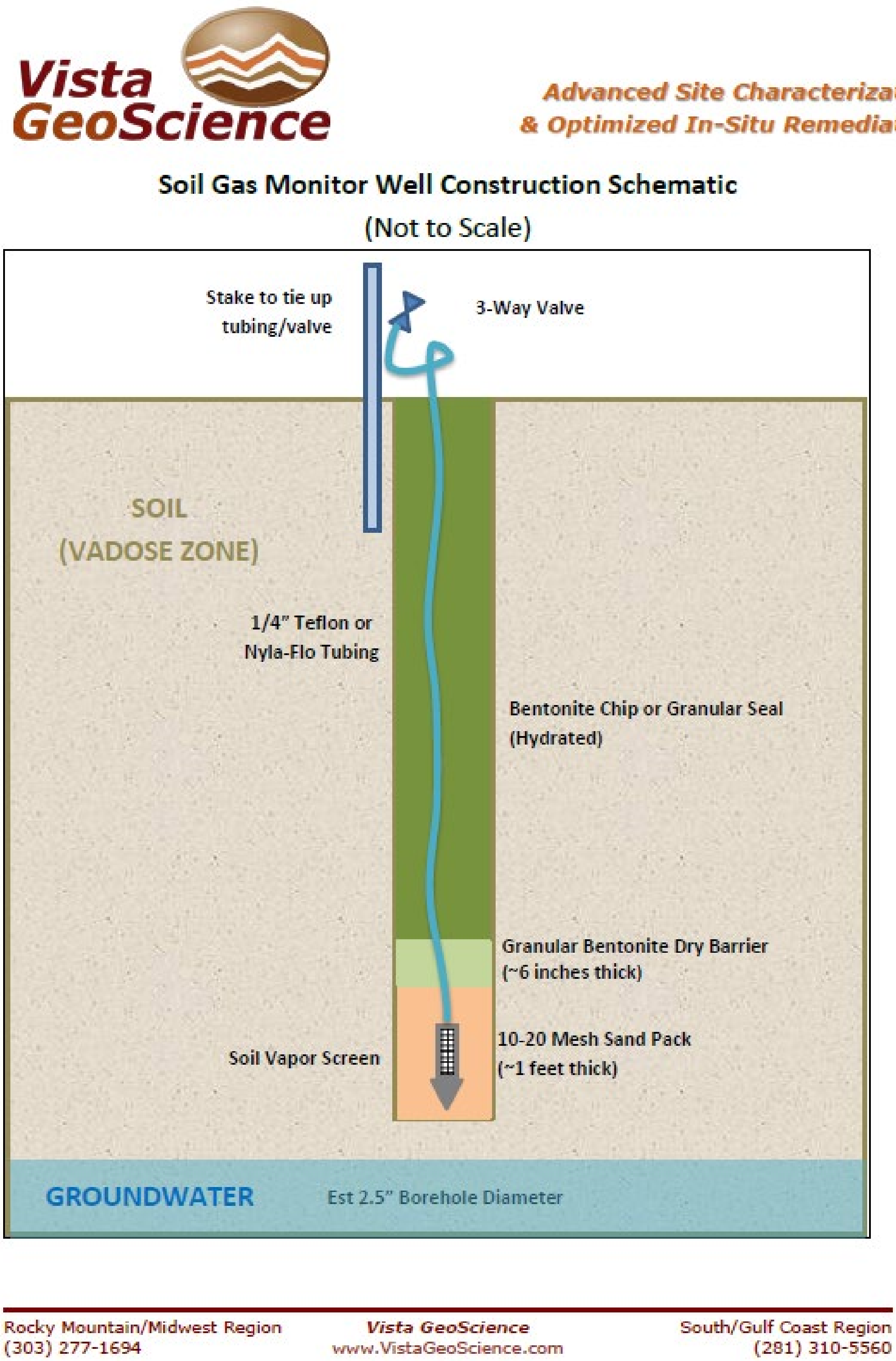



Figure C-1. Well schematic of the soil gas probe locations.

*C1.5.1.1 Soil Gas-Sampling and Analysis Protocol*
Section 5.7.2 of this application outlines the sampling plan for soil gas. Tables C-1 and C-2 indicate the analytes planned to be included in each soil gas analysis.

Blue Flint will select North Dakota service providers to install semi-permanent soil gas probe locations and soil gas profile stations, as well as sample soil gas and analyze all soil gas data. All soil gas samples are expected to be collected using a Post Run Tubing (PRT) sampling system from a projected target depth interval. Each location will be purged using a Landtec GEM 2000 or 5000 model equivalent. Field technicians will monitor and record $O_2$, $CH_4$, $CO_2$, and $H_2S$ readings while purging each location. The purging of each location should continue until either an estimated three system volumes have been purged or until readings have stabilized. The samples will then be collected in sample bags. A duplicate pair of samples should be collected from one of the soil gas sampling locations, and a pair of ambient air "sample blank" samples should be collected from each location as well. After all samples have been collected, the samples will be shipped or delivered to a commercial laboratory in North Dakota for analysis.

*C1.5.1.2 QA/QC Procedures*
Commercial laboratories selected for the performing the chemical analyses on the soil gas samples will employ standard analytical QA/QC protocols used in the industry.

**Table C-1. Soil Gas Analytes Identified with Field and Laboratory Instruments**

| ***Landtec GEM 2000 or 5000*** |
|---|
| **Analyte** |
| $CO_2$ |
| $O_2$ |
| $H_2S$ |
| $CH_4$ |

**Table C-2. Isotope Measurements of Soil Gas Samples**

| Isotope | Units |
|---|---|
| $\delta^{13}C$ of $CO_2$* | ‰ (per mil) |
| $\delta^{13}C$ of $CH_4$* | ‰ (per mil) |
| $\delta D$ of $CH_4$* | ‰ (per mil) |

* Only measured if high enough concentration detected.

### *C1.5.2 Groundwater/USDW*
Section 5.7.2 of this application describes the plan for monitoring groundwater (to the lowest USDW). The sampling procedure that Minnesota Valley Testing Laboratories (MVTL) (Bismarck, North Dakota) will utilize is described below.

*C1.5.2.1 Groundwater-Sampling and Analysis Protocol*

Baseline Groundwater Wells (five groundwater wells within 1 mile of the AOR and a dedicated Fox Hills monitoring well near the MAG 1 location)
Groundwater samples will be collected by MVTL from these wells using the wells' submersible pumps. MVTL will apply the following standard procedure for sampling the wells:

1. Determine the use of the well prior to sample collection (e.g., domestic, livestock, irrigation, municipal).

2. Purge the well using a measured bucket to determine the pumping rate when the valve is fully open.

   a. The longer the well has not been in use, the longer the well will need to be purged before sample collection. Purge time will also depend on the total depth of the well.

   b. For wells used daily, purge the well for 1–2 minutes. For wells used on a seasonal basis, such as livestock or irrigation, purge the well for 15 minutes, or longer if the well is over 100 feet deep. If the well has not been in use in the past year, three well volumes may need to be removed to ensure a freshwater sample can be collected.

3. Collect the sample.

   a. Once the well has been sufficiently purged, sample collection can proceed.
   b. Record the location of the sample point.
   c. Record the pumping rate and volume purged.
   d. Collect field readings: temperature, conductivity, and pH.
   e. Fill appropriate sample containers for analysis.

Two laboratories will be used to analyze the water samples: 1) MVTL will analyze samples for general parameters, anions, cations, metals (dissolved and total), and nonmetals (Tables C-3 and C-4); and 2) Blue Flint will select another North Dakota commercial laboratory for analyzing samples for stable isotopes (Table C-5).

**Table C-3. Measurements of General Parameters for Groundwater Samples**

| Parameter | Method |
|---|---|
| **pH** | SM[1]4500-H+-B-11 |
| **Conductivity** | SM2510B-11 |
| Alkalinity | SM 2320B |
| **Temperature** | SM2550B |
| Total Dissolved Solids | SM 2540C |
| Total Inorganic Carbon | EPA[2] 9060 |
| Dissolved Inorganic Carbon (DIC) | EPA 9060 |
| Total Organic Carbon | SM 5310B |
| Dissolved Organic Carbon | SM 5310B |
| Total Mercury | EPA 7470A |
| Dissolved Mercury | EPA 245.2 |
| Total Metals[3] (26 metals) | EPA 6010B/6020 |
| Dissolved Metals[3] (26 metals) | EPA 200.7/200.8 |
| Bromide | EPA 300.0 |
| Chloride | EPA 300.0 |
| Fluoride | EPA 300.0 |
| Sulfate | EPA 300.0 |
| Nitrite | EPA 353.2 |

[1] Standard method
[2] U.S. Environmental Protection Agency.
[3] See Table B-2 for entire sampling list of total and dissolved metals.

**Table C-4. Total and Dissolved Metals and Cation Measurements for Groundwater Samples**

| Metals | Major Cations | Trace Metals |
|---|---|---|
| Antimony | Barium | Aluminum |
| Arsenic | Boron | Cobalt |
| Beryllium | Calcium | Lithium |
| Cadmium | Iron | Molybdenum |
| Chromium | Magnesium | Vanadium |
| Copper | Manganese | |
| Lead | Potassium | |
| Mercury | Silicon | |
| Nickel | Sodium | |
| Selenium | Strontium | |
| Silver | Phosphorus | |
| Thallium | | |
| Zinc | | |

**Table C-5. Stable Isotope Measurements and Dissolved Gases in Groundwater**

| Isotope | Units |
|---|---|
| δD $H_2O$ | ‰ (per mil) |
| $\delta^{18}O$ $H_2O$ | ‰ (per mil) |
| $\delta^{13}C$ DIC | ‰ (per mil) |
| $\delta^{13}C$ Methane (if present) | ‰ (per mil) |
| $\delta^{13}C$ Ethane (if present) | ‰ (per mil) |
| $\delta^{13}C$ Propane (if present) | ‰ (per mil) |
| δD Methane (if present) | ‰ (per mil) |
| $\delta^{13}C$ $CO_2$ (if present) | ‰ (per mil) |

*C1.5.2.2 Quality Assurance/Quality Control*

Groundwater Wells

The laboratory analyses will be performed in accordance with the commercial laboratories' internal QA/QC procedures (e.g., Table C-3 and www.mvtl.com/QualityAssurance). In addition, duplicate samples will be taken to assess the combined accuracy of the field sampling and laboratory analysis methods. These duplicate samples will be collected at the same time and location for each of the groundwater wells.

## C1.6 Storage Reservoir Monitoring

Monitoring of the storage reservoir during the injection operation includes monitoring with direct and indirect methods, as described in Section 5.7 of this application. Direct methods include monitoring: the injection flow rates and volumes; wellhead injection temperature and pressure; bottomhole injection pressure and temperature; saturation profile from the storage reservoir to the AZMI; and the tubing–casing annulus pressure or casing pressure. Indirect methods include time-lapse 2D seismic surveys and passive seismicity monitoring.

### *C1.6.1 Direct Methods*

*C1.6.1.1 Wireline Logging and Retrievable Monitoring*

The wireline logging and retrievable monitoring that will be performed comprise PNLs, which include temperature and pressure data, ultrasonic logs, injection zone pressure falloff tests, and corrosion/wellbore integrity monitoring. The information provided by these monitoring efforts is as follows:

- USIT (described in Attachment A-4) or alternative casing inspection logging provides an assessment of the mechanical integrity and assessment of corrosion of the wellbore.

- PNL (example in Attachment A-5) provides information regarding gas saturation in the formations, which can be used to determine if the injected $CO_2$ is contained within the storage formation as well as ground truth information provided by the seismic surveys.

- Pressure falloff tests provide an assessment of the storage reservoir injectivity.

All wireline logging events will follow API (American Petroleum Institute) guidelines along with the standard operating procedures of a third-party wireline operator. More details regarding each of these monitoring techniques are provided below.

Ultrasonic Imaging Tool

The USIT indicates the quality of the cement bond at the cement–casing interface and provides casing inspection (corrosion detection, monitoring, and casing thickness analysis). The tool is deployed on wireline with a transmitter emitting ultrasonic pulses and measuring the reflected ultrasonic waveforms received from the internal and external casing interfaces. The entire circumference of the casing is scanned, enabling the evaluation of the radial cement bond and the detection of internal and external casing damage or deformation. The high angular and vertical tool resolutions can detect cement channels as narrow as 1.2 inches. Detailed measurement and mechanical specifications for the USIT tool are provided in Attachment A-4. The wireline operator will provide QA/QC procedures and tool calibration for this equipment.

Pulsed-Neutron Logs

PNLs provide formation evaluation and reservoir monitoring in cased holes. PNL is deployed as a wireline logging tool with an electronic pulsed-neutron source and one or more detectors that typically measure neutrons or GRs (Rose and others, 2015). High-speed digital signal electronics process the GR response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the GR energy and time relationship into concentrations of elements (Schlumberger, 2017).

Detection limits for $CO_2$ saturation for PNL tools vary with the logging speed as well as the formation porosity. Blue Flint plans to select a PNL service provider and tool and ensure the wireline operator provides QA/QC procedures and tool calibration for their equipment.

Description of Regular PNL Protocol

After the drilling and before $CO_2$ injection, a PNL will be run in the injection well and deep monitoring well to provide a baseline to which future PNL runs will be compared.

The following general procedure will be followed when running a PNL in the injection well and deep monitoring well:

1. Hold a safety meeting and ensure that all personnel are wearing proper PPE:
   a. Rig up PPE.
   b. Ensure that all safety precautions are taken.

2. Shut well in by closing the outside wing valve and upper master valve.

3. Rig up lubricator, and pressure-test connections and seals to 2000 pounds per square inch.

4. Open crown valve.

5. Open top master valve and proceed downhole to the injection packer with the PNL tool.

6. Make a 30-minute stop at the bottom of the hole and record a static BHP.

7. Proceed with running the PNL, making stops every 500 feet for five minutes each to record a static fluid pressure.

8. Once the logging tool is at the surface and in the lubricator, make a 5-minute stop to record the surface pressure in the tubing.

9. Close the crown valve and top master valve. Bleed pressure from the tree and lubricator.

10. Remove lubricator and replace the top cap and pressure gauge.

11. Open the top master valve, and again record the tubing and annular pressures.

12. Rig down the wireline company and clean the location.

13. Return the well to injection service by opening the outside wing valve.

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.

### *C1.6.2 Indirect Monitoring Methods*

The indirect monitoring that is planned for the project includes time-lapse seismic surveys and passive seismicity monitoring. This indirect monitoring method will characterize attributes associated with the injected $CO_2$, including plume extents, mass changes, pressure changes, and potential seismicity. Details regarding the application and quality of this method are provided in the remainder of this section:

#### *C1.6.2.1 Time-Lapse Seismic Surveys*

Application of time-lapse seismic surveys for monitoring changes in acoustic properties requires a quality preoperational seismic survey for baseline conditions. The monitor survey should be repeated as closely to the baseline conditions and parameters as possible. The seismic monitor data should be reprocessed simultaneously with the original baseline data or processed with the same steps and workflow to ensure repeatability. Repeatability is a measure of 4D seismic quality (Lumley and others, 1997, 2000) that can be quantified once the processed data are analyzed by an experienced 4D seismic interpreter.

#### *C1.6.2.2 Passive Seismic Recording*

Continuous monitoring of seismic activity will include USGS seismometer stations already operating in North Dakota (Figure 5-7). Additional seismometer stations may be installed as needed. The distributed acoustic sensing (DAS) fiber optic systems installed on the injection well MAG 1 and the monitoring well MAG 2, capable of autonomously and continuously measuring a wide range of seismicity (micro/macro events) with the installation of additional seismometer stations, may be used to supplement passive seismicity monitoring efforts as needed.

## C1.7 Completed Well Logging

The well testing and logging plan is described in Section 5.5 of this application. Several continuous measurements of the storage formation properties were either made in the MAG 1 wellbore or are planned for the MAG 2 wellbore using wireline-logging techniques.

All wireline logging companies who perform work for the Blue Flint $CO_2$ Storage Project will employ standard analytical QA/QC protocols used in the industry.

## C1.8 References

ASTM International, 2017, ASTM G1-03(2017)e1, Standard practice for preparing, cleaning, and evaluating corrosion specimens: West Conshohocken, Pennsylvania, ASTM International, www.astm.org/g0001-03r17e01.html (accessed April 2022).

Lumley, D.E., Behrens, R.A., and Wang, Z., 1997, Assessing the technical risk of a 4-D seismic project: The Leading Edge, v. 16, p. 1287–1292, doi: 10.1190/1.1437784.

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.

National Association of Colleges and Employers, 2018, NACE SP0775, Preparation, installation, preparation, and interpretation of corrosion coupons in oilfield operations: https://standards.globalspec.com/std/10401680/nace-sp0775 (accessed April 2022).

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 – Supervisory Control and Data Acquisition (SCADA) System**

The SCADA system is a computer-based system or systems used by personnel in a control room that aims to collect and display information about the Blue Flint $CO_2$ storage injection operations in real time. This supervisory system collects data at an assigned time interval and stores the data in the historian server. Using Blue Flint operator process control selections, the SCADA will have the ability to send commands and control the storage injection network (i.e., start or stop pumps, open or close valves, control process equipment remotely, etc.).

In addition to monitoring and control ability, the SCADA system will include warnings, both audible and visual, to alert the Blue Flint control room, which is staffed 24/7, of near or excessive violations of set parameters within the system.

**Atachment A-2 – $CO_2$ Detection Station Overview**

Honeywell

# Sensepoint XCD SPECIFICATIONS

## Flammable, toxic and oxygen gas detector for industrial applications

| | |
|---|---|
| **Use** | 3 wire, 4-20mA and RS485 MODBUS output fixed point detector with in-built alarm and fault relays for the protection of personnel and plant from flammable, toxic and Oxygen hazards. Incorporates a transmitter with local display and fully configurable via non-intrusive magnetic switch interface. |
| **Electrical** | |
| **Input Voltage Range** | 12 to 32VDC (24VDC nominal) |
| **Max Power Consumption** | Maximum power consumption is dependent on the type of gas sensor being used. Electrochemical cells = 3.7W, IR = 3.7W and catalytic = 4.9W. Maximum inrush current = 800mA at 24VDC |
| **Current Output**<br>**Relays** | Sink or source<br>3 x 5A@250VAC. Selectable normally open or normally closed (switch) and energized/de-energised (programmable)<br>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<br>Sensor: 316 stainless steel |
| **Weight (approx)** | Aluminium Alloy LM25: 4.4lbs<br>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<br>** Lowest Alarm Limit = 15 ppm; Lowest Detection Limit = 10ppm<br>*** 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**<br>**European**<br>**International** | UL/c-UL - Class I, Division 1, Groups B, C and D, Class I, Division 2, Groups B, C & D, Class II, Division 1, Groups E, F & G, Class II, Division 2, Groups F & G. -40°C to +65°C<br>ATEX Ex II 2 GD Ex d IIC Gb T6 (Ta -40ºC to +65ºC) Ex tb IIIC T85°C Db IP66<br>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-2. Measurement and mechanical specifications for Honeywell's $CO_2$ detection station.

**Attachment A-3 – FlexSteel™ Overview**

PRODUCT SHEET

FLEXSTEEL

# FLEXSTEEL™ LINE PIPE

FlexSteel is the pipeline solution that couples the durability of steel with the installation, performance and cost benefits of spoolable pipe products. Highly corrosion resistant and more dependable than other pipeline solutions, FlexSteel combines the best features of all currently available line pipe options to deliver superior life cycle performance and value.

## DURABLE BY DESIGN

Reinforced with a helically wound, steel-reinforced layer for structural integrity, FlexSteel line pipe performs where other pipeline solutions often fail. Durable enough to withstand pulsating and cyclic pressures, the system continues to perform to its original design specifications and will not derate over time.

## APPLICATIONS

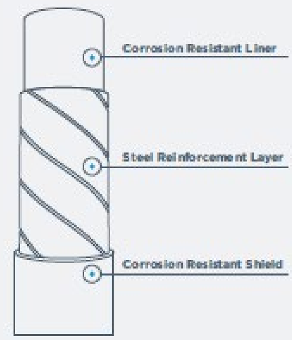
FlexSteel pipeline's unique characteristics make it the clear choice for increased safety and reliability in various environments and applications.

**PRODUCTION LINES:** FlexSteel is a smart investment that yields indisputable quality, safety, and performance advantages in multiphase, oil, and gas applications.

**DISPOSAL LINES:** Abrasion resistant and built to last, FlexSteel line pipe minimizes the risks associated with the transportation of highly corrosive produced water.

**INJECTION LINES:** Engineered to the highest quality standards, FlexSteel line pipe withstands pulsating and cyclic pressures often found in injection lines.

**GATHERING LINES:** Fast, easy, and cost effective installation coupled with extreme corrosion resistance make FlexSteel line pipe a natural choice for gathering pipelines.




### 2-INCH TO 8-INCH DIAMETER

Only 8-inch onshore spoolable pipeline with design pressures up to 3,000 psi.

### CORROSION RESISTANT DESIGN

Designed to resist corrosion including microbiologically influenced corrosion (MIC).

### BEST VALUE PIPELINE SOLUTION

Eliminates the need for expensive integrity management programs, and continuous maintenance services.



EXTREMEPERFORMANCEVALUEDURABILITY FLEXSTEELPIPE.COM

Attachment A-3. Measurement and mechanical specifications for FlexSteel's $CO_2$ flow line (continued).

**Attachment A-3 – FlexSteel™ Overview (continued)**

PRODUCT SHEET
US CUSTOMARY UNITS

FLEXSTEEL

| | Nominal Size (in) | Nominal Pressure Rating (PSI) | Reel Pipe Length (ft) | Coil Pipe Length (ft) | Pipe Inside Diameter (in) | Pipe Outside Diameter (in) | Operating Bend Radius, OBR (ft) | Weight Empty in Air (lb/ft) | Specific Gravity | Minimum Burst Pressure (PSI) | OHTC, U (based on ID) (BTU/hr-ft²°F) | Maximum Installation Tension (lbf) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STANDARD PRODUCT | 2 | 1,500 | 6,578 | - | 1.94 | 2.69 | 2.1 | 2.40 | 0.93 | 3,000 | 6.72 | 3,800 |
| | 2 | 2,250 | 4,462 | - | 1.94 | 2.85 | 2.2 | 3.53 | 1.23 | 4,500 | 6.91 | 10,500 |
| | 2 | 3,000 | 4,298 | - | 1.94 | 2.85 | 2.2 | 3.77 | 1.32 | 6,000 | 6.91 | 10,500 |
| | 3 | 750 | 4,560 | - | 2.82 | 3.65 | 2.8 | 3.53 | 0.74 | 1,500 | 5.75 | 8,000 |
| | 3 | 1,500 | 4,003 | - | 2.82 | 3.68 | 2.8 | 4.03 | 0.84 | 3,000 | 5.77 | 8,000 |
| | 3 | 2,250 | 2,871 | - | 2.82 | 3.81 | 2.9 | 5.46 | 1.06 | 4,500 | 5.86 | 9,000 |
| | 3 | 3,000 | 2,461 | - | 2.82 | 3.89 | 3.0 | 6.63 | 1.25 | 6,000 | 5.90 | 14,000 |
| | 4 | 750 | 3,264 | - | 3.67 | 4.58 | 3.5 | 4.76 | 0.63 | 1,500 | 5.08 | 8,000 |
| | 4 | 1,500 | 2,690 | - | 3.67 | 4.65 | 3.6 | 6.30 | 0.82 | 3,000 | 5.11 | 12,500 |
| | 4 | 2,250 | 1,821 | - | 3.67 | 4.81 | 3.7 | 8.79 | 1.08 | 4,500 | 5.17 | 20,000 |
| | 4 | 3,000 | 1,476 | - | 3.67 | 4.94 | 3.8 | 11.33 | 1.31 | 6,000 | 5.22 | 22,000 |
| | 6 | 750 | 1,230 | 2,543 | 5.60 | 6.89 | 5.3 | 9.52 | 0.56 | 1,500 | 3.67 | 20,000 |
| | 6 | 1,500 | 1,181 | 2,608 | 5.60 | 7.01 | 5.4 | 13.36 | 0.77 | 3,000 | 3.70 | 30,000 |
| | 6 | 2,250 | 837 | 1,509 | 5.60 | 7.17 | 5.5 | 18.34 | 1.02 | 4,500 | 3.73 | 30,000 |
| | 6 | 3,000 | 640 | 1,529 | 5.60 | 7.31 | 5.6 | 22.79 | 1.23 | 6,000 | 3.76 | 45,000 |
| | 8 | 750 | 607 | - | 7.63 | 9.19 | 7.1 | 15.87 | 0.53 | 1,500 | 2.97 | 30,000 |
| | 8 | 1,500 | 607 | - | 7.63 | 9.36 | 7.2 | 23.04 | 0.75 | 3,000 | 2.99 | 40,000 |
| | 8 | 2,250 | 459 | - | 7.63 | 9.58 | 7.4 | 32.11 | 1.01 | 4,500 | 3.02 | 45,000 |
| MXL | 8 | 750 | - | 1,260 | 7.25 | 8.77 | 6.8 | 15.85 | 0.58 | 1,500 | 3.18 | 25,000 |
| | 8 | 1,500 | - | 1,260 | 7.25 | 8.90 | 6.9 | 21.10 | 0.76 | 3,000 | 3.20 | 35,000 |
| | 8 | 2,250 | - | 1,260 | 7.25 | 9.12 | 7.0 | 29.52 | 1.02 | 4,500 | 3.22 | 40,000 |
| | 8 | 3,000 | - | 912 | 7.25 | 9.27 | 7.1 | 34.83 | 1.17 | 6,000 | 3.13 | 45,000 |

**Standard Properties for All Pipe Sizes**

| | |
|---|---|
| Absolute Roughness, ε (ft) | 5.0E-06 ft |
| Design Temperature (Water) | 150°F |
| Design Temperature (Oil/Gas) | 150°F |

**High-Temp Properties for All Pipe Sizes**

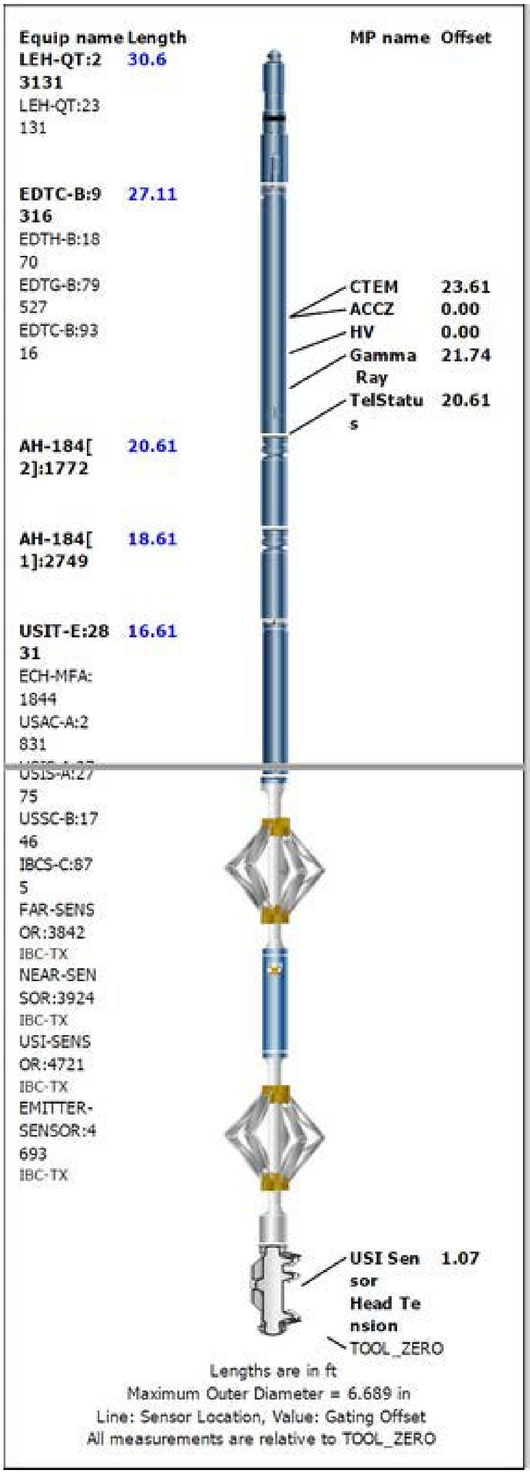
| | |
|---|---|
| Absolute Roughness, ε (ft) | 5.0E-06 ft |
| Design Temperature (Water) | 194°F |
| Design Temperature (Oil/Gas) | 185°F |



EXTREME PERFORMANCE VALUE DURABILITY FLEXSTEELPIPE.COM

Attachment A-3 (continued). Measurement and mechanical specifications for FlexSteel's $CO_2$ flow line.

# Attachment A-4 – Ultrasonic Imaging Tool (USIT)




## Measurement Specifications

| | Isolation Scanner Tool |
|---|---|
| Output[†] | Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image |
| Max. logging speed | Standard resolution (6 in, 10° sampling): 823 m/h [2,700 ft/h]<br>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]<br>Max. casing thickness: 2.01 cm [0.79 in] |
| Vertical resolution | High resolution: 1.52 cm [0.6 in]<br>High speed: 15.24 cm [6 in] |
| Acoustic impedance[‡] | Range: 0 to 10 Mrayl<br>Resolution: 0.2 Mrayl<br>Accuracy: 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15% |
| Flexural attenuation | Range: 0 to 2 dB/cm[§]<br>Resolution: 0.05 dB/cm[§]<br>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<br>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.

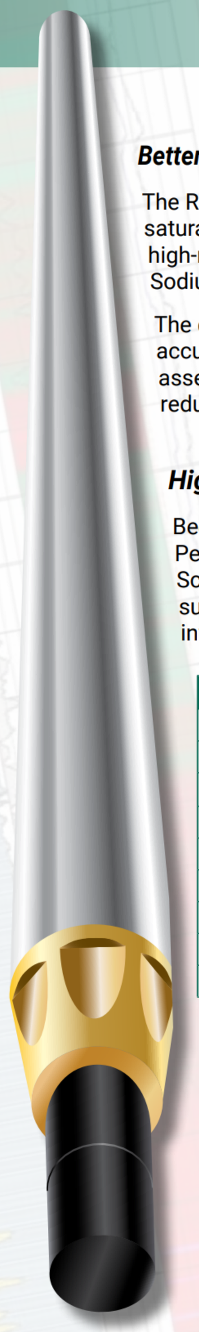
## Mechanical Specifications

| | 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]<br>IBCS-B: 11.36 cm [4.472 in]<br>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]<br>IBCS-B: 60.32 cm [23.75 in], 9.36 kg [20.64 lbm]<br>IBCS-C: 60.32 cm [23.75 in], 10.73 kg [23.66 lbm] |
| Sub max. tension | 10,000 N [2,250 lbf] |
| Sub max. compression | 50,000 N [12,250 lbf] |

[†] Limits for casing size depend on the sub used. Data can be acquired in casing larger than 9⅝ in with low-attenuation mud (e.g., water, brine).

Attachment A-4. Schlumberger's isolation scanner USIT used to provide evidence of external and internal mechanical integrity.

**Attachment A-5 – Example of a Pulsed-Neutron Logging Tool**



### *Better resolution leads to more accurate evaluation*

The Reservoir Analysis tool features three gamma detectors for measuring reservoir saturation using Sigma and Carbon-Oxygen (C/O) techniques. Near and far detectors are high-resolution Lanthanum Chloride for Sigma and C/O detection, while the long spacing Sodium Iodide detector incorporates a spacing that is sensitive to gas and porosity.

The combined RAS/SGR log provides all the necessary measurements for computing accurately the volumes of clay, rock porosity and fluid saturations; and obtain a better assessment of reservoir properties which can help optimizing completion programs that reduce CAPEX by eliminating poor frac stages.

### *High-quality log data, and the expertise for advanced interpretation*

Because data is only as good as its interpretation, our experienced Production Petrophysists, backed by available Reservoir Geoscience support from Hunter Well Science, employ advanced interpretation techniques to map RAS measurements into such properties as hydrocarbon saturation, porosity and rock type, delivering accurate information about reservoir properties.

| Specifications | | |
|---|---|---|
| Temperature rating | 320°F | 160°C |
| Pressure rating | 15,000 psi | 103.4 MPa |
| Diameter | 1 11/16 in. | 43 mm |
| Length | 140.7 in. | 3573 mm |
| Weight | 44 lb | 20 kg |
| Measure point - Near | 84 in. | 2134 mm |
| Measure point - Far | 91 in. | 2311 mm |
| Measure point - Long | 101 in. | 2565 mm |
| Materials | Corrosion resistant throughout | |

Specifications courtesy of Hunter Well Science Limited

### *...when experience matters*

Wireline Logging Solutions is staffed top to bottom by knowledgeable personnel, with deep understanding of this technology and how to get the most value from it. Our focus on service quality ensures rapid turnaround of a quality answer product, so you get the information you need, when you need it.

Attachment A-5. Measurement and mechanical specifications for Wireline Logging Solution's Reservoir Analysis tool.

# APPENDIX D

# STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| **Pore Space Amalgamation** | NDCC §§ 38-22-06(3) and (4)<br><br>NDAC §§ 43-05-01-08(1) and (2) | **NDCC § 38-22-06**<br>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.<br><br>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.<br><br>**NDAC § 43-05-01-08**<br>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:<br><br>a. Each operator of mineral extraction activities within the facility area and within one-half mile [.80 kilometer] of its outside boundary;<br><br>b. Each mineral lessee of record within the facility area and within one-half mile [.80 kilometer] of its outside boundary;<br><br>c. Each owner of record of the surface within the facility area and one-half mile [.80 kilometer] of its outside boundary;<br><br>d. Each owner of record of minerals within the facility area and within one-half mile [.80 kilometer] of its outside boundary; | a. An affidavit of mailing certifying that all pore space owners and lessees within the storage reservoir boundary and within one-half mile outside of its boundary have been notified of the proposed carbon dioxide storage project; | **1.0 PORE SPACE ACCESS** (p. 1-1, paragraph 2)<br>Blue Flint has identified the surface and mineral estate owners within the horizontal boundaries of the Blue Flint $CO_2$ storage facility area. With the exception of coal extraction, no mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles (0.8 kilometers) of its outside boundary. Blue Flint will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed $CO_2$ storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made (NDCC. §§ 38-22-06(3) and (4) and North Dakota Administrative Code [NDAC] §§ 43-05-01-08(1) and (2)). | The affidavit has not yet been prepared. |
| | | | b. A map showing the extent of the pore space that will be occupied by carbon dioxide over the life of the project; | **1.0 PORE SPACE ACCESS** (p. 1-1)<br>North Dakota statute explicitly grants title to pore space in all strata underlying the surface of lands and waters to the owner of the overlying surface estate; i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] § 47-31-03). Prior to issuance of the SFP, the storage operator is mandated by North Dakota statute for geologic storage of CO2 to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir (NDCC § 38-22-08(5)). The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation (NDCC § 38-22-10). Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application. Surface access for any potential above ground activities is not included in pore space amalgamation.<br><br>Blue Flint has identified the surface and mineral estate owners within the horizontal boundaries of the Blue Flint $CO_2$ storage facility area. With the exception of coal extraction, no mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles (0.8 kilometers) of its outside boundary. Blue Flint will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed $CO_2$ storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made (NDCC. §§ 38-22-06(3) and (4) and North Dakota Administrative Code [NDAC] §§ 43-05-01-08(1) and (2)).<br><br>All owners, lessees, and operators that require notification have been identified in accordance with North Dakota law, which vests the title to the pore space in all strata underlying the surface of lands and water to the owner of the overlying surface estate (NDCC § 47-31-03). The identification of pore space owners indicates that there was no severance of pore space or leasing of pore space to a third-party from the surface estate prior to 2009. All surface owners and pore space owners and lessees are the same owner of record.<br><br>A map showing the extent of the pore space that will be occupied by $CO_2$ over the life of the Blue Flint $CO_2$ storage project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record is illustrated in Figure 1-1. | **Figure 1-1.** Storage facility area map showing pore space ownership. |
| | | | c. A map showing the storage reservoir boundary and one-half mile outside of the storage reservoir boundary with a description of pore space ownership; | | **Figure 1-1.** Storage facility area map showing pore space ownership. |
| | | | d. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each operator of mineral extraction activities; | | **Figure 1-1.** Storage facility area map showing pore space ownership. |
| | | | e. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each mineral lessee of record; | | |
| | | | f. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each surface owner of record; | | **Figure 1-1.** Storage facility area map showing pore space ownership. |
| | | | g. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each owner of record of minerals. | | **Figure 1-1.** Storage facility area map showing pore space ownership. |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | e. Each owner and each lessee of record of the pore space within the storage reservoir and within one-half mile [.80 kilometer] of the reservoir's boundary; and<br><br>f. Any other persons as required by the commission.<br><br>2. The notice given by the applicant must contain:<br><br>a. A legal description of the land within the facility area.<br><br>b. The date, time, and place that the commission will hold a hearing on the permit application.<br><br>c. A statement that a copy of the permit application and draft permit may be obtained from the commission. | | | |
| Geologic Exhibits | NDAC § 43-05-01-05 (1)(b)(1) | **NDAC § 43-05-01-05 (1)(b)**<br>(1) The name, description, and average depth of the storage reservoirs; | a. Geologic description of the storage reservoir:<br>Name<br>Lithology<br>Average thickness<br>Average depth | **2.1 Overview of Project Area Geology** (p. 2-1)<br>The proposed Blue Flint $CO_2$ storage project will be situated near the BFE facility, located south of Underwood, North Dakota (Figure 2-1). This project site is on the eastern flank of the Williston Basin.<br><br>Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the Plains $CO_2$ Reduction (PCOR) Partnership, the Williston Basin has been identified as an excellent candidate for long-term $CO_2$ storage because of the thick sequence of clastic and carbonate sedimentary rocks and subtle structural character and tectonic stability of the basin (Peck and others, 2014; Glazewski and others, 2015).<br><br>The target $CO_2$ storage reservoir for the project is the Broom Creek Formation, a predominantly sandstone unit 4,708 ft below the surface at the MAG 1 stratigraphic test well location (Figure 2-1). Sixty-one feet of shales, siltstones, and interbedded evaporites of the undifferentiated Spearfish and Opeche Formations, hereinafter referred to as the Spearfish Formation, unconformably overlie the Broom Creek Formation. Eighty-seven feet of shales, siltstones, and anhydrites of the lower Piper Formation (undifferentiated Picard, Poe, and Dunham Members) overlie the Spearfish Formation. Together, the lower Piper and Spearfish Formations serve as the primary upper confining zone (Figure 2-2). The Amsden Formation (dolostone, limestone, anhydrite, and sandstone) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-2). Together, the lower Piper, Spearfish, Broom Creek, and Amsden Formations make up the $CO_2$ storage complex for the Blue Flint project (Table 2-1).<br><br>Including the Spearfish and lower Piper Formations, there is 859 ft (average thickness across the simulation area) of impermeable rock formations between the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. An additional 2,442 ft (average thickness across the simulation area) of impermeable rock formations separates the Inyan Kara Formation and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-2). | **Figure 2-1.** Topographic map of the project area showing the planned injection well, the planned monitoring well, and the Blue Flint Ethanol Plant (blue star). (p. 2-2)<br><br>**Figure 2-2.** Stratigraphic column identifying the potential storage reservoirs and confining zones (outlined in red) and the lowest USDW (outlined in blue). (p. 2-3)<br><br>**Table 2-1** Formations Making up the Blue Flint CO2 Storage Complex (average values calculated from the geologic model properties within simulation model area shown in Figure 2-3) (p. 2-4) |

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application<br>(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description<br>(Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>

**Table 2-1. Formations Comprising the Blue Flint $CO_2$ Storage Complex (average values calculated from the simulation model and well log data)**

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

</td><td></td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(2)(k)</td><td>NDAC § 43-05-01-05(1)(b)(2)<br>(k) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;</td><td>b. Data on the injection zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:<br>Depth<br>Areal extent<br>Thickness<br>Mineralogy<br>Porosity<br>Permeability<br>Capillary pressure<br>Facies changes</td><td>SOURCE OF THE DATA:<br>2.2.1 Existing Data (p. 2-4)<br>Existing data used to characterize the geology beneath the Blue Flint project site included publicly available well logs and formation top depths acquired from NDIC's online database. Well log data and interpreted formation top depths were acquired for 120 wellbores within the 5,500-square-mile (mi2) area covered by the geologic model of the proposed storage site (Figure 2-3). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations. Legacy 2D seismic data (70 miles) were licensed to characterize the subsurface geology in the project area and confirm the interpreted extent of the Broom Creek Formation (Figure 2-3).<br><br>Existing laboratory measurements for core samples from the Broom Creek Formation and its confining zones were available from four wells shown in Figure 2-4: Flemmer-1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), J-LOC1 (NDIC File No. 37380), and ANG 1 (Well No. ND-UIC-101) in addition to data from the site-specific stratigraphic test well, MAG 1 (NDIC File No. 37833). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and were integrated with newly acquired site-specific data.<br><br>2.2.2 Site-Specific Data (p. 2-6)<br>Site-specific efforts to characterize the proposed storage complex generated multiple data sets, including geophysical well logs, petrophysical data, and 3D seismic data. The MAG 1 well was drilled in 2020 specifically to gather subsurface geologic data to support the development of a $CO_2$ storage facility permit and serve as a future $CO_2$ injection well. Downhole logs were acquired, and sidewall core (SW Core) was collected from the proposed storage complex (i.e., the Lower Piper, Spearfish, Broom Creek, and Amsden Formations) at the time the well was drilled (Figure 2-5). In May 2022, fluid samples and temperature and pressure measurements were collected from the Broom Creek in the MAG 1 well.<br><br>Site-specific and existing data were used to assess the suitability of the storage complex for safe and permanent storage of $CO_2$. Site-specific data were also used as inputs for geologic model construction (Section 3.2), numerical simulations of $CO_2$ injection (Section 3.3.1), geochemical simulation (Sections 2.3.3, 2.4.1.2, and 2.4.3.2), and geomechanical analysis (Section 2.4.4). The site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency of collecting monitoring data, and interpretation of monitoring data with respect to potential subsurface risks. Furthermore, these data guided and influenced the design and operation of site equipment and infrastructure.</td><td>Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. (p. 2-5)<br><br>Figure 2-4. Map showing the spatial relationship between the Blue Flint project area and wells where the Broom Creek Formation core samples were collected. (p. 2-6)<br><br>Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota. (p. 2-12)<br><br>Figure 2-8. Isopach map of the Broom Creek Formation in the greater Blue Flint project area. (p. 2-13)<br><br>Figure 2-9. Well log display of the interpreted lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations in MAG 1. (p. 2-14)<br><br>Figure 2-10. Regional well log stratigraphic cross</td></tr>
</table>

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | DATA ON THE INJECTION ZONE:<br>**2.3 Storage Reservoir (injection zone)** (p. 2-11)<br>Regionally, the Broom Creek Formation is laterally extensive in the storage facility area (Figure 2-7) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals), dolomitic sandstone, and dolostone layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by the Spearfish and the lower Piper Formation (Figure 2-2) (Murphy and others, 2009).<br><br>***2.3.1 Mineralogy*** (p. 2-21)<br>Thin-section analysis of Broom Creek shows that quartz, dolomite, anhydrite, and clay (mainly illite/muscovite) are the dominant minerals. Throughout these intervals are the occurrence of feldspar (mainly K-feldspar) and iron oxide. Anhydrite obstructs the intercrystalline porosity in the upper part of the formation and dolomite in the middle and lower parts. The contact between grains is tangential. The porosity is due to the dissolution of anhydrite in the upper part and the dissolution of quartz and feldspar in the middle and lower parts. Figures 2-15, 2-16, and 2-17 show thin-section images representative of the upper, middle, and lower Broom Creek Formation. | sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15)<br><br>**Figure 2-11.** Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16)<br><br>**Figure 2-12.** Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-17)<br><br>**Figure 2-13.** Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. (p. 2-18)<br><br>**Table 2-5.** Description of $CO_2$ Storage Reservoir (injection zone) at the MAG 1 Well (p. 2-19)<br><br>**Figure 2-14.** Vertical distribution of core-derived porosity and permeability values and the laboratory-derived mineralogic characteristics in the Blue Flint storage complex from MAG 1. (p. 2-20)<br><br>**Figure 2-15**. Thin section in upper Broom Creek Formation. This interval is primarily dolomite (grey) with anhydritic cement. (p. 2-21)<br><br>**Figure 2-16**. Thin section in middle Broom Creek Formation. This interval is dominated by fine-grained quartz and minor dolomite. |

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

| Injection Zone Properties | | | |
|---|---|---|---|
| **Property** | **Description** | | |
| **Formation Name** | **Broom Creek** | | |
| **Lithology** | **Sandstone, dolomitic sandstone, dolostone** | | |
| **Formation Top Depth, ft** | **4,708** | | |
| **Thickness, ft** | **103 (sandstone 66, dolomitic sandstone 13, dolostone 24)** | | |
| **Capillary Entry Pressure (brine/$CO_2$), psi** | **0.866** | | |
| **Geologic Properties** | | | |
| **Formation** | **Property** | **Laboratory Analysis** | **Simulation Model Property Distribution** |
| **Broom Creek (sandstone)** | **Porosity, %*** | **24.12 (21.42–27.80)** | **19.15 (0.0–36.00)** |
| | **Permeability, mD**** | **298.16 (140.70–929.84)** | **132.83 (0–3237.4)** |
| **Broom Creek (dolomitic sandstone)** | **Porosity, %*** | **20.85 (16.13–23.83)** | **15.87 (1.0–29.25)** |
| | **Permeability, mD**** | **81.91 (16.40–257.00)** | **50.13 (0–650.70)** |
| **Broom Creek (dolostone)** | **Porosity, %*** | **10.50 (5.83–15.91)** | **7.85 (0.0–24.65)** |
| | **Permeability, mD**** | **1.01 (0.01–178.60)** | **0.76 (0.0–519.32)** |

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses.

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|

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

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

***2.3.3 Geochemical Information of Injection Zone*** (p. 2-26)
Geochemical simulation has been performed to calculate the effects of introducing the $CO_2$ stream to the injection zone.

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

The scenario with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (80% of bulk reservoir volume) and average formation brine composition (20% of bulk reservoir volume). XRD data from the 15 Broom Creek formation core samples were used to inform the mineralogical composition of the Broom

Porosity is high in this interval. (p. 2-22)

**Figure 2-17.** Thin section in lower Broom Creek Formation. This interval is a laminated silty mudstone. The matrix is dominated by clay and quartz. (p. 2-23)

**Table 2-6.** XRD Analysis in the Broom Creek Reservoir from MAG 1. Only major constituents are shown. (p. 2-24)

**Figure 2-18.** XRF analysis in Broom Creek Formation from MAG 1 (p. 2-25)

**Table 2-7**. Injection Stream Composition (p. 2-27)

**Table 2-8.** XRD Results for MAG 1 Broom Creek Core Sample (p. 2-27)

**Figure 2-19**. Upper graph shows cumulative injection vs. time; the bottom figure shows the gas injection rate vs. time. There is no observable difference in injection due to geochemical reactions. (p. 2-28)

**Figure 2-20**. Upper graph shows wellhead pressure vs. time; the bottom figure shows the bottomhole pressure vs. time. There is no observable difference in pressures due to geochemical reactions. (p. 2-29)

**Table 2-9**. Broom Creek Water Ionic Composition, expressed in molality (p. 2-30)

**Figure 2-21.** CO2 molality for the geochemistry case simulation results after 20

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | Creek Formation (Table 2-8). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Reported ionic composition of the Broom Creek Formation water is listed in Table 2-9.<br><br>Figure 2-24 shows the mass of mineral dissolution and precipitation due to geochemical reaction in the Broom Creek Formation. Dolomite is the most prominent dissolved mineral. Albite and K-feldspar gradually dissolves over time. Illite initially dissolves and then starts precipitating 3 years after injection stops. Quartz and anhydrite are the minerals that experienced the most precipitation over time.<br><br>Figures 2-25 and 2-26 provide an indication of the change in distribution of the mineral that experienced the most dissolution, dolomite, and the mineral that experienced the most precipitation, quartz, respectively. Considering the apparent net dissolution of minerals in the system, as indicated in Figure 2-24, there is an associated net increase in porosity in the affected areas, as shown in Figure 2-27. However, the porosity change is small, less than 0.04% porosity units, equating to a maximum increase in average porosity from 22.6% to 22.64% after the 20-year injection period. | years of injection + 25 years postinjection showing the distribution of $CO_2$ molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of simulation in Layer k = 39. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-31)<br><br>**Figure 2-22.** $CO_2$ molality for the non-geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of $CO_2$ molality in log scale. Left upper images are west-east, and right upper are north-south cross sections. Lower image is a planar view of simulation in Layer k = 39. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-32)<br><br>**Figure 2-23.** Geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the pH of formation brine in log scale. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-33)<br><br>**Figure 2-24**. Dissolution and precipitation quantities of reservoir minerals because of CO2 injection. Dissolution of albite, K-feldspar (K-fe_fel), and dolomite with |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | | precipitation of illite, quartz, and anhydrite was observed. (p. 2-34)<br><br>**Figure 2-25.** Change in molar distribution of dolomite, the most prominent dissolved mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-35)<br><br>**Figure 2-26.** Change in molar distribution of quartz, the most prominent precipitated mineral at the end of the 20-year injection + 25 years postinjection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p.2-36)<br><br>**Figure 2-27.** Change in porosity due to net geochemical dissolution at the end of the 20-year injection period. White grid cells correspond to cells omitted from calculations because of having porosity and/or permeability values that round to zero. (p. 2-37) |
| | | | c. Data on the confining zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:<br>Depth<br>Areal extent<br>Thickness<br>Mineralogy<br>Porosity<br>Permeability<br>Capillary pressure<br>Facies changes | SOURCE OF THE DATA:<br>*See discussion above under 2.2.1 Existing Data*<br><br>AND<br><br>**2.4 Confining Zones** (p. 2-38)<br>The confining zones for the Broom Creek Formation are the overlying Spearfish Formation and the lower Piper Formation and the underlying Amsden Formation (Figure 2-2, Table 2-10). Both the overlying and underlying confining formations consist primarily of impermeable rock layers. | **Table 2-10**. Properties of Upper and Lower Confining Zones in Simulation Area (p. 2-38)<br><br>**Figure 2-28.** Areal extent of the lower Piper Formation in western North Dakota (modified from Carlson, 1993). (p. 2-39)<br><br>**Figure 2-29.** Structure map of the lower Piper Formation |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | See below | See below |

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

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

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

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

***2.4.1 Upper Confining Zone*** (p. 2-39)
In the Blue Flint project area, the upper confining zone, the lower Piper and Spearfish Formations, consists of siltstone with interbedded anhydrite (Table 2-10). The upper confining zone is laterally extensive across the project area (Figure 2-28) and is 4,560 ft below the land surface and 148 ft thick (lower Piper Formation, 87 ft [Figures 2-29 and 2-30], Spearfish Formation, 61 ft [Figures 2-31 and 2-32]) as observed in the MAG 1 well. The contact between the underlying Broom Creek Formation sandstone and the upper confining zone is an unconformity that can be correlated across the Broom Creek Formation extent where the resistivity and GR logs show a significant change across the contact. A relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation changes to a relatively high GR signature representing the siltstones of the Spearfish Formation (Figure 2-9).

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

across the greater Blue Flint project area in feet below mean sea level. (p. 2-40)

**Figure 2-30.** Isopach map of the lower Piper Formation in the greater Blue Flint project area. (p. 2-41)

**Figure 2-31.** Structure map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area(p. 2-42)

**Figure 2-32.** Isopach map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area. (p. 2-43)

**Table 2-11.** Spearfish and Lower Piper Formation SW Core Sample Porosity and Permeability from MAG 1 (p. 2-44)

**Figure 2-33:** Thin section of Piper Formation. In this example, clay (brown) and anhydrite (white) dominate the depth interval. Minor porosity is observed (blue). (p. 2-45)

**Figure 2-34:** Thin section of Spearfish Formation. In this example, clay (brown), quartz (small white grains), anhydrite (large white grains), and iron oxides (black grains) dominate the depth interval. No porosity is observed. (p. 2-46)

**Figure 2-35**: Thin section of Spearfish Formation. In this example, clay (brown) and quartz (white) dominate the depth interval. Minor intergranular and intragranular porosity are observed (blue). (2-47)

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|

In situ fluid pressure testing was not performed in the Spearfish or lower Piper Formations in the MAG 1 well. The low permeability values shown in Table 2-11 suggest any fluid within the Spearfish Formation is pore- and capillary-bound fluid and likely not mobile. Several documented attempts by others to draw down reservoir fluid in order to measure the reservoir pressure or collect an in situ fluid sample using a modular formation dynamics tester (MDT) tool in the undifferentiated Spearfish/Opeche and other similar low-permeability intervals suggest collecting this information is not feasible. The Tundra SGS (secure geologic storage) SFP applications describe unsuccessful attempts to measure in situ fluid pressure because of the low permeability of the formations tested, the undifferentiated Spearfish/Opeche Formation, and the Icebox Formation (North Dakota Industrial Commission, 2021a, b). The Red Trail Energy SFP application also describes unsuccessful attempts to collect these data in the low-permeability Opeche Formation (North Dakota Industrial Commission, 2021c).

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

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

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

XRD data from the sidewall core samples in the cap rock intervals supported the thin-section analysis. Table 2-11 shows the major mineral phases identified for the samples representing these intervals. XRF data related to the upper confining zones are presented in Figure 2-33.

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

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

**Table 2-12.** XRD Analysis in the Upper Confining Intervals (Spearfish and Lower Piper) from MAG 1 Well. Only major constituents are shown. (p. 2-48)

**Figure 2-36.** XRF analysis in the upper confining zone (Spearfish and lower Piper Formations) from MAG 1. (p. 2-49)

**Table 2-13**. Mineral Composition of the Spearfish Derived from XRD Analysis of MAG 1 Core Samples (p. 2-50)

**Table 2-14**. Formation Water Chemistry from Broom Creek Formation Fluid Samples from MAG 1 (p. 2-50)

**Figure 2-37.** Change in fluid pH vs. time. Red line shows pH for the center of Cell C1, 0.5 meters above the Spearfish Formation cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to change until after Year 16. (p. 2-52)

**Figure 2-38**. Dissolution and precipitation of minerals in the Spearfish Formation cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible. Results from Cell C3, 2.5 meters above

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Spearfish | 130074 | 4,710 | 8.3 | 5.3 | 11.8 | 38.5 | 4.6 | 11.0 | 0.0 | 19.7 | 0.4 |
| Spearfish | 130073 | 4,715 | 9.6 | 6.6 | 11.4 | 37.9 | 4.5 | 13.9 | 0.0 | 15.4 | 0.4 |
| Spearfish | 130071 | 4,721 | 8.0 | 6.7 | 10.2 | 39.6 | 0.0 | 34.9 | 0.0 | 0.0 | 0.0 |
| Spearfish | 130070 | 4,724 | 13.8 | 9.8 | 15.3 | 46.0 | 10.2 | 3.3 | 0.0 | 0.8 | 0.6 |

***2.4.1.1 Mineralogy*** (p. 2-44)
The combined interpretation of SW Core samples, well logs, and thin sections shows that the Spearfish and lower Piper Formations are dominated by clays (mainly illite/muscovite), quartz, anhydrite, feldspar (mainly K-feldspar), and dolomite. Sixteen depth intervals in the Spearfish and Lower Piper Formations were sampled for thin-section creation, XRD mineralogical determination, and XRF bulk chemical analysis. For the assessment, thin sections and XRD provide independent confirmation of the mineralogical constituents of each of these intervals. Thin-section analysis of the siltstone intervals shows that clay, quartz, and anhydrite are the dominant minerals. Throughout these intervals are occurrences of dolomite, feldspar, and iron oxides (Figures 2-33, 2-34, and 2-35). The contacts between grains are typically separated by a clay matrix, with more rare occurrences of contacts between quartz grains as tangential to long.

***2.4.1.2 Geochemical Interaction*** (p. 2-50)
Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected $CO_2$ stream on the Spearfish Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to $CO_2$ at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Spearfish Formation by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the confining zone. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock–$CO_2$ exposure boundary. The mineralogical composition of the Spearfish Formation was honored (Table 2-13). Formation brine composition was assumed to be the same as the known composition from the Broom Creek Formation injection zone below (Table 2-14). For simulation, 100% $CO_2$ was used as discussed in Section 2.3.1. The exposure level, expressed in moles per year, of the $CO_2$ stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). This overestimate was done to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection. The simulation was performed at reservoir pressure and temperature conditions.

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

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

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

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

the cap rock base, are not shown as they are too small to be seen at this scale. (p. 2-52)

**Figure 2-39**. Weight percentage (wt%) of potentially reactive minerals present in the Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in Cell 1 (C1) (orange) and Cell 2 (C2) (gray, too small to see in the figure) after 20 years of injection plus 25 years of postinjection. (p. 2-53)

**Figure 2-40.** Weight percentage (wt%) of precipitated minerals in the Cell 1 (C1) (orange) and Cell 2 (C2) (gray) during 45 years of simulation time. (p. 2-54)

**Figure 2-41.** Change in percent porosity of the Spearfish cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation. (p. 2-55)

**Table 2-15.** Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the MAG 1 well) (p. 2-56)

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | | |

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

***2.4.2 Additional Overlying Confining Zones*** (p. 2-55)
Several other formations provide additional confinement above the lower Piper interval. Impermeable rocks above the primary seal include the upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-15). Together with the Spearfish and lower Piper intervals, these intervals are 859 ft thick on average across the simulation area and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-42). Above the Inyan Kara Formation at the MAG 1 well, 2,512 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and lowermost USDW, the Fox Hills Formation (see Figure 2-43). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-15).

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

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

***2.4.3 Lower Confining Zones*** (p. 2-58)
The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, limestone, and anhydrite. The Amsden Formation does include some thin sandstone and dolomitic sandstone intervals on the order of 4–6 inches thick (Figure 2-9). The sandstone intervals in the Amsden Formation are isolated from the sandstones of the Broom Creek Formation by thick impermeable dolostone intervals (Figure 2-9). The top of the Amsden Formation was placed at the top of an argillaceous dolostone, which has relatively high GR character that can be correlated across the project area (Figure 2-9). The Amsden Formation is 4,810 ft below land surface and 276 ft thick at the Blue Flint site as determined at the MAG 1 well (Figures 2-44 and 2-45).

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

**Table 2-15. Amsden SW Core Sample Porosity and Permeability from MAG 1**

| Sample Depth, ft | Porosity % | Permeability, mD |
|---|---|---|
| 4,845 | 9.59 | 0.003 |
| 4,851* | 18.80 | 117 |
| 4,860* | 8.86 | 1.46 |
| 4,865 | 2.15 | 0.0003 |

**Figure 2-42.** Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. (p. 2-56)

**Figure 2-43.** Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. (p. 2-57)

**Figure 2-44.** Structure map of the Amsden Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-58)

**Figure 2-45.** Isopach map of the Amsden Formation across the greater Blue Flint project area. (p. 2-59)

**Table 2-16**. Amsden SW Core Sample Porosity and Permeability from MAG 1. (p. 2-60)

**Figure 2-46**. Thin section in the Amsden Formation. This example shows a dolomite matrix (gray/brown) with quartz grains distributed throughout. Minor porosity is observed. (p. 2-61)

**Figure 2-47.** Thin section in the Amsden Formation. This interval is dominated by anhydrite and quartz. In this example, quartz grains are tightly cemented, and almost no porosity is observed. (p. 2-62)

**Figure 2-48.** Thin section in the Amsden Formation. This interval shows a fine micritic dolomite with minor quartz grains. Porosity is generally

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | (continued below) | low and found to be intergranular or due to the dissolution of dolomite in this example. (p. 2-63)<br><br>**Table 2-17.** XRD Analysis in the Lower Confining Zone (Amsden Formation) from MAG 1 Well. Only major constituents are shown. (p. 2-64)<br><br>**Figure 2-49**. XRF analysis in the lower confining zone (Amsden Formation) from MAG 1. (p. 2-65) |

| | | |
|---|---|---|
| 4,869 | 11.56 | 0.009 |
| 4,875** | 2.9 | 0.005 |
| 4,880* | 3.74 | 0.134 |
| 4,889* | 10.26 | 0.239 |
| **Range** | (2.15–18.80) | (0.0003–117) |
| Values measured at 2,400 psi | | |

* Sample is fractured or chipped. The measured permeability and/or porosity may be higher than its real value.
** Sample is very short; the measured porosity may be higher than its real value because of lack of conformation of boot material to plug surface.

***2.4.3.1 Mineralogy*** (p. 2-60)
Well logs and the thin-section analyses show that the Amsden Formation comprises dolostone, sandstone, anhydrite, and limestone. The porosity averages 7%, and permeability is very low. Figures 2-46, 2-47, and 2-48 show thin-section images representative of the Amsden Formation.

XRD was performed, and the results confirm the observations made during core observation, thin-section description, and well log analysis. Amsden intervals show that dolomite, anhydrite, quartz, and clay are the dominant minerals (Table 2-16). XRF data are presented in Figure 2-46 for the Amsden Formation.

**Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the MAG 1 well)**

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

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | NDAC § 43-05-01-05(1)(b)(2) | **NDAC § 43-05-01-05(1)(b)**<br>(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 | 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:<br>Rock properties<br>Regional pressure gradients<br>Adsorption processes | (continued below) | **Table 2-2.** Description of MAG 1 Temperature Measurements and Calculated Temperature Gradients (p. 2-9)<br><br>**Table 2-3.** Description of MAG 1 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-9)<br><br>**Figure 2-63.** Geomechanical parameters in the Spearfish Formation. (p. 2-81) |

***2.2.2.3 Formation Temperature and Pressure*** (p. 2-8)
Broom Creek Formation temperature and pressure measurements were collected from MAG 1 with a packer module. To collect a formation fluid sample, the Broom Creek Formation had to be perforated due to the cement sheath created while drilling out an extended cement plug in the lower portion of the wellbore. The Broom Creek Formation was perforated from 4,733 to 4,740 ft, and a packer was set at 4,096 ft with a tailpipe, dial sensor mandrel, and 4-ft perforated sub below the packer. Pressure and temperature sensors were set at depths of 4,735 and 4,741 ft, and the measurements recorded are shown in Tables 2-2 and 2-3. The calculated pressure and temperature gradients from MAG 1 were used to model the formation temperature and pressure profiles for use in the numerical simulations of $CO_2$ injection.

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

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

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

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application<br>(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description<br>(Page Number)</th></tr>
<tr><td></td><td></td><td>comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:</td><td></td><td>

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

<table>
<tr><th>Formation</th><th>Sensor Depth, ft</th><th>Formation Pressure, psi</th></tr>
<tr><td>Broom Creek</td><td>4,735</td><td>2,427.00</td></tr>
<tr><td>Broom Creek</td><td>4,741</td><td>2,427.28</td></tr>
<tr><td>Mean Broom Creek Pressure, psi</td><td>2,427.14</td><td></td></tr>
<tr><td>Broom Creek Pressure Gradient, psi/ft</td><td>0.50*</td><td></td></tr>
</table>

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

***2.3.2 Mechanism of Geologic Confinement*** (p. 2-26)

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

***2.4.4.2 Stress, Ductility, and Rock Strength*** (p. 2-80)

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

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

<table>
<tr><th>Formation</th><th>Stats</th><th>E_Stat, Mpsi</th><th>n_Stat, unitless</th><th>K, Mpsi</th><th>G, Mpsi</th><th>P, psi</th><th>E_Dyn, Mpsi</th><th>n_Dyn, unitless</th></tr>
<tr><td rowspan="3">Spearfish</td><td>Min</td><td>0.665</td><td>0.243</td><td>0.493</td><td>0.256</td><td>2821</td><td>3.090</td><td>0.243</td></tr>
<tr><td>Max</td><td>1.554</td><td>0.347</td><td>1.365</td><td>0.616</td><td>6591</td><td>5.213</td><td>0.347</td></tr>
<tr><td>Average</td><td>1.159</td><td>0.281</td><td>0.884</td><td>0.453</td><td>4916</td><td>4.331</td><td>0.281</td></tr>
<tr><td rowspan="3">Broom Creek</td><td>Min</td><td>0.089</td><td>0.231</td><td>0.084</td><td>0.034</td><td>378</td><td>0.896</td><td>0.231</td></tr>
<tr><td>Max</td><td>3.774</td><td>0.347</td><td>3.288</td><td>1.429</td><td>15884</td><td>8.963</td><td>0.347</td></tr>
<tr><td>Average</td><td>0.573</td><td>0.313</td><td>0.479</td><td>0.221</td><td>2430</td><td>2.444</td><td>0.313</td></tr>
<tr><td rowspan="3">Amsden</td><td>Min</td><td>0.117</td><td>0.152</td><td>0.137</td><td>0.043</td><td>495</td><td>1.057</td><td>0.152</td></tr>
<tr><td>Max</td><td>6.869</td><td>0.364</td><td>6.774</td><td>2.581</td><td>29140</td><td>13.026</td><td>0.364</td></tr>
<tr><td>Average</td><td>1.945</td><td>0.286</td><td>1.47</td><td>0.764</td><td>8249</td><td>5.707</td><td>0.286</td></tr>
</table>

</td><td>

**Figure 2-64**. Geomechanical parameters in the Broom Creek Formation. (p. 2-82)

**Figure 2-65.** Geomechanical parameters in the Amsden Formation. (p. 2-83)

**Table 2-19.** Ranges and Averages of the Elastic Properties Estimated from 1D MEM in Spearfish, Broom Creek and Amsden Formations (p. 2-84)

</td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(2)(g)</td><td>**NDAC § 43-05-01-05(1)(b)(2)**<br>(g) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored carbon dioxide and</td><td>e. Identification of all characteristics controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir, including:<br>Structural spill points</td><td>

*2.2.2.6 Seismic Survey* (p. 2-10)

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

</td><td>**Figure 2-9.** Well log display of the interpreted lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations in MAG 1. (p. 2-14)</td></tr>
</table>

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | associated fluids within the storage reservoir; | Stratigraphic discontinuities | Data products generated from the interpretation of the 3D seismic data were used as inputs into the geologic model that was used to simulate migration of the $CO_2$ plume. The 3D seismic data and MAG 1 well logs were used to interpret surfaces for the formations of interest within the survey area. These surfaces were converted to depth using the time-to-depth relationship derived from the MAG 1 dipole sonic log. The depth-converted surfaces for the storage reservoir and upper and lower confining zones were used as inputs for the geologic model. These surfaces captured detailed information about the structure and varying thickness of the formations between wells. A poststack inversion of the 3D seismic data was done using the MAG 1 well logs. Given the uncertainty in sonic log values related to washouts in the Broom Creek Formation in the MAG 1 well, indicated by the caliper log shown in Figure 2-5, inversion results of the 3D seismic data were not used to inform property distribution in the geologic model.<br><br>Interpretation of the 3D seismic data and legacy 2D seismic data suggests there are no major stratigraphic pinch-outs or structural features with associated spill points in the area of review. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the 2D and 3D seismic data in the area of review.<br><br>***2.3.2 Mechanism of Geologic Confinement*** (p. 2-26)<br>*See discussion above under 2.3.2 Mechanism of Geologic Confinement* | **Figure 2-10.** Regional well log stratigraphic cross sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15)<br><br>**Figure 2-11**. Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16)<br><br>**Figure 2-12.** Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops in creation of this map. (p. 2-17)<br><br>**Figure 2-13.** Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. (p. 2-18) |
| | NDAC § 43-05-01-05(1)(b)(2)(c) | **NDAC § 43-05-01-05(1)(b)(2)** (c) Any regional or local faulting; | f. Any regional or local faulting; | **2.5 Faults, Fractures, and Seismic Activity** (First two paragraphs on p. 2-85)<br>In the area of review, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. The absence of transmissive faults is supported by fluid sample analysis results from MAG 1 that suggest the injection interval, Broom Creek Formation (28,600 mg/L), is isolated from the next permeable interval, the Inyan Kara Formation (15,600 mg/L) (Appendix A).<br><br>A regional structural feature, the Stanton Fault, is discussed in this section. This section also discusses the seismic history of North Dakota and the low probability that seismic activity will interfere with containment.<br><br>***2.5.1 Stanton Fault*** (p. 2-86)<br>The Stanton Fault is a suspected Precambrian basement fault interpreted by Sims and others (1991), who–interpreted this northeast-southwest trending feature using available borehole data and regional gravity and magnetic data. The Stanton Fault is interpreted by Sims and others (1991) to be approximately 0.7 miles from the MAG 1 well (Figure 2-66). Given the resolution of the regional gravity and magnetic data and limited amount of borehole data used to interpret this suspected fault, there is a lot of uncertainty in the lateral extent and the location of the feature. No studies describing the possible vertical extent of this feature or impact on overlying sedimentary layers have been published. Lack of historical earthquakes in the area suggests that if the suspected Stanton Fault does exist it is inactive. | **Figure 2-66.** Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016). (p. 2-87)<br><br>**Figure 2-67**. Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box). (p. 2-88)<br><br>**Figure 2-68.** Cross section of Line 1 showing interpreted seismic horizons |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | 2D and 3D seismic data were used to characterize the subsurface within the project area and determine if the suspected Stanton Fault or other faults are present within the area of review. There is no indication of faulting within the 3D seismic data. Along the 2D seismic lines, there are areas where diffractions within the Precambrian basement can be seen and areas where there are discontinuities and flexures along seismic reflection events at the top of and within the Precambrian basement. These features may indicate the presence of faults.<br><br>On Lines 1 and 2, shown in Figure 2-67 and 2-68, respectively, the diagonal seismic features within the Precambrian basement may be diffractions indicating the location of a structural feature such as a fault. However, there is no visible offset within the formations that directly overly the Precambrian basement, suggesting that if a fault is present it is confined to the Precambrian basement.<br><br>On Lines 1 and 2, there are also discontinuities and flexures in several places along the interpreted top of the Precambrian basement and within the Precambrian basement that may also indicate the presence of faults. If these seismic features do correspond to faults, there is no indication that these features are present in the formations overlying the Precambrian basement and, therefore, do not have sufficient vertical extent to transect the storage reservoir and confining zones which are more than 5,000 feet above the basement. | (red lines) and area where diffractions are present withing the Precambrian basement (green box). (p. 2-88) |
| | NDAC § 43-05-01-05(1)(b)(2)(j) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(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:<br>Location<br>Orientation<br>Determination of the probability that they would interfere with containment | ***2.5.1 Stanton Fault*** (p. 2-86)<br>*See discussion above under 2.5.1 Stanton Fault* | **Figure 2-66.** Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016). (p. 2-87)<br><br>**Figure 2-67**. Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box). (p. 2-88)<br><br>**Figure 2-68.** Cross section of Line 1 showing interpreted seismic horizons (red lines) and area where diffractions are present withing the Precambrian basement (green box). (p. 2-88) |
| | NDAC §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(m) | **NDAC § 43-05-01-05(1)(b)**<br>(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, | h. Information on any regional tectonic activity, and the seismic history, including:<br>The presence and depth of seismic sources;<br>Determination of the probability that seismicity would interfere with containment; | ***2.5.2 Seismic Activity*** (p. 2-89)<br>The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2022).<br><br>Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-21) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-69). The earthquake recorded closest to the project area occurred in 2008 52.3 miles to the east, near Goodrich, North Dakota (Table 2-21). The magnitude of this earthquake is estimated to have been 2.6. | **Table 2-21**. Summary of Earthquakes Reported to Have Occurred in North Dakota (p. 2-90)<br><br>**Figure 2-69.** Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). (p. 2-91)<br><br>**Figure 2-70**. Probabilistic map showing how often scientists expect damaging earthquake shaking around |

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application<br>(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description<br>(Page Number)</th></tr>
<tr><td></td><td></td><td>local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:<br><br>NDAC § 43-05-01-05(1)(b)(2)<br>(m) Information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment;</td><td></td><td>Table 2-21. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)
<table>
<tr><th>Date</th><th>Magnitude</th><th>Depth, miles</th><th>Longitude</th><th>Latitude</th><th>City or Vicinity of Earthquake</th><th>Map Label</th><th>Distance to Blue Flint Ethanol, miles</th></tr>
<tr><td>Sept. 28, 2012</td><td>3.3</td><td>0.4*</td><td>−103.48</td><td>48.01</td><td>Southeast of Williston</td><td>A</td><td>117.0</td></tr>
<tr><td>June 14, 2010</td><td>1.4</td><td>3.1</td><td>−103.96</td><td>46.03</td><td>Boxelder Creek</td><td>B</td><td>162.9</td></tr>
<tr><td>March 21, 2010</td><td>2.5</td><td>3.1</td><td>−103.98</td><td>47.98</td><td>Buford</td><td>C</td><td>136.4</td></tr>
<tr><td>Aug. 30, 2009</td><td>1.9</td><td>3.1</td><td>−102.38</td><td>47.63</td><td>Ft. Berthold southwest</td><td>D</td><td>60.1</td></tr>
<tr><td>Jan. 3, 2009</td><td>1.5</td><td>8.3</td><td>−103.95</td><td>48.36</td><td>Grenora</td><td>E</td><td>146.7</td></tr>
<tr><td>Nov. 15, 2008</td><td>2.6</td><td>11.2</td><td>−100.04</td><td>47.46</td><td>Goodrich</td><td>F</td><td>52.3</td></tr>
<tr><td>Nov. 11, 1998</td><td>3.5</td><td>3.1</td><td>−104.03</td><td>48.55</td><td>Grenora</td><td>G</td><td>156.2</td></tr>
<tr><td>March 9, 1982</td><td>3.3</td><td>11.2</td><td>−104.03</td><td>48.51</td><td>Grenora</td><td>H</td><td>154.8</td></tr>
<tr><td>July 8, 1968</td><td>4.4</td><td>20.5</td><td>−100.74</td><td>46.59</td><td>Huff</td><td>I</td><td>58.0</td></tr>
<tr><td>May 13, 1947</td><td>3.7**</td><td>U</td><td>−100.90</td><td>46.00</td><td>Selfridge</td><td>J</td><td>96.1</td></tr>
<tr><td>Oct. 26, 1946</td><td>3.7**</td><td>U</td><td>−103.70</td><td>48.20</td><td>Williston</td><td>K</td><td>131.5</td></tr>
<tr><td>April 29, 1927</td><td>0.2**</td><td>U</td><td>−102.10</td><td>46.90</td><td>Hebron</td><td>L</td><td>55.8</td></tr>
<tr><td>Aug. 8, 1915</td><td>3.7**</td><td>U</td><td>−103.60</td><td>48.20</td><td>Williston</td><td>M</td><td>127.3</td></tr>
</table>
* Estimated depth.<br>** Magnitude estimated from reported modified Mercalli intensity (MMI) value.</td><td>the United States (U.S. Geological Survey, 2019). (p. 2-92)</td></tr>
<tr><td></td><td>NDAC §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(n)</td><td>NDAC § 43-05-01-05(1)(b)<br>(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any</td><td>i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area:<br>Geologic maps<br>Topographic maps<br>Cross sections</td><td>2.1 Overview of Project Area Geology (p. 2-1)<br>See discussion above under 2.1 Overview of Project Area Geology<br><br>4.4.3 Hydrology of USDW Formations (p. 4-16)<br>The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the area of investigation is to the northeast (Figure 4-9). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,500 ppm (Klausing, 1974). Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Honeyman, 2007). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering.</td><td>Figure 2-1. Topographic map of the project area showing the planned injection well, the planned monitoring well, and the Blue Flint Ethanol Plant (p. 2-2)<br><br>Figure 2-7. Areal extent of the Broom Creek Formation in North Dakota (red dashed line). (p. 2-12)<br><br>Figure 2-10. Regional well log stratigraphic cross</td></tr>
</table>

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | 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:<br><br>**NDAC § 43-05-01-05(1)(b)(2)**<br>(n) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the facility area; and | | Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the area of investigation. A cross section of these formations is presented in Figure 4-10. The upper formations are generally used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. The basal sandstone member of the Tongue River is persistent and a reliable source of groundwater in the region. The thickness of this basal sand ranges from approximately 50 to 200 ft and can be found at a depth of approximately 550 ft. Tongue River groundwaters are generally sodium bicarbonate with a TDS of approximately 1,000 ppm (Klausing, 1974).<br><br>The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. The upper Sentinel Butte is approximately 150 ft thick in the area of investigation (Hemish, 1975). TDS concentrations in the Sentinel Butte Formation are approximately 1,000 ppm (Klausing, 1974). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers. | sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15)<br><br>**Figure 2-11.** Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16)<br><br>**Figure 2-13.** Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. (p. 2-18)<br><br>**Figure 2-29**. Structure map of the lower Piper Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-40)<br><br>**Figure 4-9.** Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. (p. 4-17)<br><br>**Figure 4-10.** Southwest to northeast cross section of the major aquifer layers in McLean County. (p. 4-18) |
| | NDAC § 43-05-01-05(1)(b)(2)(d) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(d) An isopach map of the storage reservoirs; | j. An isopach map of the storage reservoir(s); | See Figure 2-8 on p. 2-13 | **Figure 2-8**. Isopach map of the Broom Creek Formation in the greater Blue Flint project area. (p. 2-13) |
| | NDAC § 43-05-01-05(1)(b)(2)(e) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(e) An isopach map of the primary and any secondary containment barrier for the storage reservoir; | k. An isopach map of the primary containment barrier for the storage reservoir; | See Figure 2-32 on p. 2-43 | **Figure 2-32.** Isopach map of the Spearfish Formation to the top of the Broom Creek Formation in the Blue Flint project area. (p. 2-43) |
| | | | l. An isopach map of the secondary containment barrier for the storage reservoir; | See Figure 2-30 on p. 2-41 and Figure 2-43 on p. 2-57 | **Figure 2-30.** Isopach map of the lower Piper Formation in the greater Blue Flint project area. (p. 2-41) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | | **Figure 2-43.** Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone (p. 2-57) |
| | NDAC § 43-05-01-05(1)(b)(2)(f) | **NDAC § 43-05-01-05(1)(b)(2)** (f) A structure map of the top and base of the storage reservoirs; | m. A structure map of the top of the storage formation; | See Figure 2-12 on p. 2-17 | **Figure 2-12.** Structure map of the Broom Creek Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-17) |
| | | | n. A structure map of the base of the storage formation; | See Figure 2-44 on p. 2-58 | **Figure 2-44.** Structure map of the Amsden Formation across the greater Blue Flint project area in feet below mean sea level. (p. 2-58) |
| | NDAC § 43-05-01-05(1)(b)(2)(i) | **NDAC § 43-05-01-05(1)(b)(2)** (i) Structural and stratigraphic cross sections that describe the geologic conditions at the storage reservoir; | o. Structural cross sections that describe the geologic conditions at the storage reservoir; | See Figure 2-11 on p. 2-16 and Figure 2-13 on p. 2-18 | **Figure 2-11**. Regional well log cross sections showing the structure of the lower Piper, Spearfish, and Broom Creek Formation logs. (p. 2-16)<br><br>**Figure 2-13.** Cross section of the Blue Flint storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level.. (p. 2-18) |
| | | | p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir; | See Figure 2-10 on p. 2-15 | **Figure 2-10.** Regional well log stratigraphic cross sections of the lower Piper, Spearfish, and Broom Creek Formations flattened on the top of the Amsden Formation. (p. 2-15) |
| | NDAC § 43-05-01-05(1)(b)(2)(h) | **NDAC § 43-05-01-05(1)(b)(2)** (h) Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any; | q. Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any; | **3.4 Simulation Results** (p. 3-11)<br>The target injection rate of 200,000 tonnes per year (tpy) (548 tonnes per day) was consistently achievable over 20 years (Figure 3-9), translating to a cumulative 4 MMt of $CO_2$ injection (Figure 3-10). Simulations of $CO_2$ injection with the given well constraints, listed in Table 3-3, predicted the BHP would not reach the maximum BHP constraint of 2,970 psi (90% of the formation fracture pressure) as a result of injecting the target $CO_2$ volume of 200,000 tpy. The predicted maximum BHP and the average BHP during the 20 year injection period were 2,661 and 2,570 psi (Figure 3-11), respectively.<br><br>Long-term $CO_2$ migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase $CO_2$ injected into the formation rises to the bottom of the upper confining zone or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of $CO_2$ at the center which gradually spreads out toward the model edges where the $CO_2$ saturation is lower. Trapped $CO_2$ saturations, employed in the model to represent fractions of $CO_2$ trapped in small pores as immobile, tiny bubbles, ultimately immobilize | **Figure 3-13.** Top left, top right, and bottom left display average pressure increase within the Broom Creek Formation after 1, 10, and 20 years of simulated $CO_2$ injection operation. (p. 3-16)<br><br>**Figure 6-1.** Predicted pressure increase in storage reservoir following 20 years of $CO_2$ injection at a rate of |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | the $CO_2$ plume and limit the plume's lateral migration and spreading. Figure 3-14 shows the $CO_2$ saturation at the injection well at the end of injection in north-to-south and east-to-west cross-sectional views.<br><br>***6.1.1 Pre- and Postinjection Pressure Differential*** (p. 6-1)<br>Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during injection operations and after the cessation of $CO_2$ injection. The simulations were conducted for 20 years of $CO_2$ injection at a rate of 200,000 metric tons per year, followed by a PISC period of 10 years.<br><br>Figure 6-1 illustrates the predicted pressure differential at the conclusion of $CO_2$ injection. At the time that $CO_2$ injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of up to 120 psi at the location of the $CO_2$ injection well. There is insufficient pressure increase caused by $CO_2$ injection to move more than 1 cubic meter of formation fluids from the storage reservoir to the lowest USDW. The details of this pressure evaluation are provided as part of the AOR delineation of this permit application (Section 3.0).<br><br>Figure 6-2 illustrates the predicted gradual pressure decrease following the cessation of $CO_2$ injection, with the pressure at the injection well at the end of the PISC period anticipated to decrease 80 to 100 psi as compared to the pressure at the time $CO_2$ injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches in situ reservoir pressure conditions. | 200,000 metric tons per year (p. 6-2)<br><br>**Figure 6-2.** Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of $CO_2$ injection (p. 6-3) |
| | NDAC § 43-05-01-05(1)(b)(2)(l) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(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:<br>Fractures<br>Stress<br>Ductility<br>Rock strength<br>In situ fluid pressure | *2.4.4.1 Borehole Image Fracture Analysis* (p. 2-71)<br>Borehole image logs were used to evaluate fractures within the upper and lower confining zones. The natural fractures and in situ stress directions were assessed through the interpretation of the FMI log acquired from the MAG 1 well. The FMI log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed.<br><br>Figures 2-56a, 2-56b, 2-57, 2-58, and 2-59 show sections of the interpreted borehole imagery and the primary features observed in the Piper, Spearfish Formation and Amsden Formation, respectively. Drilling induced fractures were observed in the Piper Formation as shown in Figure 2-56a in the far-right track. The far-right track on Figure 2-56b demonstrates that the tool provides information on surface boundaries and bedding features that characterize the Spearfish Formation. Figure 2-57 shows that features that have an electrically conductive signal in Spearfish Formation are observed. The logged interval of the Amsden Formation shows the main features represented by horizontal and oblique stratification fractures (Figure 2-58) and the presence of rare resistive fractures (Figure 2-59). Rose diagrams showing dip, dip azimuth, and strikes for conductive and drilling induced fractures observed in the borehole imagery are shown in Figures 2-60–2-62. These two fracture types were studied to evaluate potential leakage pathways as well as maximum horizontal stress. The diagrams shown in Figures 2-60 and 2-61 provide the dip orientation of the electrically conductive features in Spearfish and Amsden Formations, respectively. Breakouts were not identified in Spearfish or Amsden Formations. The drilling-induced fractures observed in the Piper Formation are oriented NE–SW ; these features are parallel to the maximum horizontal stress (SHmax), (Figure 2-62).<br><br>*2.4.4.2 Stress, Ductility and Rock Strength* (p. 2-80)<br>A 1D MEM was derived using the log data from MAG 1 well. Logs were edited to account for washouts in the Broom Creek and Amsden Formation sections using multilinear regressions. Geomechanical parameters in the Spearfish, Broom Creek, and Amsden Formations were estimated using the 1D MEM. The 1D MEM was used to estimate the vertical stress, pore pressure, minimum and maximum horizontal stresses (Shmin, SHmax), Poisson's ratio, Young's modulus, shear and bulk moduli, tensile, uniaxial compressive strength, and friction angle (Figure 2-63, Figure 2-64, and Figure 2-65). Table 2-19 shows the average and range of elastic and dynamic parameters, and stresses in the Spearfish, Broom Creek, and Amsden Formations.<br><br>Since the SW Core samples collected from the MAG 1 well were horizontally oriented, it was not possible to determine ductility and rock strength through laboratory testing. The dimensions of the SW Core samples were inadequate for multistage triaxial testing. The static properties (Young's modulus, Poisson's ratio, bulk modulus, shear modulus, uniaxial strain modulus) and the dynamic properties (Young's modulus, Poisson's ratio) were estimated through the evaluation of the 1D MEM in the Spearfish, Broom Creek, and Amsden Formations. The dynamic parameters determined using the 1D MEM were converted into static parameters using specific equations derived from global correlations of dynamic to static parameters (Tutuncu and Sharma, 1992; Yale and Walters, 2016; Nowakowski, 2005; Yale and others, 1995; Zhang and Bentley, 2005; Yale and Jamieson, 1994). | **Figure 2-56a.** Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Piper-Picard Formation FMI image analysis. (p. 2-73)<br><br>**Figure 2-56b**. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Spearfish Formation FMI image analysis. (p. 2-74)<br><br>**Figure 2-57**. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, resistive fracture, mixed fracture, horizontal stratification, and oblique stratification) seen in Spearfish Formation FMI image analysis. (p. 2-75) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | Log data were used to characterize stress in the storage complex to determine the fracture pressure gradient. In the injection zone, the parameters used to calculate stress were determined from the sand intervals in the Broom Creek Formation section. Rock strength defines the limit at which the stress conditions might induce the rock to mechanically fail. The unconfined compressive strength can be determined directly from rock mechanics tests, but in the MAG 1 well case, it was empirically estimated from well log data. Poisson's ratio was estimated using the available well logs, which resulted in an average value for the Broom Creek Formation of 0.32. The Biot factor was calculated using the effective porosity, static bulk modulus, and permeability, resulting in a range of 0.89-1. The pore pressure and hydropressure gradient were estimated using the true vertical depth (TVD), vertical stress (Sv), compressional slowness, and compressional velocity, respectively. The pore pressure and hydropressure gradients are equal to 0.448 and 0.429 psi/ft, respectively. In situ stresses such as Sv, maximum horizontal stress (SHmax), and minimum horizontal stress (Shmin) were calculated using specific parameters and methods (Table 2-20). Sv, which is related to the overburden or lithostatic pressure, is an important parameter in geomechanical modeling. In the Broom Creek Formation, overburden pressure was estimated through the bulk density log to the surface using the extrapolation method, resulting in an overburden gradient of 0.911 psi/ft. The poroelastic horizontal strain model is the most used method for horizontal stress calculation. The poroelastic horizontal strain model can be expressed using static Young's modulus, Poisson ratio, Biot's constant, overburden stress, and pore pressure. The poroelastic horizontal strain model was used to estimate the minimum horizontal stress (Plumb and Hickman, 1985; Aadnoy, 1990; Aadnoy and Bell, 1998; Brudy and Zoback, 1999). The SHmax is estimated from Shmin and process zone stress (as function of porosity). Based on the calculated stresses, the stress regime that can be seen in the Spearfish, Broom Creek, and Amsden Formations is a normal stress regime where Sv > SHmax > Shmin. Shmin magnitude could not be calibrated using the closure pressure measurements obtained from the openhole MDT microfracture in situ stress test because it was not performed in the MAG 1 well because of the large washout in the vicinity of the intervals of interest. The fracture gradient (FG) is calculated from pore pressure and overburden gradient. With the absence of closure pressure measurements in the Broom Creek Formation from in situ testing, a fracture gradient of 0.69 psi/ft was calculated in Schlumberger's Techlog software through the Matthew and Kelly method (Zhang and Yin, 2017). Equation 1 shows the equation used to derive the fracture gradient.<br><br>$Fracture\ Gradient = K * (\sigma_v - \alpha P_p) + \alpha P_p$ [Eq. 1]<br><br>Where:<br>σ_v is the overburden gradient.<br>α is Biot coefficient.<br>P_p is pore pressure.<br>K is the stress ratio (unitless) which Mathews and Kelly calculate with empirical correlation shown in Equation 2.<br><br>K=(-3.0*10^(-9))*〖〖TVD〗_RefGL〗^2+(8.0*10^(-5))*〖TVD〗_RefGL+0.2347 [Eq. 2]<br><br>Where:<br>〖TVD〗_RefGL is true vertical depth minus Kelly Bushing. | **Figure 2-58.** Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis. (p. 2-77)<br><br>**Figure 2-59**. Examples of the interpreted FMI log for the MAG 1 well. This example shows the common feature types (conductive fractures, stylolites, horizontal stratification, oblique stratification, and surface boundaries) seen in Amsden Formation FMI image analysis. (p. 2-77)<br><br>**Figure 2-60.** This example shows the dip azimuth and dip angle for conductive fractures seen in the Spearfish Formation. (p. 2-78)<br><br>**Figure 2-61.** This example shows the dip azimuth and dip angle for conductive fractures seen in the Amsden Formation. (p. 2-79)<br><br>**Figure 2-62.** This example shows the orientation of drilled-induced fractures in the Piper Formation. (p. 2-80)<br><br>**Figure 2-63.** Geomechanical parameters in the Spearfish Formation. (p. 2-81)<br><br>**Figure 2-64**. Geomechanical parameters in the Broom Creek Formation. (p. 2-82)<br><br>**Figure 2-65**. Geomechanical parameters in the Amsden Formation. (p. 2-83) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | | **Table 2-19.** Ranges and Averages of the Elastic Properties Estimated from 1D MEM in Spearfish, Broom Creek and Amsden Formations (p. 2-84)<br><br>**Table 2-20.** Ranges and Averages of the Sv, Hydropressure, Shmin, and Friction Angle (Fang) Estimated from 1D MEM in the Spearfish, Broom Creek, and Amsden Formations (p. 2-85) |
| | NDAC § 43-05-01-05(1)(b)(2)(o) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(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:<br>Free of transmissive faults<br>Free of transmissive fractures<br>Effect on pressure dissipation<br>Utility for monitoring, mitigation, and remediation. | ***2.4.2 Additional Overlying Confining Zones*** (pp. 2-55 and 2-56)<br>Several other formations provide additional confinement above the lower Piper interval. Impermeable rocks above the primary seal include the upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-15). Together with the Spearfish and lower Piper intervals, these intervals are 859 ft thick on average across the simulation area and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-42). Above the Inyan Kara Formation at the MAG 1 well, 2,512 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and lowermost USDW, the Fox Hills Formation (see Figure 2-43). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-15).<br><br>The formations between the Broom Creek and Inyan Kara Formations and between the Inyan Kara Formation and lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988).<br><br>Sandstones of the Inyan Kara Formation comprise the first unit, with relatively high porosity and permeability above the injection zone and the primary sealing formation. The Inyan Kara represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring digital temperature sensor (DTS) data for the Inyan Kara Formation using the downhole fiber-optic cable provides an additional opportunity for mitigation and remediation (Section 5). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, $CO_2$ would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at MAG 1 is approximately 3,604 ft, and the interval itself is about 228 ft thick. | **Table 2-15** Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the MAG 1 well) (p. 2-56)<br><br>**Figure 2-42**. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. (p. 2-56)<br><br>**Figure 2-43.** Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. (p. 2-57) |
| **Area of Review Delineation** | NDAC §§ 43-05-01-05(1)(j) and (1)(b)(3) | **NDAC § 43-05-01-05(1)**<br>j. An area of review and corrective action plan that meets the requirements pursuant to section 43-05-01-05.1;<br><br>**NDAC § 43-05-01-05(1)(b)**<br>(3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one | The carbon dioxide storage reservoir area of review includes the areal extent of the storage reservoir and one mile outside of the storage reservoir boundary, plus the maximum extent of the pressure front caused by injection activities. The area of review delineation must include the following: | ***4.1.1 Written Description*** (p. 4-1)<br>North Dakota geologic storage of $CO_2$ regulations require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water [USDW] may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of $CO_2$ and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase $CO_2$ plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the MAG 1 well (NDIC File No. 37833) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-5]).<br><br>NDAC § 43-05-01-05(1)(b)(3) requires "[a] review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate $CO_2$ injection activities and associated pressure front (Figure 4- | **Figure 4-2**. AOR map in relation to nearby groundwater wells. (p. 4-4) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: | | 1), the resulting AOR for the geologic storage project is delineated as being 1 mile from the SFP boundary. This extent ensures compliance with existing state regulations.<br><br>All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-20 and 4-2) by a professional engineer pursuant to NDAC § 43-05-01-05(1)(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 4-1). The evaluation determined that all wells within the AOR have sufficient isolation to prevent formation fluids or injected $CO_2$ from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-2 and 4-3, and Figure 4-3 and Figure 4-4).<br><br>An extensive geologic and hydrogeologic characterization performed by a team of geologists from the EERC uncovered no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.<br><br>This section of the SFP application is accompanied by maps and tables that include information required and in accordance with NDAC § 43-05-01-05(1)(a) and (b) and § 43-05-01-05.1(2), such as the storage facility area, location of any proposed injection wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05(1)(a) and (b)(3) and § 43-05-01-05.1(2). Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1.<br><br>See Figure 4-2 on p. 4-4 | |
| | NDAC §§ 43-05-01-05(1)(b)(3) and (1)(a) | **NDAC § 43-05-01-05(1)(b)**<br>(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:<br><br>**NDAC § 43-05-01-05(1)**<br>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:<br>i. Boundaries of the storage reservoir<br>ii. Location of all proposed wells<br>iii. Location of proposed cathodic protection boreholes<br>iv. Any existing or proposed aboveground facilities; | **2.3 Storage Reservoir (injection zone)** (p. 2-11)<br>See Figure 2-7 on page 2-12.<br><br>***5.7.2 Soil Gas and Groundwater Monitoring*** (p. 5-14)<br>See Figure 5-5 on page 5-14.<br><br>*3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29)<br>See Figure 3-21 on page 3-33.<br><br>**5.2 Surface Facilities Leak Detection Plan** (p. 5-3)<br>See Figure 5-1 on page 5-3. | **Figure 2-7.** Areal extent of the Broom Creek Formation in North Dakota (p. 2-12)<br><br>**Figure 5-5.** Blue Flint's planned baseline and monitoring program for soil gas, shallow groundwater aquifers, and the Fox Hills Aquifer. (p. 5-14)<br><br>**Figure 3-21.** Land use in and around the AOR. (p. 3-33)<br><br>**Figure 5-1.** Site map showing the surface facilities layout for the Blue Flint $CO_2$ storage project. (p. 5-3) |
| | NDAC § 43-05-01-05(1)(b)(2)(a) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(a) All wells, including water, oil, and natural gas exploration and | b. A map showing the following within the storage reservoir area and within one mile outside of its boundary: | ***4.1.2 Supporting Maps*** (p. 4-3)<br>See Figure 4-2 on page 4-4. | **Figure 4-2.** AOR map in relation to nearby groundwater wells. (p. 4-4) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | development wells, and other manmade subsurface structures and activities, including coal mines, within the facility area and within one mile [1.61 kilometers] of its outside boundary; | i. All wells, including water, oil, and natural gas exploration and development wells<br>ii. All other manmade subsurface structures and activities, including coal mines; | *3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29)<br>See Figure 3-21 on page 3-33. | **Figure 3-21.** Land use in and around the AOR. (p. 3-33) |
| | NDAC § 43-05-01-05(1)(c) and NDAC § 43-05-01-05.1(1)(a) | **NDAC § 43-05-01-05(1)**<br>c. The extent of the pore space that will be occupied by carbon dioxide as determined by utilizing all appropriate geologic and reservoir engineering information and reservoir analysis, which must include various computational models for reservoir characterization, and the projected response of the carbon dioxide plume and storage capacity of the storage reservoir. The computational model must be based on detailed geologic data collected to characterize the injection zones, confining zones, and any additional zones;<br><br>**NDAC § 43-05-01-05.1(1)**<br>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:<br>i. The computational model to be used<br>ii. The assumptions that will be made<br>iii. The site characterization data on which the model will be based; | ***3.5.2 Risk-Based AOR Delineation*** (p. 3-20)<br>The methods described by EPA (2013) for estimating the AOR under the Class VI rule (40 U.S. Code of Federal Regulations [CFR] 146.81 et seq.) were developed assuming that the storage reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and potentially elsewhere around the United States, candidate storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW, even prior to the planned storage project. Consequently, applying EPA (2013) methods to these geologic situations essentially results in an infinite AOR, which makes regulatory compliance infeasible.<br><br>Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer and others (2014) described the unnecessary conservatism in EPA's definition of critical pressure, which could lead to a heavy burden on storage facility permit (SFP) applicants. As an alternative, Burton-Kelly and others (2021) proposed a risk-based reinterpretation of this framework that would allow for a reduction in the AOR while ensuring protection of drinking water resources.<br><br>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").<br><br>Recently, White and others (2020) outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, NRAP-IAM-CS and the subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers.<br><br>Building a geologic model in a commercial-grade software platform (like Petrel; Schlumberger, 2020) and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform (like CMG's compositional simulator, GEM) provide the "gold standard" for estimating pressure buildup in response to $CO_2$ injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that are unwarranted given the amount of uncertainty that may be present if only a few nearby wells can be used for characterization activities. Earlier studies (e.g., Nicot and others, 2008; Birkholzer and others, 2009; Bandilla and others, 2012; Cihan and others, 2011, 2012) have shown that far-field fluid pressure changes outside of the $CO_2$ plume domain can be reasonably described by a single-phase flow calculation by representing $CO_2$ injection as an equivalent-volume injection of brine (Oldenburg and others, 2014).<br><br>The semianalytical solutions embedded within the ASLMA Model have been shown to compare with the numerical model, TOUGH2-ECO2-N, and provided accurate results for pressures beyond the $CO_2$ plume zone (Birkholzer and others, 2009; Cihan and others, 2011, 2012). Therefore, the proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and resultant effects of this buildup on the vertical migration of formation fluid via (single) hypothetical leaky wellbores located at progressively greater distances from the injection well (Figure 3-16). | **Figure 3-16.** Workflow for delineating a risk-based AOR for a SFP. (p. 3-22) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | An important distinction between EPA Methods 1 and 2, which both calculate a critical pressure threshold (either ΔPi,f for Method 1 or ΔPc for Method 2) and the risk-based AOR approach is that the risk-based approach 1) calculates and maps the potential incremental flow of formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR. | |
| | NDAC § 43-05-01-05.1(1)(b)(1-4) | **NDAC § 43-05-01-05.1(1)**<br>b. A description of:<br>(1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review;<br>(2) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date;<br>(3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and<br>(4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action. | d. A description of:<br>(1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review;<br>(2) Any monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date;<br>(3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation;<br>(4) How corrective action will be conducted if necessary, including:<br>a. What corrective action will be performed prior to injection<br>b. How corrective action will be adjusted if there are changes in the area of review; | **4.3 Reevaluation of AOR and Corrective Action Plan** (p. 4-13)<br>BFE will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place no later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following:<br>• Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date will be identified.<br>• Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and the computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and the operational data to be utilized as the basis for that update will be identified.<br>• The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR. | N/A |
| | NDAC § 43-05-01-05(1)(b)(2)(b) | **NDAC § 43-05-01-05(1)(b)(2)**<br>(b) All manmade surface structures that are intended for temporary or permanent human occupancy within the | e. A map showing the areal extent of all manmade surface structures that are intended for temporary or permanent human occupancy within the storage reservoir area, | *3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29)<br>See Figure 3-21 on p. 3-33 | **Figure 3-21.** Land use in and around the AOR. (p. 3-33) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | facility area and within one mile [1.61 kilometers] of its outside boundary; | and within one mile outside of its boundary; | | |
| | NDAC § 43-05-01-05(1)(b)(2) | **NDAC § 43-05-01-05(1)(b)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following: | f. A map and cross section identifying any productive existing or potential mineral zones occurring within the storage reservoir area and within one mile outside of its boundary; | **2.6 Potential Mineral Zones** (p. 2-92)<br>See Figure 2-71 and Figure 2-72. | **Figure 2-71.** Coal beds of the Sentinel Butte and Bullion Creek (Tongue River) Formations showing the lignite coals in western North Dakota (p. 2-94)<br><br>**Figure 2-72.** Hagel net coal isopach map. (p. 2-95) |
| | NDAC § 43-05-01-05(1)(b)(3) and NDAC § 43-05-01-05.1(2)(b) | **NDAC § 43-05-01-05(1)(b)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, | g. A map identifying all wells within the area of review, which penetrate the storage formation or primary or secondary seals overlying the storage formation. | *3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-29)<br>See Figure 3-20 on p. 3-32 for nearby legacy wells. | **Figure 3-20.** Final AOR in relation to nearby legacy wells. (p. 3-32) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | 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:<br><br>**NDAC § 43-05-01-05.1(2)**<br>b. Using methods approved by the commission, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone. Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the commission may require; | | | |
| | NDAC § 43-05-01-05(1)(b)(3)(a)<br><br>NDAC § 43-05-01-05(1)(b)(3)(b)<br><br>NDAC § 43-05-01-05(1)(b)(3)(c) | **NDAC § 43-05-01-05(1)(b)(3)**<br>(a) A determination that all abandoned wells have been plugged and all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping from the storage reservoir;<br><br>**NDAC § 43-05-01-05(1)(b)(3)**<br>(b) A description of each well's type, construction, date drilled, location, depth, record of plugging, and completion;<br><br>**NDAC § 43-05-01-05(1)(b)(3)**<br>(c) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all underground sources of drinking water, water wells, and springs | h. A review of these wells must include the following:<br><br>(1) A determination that all abandoned wells have been plugged in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation;<br><br>(2) A determination that all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation;<br><br>(3) A description of each well:<br>a. Type<br>b. Construction<br>c. Date drilled<br>d. Location<br>e. Depth | ***4.1.1 Written Description*** (4th paragraph, p. 4-1)<br>North Dakota geologic storage of $CO_2$ regulations require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water [USDW] may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of $CO_2$ and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase $CO_2$ plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the MAG 1 well (NDIC File No. 37833) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero [Section 3, Table 3-5]).<br><br>NDAC § 43-05-01-05(1)(b)(3) requires "[a] review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate $CO_2$ injection activities and associated pressure front (Figure 4-1), the resulting AOR for the geologic storage project is delineated as being 1 mile from the SFP boundary. This extent ensures compliance with existing state regulations.<br><br>***4.1.2 Supporting Maps***<br>See Figure 4-2 on p. 4-4.<br><br>**4.2 Corrective Action Evaluation (p. 4-8)**<br>See Table 4-2 on p. 4-6, Table 4-3 on p. 4-7, Table 4-4 on p. 4-8, and Table 4-5 on p. 4-9. | **Figure 4-2.** AOR map in relation to nearby groundwater wells. Shown are the stabilized CO2 plume extent postinjection (dashed red boundary), storage facility area (dashed purple boundary), and 1-mile AOR (dashed black boundary). All groundwater wells in the AOR are identified above. All observation/monitoring wells shown are shallow groundwater wells associated with the mine activities. No springs are present in the AOR. (p. 4-4)<br><br>**Figure 3-20.** Final AOR in relation to nearby legacy wells. Shown is the storage facility area (purple polygon) and AOR (black polygon). Orange circles represent legacy oil and gas wells near |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | NDAC §§ 43-05-01-05(1)(b)(3)(d) and (e)<br><br>NDAC § 43-05-01-05(1)(b)(3)(f) | within the area of review; their positions relative to the injection zone; and the direction of water movement, where known;<br><br>**NDAC § 43-05-01-05(1)(b)(3)**<br>(d) Maps and cross sections of the area of review;<br><br>**NDAC § 43-05-01-05(1)(b)(3)**<br>(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;<br><br>**NDAC § 43-05-01-05(1)(b)(3)**<br>(f) A list of contacts, submitted to the commission, when the area of review extends across state jurisdiction boundary lines; | f. Record of plugging<br>g. Record of completion<br><br>(4) Maps and stratigraphic cross sections of all underground sources of drinking water within the area of review indicating the following:<br>a. Their positions relative to the injection zone<br>b. The direction of water movement, where known<br>c. General vertical and lateral limits<br>d. Water wells<br>e. Springs<br><br>(5) Map and cross sections of the area of review;<br><br>(6) A map of the area of review showing the following:<br>a. Number or name and location of all injection wells<br>b. Number or name and location of all producing wells<br>c. Number or name and location of all abandoned wells<br>d. Number of name and location of all plugged wells or dry holes<br>e. Number or name and location of all deep stratigraphic boreholes<br>f. Number or name and location of all state-approved or United States Environmental Protection Agency-approved subsurface cleanup sites<br>g. Name and location of all surface bodies of water | See Figure 4-3 on p. 4-10, Figure 4-4 on p. 4-11, and Figure 4-5 on p. 4-12.<br><br>**4.4 Protection of USDWs (Broom Creek Formation)** (p. 4-13)<br>Figure 4-9 on page 4-17 and Figure 4-10 on page 4-18 | the storage facility area. (p. 3-32)<br><br>**Table 4-2.** Wells in AOR Evaluated for Corrective Action (p. 4-6)<br><br>**Table 4-3**. Ellen Samuelson 1 (NDIC File No. 1516) Well Evaluation (p. 4-7)<br><br>**Table 4-4.** Well #1 (ND-UIC-106) Well Evaluation (p. 4-8)<br><br>**Table 4-5.** Wallace O. Gradin 1 (NDIC File No. 4810) Well Evaluation (p. 4-9)<br><br>**Figure 4-3** Ellen Samuelson 1 (NDIC File No. 1516) well schematic showing the location of cement plugs. (p. 4-9)<br><br>**Figure 4-4.** Well #1 (ND-UIC-106) well schematic. (p. 4-10)<br><br>**Figure 4-5.** Wallace O. Gradin 1 (NDIC File No. 4810) well schematic showing the location of cement plugs. (p. 4-12)<br><br>**Figure 4-9.** Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central McLean County (modified from Fischer, 2013). (p. 4-17)<br><br>**Figure 4-10**. Southwest to northeast cross section of the major aquifer layers in McLean County. The black dots on the inset map represent the locations of the |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | h. Name and location of all springs<br>i. Name and location of all mines (surface and subsurface)<br>j. Name and location of all quarries<br>k. Name and location of all water wells<br>l. Name and location of all other pertinent surface features<br>m. Name and location of all structures intended for human occupancy<br>n. Name and location of all state, county, or Indian country boundary lines<br>o. Name and location of all roads<br><br>(7) A list of contacts, submitted to the Commission, when the area of review extends across state jurisdiction boundary lines. | | six wells used to create the cross section. The wells are labeled with their designation at the top of the cross section. (p. 4-18) |
| | NDAC § 43-05-01-05(1)(b)(3)(g) | **NDAC § 43-05-01-05(1)(b)(3)**<br>(g) Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review; and | i. Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review. | See Appendices A (p. A-1) and B (p. B-1) | N/A |
| **Required Plans** | NDAC § 43-05-01-05(1)(k) | **NDAC § 43-05-01-05(1)**<br>k. The storage operator shall comply with the financial responsibility requirements pursuant to section 43-05-01-9.1; | a. Financial Assurance Demonstration | **12.2 Financial Instruments** (pp. 12-1 and p. 12-2)<br>Blue Flint is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments:<br>• Blue Flint will increase the existing MAG 1 well bond to cover the costs of plugging the injection well in accordance with NDAC § 43-05-01-11.5.<br>• Blue Flint will establish a bond, escrow account or other financial instrument to implement PISC and facility closure activities in accordance with NDAC § 43-05-01-19.<br>• A third-party pollution liability insurance policy with an aggregate limit of $9 million will be secured to cover the costs of implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13. | **Table 12-1.** Cost estimates for Activities to Be Covered (p. 12-2) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | The estimated total costs of these activities are presented in Table 12-1. Section 12.2 of this FADP provides additional details of the financial responsibility cost estimates for each activity. | |
| | NDAC § 43-05-01-05(1)(d) | **NDAC § 43-05-01-05(1)(d)**<br>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)<br>Blue Flint Sequester Company LLC (Blue Flint) and Blue Flint Ethanol LLC, operator of the Blue Flint Ethanol (BFE) facility, will enter into an agreement whereby Blue Flint employees, contractors and agents are required to follow the BFE facility emergency action plans, including, but not limited to, the BFE facility response plan. This emergency and remedial response plan (ERRP) for the geologic storage project 1) describes the local resources and infrastructure in proximity to the project site; 2) identifies events that have the potential to endanger USDWs during the construction, operation, and postinjection site care periods of the geologic storage project, building upon the screening-level risk assessment (SLRA); and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing BFE facility response plan and risk management plan (and incorporated into the BFE Integrated Contingency Plan [ICP]) is described, emphasizing the facility response team and command structure, facility evacuation plans, HazMat (hazardous materials) capabilities, and emergency communication plans. Lastly, procedures are presented for regularly conducting an evaluation of the adequacy of the ERRP and updating it, if warranted, over the lifetime of the geologic storage project. Copies of this ERRP are available at the Blue Flint's office and the BFE facility.<br><br>Note: Refer to the following key tables: Table 7-4 on p. 7-5 and Table 7-5 on p. 7-6 through 7-8. | **Table 7-4**. Potential Project Emergency Events and Their Detection (p. 7-5)<br><br>**Table 7-5.** Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (pp. 7-6 through 7-8) |
| | NDAC § 43-05-01-05(1)(e) | **NDAC § 43-05-01-05(1)**<br>e. A detailed worker safety plan that addresses carbon dioxide safety training and safe working procedures at the storage facility pursuant to section 43-05-01-13; | c. A detailed worker safety plan that addresses the following:<br>i. Carbon dioxide safety training<br>ii. Safe working procedures at the storage facility; | **8.0 WORKER SAFETY PLAN** (p. 8-1) | N/A |
| | NDAC § 43-05-01-05(1)(f) | **NDAC § 43-05-01-05(1)**<br>f. A corrosion monitoring and prevention plan for all wells and surface facilities pursuant to section 43-05-01-15; | d. A corrosion monitoring and prevention plan for all wells and surface facilities; | **5.3 Flowline Corrosion Prevention and Detection Plan (p. 5-5)**<br>The purpose of this corrosion prevention and detection plan is to monitor the flowline and well materials during the operational phase of the project to ensure that all materials meet the minimum standards for material strength and performance.<br><br>**5.3.1 Corrosion Prevention (p. 5-5)**<br>The chemical composition of the $CO_2$ stream is highly pure and dry (Table 5-2), and the target moisture level for the $CO_2$ stream is estimated to be up to 12 ppm by volume. These factors help to prevent corrosion of the surface facilities. In addition, the flowline construction materials will be $CO_2$-resistant in accordance with API 17J (2017) requirements. The flowline will be constructed using FlexSteel, a 3-layer flexible steel pipe product. The inner and outer layers contain a $CO_2$-resistant polyethylene liner, and the middle layer comprises reinforcing steel. FlexSteel product specifications can be found in Appendix C (Attachment A-3).<br><br>**5.3.2 Corrosion Detection (p. 5-5)**<br>The flowline will use the corrosion coupon method to monitor for corrosion throughout the operational phase of the project, focusing on the loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. A coupon sample port will be located near the liquefaction outlet, and sampling will occur quarterly during the first year of injection and once a year thereafter. The process that will be used to conduct each coupon test is described in Appendix C under Section 1.3.<br><br>**5.6 Wellbore Corrosion Prevention and Detection Plan (p. 5-9)**<br>To prevent corrosion of the well materials, the following preemptive measures will be implemented in the MAG 1 and MAG 2 wellbores: 1) cement in the injection well opposite the injection interval and extending 1850 feet uphole will be $CO_2$-resistant; 2) the well casing will also be $CO_2$-resistant from the bottomhole to a depth just above the Spearfish Formation (upper confining zone); 3) the well tubing (poly-lined) will be $CO_2$-resistant from the injection interval to surface; 4) the packer (Ni-Plated) will be $CO_2$-resistant; and 5) the packer fluid will be an industry standard corrosion inhibitor.<br><br>To detect possible signs of corrosion in the MAG 1 and MAG 2, corrosion coupon samples will be used which will be constructed from the well materials. The corrosion coupon method is described in Section 5.3.2 of this testing and monitoring plan. In addition, the USIT or an equivalent wall thickness or imaging tool (e.g., EM CIL) may also be considered for detecting corrosion in the MAG 1 and MAG 2 wellbores. The USIT (or equivalent tool) may be used during workovers but no less than every 5 years. | **Figure 5-1.** Site map showing the surface facilities layout for the Blue Flint CO2 Storage Project. (p. 5-3)<br><br>**Figure 5-2**. Diagram of surface connections and major components of the CCS system from the liquefaction outlet to the MAG 1 wellsite. (p. 5-4)<br><br>**Table 5-2.** Chemical Content of the CO2 Stream (p. 5-3) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | **Table 5-2. Chemical Content of the captured $CO_2$**<br>**Chemical Content** — **Volume %**<br>Carbon Dioxide — 99.98<br>Water, Oxygen, Nitrogen, Hydrogen Sulfide, $C_2^+$, and Hydrocarbons — Trace amounts of each (0.02 total)<br>Total — 100.00 | |
| | NDAC § 43-05-01-05(1)(g) | **NDAC § 43-05-01-05(1)**<br>g. A leak detection and monitoring plan for all wells and surface facilities pursuant to section 43-05-01-14. The plan must:<br>(1) Identify the potential for release to the atmosphere;<br>(2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and<br>(3) Identify potential migration of carbon dioxide into any mineral zone in the facility area. | e. A surface leak detection and monitoring plan for all wells and surface facilities pursuant to NDAC § 43-05-01-14; | **5.2 Surface Facilities Leak Detection Plan** (p. 5-3)<br>The purpose of this leak detection plan is to monitor the surface facilities from the liquefaction outlet to the injection wellsite during the operational phase of the Blue Flint $CO_2$ storage project.<br><br>Surface components of the injection system, including the flowline and $CO_2$ injection wellhead, will be monitored with leak detection equipment. The flowline will be monitored continuously via dual flowmeters located at the liquefaction outlet and near the wellhead for performing mass balance calculations. The flowline will also be regularly inspected for any visual or auditory signs of equipment failure and monitored continuously with one pressure gauge at the capture facility outlet and one at the wellhead. $CO_2$ detection stations will be located on the flowline risers and the $CO_2$ injection wellhead. The leak detection equipment will be integrated with automated warning systems that notify Blue Flint's operations center, giving the operator the ability to remotely close the valves in the event of an anomalous reading.<br><br>Performance targets designed for the Blue Flint $CO_2$ storage project to detect potential leaks in the flowline are provided in Table 5-3. The performance targets are dependent upon the actual performance of instrumentation (e.g., pressure gauges) and the SCADA system (described further in Attachment A-1 of Appendix C), which uses software to track the status of the flowline in real time by comparing live pressure and flow rate data to a comprehensive predictive model. The performance targets assume a flow rate of approximately 550 metric tons of $CO_2$ per day. An alarm will trigger on the SCADA system if a volume deviation of more than 1% is registered.<br><br>$CO_2$ detection stations will be mounted on the inside of the wellhead enclosures to detect any potential indoor leaks. An additional $CO_2$ detection station will be mounted outside the injection wellhead enclosure to detect any potential atmospheric leaks at the wellsite. The stations can detect $CO_2$ concentrations as low as 2% by volume and have an integrated alarm system for increases of from 0% to 0.4% and 0.4% to 0.8% by volume. The stations are further described in Appendix C (Attachment A-2).<br><br>Field personnel will have multigas detectors with them for wellsite visits or flowline inspections to detect potential leaks from the equipment. The multigas detectors will primarily monitor $CO_2$ levels in workspace atmospheres.<br><br>Any defective equipment will be repaired or replaced and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be made available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC. | N/A |
| | NDAC § 43-05-01-05(1)(h) | **NDAC § 43-05-01-05(1)**<br>h. A leak detection and monitoring plan to monitor any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile [1.61 kilometers] of the facility area's | f. A subsurface leak detection and monitoring plan to monitor for any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile of the facility area's outside boundary; | **5.7 Environmental Monitoring Plan** (p. 5-9, paragraphs 1, 3, and 4)<br>To verify the injected $CO_2$ is contained in the storage reservoir and to protect all USDWs, multiple environments will be monitored.<br><br>The deep subsurface environment, defined as the region from below the lowest USDW to the base of the storage reservoir, will be monitored with multiple methods, starting with the above-zone monitoring interval (AZMI) or the geologic interval from the Spearfish Formation to the Inyan Kara Formation. The AZMI will be monitored with DTS in the MAG 1 and MAG 2 as well as PNLs in the MAG 2 (further described in Attachment A-5 of Appendix C).<br><br>The storage reservoir will be monitored with both direct and indirect methods. Direct methods include DTS and BHP/T measurements in the MAG 1 and MAG 2, as well as PNLs in the MAG 2. Indirect methods include time-lapse seismic and passive seismicity. During injection operations, pressure falloff testing to demonstrate storage reservoir injectivity in the MAG 1 wellbore will be carried out at least once every 5 years. These efforts will provide additional assurance that surface and near-surface environments are protected and that the injected $CO_2$ is safely and permanently stored in the storage reservoir. | |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | outside boundary. Provisions in the plan will be dictated by the site characteristics as documented by materials submitted in support of the permit application but must:<br><br>(1) Identify the potential for release to the atmosphere;<br><br>(2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and<br><br>(3) Identify potential migration of carbon dioxide into any mineral zone in the facility area. | | ***5.7.3 Deep Subsurface Monitoring*** (p. 5-15)<br>Blue Flint will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase $CO_2$ plume and associated pressure relative to the permitted storage reservoir. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and postoperational periods. The methods described in Table 5-6 will be used to characterize the $CO_2$ plume's saturation and pressure within the AOR.<br><br>Blue Flint will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan (Ayash and others, 2017) at least once every 5 years. During each review, monitoring and operational data will be analyzed, and the AOR will be reevaluated. Based on this reevaluation, it will either be demonstrated that 1) no amendment to the testing and monitoring program is needed or 2) modifications are necessary to ensure proper monitoring of storage performance is achieved moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.<br><br>Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the $CO_2$ plume and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will, in turn, be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected $CO_2$ within the permitted geologic storage facility. | |
| | NDAC § 43-05-01-05(1)(l) | **NDAC § 43-05-01-05(1)**<br>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**<br><br>Note: See Table 5-1 on p. 5-2; Table 5-4 on p. 5-7; Table 5-5 on pp. 5-8 through 5-9; and Table 5-6 on pp. 5-10 through 5-11, for detailed summaries of the testing and monitoring plan. | **Table 5-1.** Overview of Blue Flint's Testing and Monitoring Plan (p. 5-2)<br><br>**Table 5-4.** Overview of Blue Flint's Mechanical Integrity Testing Plan (p. 5-7)<br><br>**Table 5-5.** Testing and Logging Plan for the MAG 1 Wellbore (pp. 5-8 through 5-9)<br><br>**Table 5-6.** Summary of Environmental Baseline and Operational Monitoring (pp. 5-10 through 5-11) |
| | NDAC § 43-05-01-05(1)(i) | **NDAC § 43-05-01-05 (1)**<br>i. The proposed well casing and cementing program detailing compliance with section 43-05-01-09; | h. The proposed well casing and cementing program; | **9.0 WELL CASING AND CEMENTING PROGRAM** (p. 9-1) | **Figure 9-1.** MAG 1 as-constructed wellbore schematic. Note: top of cement (TOC), workover (WO). (p. 9-2)<br><br>**Figure 9-2.** MAG 1 Proposed wellbore schematic as CO2 injector. (p. 9-3)<br><br>**Figure 9-3.** Monitor Well MAG 2 proposed wellbore schematic. (p. 9-7) |

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | NDAC § 43-05-01-05(1)(m) | **NDAC § 43-05-01-05(1)**<br>m. A plugging plan that meets requirements pursuant to section 43-05-01-11.5; | i. A plugging plan; | **10.1 MAG 1: P&A Program** (p. 10-1)<br><br>**10.2 MAG 2 P&A Program** (p. 10-7) | **Figure 10-1**. Proposed CO2 injection well schematic for MAG 1. (p. 10-2)<br><br>**Figure 10-2.** Schematic of proposed P&A plan for MAG 1. (p. 10-6)<br><br>**Figure 10-3.** Proposed monitoring wellbore schematic for MAG 2. (p. 10-7)<br><br>**Figure 10-4.** Schematic of proposed abandonment plan for monitoring well MAG 2. (p. 10-11) |
| | NDAC § 43-05-01-05(1)(n) | **NDAC § 43-05-01-05(1)**<br>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)**<br><br>Note: Refer to Tables 6-1 on p. 6-4, and 6-2 on p. 6-5 for a summary of the postinjection site care monitoring plan. | **Table 6-1**. Overview of Blue Flint's PISC MAG 2 Mechanical Integrity Testing and Corrosion Monitoring Plan (p. 6-4)<br><br>**Table 6-2.** Overview of Blue Flint's PISC Environmental Monitoring Plan. (p. 6-5) |
| **Storage Facility Operations** | NDAC § 43-05-01-05(1)(b)(4) | **NDAC § 43-05-01-05(1)(b)**<br>(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:<br><br>a. The proposed average and maximum daily injection rates; | **11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)**<br>This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.<br><br>(Table 11-1, below) | **Table 11.1.** Proposed Injection Well Operating Parameters (p. 11-1) |
| | | | b. The proposed average and maximum daily injection volume;<br>c. The proposed total anticipated volume of the carbon dioxide to be stored; | | |

**Table 11-1. Proposed Injection Well Operating Parameters**

| Item | Values | Description/Comments |
|---|---|---|
| **Injected Volume** | | |
| Total Injected Volume | 4,000,000 tonnes | Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day |
| **Injection Rates** | | |
| Average Injection Rate | 548 tonnes/day (10.35 MMscf/day) | Based on 200,000 tonnes/year for 20 years of injection (using 365 operating days per year) |
| Average Maximum Daily Injection Rate | 2,729 tonnes/day (51.56 MMscf/day) | Based on maximum bottomhole injection pressure (2,970 psi) |

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application<br>(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description<br>(Page Number)</th></tr>
<tr><td rowspan="4"></td><td rowspan="2">NDAC § 43-05-01-05(1)(b)(5)</td><td rowspan="2">NDAC § 43-05-01-05(1)(b)<br>(5) The proposed average and maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in pounds per square inch gauge, shall be approved by the commission and specified in the permit. In approving a maximum injection pressure limit, the commission shall consider the results of well tests and other studies that assess the risks of tensile failure and shear failure. The commission shall approve limits that, with a reasonable degree of certainty, will avoid initiating a new fracture or propagating an existing fracture in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water;</td><td>d. The proposed average and maximum bottom hole injection pressure to be utilized;</td><td rowspan="2"><table>
<tr><th>Pressures</th><th></th><th></th></tr>
<tr><td>Formation Fracture Pressure at Top Perforation</td><td>3,300 psi</td><td>Based on geomechanical analysis of formation fracture gradient as 0.69 psi/ft (see Section 2.0)</td></tr>
<tr><td>Average Surface Injection Pressure</td><td>1,158 psi</td><td>Based on 200,000 tonnes/year for 20 years at an average daily injection rate of 548 tonnes/day) using the designed 2.875-inch tubing</td></tr>
<tr><td>Surface Maximum Injection Pressure</td><td>4,300 psi</td><td>Based on maximum bottomhole injection pressure (2,970 psi) using the designed 2.875-inch tubing</td></tr>
<tr><td>Average Bottomhole Pressure (BHP)</td><td>2,570 psi</td><td>Based on average daily injection rate of 548 tonnes/day</td></tr>
<tr><td>Calculated Maximum BHP</td><td>2,970 psi</td><td>Based on 90% of the formation fracture pressure of 3,300 psi</td></tr>
</table></td><td rowspan="2"></td></tr>
<tr><td>e. The proposed average and maximum surface injection pressures to be utilized;</td></tr>
<tr><td rowspan="2">NDAC § 43-05-01-05(1)(b)(6)</td><td rowspan="2">NDAC § 43-05-01-05(1)(b)<br>(6) The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone pursuant to section 43-05-01-11.2;</td><td>f. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone;</td><td rowspan="2">5.5 Well Testing and Logging Plan (p. 5-7)<br>Table 5-5 describes the testing and logging plan developed for the MAG 1 wellbore (exclusive of any coring) to establish baseline conditions. Included in the table is a description of fluid sampling and pressure testing performed. The logging and testing plan for the MAG 2 wellbore will be the same as what is presented in Table 5-5, with the addition of a PNL but excluding dipole, elemental capture spectroscopy (ECS), fluid swab, and FMI. Table 5-4 and Table 5-6 (see Section 5.7) detail the frequency with which logging data will be acquired and in which wellbores throughout the operational period of the project.<br>See Appendix A: MAG 1 FORMATION FLUID SAMPLING<br><br>2.0 GEOLOGIC EXHIBITS<br>2.2 Data and Information Services (p. 2-4)<br>Several sets of data were used to characterize the injection and confining zones to establish their suitability for the storage and containment of injected $CO_2$. Data sets used for characterization included both existing data (e.g., from published literature, publicly available databases, private data from brokers) and site-specific data acquired specifically to characterize the storage complex.<br><br>2.2.2 Site-Specific Data (p. 2-6)<br>Site-specific efforts to characterize the proposed storage complex generated multiple data sets, including geophysical well logs, petrophysical data, and 3D seismic data. The MAG 1 well was drilled in 2020 specifically to gather subsurface geologic data to support the development of a $CO_2$ storage facility permit and serve as a future $CO_2$ injection well. Downhole logs were acquired, and sidewall core (SW Core) was collected from the proposed storage complex (i.e., the Lower Piper, Spearfish, Broom Creek, and Amsden Formations) at the time the well was drilled (Figure 2-5). In May 2022, fluid samples and temperature and pressure measurements were collected from the Broom Creek in the MAG 1 well.<br><br>2.2.2.2 Core Sample Analyses (p. 2-8)<br>Fifty 1.5" SW Core samples were recovered from the Broom Creek storage complex in MAG 1: five samples from the lower Piper Formation, twelve from the Spearfish Formation, twenty-three from the Broom Creek Formation, and ten from the Amsden Formation. Forty-two of the SW Core samples were analyzed to determine petrophysical properties. This core was analyzed to characterize the lithologies of the lower Piper, Spearfish, Broom Creek, and Amsden Formations and correlated to the well log data. Core analysis also</td><td rowspan="2">Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore (p. 5-8 through 5-9)</td></tr>
<tr><td>g. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the confining zone;</td></tr>
</table>

| Subject | NDCC / NDAC Reference | Requirement | Regulatory Summary | Storage Facility Permit Application (Section and Page Number; see main body for reference cited) | Figure/Table Number and Description (Page Number) |
|---|---|---|---|---|---|
| | | | | included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), thin-section analysis, and capillary entry pressure measurements. The results were used to inform geologic modeling and predictive simulation inputs and assumptions. | |

**Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore**

| OH/CH* Depth, ft | Logging/Testing | Justification | NDAC § 43-05-01 |
|---|---|---|---|
| **Surface Section** | | | |
| OH 1340-0 | Triple combo (resistivity, bulk density, density and neutron porosity, GR, caliper, and spontaneous potential [SP]) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. | 11.2(1)(b)(1) |
| CH 1260-0 | Ultrasonic, casing collar locator (CCL), variable-density log (VDL), GR, and temperature log | Identified cement bond quality radially. Interpreted minor cement channeling throughout several isolated intervals and determined good azimuthal cement coverage and zonal isolation. | 11.2(1)(b)(2) |
| **Intermediate Section** | | | |
| OH 4170-1334 | Triple Combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for enhanced geomodeling and predictive simulation of $CO_2$ injection into the interest zones to improve test design and interpretations. Generated core-log correlations. | 11.2(1)(c)(1) |
| OH 4170-1334 | Dipole sonic | Identified mechanical properties in intermediate section. | 11.2(1)(c)(1) |
| OH 4170-3070 | Dielectric scanner | Quantified petrophysical properties and salinity calculations within the intermediate zones (Inyan Kara Formation). Provided information on rock properties and fluid distribution as inputs for reservoir evaluation and management. | 11.2(4) |
| CH 4070-30 | Ultrasonic, CCL, VDL, GR, and temperature log | Identified cement bond quality radially. Interpreted good azimuthal cement coverage and casing condition. Evaluated the cement top and zonal isolation. | 11.2(1)(c)(2) |

* OH/CH – openhole/cased-hole

**Table 5-5. Testing and Logging Plan for the MAG 1 Wellbore (continued)**

| OH/CH Depth, ft | Logging/Testing | Justification | NDAC Code § 43-05-01 |
|---|---|---|---|
| **Long-string Section** | | | |
| OH 7068-4163 | Triple combo (laterolog resistivity, bulk density, density and neutron porosity, GR, caliper, and SP) | Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. | 11.2(1)(c)(1) |
| OH 7556-4163 | Dipole sonic | Identified mechanical properties of the rock including stress anisotropy. Provided compression | 11.2(1)(c)(1) |

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application<br>(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description<br>(Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>
<table>
<tr><td></td><td></td><td>and shear waves for seismic tie in and quantitative analysis of seismic data.</td><td></td></tr>
<tr><td>OH<br>5250-4250</td><td>Fullbore FMI</td><td>Verified no fracture networks exist in the Broom Creek Formation or confining layers to ensure safe storage of $CO_2$.</td><td>11.2(1)(c)(1)</td></tr>
<tr><td>OH<br>4741 and 4735</td><td>BHP/T survey</td><td>Measured Broom Creek Formation pressure and temperature in the wellbore.</td><td>11.2(2)</td></tr>
<tr><td>OH<br>4740-4733</td><td>Fluid swab</td><td>Collected fluid sample from the Broom Creek Formation for analysis.</td><td>11.2(2)</td></tr>
<tr><td>CH**<br>TBD</td><td>Ultrasonic, CCL, VDL, and GR</td><td>Will identify cement bond quality radially and determine azimuthal cement coverage. Will evaluate the cement top and zonal isolation.</td><td>11.2(1)(b)(2)</td></tr>
</table>
** Planned activity at the time of writing this permit to be completed prior to injection.
</td><td></td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(7)</td><td>NDAC § 43-05-01-05(1)(b)<br>(7) The proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment; and</td><td>h. The proposed stimulation program:<br>1. A description of the stimulation fluids to be used<br>2. A determination of the probability that stimulation will interfere with containment;</td><td>11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)<br>This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.<br><br>11.1 MAG 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-1)<br>As described in Section 9.1, the MAG 1 well will be reentered and completed as a CO2 injector (Figures 11-1 and 11-2 and Tables 11-2 through 11-4). The following proposed completion procedure outlines the steps necessary to complete and test the well.<br><br>Note: See full procedure provided on pp. 11-1 through 11-3.</td><td>N/A</td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(8)</td><td>NDAC § 43-05-01-05(1)(b)<br>(8) The proposed procedure to outline steps necessary to conduct injection operations.</td><td>i. Steps to begin injection operations</td><td>11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)<br>This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as documented in NDAC § 43-05-01-05 (Table 11-1) and § 43-05-01-11.3.<br><br>11.1 MAG 1 Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-1)<br><br>Note: See full procedure provided on pp. 11-1 through 11-3.</td><td>N/A</td></tr>
</table>

February 1, 2023

U.S. Department of the Interior
1849 C Street NW
Washington, DC 20240

Re: NDIC Case Nos. 29888-29890

**NOTICE OF HEARING**
**N.D. INDUSTRIAL COMMISSION**
**OIL AND GAS DIVISION**

You are hereby notified of a hearing pursuant to North Dakota Administrative Code § 43-05-01 requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota. **The hearing will be held March 21, 2023 at 9:00 a.m.**, 1000 East Calgary Avenue, Bismarck, North Dakota.

Case No. 29888: Application of Blue Flint Sequester Company, LLC requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Blue Flint Sequester Company, LLC intends to capture carbon dioxide from the Blue Flint Ethanol Facility and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT March 20, 2023. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Tammy Madche, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Blue Flint Sequester Company, LLC, 2841 3rd St. SW, Underwood, North Dakota 58576.

Case No. 29889: A motion of the Commission to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Blue Flint Sequester Company, LLC storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.

Case No. 29890: A motion of the Commission to determine the amount of financial responsibility for the geologic storage of carbon dioxide from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean

County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.

Please contact our office if you have any questions.

Sincerely,

Lynn D. Helms

Lynn D. Helms
Director

NORTH Dakota | Mineral Resources
Be Legendary.™

NORTH DAKOTA D M R Department of Mineral Resources

#

February 1, 2023

Bureau of Indian Affairs
MS-4606
1849 C Street, N.W.
Washington, D.C. 20240

Re: NDIC Case Nos. 29888-29890

**NOTICE OF HEARING**
**N.D. INDUSTRIAL COMMISSION**
**OIL AND GAS DIVISION**

You are hereby notified of a hearing pursuant to North Dakota Administrative Code § 43-05-01 requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota. **The hearing will be held March 21, 2023 at 9:00 a.m.**, 1000 East Calgary Avenue, Bismarck, North Dakota.

Case No. 29888: Application of Blue Flint Sequester Company, LLC requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Blue Flint Sequester Company, LLC intends to capture carbon dioxide from the Blue Flint Ethanol Facility and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT March 20, 2023. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Tammy Madche, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Blue Flint Sequester Company, LLC, 2841 3rd St. SW, Underwood, North Dakota 58576.

Case No. 29889: A motion of the Commission to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Blue Flint Sequester Company, LLC storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.

Case No. 29890: A motion of the Commission to determine the amount of financial responsibility for the geologic storage of carbon dioxide from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.

Please contact our office if you have any questions.

Sincerely,

Lynn D Helms

Lynn D. Helms
Director

| | |
|---|---|
| **From:** | Kadrmas, Bethany R. |
| **Bcc:** | ctyunder@westriv.com |
| **Subject:** | North Dakota Industrial Commission Notice of Hearing |
| **Date:** | Monday, January 30, 2023 4:40:00 PM |
| **Attachments:** | Blue Flint Notice of Hearing.pdf<br>image001.png |

---

The attached hearing notice is sent pursuant to North Dakota Administrative Code Section 43-05-01-08(5).

Please contact our office if you have any questions.


Bethany Kadrmas

*Legal Assistant, Oil and Gas Division*

701.328.8020 • brkadrmas@nd.gov • www.dmr.nd.gov

NORTH Dakota Be Legendary.™ | Mineral Resources

600 E Boulevard Ave, Dept. 405 • Bismarck, ND 58505

| | |
|---|---|
| **From:** | Kadrmas, Bethany R. |
| **Bcc:** | adunlop@midwestagenergy.com; LBender@fredlaw.com; Anderson, Carl J.; Murphy, Ed C.; Paczkowski, John A.; Best, Steve L.; boomgaard.craig@epa.gov; Minter.Douglas@epa.gov; ndfieldoffice@fws.gov; achp@achp.gov; Williams, Jeb R.; Peterson, Bill; lwickstr@blm.gov; BLM_MT_North_Dakota_FO@blm.gov; Kbear@mhanation.com; slhall@mhanation.com; texx@restel.com; klyson@mhanation.com; chairmanfox; Cynthia.monteau@Tax-MHANation.com; ceverett@mhanation.com |
| **Subject:** | North Dakota Industrial Commission Notice of Hearing |
| **Date:** | Monday, January 30, 2023 4:37:00 PM |
| **Attachments:** | image001.png<br>Blue Flint_Notice of Hearing.pdf |

The attached hearing notice is sent pursuant to North Dakota Administrative Code Section 43-05-01-08(5).
The fact sheet, storage facility permit application, and draft permit are available for download at:
https://www.dmr.nd.gov/oilgas/GeoStorageofCO2.asp

Please contact our office if you have any questions.

Bethany Kadrmas
*Legal Assistant, Oil and Gas Division*

701.328.8020 • brkadrmas@nd.gov • www.dmr.nd.gov

NORTH Dakota | Mineral Resources
Be Legendary.™

600 E Boulevard Ave, Dept. 405 • Bismarck, ND 58505

| | |
|---|---|
| **From:** | Kadrmas, Bethany R. |
| **Bcc:** | cityunder@westriv.com; washaud@westriv.com; -Info-Public Service Commission; Schreiner, Todd A.; Heringer, Joe A.; Schulz, Cody J.; Henke, Ronald J.; Knutson, Beth A. |
| **Subject:** | North Dakota Industrial Commission Notice of Hearing |
| **Date:** | Monday, January 30, 2023 4:37:00 PM |
| **Attachments:** | Blue Flint  Notice of Hearing.pdf<br>image001.png |

The attached hearing notice is sent pursuant to North Dakota Administrative Code Section 43-05-01-08(5).

Please contact our office if you have any questions.


Bethany Kadrmas

*Legal Assistant, Oil and Gas Division*

701.328.8020 • brkadrmas@nd.gov • www.dmr.nd.gov

NORTH Dakota | Mineral Resources
Be Legendary.™

600 E Boulevard Ave, Dept. 405 • Bismarck, ND  58505

**From:** Kadrmas, Bethany R.
**Bcc:** ssyvertson@deltaconstructors.net; jeff.bergeron@exxonmobil.com; jcather@summitag.com; jerickson@e-m-services.com; phoenixenergyadvisors@gmail.com; jessica.gregg@carbonamerica.com; cynthia.fischer7@gmail.com; JASON_MARTIN@TCENERGY.COM; kjsrental1@gmail.com; mhj303@gmail.com; sarah.leung@hq.doe.gov; tylerh@bepc.com; findooley@gmail.com; madison@colgatemanagement.com; Edison, Ross W.; tjiang@undeerc.org; katie@mckennettlaw.com; michael@newscoopnd.org; kate@inlandoil.net; megan.lindquist@dvn.com; drew_lingle@cramer.senate.gov; brett.holmes@argusmedia.com; LEWIS18022@AOL.COM; bthoma@gmellc.com; aim.marcher@comcast.net; levijohns@vitesseoil.com; eliot@drcinfo.com; carlaneal@eis-llc.com; nkoudouonambelesimplice@gmail.com; christopher.friez@nacco.com; jonwgt@viagellc.com; jay.g@badlandshydrovac.com; jackie.jahfetson@bismarcktribune.com; tip.meckel@beg.utexas.edu; arathy.s@tr.com; LGARCIA@HEWTEX.COM; bbree45@hotmail.com; jacob.cullip@outlook.com; jlarson@nacompanies.com; keefekat@bresnan.net; Christian.Sizemore@ovintiv.com; jbradfute@marathonoil.com; jeb@evosquared.com; mark.rainey@radpros.com; snance@catahoularesources.com; pmttransport@me.com; quimber@yahoo.com; cmarshall@targaresources.com; daveb@redtrailenergy.com; derrick@braatenlawfirm.com; pdjordan@lbl.gov; Espy, Jackie M.; kdarnay@kxnet.com; gburshteyn@wellington.com; miles.demster@nexteraenergy.com; will.houser@clr.com; julia.johnson@agribank.com; rfvanvoorhees@bclplaw.com; ccarlson@limerockresources.com; c-jwentz@gmellc.com; cfgress@yahoo.com; brad@fayglobal.com; kconnors@undeerc.org; kanagnost@undeerc.org; hvettleson@undeerc.org; jon@tradesmanadvisors.com; ejbrown@blm.gov; scook8@slb.com; charlesb@ajcm.com; rklute@ndoil.org; hdemuth@petrotek.com; ejahner@ndoil.org; SHHS70@GMAIL.COM; orleysinkler@outlook.com; rab@inflowpetro.com; Petrick, Jessica K.; cebreckon@aol.com; Tyler.C.McCormack@hess.com; DJSNOW@MARATHONPETROLEUM.COM; katrinachristiansen@gmail.com; dness777@gmail.com; publisher@esidney.com; hillsvalleyranch@gmail.com; colsen@undeerc.org; cjacobson@bepc.com; ktracy@elysian.cc; klesmann@fibt.com; darst@google.com; zeiken@crowleyfleck.com; melodyhacker@me.com; jeggleton@dorahg.com; kennethaschmidt@hotmail.com; mtwocrow@gmail.com; littlejudyd@gmail.com; ejedison@crowleyfleck.com; rcoskey@roseexp.com; dthorson@inbox.lv; keith.hapipsr1@gmail.com; klurfeld@nyc.rr.com; kurt@mapmechanical.com; Sales@dacotahwest.com; cevans@energyintel.com; courtneyturich@echantillonadvising.com; mha.energyliaison@gmail.com; swapnil@fusionnd.com; tonya@ironoil.com; paulsonken@tcrfortberthold.com; Nodaky12@gmail.com; smh@rampartenergy.com; ryanokland@gmail.com; dave_french@mckinsey.com; clweaver@eprod.com; laura.bird@whiting.com; josh.armstrong@ameritas.com; jwilcoxen@cliftygroup.com; cctschirhart@marathonoil.com; matthew.elias@ashlercapital.com; VanEckhout, Brendan F.; cbellet55@gmail.com; brentbrannan@gmail.com; abargelski@gmail.com; sara.phiaxay@steelreef.ca; jennifer_lee@tcenergy.com; dhuffington@petrotek.com; abdelmalek.bellal@und.edu; kaylae@jmacresources.com; Spangelo, Kayla M.; brentbrannan@auroraenergyllc.com; nnowiski@slb.com; matthew_maher@tcenergy.com; chelsea.carpenter@ovintiv.com; Hecker, Garret; JDeWitt@MarathonOil.com; darnell.bortz@kochind.com
**Subject:** North Dakota Industrial Commission Notice of Hearing
**Date:** Monday, January 30, 2023 4:36:00 PM
**Attachments:** Blue Flint_Notice of Hearing.pdf
image001.png

---

The attached hearing notice is sent pursuant to North Dakota Administrative Code Section 43-05-01-08(5).

Please contact our office if you have any questions.


Bethany Kadrmas
*Legal Assistant, Oil and Gas Division*

701.328.8020 • brkadrmas@nd.gov • www.dmr.nd.gov

NORTH Dakota | Mineral Resources
Be Legendary.™

600 E Boulevard Ave, Dept. 405 • Bismarck, ND 58505

NORTH
Dakota | Mineral Resources
Be Legendary.™

January 30, 2023

**NOTICE OF HEARING**
**N.D. INDUSTRIAL COMMISSION**
**OIL AND GAS DIVISION**

You are hereby notified of a hearing pursuant to North Dakota Administrative Code § 43-05-01 requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota. **The hearing will be held March 21, 2023 at 9:00 a.m.**, 1000 East Calgary Avenue, Bismarck, North Dakota.

Application of Blue Flint Sequester Company, LLC requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Blue Flint Sequester Company, LLC intends to capture carbon dioxide from the Blue Flint Ethanol Facility and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT March 20, 2023. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Tammy Madche, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Blue Flint Sequester Company, LLC, 2841 3rd St. SW, Underwood, North Dakota 58576.

A motion of the Commission to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Blue Flint Sequester Company, LLC storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.

A motion of the Commission to determine the amount of financial responsibility for the geologic storage of carbon dioxide from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.

Please contact our office if you have any questions.

Sincerely,

Lynn D Helms

Lynn D. Helms
Director

**Kadrmas, Bethany R.**

**From:** Hogue, Trudi L.
**Sent:** Tuesday, February 7, 2023 1:40 PM
**To:** Kadrmas, Bethany R.
**Subject:** FW: FedEx Shipment 771188973275: Your packages have been delivered

For your records.

**From:** TrackingUpdates@fedex.com <TrackingUpdates@fedex.com>
**Sent:** Tuesday, February 7, 2023 1:21 PM
**To:** Hogue, Trudi L. <tlhogue@nd.gov>
**Subject:** FedEx Shipment 771188973275: Your packages have been delivered

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

# Hi. All of your packages were delivered.

Delivered Tue, 02/07/2023 at 1:49pm to 1849 C ST NW, Washington, DC 20240
Received by AAGNES

**OBTAIN PROOF OF DELIVERY**

| TRACKING ID | STATUS |
| --- | --- |
| 771188973757 | Delivered |

771188973275

Delivered

| | |
|---|---|
| **MASTER TRACKING NUMBER** | 771188973275 |
| **FROM** | NORTH DAKOTA INDUSTRL COMMISSN<br>1016 E Calgary Ave<br>BISMARCK, ND, US, 58503 |
| **TO** | Bureau of Indian Affairs<br>MS-4606<br>MS-4606<br>1849 C St NW<br>Washington, DC, US, 20240 |
| **REFERENCE** | CO2 |
| **SHIP DATE** | Thu 2/02/2023 12:00 AM |
| **PACKAGING TYPE** | Package |
| **ORIGIN** | BISMARCK, ND, US, 58503 |
| **DESTINATION** | Washington, DC, US, 20240 |
| **NUMBER OF PIECES** | 2 |
| **TOTAL SHIPMENT WEIGHT** | 6.00 LB |
| **SERVICE TYPE** | FedEx Ground |

## Get the FedEx® Mobile app

Create shipments, receive tracking alerts, redirect packages to a FedEx retail location for pickup, and more from the palm of your hand
- **Download now**.

FOLLOW FEDEX

Please do not respond to this message. This email was sent from an unattended mailbox. This report was generated at approximately 1:20 PM CST 02/07/2023.

All weights are estimated.

To track the latest status of your shipment, click on the tracking number above.

Standard transit is the date and time the package is scheduled to be delivered by, based on the selected service, destination and ship date. Limitations and exceptions may apply. Please see the FedEx Service Guide for terms and conditions of service, including the FedEx Money-Back Guarantee, or contact your FedEx Customer Support representative.



Thank you for your business.

RECEIVED

FEB - 6 2023

N.D. INDUSTRIAL COMMISSION

# Affidavit of Publication

The North Dakota Industrial Commission will hold a public hearing at 09:00 AM Tuesday, March 21, 2023 at N.D. Oil & Gas Division 1000 East Calgary Avenue Bismarck, North Dakota. At the hearing the Commission will receive testimony and exhibits. Persons with any interest in the cases listed below, take notice.

PERSONS WITH DISABILITIES: If at the hearing you need special facilities or assistance, contact the Oil and Gas Division at 701-328-8038 by Tuesday, March 14, 2023.

STATE OF NORTH DAKOTA TO:

Case No. 29888: Application of Blue Flint Sequester Company, LLC requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Blue Flint Sequester Company, LLC intends to capture carbon dioxide from the Blue Flint Ethanol Facility and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT March 20, 2023. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Tammy Madche, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Blue Flint Sequester Company, LLC, 2841 3rd St. SW, Underwood, North Dakota 58576.

Case No. 29889: A motion of the Commission to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Blue Flint Sequester Company, LLC storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.

Case No. 29890: A motion of the Commission to determine the amount of financial responsibility for the geologic storage of carbon dioxide from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.

Signed by,
Doug Burgum, Governor, Chairman, NDIC
(Feb. 2, 2023)

STATE OF NORTH DAKOTA,
COUNTY OF McLean, ss.

I, Tamara Huston, employee of the McLean County Independent of said County and State, being first duly sworn, on oath says, that the McLean County Independent is a weekly newspaper published in Garrison ND County of McLean, and has full and personal knowledge of all the facts herein stated; that said newspaper is a legal newspaper and has a bona fide circulation of at least two hundred copies weekly, and has been published within said county for fifty-two successive weeks next prior to the publication of the notice herein mentioned; that the

Notice of Hearing Case #29888

ND Oil & Gas Division

a printed copy of which, taken from the paper in which same was published, is attached to this sheet, and is made a part of this Affidavit, was published in said newspaper at least once each week for 1 successive week, on the day of each week on which said newspaper was regularly published to-wit:

4- McLean County Independant: 2/2/2023

That the full amount of the fees for the publication of the annexed notice is: $ 45.10

Tamara Huston

Subscribed and sworn to before me this 2/1/2023

Darla J Mautz

Darla J. Mautz, Notary Public
State of North Dakota

XN

DARLA J MAUTZ
Notary Public
State of North Dakota
My commission expires July 22, 2026

# *** Proof of Publication ***

State of North Dakota )
) SS:
County of Burleigh )

Before me, a Notary Public for the State of North Dakota personally

appeared Jill Lindsay who being duly sworn, deposes and says that he (she) is the Clerk of Bismarck Tribune Co., and that the publication(s) were made through the

Bismarck Tribune on the following dates:

2/3/2023

Signed Jill Lindsay

OIL & GAS DIVISION

600 E BLVD AVE #405
BISMARCK, ND 58505

ORDER NUMBER 56219

Sworn and subscribed to before me this 3 day of
February 2023
Candice Blohm
Notary Public in and for the State of North Dakota

CANDICE BLOHM
Notary Public
State of North Dakota
My Commission Expires Aug 30, 2026

Section: Legals
Category: 5380 Public Notices
PUBLISHED ON: 02/03/2023

TOTAL AD COST: 124.40
FILED ON: 2/3/2023

NOTICE OF HEARING
N.D. INDUSTRIAL COMMISSION
OIL AND GAS DIVISION

The North Dakota Industrial Commission will hold a public hearing at 09:00 AM Tuesday, March 21, 2023 at N.D. Oil & Gas Division 1000 East Calgary Avenue Bismarck, North Dakota. At the hearing the Commission will receive testimony and exhibits. Persons with any interest in the cases listed below, take notice.

PERSONS WITH DISABILITIES: If at the hearing you need special facilities or assistance, contact the Oil and Gas Division at 701-328-8038 by Tuesday, March 14, 2023.

STATE OF NORTH DAKOTA TO:

Case No. 29888: Application of Blue Flint Sequester Company, LLC requesting consideration for the geologic storage of carbon dioxide in the Broom Creek Formation from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Blue Flint Sequester Company, LLC intends to capture carbon dioxide from the Blue Flint Ethanol Facility and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT March 20, 2023. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Tammy Madche, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Blue Flint Sequester Company, LLC, 2841 3rd St. SW, Underwood, North Dakota 58576.

Case No. 29889: A motion of the Commission to consider the amalgamation of the storage reservoir pore space, in which the Commission may require that the pore space owned by nonconsenting owners be included in the geologic storage facility and subject to geologic storage, as required to operate the Blue Flint Sequester Company, LLC storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Century Code Section 38-22-10.

Case No. 29890: A motion of the Commission to determine the amount of financial responsibility for the geologic storage of carbon dioxide from the Blue Flint Ethanol Facility in the storage facility located in Sections 11, 12, 13, 14, and 24, Township 145 North, Range 83 West and Sections 6, 7, 8, 17, 18, and 19, Township 145 North, Range 82 West, McLean County, North Dakota, in the Broom Creek Formation, pursuant to North Dakota Administrative Code Section 43-05-01-09.1.

Signed by,
Doug Burgum, Governor
Chairman, NDIC

2/3 - 56219