Case No.: 30869
Date Established: April 15, 2024

DRAFT STORAGE FACILITY PERMIT

STORAGE FACILITY FOR CARBON SEQUESTRATION UNDER THE NORTH DAKOTA UNDERGROUND INJECTION CONTROL PROGRAM

In compliance with North Dakota Century Code (NDCC) Chapter 38-22 (Carbon Dioxide Underground Storage) and North Dakota Administrative Code (NDAC) Chapter 43-05-01 (Geologic Storage of Carbon Dioxide), Summit Carbon Storage #1, 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 Section 43-05-01-07.2 indicating the Commission's tentative decision to issue a storage facility permit. Before preparing the draft permit, the Commission through the Department of Mineral Resources Oil and Gas Division, consulted with the Department of Environmental Quality, and has determined the storage facility permit application to be complete. The draft permit contains permit conditions required under NDAC Sections 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 of 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 April 15, 2024, and shall remain in effect until a storage facility permit is granted under NDAC Section 43-05-01-05, unless amended or terminated by the Department of Mineral Resources Oil and Gas Division (Commission).

Tamara Madche, Geologist
Department of Mineral Resources
Oil and Gas Division
Date: April 15, 2024

I. APPLICANT

Summit Carbon Storage #1, LLC
2321 North Loop Drive, Suite #221
Ames, IA 50010

II. PERMIT CONDITIONS (NDAC Section 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 section 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 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 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 post-injection site care and facility closure plan pursuant to section 43-05-01-19.

III. CASE SPECIFIC PERMIT CONDITIONS

1. NDAC Section 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 gauges in the TB Leingang 1 (File No. 40158 – SENE 18-141N-87W) and TB Leingang 2 (File No. 40178 – SENE 18-141N-87W) injectors and the Milton Flemmer 1 (File No. 38594 – NWNE 35-141N-88W) monitor well.

2. NDAC Section 43-05-01-11, subsection 14 and NDAC Section 43-05-01-11.4, subsection 1, subdivision c; The operator shall run an ultrasonic or other log capable of evaluating internal and external pipe condition to establish a baseline for corrosion monitoring for the TB Leingang 1, TB Leingang 2 and Milton Flemmer 1 wells. The operator shall run logs with the same capabilities for the TB Leingang 1 and TB Leingang 2 wells on a 5 year schedule, unless analysis of corrosion coupons or subsequent logging necessitates a more frequent schedule.

3. NDAC Section 43-05-01-11.4, subsection 1, subdivision d and NDAC Section 43-05-01-13, subsection 2; The storage operator shall notify the Commission within 24 hours of any release of carbon dioxide from the storage facility, flow lines, or of carbon dioxide detected above the upper confining zone. Where the Commission or the storage operator obtains evidence that the injected carbon dioxide stream and associated pressure front may endanger an underground source of drinking water, the storage operator shall cease injection immediately, implement the emergency and remedial plan approved by the Commission, and take all steps reasonably necessary to identify and characterize any release.

4. NDAC 43-05-01-11.1 subsections 3 and 5 and NDAC 43-05-01-11.4, subsection 1, subdivision e; External mechanical integrity shall be continuously monitored with the proposed fiber optic lines for the TB Leingang 1, TB Leingang 2 and Milton Flemmer 1 wells. 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 to be implemented as planned by the operator in Section 5.2 (Surface Facilities Leak Detection Plan) and Section 5.7.1 (Soil Gas 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 for the injection and monitoring wells. The packer must be set within 100’ of the upper most perforation and in the 25CR-80 casing for the TB Leingang 1 and TB Leingang 2 injectors and 13CR-80 casing for the Milton Flemmer 1 monitor. Dependent on evaluation, the operator shall run the same test on a 5 year schedule for the TB Leingang 1, TB Leingang 2 and Milton Flemmer 1 wells.

7. NDAC 43-05-01-11, subsections 3 and 5; The operator shall continuously monitor the surface casing-long string casing annulus with proposed fiber optic lines, and a gauge not to exceed 300 psi. The Commission must be notified of any pressure that needs to be bled off.

8. NDAC 43-05-01-05, subsection 1; Any other information that the Commission requires the storage facility permit to include. The operator shall implement a data sharing plan that provides for real-time sharing of data between Summit Carbon Storage #1, LLC, Summit Carbon Storage #2, LLC, Summit Carbon Storage #3, LLC and SCS Carbon Transport LLC operations. If a discrepancy in the shared data is observed, the party observing the data discrepancy shall notify all other parties, take action to determine the cause, and record the instance. Copies of such records must be filed with the Commission upon request.

9. NDAC 43-05-01-17, subsection 1; The storage operator must pay fees based upon the carbon dioxide source and the amount of carbon dioxide injected for storage. The Commission must make a determination on the contribution to the energy and agriculture production economy of North Dakota of each additional carbon dioxide source, before it is approved to be stored. If the Commission deems a carbon dioxide source does not contribute to the energy and agricultural production economy of North Dakota, the fees will be determined by hearing.

10. NDAC 43-05-01-11.3, subsection 3; The operator shall fill the annulus between the tubing and the long string casing with a noncorrosive fluid approved by the Commission. The storage operator shall maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Commission determines that such a requirement might harm the integrity of the well or endanger the underground sources of drinking water. Section 5.4 (Wellbore Mechanical Integrity Testing) proposes a nitrogen cushion of 300 psi minimum to maintain constant positive pressure on the well annulus in each injector. Section 11.0 (Injection Well and Storage Operations) proposes a maximum operating injection pressure of 2100 psi.

Fact Sheet

1. Description of Facility

Summit Carbon Storage #1, LLC (SCS #1) is a wholly owned subsidiary of SCS Permanent Carbon Storage LLC (SCS PCS) which is a wholly owned subsidiary of Summit Carbon Solutions, LLC (SCS). SCS, under the wholly owned subsidiary SCS Carbon Transport LLC, intends to construct, own, and operate a carbon dioxide transmission pipeline, the Midwest Carbon Express (MCE) pipeline. The MCE pipeline will receive carbon dioxide from over 30 anthropogenic sources, including biofuels from ethanol facilities and other industries across the Midwest, including Iowa, Minnesota, Nebraska, South Dakota, and North Dakota. The MCE pipeline will be capable of transporting up to 18 million metric tons per year, to North Dakota to be stored in three storage facilities located in Mercer, Morton, and Oliver Counties, near the city of Beulah, North Dakota, owned by SCS #1, Summit Carbon Storage #2, LLC (SCS #2) and Summit Carbon Storage #3, LLC (SCS #3). SCS #2 and SCS #3 are wholly owned subsidiaries of SCS PCS. All three storage facilities are intended to operate in tandem with each other.

2. Quantity and Quality of Carbon Dioxide Stream

The storage facility was modeled to receive a maximum of 124.4 million metric tons over a 20-year injection period, equating to approximately 6.22 million metric tons annually. The combined maximum modeled storage volume across all three storage facilities is 352 million metric tons over 20 years.

The commingled carbon dioxide stream being transported by the MCE pipeline at the time of this application is anticipated to average at least 98.25% carbon dioxide, <1.44% nitrogen, with trace quantities of oxygen, water, hydrocarbons, hydrogen sulfide, sulfur, and glycol, equaling less than 0.31% combined.

The MCE pipeline and storage facility have been conservatively designed to accommodate a carbon dioxide stream that is 95% carbon dioxide, 2% oxygen, and 3% nitrogen. SCS #1 is proposing that the carbon dioxide stream must be between 95% and 99.9% carbon dioxide to be accepted into the MCE pipeline to allow flexibility to receive carbon dioxide from a variety of industrial sources.

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

Draft Permit Section III. Case Specific Conditions are referenced below by number from aforementioned section.

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 outside the casing by running an approved tracer survey or temperature log or noise log. The proposed fiber optic lines shall provide continuous temperature logs for the length of the injection wellbores.

10. NDAC 43-05-01-11.3, subsection 3; The operator shall fill the annulus between the tubing and the long string casing with a noncorrosive fluid approved by the Commission. The storage operator shall maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Commission determines that such a requirement might harm the integrity of the well or endanger the underground sources of drinking water. The proposed nitrogen cushion of 300 psi minimum to maintain constant positive pressure on the well annulus in each injector will provide corrosion protection without risking the creation of a micro annulus by debonding of the long string casing-cement sheath during the operational life of the well. The Commission finds a micro annulus would harm external mechanical integrity and provide a potential pathway for endangerment of USDWs.

5. Procedures Required for Final Decision

The beginning and ending dates of the comment period:
April 15, 2024 to 5:00 P.M. CDT June 10, 2024

The address where comments will be received:
Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512
or slforsberg@nd.gov

Date, time, and location of the storage facility permit hearing:
June 11-12, 2024 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: Sara Forsberg – slforsberg@nd.gov – 701-328-8020

SUMMIT
CARBON
SOLUTIONS

February 6, 2024

Tammy Madche
North Dakota Department of Mineral Resources
1000 East Calgary Avenue
Bismarck, ND 58502

RE: SUMMIT CARBON STORAGE #1, LLC SFP AND CLASS VI APPLICATION

Dear Mrs. Madche,

Summit Carbon Storage #1, LLC (SCS1) respectfully submits for the review and consideration of the Department of Mineral Resources – Oil & Gas Division, one application for carbon dioxide storage facility permits for the injection site called the TB Leingang; which is located in Oliver County, North Dakota. This application was prepared 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.

The storage facility permit application, associated simulation data and the Permit Application Certification – Broom Creek, has been sent electronically.

Please contact me with any questions.

Sincerely,

Jy M Volk

Jay M. Volk, PhD
Sequestrations – Director of Health, Safety & Environmental

Enclosure
Cc: Lawrence Bender, lbender@fredlaw.com (w/o enclosure)

3442 E. Century Ave., Bismarck, ND 58503 | PO Box 2655, Bismarck, ND 58502 | SummitCarbonSolutions.com

Permit Application Certification
-Broom Creek-

BEFORE ME, the undersigned authority, personally appeared Wade Boeshans, Executive Vice President of Summit Carbon Solutions, LLC the ultimate parent company of the wholly owned subsidiary, **Summit Carbon Storage #1, LLC**, a Delaware Limited Liability Company whose office is located at 2321 North Loop Drive, Suite #221, Ames, IA, 50010 who being duly sworn, upon oath stated and certified that:

1. I, Wade Boeshans, am over eighteen years of age. I have personal knowledge of the information and facts stated by me in the Certification and that 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 Executive Vice President for Summit Carbon Solutions, LLC. As required in accordance with North Dakota Administrative Code § 43-05-01-07.1 and by virtue of my position with Summit Carbon Solutions, LLC, I am authorized to make these representations on behalf of **Summit Carbon Storage #1, LLC**.
3. Attached hereto is the storage facility permit application requesting permits 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 carbon dioxide storage facilities located in Oliver, Mercer and Morton County's, North Dakota. Further, enclosed is the accompanying Class VI drilling permit information for two (2) carbon dioxide injection wells and one (1) monitoring well.
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 enclosed documents and attachments to the permit applications. Based upon information and belief, the information contained herein is true, accurate and complete.
5. I affirm under penalty of perjury that the representation contained in the 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 enclosed applications and supporting documents and information on behalf of **Summit Carbon Storage #1, LLC**.

Executed this 6 day of February, 2024

Wade Boeshans

STATE OF NORTH DAKOTA)
) SS
COUNTY OF BURLEIGH)

Subscribed and sworn to before me this 10 day of February, 2024

(SEAL)

AMANDA HOFFER
Notary Public
State of North Dakota
My Commission Expires September 11, 2024

Amanda Hoffer
Notary Public

TB LEINGANG/MILTON FLEMMER 1

SUMMIT CARBON STORAGE #1, LLC – CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT

North Dakota CO_2 Storage Facility Permit Application

Prepared for:

Richard Suggs
Tammy Madche

Department of Mineral Resources
Oil and Gas Division
600 East Boulevard Avenue
Department 474
Bismarck, ND 58505-0614

Prepared by:

Summit Carbon Storage #1, LLC
2321 North Loop Drive, Suite 221
Ames, IA 50010-8218

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

February 2024

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LIST OF ACRONYMS

1D MEM	1D mechanical earth model
AI	acoustic impedance
amsl	above mean sea level
AOR	area of review
API	American Petroleum Institute
ASLMA	Analytical Solution for Leakage in Multilayered Aquifers
AZMI	above-zone monitoring interval
bbl	oilfield barrel
BHA	bottomhole assembly
BHP	bottomhole pressure
BOP	blowout preventer
BPV	backpressure valve
BTC	buttress
CA	contact angle
$CaCO_3$	calcium carbonate
CBL	cement bond log
CCS	carbon capture and storage
CFR	Code of Federal Regulations
CI	carbon intensity
CIBP	cast iron bridge plug
CICR	cast iron cement retainer
CIL	casing inspection log
CMG	Computer Modelling Group Ltd.
CMR	combinable magnetic resonance
CO_2	carbon dioxide
CRA	corrosion-resistant alloy
CRC	Company Response Crew
CST	Company Support Team
DMR-O&G	Department of Mineral Resources, Oil and Gas Division
DOC	dissolved organic carbon
DST	drillstem test
DTC	dipole sonic compressional slowness values (delta-T compressional)
DSSS	dipole shear sonic slowness
DTS	distributed temperature sensing
DWR	Department of Water Resources
E	dynamic Young’s moduli
EC	electrical conductivity
ECS	elemental capture spectroscopy
EDS	energy-dispersive spectrometry
EERC	Energy & Environmental Research Center
EMS	emergency management service
EPA	U.S. Environmental Protection Agency

Continued . . .

LIST OF ACRONYMS (continued)

ER	electrical resistance
ERRP	emergency remedial response plan
FA	friction angle
FADP	financial assurance demonstration plan
FANG	friction angle
FEL	from the east line
FNL	from the north line
FSP	fault slip potential
GHG	greenhouse gas
GL	ground level
GR	gamma ray
H_2S	hydrogen sulfide
HazMat	hazardous materials
HAZWOPER	hazardous waste operations and emergency response
HCON	hydraulic conductivity
HSE	health, safety, and environmental
HSGR	standard (total) gamma ray
IAM-CS	Integrated Assessment Model for Carbon Storage
IC	Incident Commander
ICS	Incident Command System
IFT	interfacial tension
JFE BEAR	gastight premium connection
K	permeability
K_{int}	intrinsic permeability
KINT	permeability
LAS	low alloy steel
LCFS	low-carbon fuel standard
LD	lay down
LDS	leak detection system
LEPC	Local Emergency Planning Committee
LRT	Local Response Team
LTC	long-thread and coupled
MASP	maximum anticipated surface pressure
MCE	Midwest Carbon Express
mD	millidarcy
MD	measured depth
MDT	modular dynamics testing
MI	mechanical integrity
MICP	mercury injection capillary pressure
MIRU	move in and rig up
MIT	mechanical integrity text
MLVs	main line valves
MMI	modified Mercalli intensity

Continued . . .

LIST OF ACRONYMS (continued)

MMt	million metric tonnes
MMtpa	million metric tonnes per annum
MMscf	million standard cubic ft
MU	make up
MVTL	Minnesota Valley Testing Laboratories
NAD	North American Datum
ND	nipple down
N.D.A.C.	North Dakota Administrative Code
N.D.C.C.	North Dakota Century Code
NDIC	North Dakota Industrial Commission
NEUT	neutron porosity
NFPA	National Fire Protection Association
NRU	National Response Center
NU	nipple up
O_2	oxygen
OSHA	Occupational Safety and Health Administration
P&A	plugged and abandoned
PBTD	plug back total depth
Pce	entry pressure
PCOR	Plains CO_2 Reduction [Partnership]
Phi	porosity
PHIE	effective porosity
PHIT	total porosity
PHMSA	Pipeline and Hazardous Materials Administration
PIG	pipeline inspection gauge
PISC	postinjection site care, postinjection site closure
PLT	production logging tool
PNL	pulsed-neutron log
POOH	pull out of hole
PPE	personal protective equipment
ppg	pounds per gallon
PSAP	public safety answering point
psig	pounds per square inch gauge
P/T	pressure/temperature
PU	pick up
PV	pore volume
PVC	pore volume compressibility
QASP	quality assurance and surveillance plan
QI	qualified individual
qtr	quarter
RCBL	radial cement bond log
RD	rig down

Continued . . .

LIST OF ACRONYMS (continued)

RDMO	rig down and move out
RHOB	drop in bulk density
RIH	run in hole
RNG	range
RQI	reservoir quality index
SCADA	supervisory control and data acquisition
scf	standard cubic foot
SCS	Summit Carbon Solutions, LLC
SCS1	Summit Carbon Storage #1, LLC
SCS2	Summit Carbon Storage #2, LLC
SCS3	Summit Carbon Storage #3, LLC
SCS PCS	SCS Permanent Carbon Storage LLC
SEM	scanning electron microscopy
SERC	State Emergency Response Committee
SFA	storage facility area
SFP	storage facility permit
SHmax	maximum horizontal stress
Shmin	minimum horizontal stress
SLRA	screening-level risk assessment
SP	spontaneous potential
SRT	step rate test
SS	specific storage
SSTVD	subsea true vertical depth
STC	short-thread and coupled
sx	sacks
TA	temporarily abandoned
TATD	temporarily abandoned, drilled to total depth
TBD	to be determined
TD	total depth
TDS	total dissolved solids
TIH	trip in hole
To	tensile strength
TOC	top of cement, total organic carbon
TOOH	trip out of hole
TVD	true vertical depth
TWP	township
UC	Unified Command
UCS	uniaxial compressive strength
UIC	underground injection control
USDW(s)	underground source of drinking water
USGS	U.S. Geological Survey
USIT	ultrasonic imaging tool

Continued . . .

LIST OF ACRONYMS (continued)

VAM TOP	gastight premium connection
VBA	Visual Basic for Applications
VDL	variable-density log
WHP	wellhead pressure
WHT	wellhead temperature
WO	workover
WSP	Worker Safety Plan
XRD	x-ray diffraction
XRF	x-ray fluorescence

SUMMIT CARBON STORAGE #1, LLC
CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT APPLICATION

PROJECT SUMMARY

General Applicant and Project Information. Summit Carbon Storage #1, LLC (SCS1), a wholly owned subsidiary of SCS Permanent Carbon Storage LLC (SCS PCS) which is a wholly owned subsidiary of Summit Carbon Solutions, LLC (SCS), as shown in Figure PS-1, is requesting consideration of this storage facility permit (SFP) application for the geologic storage of anthropogenic carbon dioxide (CO_2) within Mercer, Morton, and Oliver Counties, North Dakota.

The current mailing address for SCS1, as the storage facility operator of TB Leingang, is as follows:

Summit Carbon Storage #1, LLC
c/o Summit Carbon Solutions, LLC
Attn: Wade Boeshans
2321 North Loop Drive, Suite 221
Ames, IA 50010-8218

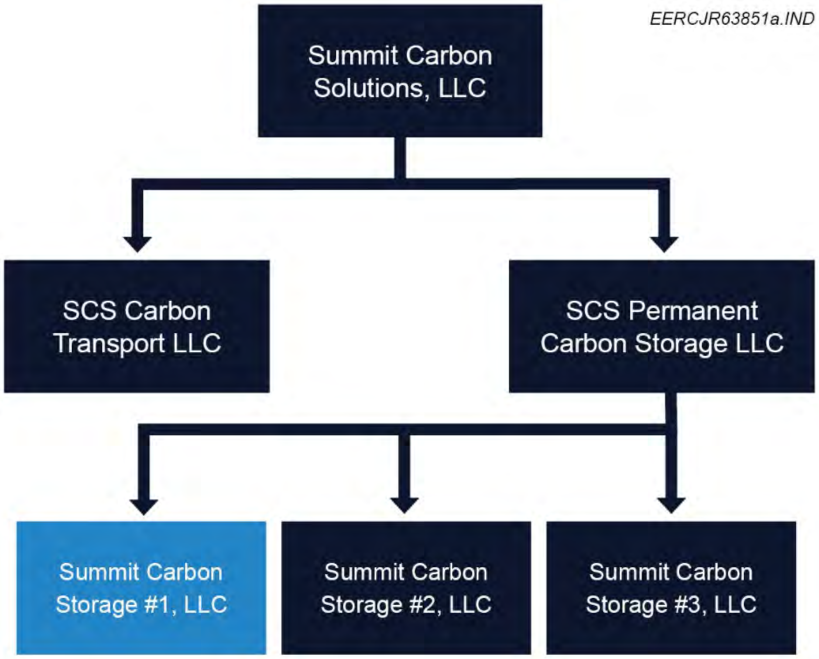

Figure PS-1. SCS1 business structure.

SCS proposes to construct, own, and operate the Midwest Carbon Express (MCE) Project (Figure PS-2), which will capture or receive CO_2 from over 30 anthropogenic sources (biofuel and

Figure PS-2. MCE Project overview map.

other industrial facilities) across the Midwest and transport the CO_2 via pipeline to North Dakota to be permanently stored within deep underground formations. The commingled stream composition in the MCE pipeline from all sources is anticipated to average ≥98.25% CO_2, with less than 1.75% trace quantities of other constituents (Table PS-1). The MCE Project is conservatively designed with a 95% CO_2, 2% O_2, and 3% N_2 specification; therefore, SCS1 is requesting a commercial permit for the operation of the storage facility for injection of a CO_2 stream that will range from 95% CO_2 to ≤99.9% CO_2. This commercial permit will provide flexibility to receive CO_2 from a variety of industrial sources.

Table PS-1. Anticipated Average CO_2 Stream Composition

Chemical Content	System Specification
Carbon Dioxide, CO_2	≥98.25%
Inert, N_2	≤1.44%
Oxygen, O_2	≤0.31%
Water, H_2O*	≤20 lb/MMscf
Total Hydrocarbons*	≤1800 ppm by volume
Hydrogen Sulfide, H_2S*	≤10 ppm by volume
Total Sulfur, S*	≤10 ppm by volume
Glycol	≤0.3 gallons/MMscf

* Denotes trace constituents that do not make up notable percentages of stream composition.

The MCE Project will generate approximately 11,400 construction and 1100 operational jobs across the project. The MCE Project contributes to the North Dakota economy by employing workers, paying salaries and benefits, purchasing goods and services from local businesses, contributing to other household consumption, and paying taxes. Capital expenditures in North Dakota from SCS and its contractors during the construction phase will support 1934 annual jobs on average consisting of direct, indirect, and through induced contributions Likewise, during operations, SCS will support 150 jobs in North Dakota through direct, indirect, and induced contributions (Ernst and Young, LLP, 2022).

The MCE Project aims to reduce the carbon intensity (CI) of biofuels produced from ethanol facilities and work toward achieving climate goals while creating jobs and other economic benefits across the project. The MCE Project is being designed to transport up to 18 million metric tonnes per annum (MMtpa) of CO_2 via a 2000-mile greenfield pipeline system (permitted through relevant state regulatory agencies and associated processes) to North Dakota for permanent storage approximately 1 mile underground in secure geologic formations across three CO_2 storage facilities owned and operated by SCS1; Summit Carbon Storage #2, LLC (SCS2); and Summit Carbon Storage #3, LLC (SCS3). Within this application, SCS1 was modeled at 124.4 million metric tonnes (MMt) over 20 years while all three storge facilities were modeled over 352 MMt. (124.4 TB Leingang + 98.3 BK Fischer + 129.7 KJ Hintz). TB Leingang 1 and TB Leingang 2 were modeled at 3.15 and 3.08 MMtpa, respectfully. The captured CO_2 will be injected into the Broom Creek Formation, a sandstone reservoir and saline aquifer underlying the project area (Figure PS-3) and surrounding region. SCS1's proposed CO_2 storage facility location in North Dakota provides not only favorable and plentiful geologic storage capacity supportive of the MCE Project but also CO_2 storage critical to both the agriculture and energy industries in North Dakota and surrounding regions.

By efficiently utilizing North Dakota's vast pore-space resource, estimated at approximately 250 billion metric tons of potential (U.S. Department of Energy, 2015), SCS seeks to lower greenhouse gas (GHG) emissions by storing up to 18 MMtpa of CO_2 through the MCE Project across three CO_2 storage facilities owned and operated by SCS1, SCS2, and SCS3, equivalent to removing the annual CO_2 emissions from approximately 3.9 million vehicles. This initiative directly supports U.S. and international climate change policies, goals, and efforts. When placed into service, the MCE Project will provide the largest and single most meaningful technology-based reduction of carbon emissions in the world. To date, more than 30 ethanol plants across the MCE Project's footprint have entered long-term CO_2 offtake agreements with SCS, opening new economic opportunities to sell their products in markets that pay more for lower-carbon fuels. This improved market accessibility ensures Midwestern ethanol plants' environmental and economic sustainability by significantly reducing their CO_2 emissions' footprint and lowering the CI of ethanol-based fuels. Specifically, by participating in the MCE Project and reducing the CI of their product, ethanol producers can compete in low-carbon fuel standard (LCFS) markets for an increased margin. If ethanol facilities are unable to reduce their CI, their access to the LCFS markets will decline, thus limiting their ability to compete in these markets and risking the jobs and communities they help sustain.

The importance of CO_2 pipelines for the ethanol industry and the agriculture industry that relies on them, as well as other anthropogenic industrial CO_2 sources, is further supported by the fact that other proposed carbon capture, pipeline transportation, and geologic storage projects in the Midwest have entered similar agreements with other ethanol plants. The primary challenge for Midwestern ethanol plants and other industrial sources of CO_2 is the lack of suitable and economic geologic formations for stored in proximity to their sites, as well as other economic and practicable solutions for use of the CO_2. The MCE Project offers a solution for this proximity challenge and a service for biofuel and industrial facilities across the Midwest by connecting these facilities via a greenfield pipeline system directly to the project area (Figure PS-2) located within North Dakota.

The project area (Figure PS-3) will consist of three separate CO_2 SFP locations: TB Leingang, BK Fischer, and KJ Hintz (Figure PS-3). Each SFP location will be owned and operated by individual operators: SCS1, SCS2, and SCS3. Each proposed SFP's surface use area covers approximately 30,000 acres and will include up to two Broom Creek Formation injection wells, a dedicated Broom Creek Formation stratigraphic and reservoir-monitoring well, and a dedicated monitoring well(s) for the lowest underground source of drinking water (USDW). Each site will also have associated surface facility infrastructure that will accept CO_2 transported via a CO_2 flowline. SCS1 will own and operate the CO_2 flowline (NDL-327) beginning at the terminus point in Oliver County (Figure PS-3) of the MCE (North Dakota Public Service Commission Case No. PU 22-391; NDM-106) and consists of approximately 8.6 miles of 24/20-inch flowline delivering CO_2 downstream to the TB Leingang 1 and 2 injection wells, also located in Oliver County. Operating agreements between SCS1, SCS2, SCS3, SCS PCS, and Summit Carbon Transport, LLC will include, but are not limited to, defining financial responsibilities, measurement and custody transfers, data access and data sharing, and general operations including leak detection and reporting, emergency response, monitoring, and maintenance of the NDL-327 as Summit Carbon Transport, LLC will be operating the MCE line and respective SCS1, SCS2, and SCS3 flowlines as one system. Likewise, operating agreements will include, but are not limited to, allowing the sharing of geologic models, monitoring equipment and associated data, as well as operational data, leak detection and monitoring, and emergency response actions.

The underlying target storage reservoir for this application, the Broom Creek Formation and, more specifically, its CO_2 storage potential, has been the subject of numerous studies conducted by the North Dakota Geological Survey, the U.S. Geological Survey (USGS), and the Energy & Environmental Research Center (EERC). The Broom Creek Formation is an ideal storage

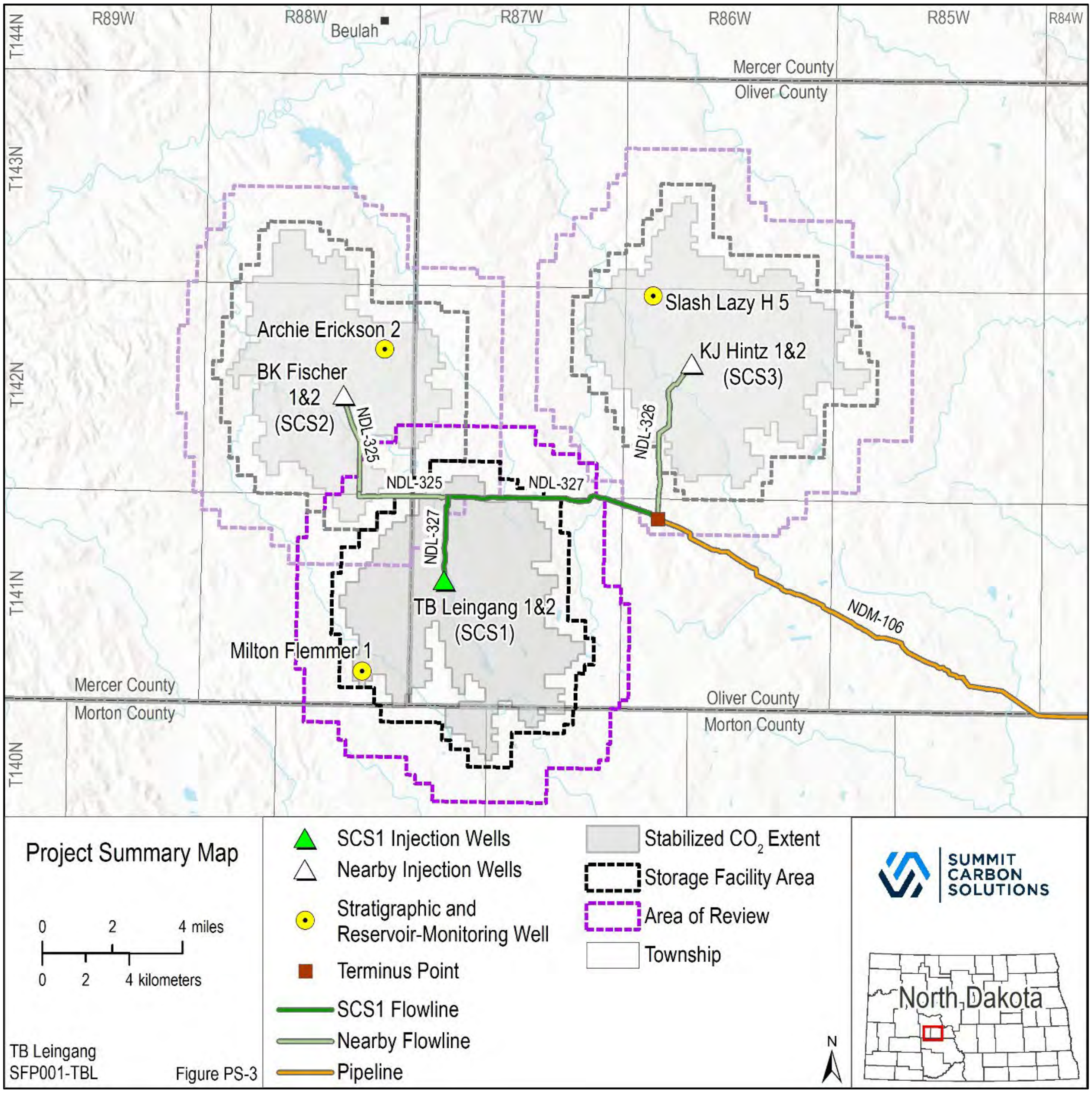

Figure PS-3. Project summary map.

candidate because of its superior reservoir quality, depth, impermeable upper and lower confining zones, and expansive areal extent. The suitability of these formations has been further verified by the extensive data sets collected by SCS to illustrate the long-term, safe storage of CO_2 within the proposed project area.

SCS collected data and completed a detailed characterization of the injection and confining zones to ensure that the injected CO_2 will remain permanently stored in the subsurface. Data acquisition began by first obtaining seismic consent from >95% of landowners via surface access agreements, allowing SCS to collect seismic data. Seismic data collection commenced in October 2021 and spanned approximately six townships over 200 square miles. Thereafter, three stratigraphic wells were drilled and completed; drilling operations started in January 2022 and ended in May 2022. The Milton Flemmer 1 (North Dakota Industrial Commission [NDIC] File No. 38594, American Petroleum Institute (API) No. 33-057-00041, Mercer County) well was drilled, cored, and logged into the Deadwood Formation at approximately 12,000 ft, while Archie Erickson 2 (NDIC File No. 38622, API No. 33-057-00042, Mercer County) and Slash Lazy H 5 (NDIC File No. 38701, API No. 33-065-00021, Oliver County) were both drilled, cored, and logged through the Broom Creek Formation, at approximately 6400 and 6100 ft, respectively.

In the following SFP application, SCS1 presents a detailed evaluation of site geology and characterizations that provide the data required to conduct an in-depth evaluation of the proposed SFP. Thus confirming the proposed SCS1 storage facility is suitable to receive and permanently store CO_2. This SFP application has been presented in conjunction with two other SFP applications within the project area (Figure PS-3): BK Fischer (SCS2) and KJ Hintz (SCS3).

References

Ernst and Young, LLP, 2022, Economic contributions of Summit Carbon Solutions: Final report prepared for Summit Carbon Solutions, April 2022, 60 p.

U.S. Department of Energy National Energy Technology Laboratory, 2015, Carbon storage atlas, 114 p., 5th ed.: www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf (accessed 2023).

SECTION 1.0

PORE SPACE ACCESS

1.0 PORE SPACE ACCESS

North Dakota law 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 [N.D.C.C.] § 47-31-03). Prior to issuance of the storage facility permit (SFP), North Dakota law mandates the storage operator obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir for geologic storage of CO_2 (N.D.C.C. § 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 (N.D.C.C. §§ 38-22-08[4], [14]). 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 (N.D.C.C. § 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 aboveground activities is not included in pore space amalgamation.

Summit Carbon Storage #1, LLC (SCS1) has identified the owners (surface and mineral) (N.D.C.C. §§ 38-22-06[3], [4]; North Dakota Administrative Code [N.D.A.C.] § 43-05-01-08[1]). No mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles of its outside boundary. SCS1 will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made (N.D.C.C. §§ 38-22-06[3], [4]; N.D.A.C. §§ 43-05-01-08[1], [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 (N.D.C.C. § 47-31-03). The review of pertinent county recorder records identified no severance of pore space from the surface estate or leasing of pore space to a third party prior to April 9, 2009. All surface owners and pore space owners and lessees are the same owner of record.

The map in Figure 1-1 shows the extent of the pore space that will be occupied by CO_2 at the cessation of injection (20 years) and over the life of the project (the stabilized CO_2 extent) as well as the storage facility area boundary and 0.5 miles outside of the storage facility area boundary (the hearing notification area).

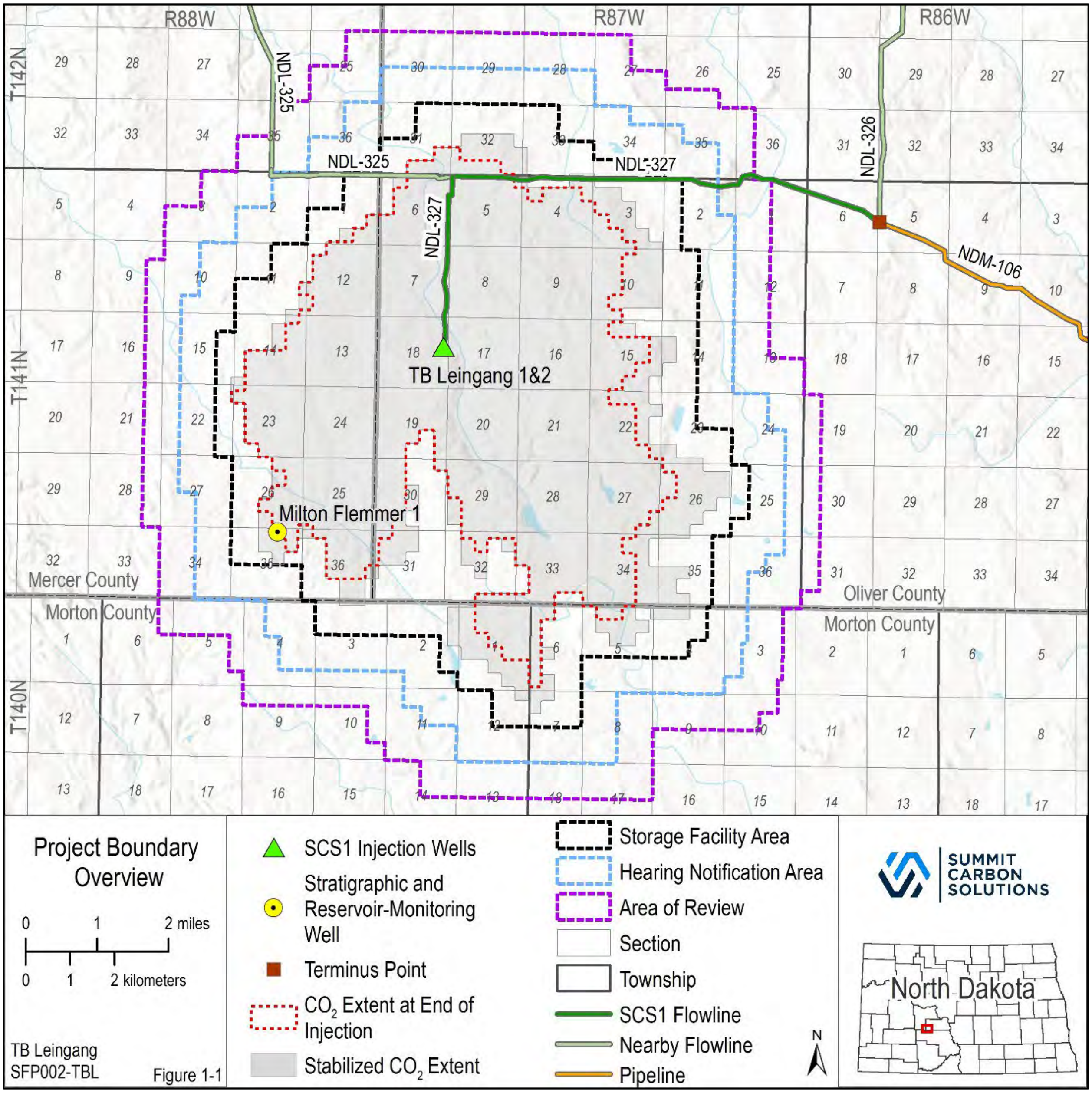

Figure 1-1. Map illustrating the pore space CO_2 extent at the cessation of injection (20 years), alongside the stabilized CO_2 extent over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted.

Fredrikson

Fredrikson & Byron, P.A.
Attorneys and Advisors

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Main: 701.221.8700
fredlaw.com

April 8, 2024

RECEIVED
APR - 8 2024
N.D. INDUSTRIAL COMMISSION

HAND DELIVERED

Mr. Mark Bohrer
Assistant Director
North Dakota Industrial Commission
Oil and Gas Division
1016 East Calgary Avenue
Bismarck, North Dakota 58503

RE: IN THE MATTER OF A HEARING CALLED ON A MOTION OF THE COMMISSION TO CONSIDER THE APPLICATIONS OF SUMMIT CARBON STORAGE #1, LLC, SUMMIT CARBON STORAGE #2, LLC AND SUMMIT CARBON STORAGE #3, LLC FOR THE GEOLOGIC STORAGE OF CARBON DIOXIDE IN THE BROOM CREEK FORMATION

Dear Mr. Bohrer:

Enclosed herewith for filing in the above-captioned matters, please find copies of the following storage agreements:

1. STORAGE AGREEMENT, SCS #1 BROOM CREEK – SECURE GEOLOGIC STORAGE, MERCER, MORTON, & OLIVER COUNTIES, NORTH DAKOTA;
2. STORAGE AGREEMENT, SCS #2 BROOM CREEK – SECURE GEOLOGIC STORAGE, MERCER & OLIVER COUNTIES, NORTH DAKOTA; and
3. STORAGE AGREEMENT, SCS #3 BROOM CREEK – SECURE GEOLOGIC STORAGE, OLIVER COUNTY, NORTH DAKOTA.

Should you have any questions, please advise.

Sincerely,

LAWRENCE BENDER

LB/tjg
Enclosures
#82133072v1

cc: Mr. Wade Boeshans *via e-mail* (w/enc.)

STORAGE AGREEMENT
SCS #1 BROOM CREEK – SECURE GEOLOGIC STORAGE
MERCER, MORTON, & OLIVER COUNTIES, NORTH DAKOTA

STORAGE AGREEMENT
SCS #1 BROOM CREEK – SECURE GEOLOGIC STORAGE
MERCER, MORTON, & OLIVER COUNTIES, 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 it 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 (NDIC) acting by and through the Department of Mineral Resources.

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 29,444.72 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, easement, 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 Opeche/Spearfish (Upper Confining Zone), Broom Creek (Injection Zone), and Amsden (Lower Confining Zone) Formation(s) and which are defined as identified by the well logging suite performed at one stratigraphic well, the Milton Flemmer 1 well (NDIC File No. 38594) located in the NW¼ of the NE¼, Section 35, Township 141 North, Range 88 West, Mercer County, North Dakota. The Storage Reservoir is defined as the stratigraphic interval from below the top of the Opeche/Spearfish Formation found at a depth of 5,587 feet below the Kelly Bushing, to above the base of the Amsden Formation, found at a depth of 6,421 feet below the Kelly Bushing, as identified by the Array Induction Gamma log run in the Milton Flemmer 1 well. The logging suite included triple combo (gamma ray [GR], density porosity, and resistivity), caliper, spectral GR, combinable magnetic resonance (CMR), elemental capture spectroscopy (ESC), dipole sonic including four-arm caliper and inclinometer, and an image log. Further, the acquired logs were used to pick formation top depths and interpret lithology, petrophysical properties, and time-to-depth shifting of seismic data obtained from three 3D seismic surveys and one 5-mile long 2D seismic line covering an area totaling 208 miles in and around the Milton Flemmer 1 stratigraphic well. Formation top depths were picked from the top of the Pierre Formation to the base of the Amsden Formation. The average depth of the top of the Opeche/Spearfish Formation (Upper Confining Zone) across the storage facility area is 5,464 total vertical depth (TVD). The average depth of the base of the Amsden Formation (Lower Confining

Zone) across the storage facility area is 6,270 feet TVD. The average thickness of the Storage Reservoir across the storage facility area is 806 feet.

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."

1.19 **Transfer Storage Facility** has the meaning given such term in Section 3.7 of this Agreement.

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 SCS #1 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 SCS #1 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 (a "Transfer Storage Facility"), *provided that*, the Pore Space ownership between the Storage Facility and Transfer Storage Facility is common.

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 Transfer Storage Facility, *provided that,* the Pore Space ownership between the Storage Facility and Transfer Storage Facility is common.

3.9 **Royalty Payments Upon Transfer.** The transfer or receipt of Storage Substances to or from a Transfer Storage Facility in accordance with Section 3.7 and Section 3.8 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.

3.10 **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.

3.11 **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.** Summit Carbon Storage #1, 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. Subject to Section 3.9, 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 to 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 up to an amount sufficient to defray the costs of such payment or redemption; *provided* that 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 their 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 **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

Summit Carbon Storage #1, LLC

By:_________________________________
[Name]
Its: [Title]

#81617907v1

EXHIBIT A

Tract Map

Attached to and made part of the Storage Agreement
SCS #1 Broom Creek – Secure Geological Storage
Mercer, Morton, & Oliver Counties, North Dakota

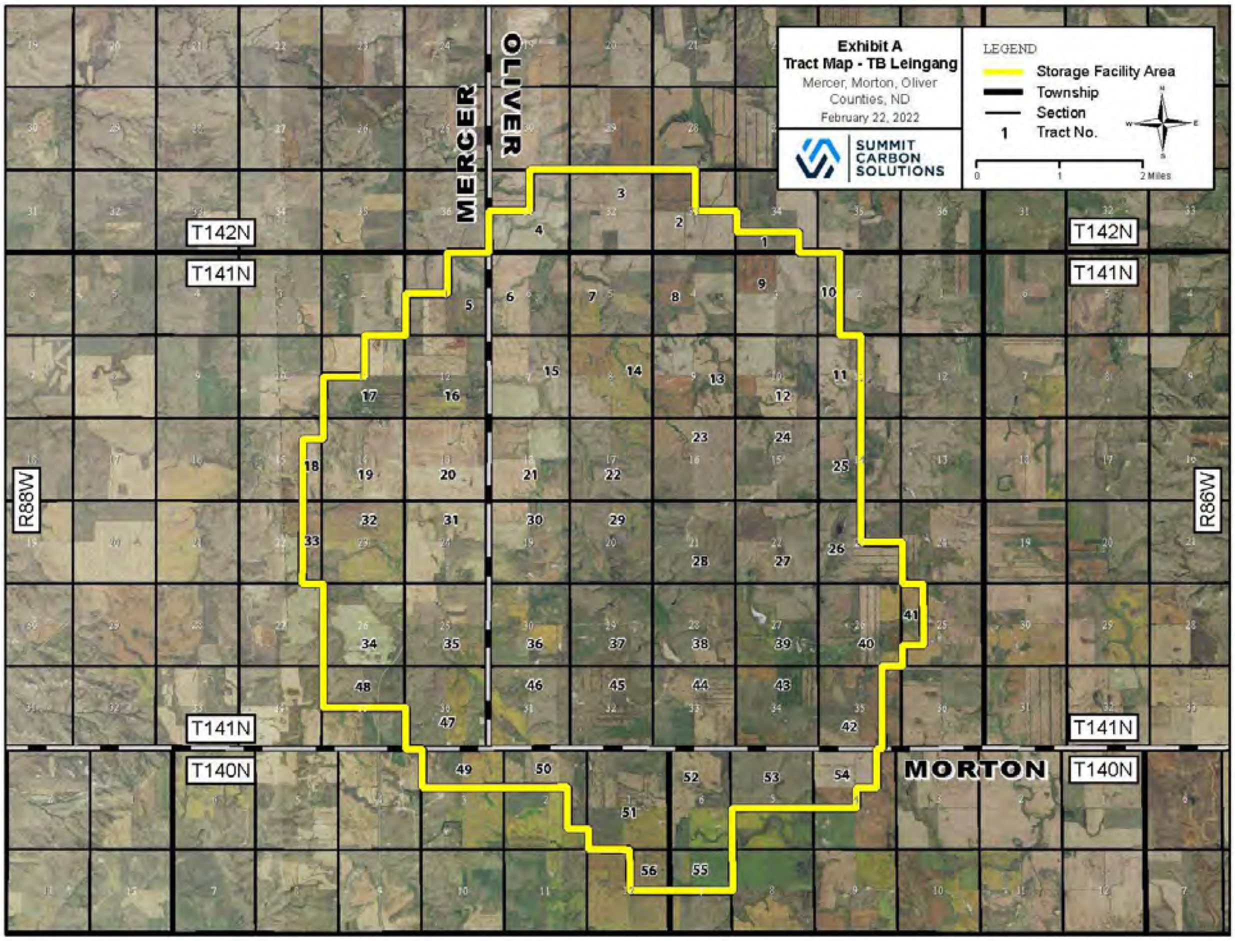


EXHIBIT B

Tract Summary

Attached to and made part of the Storage Agreement
SCS #1 Broom Creek – Secure Geological Storage
Mercer, Morton & Oliver Counties, North Dakota

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
1	Section 34-T142N-R87W	120	Gerald R. Skalsky	40.0000	33.33333333%	0.13584779%
			Greg Skalsky	40.0000	33.33333333%	0.13584779%
			Carla R. Lloyd & Willard E. Lloyd, wife & husband, as Joint Tenants	40.0000	33.33333333%	0.13584779%
2	Section 33-T142N-R87W	480	Edward Weiand, Life Estate	480.0000	100.00000000%	1.63017342%
			James Weiand, Remainderman	0.0000	0.00000000%	0.00000000%
3	Section 32-T142N-R87W	640	Lionel Doll & Kathy Doll, as Joint Tenants	160.0000	25.00000000%	0.54339114%
			Robert Schutt & Alberta E. Schutt, Trustees, or their successors in trust, under the Robert Schutt and Alberta E. Schutt Living Trust, dated December 7, 2015, and any amendments thereto	160.0000	25.00000000%	0.54339114%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			Edward Weiand, Life Estate	240.0000	37.50000000%	0.81508671%
			James Weiand, Remainderman	0.0000	0.00000000%	0.00000000%
			Gerald R. Skalsky	80.0000	12.50000000%	0.27169557%
4	Section 31-T142N-R87W	477.33	Kelly James Kessler & Kimberly Ann Kessler, as Trustees of the Kelly James Kessler Revocable Trust under Agreement dated 10/07/2009	317.3300	66.48021285%	1.07771444%
			Robb M. Moore & Heidi K. Moore, husband & wife, as Joint Tenants	160.0000	33.51978715%	0.54339114%
5	Section 01-T141N-R88W	479.94	Stephen Kessler & Leah Kessler, as Joint Tenants	60.0000	12.50156270%	0.20377168%
			Diana Schulz & Clyde Schulz, wife & husband as Joint Tenants	100.0000	20.83593783%	0.33961946%
			Larry Flemmer, aka Larry L. Flemmer	159.9400	33.32499896%	0.54318737%
			Keith G. Kessler & Deanna A. Kessler, as Joint Tenants	160.0000	33.33750052%	0.54339114%
6	Section 06-T141N-R87W	633.76	Stanley M. Flemmer & Ginger M. Flemmer, husband & wife, as Joint Tenants	159.8300	25.21932593%	0.54281379%
			Larry Flemmer, aka Larry L. Flemmer	313.9300	49.53452411%	1.06616738%

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
			Wayne Cline & Kathy Cline, husband & wife, as Joint Tenants	160.0000	25.24614996%	0.54339114%
7	Section 05-T141N-R87W	639.65	Edward Weiand, Life Estate	159.8400	24.98866568%	0.54284775%
			James Weiand, Remainderman	0.0000	0.00000000%	0.00000000%
			Clinton H. Redmann	159.8100	24.98397561%	0.54274586%
			Addriene D. Hafner, Trustee of the Addriene D. Hafner Revocable Living Trust U/I/D July 10, 2003	320.0000	50.02735871%	1.08678228%
8	Section 04-T141N-R87W	638.64	JoAnne Skalsky, Life Estate	318.6400	49.89352374%	1.08216346%
			Kimberly Delabarre, Remainderman	0.0000	0.00000000%	0.00000000%
			Lana Erasmus, Remainderman	0.0000	0.00000000%	0.00000000%
			Tanya Doe, Remainderman	0.0000	0.00000000%	0.00000000%
			Heather Horning, Remainderman	0.0000	0.00000000%	0.00000000%
			David L. Skalsky & Carol J. Skalsky, husband & wife, as Joint Tenants	70.5600	11.04847802%	0.23963549%
			Leonard Hueske & Mary Hueske, husband & wife, as Joint Tenants	70.5600	11.04847802%	0.23963549%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			Glen C. Lennick & Wanda J. Lennick, husband & wife, as Joint Tenants	160.0000	25.05323813%	0.54339114%
			Paul R. Metz & Christine E. Metz, husband & wife, as Joint Tenants	18.8800	2.95628210%	0.06412015%
9	Section 03-T141N-R87W	638.62	Deborah A. Schlecht & Wayne R. Schlecht, wife & husband, as Joint Tenants	99.8300	15.63214431%	0.33904211%
			Carla R. Lloyd & Willard E. Lloyd, wife & husband, as Joint Tenants	59.7100	9.34984811%	0.20278678%
			Kimberly M. Montoya & Javier Montoya, Trustees, or their successors in trust, under the Kimberly M. Montoya Living Trust, dated November 27, 2018, and any amendments thereto	79.5400	12.45498105%	0.27013332%
			Marvin Fiest & Karen Fiest, husband & wife, as Joint Tenants, Life Estate	79.5400	12.45498105%	0.27013332%
			Amber Myhre, Remainderman	0.0000	0.00000000%	0.00000000%
			Nicole Johnson, Remainderman	0.0000	0.00000000%	0.00000000%

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
			Kristen Fiest, Remainderman	0.0000	0.00000000%	0.00000000%
			David L. Skalsky & Carol J. Skalsky, husband & wife, as Joint Tenants	80.0000	12.52701137%	0.27169557%
			Leonard Hueske & Mary Hueske, husband & wife, as Joint Tenants	80.0000	12.52701137%	0.27169557%
			Glen C. Lennick & Wanda J. Lennick, husband & wife, as Joint Tenants	160.0000	25.05402274%	0.54339114%
10	Section 02-T141N-R87W	159.9	Keith C. Unruh, aka Keith Clayton Unruh, aka Keith Unruh	159.9000	100.00000000%	0.54305152%
11	Section 11-T141N-R87W	320	Gaylen G. Lennick & Koni R. Lennick, husband & wife, as Joint Tenants	320.0000	100.00000000%	1.08678228%
12	Section 10-T141N-R87W	640	Glen C. Lennick & Wanda J. Lennick, husband & wife, as Joint Tenants	240.0000	37.50000000%	0.81508671%
			Jean J. Hoepfner & Debra D. Hoepfner, husband & wife, as Joint Tenants	200.0000	31.25000000%	0.67923893%
			Delaphine Schafer (Appears Deceased)	160.0000	25.00000000%	0.54339114%
			Mary Winckler (nka Mary Winckler-Beierlein)	40.0000	6.25000000%	0.13584779%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
13	Section 09-T141N-R87W	640	Glen C. Lennick & Wanda J. Lennick, husband & wife, as Joint Tenants	160.0000	25.00000000%	0.54339114%
			David L. Skalsky & Carol J. Skalsky, husband & wife, as Joint Tenants	80.0000	12.50000000%	0.27169557%
			Leonard Hueske & Mary Hueske, husband & wife, as Joint Tenants	80.0000	12.50000000%	0.27169557%
			Glynn R. Haag & Dianne D. Haag, Co-Trustees of the Haag Family Trust	160.0000	25.00000000%	0.54339114%
			Jean J. Hoepfner & Debra D. Hoepfner, husband & wife, as Joint Tenants	160.0000	25.00000000%	0.54339114%
14	Section 08-T141N-R87W	640	Darwin Huber & Susan E. Huber, husband & wife, as Joint Tenants, Life Estate	360.0000	56.25000000%	1.22263007%
			Daryl D. Huber, Remainderman	0.0000	0.00000000%	0.00000000%
			Darren D. Huber, Remainderman	0.0000	0.00000000%	0.00000000%
			Jeffrey Schutt	160.0000	25.00000000%	0.54339114%
			Jason J. Pulver & Melanee L. Pulver, as Joint Tenants	120.0000	18.75000000%	0.40754336%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
15	Section 07-T141N-R87W	636.04	Jeffrey Schutt, aka Jeffrey J. Schutt	160.0000	25.15565059%	0.54339114%
			Jason J. Pulver & Melanee L. Pulver, as Joint Tenants	157.6700	24.78932143%	0.53547801%
			Terrence M. Leingang, aka Terry Leingang and Beverly J. Leingang, husband & wife, Life Estate	318.3700	50.05502799%	1.08124648%
			Adrienne Arndt, Remainderman	0.0000	0.00000000%	0.00000000%
			Brandi Mittleider, Remainderman	0.0000	0.00000000%	0.00000000%
			Dylan Leingang, Remainderman	0.0000	0.00000000%	0.00000000%
16	Section 12-T141N-R88W	640	Keith G. Kessler & Deanna A. Kessler, as Joint Tenants	197.6900	30.88906250%	0.67139372%
			Hayden Kessler & Megan Kessler, as Joint Tenants	2.3100	0.36093750%	0.00784521%
			Kelly James Kessler & Kimberly Ann Kessler, as Trustees of the Kelly James Kessler Revocable Trust under Agreement dated 10/07/2009	60.0000	9.37500000%	0.20377168%
			Diana Schulz & Clyde Schulz, wife & husband as Joint Tenants	120.0000	18.75000000%	0.40754336%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			Kim K. Kessler & Trisha L. Kessler, as Trustees of the Kim K. Kessler and Trisha L. Kessler Living Trust dated November 30, 2023	60.0000	9.37500000%	0.20377168%
			Larry Flemmer, aka Larry L. Flemmer	200.0000	31.25000000%	0.67923893%
17	Section 11-T141N-R88W	480	Diana Schulz & Clyde Schulz, wife & husband as Joint Tenants	80.0000	16.66666667%	0.27169557%
			Corey M. Voegele & Roxanne Voegele, husband & wife, as Joint Tenants	80.0000	16.66666667%	0.27169557%
			Larry Flemmer, aka Larry L. Flemmer	320.0000	66.66666667%	1.08678228%
18	Section 15-T141N-R88W	120	Kim K. Kessler & Trisha L. Kessler, as Trustees of the Kim K. Kessler and Trisha L. Kessler Living Trust dated November 30, 2023	120.0000	100.00000000%	0.40754336%
19	Section 14-T141N-R88W	640	Kim K. Kessler & Trisha L. Kessler, as Trustees of the Kim K. Kessler and Trisha L. Kessler Living Trust dated November 30, 2023	320.0000	50.00000000%	1.08678228%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			Kelly James Kessler & Kimberly Ann Kessler, as Trustees of the Kelly James Kessler Revocable Trust under Agreement dated 10/07/2009	320.0000	50.00000000%	1.08678228%
20	Section 13-T141N-R88W	640	Daniel E. Sipes & Esther L. Sipes as Trustees of the Sipes Family Trust U/A Dated 5/11/05	373.0000	58.28125000%	1.26678060%
			Dean Gerving	133.5000	20.85937500%	0.45339198%
			Glenn Gerving	133.5000	20.85937500%	0.45339198%
21	Section 18-T141N-R87W	637.72	Terrence M. Leingang, aka Terry Leingang and Beverly J. Leingang, husband & wife, Life Estate	160.0000	25.08938092%	0.54339114%
			Adrienne Arndt, Remainderman	0.0000	0.00000000%	0.00000000%
			Brandi Mittleider, Remainderman	0.0000	0.00000000%	0.00000000%
			Dylan Leingang, Remainderman	0.0000	0.00000000%	0.00000000%
			Keith G. Kessler and Deanna A. Kessler, husband & wife, as Joint Tenants	158.7900	24.89964248%	0.53928175%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			Jason J. Pulver & Melanee L. Pulver, as Joint Tenants	318.9300	50.01097660%	1.08314835%
22	Section 17-T141N-R87W	640	Clinton H. Redmann	160.0000	25.00000000%	0.54339114%
			Jeffrey S. Biesterfeld and Jessica J. Pulver Biesterfeld, as Joint Tenants	7.7900	1.21718750%	0.02645636%
			Jason J. Pulver & Melanee L. Pulver, as Joint Tenants	472.2100	73.78281250%	1.60371707%
			Jean P. Pulver, aka Penny Pulver, Contract for Deed Seller	0.0000	0.00000000%	0.00000000%
23	Section 16-T141N-R87W	640	Keith G. Kessler and Deanna A. Kessler, husband & wife, as Joint Tenants	480.0000	75.00000000%	1.63017342%
			Hayden Kessler & Megan Kessler, as Joint Tenants	160.0000	25.00000000%	0.54339114%
24	Section 15-T141N-R87W	640	Glen C. Lennick & Wanda J. Lennick, husband & wife, as Joint Tenants	160.0000	25.00000000%	0.54339114%
			Keith Kessler	280.0000	43.75000000%	0.95093450%
			Clinton H. Redmann	160.0000	25.00000000%	0.54339114%
			Marlene M. Redmann, Life Estate	40.0000	6.25000000%	0.13584779%
			Donald L. Redmann	0.0000	0.00000000%	0.00000000%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			Michele Seaman	0.0000	0.00000000%	0.00000000%
			Pamela Dugan	0.0000	0.00000000%	0.00000000%
25	Section 14-T141N-R87W	320	Glen C. Lennick & Wanda J. Lennick, husband & wife, as Joint Tenants	200.0000	62.50000000%	0.67923893%
			Marlene M. Redmann, Life Estate	120.0000	37.50000000%	0.40754336%
			Donald L. Redmann	0.0000	0.00000000%	0.00000000%
			Michele Seaman	0.0000	0.00000000%	0.00000000%
			Pamela Dugan	0.0000	0.00000000%	0.00000000%
26	Section 23-T141N-R87W	480	Jerome Voegele, aka Jerome G. Voegele & Yvonne Voegele, husband & wife, as Joint Tenants Life Estate	480.0000	100.00000000%	1.63017342%
			Brent Voegele, Remainderman	0.0000	0.00000000%	0.00000000%
			Jason Voegele, Remainderman	0.0000	0.00000000%	0.00000000%
			Jodi Wos, Remainderman	0.0000	0.00000000%	0.00000000%
27	Section 22-T141N-R87W	640	Marlene M. Redmann, Life Estate	240.0000	37.50000000%	0.81508671%
			Donald L. Redmann	0.0000	0.00000000%	0.00000000%
			Michele Seaman	0.0000	0.00000000%	0.00000000%
			Pamela Dugan	0.0000	0.00000000%	0.00000000%
			Delma Renner	160.0000	25.00000000%	0.54339114%

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
			Keith G. Kessler and Deanna A. Kessler, husband & wife, as Joint Tenants	160.0000	25.00000000%	0.54339114%
			Mary Winckler (nka Mary Winckler-Beierlein)	80.0000	12.50000000%	0.27169557%
28	Section 21-T141N-R87W	640	Keith G. Kessler and Deanna A. Kessler, husband & wife, as Joint Tenants	480.0000	75.00000000%	1.63017342%
			Terrence M. Leingang, aka Terry Leingang and Beverly J. Leingang, husband & wife, Life Estate	158.0000	24.68750000%	0.53659875%
			Adrienne Arndt, Remainderman	0.0000	0.00000000%	0.00000000%
			Brandi Mittleider, Remainderman	0.0000	0.00000000%	0.00000000%
			Dylan Leingang, Remainderman	0.0000	0.00000000%	0.00000000%
			Dylan Leingang & Miranda Leingang, as Joint Tenants	2.0000	0.31250000%	0.00679239%
29	Section 20-T141N-R87W	640	Clinton Redmann	400.0000	62.50000000%	1.35847785%
			Lance Johnson	80.0000	12.50000000%	0.27169557%
			Rosalie R. Wilmes & Duane L. Wilmes, wife & husband, as Joint Tenants, Life Estate	40.0000	6.25000000%	0.13584779%

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
			Da Lynn Twigg, Remainderman	0.0000	0.00000000%	0.00000000%
			Tracy Wilmes, Remainderman	0.0000	0.00000000%	0.00000000%
			Rowene J. Skalsky, Life Estate	40.0000	6.25000000%	0.13584779%
			Brenda Owen, fka Brenda Ross, Remainderman	0.0000	0.00000000%	0.00000000%
			David Skalsky, Remainderman	0.0000	0.00000000%	0.00000000%
			Cheryl Weigel, Remainderman	0.0000	0.00000000%	0.00000000%
			Sandra McKay, Remainderman	0.0000	0.00000000%	0.00000000%
			Rodney Skalsky, Remainderman	0.0000	0.00000000%	0.00000000%
			Kirk E. Maize, aka Kirk Maize, and Linda L. Maize, aka Linda Maize, husband & wife, as Joint Tenants, a Life Estate	80.0000	12.50000000%	0.27169557%
			Allen Maize, Remainderman	0.0000	0.00000000%	0.00000000%
30	Section 19-T141N-R87W	638.48	Clinton Redmann	390.5300	61.16558075%	1.32631589%
			Bryant H. Voegele & Lora Voegele, husband & wife, as Joint Tenants	238.9500	37.42482145%	0.81152071%
			Lance Johnson	9.0000	1.40959779%	0.03056575%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
31	Section 24-T141N-R88W	640	Bryant H. Voegele & Lora Voegele, husband & wife, as Joint Tenants	422.6100	66.03281250%	1.43526581%
			Dean Gerving	100.0000	15.62500000%	0.33961946%
			Glenn Gerving & Lisa Gerving, husband & wife, as Joint Tenants	100.0000	15.62500000%	0.33961946%
			Leslie Ferguson	17.3900	2.71718750%	0.05905982%
32	Section 23-T141N-R88W	640	Keith R. Unruh and Stacey Unruh, husband & wife, as Joint Tenants	320.0000	50.00000000%	1.08678228%
			Pearl R. Voegele, Life Estate	320.0000	50.00000000%	1.08678228%
			Linda Jean Stensrud, Remainderman	0.0000	0.00000000%	0.00000000%
33	Section 22-T141N-R88W	160	Kelly James Kessler & Kimberly Ann Kessler, as Trustees of the Kelly James Kessler Revocable Trust under Agreement dated 10/07/2009	60.0000	37.50000000%	0.20377168%
			Kim K. Kessler & Trisha L. Kessler, as Trustees of the Kim K. Kessler and Trisha L. Kessler Living Trust dated November 30, 2023	40.0000	25.00000000%	0.13584779%
			Michael Kessler	20.0000	12.50000000%	0.06792389%
			Lavern J. Schilling, Life Estate	40.0000	25.00000000%	0.13584779%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			Glenn Schilling, Remainderman	0.0000	0.00000000%	0.00000000%
34	Section 26-T141N-R88W	640	Debra Koenig & Rodney Koenig	80.0000	12.50000000%	0.27169557%
			Lavern J. Schilling, Life Estate	160.0000	25.00000000%	0.54339114%
			Debra Koenig, Remainderman	0.0000	0.00000000%	0.00000000%
			Pearl R. Voegele, Life Estate	80.0000	12.50000000%	0.27169557%
			Linda Jean Stensrud, Remainderman	0.0000	0.00000000%	0.00000000%
			Mund Family Enterprises, LLP, Ervin Mund, as Managing Member	320.0000	50.00000000%	1.08678228%
35	Section 25-T141N-R88W	640	Bryant H. Voegele & Lora Voegele, husband & wife, as Joint Tenants	120.0000	18.75000000%	0.40754336%
			Clinton H. Redmann	200.0000	31.25000000%	0.67923893%
			Pearl R. Voegele, Life Estate	320.0000	50.00000000%	1.08678228%
			Cynthia Martin, Remainderman	0.0000	0.00000000%	0.00000000%
36	Section 30-T141N-R87W	639.32	Rosalie R. Wilmes & Duane L. Wilmes, wife & husband, as Joint Tenants, Life Estate	80.0000	12.51329538%	0.27169557%
			Da Lynn Twigg, Remainderman	0.0000	0.00000000%	0.00000000%

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
			Tracy Wilmes, Remainderman	0.0000	0.00000000%	0.00000000%
			Rowene J. Skalsky, Life Estate	80.0000	12.51329538%	0.27169557%
			Brenda Owen, fka Brenda Ross, Remainderman	0.0000	0.00000000%	0.00000000%
			David Skalsky, Remainderman	0.0000	0.00000000%	0.00000000%
			Cheryl Weigel, Remainderman	0.0000	0.00000000%	0.00000000%
			Sandra McKay, Remainderman	0.0000	0.00000000%	0.00000000%
			Rodney Skalsky, Remainderman	0.0000	0.00000000%	0.00000000%
			Lance A. Gartner & Anissa M. Gartner, husband & wife, as Joint Tenants	319.9000	50.03753989%	1.08644266%
			Pearl R. Voegele, Life Estate	159.4200	24.93586936%	0.54142135%
			Cynthia Martin, Remainderman	0.0000	0.00000000%	0.00000000%
37	Section 29-T141N-R87W	640	Rosalie R. Wilmes & Duane L. Wilmes, wife & husband, as Joint Tenants, Life Estate	240.0000	37.50000000%	0.81508671%
			Da Lynn Twigg, Remainderman	0.0000	0.00000000%	0.00000000%
			Tracy Wilmes, Remainderman	0.0000	0.00000000%	0.00000000%

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
			Rowene J. Skalsky, Life Estate	240.0000	37.50000000%	0.81508671%
			Brenda Owen, fka Brenda Ross, Remainderman	0.0000	0.00000000%	0.00000000%
			David Skalsky, Remainderman	0.0000	0.00000000%	0.00000000%
			Cheryl Weigel, Remainderman	0.0000	0.00000000%	0.00000000%
			Sandra McKay, Remainderman	0.0000	0.00000000%	0.00000000%
			Rodney Skalsky, Remainderman	0.0000	0.00000000%	0.00000000%
			William K. Schultz & Louise M. Schultz, Trustees, or their successors in trust, under the William and Louise Schultz Living Trust dated September 10, 1997	160.0000	25.00000000%	0.54339114%
38	Section 28-T141N-R87W	640	Mary Winckler (nka Mary Winckler-Beierlein)	480.0000	75.00000000%	1.63017342%
			Gregory J. Voegele and Jeanne M. Voegele, husband & wife, as Joint Tenants	120.0000	18.75000000%	0.40754336%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			James A. Swenson, aka James Swenson, aka Jim Swenson & Darlene A. Swenson, aka Darlene Swenson, husband & wife, Life Estate	40.0000	6.25000000%	0.13584779%
			Trent T. Martin & Dawn Martin, as Joint Tenants, Remainderman	0.0000	0.00000000%	0.00000000%
39	Section 27-T141N-R87W	640	Delma Renner	160.0000	25.00000000%	0.54339114%
			Robert L. Martin, Life Estate	320.0000	50.00000000%	1.08678228%
			Robert L. Martin, Trustee of the RM Martin Trust, under trust agreement dated May 31, 2002, Remainderman	0.0000	0.00000000%	0.00000000%
			Gregory J. Voegele and Jeanne M. Voegele, husband & wife, as Joint Tenants	160.0000	25.00000000%	0.54339114%
40	Section 26-T141N-R87W	640	Andrew Peltz	80.0000	12.50000000%	0.27169557%
			Daniel Peltz	80.0000	12.50000000%	0.27169557%
			Jerome Voegele, aka Jerome G. Voegele & Yvonne Voegele, husband & wife, as Joint Tenants, Life Estate	160.0000	25.00000000%	0.54339114%
			Brent Voegele, Remainderman	0.0000	0.00000000%	0.00000000%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			Jason Voegele, Remainderman	0.0000	0.00000000%	0.00000000%
			Jodi Wos, Remainderman	0.0000	0.00000000%	0.00000000%
			Gregory J. Voegele and Jeanne M. Voegele, husband & wife, as Joint Tenants	312.0900	48.76406250%	1.05991838%
			Teasha Voegele (nka Teasha Bettenhausen)	7.9100	1.23593750%	0.02686390%
41	Section 25-T141N-R87W	120	Karen Boehm, aka Karen D. Boehm, Life Estate	35.0000	29.16666700%	0.11886681%
			Renee Doll and Sandra Kunz, Trustee of the Karen D. Boehm Family Property Trust, created under a declaration of trust, dated January 26, 2021, Remainderman	0.0000	0.00000000%	0.00000000%
			Richard T. Kruger & Richard E. Kruger, as Joint Tenants	30.0000	25.00000000%	0.10188584%
			Keith C. Kruger	10.0000	8.33333300%	0.03396194%
			Jill R. Pacini	8.3333	6.94444400%	0.02830162%
			Gayle M. Williams	8.3333	6.94444400%	0.02830162%
			David C. Henke	8.3333	6.94444400%	0.02830162%
			Russel C. Kruger	5.0000	4.16666700%	0.01698097%
			Kyle Grindahl	5.0000	4.16666700%	0.01698097%
			Kevin Grindahl	5.0000	4.16666700%	0.01698097%
			Kelly Grindahl	5.0000	4.16666700%	0.01698097%

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
42	Section 35-T141N-R87W	480	Gary L. Hicks, aka Gary Hicks and Carol L. Hicks, aka Carol Hicks, husband & wife, Life Estate	320.0000	66.66666667%	1.08678228%
			Keith G. and Shannon D. Becher as Trustees of the Amended and Restated Keith G. and Shannon D. Becher Family Revocable Trust Dated May 5, 1998 and as Amended and Restated April 24, 2002, Remainderman	0.0000	0.00000000%	0.00000000%
			Andrew L. Peltz	80.0000	16.66666667%	0.27169557%
			Daniel Peltz	80.0000	16.66666667%	0.27169557%
43	Section 34-T141N-R87W	640	Gregory J. Voegele and Jeanne M. Voegele, husband & wife, as Joint Tenants	300.0000	46.87500000%	1.01885839%
			Jerome Voegele, aka Jerome G. Voegele & Yvonne Voegele, husband & wife, as Joint Tenants, Life Estate	340.0000	53.12500000%	1.15470617%
			Brent Voegele, Remainderman	0.0000	0.00000000%	0.00000000%
			Jason Voegele, Remainderman	0.0000	0.00000000%	0.00000000%
			Jodi Wos, Remainderman	0.0000	0.00000000%	0.00000000%

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
44	Section 33-T141N-R87W	640	Gregory J. Voegele and Jeanne M. Voegele, husband & wife, as Joint Tenants	160.0000	25.00000000%	0.54339114%
			William K. Schultz & Louise M. Schultz, Trustees, or their successors in trust, under the William and Louise Schultz Living Trust dated September 10, 1997	160.0000	25.00000000%	0.54339114%
			Glen Beierlein, Life Estate	40.0000	6.25000000%	0.13584779%
			James Beierlein & Mary J. Beierlein, as Joint Tenants, Remaindermen	0.0000	0.00000000%	0.00000000%
			James Beierlein & Mary J. Beierlein, as Joint Tenants, Life Estate	40.0000	6.25000000%	0.13584779%
			Jamie Beierlein, Remainderman	0.0000	0.00000000%	0.00000000%
			Jessica Miller, Remainderman	0.0000	0.00000000%	0.00000000%
			Amanda Gustin, Remainderman	0.0000	0.00000000%	0.00000000%
			Roderick (Rick) Schirado	30.0000	4.68750000%	0.10188584%
			Allen Schirado	30.0000	4.68750000%	0.10188584%
			Timothy Schirado	30.0000	4.68750000%	0.10188584%
			Bruce Schirado	30.0000	4.68750000%	0.10188584%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			Russell Schirado	30.0000	4.68750000%	0.10188584%
			Bryan Schirado	30.0000	4.68750000%	0.10188584%
			Kyle Schirado	30.0000	4.68750000%	0.10188584%
			Corrine Vatnsdal	30.0000	4.68750000%	0.10188584%
45	Section 32-T141N-R87W	640	William K. Schultz & Louise M. Schultz, Trustees, or their successors in trust, under the William and Louise Schultz Living Trust dated September 10, 1997	160.0000	25.00000000%	0.54339114%
			Roderick (Rick) Schirado	40.0000	6.25000000%	0.13584779%
			Allen Schirado	40.0000	6.25000000%	0.13584779%
			Timothy Schirado	40.0000	6.25000000%	0.13584779%
			Bruce Schirado	40.0000	6.25000000%	0.13584779%
			Russell Schirado	40.0000	6.25000000%	0.13584779%
			Bryan Schirado	40.0000	6.25000000%	0.13584779%
			Kyle Schirado	40.0000	6.25000000%	0.13584779%
			Corrine Vatnsdal	40.0000	6.25000000%	0.13584779%
			Lynnette Schirado	160.0000	25.00000000%	0.54339114%
46	Section 31-T141N-R87W	639.84	Lance A. Gartner & Anissa M. Gartner, husband & wife, as Joint Tenants	159.8800	24.98749687%	0.54298360%
			Bernard L. Weinhardt	159.9600	25.00000000%	0.54325529%
			Roderick (Rick) Schirado	40.0000	6.25156289%	0.13584779%
			Allen Schirado	40.0000	6.25156289%	0.13584779%
			Timothy Schirado	40.0000	6.25156289%	0.13584779%

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
			Bruce Schirado	40.0000	6.25156289%	0.13584779%
			Russell Schirado	40.0000	6.25156289%	0.13584779%
			Bryan Schirado	40.0000	6.25156289%	0.13584779%
			Kyle Schirado	40.0000	6.25156289%	0.13584779%
			Corrine Vatnsdal	40.0000	6.25156289%	0.13584779%
47	Section 36-T141N-R88W	640	Michael Rogstad	160.0000	25.00000000%	0.54339114%
			Pearl R. Voegele, Life Estate	160.0000	25.00000000%	0.54339114%
			Cynthia Martin, Remainderman	0.0000	0.00000000%	0.00000000%
			Lance A. Gartner & Anissa M. Gartner, husband & wife, as Joint Tenants	120.0000	18.75000000%	0.40754336%
			Minnesota Power, a Division of Allete, Inc., a MN corporation	30.0000	4.68750000%	0.10188584%
			Glen Ullin Energy Center, LLC, a Delaware limited liability company c/o ALLETE Clean Energy	10.0000	1.56250000%	0.03396195%
			State of North Dakota	160.0000	25.00000000%	0.54339114%
48	Section 35-T141N-R88W	320	Larry J. Steffen & Lorie L. Steffen, Life Estate	160.0000	50.00000000%	0.54339114%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			Angela Erickson & Jason Erickson, as Joint Tenants, Remaindermen	0.0000	0.00000000%	0.00000000%
			Scott Steffen & Amber Stefffen, as Joint Tenants, Remaindermen	0.0000	0.00000000%	0.00000000%
			Sandra M. Schnaidt & Larry L. Schnaidt, wife & husband, as Joint Tenants	160.0000	50.00000000%	0.54339114%
49	Section 03-T140N-R88W	298.72	Richard M. Schirado & Deborah Schirado, as Joint Tenants, Life Estate	149.0500	49.89622389%	0.50620281%
			Brandon Schirado, Remainderman	0.0000	0.00000000%	0.00000000%
			Michael Schirado, Remainderman	0.0000	0.00000000%	0.00000000%
			Nathan Schirado, Remainderman	0.0000	0.00000000%	0.00000000%
			Miranda Bergquist, Remainderman	0.0000	0.00000000%	0.00000000%
			Viola M. Weinhardt, Life Estate	149.6700	50.10377611%	0.50830845%
			Linda Steiger, Remainderman	0.0000	0.00000000%	0.00000000%
			Bernard Weinhardt, Remainderman	0.0000	0.00000000%	0.00000000%
			Julie Kramer, Remainderman	0.0000	0.00000000%	0.00000000%
50	Section 2-T140N-R88W	378	Glen Beierlein, Life Estate	77.2350	20.43253968%	0.26230509%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			James Beierlein & Mary J. Beierlein, as Joint Tenants, Remaindermen	0.0000	0.00000000%	0.00000000%
			James Beierlein & Mary J. Beierlein, as Joint Tenants, Life Estate	77.2350	20.43253968%	0.26230509%
			Jamie Beierlein, Remainderman	0.0000	0.00000000%	0.00000000%
			Jessica Miller, Remainderman	0.0000	0.00000000%	0.00000000%
			Amanda Gustin, Remainderman	0.0000	0.00000000%	0.00000000%
			Roderick (Rick) Schirado	18.6250	4.92724868%	0.06325413%
			Allen Schirado	18.6250	4.92724868%	0.06325413%
			Timothy Schirado	18.6250	4.92724868%	0.06325413%
			Bruce Schirado	18.6250	4.92724868%	0.06325413%
			Russell Schirado	18.6250	4.92724868%	0.06325413%
			Bryan Schirado	18.6250	4.92724868%	0.06325413%
			Kyle Schirado	18.6250	4.92724868%	0.06325413%
			Corrine Vatnsdal	18.6250	4.92724868%	0.06325413%
			Viola M. Weinhardt, Life Estate	74.5300	19.71693122%	0.25311839%
			Linda Steiger, Remainderman	0.0000	0.00000000%	0.00000000%
			Bernard Weinhardt, Remainderman	0.0000	0.00000000%	0.00000000%
			Julie Kramer, Remainderman	0.0000	0.00000000%	0.00000000%

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
51	Section 01-T140N-R88W	775.56	Glen Beierlein, Life Estate	387.7800	50.00000000%	1.31697635%
			James Beierlein & Mary J. Beierlein, as Joint Tenants, Remaindermen	0.0000	0.00000000%	0.00000000%
			James Beierlein & Mary J. Beierlein, as Joint Tenants, Life Estate	387.7800	50.00000000%	1.31697635%
			Jamie Beierlein, Remainderman	0.0000	0.00000000%	0.00000000%
			Jessica Miller, Remainderman	0.0000	0.00000000%	0.00000000%
			Amanda Gustin, Remainderman	0.0000	0.00000000%	0.00000000%
52	Section 06-T140N-R87W	575.82	Julianna S. Prescott	191.1300	33.19266437%	0.64911468%
			Jeana J. Phillips, fka Jeana J. Beierlein	191.1300	33.19266437%	0.64911468%
			Glen Beierlein, Life Estate	16.7800	2.91410510%	0.05698815%
			James Beierlein & Mary J. Beierlein, as Joint Tenants, Remaindermen	0.0000	0.00000000%	0.00000000%
			James Beierlein & Mary J. Beierlein, as Joint Tenants, Life Estate	16.7800	2.91410510%	0.05698815%
			Jamie Beierlein, Remainderman	0.0000	0.00000000%	0.00000000%
			Jessica Miller, Remainderman	0.0000	0.00000000%	0.00000000%

Tract No.	Land Description	Total Acres	Owner	Acres Owned	Tract Participation	Storage Facility Participation
			Amanda Gustin, Remainderman	0.0000	0.00000000%	0.00000000%
			Andrew L. Peltz	80.0000	13.89323052%	0.27169557%
			Andrew L. Peltz & Heidi Peltz, husband & wife	80.0000	13.89323052%	0.27169557%
53	Section 05-T140N-R87W	458.2	Darlene A. Swenson	229.1000	50.00000000%	0.77806819%
			Dawn Martin	229.1000	50.00000000%	0.77806819%
54	Section 04-T140N-R87W	304.1	Kevin Opp, aka Kevin M. Opp	224.1000	73.69286419%	0.76108722%
			Andrew L. Peltz	80.0000	26.30713581%	0.27169557%
55	Section 07-T140N-R87W	235.08	Julianna S. Prescott	37.5400	15.96903182%	0.12749315%
			Jeana J. Phillips, fka Jeana J. Beierlein	37.5400	15.96903182%	0.12749315%
			Daryl Winckler, aka Daryl A. Winckler & Brenda Winckler, aka Brenda K. Winckler, husband & wife as Joint Tenants, Life Estate	160.0000	68.06193636%	0.54339114%
			Tanner J. Winckler, Remainderman	0.0000	0.00000000%	0.00000000%
			Tracy Winckler Hulberg, Remainderman	0.0000	0.00000000%	0.00000000%
56	Section 12-T140N-R88W	160	James Beierlein & Mary J. Beierlein, as Joint Tenants, Remaindermen	0.0000	0.00000000%	0.00000000%
			James Beierlein & Mary J. Beierlein, as Joint Tenants, Life Estate	80.0000	50.00000000%	0.27169557%

Tract No.	**Land Description**	**Total Acres**	**Owner**	**Acres Owned**	**Tract Participation**	**Storage Facility Participation**
			Jamie Beierlein, Remainderman	0.0000	0.00000000%	0.00000000%
			Jessica Miller, Remainderman	0.0000	0.00000000%	0.00000000%
			Amanda Gustin, Remainderman	0.0000	0.00000000%	0.00000000%
			Glen Beierlein, Life Estate	80.0000	50.00000000%	0.27169557%
	Total Acres:	**29,444.72**		**29,444.72**	**Total Participation:**	**100.00000000%**

EXHIBIT C

Tract Participation Factors

Attached to and made part of the Storage Agreement
SCS #1 Broom Creek – Secure Geological Storage
Mercer, Morton & Oliver Counties, North Dakota

Tract No.	Land Description	Acres	Tract Participation Factor
1	Section 34-T142N-R87W	120	0.40754336%
2	Section 33-T142N-R87W	480	1.63017342%
3	Section 32-T142N-R87W	640	2.17356456%
4	Section 31-T142N-R87W	477.33	1.62110558%
5	Section 01-T141N-R88W	479.94	1.62996965%
6	Section 06-T141N-R87W	633.76	2.15237231%
7	Section 05-T141N-R87W	639.65	2.17237590%
8	Section 04-T141N-R87W	638.64	2.16894574%
9	Section 03-T141N-R87W	638.62	2.16887782%
10	Section 02-T141N-R87W	159.9	0.54305152%
11	Section 11-T141N-R87W	320	1.08678228%
12	Section 10-T141N-R87W	640	2.17356456%
13	Section 09-T141N-R87W	640	2.17356456%
14	Section 08-T141N-R87W	640	2.17356456%
15	Section 07-T141N-R87W	636.04	2.16011563%
16	Section 12-T141N-R88W	640	2.17356456%
17	Section 11-T141N-R88W	480	1.63017342%
18	Section 15-T141N-R88W	120	0.40754336%
19	Section 14-T141N-R88W	640	2.17356456%
20	Section 13-T141N-R88W	640	2.17356456%
21	Section 18-T141N-R87W	637.72	2.16582124%
22	Section 17-T141N-R87W	640	2.17356456%
23	Section 16-T141N-R87W	640	2.17356456%
24	Section 15-T141N-R87W	640	2.17356456%
25	Section 14-T141N-R87W	320	1.08678228%
26	Section 23-T141N-R87W	480	1.63017342%
27	Section 22-T141N-R87W	640	2.17356456%
28	Section 21-T141N-R87W	640	2.17356456%
29	Section 20-T141N-R87W	640	2.17356456%
30	Section 19-T141N-R87W	638.48	2.16840235%
31	Section 24-T141N-R88W	640	2.17356456%
32	Section 23-T141N-R88W	640	2.17356456%

33	Section 22-T141N-R88W	160	0.54339114%
34	Section 26-T141N-R88W	640	2.17356456%
35	Section 25-T141N-R88W	640	2.17356456%
36	Section 30-T141N-R87W	639.32	2.17125515%
37	Section 29-T141N-R87W	640	2.17356456%
38	Section 28-T141N-R87W	640	2.17356456%
39	Section 27-T141N-R87W	640	2.17356456%
40	Section 26-T141N-R87W	640	2.17356456%
41	Section 25-T141N-R87W	120	0.40754336%
42	Section 35-T141N-R87W	480	1.63017342%
43	Section 34-T141N-R87W	640	2.17356456%
44	Section 33-T141N-R87W	640	2.17356456%
45	Section 32-T141N-R87W	640	2.17356456%
46	Section 31-T141N-R87W	639.84	2.17302117%
47	Section 36-T141N-R88W	640	2.17356456%
48	Section 35-T141N-R88W	320	1.08678228%
49	Section 03-T140N-R88W	298.72	1.01451126%
50	Section 02-T140N-R88W	378	1.28376157%
51	Section 01-T140N-R88W	775.56	2.63395271%
52	Section 06-T140N-R87W	575.82	1.95559679%
53	Section 05-T140N-R87W	458.2	1.55613638%
54	Section 04-T140N-R87W	304.1	1.03278279%
55	Section 07-T140N-R87W	235.08	0.79837743%
56	Section 12-T140N-R88W	160	0.54339114%
Total:		**29,444.72**	**100.00000000%**

EXHIBIT D

Form of Pore Space Lease

Attached to and made part of the Storage Agreement
SCS #1 Broom Creek – Secure Geological Storage
Mercer, Morton & Oliver Counties, 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____, whose address is____, (whether one or more, "Lessor"), and Summit Carbon Storage #1, LLC, a Delaware limited liability company, whose address is 2321 N. Loop Dr., Ames, IA 50010 (whether one or more, "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 and incorporated herein by reference in Exhibit A attached (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 TWENTY-FIVE and NO/100 DOLLARS ($25.00) per acre as a single one-time bonus payment, and an annual rental of Four and No/100 Dollars ($4.00) per acre on or before January 1 of each year of the Initial Term. The annual rental shall increase by TWO percent (2.0%) commencing on January 1, 2026 and on January 1 each year thereafter. The first year's rental has been paid in full, the receipt and sufficiency of which is hereby acknowledged by Lessor. 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 One Hundred and No/100 Dollars ($100.00) 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. Lessee shall pay to Lessor the annual rentals when due throughout the Primary Term; *provided*, *however*, Lessee shall not be liable to Lessor for annual rentals with respect to any portion of the Leased Premises which are or become subject to Permit as set forth in Section 2(b), below.

(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 FIFTY cents ($0.50) 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 royalty shall increase TEN percent (10.0%) on January 1, 2026 and an additional TEN percent (10.0%) every five years thereafter, as outlined on attached Exhibit B. 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 Section 1 shall be used to calculate Lessor's proportionate share. The quantity of CO_2 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 CO_2 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 31st 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 (CO_2) 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 CO_2 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. 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.

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.

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. Favored Nations. If, at any time within the twelve (12) month period following the Effective Date, Lessee enters into a pore space lease agreement with a third party landowner covering any part of Lessee's storage facility ("Third-Party Lease"), and if any of the payments specified in the Third-Party Lease would have been more favorable to Lessor had Lessor executed a lease agreement similar to the Third-Party Lease, then Lessor and Lessee will amend this Lease so that it reflects compensation terms similar to the Third-Party Lease, and Lessee will pay to Lessor the additional compensation, if any, that Lessor would have been paid had Lessor signed a lease agreement similar to the Third-Party Lease. For the purposes of this Section 32, "Lessee's storage facility" shall mean any storage facility (as such term in defined in ch. 38-22 of the North Dakota Century Code) operated by Lessee within a ten (10) mile radius of the Leased Premises which is subject to a permit is issued by the Commission pursuant to ch. 38-22 of the North Dakota Century Code.

33. 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.

34. Insurance. Lessee shall obtain and maintain in force commercial general liability insurance covering the Facilities and Lessee's activities on the Leased Premises at all times during the term of this Lease, with a minimum occurrence and aggregate limit of one million dollars ($1,000,000). Such insurance coverage for the Facilities and Leased Premises may be provided as part of a blanket policy that covers other Facilities or properties as well. Any such policies shall include Lessor as an additional insured. Lessee, or its insurer, shall provide thirty (30) days prior written notice (except ten (10) days for nonpayment of premium) to Lessor of any cancellation. Lessee shall provide Lessor with copies of certificates of insurance evidencing this coverage upon request by Lessor.

IN WITNESS WHEREOF, the Parties have executed this Lease effective for all purposes as of the Effective Date.

LESSOR:

By: ______________________________

Print: ______________________________

By: ______________________________

Print: ______________________________

LESSEE: SUMMIT CARBON STORAGE #1, LLC

By: ______________________________

Print: ______________________________

Its: ______________________________

EXHIBIT A

Leased Premises

EXHIBIT B

Royalty Escalation Provision

This Lease is subject to a Royalty Escalation. The royalty shall increase TEN percent (10.0%) on January 1, 2026, and an additional TEN percent (10.0%) every five years thereafter. For the avoidance of doubt, the royalty to be paid is calculated below:

Date:	Royalty Rate:
Beginning January 1, 2026	$0.550
Beginning January 1, 2031	$0.605
Beginning January 1, 2036	$0.666
Beginning January 1, 2041	$0.733
Beginning January 1, 2046	$0.806
Beginning January 1, 2051	$0.887
Beginning January 1, 2056	$0.976
Beginning January 1, 2061	$1.074
Beginning January 1, 2066	$1.181
Beginning January 1, 2071	$1.299
Beginning January 1, 2076	$1.429

SUMMIT CARBON STORAGE #1, LLC

Dated: ____________________

By: ____________________________________

Print:____________________________________

Its: ____________________________________

TB LEINGANG

UNIT LEGAL DESCRIPTION

OLIVER COUNTY
Township 142 North, Range 87 West
Section 31: Lots 3 (38.84), 4 (38.49) (a/k/a W2SW), E2SW, E2
Section 32: All
Section 33: NW, S2
Section 34: S2SW, SWSE

[Containing 1,717.33 acres]

Township 141 North, Range 87 West
Section 02: Lot 4 (39.90), SWNW, W2SW (a/k/a W2W2)
Section 03: Lots 1 (39.83), 2 (39.71), 3 (39.60), 4 (39.48), S2N2, S2 (a/k/a All)
Section 04: Lots 1 (39.48), 2 (39.60), 3 (39.72), 4 (39.84), S2N2, S2 (a/k/a All)
Section 05: Lots 1 (39.92), 2 (39.92), 3 (39.91), 4 (39.90), S2N2, S2 (a/k/a All)
Section 06: Lots 1 (39.90), 2 (39.93), 3 (39.96), 4 (38.36), 5 (38.45), 6 (38.54), 7 (38.62), S2NE, SENW, E2SW, SE (a/k/a All)
Section 07: Lots 1 (38.75), 2 (38.92), 3 (39.10), 4 (39.27), E2W2, E2 (a/k/a All)
Section 08: All
Section 09: All
Section 10: All
Section 11: W2
Section 14: W2
Section 15: All
Section 16: All
Section 17: All
Section 18: Lots 1 (39.38), 2 (39.41), 3 (39.45), 4 (39.48), E2W2, E2 (a/k/a All)
Section 19: Lots 1 (39.53), 2 (39.59), 3 (39.65), 4 (39.71), E2W2, E2 (a/k/a All)
Section 20: All
Section 21: All
Section 22: All
Section 23: NW, S2
Section 25: W2NW, NWSW
Section 26: All
Section 27: All
Section 28: All
Section 29: All
Section 30: Lots 1 (39.76), 2 (39.81), 3 (39.85), 4 (39.90), E2W2, E2 (a/k/a All)

Section 31: Lots 1 (39.93), 2 (39.95), 3 (39.97), 4 (39.99), E2W2, E2 (a/k/a All)
Section 32: All
Section 33: All
Section 34: All
Section 35: W2, W2E2

[Containing 17,861.97 acres]

MORTON COUNTY
Township 140 North, Range 87 West
Section 04: Lot 2 (74.68) (a/k/a NWNE), Lots 3 (74.70), 4 (74.72), S2NW (a/k/a NW)
Section 05: Lots 1 (74.67), 2 (74.59), 3 (74.51), 4 (74.43), S2N2 (a/k/a N2)
Section 06: Lots 1 (74.47), 2 (74.53), 3 (74.52), 4 (37.66), 5 (37.50), 6 (37.14), S2NE, SE (a/k/a All)
Section 07: Lots 1 (37.25), 2 (37.83), NE (a/k/a N2)

[Containing 1,573.20]

Township 140 North, Range 88 West
Section 01: Lots 1 (74.01), 2 (73.93), 3 (73.85), 4 (73.77), S2N2, S2 (a/k/a All)
Section 02: Lots 1 (74.47), 2 (74.49), 3 (74.51), 4 (74.53) (a/k/a N2N2), SENE, NESE
Section 03: Lots 1 (74.46), 2 (74.59), 3 (74.72), 4 (74.95) (a/k/a N2N2)
Section 12: NE

[Containing 1,612.28]

MERCER COUNTY
Township 141 North, Range 88 West
Section 01: Lots 1 (39.98), 2 (39.96), S2NE (a/k/a NE), S2
Section 11: NE, S2
Section 12: All
Section 13: All
Section 14: All
Section 15: SENE, E2SE
Section 22: E2E2
Section 23: All
Section 24: All
Section 25: All
Section 26: All
Section 35: N2
Section 36: All
[Containing 6,679.94]

UNIT LEGAL DESCRIPTION BY TRACT NUMBER

Tract 1 – Oliver County
Township 142 North, Range 87 West
Section 34: S2SW, SWSE containing 120 acres

Tract 2 – Oliver County
Township 142 North, Range 87 West
Section 33: NW, S2 containing 480 acres

Tract 3 – Oliver County
Township 142 North, Range 87 West
Section 32: All containing 640 acres

Tract 4 – Oliver County
Township 142 North, Range 87 West
Section 31: Lots 3 (38.84), 4 (38.49), E2SW, E2 containing 477.33 acres

Tract 5 – Mercer County
Township 141 North, Range 88 West
Section 01: Lots 1 (39.98), 2 (39.96), S2NE, S2 containing 479.94 acres

Tract 6 – Oliver County
Township 141 North, Range 87 West
Section 06: Lots 1 (39.90), 2 (39.93), 3 (39.96), 4 (38.36), 5 (38.45), 6 (38.54), 7 (38.62), S2NE, SENW, E2SW, SE [aka All] containing 633.76 acres

Tract 7 – Oliver County
Township 141 North, Range 87 West
Section 5: Lots 1 (39.92), 2 (39.92), 3 (39.91), 4 (39.90), S2N2, S2 [aka All] containing 639.65 acres

Tract 8 – Oliver County
Township 141 North, Range 87 West
Section 04: Lots 1 (39.48), 2 (39.60), 3 (39.72), 4 (39.84), S2N2, S2 [aka All] containing 638.64 acres

Tract 9 – Oliver County
Township 141 North, Range 87 West
Section 03: Lots 1 (39.83), 2 (39.71), 3 (39.60), 4 (39.48), S2N2, S2 [aka All] containing 638.62 acres

Tract 10 – Oliver County
Township 141 North, Range 87 West
Section 02: Lot 4 (39.90), SWNW, W2SW containing 159.9 acres

Tract 11 – Oliver County
Township 141 North, Range 87 West
Section 11: W2 containing 320 acres

Tract 12 – Oliver County
Township 141 North, Range 87 West
Section 10: All containing 640 acres

Tract 13 – Oliver County

Township 141 North, Range 87 West
Section 09: All containing 640 acres

Tract 14 – Oliver County
Township 141 North, Range 87 West
Section 08: All containing 640 acres

Tract 15 – Oliver County
Township 141 North, Range 87 West
Section 07: Lots 1 (38.75), 2 (38.92), 3 (39.10), 4 (39.27), E2W2, E2 [aka All] containing 636.04 acres

Tract 16 – Mercer County
Township 141 North, Range 88 West
Section 12: All containing 640 acres

Tract 17 – Mercer County
Township 141 North, Range 88 West
Section 11: NE, S2 containing 480 acres

Tract 18 – Mercer County
Township 141 North, Range 88 West
Section 15: SENE, E2SE containing 120 acres

Tract 19 – Mercer County
Township 141 North, Range 88 West
Section 14: All containing 640 acres

Tract 20 – Mercer County
Township 141 North, Range 88 West
Section 13: All containing 640 acres

Tract 21 – Oliver County
Township 141 North, Range 87 West
Section 18: Lots 1 (39.38), 2 (39.41), 3 (39.45), 4 (39.48), E2W2, E2 [aka All] containing 637.72 acres

Tract 22 – Oliver County
Township 141 North, Range 87 West
Section 17: All containing 640 acres

Tract 23 – Oliver County
Township 141 North, Range 87 West
Section 16: All containing 640 acres

Tract 24 – Oliver County
Township 141 North, Range 87 West
Section 15: All containing 640 acres

Tract 25 – Oliver County
Township 141 North, Range 87 West
Section 14: W2 containing 320 acres

Tract 26 – Oliver County
Township 141 North, Range 87 West

Section 23: NW, S2 containing 480 acres

Tract 27 – Oliver County

Township 141 North, Range 87 West

Section 22: All containing 640 acres

Tract 28 – Oliver County

Township 141 North, Range 87 West

Section 21: All containing 640 acres

Tract 29 – Oliver County

Township 141 North, Range 87 West

Section 20: All containing 640 acres

Tract 30 – Oliver County

Township 141 North, Range 87 West

Section 19: Lots 1 (39.53), 2 (39.59), 3 (39.65), 4 (39.71), E2W2, E2 [aka All] containing 638.48 acres

Tract 31 – Mercer County

Township 141 North, Range 88 West

Section 24: All containing 640 acres

Tract 32 – Mercer County

Township 141 North, Range 88 West

Section 23: All containing 640 acres

Tract 33 – Mercer County

Township 141 North, Range 88 West

Section 22: E2E2 containing 160 acres

Tract 34 – Mercer County

Township 141 North, Range 88 West

Section 26: All containing 640 acres

Tract 35 – Mercer County

Township 141 North, Range 88 West

Section 25: All containing 640 acres

Tract 36 – Oliver County

Township 141 North, Range 87 West

Section 30: Lots 1 (39.76), 2 (39.81), 3 (39.85), 4 (39.90), E2W2, E2 [aka All] containing 639.32 acres

Tract 37 – Oliver County

Township 141 North, Range 87 West

Section 29: All containing 640 acres

Tract 38 – Oliver County

Township 141 North, Range 87 West

Section 28: All containing 640 acres

Tract 39 – Oliver County

Township 141 North, Range 87 West

Section 27: All containing 640 acres

Tract 40 – Oliver County

Township 141 North, Range 87 West

Section 26: All containing 640 acres

Tract 41 – Oliver County

Township 141 North, Range 87 West

Section 25: W2NW, NWSW containing 120 acres

Tract 42 – Oliver County

Township 141 North, Range 87 West

Section 35: W2, W2E2 containing 480 acres

Tract 43 – Oliver County

Township 141 North, Range 87 West

Section 34: All containing 640 acres

Tract 44 – Oliver County

Township 141 North, Range 87 West

Section 33: All containing 640 acres

Tract 45 – Oliver County

Township 141 North, Range 87 West

Section 32: All containing 640 acres

Tract 46 – Oliver County

Township 141 North, Range 87 West

Section 31: Lots 1 (39.93), 2 (39.95), 3 (39.97), 4 (39.99), E2W2, E2 [aka All] containing 639.84 acres

Tract 47 – Mercer County

Township 141 North, Range 88 West

Section 36: All containing 640 acres

Tract 48 – Mercer County

Township 141 North, Range 88 West

Section 35: N2 containing 320 acres

Tract 49 – Morton County

Township 140 North, Range 88 West

Section 03: Lots 1 (74.46), 2 (74.59), 3 (74.72), 4 (74.95) containing 298.72 acres

Tract 50 – Morton County

Township 140 North, Range 88 West

Section 02: Lots 1 (74.47), 2 (74.49), 3 (74.51), 4 (74.53), SENE, NESE containing 378 acres

Tract 51 – Morton County

Township 140 North, Range 88 West

Section 01: Lots 1 (74.01), 2 (73.93), 3 (73.85), 4 (73.77), S2N2, S2 [aka All] containing 775.56 acres

Tract 52 – Morton County

Township 140 North, Range 87 West

Section 06: Lots 1 (74.47), 2 (74.53), 3 (74.52), 4 (37.66), 5 (37.50), 6 (37.14), S2NE, SE [aka All] containing 575.82 acres

Tract 53 – Morton County

Township 140 North, Range 87 West
Section 05: Lots 1 (74.67), 2 (74.59), 3 (74.51), 4 (74.43), S2N2 containing 458.20 acres

Tract 54 – Morton County

Township 140 North, Range 87 West
Section 04: Lots 2 (74.68), 3 (74.70), 4 (74.72), S2NW containing 304.10 acres

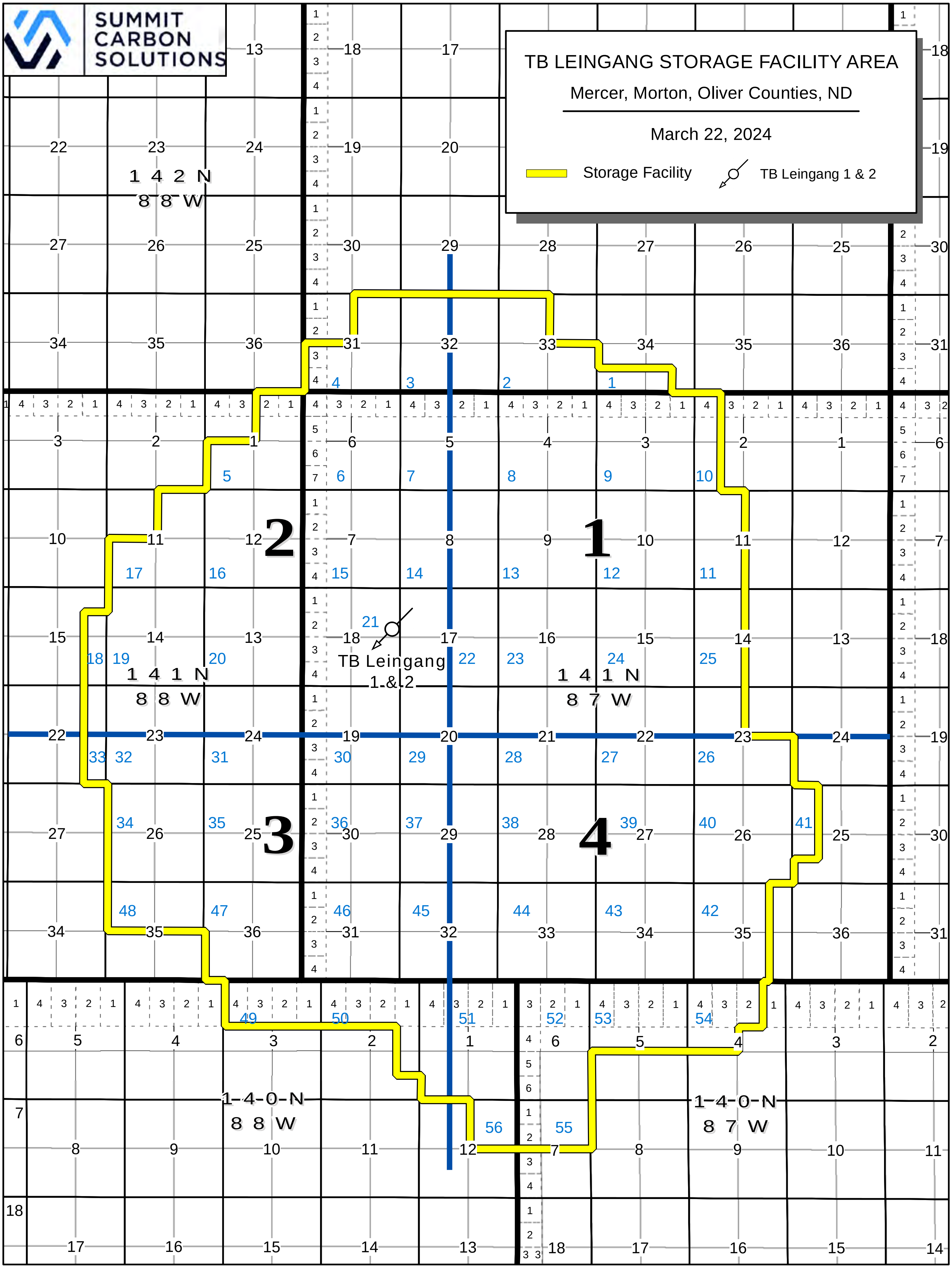
Tract 55 – Morton County

Township 140 North, Range 87 West
Section 07: Lots 1 (37.25), 2 (37.83), NE containing 235.08 acres

Tract 56 – Morton County

Township 140 North, Range 88 West
Section 12: NE containing 160 acres

SUMMIT CARBON SOLUTIONS



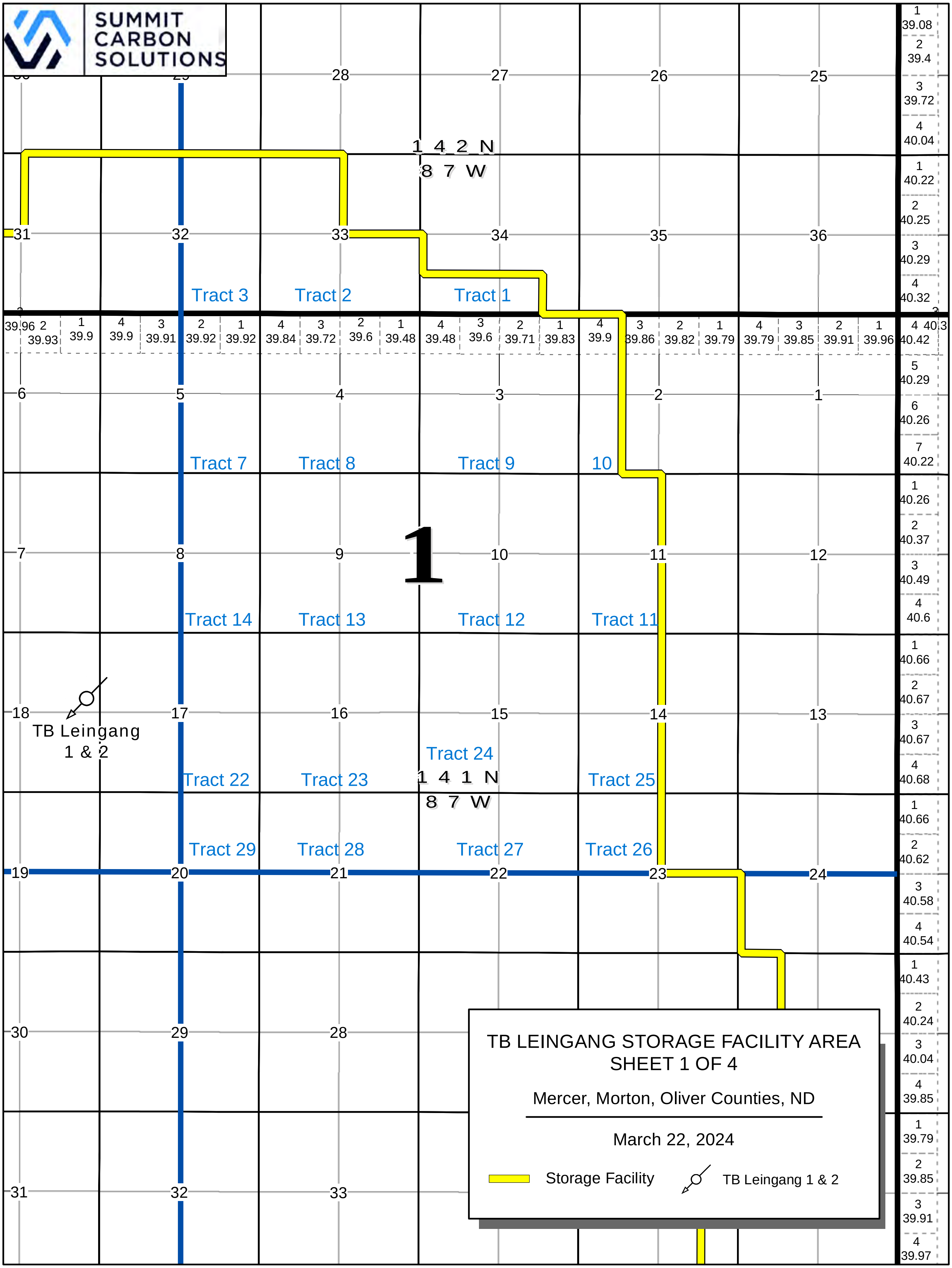
TB LEINGANG STORAGE FACILITY AREA

Mercer, Morton, Oliver Counties, ND

March 22, 2024

🟨 Storage Facility

TB Leingang 1 & 2

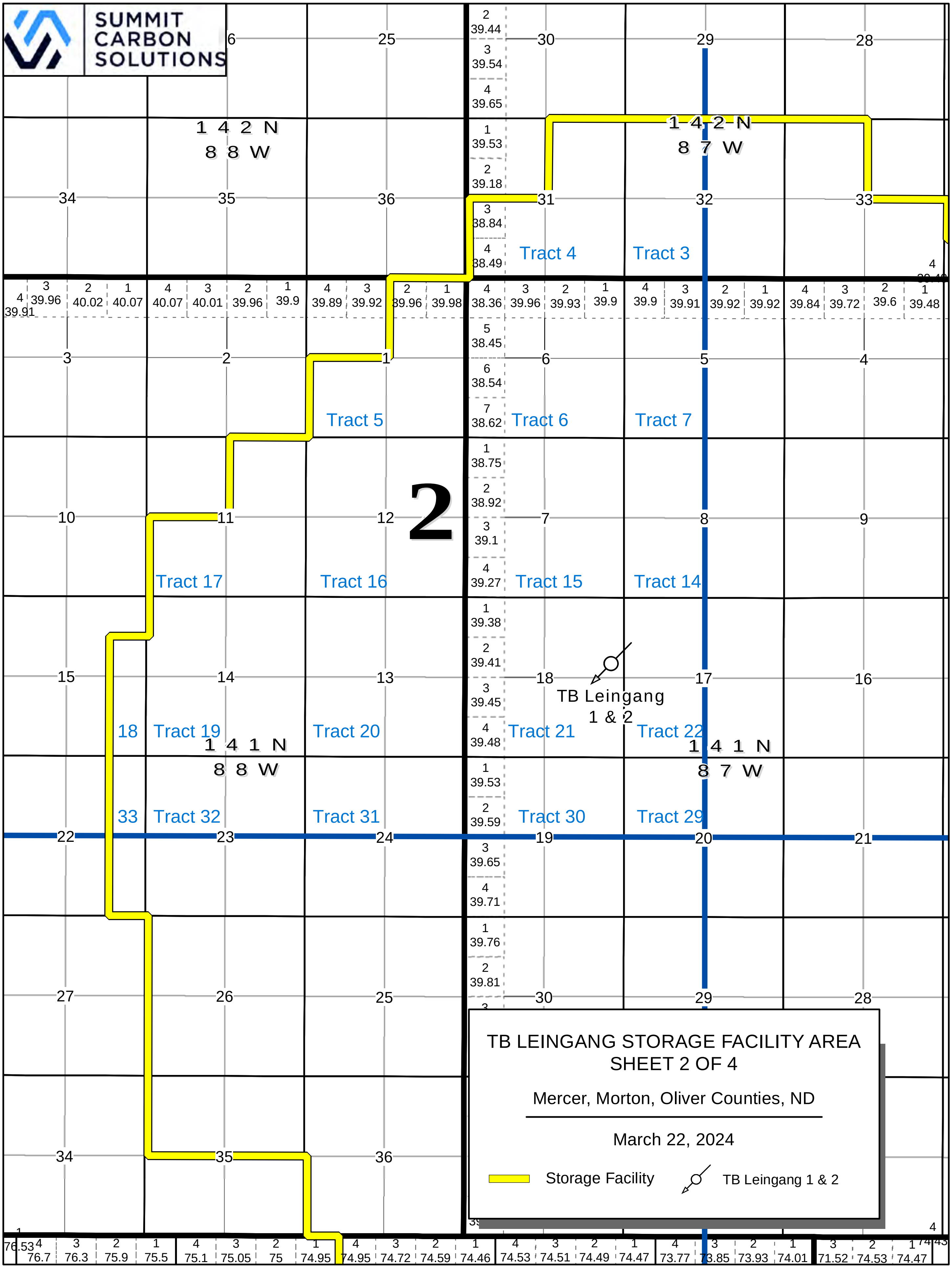


TB LEINGANG STORAGE FACILITY AREA
SHEET 1 OF 4

Mercer, Morton, Oliver Counties, ND

March 22, 2024

SUMMIT CARBON SOLUTIONS



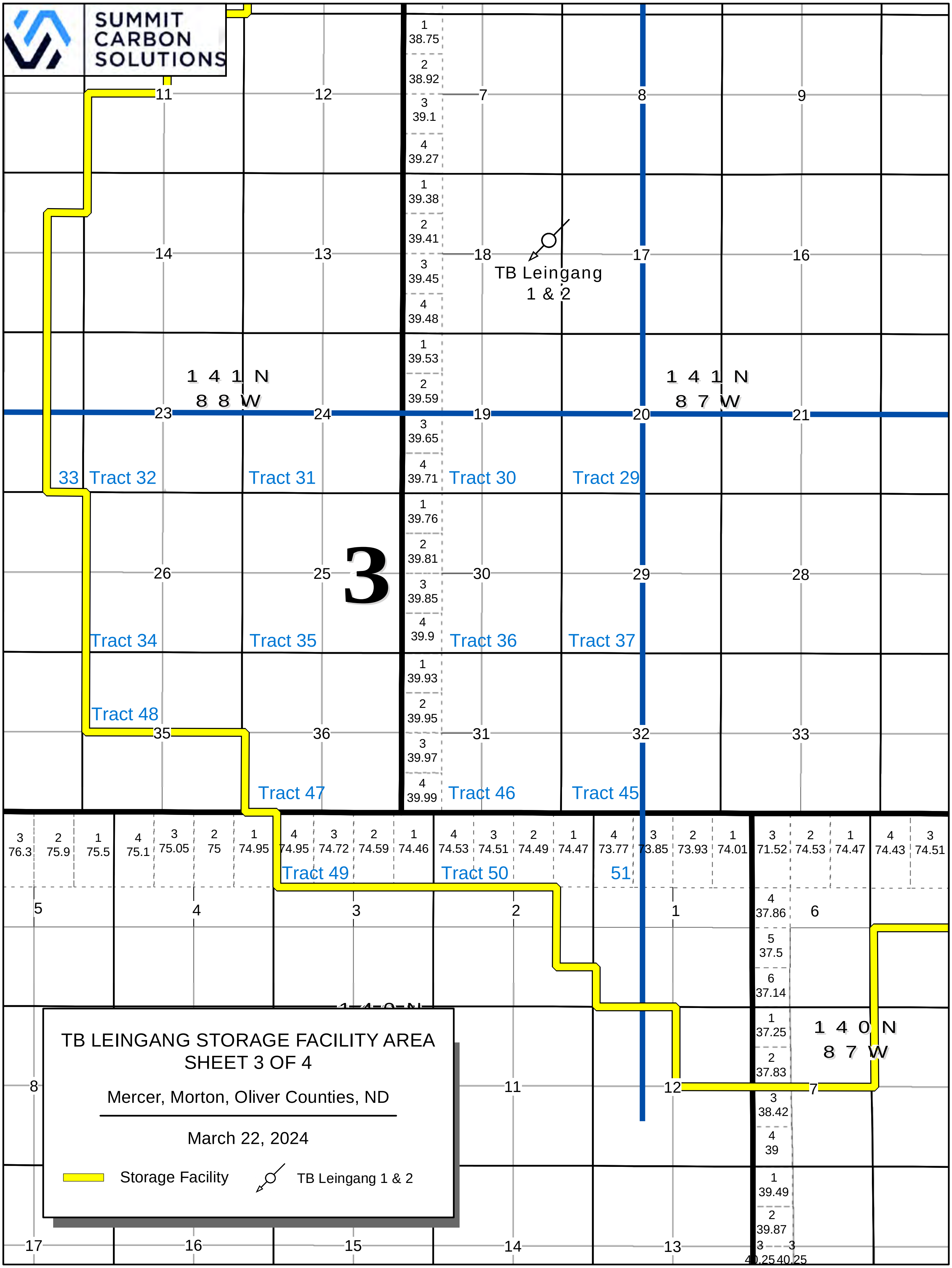
TB LEINGANG STORAGE FACILITY AREA
SHEET 2 OF 4

Mercer, Morton, Oliver Counties, ND

March 22, 2024

🟨 Storage Facility

TB Leingang 1 & 2



TB LEINGANG STORAGE FACILITY AREA
SHEET 3 OF 4

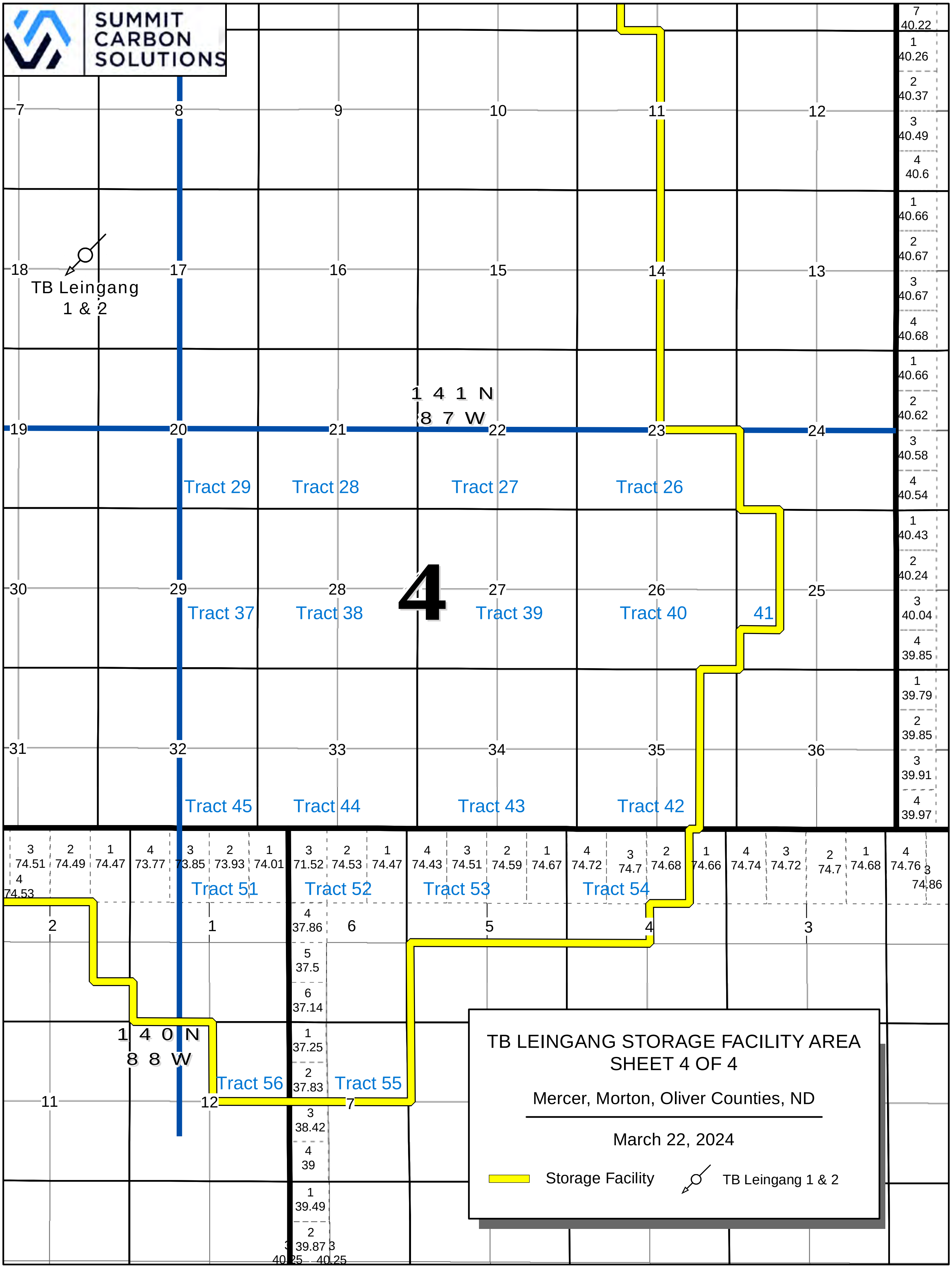
Mercer, Morton, Oliver Counties, ND

March 22, 2024

🟨 Storage Facility

TB Leingang 1 & 2

SUMMIT CARBON SOLUTIONS



TB LEINGANG STORAGE FACILITY AREA
SHEET 4 OF 4

Mercer, Morton, Oliver Counties, ND

March 22, 2024

▬ Storage Facility
TB Leingang 1 & 2

SECTION 2.0

GEOLOGIC EXHIBITS

2.0 GEOLOGIC EXHIBITS

2.1 Overview of Project Area Geology

TB Leingang is situated approximately 16 miles south of Beulah, 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 by the Energy & Environmental Research Center (EERC) via the Plains CO_2 Reduction (PCOR) Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO_2 storage due, in part, to 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 CO_2 storage reservoir for this project is the Broom Creek Formation, a predominantly sandstone formation 5818 ft below kelly bushing (KB) elevation at the stratigraphic and reservoir-monitoring well (Milton Flemmer 1, NDIC File No. 38594) (Figure 2-2). Unconformably overlying the Broom Creek Formation is 231 ft of predominantly siltstone with interbedded dolostone and anhydrite of the Spearfish, Minnekahta, and Opeche Formations, hereinafter referred to as the Opeche/Spearfish Formation. The Minnekahta Formation (limestone) is used to distinguish between the Spearfish Formation (above) and Opeche Formation (below). The Minnekahta Formation is interpreted to pinch out within the storage facility area. Where the Minnekahta does not exist, because of the similarity in lithology between the two formations, the Opeche and Spearfish are undifferentiated. The Opeche/Spearfish Formation serves as the primary upper confining zone (Figure 2-2). The Amsden Formation (dolostone, anhydrite, sandstone) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-2). Together, the Opeche/Spearfish, Broom Creek, and Amsden Formations comprise the storage complex for TB Leingang (Table 2-1).

Including the Opeche/Spearfish Formation, there are 1082 ft (thickness in Milton Flemmer 1) of impermeable rock formations between the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. An additional 2670 ft (thickness at Milton Flemmer 1) of impermeable intervals separates the Inyan Kara Formation and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-2).

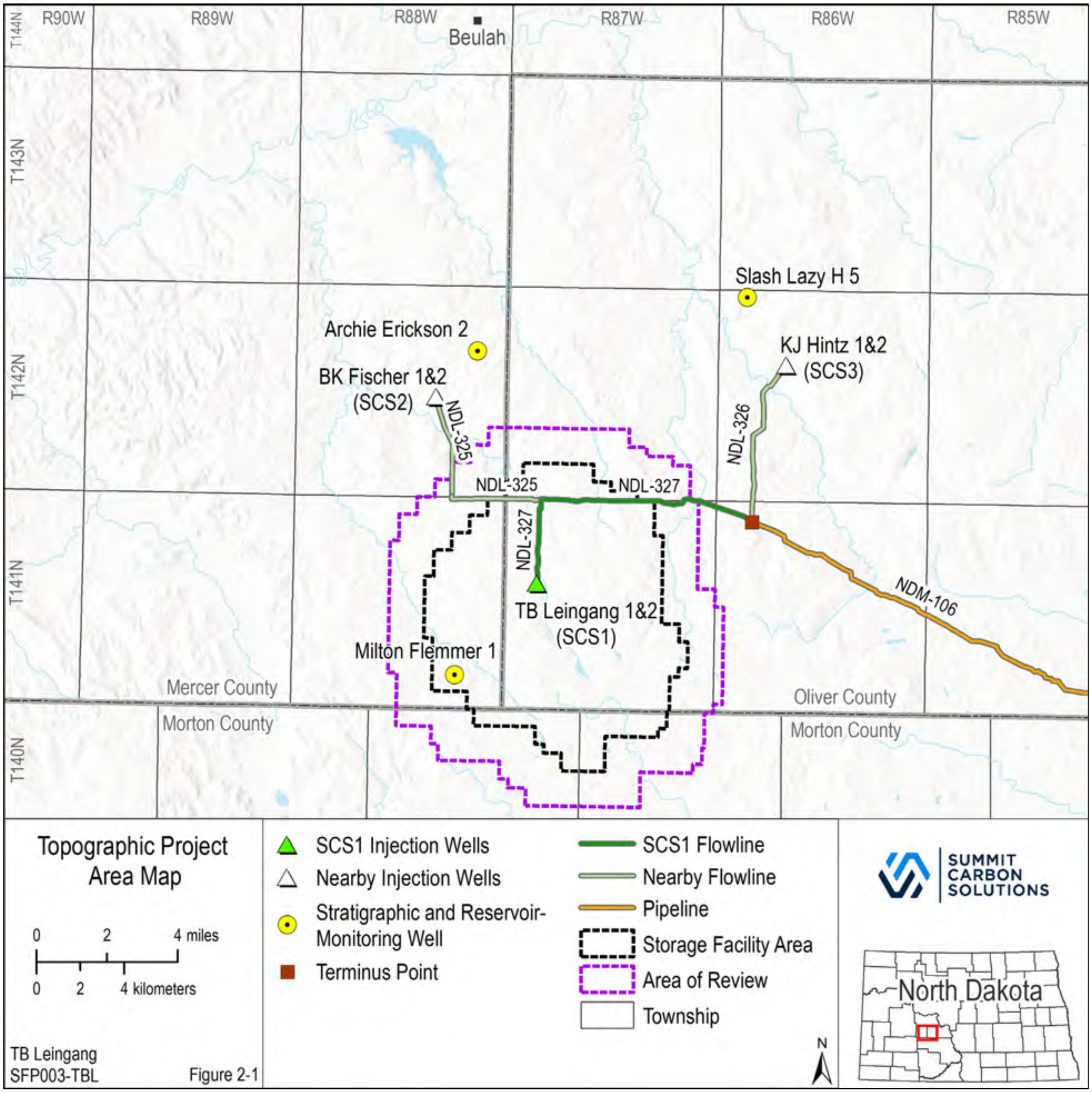


Figure 2-1. Topographic map showing well locations and TB Leingang in relation to the city of Beulah, North Dakota.

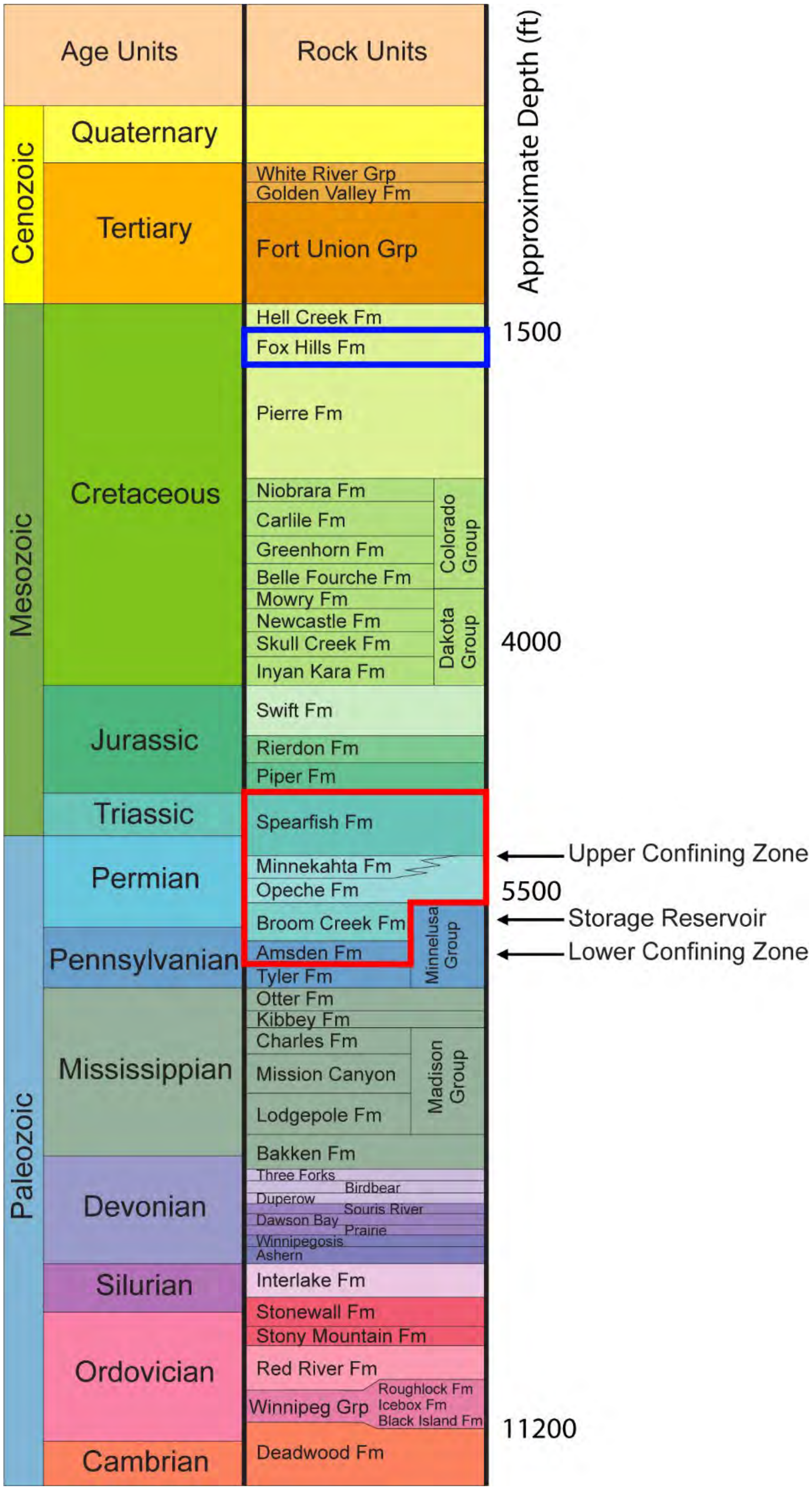


Figure 2-2. Stratigraphic column identifying the storage reservoir and confining zones (outlined in red) and the lowest USDW (outlined in blue). The Minnekahta Formation occurs at the stratigraphic test and reservoir-monitoring well location (Milton Flemmer 1) but pinches out within the simulation model area shown in Figure 2-3.

Table 2-1. Formations Comprising the TB Leingang Storage Complex (simulation model values calculated from model extent shown in Figure 2-3)

Formation	Purpose	Thickness at Milton Flemmer 1, ft	Depth at Milton Flemmer 1, ft, MD*	Average Simulation Model Thickness, ft	Average Simulation Model Depth, ft, TVD**	Lithology
Opeche/ Spearfish	Upper Confining Zone	231	5587	138	5106	Siltstone, dolostone anhydrite
Broom Creek	Storage reservoir (i.e., injection zone)	342	5818	280	5244	Sandstone, dolostone, anhydrite, siltstone
Amsden	Lower confining zone	261	6160	257	5524	Dolostone, sandstone, anhydrite

* Measured depth.
** True vertical 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, purchased/leased digital well logs, existing 3D and 2D seismic) and site-specific data acquired specifically to characterize the storage complex.

2.2.1 Existing Data

Well log data and interpreted formation top depths from 115 wellbores within the 4070-mi^2 (74-mi × 55-mi) area covered by the geologic model were used to characterize the depth, thickness, and extent of the subsurface geologic formations (Figure 2-3). Seismic interpretation products (seismic horizons and acoustic impedance volumes) from legacy 3D seismic data and 2D seismic data shown in Figure 2-3 were used to support generation of the 3D geologic model.

In addition to data from Milton Flemmer 1, existing laboratory measurements for core samples from the Broom Creek Formation and its confining zones were available from nine additional wells: ANG 1 (ND-UIC-101), Flemmer 1 (NDIC File No. 34243), BNI 1 (NDIC File No. 34244), J-LOC 1 (NDIC File No. 37380), Liberty 1 (NDIC File No. 37672), MAG 1 (NDIC File No. 37833), Coteau 1 (NDIC File No. 38379), Archie Erickson 2 (NDIC File No. 38622), and Slash Lazy H 5 (NDIC File No. 38701) (Figure 2-4). 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.

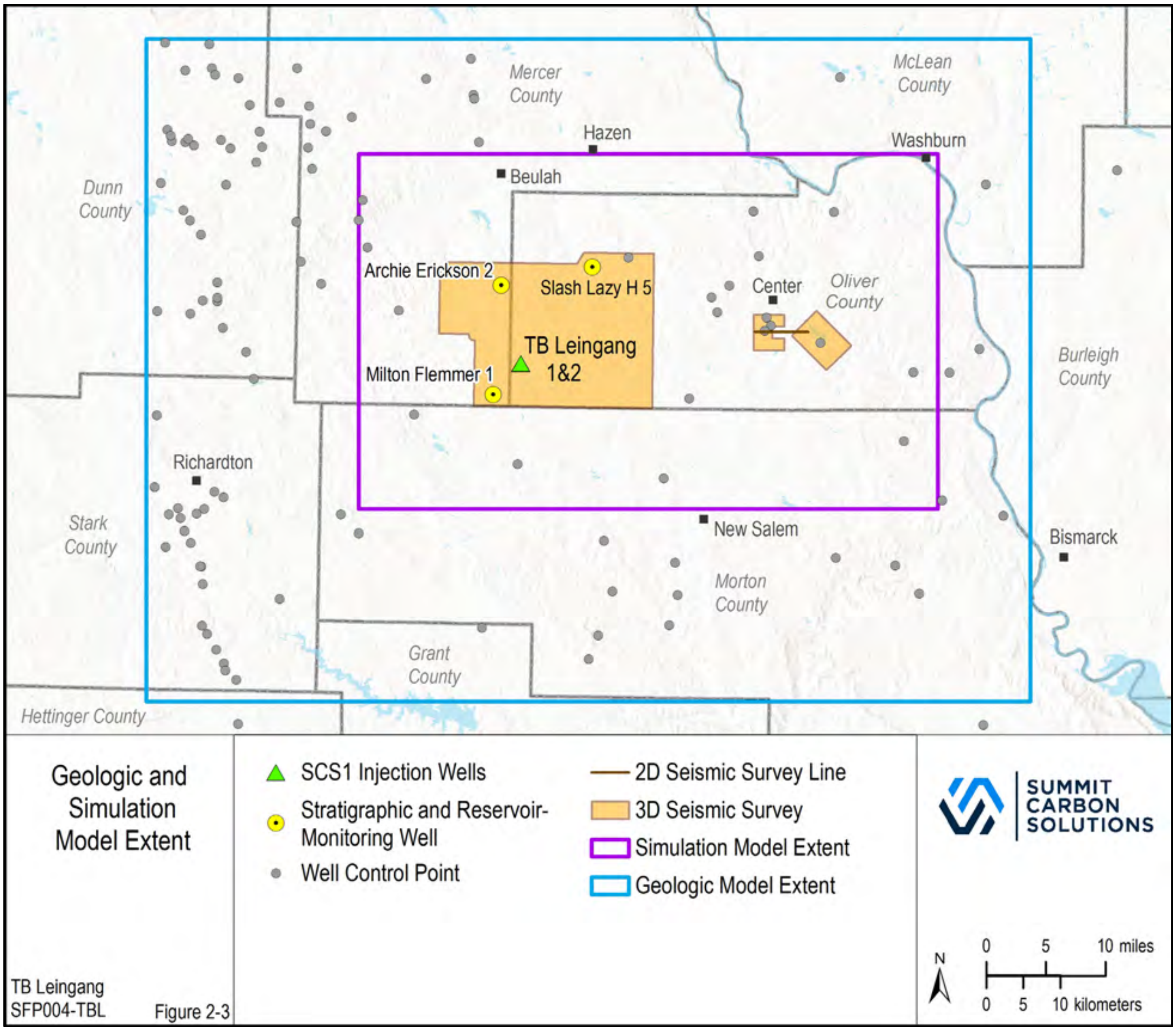


Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, 2D and 3D seismic, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

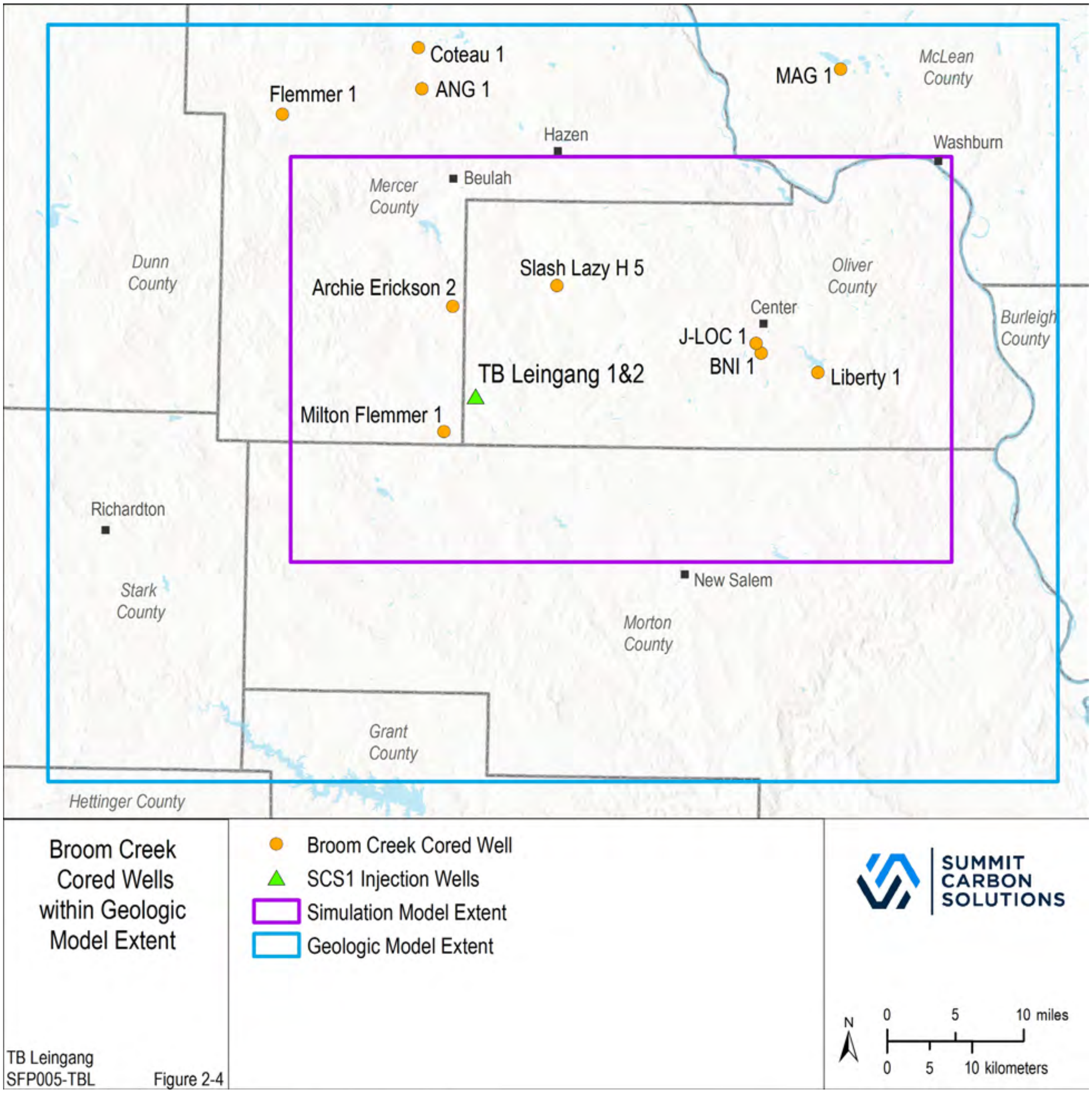


Figure 2-4. Map showing the spatial relationship between TB Leingang and ten wells where core samples were collected from the formations comprising the storage complex.

2.2.2 Site-Specific Data

Site-specific efforts to characterize the storage complex generated multiple data sets, including geophysical well logs, petrophysical data, fluid analyses, whole core, and 3D seismic data. Milton Flemmer 1 was drilled to a depth of 12,009 ft in 2022, specifically to gather subsurface geologic data to support the development of this CO_2 storage facility permit (SFP) application and serve as a future CO_2 reservoir-monitoring well. Downhole logs were acquired, and cores were collected from the associated storage complex (Opeche/Spearfish, Broom Creek, and Amsden Formations). Broom Creek Formation stress tests, a fluid sample, and temperature and pressure measurements were collected in the Milton Flemmer 1 (Figure 2-5).

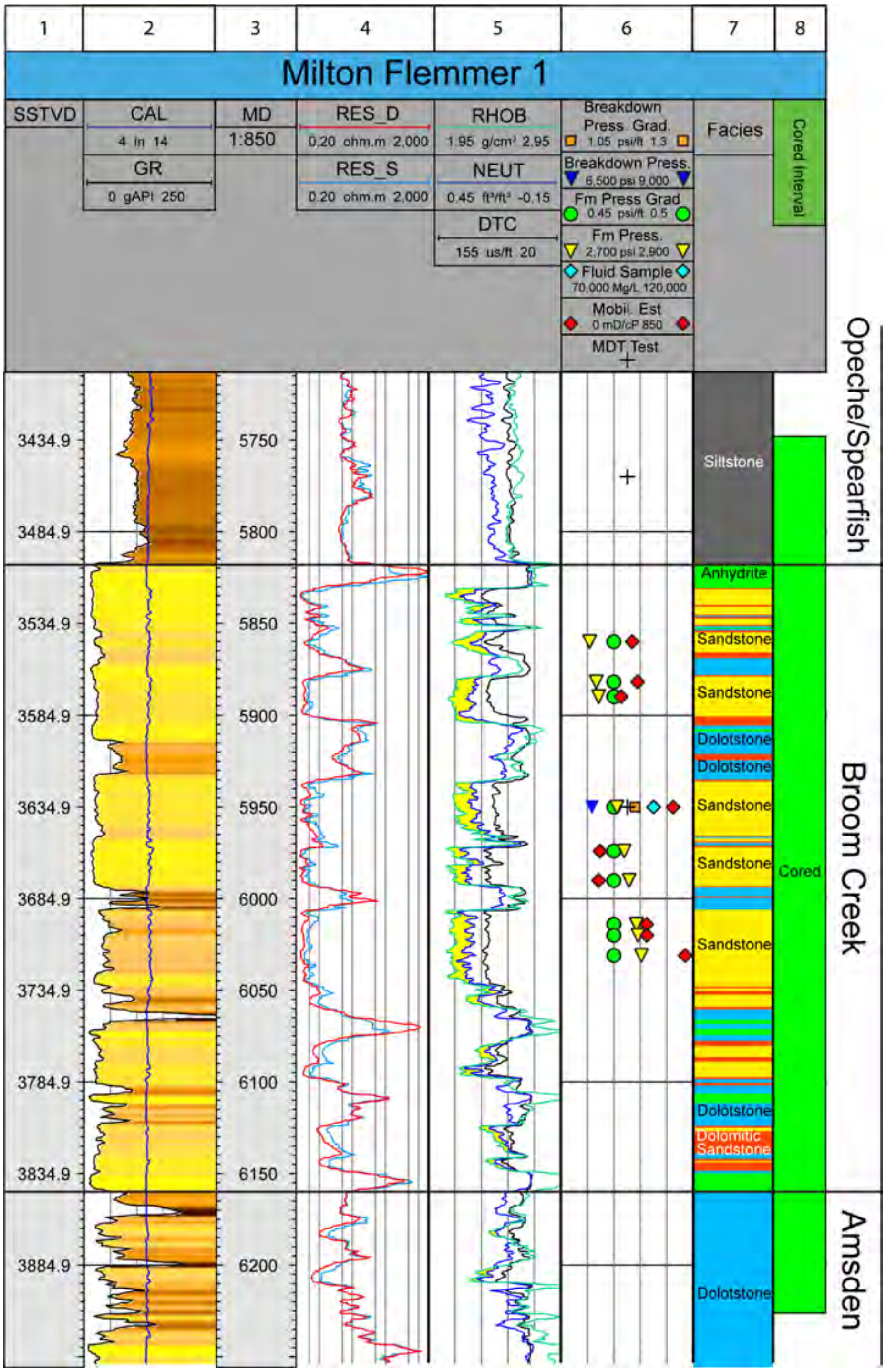


Figure 2-5. Schematic showing vertical relationship of coring and testing intervals in the Opeche/Spearfish Formation, the Broom Creek Formation, and the Amsden Formation in Milton Flemmer 1. Tracks from left to right are 1) subsea true vertical depth (SSTVD); 2) gamma ray (GR or HSGR [standard (total) gamma ray]) (black) and caliper (dark blue); 3) MD (measured depth); 4) resistivity – deep (red) and resistivity – shallow (light blue); 5) delta time (black), neutron porosity (NEUT) (blue), and density (green); 6) testing intervals; 7) facies; and 8) cored interval.

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 3.0), numerical simulations of CO_2 injection (Section 3.0), geochemical simulation (Appendix C), and geomechanical information (Section 2.4). The site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency for monitoring data collection, 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 Milton Flemmer 1. The logging suite included triple combo (GR, density, porosity, and resistivity), caliper, spectral GR, combinable magnetic resonance (CMR), elemental capture spectroscopy (ECS), dipole sonic including four-arm caliper and inclinometer, and an image 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 Pierre Formation to the base of the Deadwood Formation (Figure 2-2). The site-specific formation top depths were added to the existing data of the 115 wellbores within the 4070-mi^2 area covered by TB Leingang to understand the geologic extent, depth, and thickness of the subsurface geologic strata. Formation top depths of the Opeche/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

Four hundred seventy-eight (478) ft of 4-in. whole core was recovered from the storage complex in the Milton Flemmer 1: 77 ft of core from the Opeche/Spearfish Formation, 342 ft of core from the Broom Creek Formation, and 59 ft of core from the Amsden Formation. Core was analyzed to characterize the lithologies of the Opeche/Spearfish, Broom Creek, and Amsden Formations and correlated to the well log data. A core gamma ray log was acquired and matched to wireline gamma ray-to-depth correct core depth measurements (Table 2-2a). Core analyses included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), thin-section analysis, scanning electron microscopy (SEM), interfacial tension (IFT) and contact angle (CA), geomechanics, and capillary entry pressure measurements. The results were used to inform geologic modeling and predictive simulation inputs and assumptions, geochemical modeling, and geomechanical modeling.

Table 2-2a. Core Depth Shift

Core No.	Start Bit Depth, ft	End Bit Depth, ft	Depth Shift, ft
Core 6	5748	5828	–7.00
Core 7	5828	5948	–7.00
Core 8	5948	6010	–8.00
Core 9	6010	6130	–7.00
Core 10	6130	6227	–7.00

Core depth + depth shift = log depth.

2.2.2.3 Formation Temperature and Pressure

Temperature measurements from Milton Flemmer 1 were used to derive a temperature gradient for the proposed injection site (Table 2-2b). In combination with depth, the temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for geochemical modeling.

Formation pressure testing at Milton Flemmer 1 was performed with the SLB (formerly Schlumberger) MDT (modular formation dynamics tester) tool. The MDT tool's formation pressure measurements from the Broom Creek Formation are included in Table 2-3. The calculated pressure gradients were used to model formation pressure profiles for use in the numerical simulations of CO_2 injection.

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

Formation	**Sensor Depth MD, ft**	**Sensor Depth TVD, ft**	**Temperature, °F**
Opeche/Spearfish	5771.02	5770.82	–*
Broom Creek	5860.03	5859.81	132.7
	5882.02	5881.80	134.7
	5890.08	5889.86	136.2
	5950.02	5949.79	137.9
	5974.04	5973.81	139.4
	5990.06	5989.83	140.4
	6014.00	6013.77	141.2
	6020.00	6019.77	141.9
	6031.02	6030.78	142.6
Mean Broom Creek Temperature, °F			138.56
Broom Creek Temperature Gradient, °F/ft			0.017**

* Dry test. Temperature measurement is unreliable because it was impacted by tool temperature rather than fluid.

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

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

Formation	Sensor Depth MD, ft	Sensor Depth TVD, ft	Sensor Formation Pressure, psia
Opeche/Spearfish	5771.02	5770.82	–*
Broom Creek	5860.03	5859.81	2743.45
	5882.02	5881.80	2753.45
	5890.08	5889.86	2757.04
	5950.02	5949.79	2784.61
	5974.04	5973.81	2795.56
	5990.06	5989.83	2802.94
	6014.00	6013.77	2814.05
	6020.00	6019.77	2816.57
	6031.02	6030.78	2821.66
Mean Broom Creek Pressure, psi			2787.70
Broom Creek Pressure Gradient, psi/ft			0.466**

* Dry test. No fluid was withdrawn because of low permeability.

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

2.2.2.4 Microfracture In Situ Stress Tests

Using the SLB MDT tool, microfracture in situ stress tests were performed in the Milton Flemmer 1 wellbore. As shown in Figures 2-6 and 2-7, in situ reservoir stress-testing measurements provided real-time formation breakdown, instantaneous shut-in, propagation, and closure pressures.

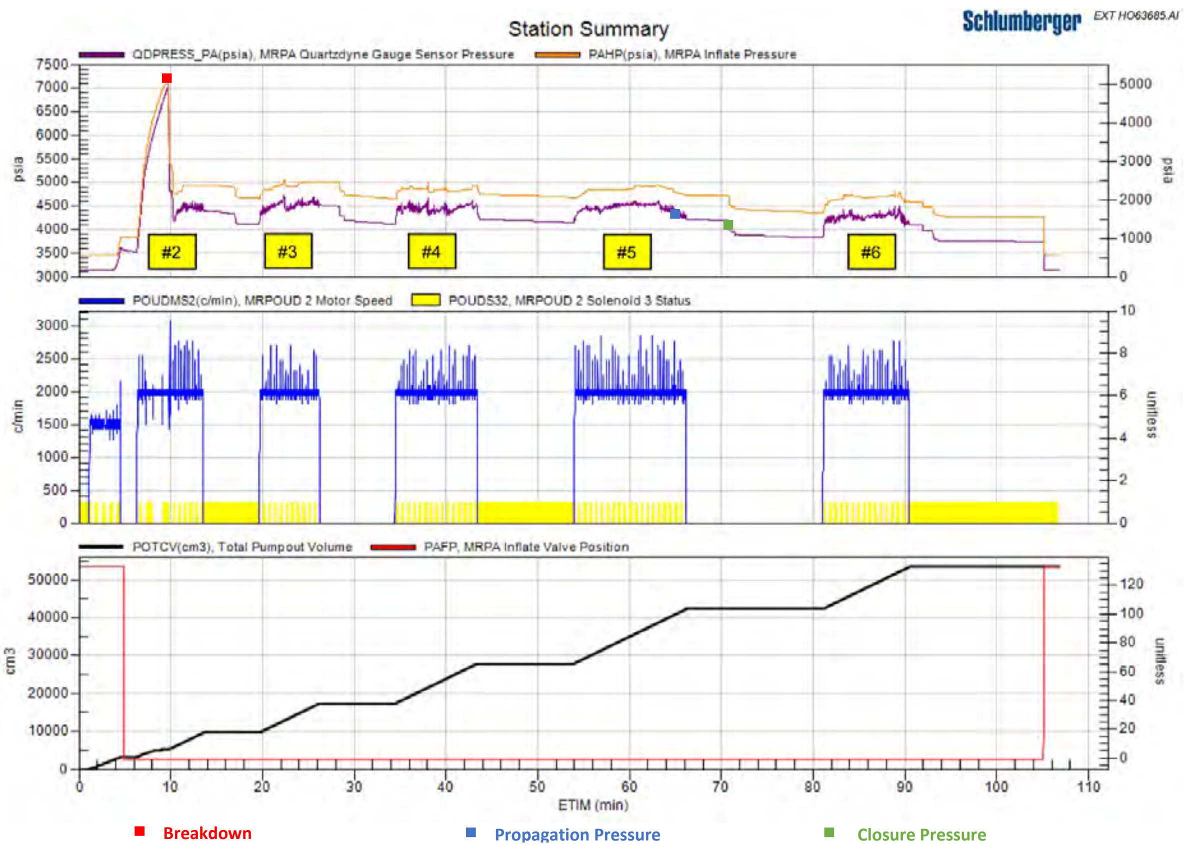


Figure 2-6. Milton Flemmer 1, Broom Creek Formation MDT microfracture in situ stress pump cycle graph at 5949.98 ft MD.

Figure 2-7. Milton Flemmer 1, Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 5770.99 ft MD. No clear breakdown was observed.

Microfracture in situ stress tests were performed in the Opeche/Spearfish and Broom Creek Formations (Table 2-4). The use of the dual-packer module on the MDT tool assembly to isolate the designated intervals tested a 1.5-ft section of the zone of interest. This small representative sample should be taken into consideration in the analysis of the pressures. Fracture propagation pressures determined from the microfracture test were used to calculate pressure constraints related to the maximum allowable bottomhole pressure (BHP) and a 1D mechanical earth model (1D MEM) that was generated using well log data from Milton Flemmer 1. Discussion of the 1D MEM can be found in Section 2.4.

Table 2-4. Description of Milton Flemmer 1 Microfracture In Situ Stress Tests

Formation	Test Depth		Breakdown Pressure		Propagation Pressure		Closure Pressure (G-func)	
	MD, ft	TVD, ft	psia	Gradient, psi/ft*	Avg., psia	Gradient, psi/ft*	Avg., psia	Gradient, psi/ft*
Opeche/Spearfish	5770.99	5770.79	No observed formation breakdown.		4768.79	0.82**	4287.72	0.740
Broom Creek	5949.98	5949.75	7087.75	1.19	4287.52	0.718	4047.35	0.678

* 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.

** Propagation observed in Opeche/Spearfish is likely associated with a drilling-induced fracture.

No breakdown pressure was observed for Milton Flemmer 1 in the Opeche/Spearfish Formation at 5770.99 ft MD, Figure 2-7. The MDT stress test results show that the average formation fracture propagation pressure observed was 4768.79 psi, providing a fracture propagation pressure gradient of 0.82 psi/ft. The result indicates that the cap rock has a higher fracture propagation pressure than the injection zone (0.718 psi/ft), which means that the cap rock has good integrity to contain the injected CO_2.

2.2.2.5 Fluid Sample Testing

A fluid sample from the Inyan Kara Formation was collected from the Milton Flemmer 1 wellbore during the DST (drill stem test). A fluid sample from the Broom Creek Formation was collected using SLB's Saturn 3D Radial Probe. Results were analyzed by Minnesota Valley Testing Laboratories (MVTL), a state-certified lab. The salinity values from the Milton Flemmer 1 wellbore sample are shown in Table 2-5. A more detailed fluid sample analysis report can be found in Appendix A. Fluid sample analysis results were used as inputs for geochemical modeling and dynamic reservoir simulations.

Table 2-5. Description of Fluid Sample Test and Corresponding Total Dissolved Solids (TDS) Value

Formation	Well	Test Depth/Interval, ft MD	MVTL TDS, mg/L
Inyan Kara	Milton Flemmer 1	4480–4781	3560
Broom Creek	Milton Flemmer 1	5950	105,000

In situ fluid pressure testing was performed in the Opeche/Spearfish and Broom Creek Formations with the MDT tool. This test utilized the tool's extra-large-diameter probe to test both the mobility and reservoir pressure. The MDT probe was unable to draw down reservoir fluid from the Opeche/Spearfish Formation in order to determine the reservoir pressure or to collect an in situ fluid sample, and the formation was unable to rebound (build pressure) because of low to almost zero permeability. The testing results provide further evidence of the confining properties of the Opeche/Spearfish Formation, ensuring sufficient geologic integrity to contain the injected CO_2 stream.

2.2.2.6 Seismic Survey

A 208-square-mile 3D seismic survey was conducted from November 2021 to February 2022 south of Beulah, North Dakota (Figure 2-8). The Beulah 3D seismic data provided visualization of deep geologic formations at lateral-spatial intervals as short as 82.5 ft. Additionally, seismic data from nearby 3D surveys to the east, namely, the Center 3D and Minnkota 3D, and a connecting 2D line were used to interpret and evaluate the subsurface (Figure 2-8). The seismic data were used for assessment of the geologic structure and reservoir properties.

Data products generated from the interpretation of the Beulah 3D were used as inputs for the geologic model that was used to simulate migration of the CO_2 plume. The Beulah 3D seismic data and the Milton Flemmer 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 Archie Erickson 2, Milton Flemmer 1, and Slash Lazy H 5 dipole sonic logs. The depth-converted surfaces for the storage reservoir and upper and lower confining zones were used as inputs for the geologic model. Detailed information about the structure and varying thickness of the formations away from well control was derived from these surfaces. A prestack seismic inversion was generated from the 3D seismic data and well logs from the Milton Flemmer 1, Archie Erickson 2, and Slash Lazy H 5 stratigraphic test wells. Depth-converted surfaces and poststack seismic inversion results from the Center 3D and Minnkota 3D were also used as inputs for the geologic model.

Interpretation of the 3D seismic data suggests there are no major stratigraphic pinch-outs or structural features with associated spill points (e.g., folds, domes, or fault traps) in TB Leingang. 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 3D seismic data in the TB Leingang.

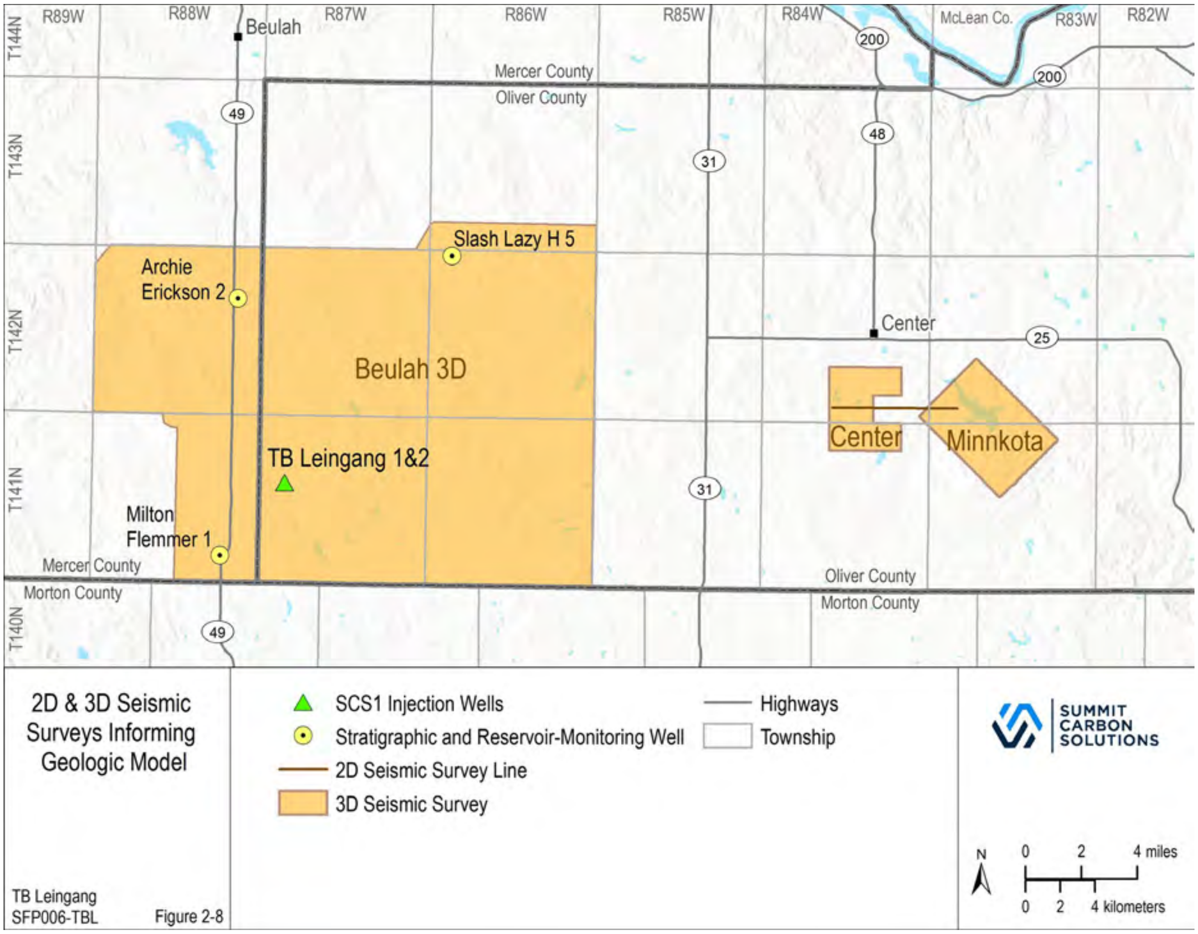


Figure 2-8. Map showing the 2D and 3D seismic surveys used to characterize TB Leingang and inform the construction of the geologic model. The 3D seismic surveys from west to east are the Beulah 3D, Center 3D, and Minnkota 3D.

2.3 Storage Reservoir (injection zone)

The Broom Creek Formation is laterally extensive across the simulation model area and surrounding region (Figure 2-9). The Broom Creek Formation comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone layers (impermeable layers) with minor amounts of siltstone and anhydrite layers. The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by the Opeche/Spearfish Formation (Figure 2-2) (Murphy and others, 2009).

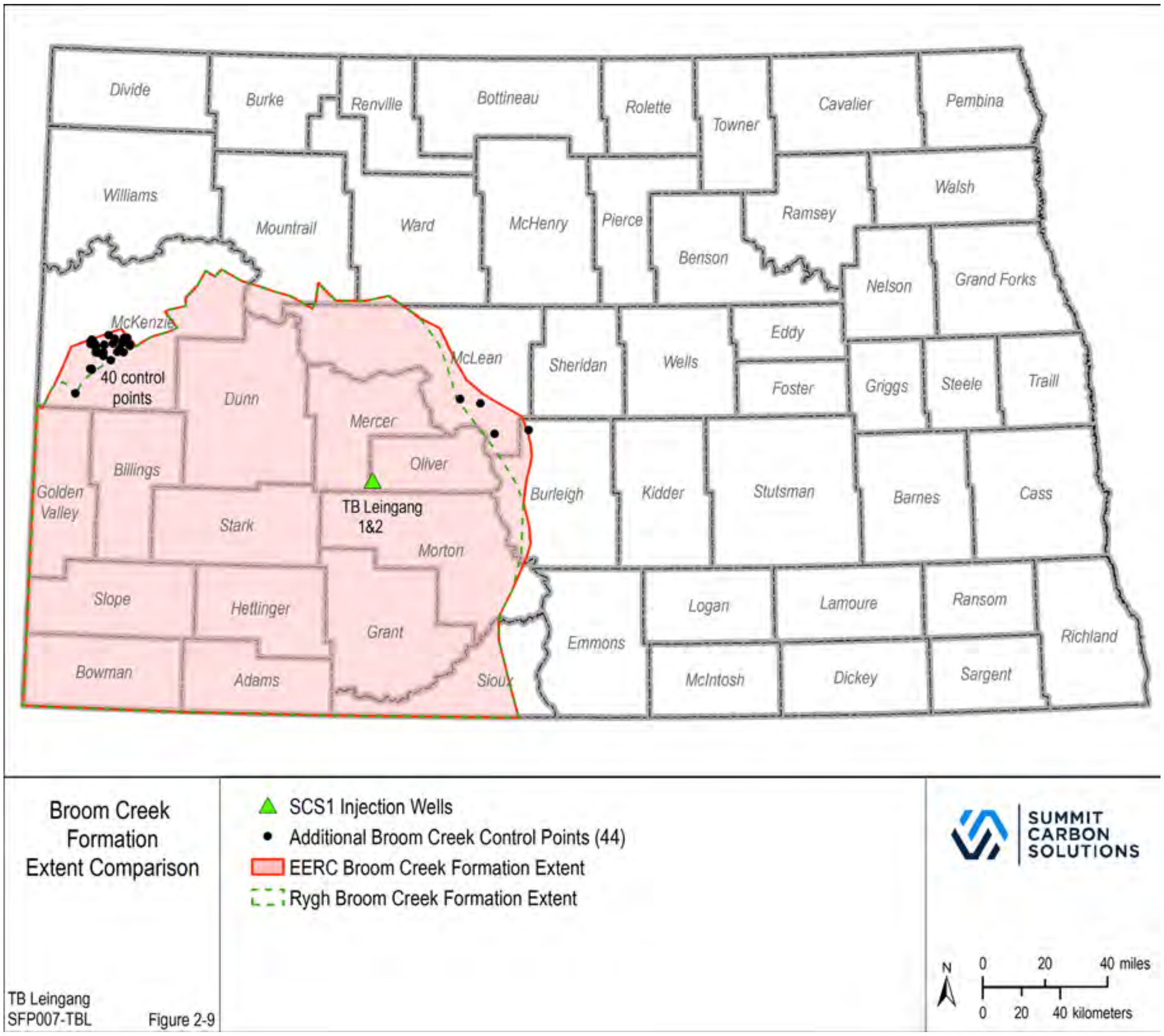


Figure 2-9. Broom Creek Formation in North Dakota. The area within the green dashed line shows the extent originally proposed by Rygh (1990), and the area outside of the green dashed line has been modified based on new well control.

The top of the Broom Creek Formation is located at a depth of 5818 ft below KB elevation at Milton Flemmer 1, and the cored interval is made up of 240 ft of sandstone, 81 ft of dolostone, and 21 ft of anhydrite. The thickness of the Broom Creek Formation at Milton Flemmer 1 is 342 ft. Cored wells within the extent of the simulation model show minor anhydrite and siltstone intervals are also present in the Broom Creek Formation. Across the simulation model area, the Broom Creek Formation ranges in thickness from 139 to 492 ft (Figure 2-10a, 2-10b), with an average thickness of 280 ft based on offset-well data and geologic model characteristics. The net sandstone thickness within the simulation model area ranges from 6 to 397 ft, with an average thickness of 140 ft.

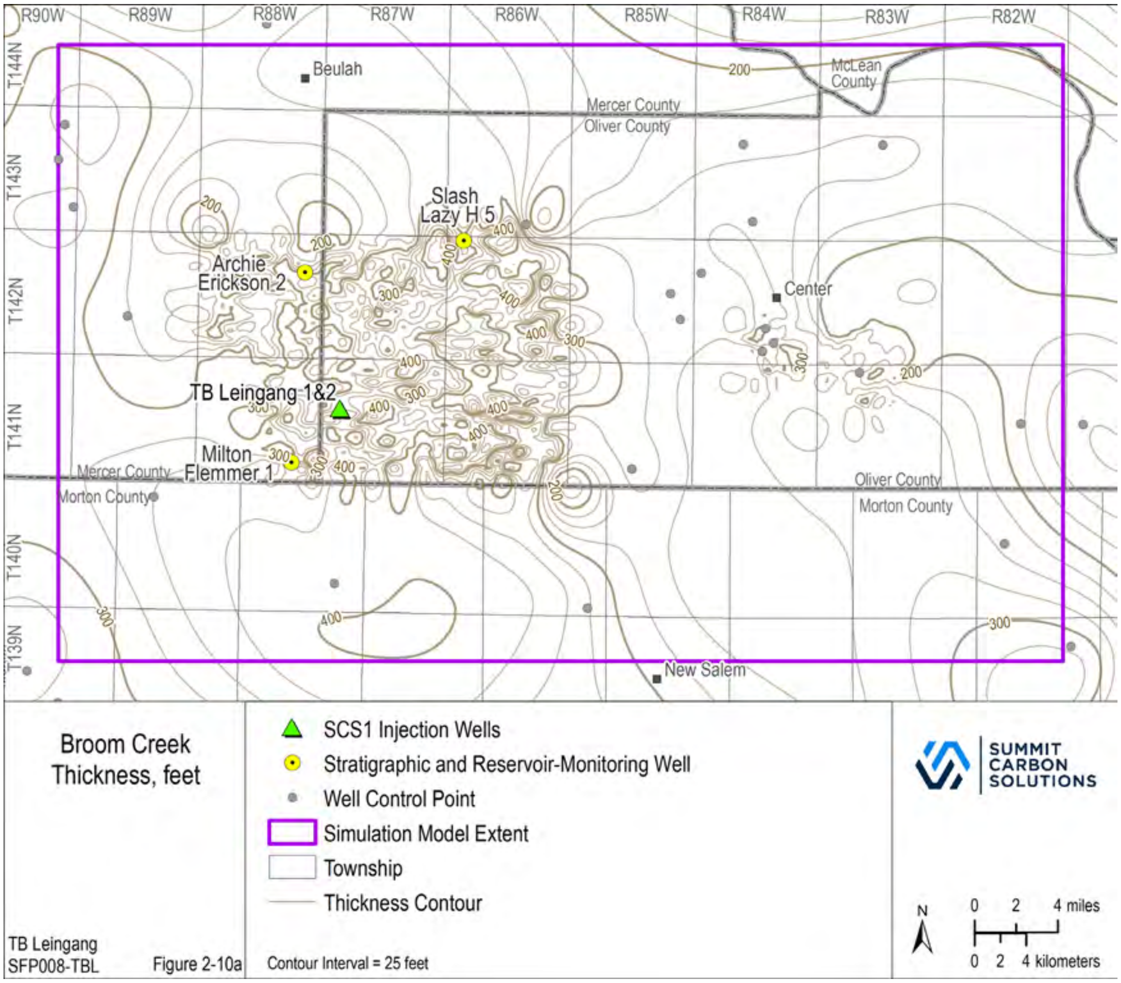


Figure 2-10a. Isopach map of the Broom Creek Formation in the simulation model area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map (thickness of the Broom Creek Formation at Milton Flemmer 1 is 342 ft, see Table 2-6).

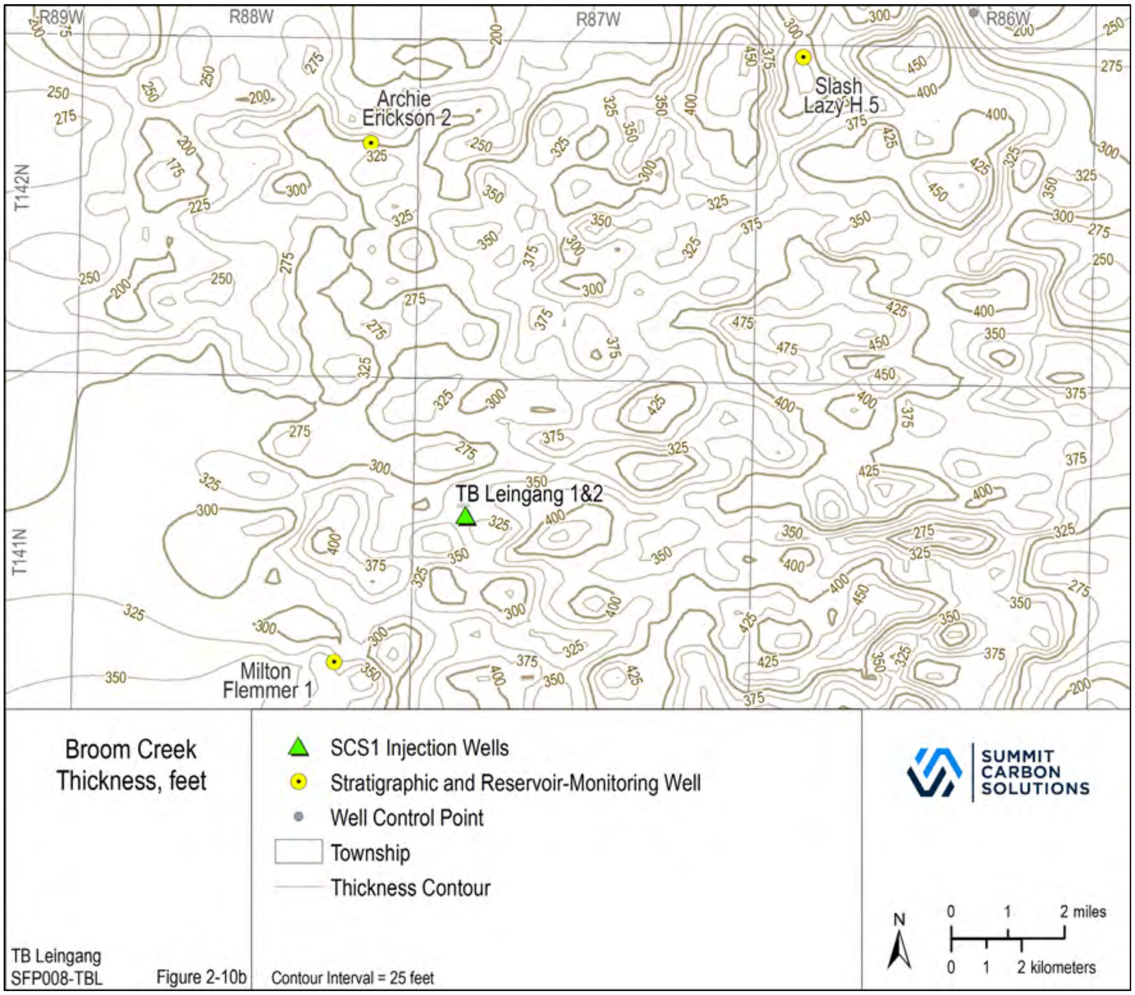


Figure 2-10b. Isopach map of the Broom Creek Formation focused around the three stratigraphic and reservoir-monitoring wells (thickness of the Broom Creek Formation at Milton Flemmer 1 is 342 ft, see Table 2-6).

The top of the Broom Creek Formation was picked 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 Opeche/Spearfish Formation (Figure 2-11). This transition is also noted with a drop in bulk density (RHOB) and dipole sonic compressional slowness values (DTC) and an increase in NEUT and resistivity (RES_D, RES_S). The bottom of the Broom Creek Formation was placed at the base of a relatively low GR package representing a 10-ft package of anhydrite that can be correlated across much of the study area. This rock package divides the clean sandstones and dolostone lithologies of the Broom Creek Formation from the dolostone and anhydrite of the Amsden Formation. Seismic data collected as part of site characterization efforts (Figure 2-8) were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and seismic interpretation indicate that the formation is continuous across the area near Milton Flemmer 1 (Figures 2-12 and 2-13). A structure map of the Broom Creek Formation shows no detectable features with associated spill points in the simulation model area (Figures 2-14 and 2-15).

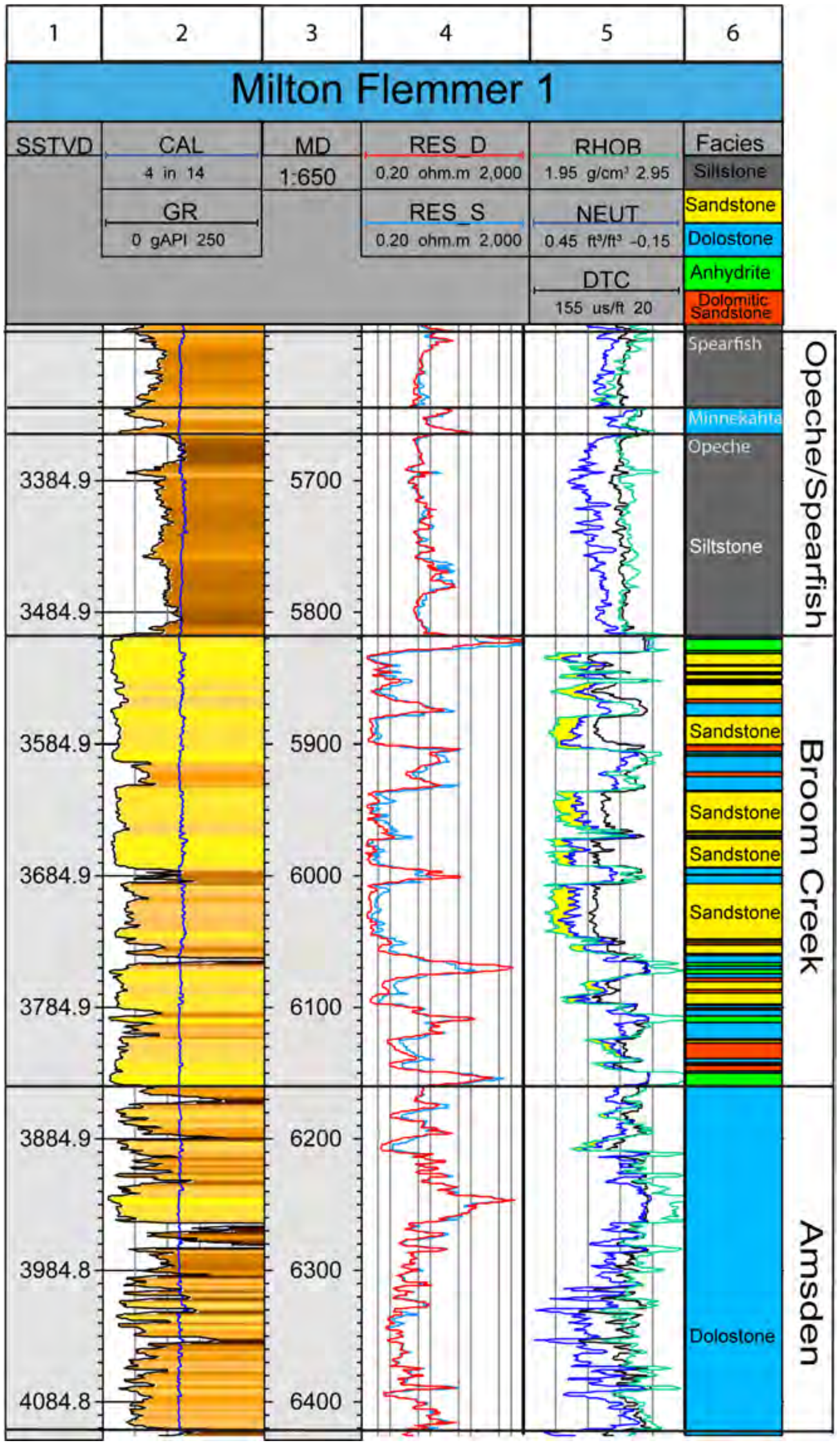


Figure 2-11. Well log display of the interpreted facies of the Opeche/Spearfish, Broom Creek, and Amsden Formations in the Milton Flemmer 1. Tracks from left to right are 1) SSTVD; 2) GR (black) and caliper (dark blue); 3) MD; 4) resistivity – deep (red) and resistivity – shallow (light blue); 5) delta time (black), NEUT (blue), and density (green); and 6) facies.

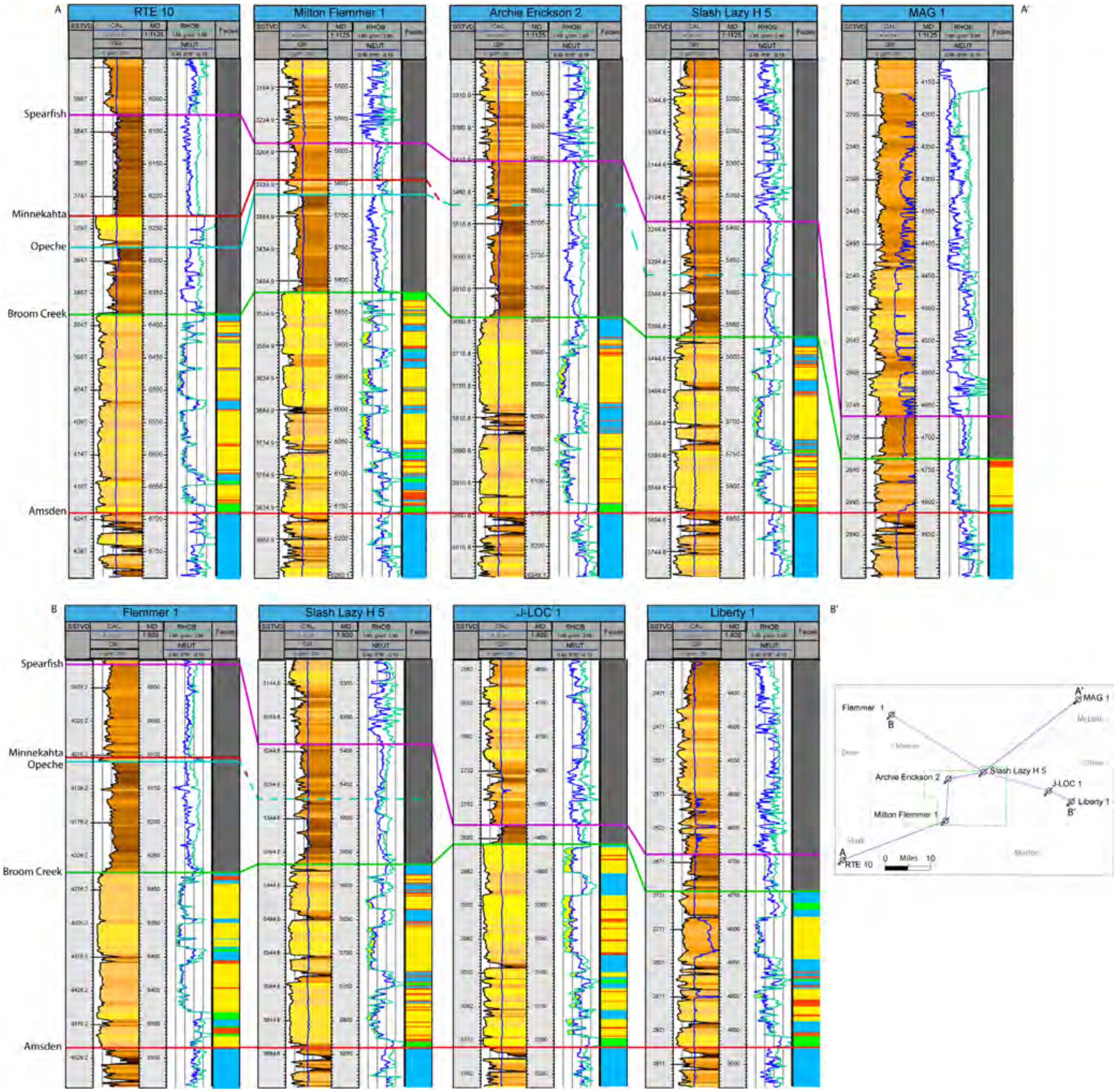


Figure 2-12. Regional well log stratigraphic cross sections of the upper confining zone and injection zone flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' 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, the structure may appear more drastic than it actually is.

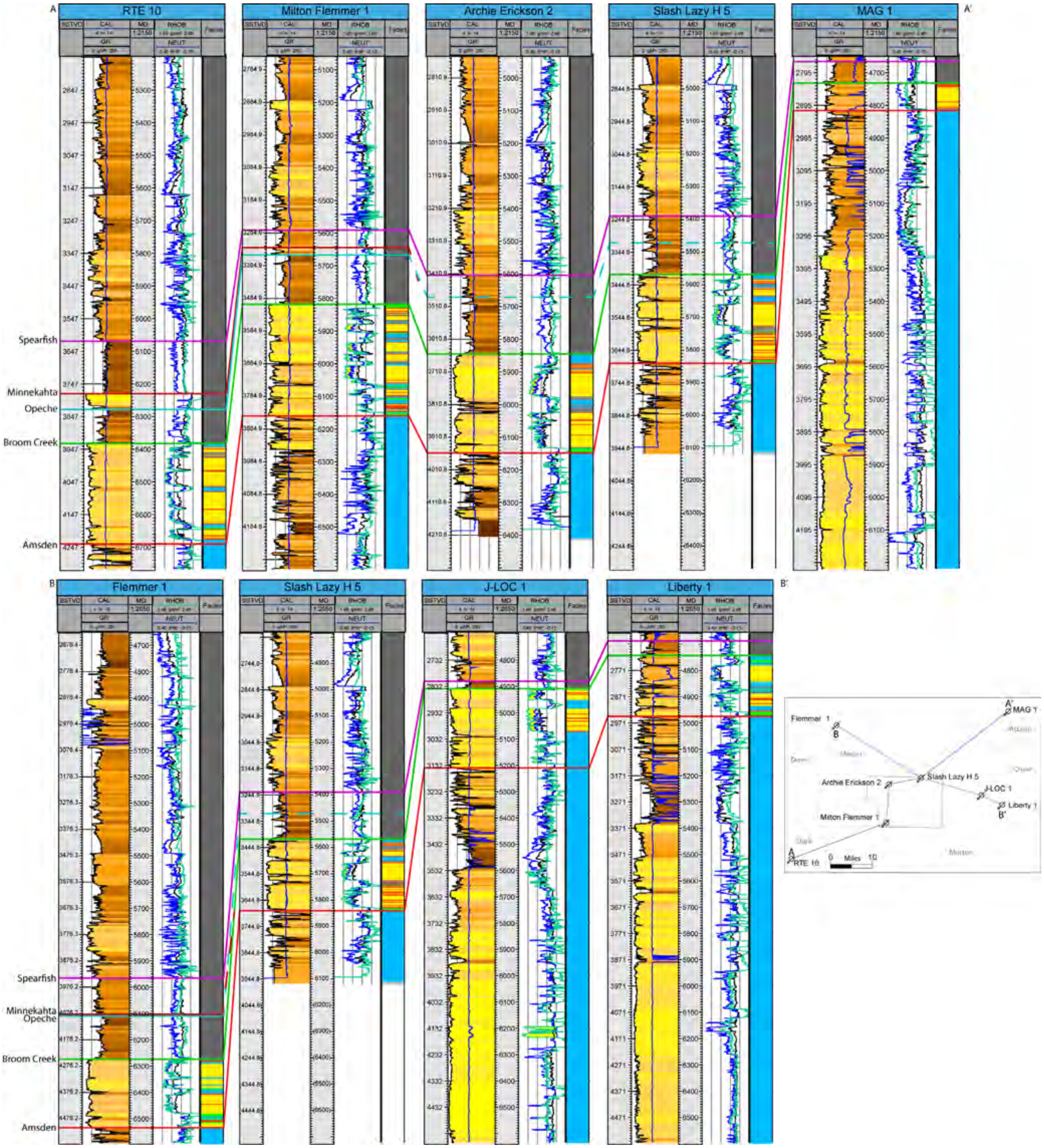


Figure 2-13. Regional well log cross sections showing the structure of the upper confining zone and injection zone. Displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' 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, the structure may appear more drastic than it actually is.

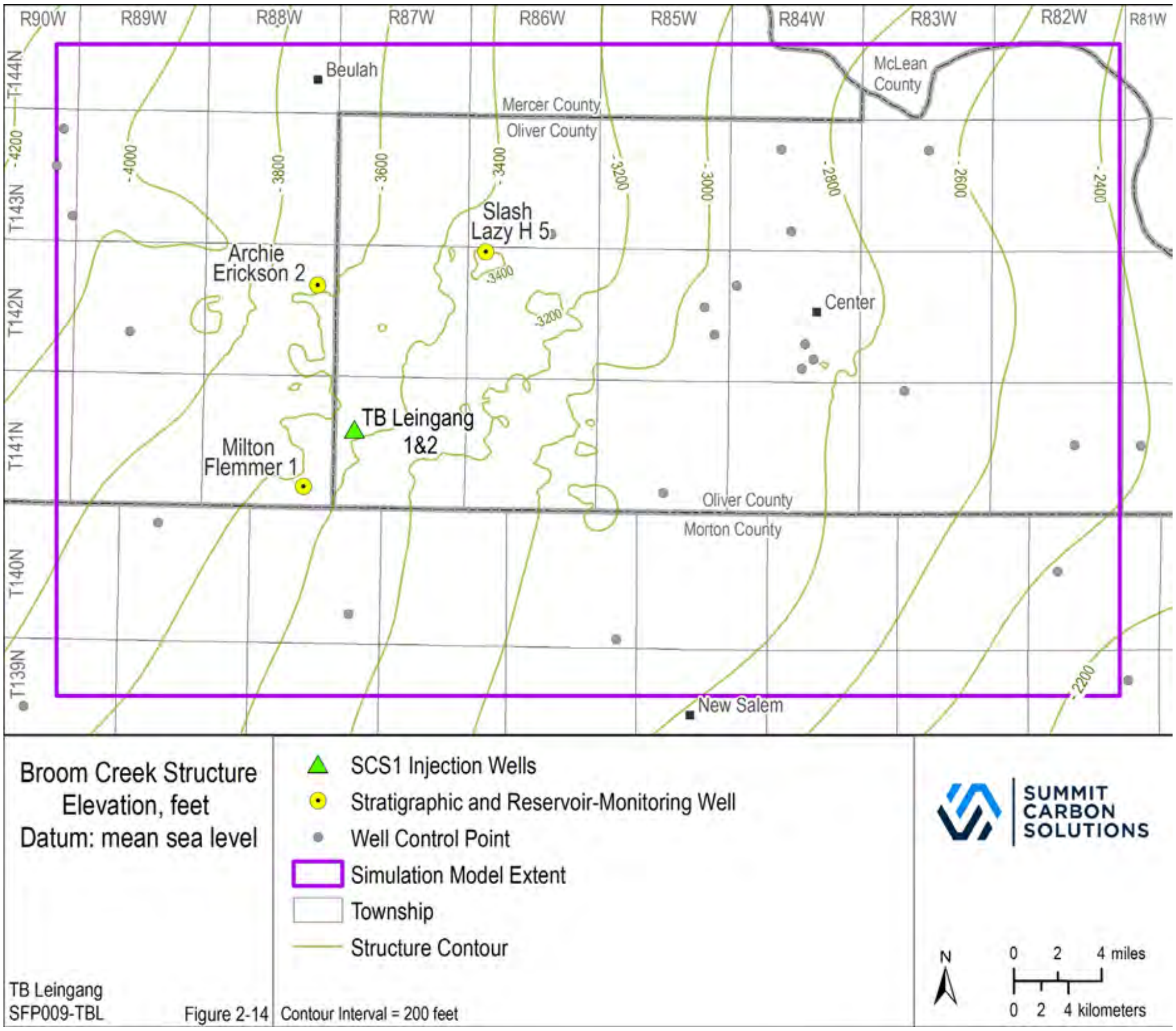


Figure 2-14. Structure map of the Broom Creek Formation in the simulation model referenced in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map.

Thirty-two (32) 1-in.-diameter 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 2-6, Figure 2-16). The range in porosity and permeability predominantly captured the sandstone variability as this rock type was prominent in the sampling program over the dolostone.

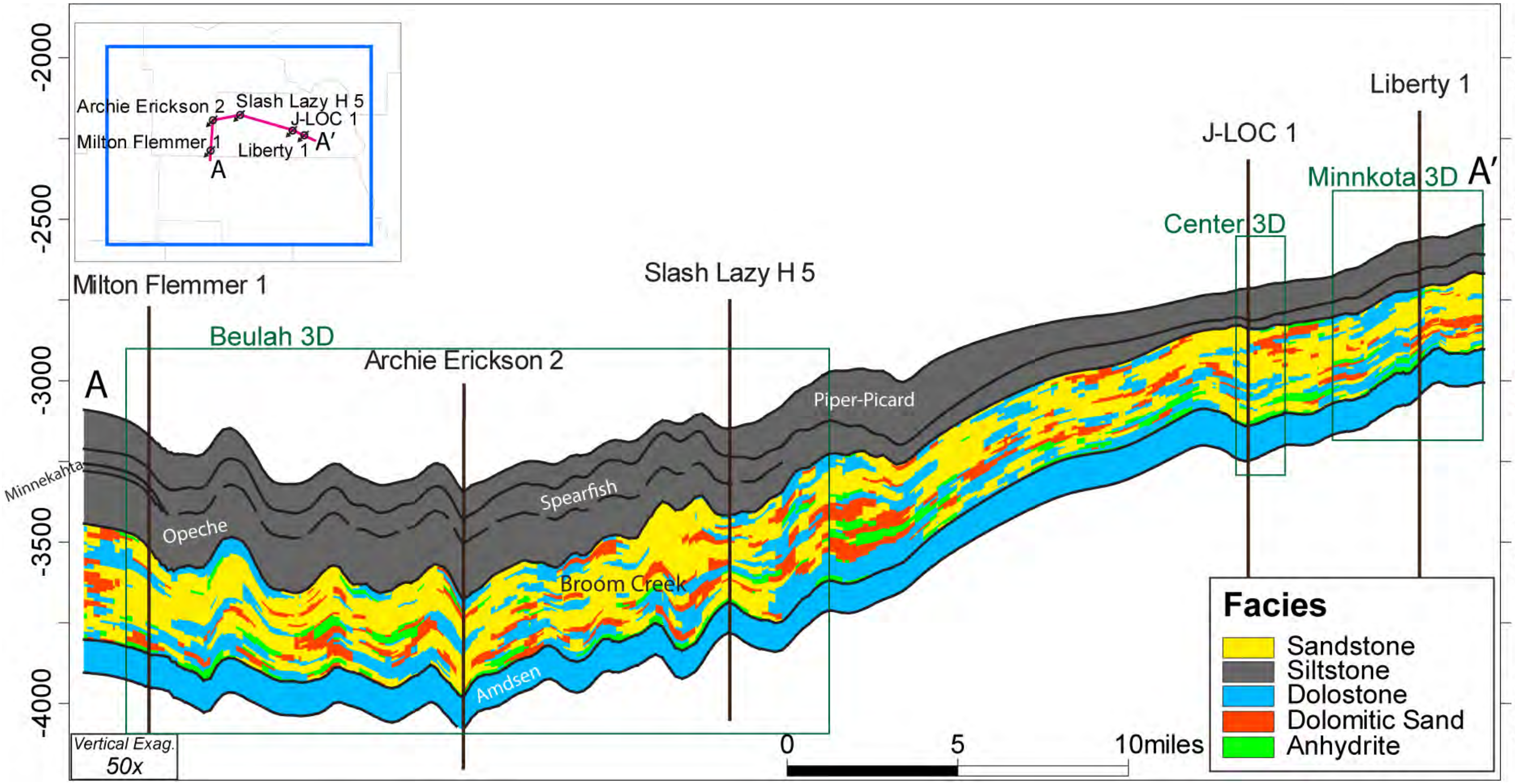


Figure 2-15. Cross section of the TB Leingang storage complex from the geologic model showing facies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. Geologic model extent is displayed by the blue box in the inset map in the upper-left corner.

Table 2-6. Description of CO_2 Storage Reservoir (injection zone) at Milton Flemmer 1

Injection Zone Core Derived Properties

Property	**Description**
Formation Name	Broom Creek
Lithology	Sandstone, dolostone, anhydrite
Formation Top Depth (MD), ft	5818
Thickness, ft	342 (sandstone 240, dolostone 81, anhydrite 21)
Capillary Entry Pressure (brine/ CO_2), psi	1.12

Geologic Properties

Formation	**Property**	**Laboratory Analysis**	**Simulation Model Property Distribution**
Broom Creek (sandstone)	Porosity, % *	15.5 (0.3–26.1)	22.0 (0.0–35.3)
	Permeability, mD**	674.71, 13.55 (0.00103–2700)	458.79, 136.96 (0.0–3401.2)
Broom Creek (dolostone)	Porosity, %*	6.1 (1.4–14.6)	4.4 (0.0–34.9)
	Permeability, mD**	0.4107, 0.0147 (0.0005–3.34)	2.07, 0.0221 (0.0–919.6)

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses. Values are measured at 2400 psi.

** Permeability values are reported as the arithmetic mean and geometric mean, respectively, followed by the range of values in parentheses and do not have the 2.5 permeability calibration factor applied during simulation. Values are measured at 2400 psi.

Core-derived measurements from Milton Flemmer 1 were used as the foundation for the generation of porosity and permeability properties within the 3D geologic model. The 1-in.-diameter core plug sample measurements showed good agreement with the geologic model property distribution at the location of Milton Flemmer 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 geologic model property distribution statistics shown in Table 2-6 are derived from a combination of the 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 because of brine salinity, and high sonic slowness measurements (Figure 2-11). 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 begins to increase in a transition from predominantly sandstone to dolostone (Figure 2-16).

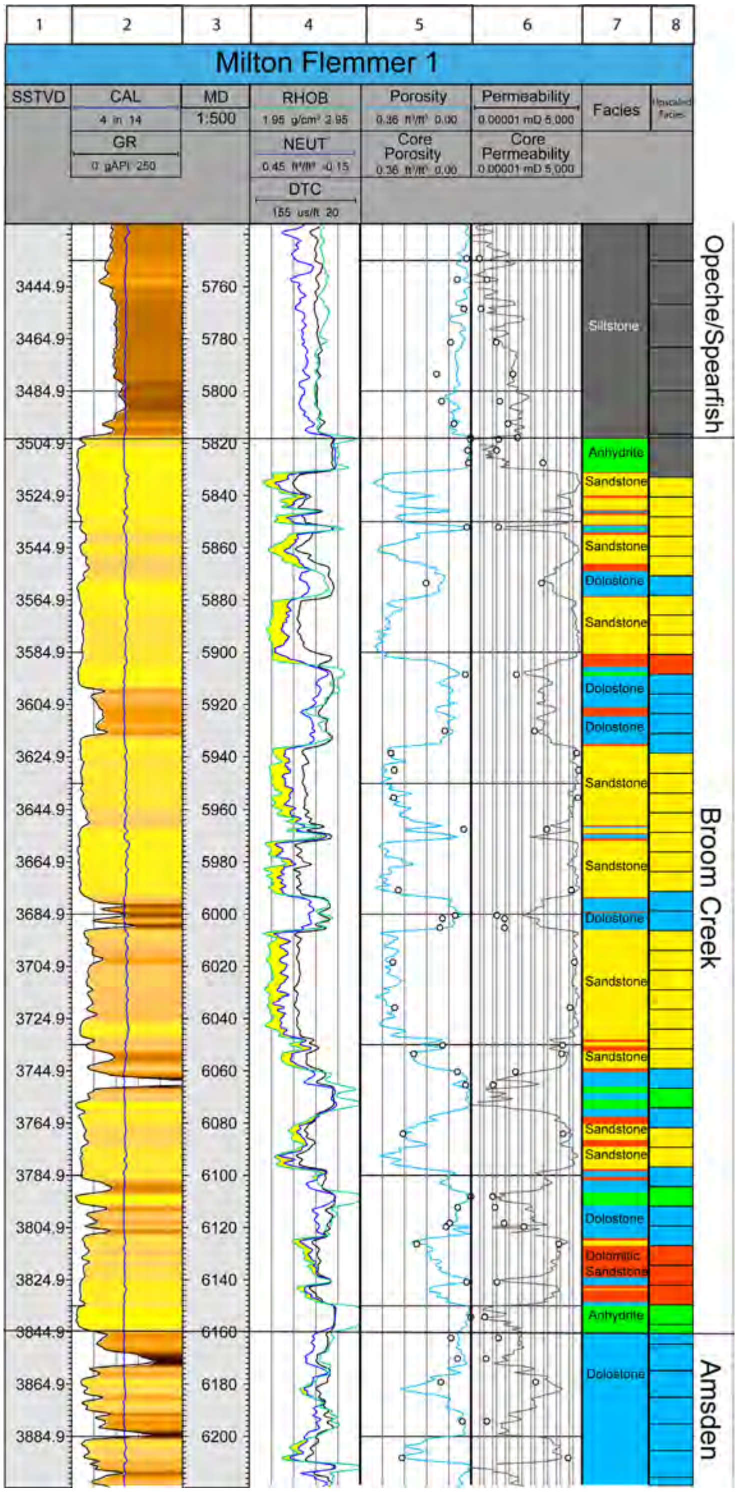


Figure 2-16. Vertical distribution of core-derived porosity and permeability values in the TB Leingang storage complex from Milton Flemmer 1. Tracks from left to right are 1) SSTVD; 2) GR (black) and caliper (dark blue); 3) MD; 4) delta time (black), NEUT (blue), and bulk density (green); 5) core porosity (2400 psi) and log porosity (light blue); 6) core permeability (2400 psi) and log permeability (black); 7) facies; and 8) upscaled facies.

2.3.1 Mineralogy of the Injection Zone

Powder XRD for average bulk composition analysis of 36 finely ground, homogenized samples from the Broom Creek Formation shows quartz as the most common mineral (~52%) followed by carbonates (~22%, primarily dolomite with minor contributions from ankerite and siderite), sulfates (~16%, mostly anhydrite with a minor amount of gypsum), feldspar (~6%, mostly K-feldspar), and clay minerals (~3%, mostly illite) (Figure 2-17a). Minor amounts of oxide/hydroxide (~0.3%), halide (~0.1%), and sulfide (~0.1%) make up the rest of the mineralogy. The major constituents of the Broom Creek Formation are shown in Table 2-7a. These results align with the average elemental composition obtained by XRF which shows silica (Si) as the dominant element followed by calcium (Ca), sulfur (S), magnesium (Mg), aluminum (Al), potassium (K), and other trace elements (Figure 2-17b).

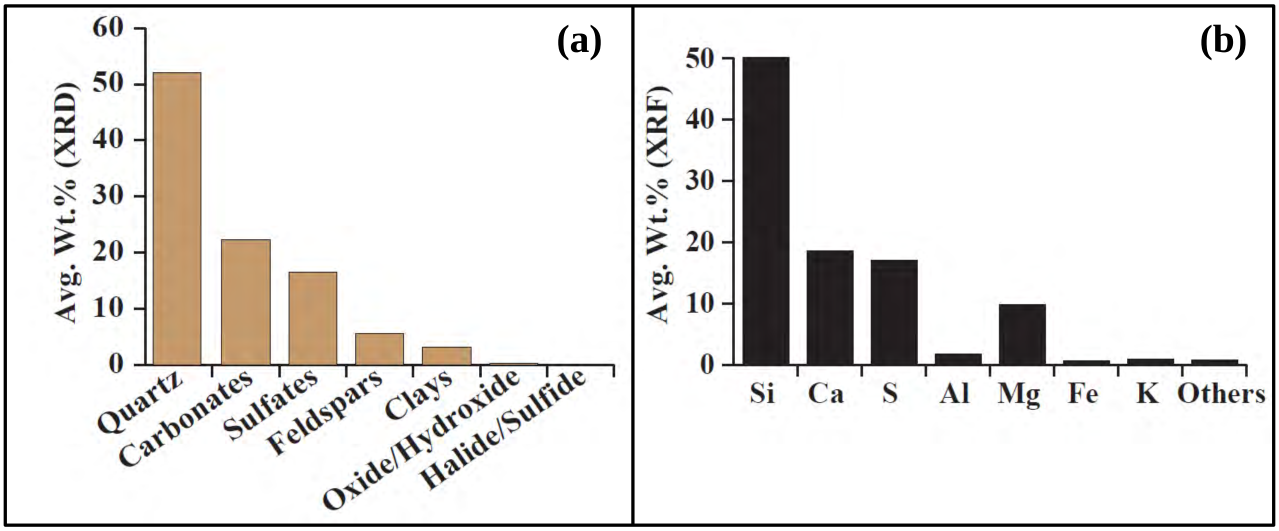


Figure 2-17a. Bar charts showing a) average mineralogy (wt%) and b) average elemental composition (wt%) of the Broom Creek Formation at Milton Flemmer 1 (note: elemental data by XRF were determined as oxides of the respective elements).

XRF analysis of the Broom Creek Formation (Figure 2-17b) shows a high percentage of SiO_2 (0.4%–97%), CaO (0.1%–40%), and MgO (0%–21%) that confirms the presence of sandstone and dolomite intervals in the Broom Creek Formation. A high percentage of CaO and SO_3 at the top and the base of the formation indicates the presence of anhydrite layers that isolate the Broom Creek Formation from the Opeche/Spearfish Formation from the top and Amsden Formation from the bottom. The Broom Creek Formation consists of a clay content ranging from 0% to 24%, with illite being the dominant clay type.

Table 2-7a. XRD Analysis of the Broom Creek Formation at Milton Flemmer 1. Only major constituents are shown.

Sample Name	Core Depth, ft, MD	Log Depth, ft, MD	Feldspar, wt%	Quartz, wt%	Anhydrite, wt%	Dolomite, wt%	Clay, wt%	Others wt%	Illite/Total Clay,* wt%
Broom Creek	5825.5	5818.5	0.00	0.22	86.93	7.74	3.55	1.56	NA**
Broom Creek	5829.7	5822.7	0.00	62.41	35.58	0.00	1.44	0.57	100
Broom Creek	5834.5	5827.5	3.97	56.10	39.35	0.00	0.00	0.58	NA
Broom Creek	5841.6	5834.5	9.50	87.95	0.00	0.00	0.63	1.92	100
Broom Creek	5859.1	5852.1	0.00	64.93	33.45	0.00	1.01	0.61	100
Broom Creek	5880.5	5873.5	0.00	1.59	18.95	77.14	0.00	2.32	NA
Broom Creek	5891.3	5884.3	6.81	91.54	0.00	0.00	0.75	0.90	100
Broom Creek	5906.7	5898.0	13.56	82.57	0.00	0.00	2.28	1.59	100
Broom Creek	5915.5	5908.5	0.00	1.31	41.07	53.75	0.00	3.87	NA
Broom Creek	5937.1	5930.1	3.67	66.73	2.91	21.04	2.77	2.88	100
Broom Creek	5945.6	5938.6	6.06	88.62	0.00	1.36	1.25	2.71	100
Broom Creek	5953.0	5945.0	7.32	89.48	0.44	0.73	1.02	1.01	100
Broom Creek	5963.4	5955.4	6.30	90.48	0.00	0.60	1.07	1.55	100
Broom Creek	5975.5	5967.8	1.18	0.54	6.91	82.89	2.57	5.91	100
Broom Creek	5998.8	5990.8	14.03	78.15	0.00	4.35	1.95	1.52	100
Broom Creek	6008.5	6000.5	7.49	1.97	0.00	78.82	3.38	8.34	100
Broom Creek	6009.7	6003.3	17.05	54.88	0.00	1.72	23.42	2.93	100
Broom Creek	6012.2	6005.2	5.42	5.44	1.71	75.20	4.00	8.23	100
Broom Creek	6019.5	6012.5	4.10	87.51	0.00	3.17	2.40	2.82	100
Broom Creek	6025.4	6018.4	7.05	86.79	2.97	1.00	1.07	1.12	100
Broom Creek	6031.4	6024.4	8.06	86.51	0.00	2.09	0.59	2.75	100
Broom Creek	6039.7	6032.7	4.01	88.73	0.00	3.59	1.42	2.25	100
Broom Creek	6042.8	6035.8	15.78	72.86	0.00	8.03	1.75	1.58	100
Broom Creek	6057.2	6050.2	6.34	52.59	33.44	2.10	2.07	3.46	100
Broom Creek	6060.5	6053.9	3.87	71.02	10.71	6.92	1.66	5.82	100
Broom Creek	6067.4	6060.4	4.46	46.71	0.00	30.03	11.42	7.38	100
Broom Creek	6072.4	6065.3	1.69	3.98	0.97	85.95	3.57	3.84	100
Broom Creek	6091.1	6084.1	14.40	57.33	7.46	17.34	1.54	1.93	100
Broom Creek	6100.1	6093.1	3.30	81.56	11.30	0.00	1.09	2.75	100
Broom Creek	6115.1	6108.1	0.00	2.15	88.42	7.60	1.08	0.75	100
Broom Creek	6119.3	6112.3	8.50	17.63	0.94	66.26	1.97	4.70	100
Broom Creek	6125.3	6118.3	6.02	53.08	8.73	6.93	24.39	0.85	100
Broom Creek	6126.7	6119.3	1.23	10.60	6.72	79.24	0.00	2.21	NA
Broom Creek	6133.3	6126.3	8.03	71.50	0.00	18.60	1.57	0.30	100
Broom Creek	6147.9	6140.9	2.97	59.36	36.25	0.00	1.20	0.22	100
Broom Creek	6161.2	6154.1	0.00	1.49	93.29	2.62	2.00	0.60	100

*Illite component of clays.

**NA; no illite component was detected by XRD.

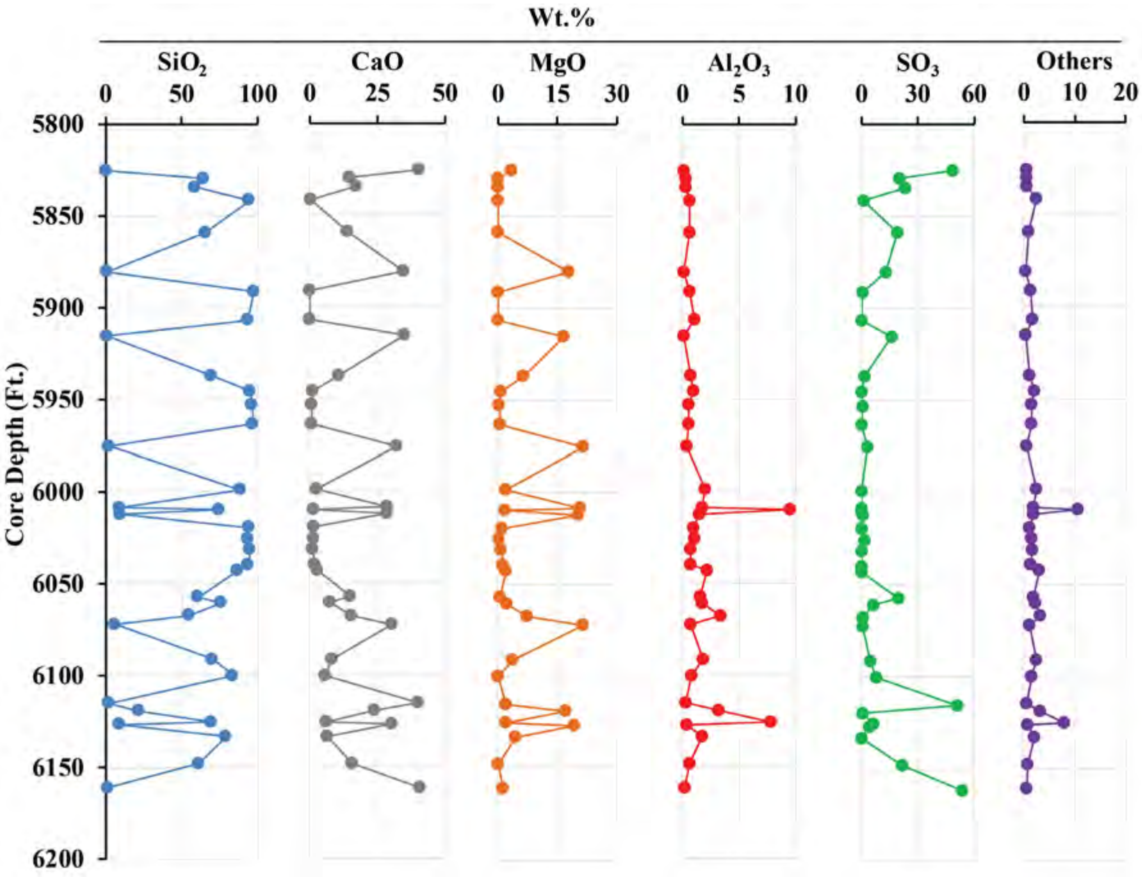


Figure 2-17b. Elemental composition by XRF as a function of depth in the Broom Creek Formation at Milton Flemmer 1.

The Broom Creek Formation midsection at a core depth of 5945.6–6091.1 ft and KB elevation of 5938.6–6084.1 ft represents a highly porous and permeable zone averaging more than 20% total porosity, reaching as high as 33% total porosity at some intervals, with permeability of >1000 mD. Thin-section and SEM–EDS (energy-dispersive spectroscopy) micrographs of the most porous sample show moderately to well-sorted, subrounded to subangular, and fine quartz and feldspar grains, with quartz grains constituting about 87% of the composition (Figures 2-18a and c). Contacts between the grains are mostly tangential with intergranular spaces occasionally occupied by minor amounts of siderite, dolomite, and silica (Figure 2-18c). In contrast, the least porous sample with ultralow permeability located at the Opeche/Spearfish Formation–Broom Creek Formation boundary primarily consists of anhydrite (~87%), dolomite (~8%), and clay minerals with some microfractures (Figures 2-18b and d). Figure 2-19 shows changes in the mineralogy at Milton Flemmer 1 as a function of depth next to the core sample porosity and permeability data. The Broom Creek Formation is highlighted in gray.

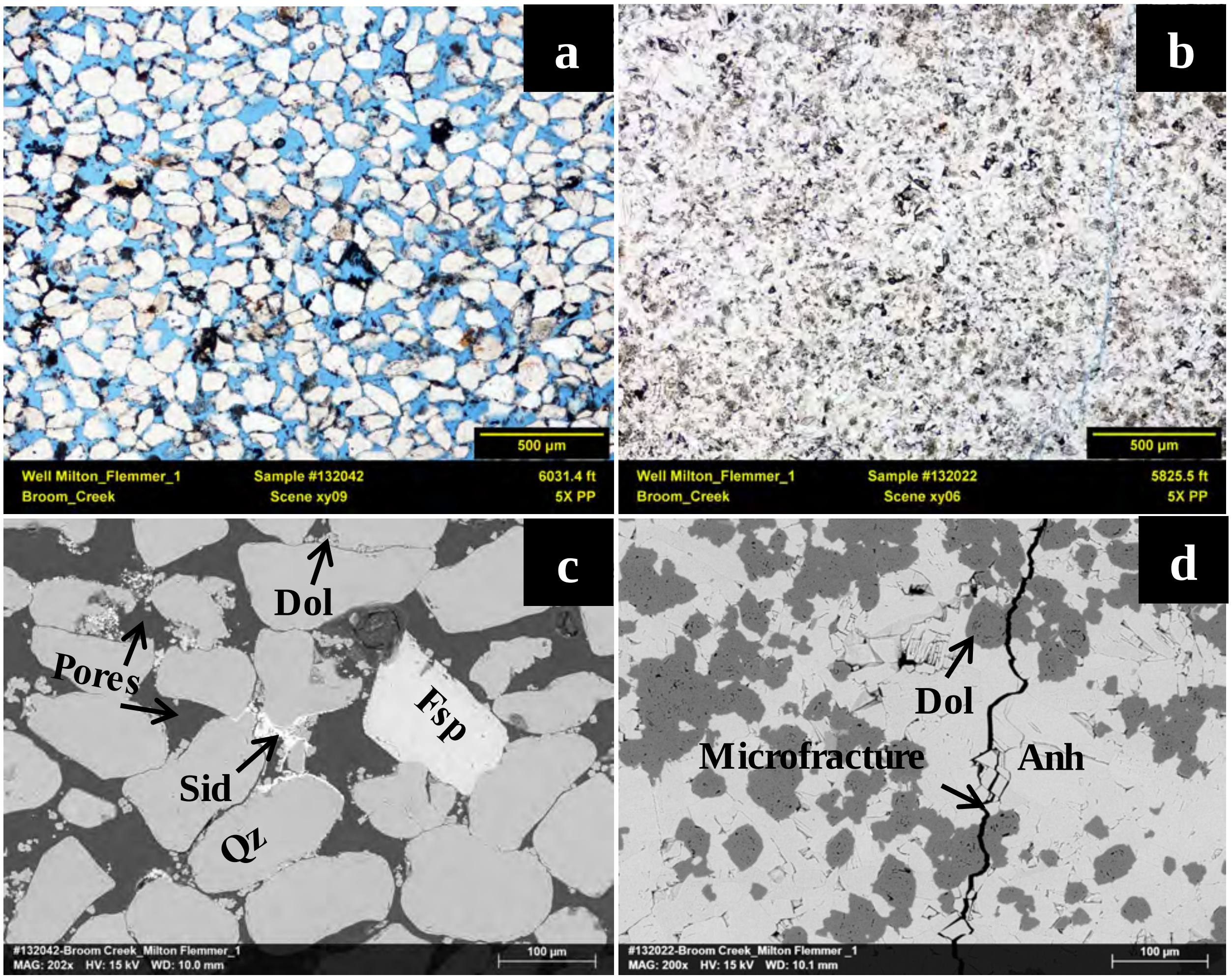


Figure 2-18. Thin-section (a, b) and SEM (c, d) micrographs of the most porous (a, c) and the least porous (b, d) samples from the Broom Creek Formation at Milton Flemmer 1. The most porous sample has a total porosity and permeability of 33% and >1000 mD, respectively, which notably reduced to 0.37% and 0.000891 mD in the least porous sample. The blue color in the thin-sections (a and b) represents porosity.

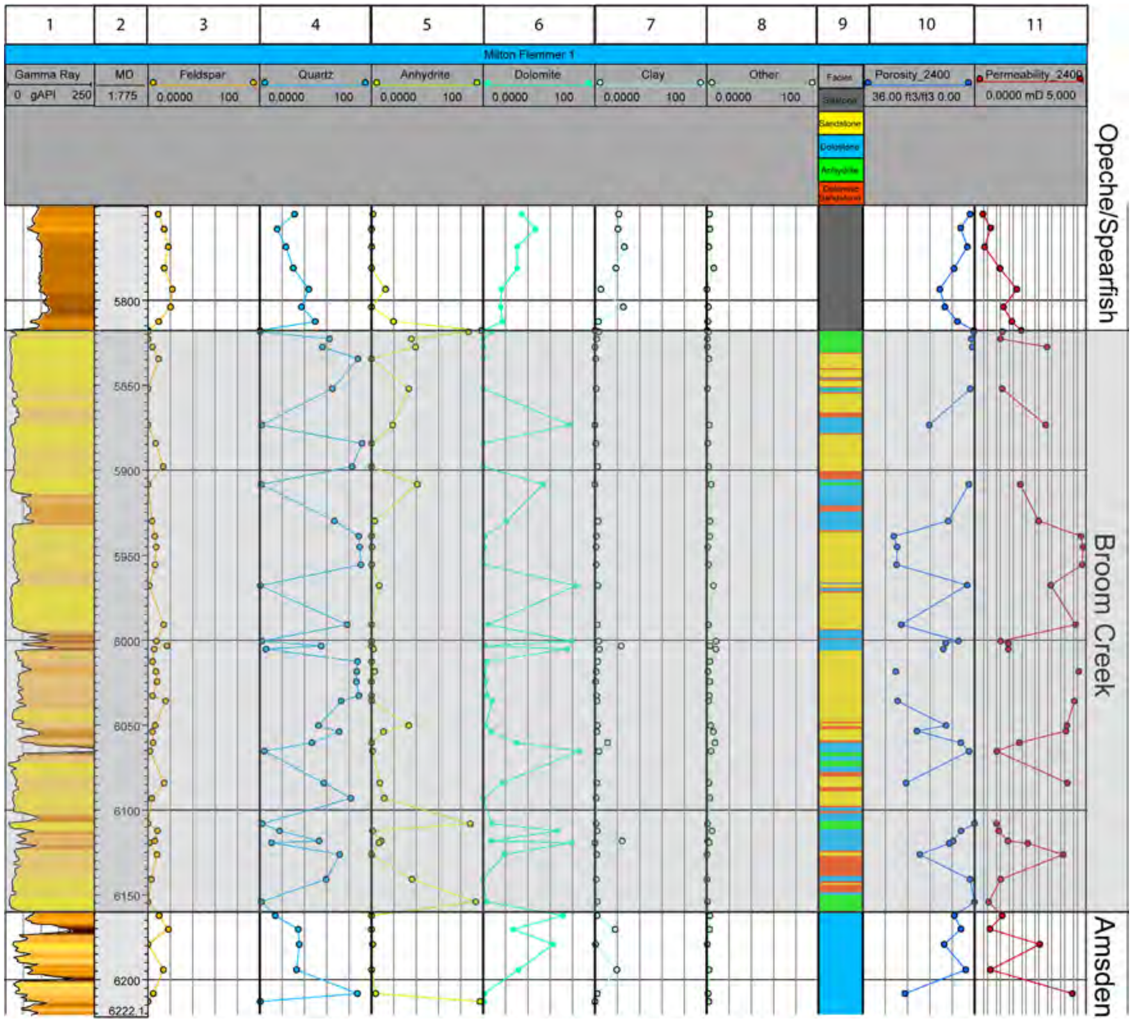


Figure 2-19. Change in the mineralogy of the target reservoir Broom Creek Formation (highlighted in gray) at Milton Flemmer 1 as a function of depth based on XRD in comparison to GR, facies, core sample total porosity (%), and permeability (mD). Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (e.g., samples too soft/brittle). Tracks from left to right are 1) GR (black), 2) MD, 3) total feldspar (orange), 4) quartz (blue), 5) anhydrite (yellow green), 6) dolomite (green), 7) total clay (light blue), 8) other (light green), 9) facies, 10) core porosity (2400 psi) (dark blue), and 11) core permeability (2400 psi) (red).

2.3.2 Mechanism of Geologic Confinement

For TB Leingang, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the upper confining formation (Opeche/Spearfish Formation), which will contain the initially buoyant CO_2 in the reservoir 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.

2.3.3 Geochemical Information of the Injection Zone

Geochemical simulation was 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 GEM, the compositional simulation software package from Computer Modelling Group Ltd. (CMG). For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 20-year period with maximum BHP and maximum wellhead pressure (WHP) constraints of 3663 and 2100 psi, 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.

A geochemical simulation scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared. The results do not show an evident difference in the CO_2 gas molality fraction between the two cases for volume injected and injection pressure simulation results. As a result of geochemical reactions in the reservoir, cumulative volume and injection rate have no observable difference between the geochemical and nongeochemical cases. Additionally, the simulation results showed no significant precipitation caused by the presence of O_2 that would affect the CO_2 injection volume as demonstrated by the comparison in injection rates between the case with and without geochemical modeling. Simulation results show that, during CO_2 injection, the supercritical CO_2 (free-CO_2 gas) remains dominant. CO_2 dissolution in the formation water and residual trapping of CO_2 slowly increased over time, while CO_2 mineralization is negligible. The result is a small change in simulated porosity, less than 0.01% porosity units, equating to a maximum increase in average porosity from 22.00% to 22.01% after the 20-year injection period plus 25 years of postinjection. A full description of the geochemical results for the injection zone can be found in Appendix C.

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the overlying Opeche/Spearfish Formation and the underlying Amsden Formation (Figure 2-2, Table 2-7b). Both the overlying and underlying confining formations consist primarily of impermeable rock layers.

Table 2-7b. Properties of Upper and Lower Confining Zones at Milton Flemmer 1

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Stratigraphic Unit	Opeche/Spearfish	Amsden
Lithology	Siltstone/anhydrite/ dolostone	Dolostone/ anhydrite/sandstone
Formation Top Depth (MD), ft	5587	6160
Thickness, ft	231	261
Capillary Entry Pressure (brine/CO_2), psi	750.8	306.5
Depth below Lowest Identified USDW, ft	3788	4361

Formation	Property	Laboratory Analysis	Simulation Model Property Distribution
Opeche/Spearfish	Porosity, %*	5.2 (0.2–11.2)	2.1 (0.0–14.6)
	Permeability, mD **	0.009189, 0.001224 (0.0000439–0.0434)	0.1088, 0.0021 (0.00–6.37)
Amsden	Porosity, % *	9.2 (2.9–22.5)	2.9 (0.0–35.1)
	Permeability, mD **	81.83, 0.028012 (0.000152–408)	0.7056, 0.0070 (0.00–156.05)

* Porosity values recorded at 2400-psi confining pressure. Porosity values from the model are reported as the arithmetic mean followed by the range of values in parentheses.

** Permeability values recorded at 2400-psi confining pressure. Permeability values are reported as the arithmetic mean and geometric mean, respectively, followed by the range of values in parentheses and do not have the 2.5 permeability calibration factor applied during simulation.

2.4.1 Upper Confining Zone

In TB Leingang, the upper confining zone, the Opeche/Spearfish Formation, consists of predominantly siltstone with interbedded dolostone and anhydrite (Table 2-7a). The upper confining zone is laterally extensive across the simulation model area (Figure 2-20) and is 5587 ft below KB elevation and 231 ft thick as observed in Milton Flemmer 1 (Figures 2-20 and 2-21). The contact between the underlying Broom Creek Formation 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 Opeche/Spearfish Formation (Figure 2-11).

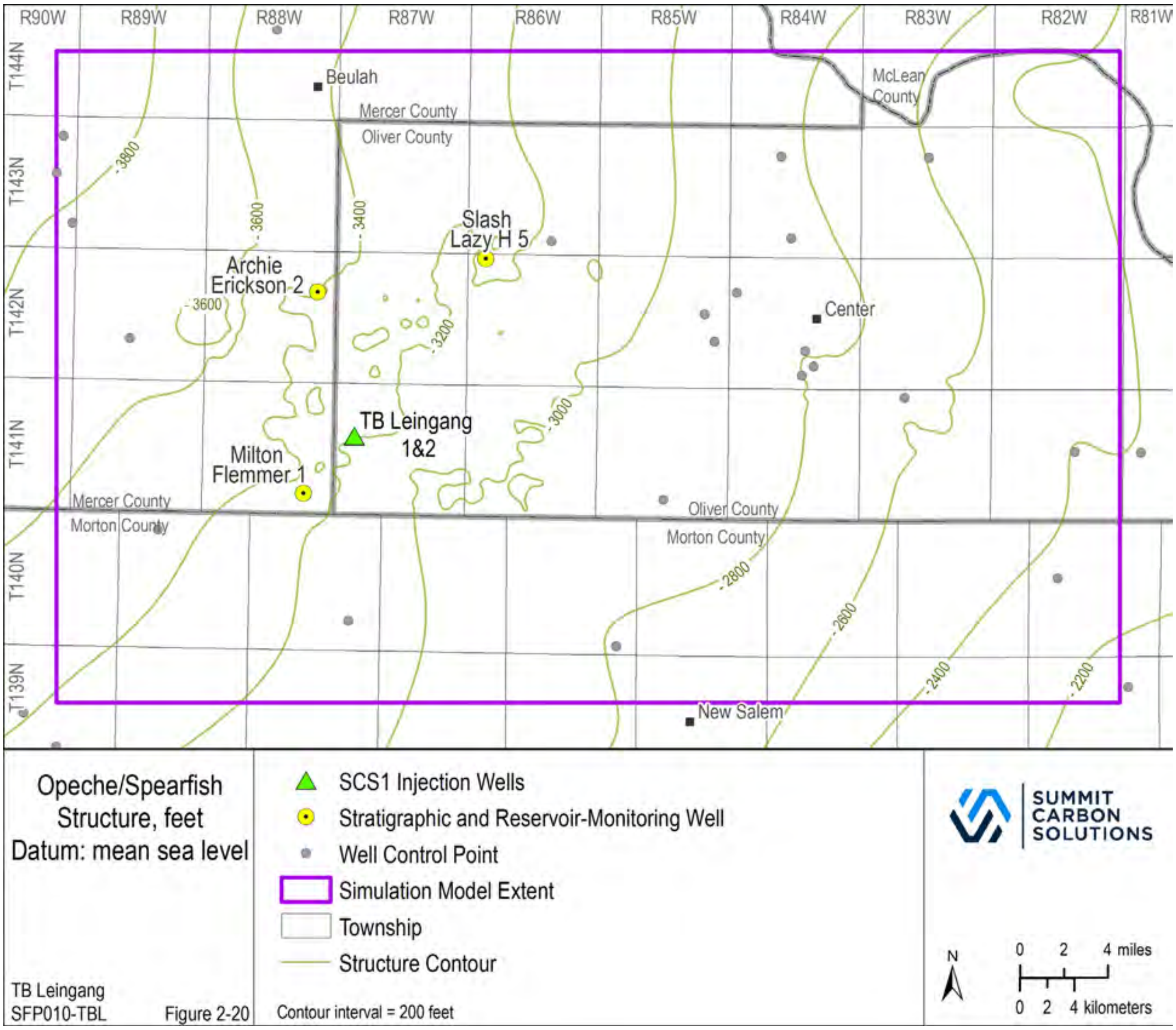


Figure 2-20. Structure map of the Opeche/Spearfish Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

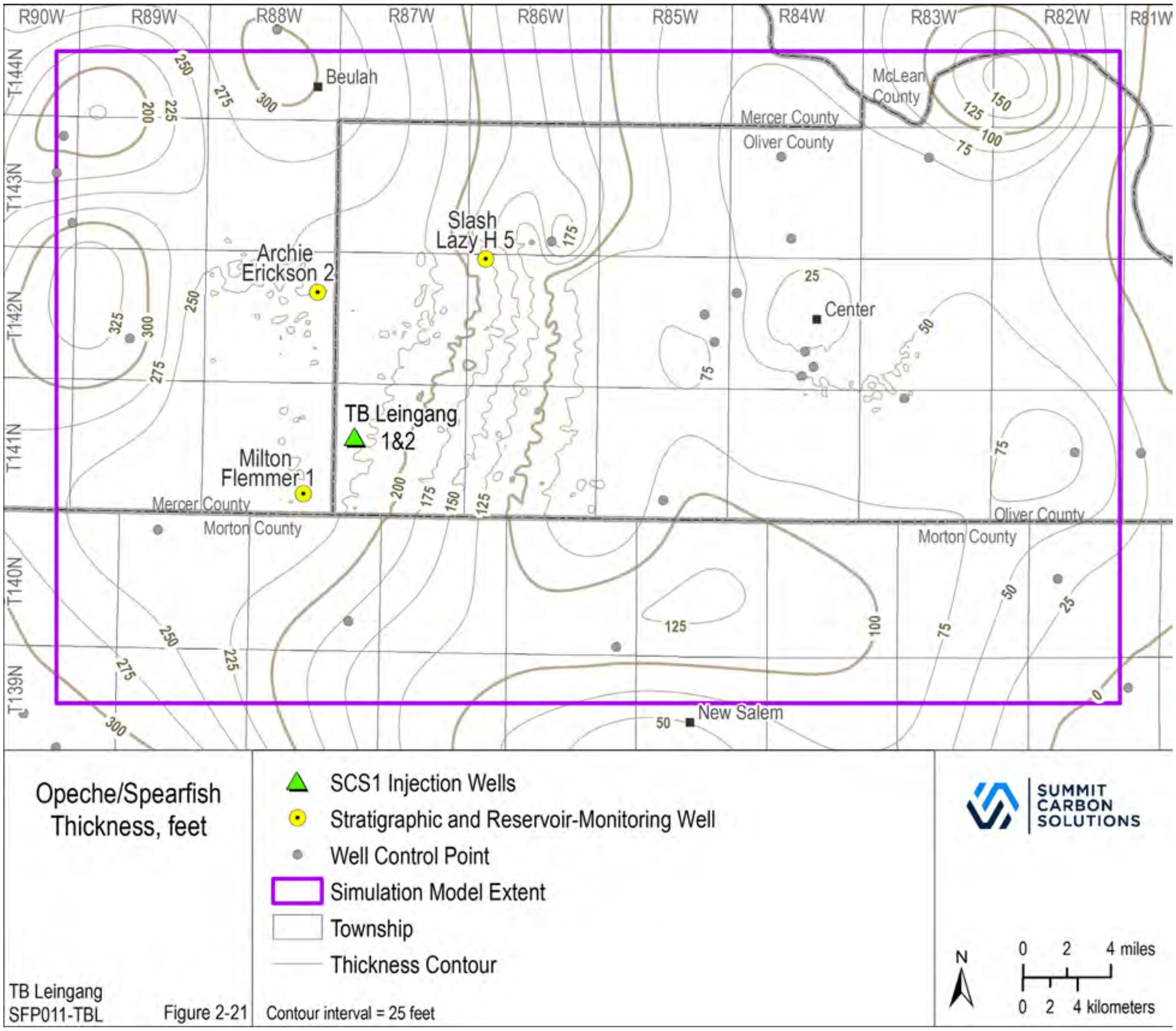


Figure 2-21. Isopach map of the Opeche/Spearfish Formation in the simulation model area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

2.4.1.1 Mineralogy of the Upper Confining Zone

Powder XRD for average bulk composition analysis of eight finely ground, homogenized samples from the Opeche/Spearfish Formation shows quartz as the most common mineral (~29%) followed by carbonates (~25%, mostly dolomite with a minor contribution from ankerite), sulfates (~17%, mostly anhydrite), potassium- and sodium-feldspar (~7% each), and clay minerals (~15%, mostly illite and chlorite) (Figure 2-22a). Minor amounts of sulfide (~0.1%) and oxide/hydroxide (~0.1%) minerals make up the rest of the mineralogy. The major constituents of the Opeche/Spearfish Formation are also shown in Table 2-7c. XRD data align with the average elemental composition obtained by XRF which show silica (Si) as the dominant element followed by calcium (Ca), sulfur (S), aluminum (Al), magnesium (Mg), potassium (K), iron (Fe), and other trace elements (Figure 2-22b).

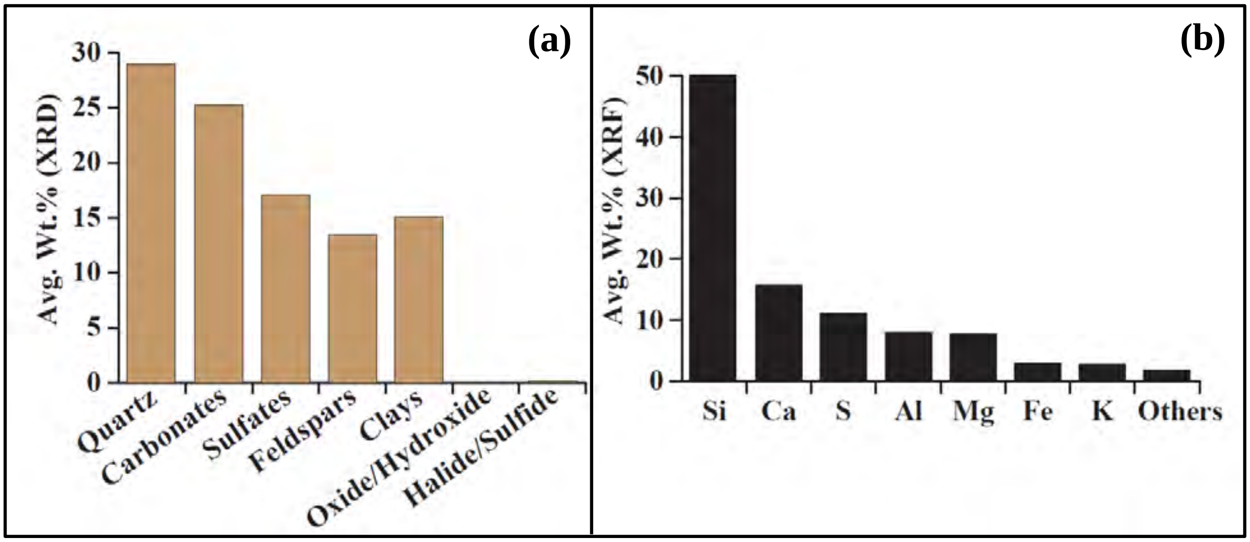


Figure 2-22a. Bar charts showing a) average mineralogy (wt%) and b) average elemental composition (wt%) of the Opeche/Spearfish Formation at Milton Flemmer 1 (note: elemental data by XRF were determined as oxides of the respective elements).

XRF analysis of the Opeche/Spearfish Formation (Figure 2-22b) identifies SiO_2 (0.3%–61%), CaO (5%–41%), and MgO (0.2%–16%) correlating well with the silicate, carbonate, and aluminum-rich mineralogy determined by XRD. A high percentage of CaO and SO_3 at the base of the Opeche/Spearfish Formation indicates the presence of an anhydrite interval separating the Opeche/Spearfish Formation from the Broom Creek Formation. The Opeche/Spearfish Formation consists of a much higher clay content compared to the Broom Creek Formation ranging from 56% to 89%, with illite being the most dominant clay type.

Table 2-7c. XRD Analysis of the Opeche/Spearfish Formation at Milton Flemmer 1. Only major constituents are shown.

Sample Name	Core Depth, ft, MD	Log Depth, ft, MD	Feldspar, wt%	Quartz, wt%	Anhydrite, wt%	Dolomite, wt%	Clay, wt%	Others, wt%	Illite/Total Clay,* %
Opeche/Spearfish	5756.2	5749.2	9.18	31.17	1.28	34.56	21.33	2.48	85
Opeche/Spearfish	5764.3	5758.0	14.40	15.59	0.00	46.57	20.59	2.85	83
Opeche/Spearfish	5775.5	5768.5	18.15	23.44	0.00	30.34	26.28	1.79	89
Opeche/Spearfish	5788.3	5781.0	14.41	30.01	0.00	30.49	18.74	6.35	85
Opeche/Spearfish	5800.5	5793.5	21.77	43.89	12.57	16.24	5.29	0.24	56
Opeche/Spearfish	5810.9	5803.9	20.19	37.33	0.00	15.66	25.42	1.40	88
Opeche/Spearfish	5819.5	5812.5	9.55	49.66	19.71	17.15	3.02	0.91	84
Opeche/Spearfish	5824.8	5817.8	0.00	0.29	98.34	0.96	0.00	0.41	NA**

*Illite component of clays.

**NA; no Illite component was detected by XRD.

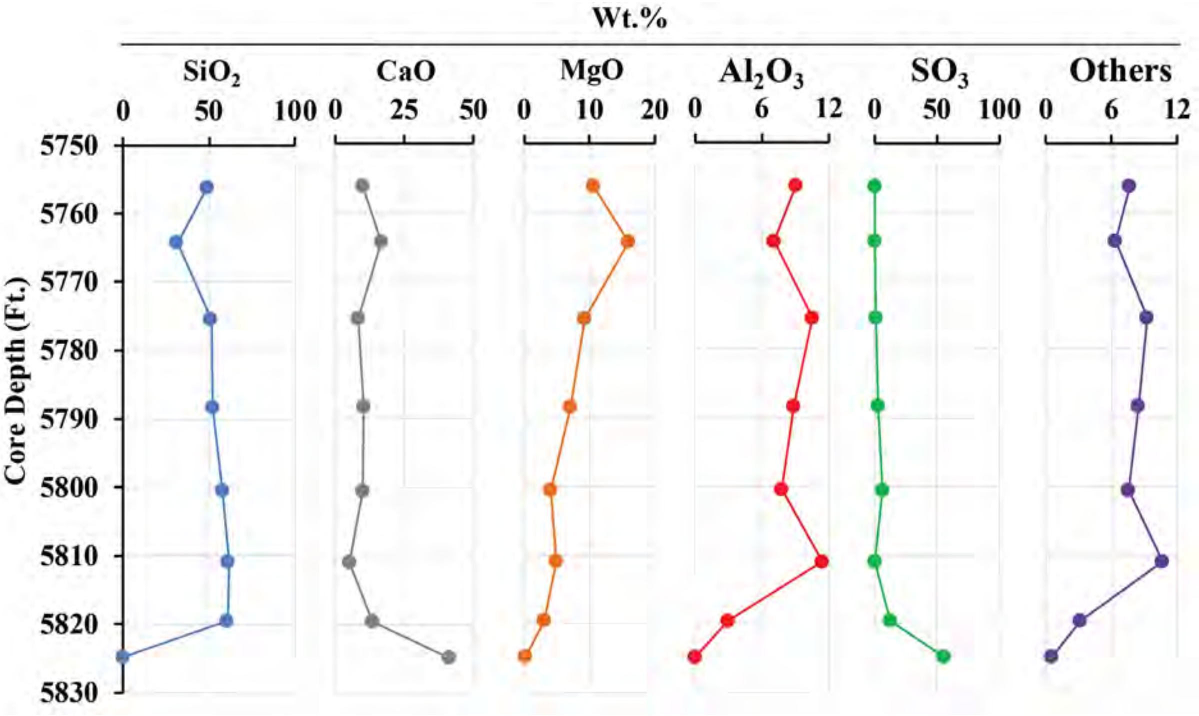


Figure 2-22b. Elemental composition by XRF as a function of depth in the Opeche/Spearfish Formation at Milton Flemmer 1.

Thin-section and SEM–EDS micrographs of the most porous sample located at the midsection (core depth of 5800.5 ft KB elevation of 5793.5 ft) of the Opeche/Spearfish Formation show tightly associated fine grains of quartz, feldspar, and dolomite with anhydrite and clay cement (Figures 2-23a and c). Contacts between the grains are mostly long, sutured, and concavo-convex, giving rise to isolated and discontinuous pore spaces (Figure 2-23c). The least porous sample, located at the Opeche/Spearfish Formation–Broom Creek Formation boundary (core depth of 5824.8 ft KB elevation of 5817.8 ft) primarily consists of anhydrite (~98%) with some microfractures (Figures 2-23b and d). Figure 2-24 shows changes in the mineralogy at Milton Flemmer 1 as a function of depth next to the core sample porosity and permeability data. The Opeche/Spearfish Formation is highlighted in gray.

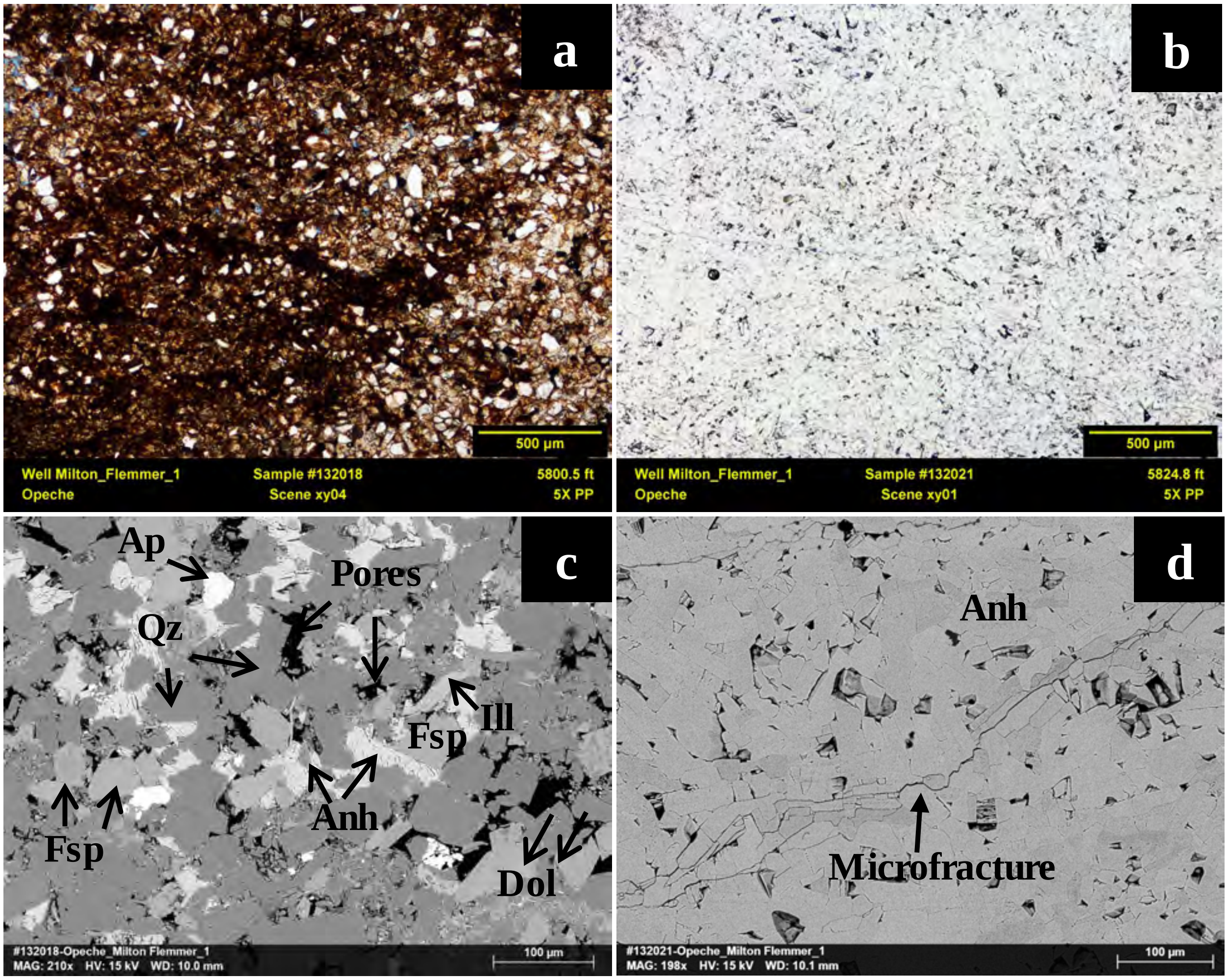


Figure 2-23. Thin-section (a, b) and SEM (c, d) micrographs of the most porous (a, c) and the least porous (b, d) samples from the Opeche/Spearfish Formation at Milton Flemmer 1. The most porous sample has a total porosity and permeability of 11% and 0.0359 mD, respectively, which is notably reduced to 0.33% and 0.178 mD in the least porous sample. The blue color in the thin-sections (a and b) represents porosity.

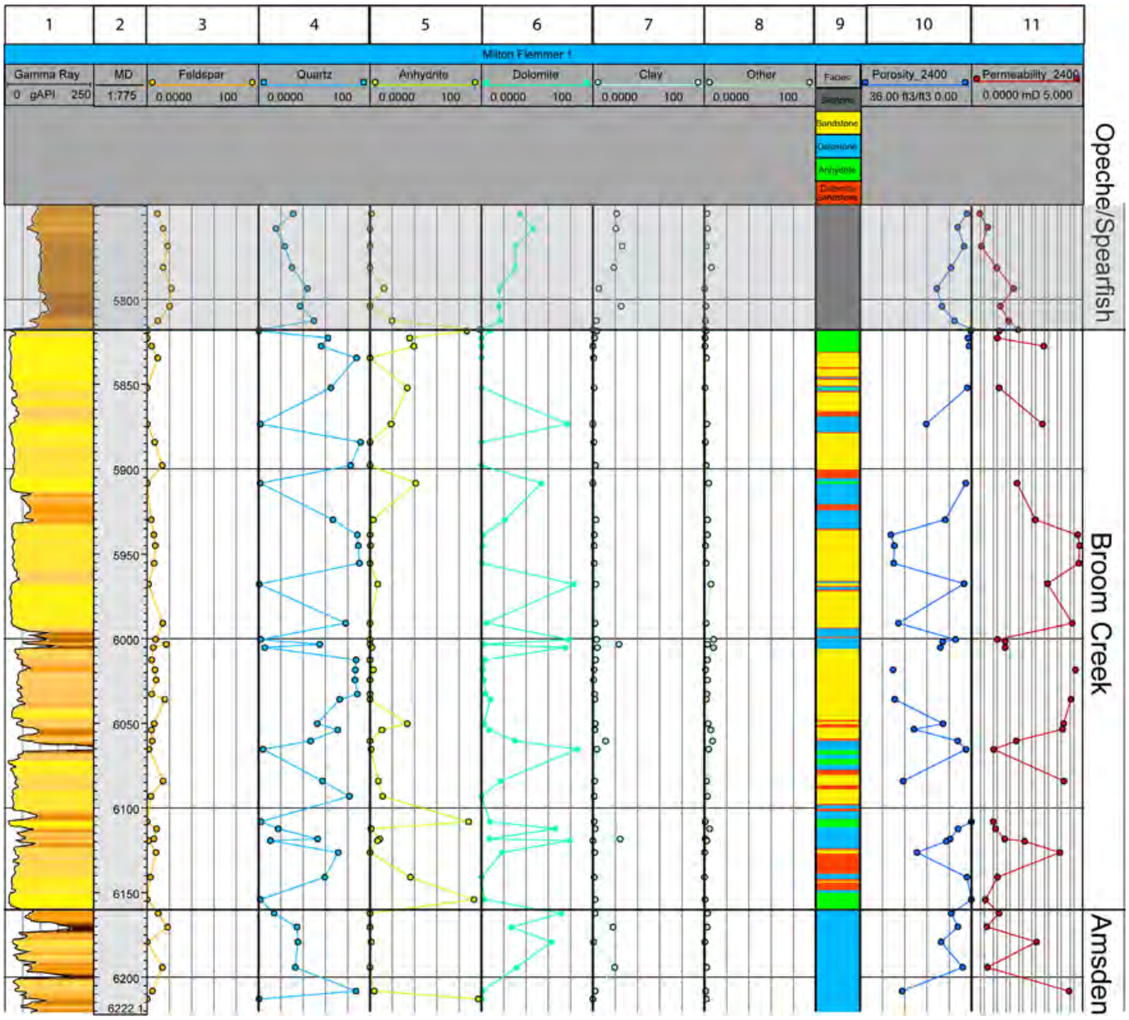


Figure 2-24. Change in the mineralogy of the upper-confining Opeche/Spearfish Formation (highlighted in gray) at Milton Flemmer 1 as a function of depth based on XRD in comparison to GR, facies, core sample total porosity (%), and permeability (mD). Very low total porosity and permeability with a high clay content make the Opeche/Spearfish Formation an ultralow permeable formation. Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (i.e., samples too soft/brittle). Tracks from left to right are 1) GR (black), 2) MD, 3) total feldspar (orange), 4) quartz (blue), 5) anhydrite (yellow green), 6) dolomite (green), 7) total clay (light blue), 8) other (light green), 9) facies, 10) core porosity (2400 psi) (dark blue), and 11) core permeability (2400 psi) (red).

2.4.1.2 Geochemical Interaction

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected multicomponent CO_2 stream on the Opeche/Spearfish Formation. This geochemical simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection.

Results showed geochemical processes at work. The pH at the interface between the injection zone and upper confining zone has the greatest change in value, declining from its initial value of 6.47 to a level of 5.05 after 10 years of injection, and stabilizes at 5.03 by the end of 25 years of postinjection. K-feldspar starts to dissolve from the beginning of the simulation period, while illite and quartz start to precipitate at the same time. The net change due to precipitation or dissolution at a 1–2-meter interval above the injections zone is less than 5 kg per cubic meter, with little dissolution or precipitation taking place during the later years of simulation. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.1% change during the life of the simulation. These results suggest that geochemical change from exposure to CO_2 is minor; therefore, the ability of the Opeche/Spearfish Formation to maintain its sealing integrity will not be compromised by geochemical processes. A full description of the geochemical results for the upper confining zone can be found in Appendix C.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Opeche/Spearfish Formation. Impermeable rocks above the primary seal include the Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-8a). At Milton Flemmer 1, together with the Opeche/Spearfish Formation, these intervals are 1082 ft thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-25). Above the Inyan Kara Formation, 2670 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and the lowermost USDW, the Fox Hills Formation (Figure 2-26). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-8a).

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).

Table 2-8a. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on Milton Flemmer 1)

Name of Formation	Lithology	Formation Top Depth MD, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Mudstone	1799	1480	0
Niobrara	Mudstone	3279	418	1480
Carlile	Mudstone	3697	49	1898
Greenhorn	Mudstone	3746	116	1947
Belle Fourche	Mudstone	3862	291	2063
Mowry	Mudstone	4153	75	2354
Skull Creek	Mudstone	4231	238	2432
Swift	Mudstone	4736	458	2937
Rierdon	Mudstone	5193	196	3394
Piper (Kline Member)	Carbonate	5389	94	3590
Piper (Picard Member)	Mudstone	5483	104	3684

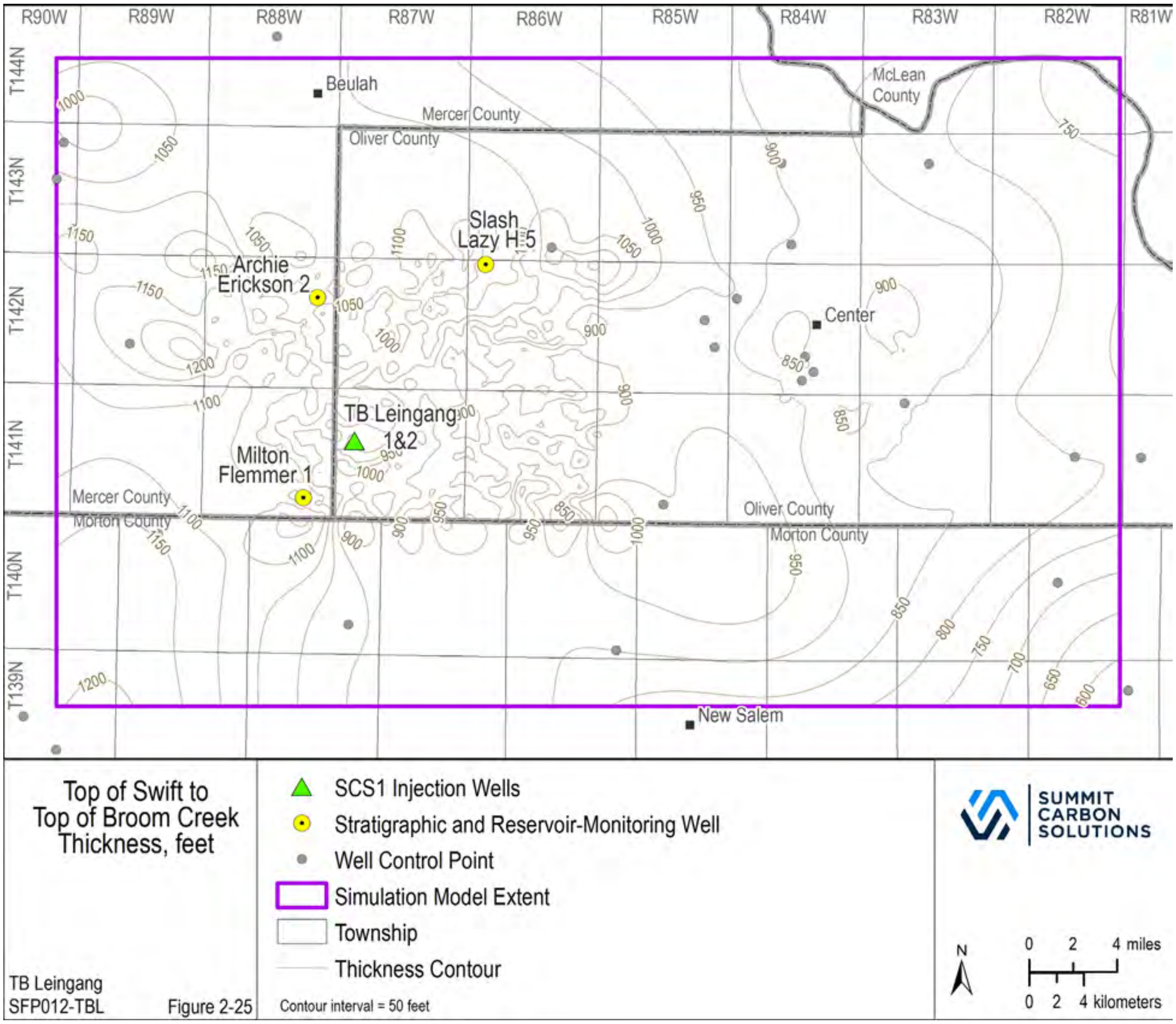


Figure 2-25. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability stratigraphically 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 distributed temperature sensor data for the Inyan Kara Formation using the downhole fiber-optic cable provides an additional opportunity for mitigation and remediation (Section 5.0). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at the Milton Flemmer 1 location is approximately 4469 ft below KB elevation, and the interval itself is 267 ft thick.

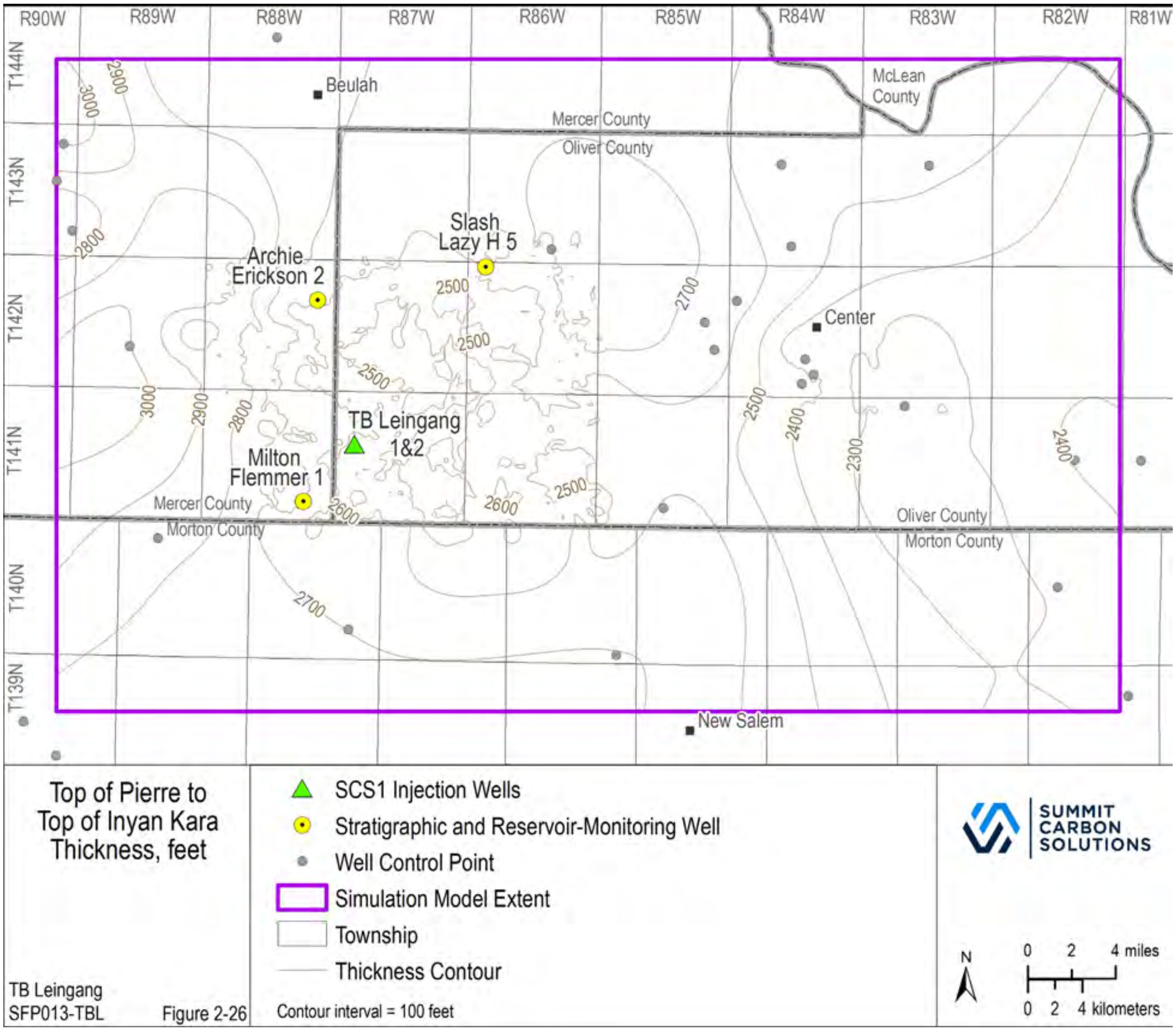


Figure 2-26. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

2.4.3 Lower Confining Zone

The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone and anhydrite. The Amsden Formation does include some thin sandstone intervals on the order of 1 to 8 in. thick. The sandstone intervals in the Amsden Formation are isolated from the sandstones of the Broom Creek Formation by thick impermeable dolostone and anhydrite intervals. 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 simulation model area (Figure 2-11). The Amsden Formation is 6160 ft below KB elevation and 261 ft thick at TB Leingang as determined at Milton Flemmer 1 (Figures 2-27 and 2-28).

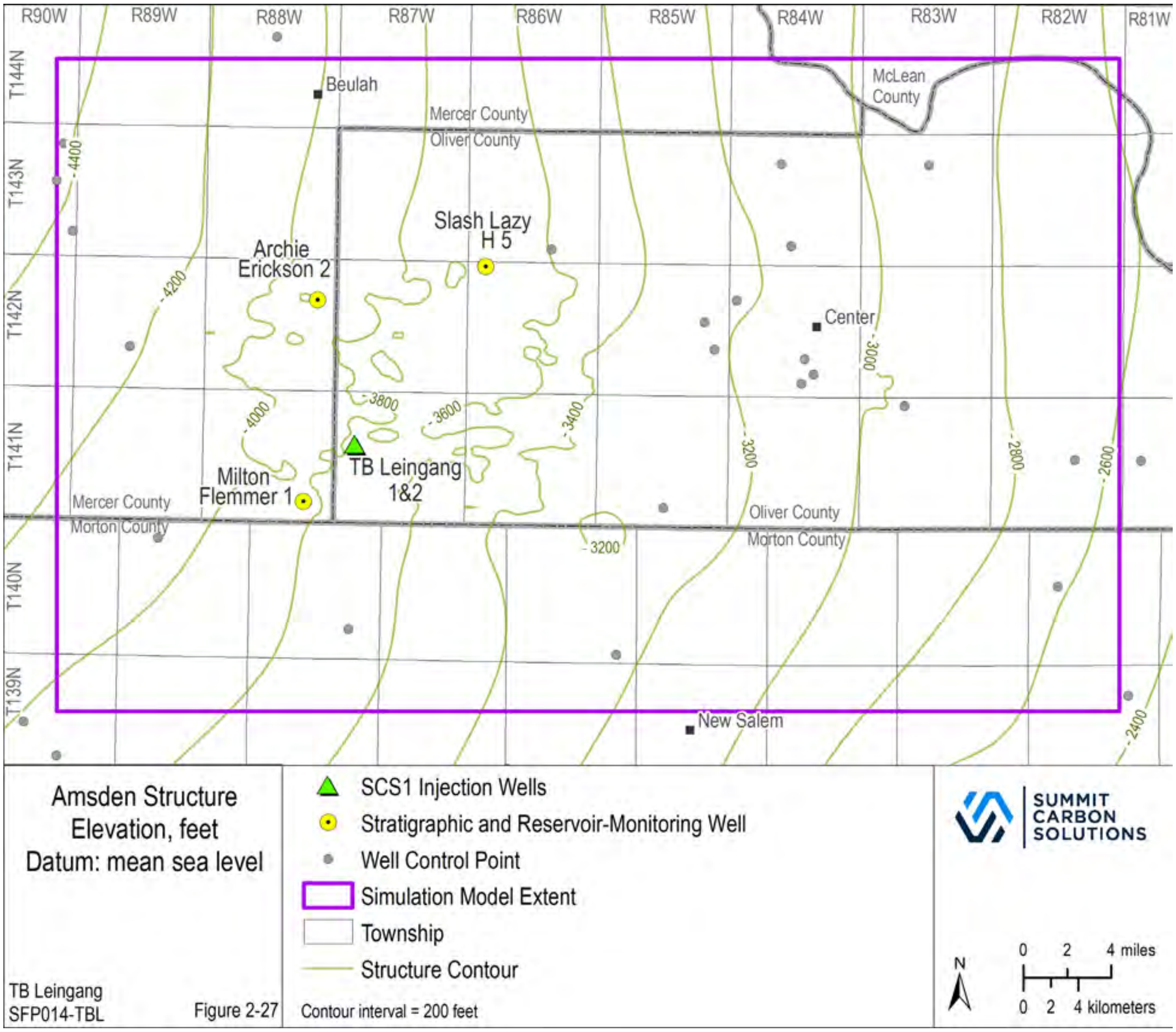


Figure 2-27. Structure map of the Amsden Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

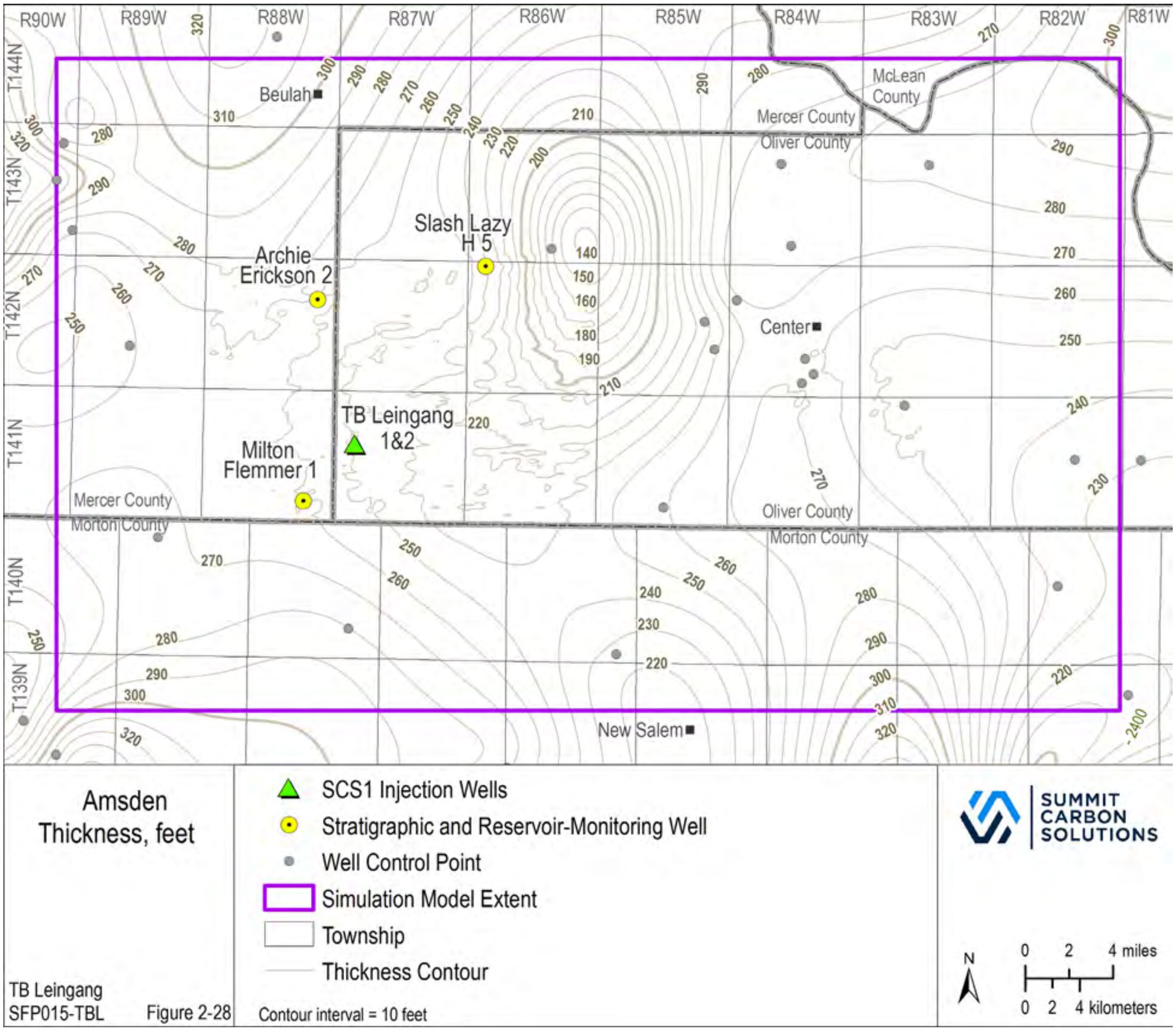


Figure 2-28. Isopach map of the Amsden Formation across the simulation model area. The convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

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 (Figure 2-11). The top of the Amsden in Milton Flemmer 1 is picked at the base of a 10-ft anhydrite bed which can be correlated across much of the study area. This lithologic change is also recognized in the core from Milton Flemmer 1. The lithology of the cored section of the Amsden Formation from Milton Flemmer 1 is predominantly dolostone and anhydrite, with lesser predominant lithologies of sandstone.

2.4.3.1 Mineralogy of the Lower Confining Zone

Powder XRD for average bulk composition analysis of six finely ground, homogenized samples from the Amsden Formation shows equal proportions of quartz (~34%) and carbonates (~33%, mostly dolomite with minor contributions from calcite and ankerite) followed by sulfate (~17%, mostly anhydrite) (Figure 2-29a[a]). Feldspar (mostly K-feldspar) and clay minerals (mostly illite) each account for about 7% of the composition of the Amsden Formation with minor amounts of halide (~0.1%), oxide/hydroxide (~0.1%), and sulfide (~0.2%). The major constituents of the Amsden Formation are also shown in Table 2-8b. These data align with the average elemental composition obtained by XRF which show Si as the dominant element followed by calcium (Ca), sulfur (S), magnesium, (Mg), aluminum (Al), potassium (K), iron (Fe), and other trace elements (Figure 2-29a[b]).

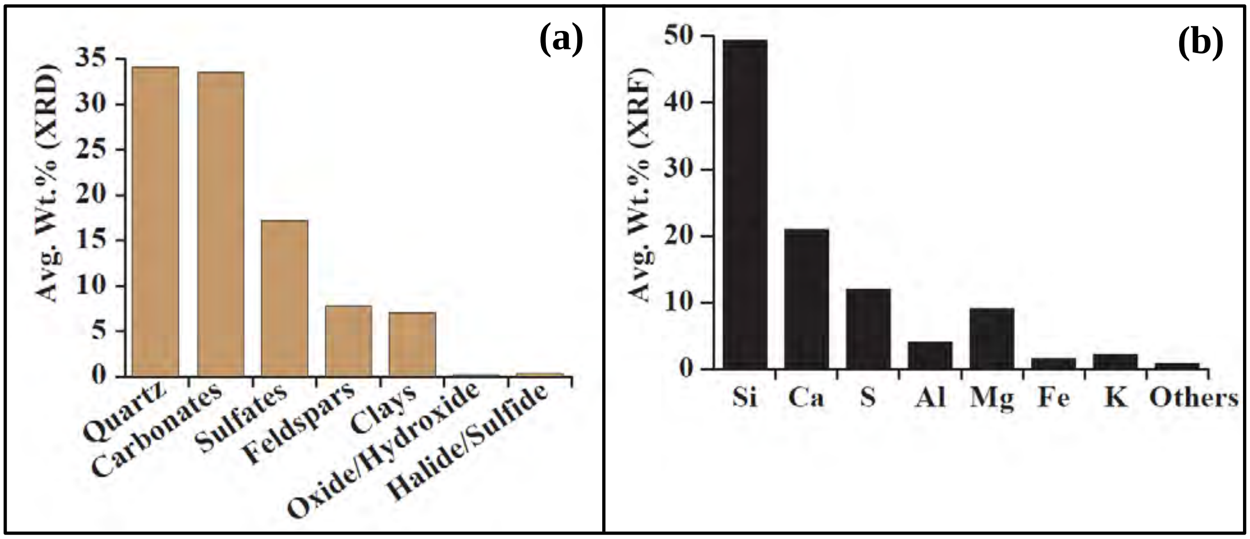


Figure 2-29a. Bar charts showing a) average mineralogy (wt%) and b) average elemental composition (wt%) of the Amsden Formation at the Milton Flemmer 1 well. Elemental data by XRF were determined as oxides of the respective elements.

XRF analysis of the Amsden Formation (Figure 2-29b) shows that the contact between the Amsden and Broom Creek Formations is dominated by CaO and MgO, indicating the presence of dolomite. As the formation gets deeper, the chemistry changes to more anhydrite-rich, fine to medium-grained sandstones, as shown by the high percentage of SiO_2, CaO, and SO_3. The Amsden Formation contains clay up to 20% with illite being the dominant clay type.

Similar to the Opeche/Spearfish Formation, the higher content of anhydrite (~17%) and clay minerals (~7%) makes the Amsden Formation less porous and more impermeable compared to the target Broom Creek Formation. The thin-section and SEM–EDS micrographs of the most porous sample at the cored depth of 6215.2 ft (6208.2 ft KB elevation) show moderately sorted, fine-grained subangular quartz and feldspar grains with anhydrite cement (Figures 2-30a and c).

Table 2-8b. XRD Analysis of the Amsden Formation at Milton Flemmer 1. Only major constituents are shown.

Sample Name	Core Depth, ft, MD	Log Depth, ft, MD	Feldspar, wt%	Quartz, wt%	Anhydrite, wt%	Dolomite, wt%	Clay, wt%	Others, wt%	Illite/Total Clay,* wt%
Amsden	6169.3	6162.3	9.93	13.91	0.00	71.44	1.87	2.85	100
Amsden	6177.2	6170.4	18.23	34.48	0.00	26.79	18.03	2.47	100
Amsden	6186.2	6179.2	0.00	35.33	0.99	62.75	0.51	0.42	100
Amsden	6201.2	6194.2	13.78	32.94	0.00	31.62	19.56	2.10	100
Amsden	6215.2	6208.2	4.70	87.37	3.83	0.91	2.01	1.18	100
Amsden	6219.9	6212.9	0.00	0.43	97.10	0.62	0.00	1.85	NA**

* Illite component of clays.

**NA; no illite component was detected by XRD.

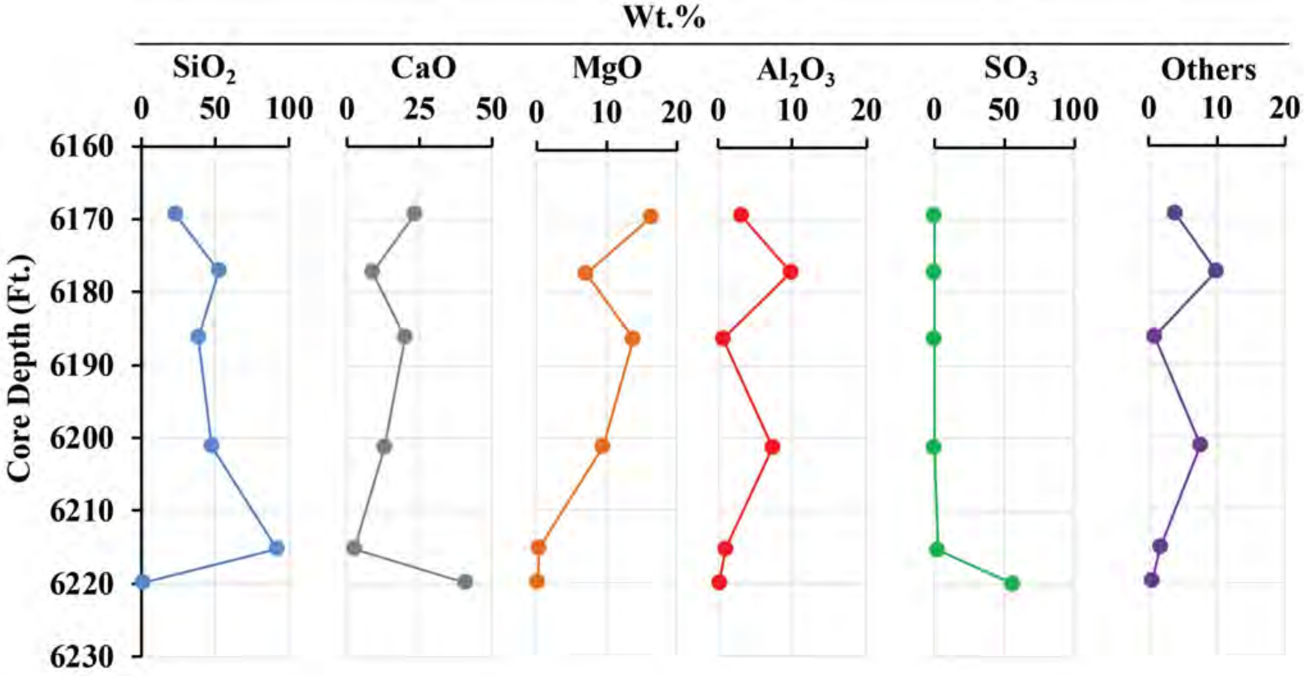


Figure 2-29b. Elemental composition by XRF as a function of depth in the Amsden Formation at Milton Flemmer 1.

The least porous sample, located at the bottom of the section at the core depth of 6219.9 ft (6212.9 ft KB elevation), predominantly consists of anhydrite (~97%) with microfractures (Figures 2-30b and d). Figure 2-31 shows changes in the mineralogy at the Milton Flemmer 1 well as a function of depth next to the core sample porosity and permeability data. The Amsden Formation is highlighted in gray. Although a total porosity of 22% with a permeability of 419 mD was observed at the core depth of 6215.2 ft (6208.2 ft KB elevation), it must be noted that this layer is isolated and confined between ultralow permeable layers (a clay-rich quartz dolomite layer above and an anhydrite-rich layer below).

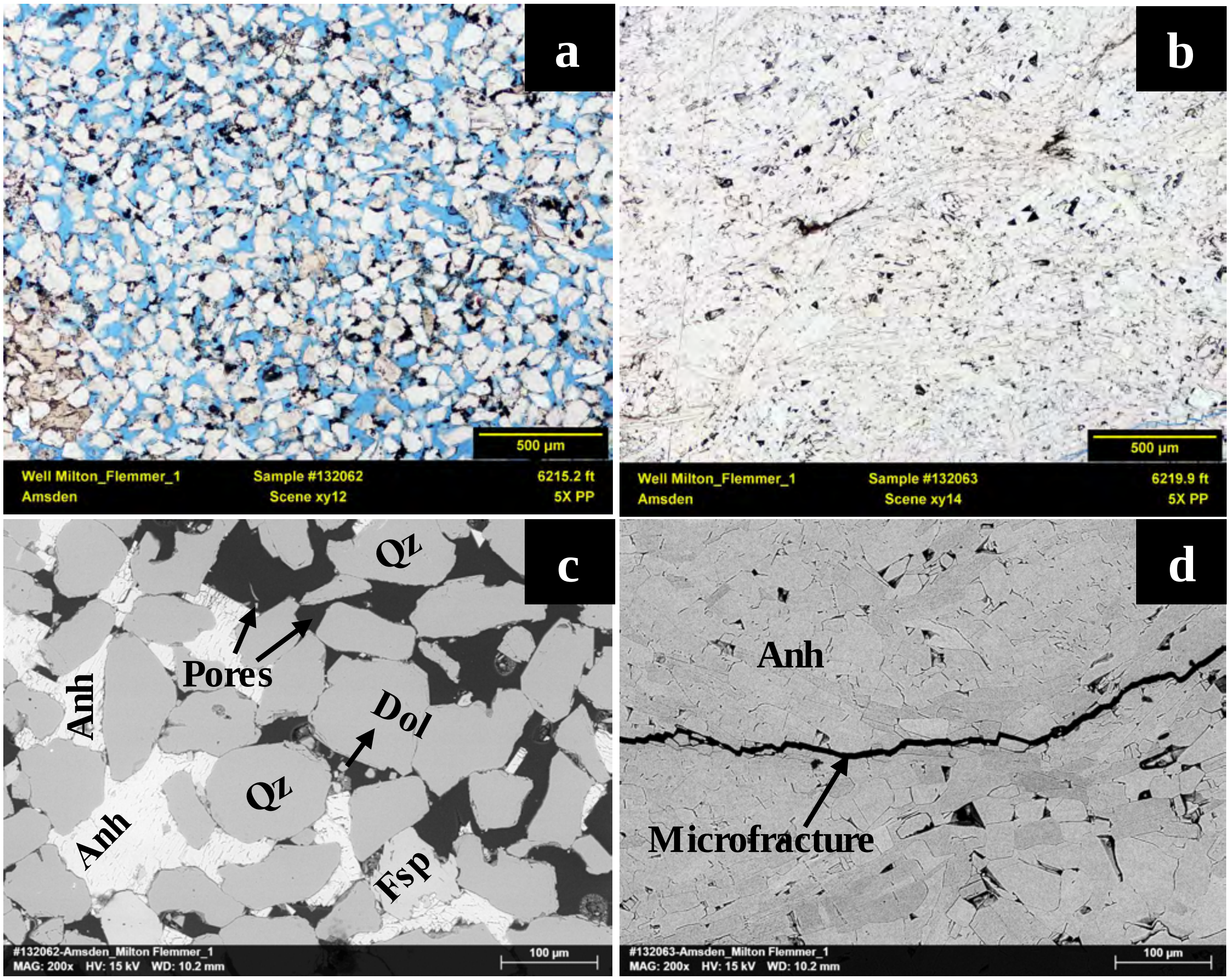


Figure 2-30. Thin-section (a, b) and SEM (c, d) micrographs of the most porous portion (a, c) and the least porous (b, d) samples of the Amsden Formation at Milton Flemmer 1 well. The most porous sample of the Amsden Formation has a total porosity and permeability of 22% and 419 mD, respectively, which is notably reduced to 0.26% and 0.0008 mD in the least porous sample. The blue color in the thin-sections (a and b) represents porosity.

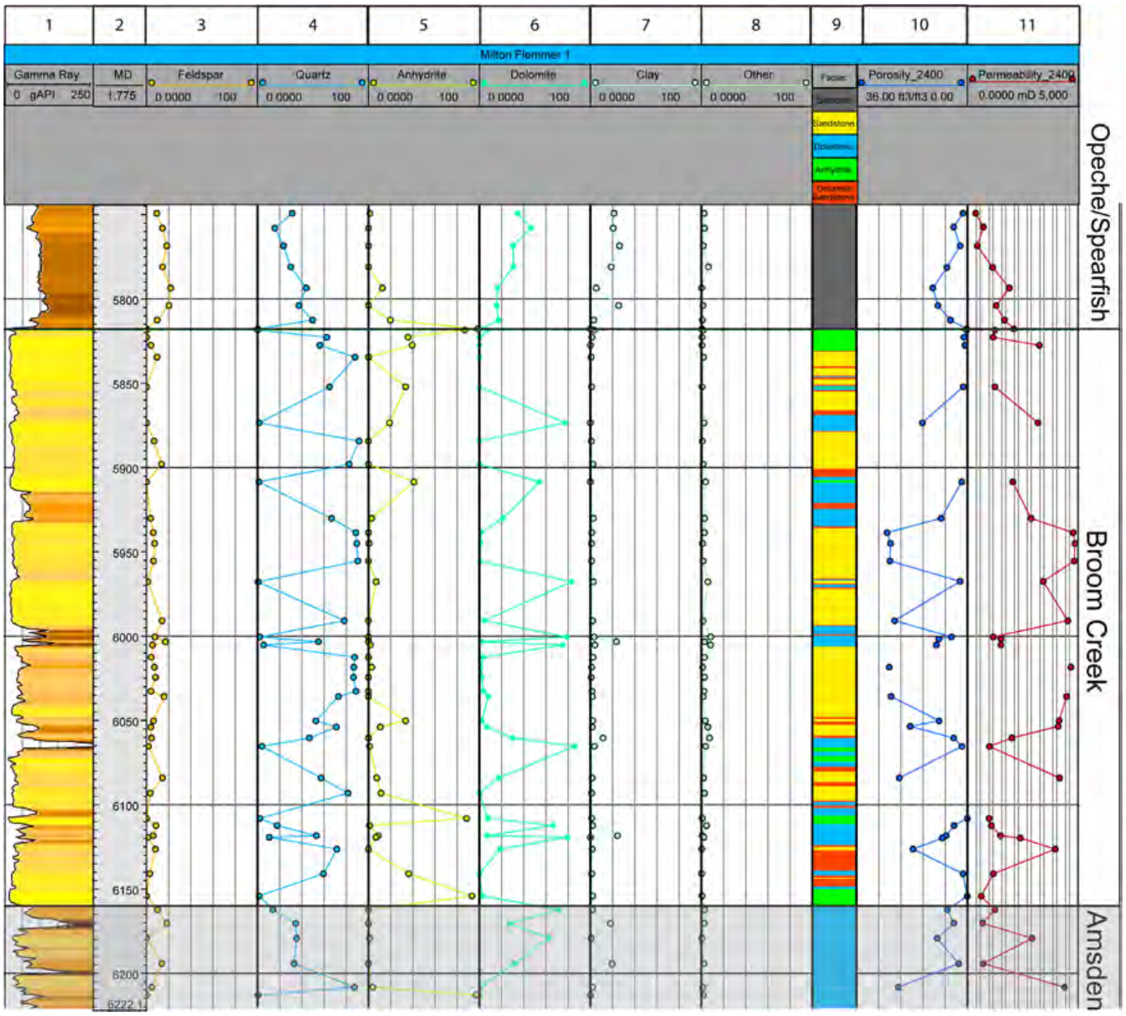


Figure 2-31. Change in the mineralogy of the lower confining Amsden Formation (highlighted in gray) at Milton Flemmer 1 as a function of depth based on XRD in comparison to GR, facies, core sample total porosity (%), and permeability (mD). Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (samples too soft/brittle). Tracks from left to right are 1) GR (black), 2) MD, 3) total feldspar (orange), 4) quartz (blue), 5) anhydrite (yellow green), 6) dolomite (green), 7) total clay (light blue), 8) other (light green), 9) facies, 10) core porosity (2400 psi) (dark blue), and 11) core permeability (2400 psi) (red).

2.4.3.2 Geochemical Interaction

Geochemical simulation using PHREEQC geochemical software was performed to calculate the potential effects of an injected multicomponent CO_2 stream on the Amsden Formation. This simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection.

Modeling results show geochemical processes at work. The pH at the interface between the injection zone and lower confining zone has the greatest change in value, declining to a level of 5.7 after 7 years of injection, further declining to 4.8 by the end of the modeled injection period, and hits 4.5 by the end of simulation period. Progressively lower or slower pH changes occur for each cell that is more distant from the CO_2 interface. Albite and K-feldspar start to dissolve from the beginning of the simulation period, while quartz and illite start to precipitate. Albite and K-feldspar are the primary minerals that dissolve, and their initial fractions have almost completely dissolved. No dissolution is observed for illite and quartz. The minerals that experience dissolution in the model are almost completely replaced by the precipitation of other minerals. The overall net porosity changes from dissolution and precipitation are minimal, less than 2% change during the life of the simulation. These results suggest that geochemical change from exposure to CO2 is minor and therefore the ability of the Amsden Formation to maintain its sealing integrity will not be compromised by geochemical processes. A full description of the geochemical results for the upper confining zone can be found in Appendix C.

2.4.4 Geomechanical Information of Confining Zone

2.4.4.1 Fracture Analysis

Fractures within the overlying confining zone (the Opeche/Spearfish Formation) and the underlying confining zone (Amsden Formation) were assessed during the description of the Milton Flemmer 1 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural fractures and in situ stress were assessed through the interpretation of the image log acquired during the drilling of the Milton Flemmer 1 well.

2.4.4.2 Core-Fracture Analysis

The fractures observed in the Opeche Formation were tectonic, vertical to subvertical, closed, and cemented with anhydrite. The Amsden Formation was determined to be a nonfractured interval. A few discontinuous closed fractures were noted. The presence of stylolites was also noted in the dolomitic intervals of the Amsden Formation.

2.4.4.3 Borehole Image Fracture Analysis

Natural fractures and in situ stresses were assessed through the interpretation of borehole image log, dipole shear sonic slowness (DTS), and DTC logs acquired during the drilling of the Milton Flemmer 1 well. Borehole image logs provide a 360-degree image of the formation of interest and are oriented to provide an understanding of the general orientation of the observed features. The fractures within the upper confining zone formations, specifically Spearfish, Minnekahta, and Opeche, exhibit unique characteristics and are classified individually.

Fractures within Opeche Formation were primarily litho-bound resistive fractures, mainly oriented NNW-SSE with the presence of other fracture sets oriented N-S, NW-SE, and NE-SW. They were commonly filled with anhydrite. Some litho-bound conductive fractures were identified and determined to have a N-S and NW-SE orientation. The litho-bound conductive fractures are filled with clay and are interpreted as closed fractures (Figure 2-32a). In the Spearfish formation, one resistive litho-bound fracture and one resistive continuous fracture, oriented N-S and NNE-SSW, were highlighted (Figure 2-32b). In the Minnekahta Formation, one conductive litho-bound fracture, oriented NE-SW was highlighted (Figure 2-32C). The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. They are closed, and the aperture varies from close to centimeter-scale (Figures 2-33 and 2-34). No microfaults were found in the Spearfish, Minnekahta, and Opeche intervals.

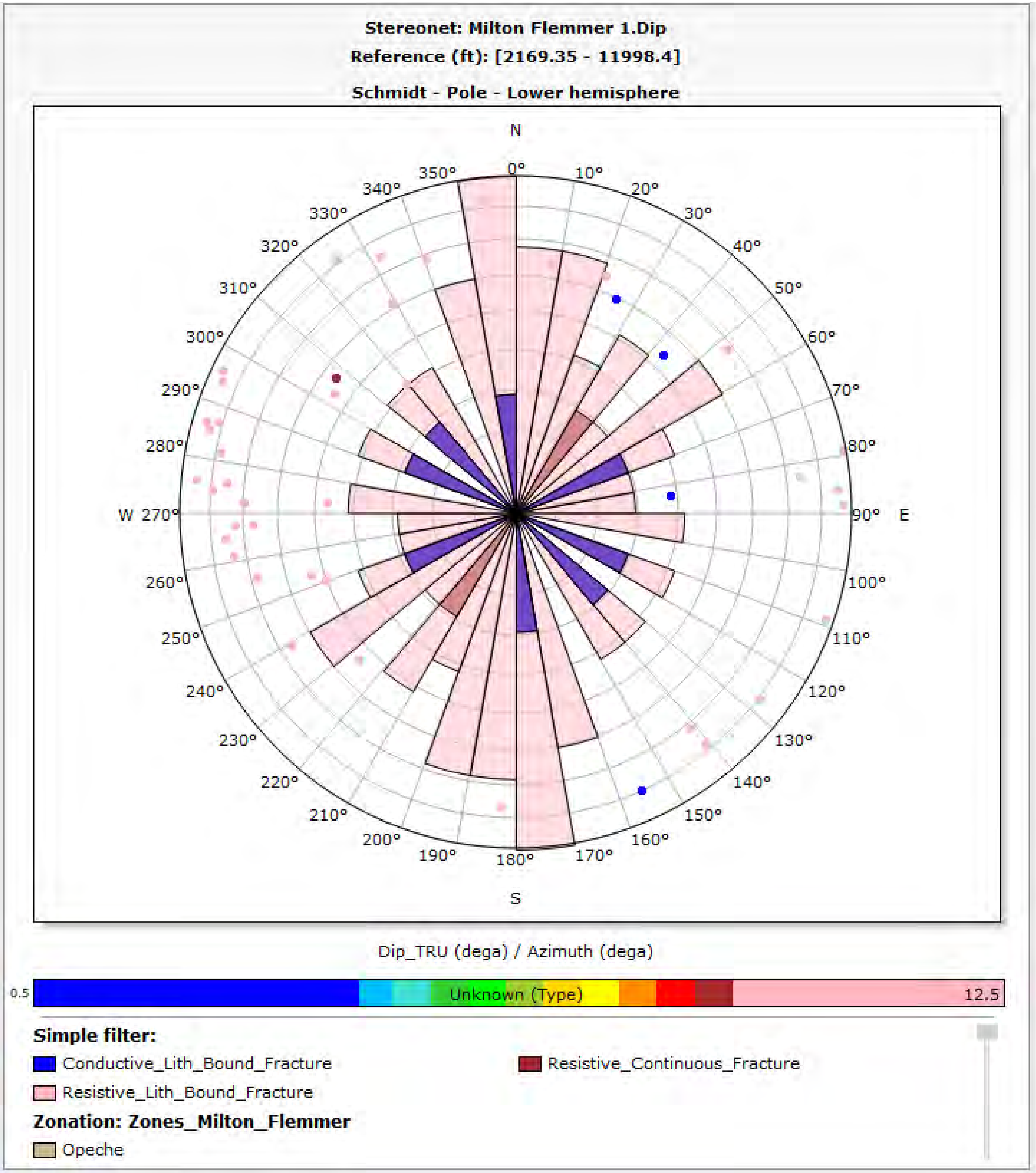


Figure 2-32a. Strike orientation per type of fracture that characterizes the Opeche Formation: resistive litho-bound fractures (pink), resistive continuous fractures (brown), and conductive litho-bound fractures (blue). The colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

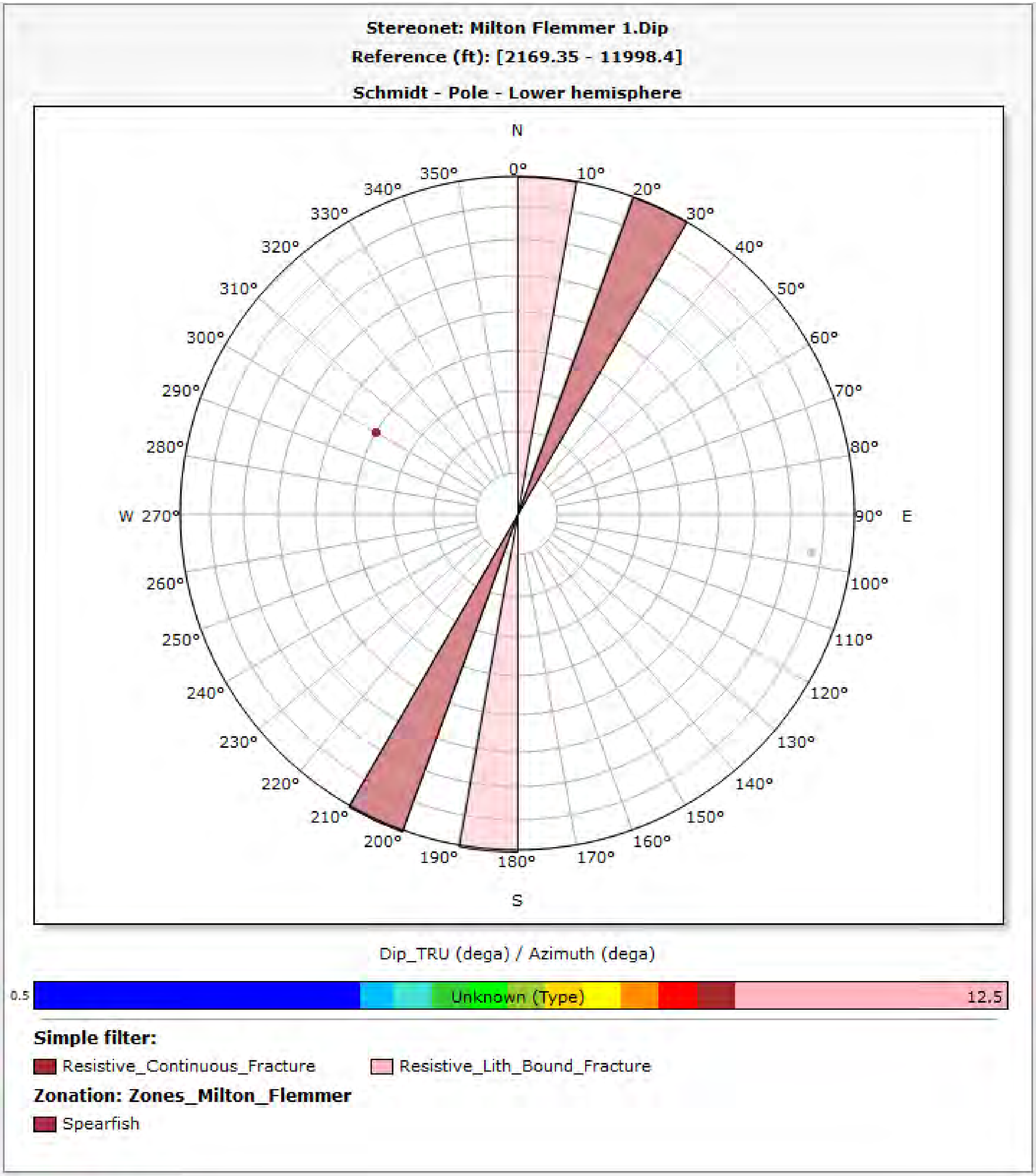


Figure 2-32b. Strike orientation per type of fracture that characterizes the Spearfish Formation: resistive litho-bound fracture (pink) and resistive continuous fracture (brown). The colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

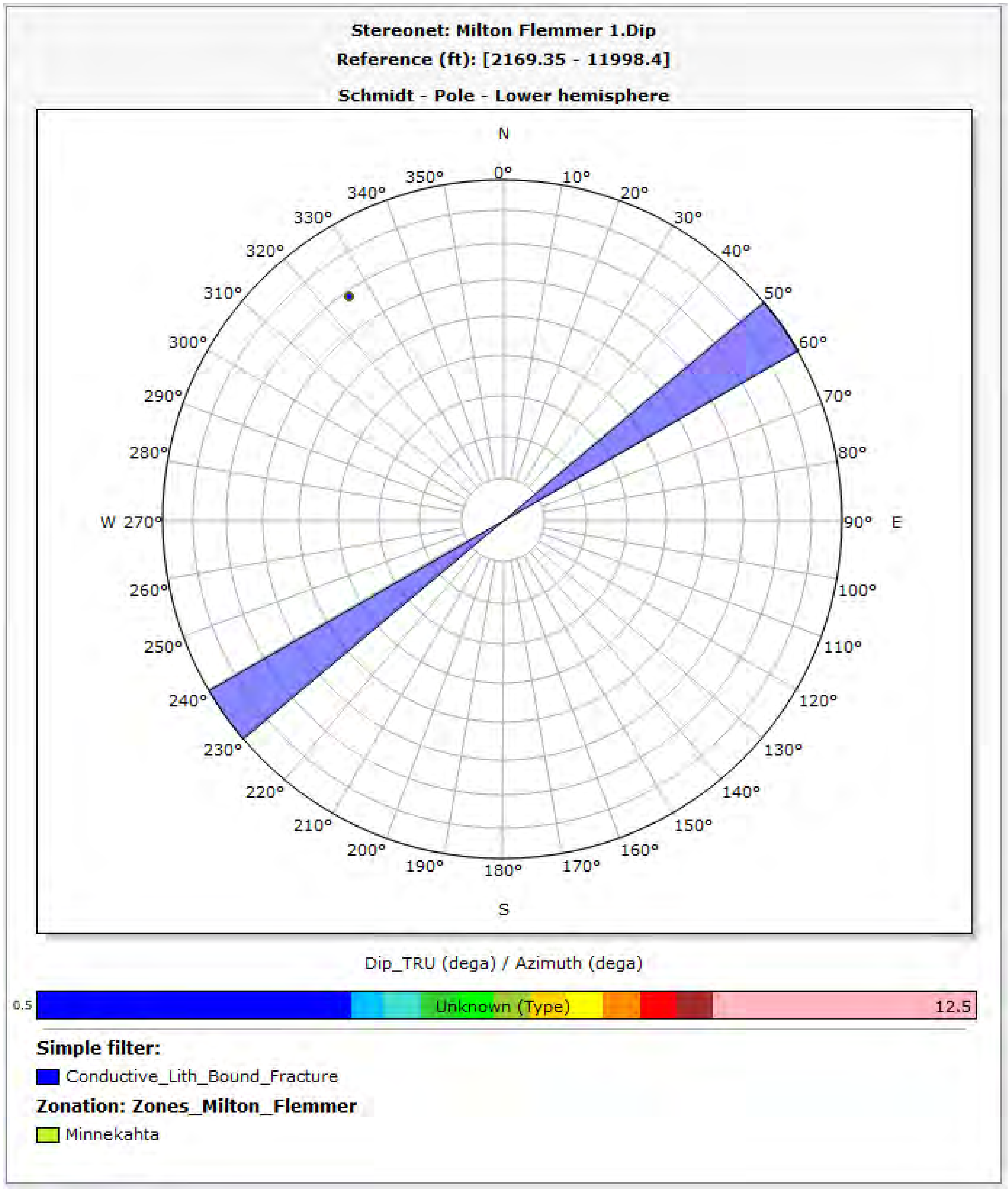


Figure 2-32c. Strike orientation per type of fracture that characterizes the Minnekahta Formation: conductive litho-bound fracture (blue). The colored dot represents the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

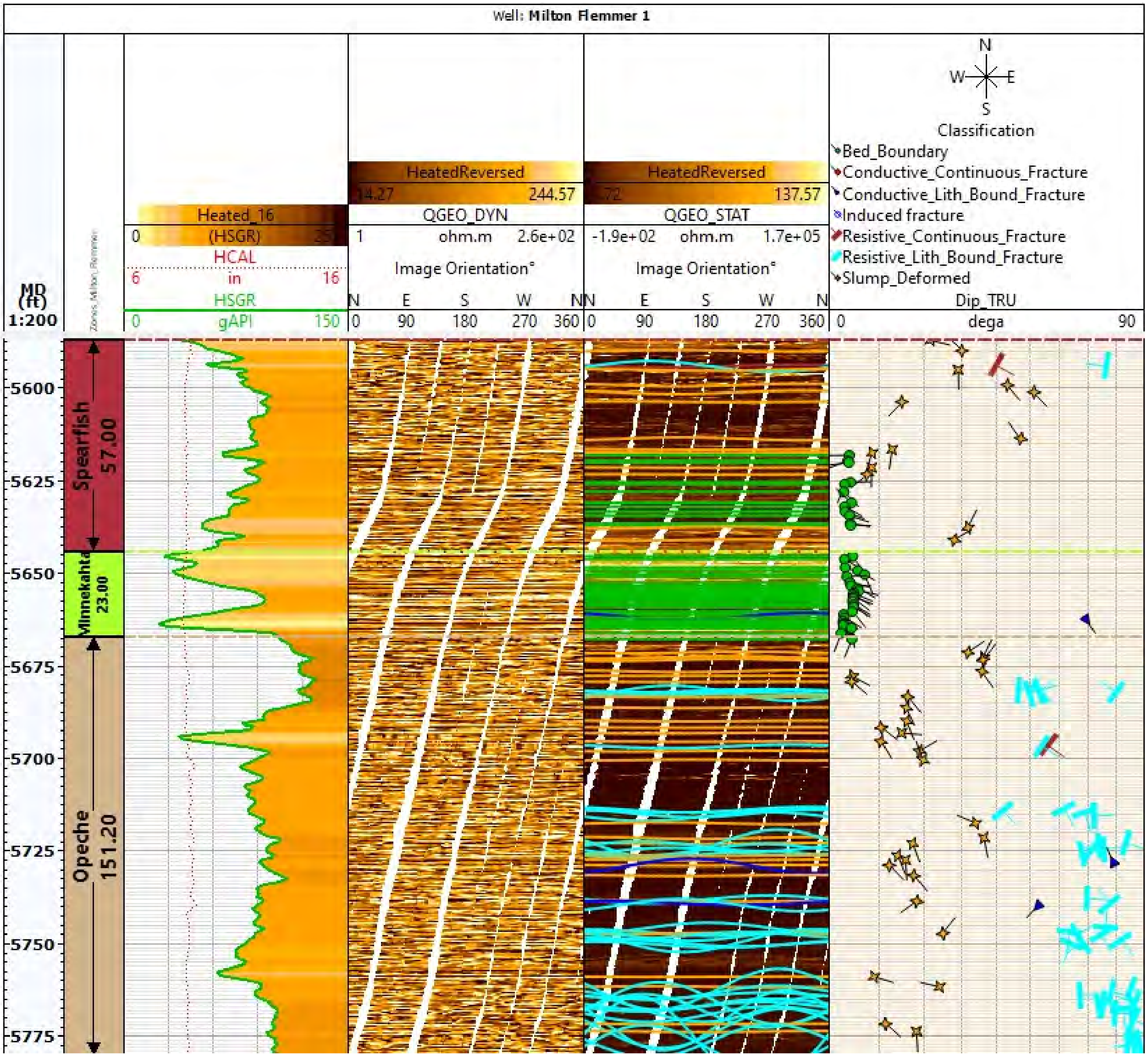


Figure 2-33. Sedimentary and tectonic features in Spearfish, Minnekahta, and Opeche Formations observed on the borehole image log. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, caliper (HCal); 4) borehole dynamic image log; 5) borehole static image log; and 6) tectonic and sedimentary tadpole orientation in the interval between 5,595 and 5,777 ft MD.

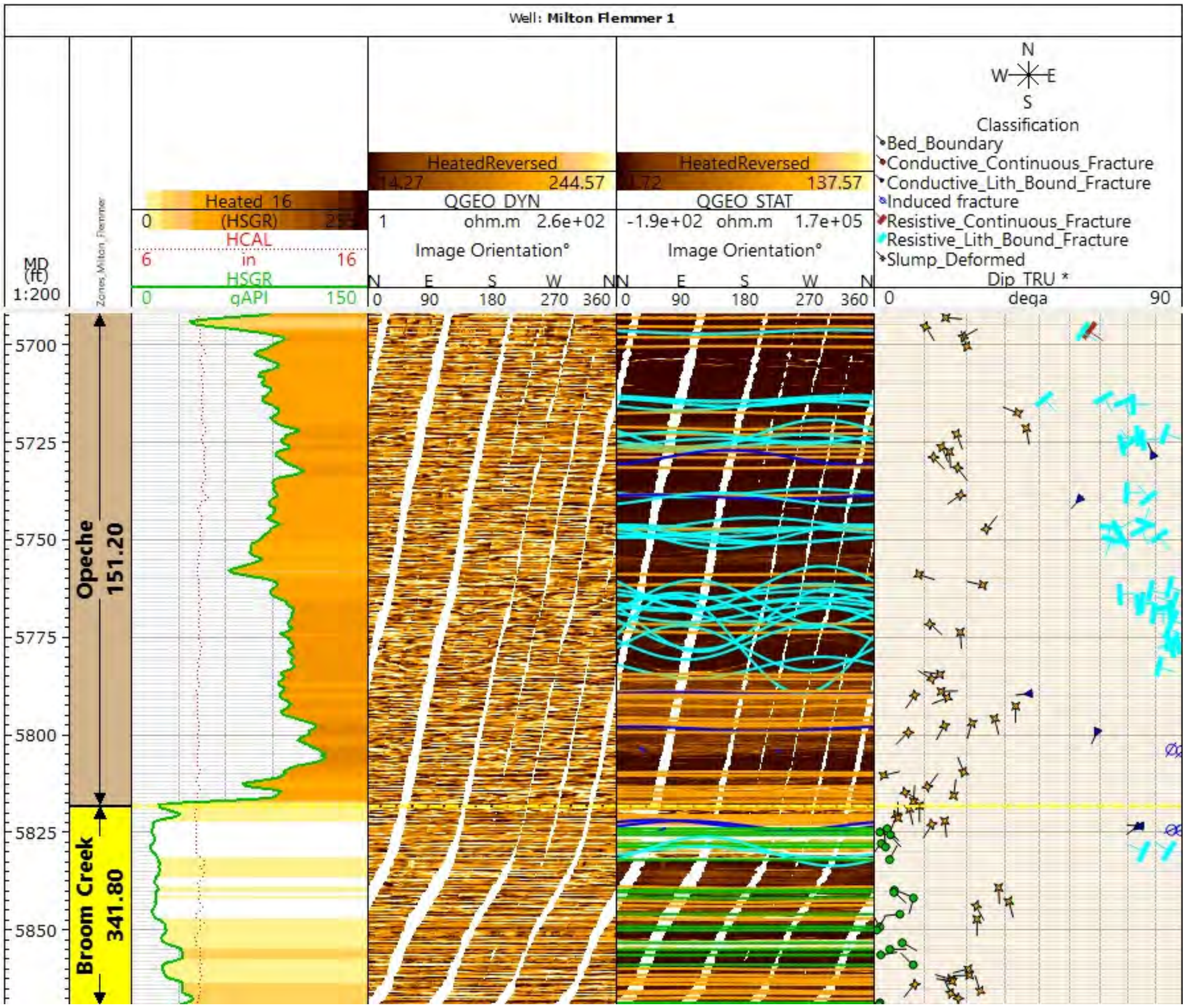


Figure 2-34. Sedimentary and tectonic features, and tensile fractures in Opeche and Upper Broom Creek Formations observed on the borehole image log. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) induced fracture, tectonic, and sedimentary tadpole orientation in the interval between 5,692.5 and 5,872.5 ft MD.

The Amsden Formation is considered to be a nonfractured interval; however, a few litho-bound conductive and resistive fractures are highlighted with the presence of horizontal compaction features (stylolites). The fractures are oriented E-W, NNE-SSW, and NNW-SSE (Figure 2-35). The fractures vary in orientation and exhibit oblique and vertical trends. The fractures are filled, and the aperture varies from closed to millimeter-scale (Figures 2-36 and 2-37). No microfaults were found in the Amsden interval.

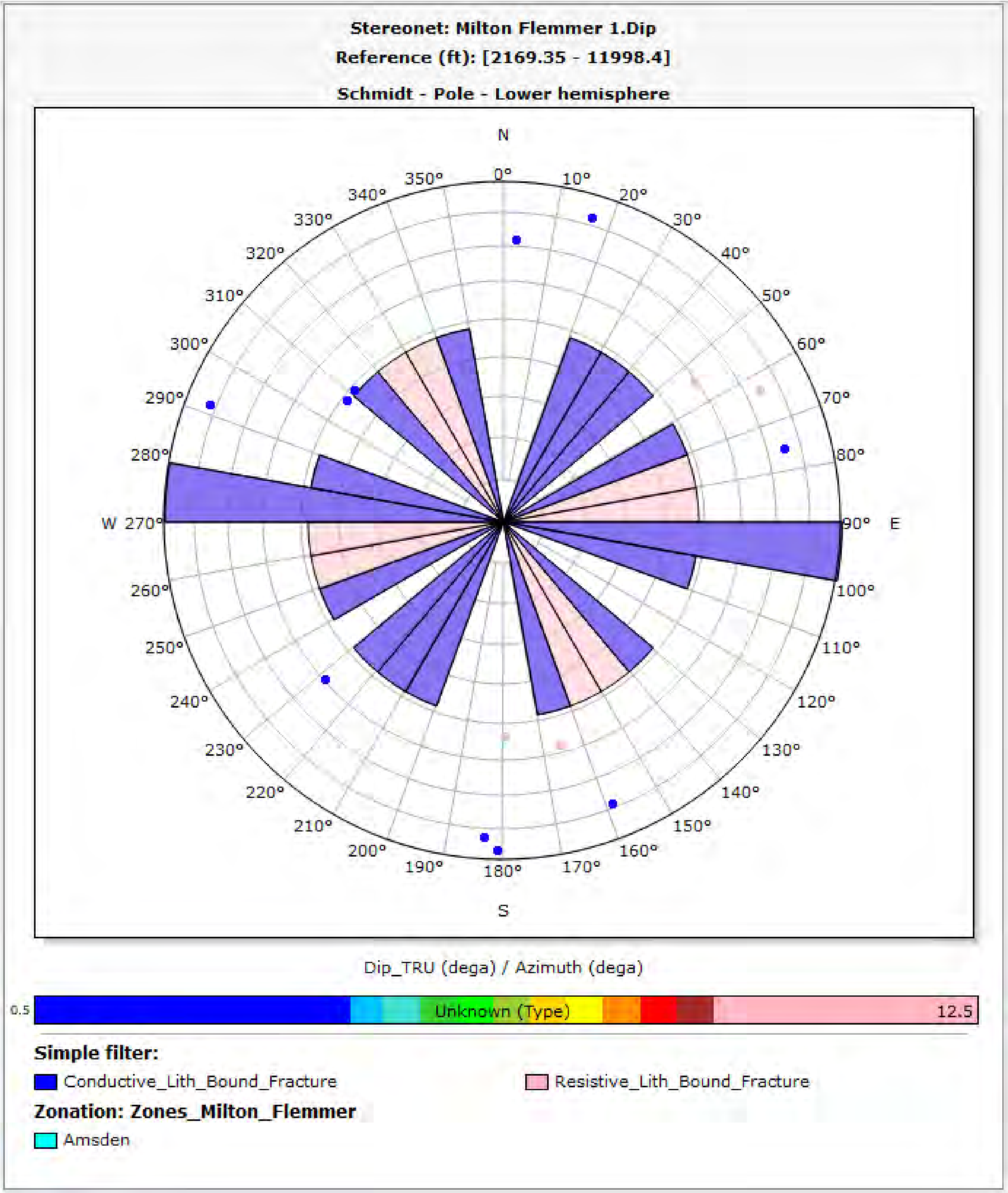


Figure 2-35. Strike orientation per type of fracture that characterizes the Amsden Formation: resistive litho-bound fractures (pink) and conductive litho-bound fractures (blue). Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

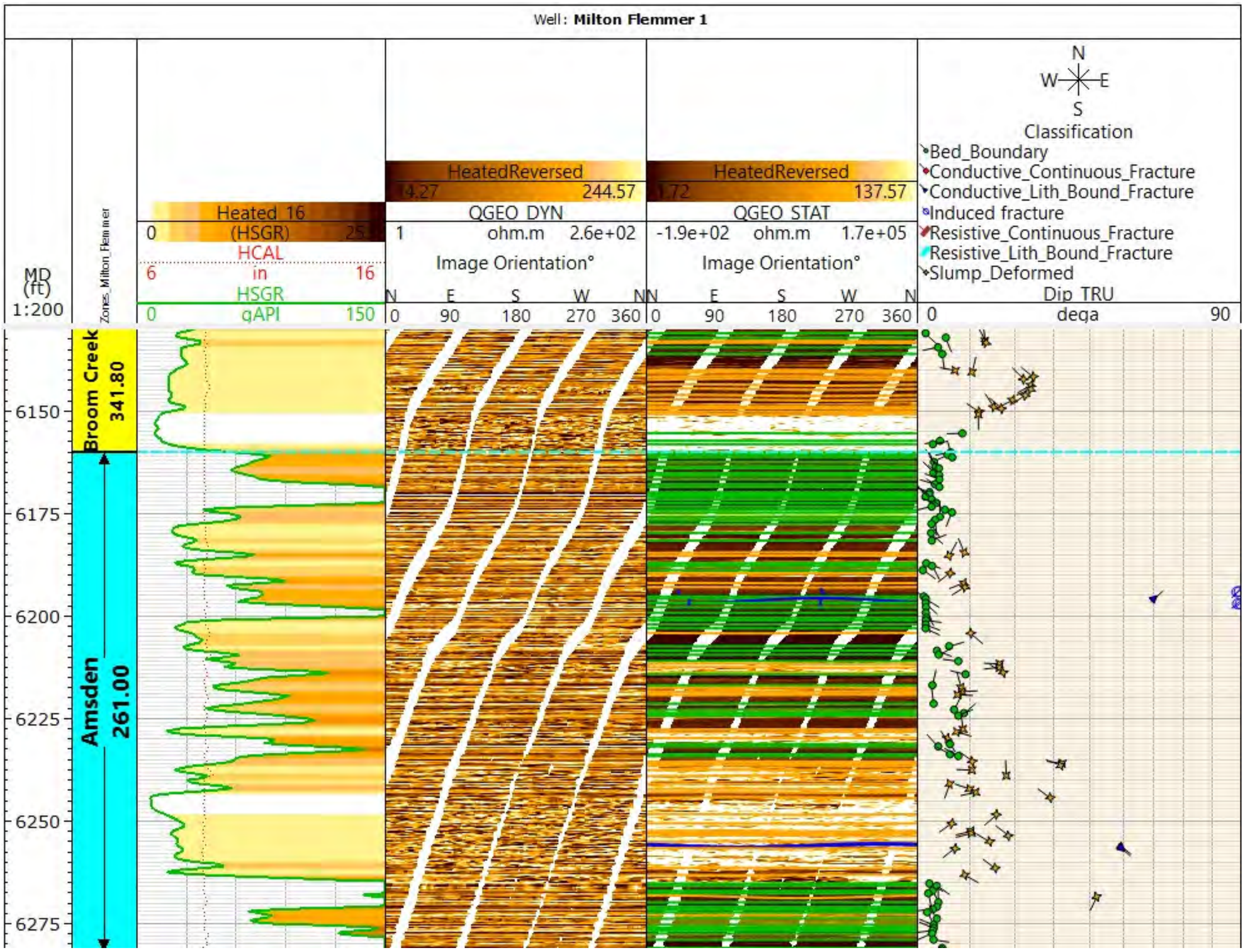


Figure 2-36. Sedimentary and tectonic features, and tensile fractures in lower Broom Creek and Amsden Formation (upper part) observed on the borehole image log. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) induced fracture, tectonic, and sedimentary tadpole orientation in the interval between 6130 and 6282.5 ft MD.

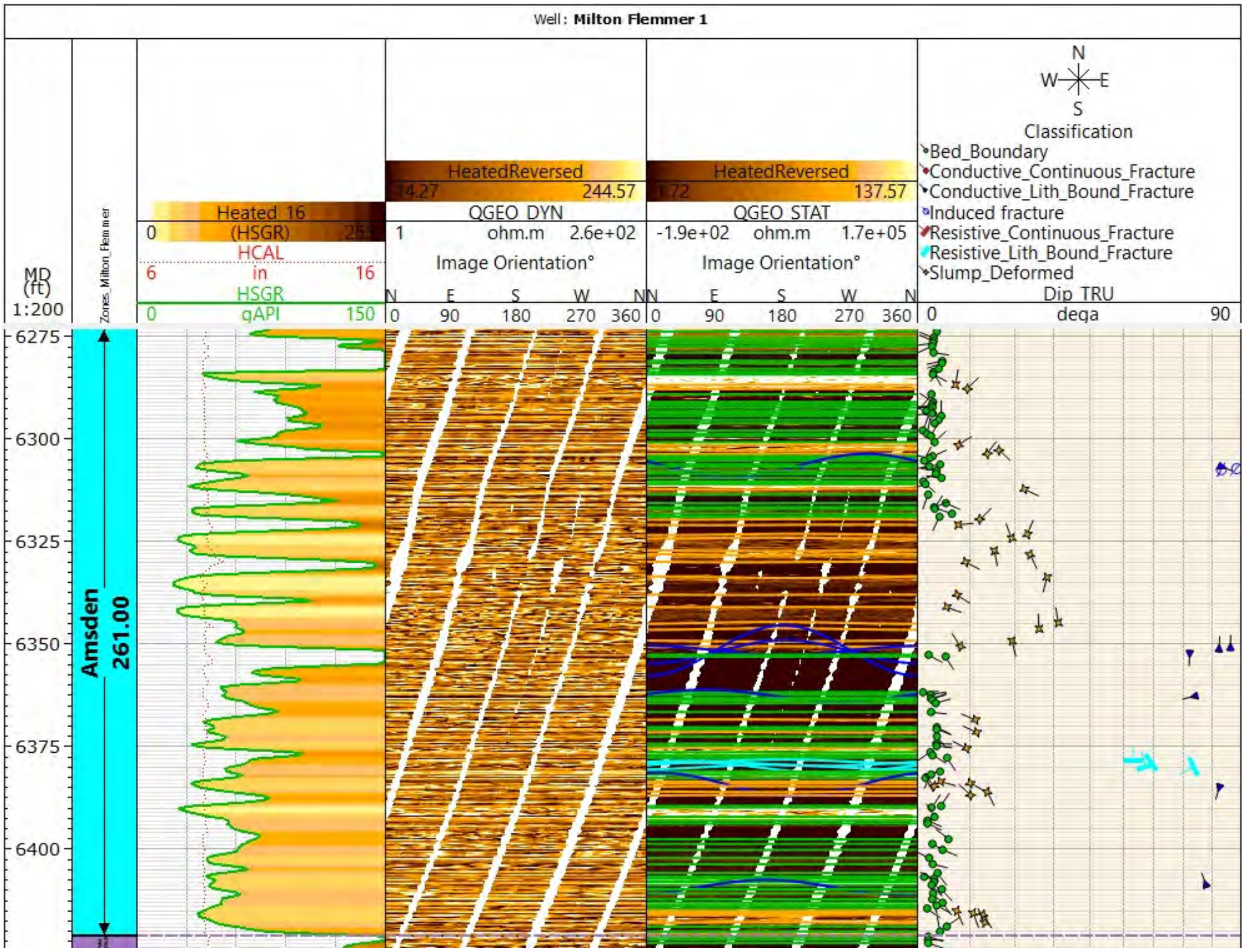


Figure 2-37. Sedimentary and tectonic features, and tensile fractures in the Amsden Formation (lower part) observed on the borehole image log. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) induced fracture, tectonic, and sedimentary tadpole orientation in the interval between 6130 and 6422.5 ft MD.

Breakout and tensile fractures induced by drilling were identified in several formations such as Precambrian and Ordovician units and Amsden, Broom Creek, and Opeche Formations. Breakouts and tensile fractures have NW-SE and NE-SW orientations, respectively (Figure 2-38). In the confining and injection zones, the tensile fractures were identified at different depths 5804, 5826, 6195, and 6307 ft MD. The tensile fractures are oriented NE-SW, indicating that the maximum horizontal stress (SHmax) has an orientation of N050°.

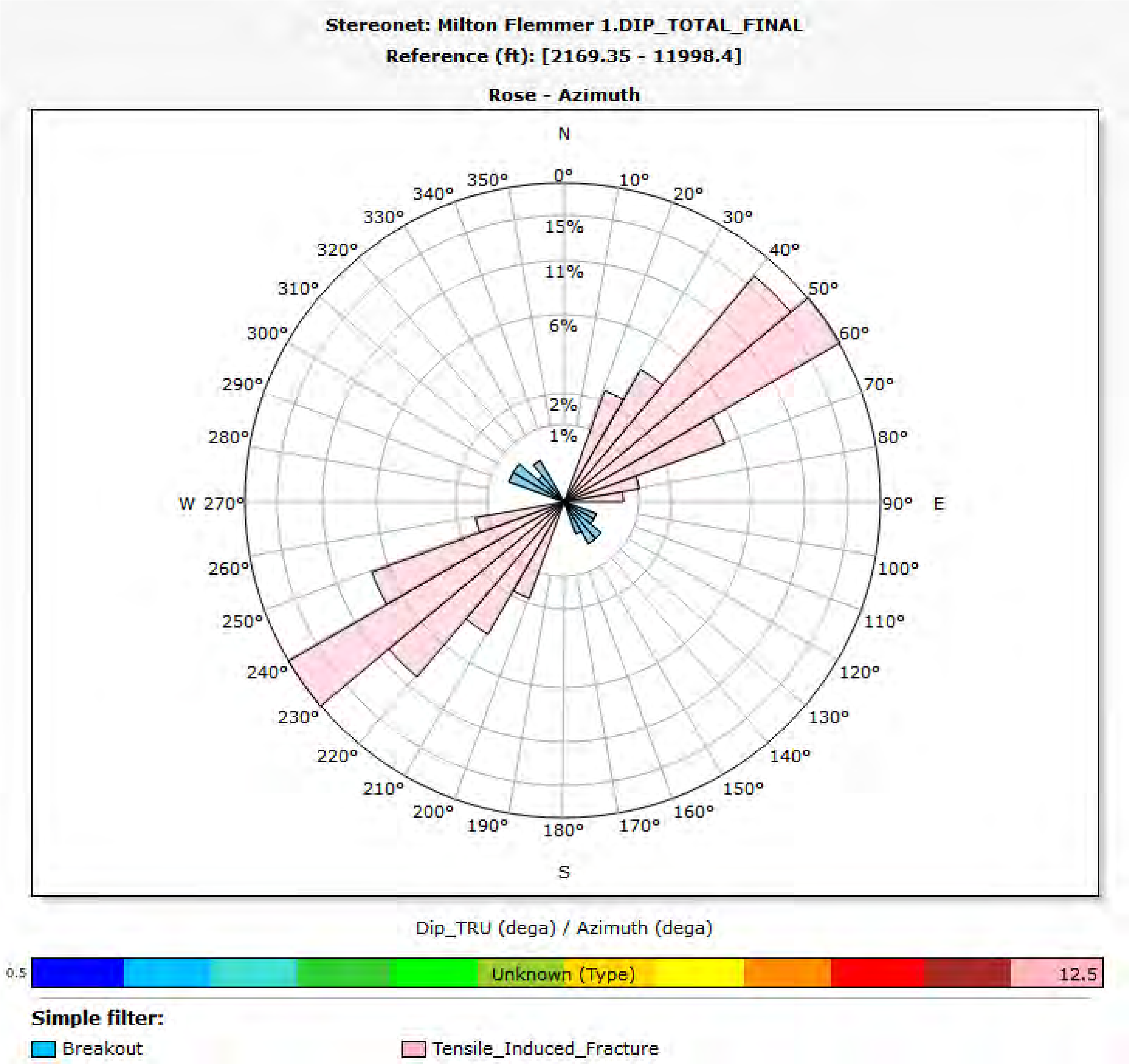


Figure 2-38. Orientation of the tensile fractures and breakout in Milton Flemmer 1 observed mainly in Precambrian and Ordovician units and Amsden, Broom Creek, and Opeche Formations, showing maximum horizontal stress (SHmax) direction about N050° and minimum horizontal stress (Shmin) about N140°.

2.4.4.4 Stress, Ductility and Rock Strength

The dynamic elastic properties (dynamic Young's modulus and Poisson's ratio) for the Opeche/Spearfish, Broom Creek, and Amsden Formations were calculated by using DTC, DTS, and density log collected from Milton Flemmer 1. These dynamic elastic properties were converted to static elastic properties with calibrations of geomechanical lab core measurements.

A 1D MEM in the Broom Creek section was built for Milton Flemmer 1 using the available wireline data such as GR logs, caliper logs, density logs (RHOB), dipole sonic logs (DTC, DTS), and image logs. The 1D MEM consists of pore pressure, the vertical in situ stress (Sv, overburden), minimum and maximum horizontal in situ stresses (Shmin, SHmax), static and dynamic Young's moduli (E), static and dynamic Poisson's ratio (ν), bulk modulus (K), shear modulus (G), unconfined compressive strength (UCS), tensile strength (To), and friction angle (FA or FANG) (Tables 2-9 and 2-10).

Table 2-9. Ranges and Averages of the Elastic Properties Estimated from 1D MEM in the Opeche/Spearfish, Broom Creek, and Amsden Formations: Static Young's Modulus (E_Stat), Static Poisson's Ratio (ν_Stat), Static Bulk Modulus (K), Static Shear Modulus (G), Unconfined Compressive Strength (UCS), Dynamic Young's Modulus (E_Dyn), and Dynamic Poisson's Ratio (ν_Dyn)

Formation	Stats	E_Stat, Mpsi	n_Stat, unitless	K, Mpsi	G, Mpsi	UCS, psi	E_Dyn, Mpsi	n_Dyn, unitless
Opeche/Spearfish	Min.	2.69	0.21	3.20	0.57	5700.90	3.49	0.21
	Max.	7.65	0.35	9.67	4.43	22,017.44	9.93	0.35
	Average	3.98	0.29	4.08	2.52	8395.01	5.17	0.29
Broom Creek	Min.	1.53	0.14	1.69	0.73	5765.82	1.93	0.14
	Max.	9.48	0.40	10.03	5.16	36,039.37	11.97	0.40
	Average	4.39	0.28	4.10	2.22	17,508.59	5.55	0.28
Amsden	Min.	1.22	0.20	1.94	1.34	2785.29	1.54	0.20
	Max.	9.03	0.40	11.74	3.93	52,995.54	11.41	0.40
	Average	4.14	0.31	5.71	2.15	16,611.06	6.49	0.31

Table 2-10. Ranges and Averages of the Sv, Pore Pressure, Shmin, and FA Estimated from 1D MEM in the Opeche/Spearfish, Broom Creek, and Amsden Formations

Formation	Stats	Sv, Vertical Stress, psi	Pore Pressure, psi	Shmin, psi	FANG, FA, degrees
Opeche/Spearfish	Min.	5541.70	2458.85	3344.28	33.53
	Max.	5713.77	2589.60	4179.36	51.12
	Average	5627.63	2492.22	3758.20	38.04
Broom Creek	Min.	5713.77	2589.6	3258.54	24.43
	Max.	6071.36	2865.54	4897.82	57.80
	Average	5890.36	2799.27	4014.88	40.54
Amsden	Min.	6071.70	2673.18	3562.27	36.86
	Max.	6445.11	2813.46	5137.82	57.80
	Average	6258.59	2743.53	4375.16	54.20

Sv is one of the three principal stresses that act upon a rock. It is defined as the stress applied by the overlaying lithostatic column, at the depth (z), and is estimated using the Plumb and others (1991) equation. Sv is calculated using the RHOB log as an input. For the pore pressure, porosity proxy logging data based on a normal compaction trendline concept were used (for hydraulic static pressure, 1.03 g/cm^3 = 0.44675 psi/ft = 8.6 ppg). For the Broom Creek Formation, the MDT data taken in sand bodies show pore pressure equivalent to 9 ppg equivalent to 0.466 psi/ft, which is slightly overpressured. The pore pressure estimation honored the MDT measurement. Dynamic to static Young's modulus function used a linear conversion where a dynamic Young's modulus log was calculated from the available sonic (DTC, DTS) and density logs. For Poisson's ratio, dynamic and static parameters are assumed to be equal. The Biot factor was estimated using the formula Biot's factor =1 – (K0/Kmineral), where K0 is the bulk modulus of the porous medium and Kmineral is the bulk modulus of solid parts of the porous medium. It is a function of mineral volumes and minerals' bulk modulus. For rock properties, Young's modulus and Poisson's ratio were estimated from well logs and were calibrated with the triaxial core laboratory measurements (Figure 2-39).

Unconfined compressive strength (UCS) was calculated using empirical correlations between UCS and DTC for shale, sandstone, and dolostone: the Chang (2006) method was used for shale formation, the McNally (1987) method was used for sandstone formation, and the Golubev and Rabinovich (1976) method was used for dolostone formation. The tensile strength was assumed to be 10% of the calculated UCS. The friction angle (FA or FANG) was estimated using an empirical correlation between the internal angle of friction and DTC: Lal's approach (1999) was used to calculate the FA in the Opeche/Spearfish and Amsden Formations, and Weingarten and Perkins (1995) in Broom Creek Formation. Horizontal stresses (Shmin and SHmax) were estimated using the poroelastic equations (Plumb and others, 2000). The orientations of Shmin and SHmax were estimated with the help of image logs (Figure 2-38). The magnitude of Shmin was calibrated by the closure pressures which were measured with a mini-frac stress test. In addition, the 1D MEM shows that the stress regime observed in the Opeche/Spearfish, Broom Creek, and Amsden Formations is normal (Sv > SHmax > Shmin).

The analysis of the pore pressure measured in the Broom Creek Formation attests that it could be considered an overpressured reservoir with a gradient equal to 0.466 psi/ft.

Triaxial test (static elastic properties), ultrasonic velocity (dynamic elastic properties), destructive test (compressive strength) at reservoir conditions, and pore volume compressibility (PVC) for reservoir samples were conducted on nine core samples acquired from the Opeche/Spearfish, Broom Creek, and Amsden Formations in the Milton Flemmer 1 well. These values were used to calibrate the static and dynamic Young's modulus and Poisson's ratio generated from well logs (Table 2-11).

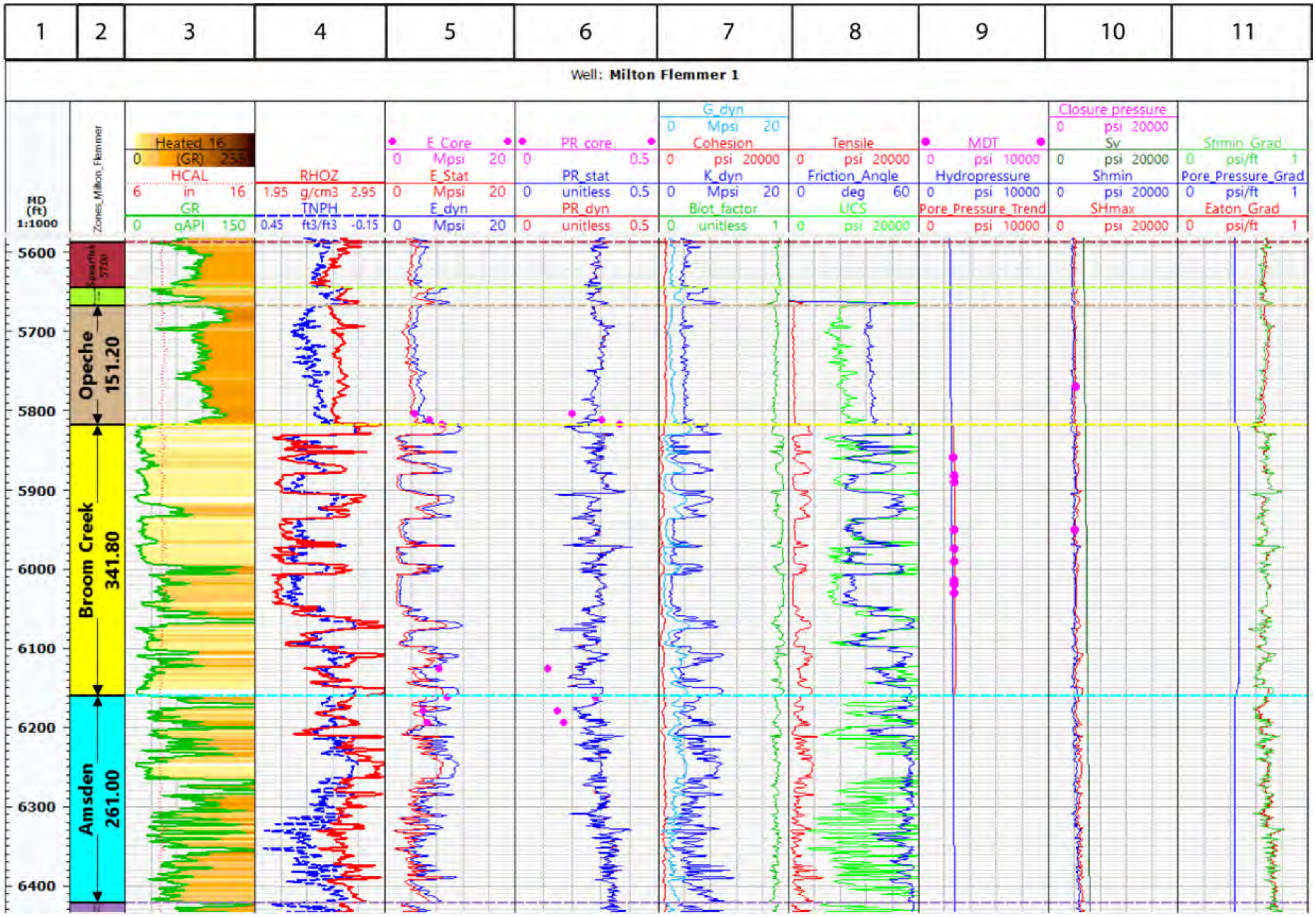


Figure 2-39. Geomechanical parameters in the Spearfish, Minnekahta, Opeche, Broom Creek, and Amsden Formations. The tracks from left to right are 1) MD; 2) formation; 3) GR, HCal; 4) TNPH (neutron porosity), and RHOZ (bulk density); 5) dynamic Young's modulus (E_dyn), and static Young's modulus (E_Stat) calibrated with core measurements (E_Core); 6) dynamic Poisson's ratio (PR_dyn) calibrated with core measurements (PR_Core); 7) cohesion, bulk modulus (K_dyn), shear modulus (G_dyn), and Biot's factor; 8) UCS, tensile strength, and FA; 9) pore pressure, hydropressure calibrated with MDT pressure data; 10) Sv, SHmax, and Shmin calibrated with the MDT stress test; and 11) pore pressure, Shmin, and Eaton fracture gradients.

Table 2-11. Formation, Lithology, Sample Depth (MD), Vertical Stress, Pore Pressure, Effective Vertical Stress, Horizontal Stress, Static Young's Modulus, Poisson's Ratio, and Compressive Strength in Opeche/Spearfish, Broom Creek, and Amsden Formations

Sample Information			Reservoir Conditions				Elastic Properties		
Formation	**Lithology/ Rock Type**	**Depth, * ft, MD**	**Vertical Stress, psi**	**Pore Pressure, psi**	**Effective Stress, psi**	**Horizontal Stress, psi**	**Static Young's Modulus, Mpsi**	**Static Poisson's Ration, unitless**	**Compressive Strength,*** psi**
Opeche/ Spearfish	Siltstone	5811	5753	2673	3080	1232	4.61	0.20	19,279
Opeche/ Spearfish	Silty sandstone	5820	5761	2677	3084	1234	6.95	0.30	6866
Broom Creek	Anhydrite	5825	5767	2679	3087	1235	8.90	0.37	18,148
Broom Creek	Sandstone	5999	5939	2759	3179	1272	NA**	NA**	1677
Broom Creek	Anhydritics andstone	6091	6030	2802	3228	1291	NA**	NA**	9822
Broom Creek	Dolomitic sandstone	6133	6072	2821	3251	1300	8.34	0.11	12,733
Amsden	Dolostone	6169	6108	2838	3270	1308	9.69	0.28	29,612
Amsden	Dolomitic sandstone	6186	6124	2846	3279	1311	5.85	0.15	27,394
Amsden	Sandy dolostone	6201	6139	2853	3287	1315	6.51	0.17	23,985

* Sample depth corresponds to cored depth. A depth shift must be applied to align the values with log depth (see Table 2-2a).

** Because of the unconsolidated nature of the Broom Creek sandstone and anhydritic sandstone samples, velocity and triaxial test data could not be collected.

*** Compressive strength is equivalent to the peak failure pressure of the sample.

2.5 Faults, Fractures, and Seismic Activity

This section discusses local and regional faults, including a regional structural feature, the Stanton Fault, and interpreted basement faults. In the area of review (AOR), none of these known or suspected faults or fractures has sufficient permeability and vertical extent to allow fluid movement out of the storage reservoir. The absence of transmissive faults is supported by fluid sample analysis results from Milton Flemmer 1 that suggest the injection interval, the Broom Creek Formation (105,000 mg/L), is isolated from the next permeable interval, the Inyan Kara Formation (3560 mg/L) (Appendix A).

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) using available borehole data and regional gravity and magnetic data as a northeast-southwest trending feature. The Stanton Fault as interpreted by Sims and others (1991) is ~11.5 mi from the Milton Flemmer 1 stratigraphic and reservoir-monitoring well (Figure 2-40). 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. The Beulah 3D survey was used to characterize the subsurface, with a primary objective of identifying structures. No basement faults were identified with the orientation of the mapped Stanton fault, which was mapped just north of the survey extent. No indication of the Stanton fault was interpreted within the Beulah 3D survey.

2.5.2 Interpreted Basement Faults

Basement-rooted faults with offset apparent in the overlying rock formations were interpreted from the 3D seismic data (Figures 2-40 and 2-41). Displacement along the interpreted basement faults diminishes below or within the Interlake Formation, the top of which is located over 3000 feet below the base of the Broom Creek Formation. These faults do not extend into the Broom Creek formation or into any associated Broom Creek confining intervals.

Figure 2-41 shows a map and cross-sectional view of the discontinuities that are interpreted as faults and fractures. The linear trends visible in Figure 2-41 are interpreted as basement-rooted faults. The bottom of Figure 2-41 shows Section A-A' from the Beulah 3D survey where offset is visible along basement-rooted faults in the Deadwood Formation. These faults extend through the Deadwood Formation into the overlying confining interval, the Winnipeg group. Some of the interpreted faults extend into the Red River Formation with offset ultimately diminishing by the Interlake Formation.

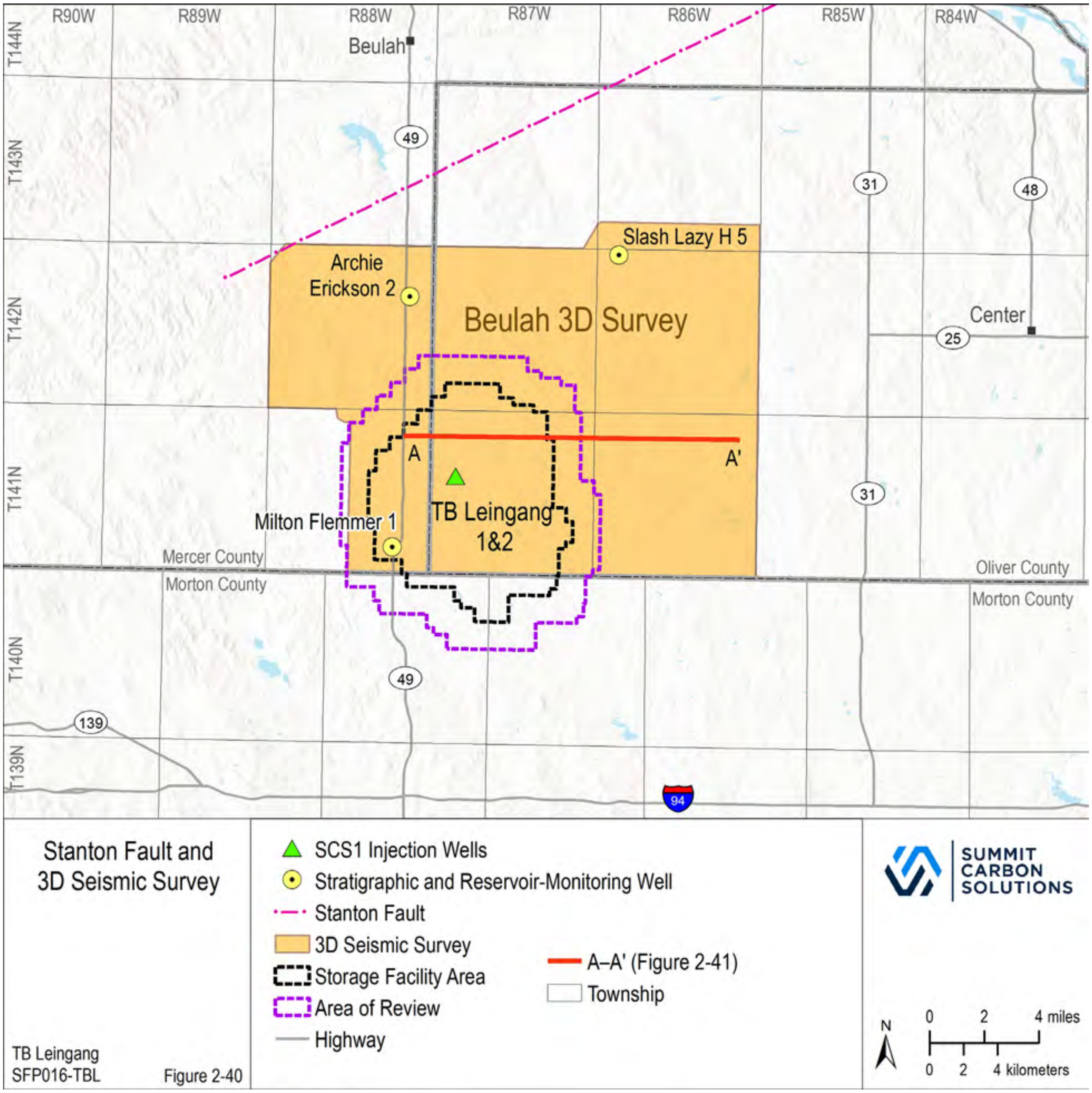


Figure 2-40. Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016) in relation to the Beulah 3D seismic survey extent. The red line on the map shows the location of the seismic section A-A' shown in Figure 2-41.

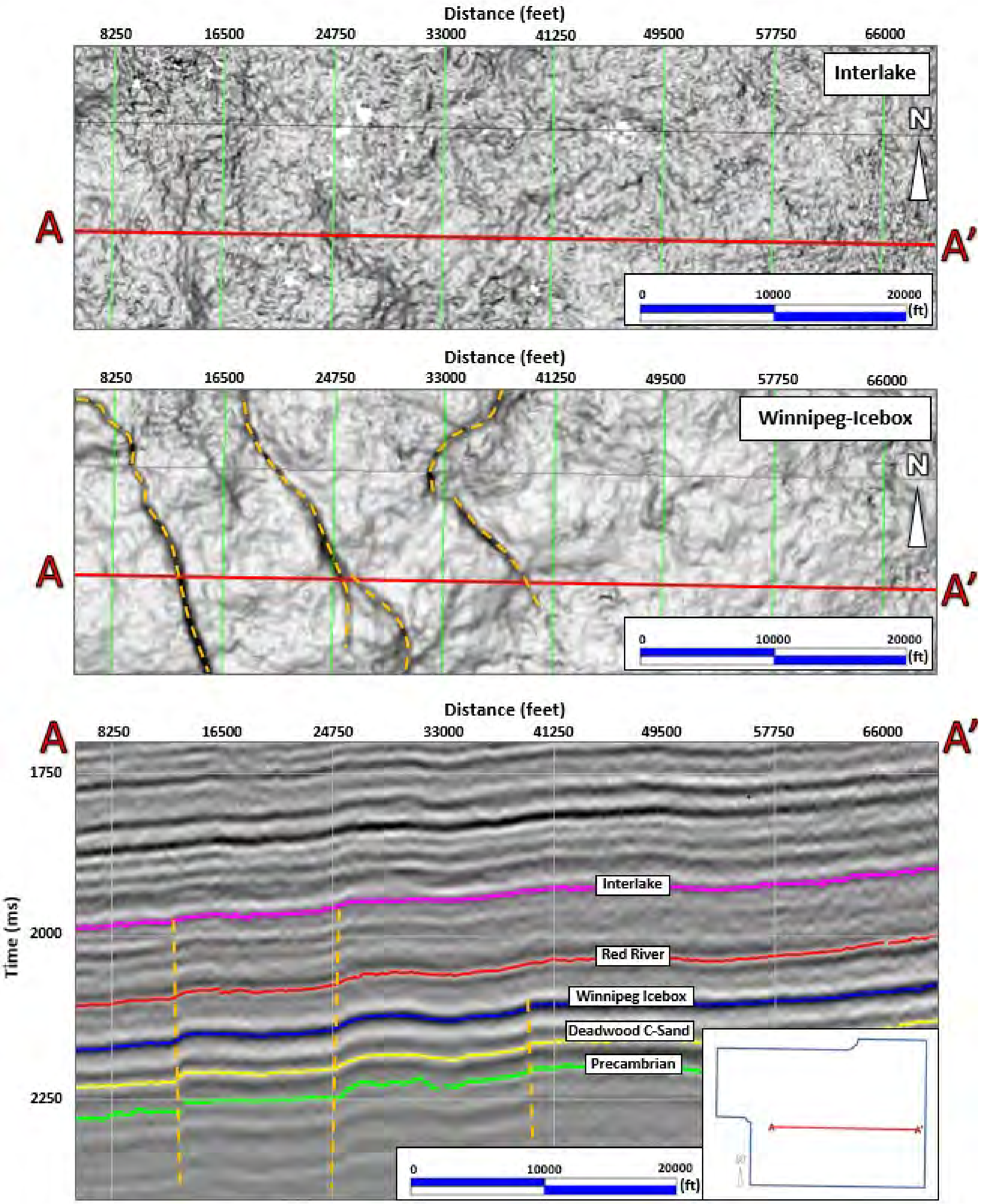


Figure 2-41. Top: similarity attribute map taken from the Beulah 3D survey of the Interlake Formation (magenta horizon) and the Winnipeg–Icebox Formation (blue horizon). Time is displayed on the y-axis in milliseconds; distance is shown on x-axis in feet. Bottom: cross-section A-A' (location within the Beulah 3D extent shown in the inset) showing seismic amplitude data, interpreted horizons, and interpreted faults. Similarity attributes highlight discontinuities shown as black linear trends marked with dashed yellow lines in the top figure. These linear trends are interpreted as faults and fractures rooted within the Precambrian basement (green horizon). Displacement along these faults diminishes below the Interlake Formation (magenta horizon).

2.5.3 Mohr–Coulomb Critical Stress Analysis of Faults

An integrated Mohr–Coulomb deterministic and probabilistic critical stress analysis study was carried out across the Beulah 3D seismic survey area. Results of the study allowed for evaluation of the risk and range of uncertainty for potential fault slippage in response to CO_2 injection. The analysis used the fault segments interpreted from the 3D seismic data which exhibit a range of strikes and dips. Four injection locations were selected for this evaluation with the objective of testing a full range of fault slip stability scenarios. Three of these locations are planned SCS injection wells, Wells 1, 2, and 4 in Figure 2-42, with Well 3 being a potential location that was ultimately not selected for further development.

The Milton Flemmer 1 1D MEM was used as a basis for the boundary conditions for the Mohr–Coulomb critical stress analysis across the Beulah 3D seismic study area. SLB Techlog, Ikon RokDoc, and Stanford University Fault Slip Potential (FSP) software tools were used to carry out the integrated study.

The evaluation's main conclusion is the interpreted fault segments have a low probability of slippage in response to pore pressure increases caused by CO_2 injection, if the maximum differential pressure increase at the fault is below ~3000 psi (Figures 2-42 and 2-43). The pore pressure necessary to initiate slip on the interpreted fault segments is dominantly controlled by the geomechanical factors: fault strike, SHmax azimuth, and pore pressure gradient. Additionally, the fault segments have a very low probability of slippage in response to pore pressure increases from injection in the Broom Creek Formation because of the large vertical distance between the reservoir and the interpreted fault (>3000 ft).

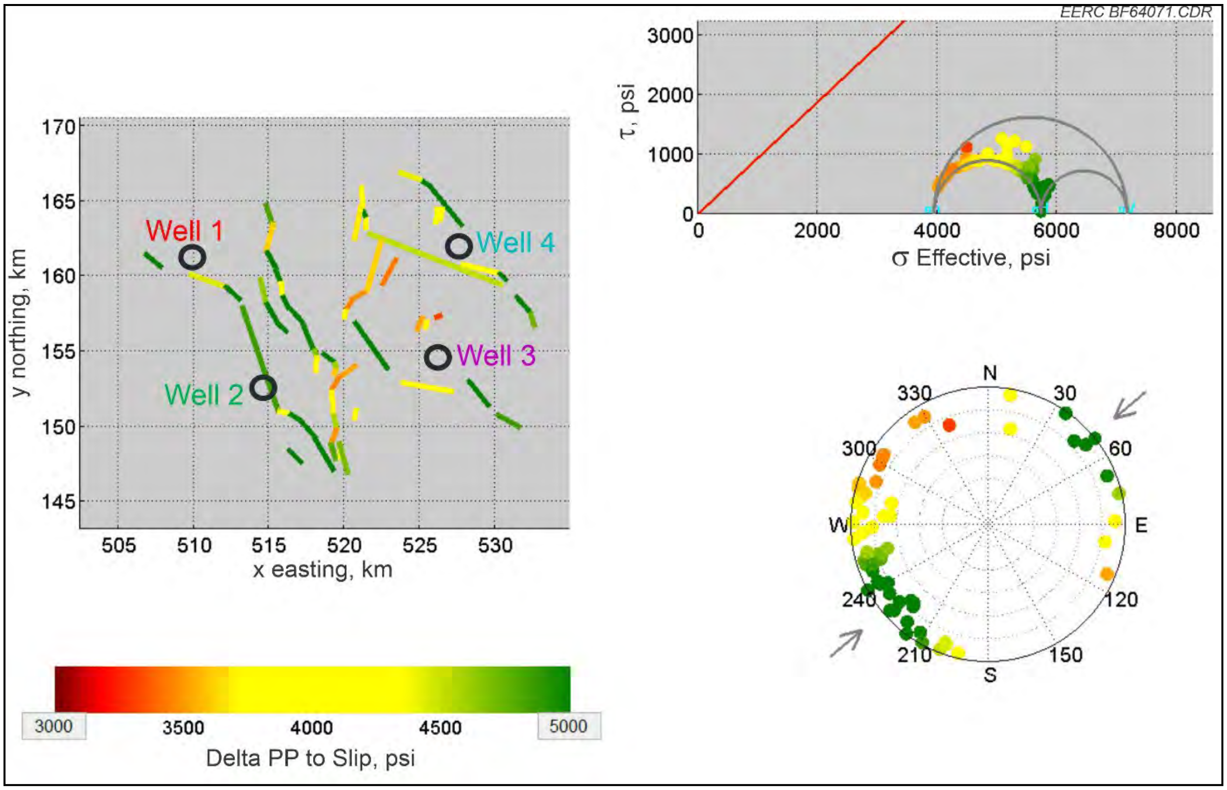


Figure 2-42. Results of the deterministic FSP analysis of the interpreted fault segments in response to pore pressure increase associated with injection at four well locations. Dominant SHmax azimuth is north 50 degrees east, indicated by the arrows in the polar plot of fault strikes and dips in the lower right of the figure.

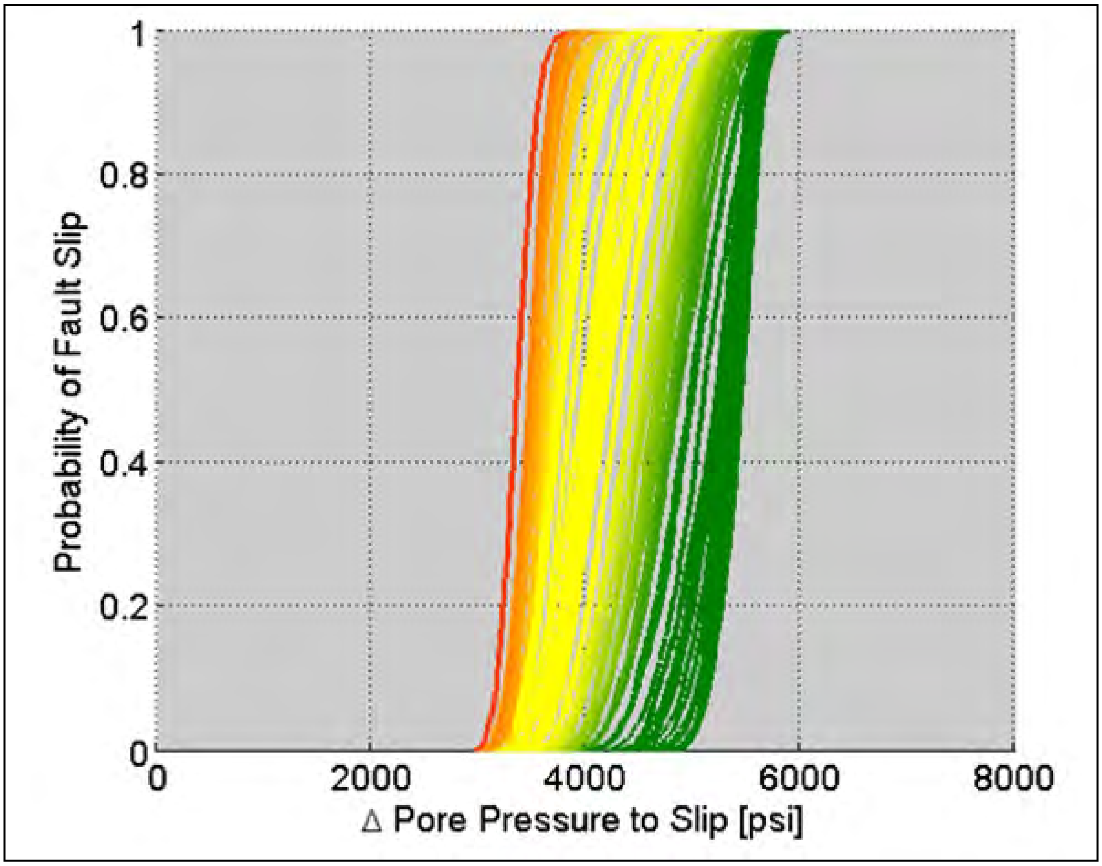


Figure 2-43. Probabilistic FSP analysis of the interpreted fault segments in response to pore pressure and four injection well locations showing a minimum of ~3000-psi pressure increase is needed to initiate slip on the most unstable interpreted faults in red vs. the more stable faults in green, where a minimum of ~5000 psi is required to initiate slip.

2.5.4 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 2-12) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight Precambrian basement faults interpreted by Anderson (2016) in the North Dakota portion of the Williston Basin (Figure 2-44). The earthquake recorded closest to the project area occurred in 1927, located 19.15 miles southwest of the TB Leingang 1 injection well, near Hebron, North Dakota (Table 2-12). The magnitude of this earthquake is estimated to have been 3.2.

Table 2-12. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)

Map Label	Date	Magnitude	Depth, miles	Longitude	Latitude	City or Vicinity of Earthquake	Distance to TB Leingang 1 Well, miles
A	Sept. 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	109.59
B	June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	126.30
C	March 21, 2010	2.5	3.1	−103.98	47.98	Buford	123.40
D	Aug. 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	50.89
E	Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	137.75
F	Nov. 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	86.76
G	Nov. 11, 1998	3.5	3.1	−104.03	48.55	Grenora	149.33
H	March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	147.41
I	July 8, 1968	4.4	20.5	−100.74	46.59	Huff	56.63
J	May 13, 1947	3.7**	U***	−100.90	46.00	Selfridge	81.94
K	Oct. 26, 1946	3.7**	U	−103.70	48.20	Williston	121.84
L	April 29, 1927	3.2**	U	−102.10	46.90	Hebron	19.15
M	Aug. 8, 1915	3.7**	U	−103.60	48.20	Williston	118.35

* Estimated depth.

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

*** Unknown.

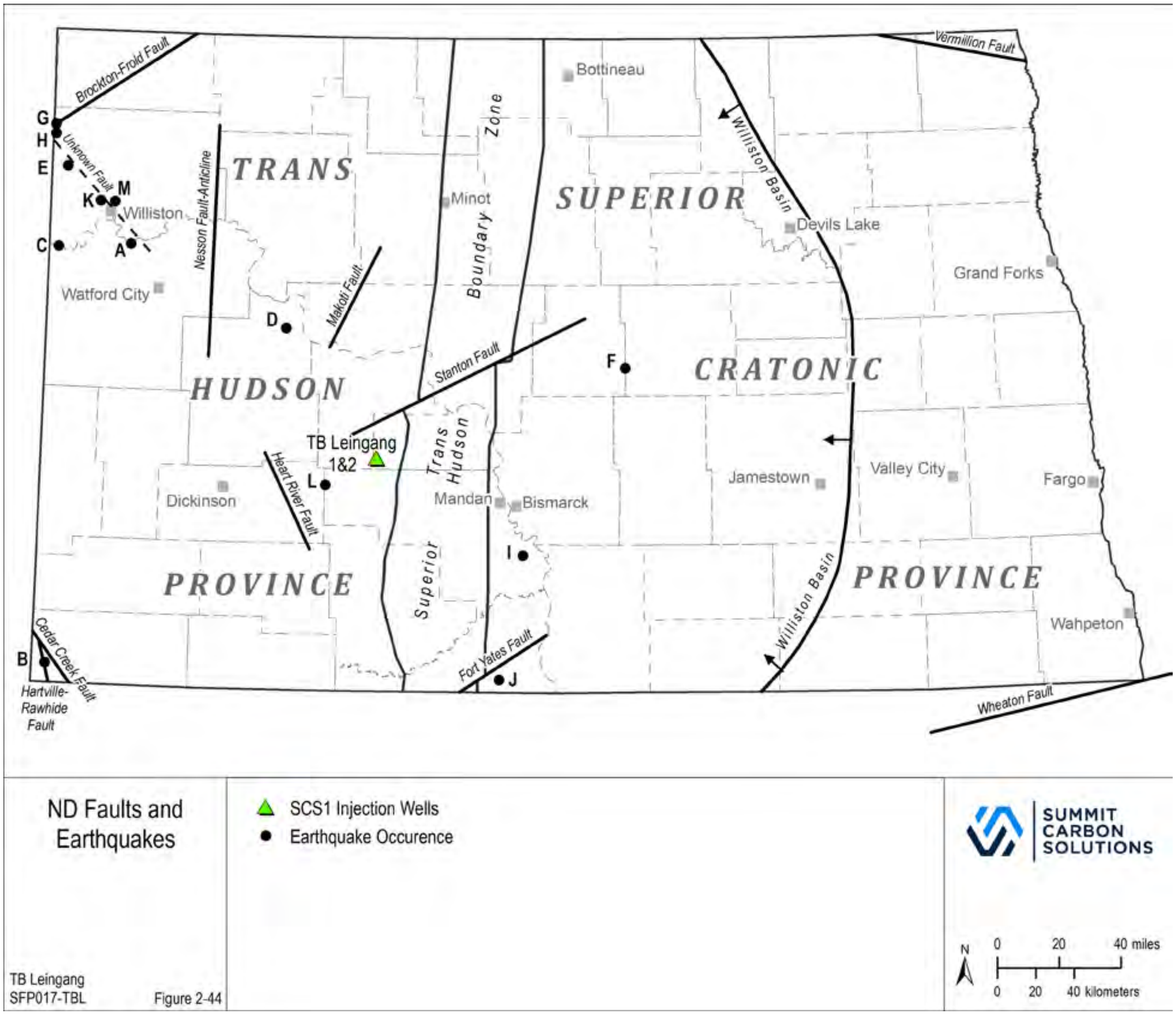


Figure 2-44. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-12.

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 2-45) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by USGS in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) state there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic earthquake events in North Dakota that could be associated with nearby oil and gas activities. Additionally, no earthquakes occurring along the Stanton Fault have been reported. This indicates stable geologic conditions in the region

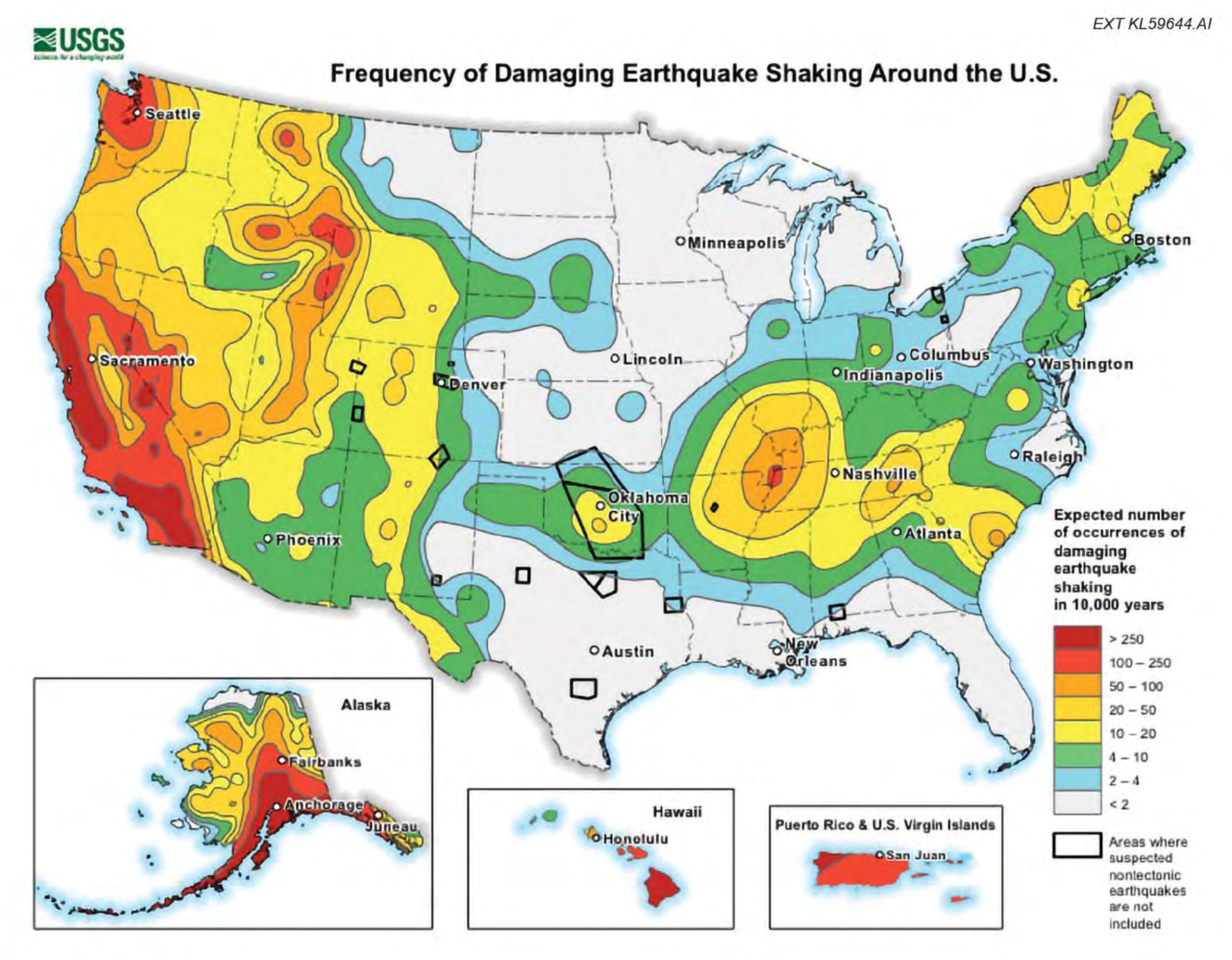


Figure 2-45. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

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 depth of the target reservoir in proximity to the basement and vertical extents of the interpreted faults) suggest the probability that seismicity interfering with CO_2 containment is low.

2.6 Potential Mineral Zones

The North Dakota Geological Survey recognizes the Spearfish Formation as the only potential oil-bearing formation above the Broom Creek Formation. However, production from the Spearfish Formation is limited to the northern tier of counties in western North Dakota (Figure 2-46). There has been no exploration for, nor development of, a hydrocarbon resource from the Spearfish Formation in the storage facility area. There has not been historic hydrocarbon exploration in, or production from, formations below the Broom Creek Formation in the storage facility area. The two wells closest to the storage facility area, NDIC File No. 7818 and 7340, drilled to the Duperow Formation and the Precambrian, respectively, were dry and did not suggest the presence of

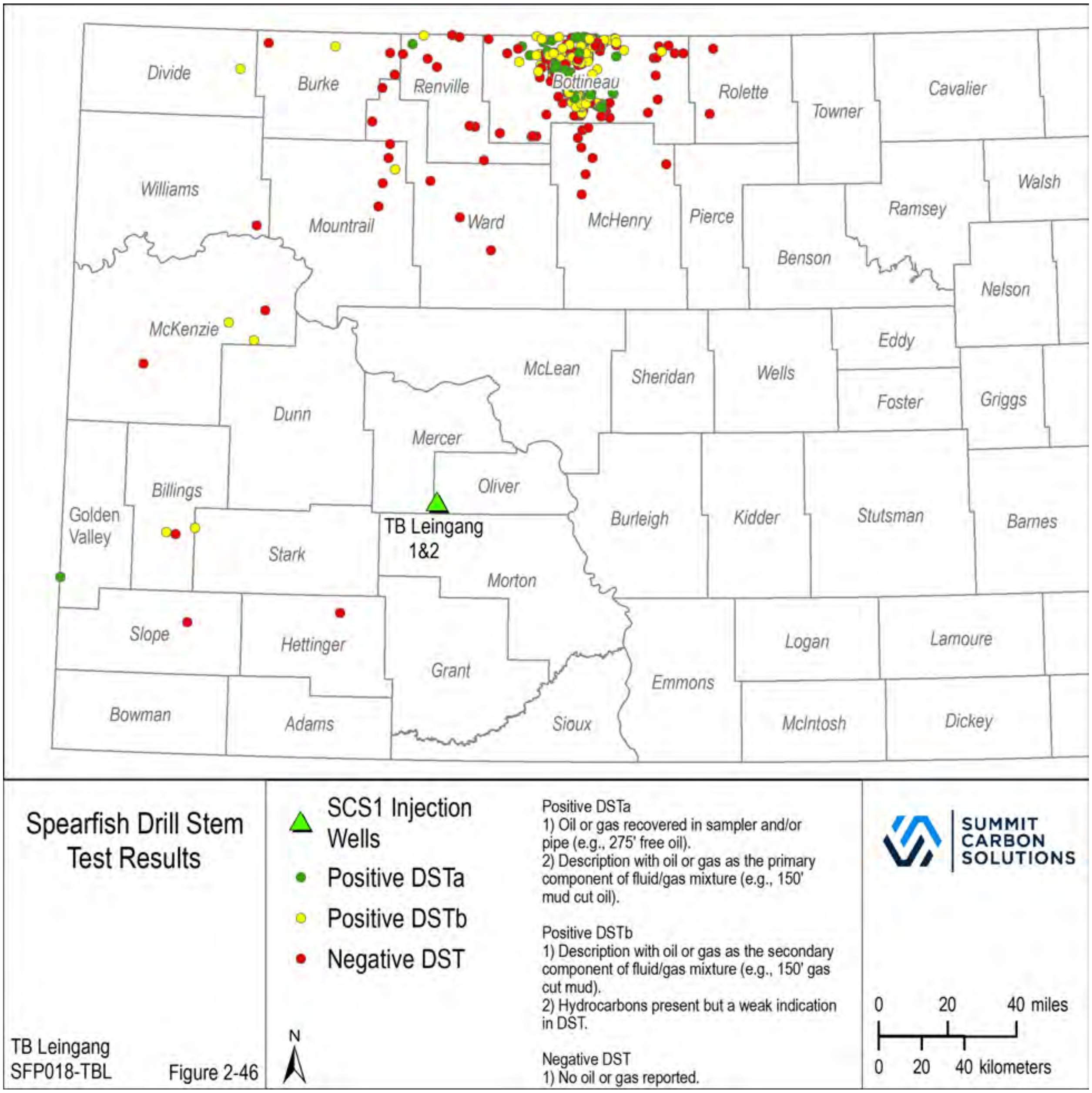


Figure 2-46. DST results indicating the presence of oil in the Spearfish Formation (modified from Stolldorf, 2020).

hydrocarbons. Published studies suggest no economic deposits of hydrocarbons in the Bakken Formation in the storage facility area (Bergin, 2012; Theloy, 2016). The nearest hydrocarbon production well is Entze 29 1 (NDIC File No. 7616), located ~19 mi northwest (Figure 2-47). Entze 29 1 was drilled in June 1980 and produced from the Red River Formation a cumulative total of 7799 barrels (bbl) until June 1982. The well is now plugged and abandoned (P&A).

Shallow gas resources can be found in many areas of North Dakota. Shallow gas is “gas produced from a gas well completed in or producing from a shallow gas zone…,” which 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 (1524 meters) below the surface but above the top of the Rierdon Formation [Jurassic], from which gas is or may be produced” (N.D.C.C. §§ 57-51-01[10]-[11].

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a horizontal well could be used to produce hydrocarbons while avoiding drilling through the CO_2 plume, or a vertical well could be drilled using proper controls. Aside from meeting regulatory and jurisdictional requirements, should an operator decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation BHP data will be available while the TB Leingang 1 and TB Leingang 2 wells are 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.

Active and reclaimed coal mines are near the storage facility area. Coal is mined from the Sentinel Butte Formation of the Fort Union Group of Paleocene age (the Beulah of the Beulah–Zap interval and Twin Butte coal beds) (Figure 2-48). The thickness of the Beulah–Zap interval averages between 18 and 22 ft (Figure 2-49). Above the Beulah horizon are several thin beds of lignite. In ascending order, these are the Schoolhouse and Twin Butte beds. Overburden on top of the Beulah horizon ranges from 95 to 145 ft (Figure 2-50). The Twin Butte has an average thickness of about 6 ft, under 25–30 ft of overburden, where it is actively mined (Zygarlicke and others, 2019). The Beulah, Twin Butte, and other coal seams thicken and deepen to the west. The Beulah–Zap and Twin Butte seams pinch out to the east. The underlying Hagel coal seam is mined farther to the east by BNI Coal at its Center Mine and the Falkirk Mine near Falkirk, North Dakota. Coal seams in the Bullion Creek Formation exist in the area below the Hagel seam but are too deep to be economically mined. Currently, no existing mine has plans to mine coal in the storage facility area during the project’s operational period. The Coyote Creek Mine is the closest mine to the storage facility area. Figure 2-51 depicts the future mining area for the Coyote Creek Mine through 2040. The Beulah Mine is a mine near the storage facility area that no longer has active coal removal and is undergoing final reclamation. Figure 2-51 depicts areas that have been mined out at both the Coyote Creek Mine and the Beulah Mine.

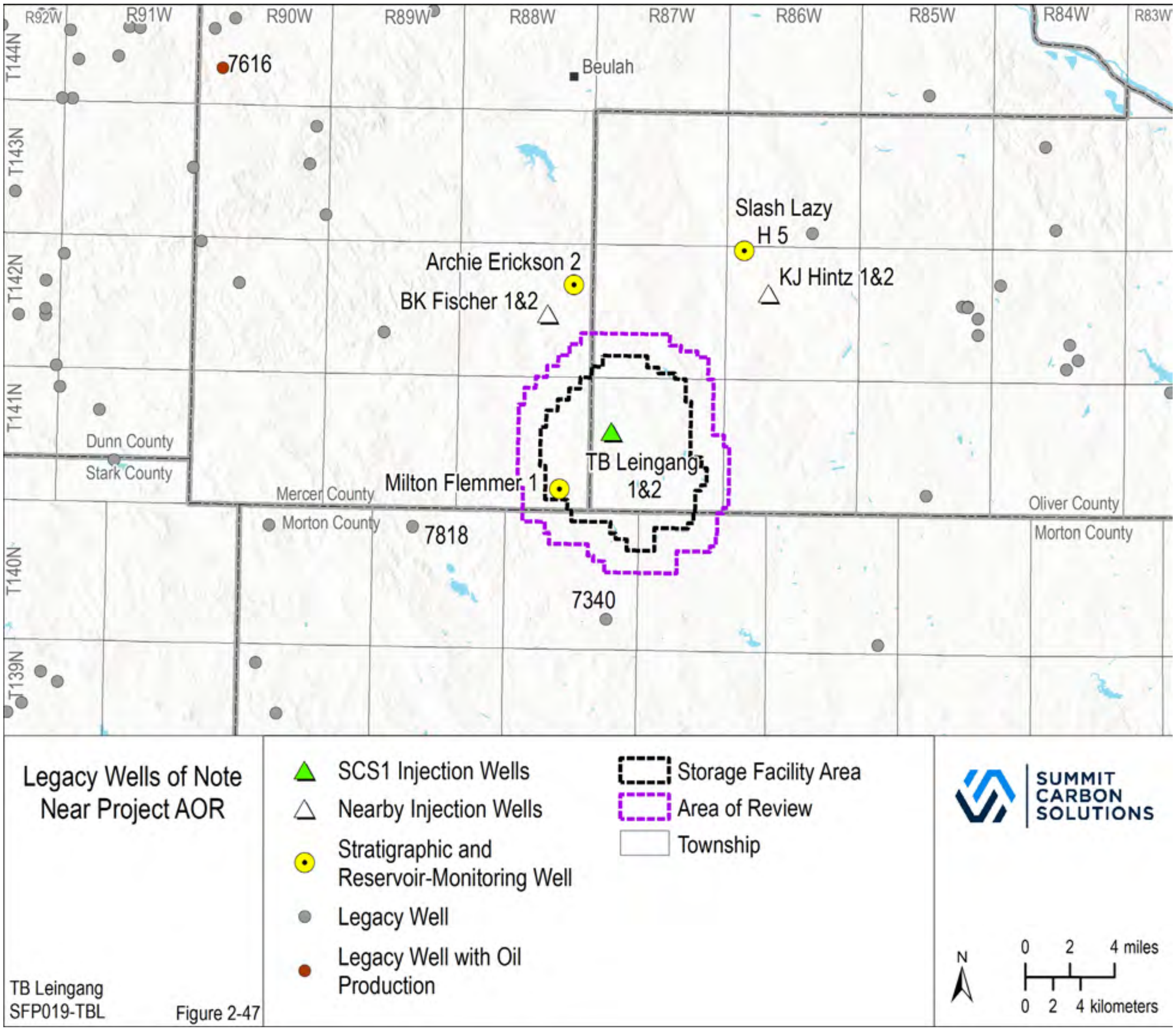


Figure 2-47. Map showing stratigraphic wells for the project and nearest legacy wells. Gray circles indicate dry wells. The red circle indicates the closest oil and gas producing well (NDIC File No. 7616).

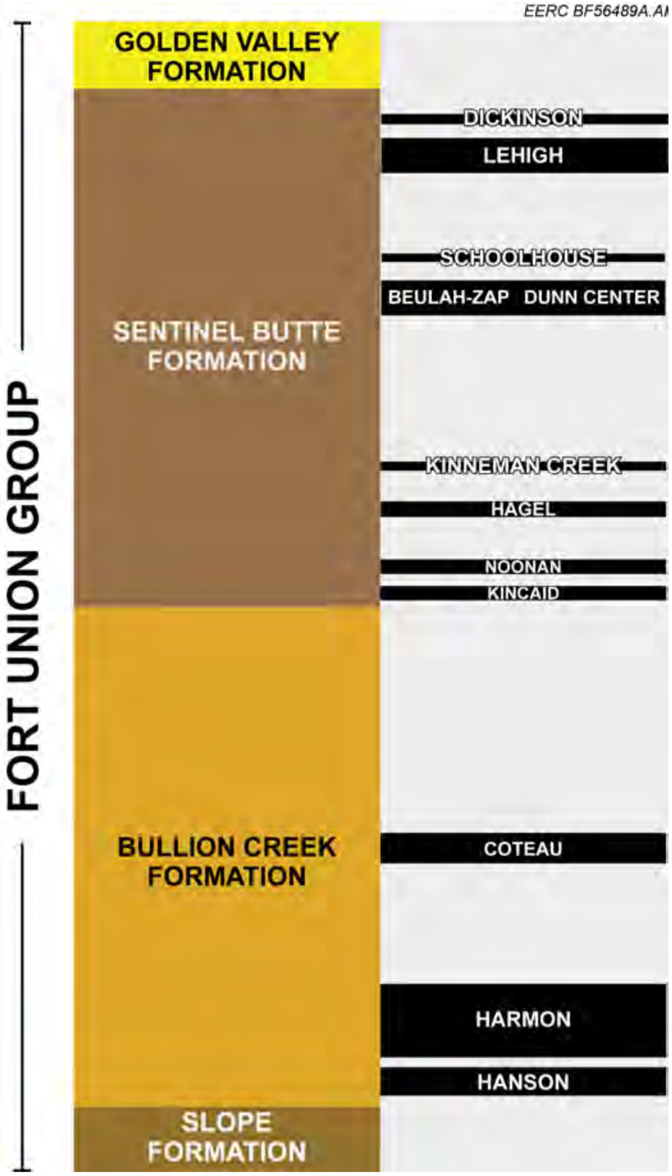


Figure 2-48. Coal beds of the Sentinel Butte and Bullion Creek (Tongue River) Formations showing the lignite coals in western North Dakota (Zygarlicke and others, 2019).

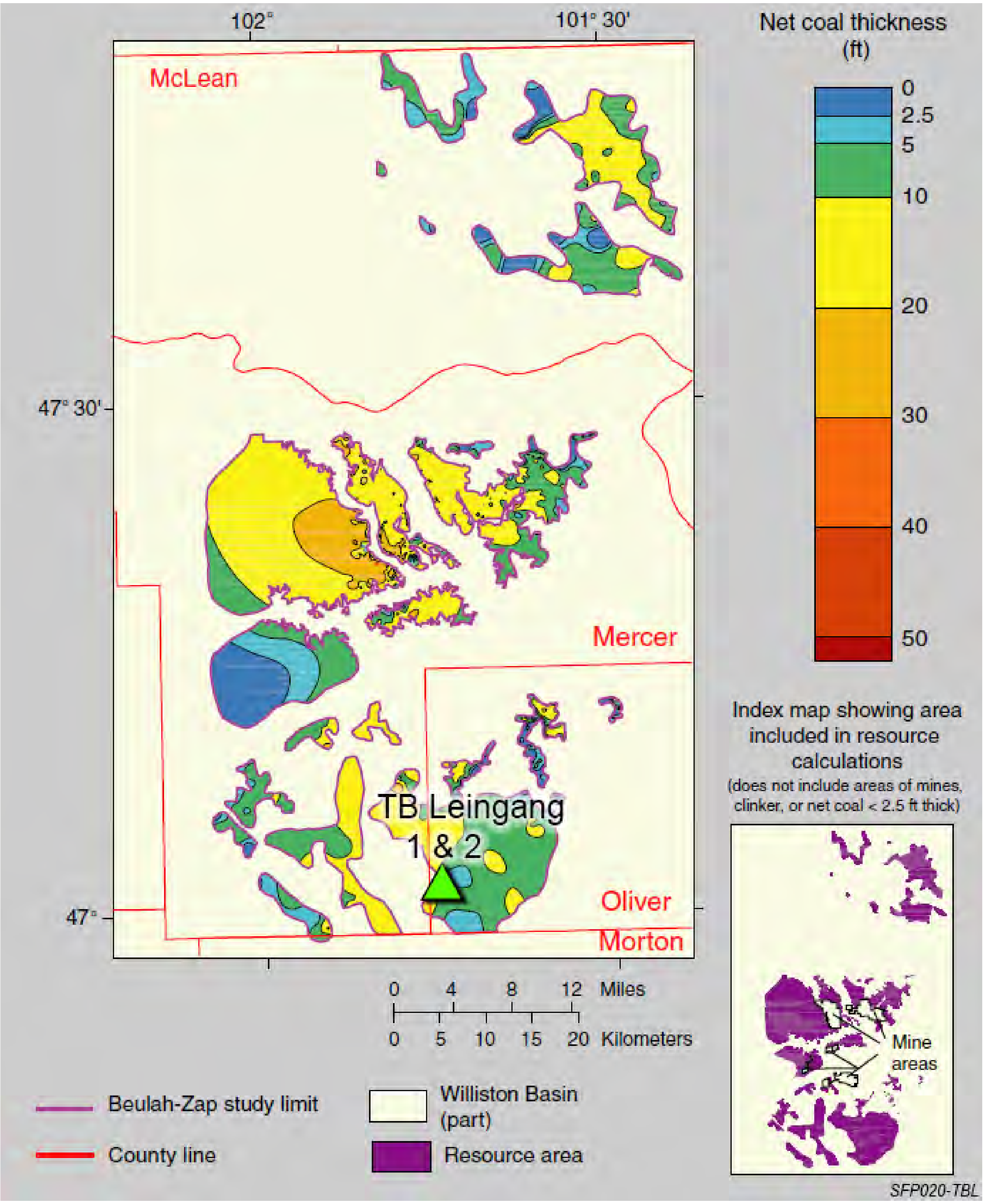


Figure 2-49. Beulah net coal isopach map and resource area (modified from Ellis and others, 1999).

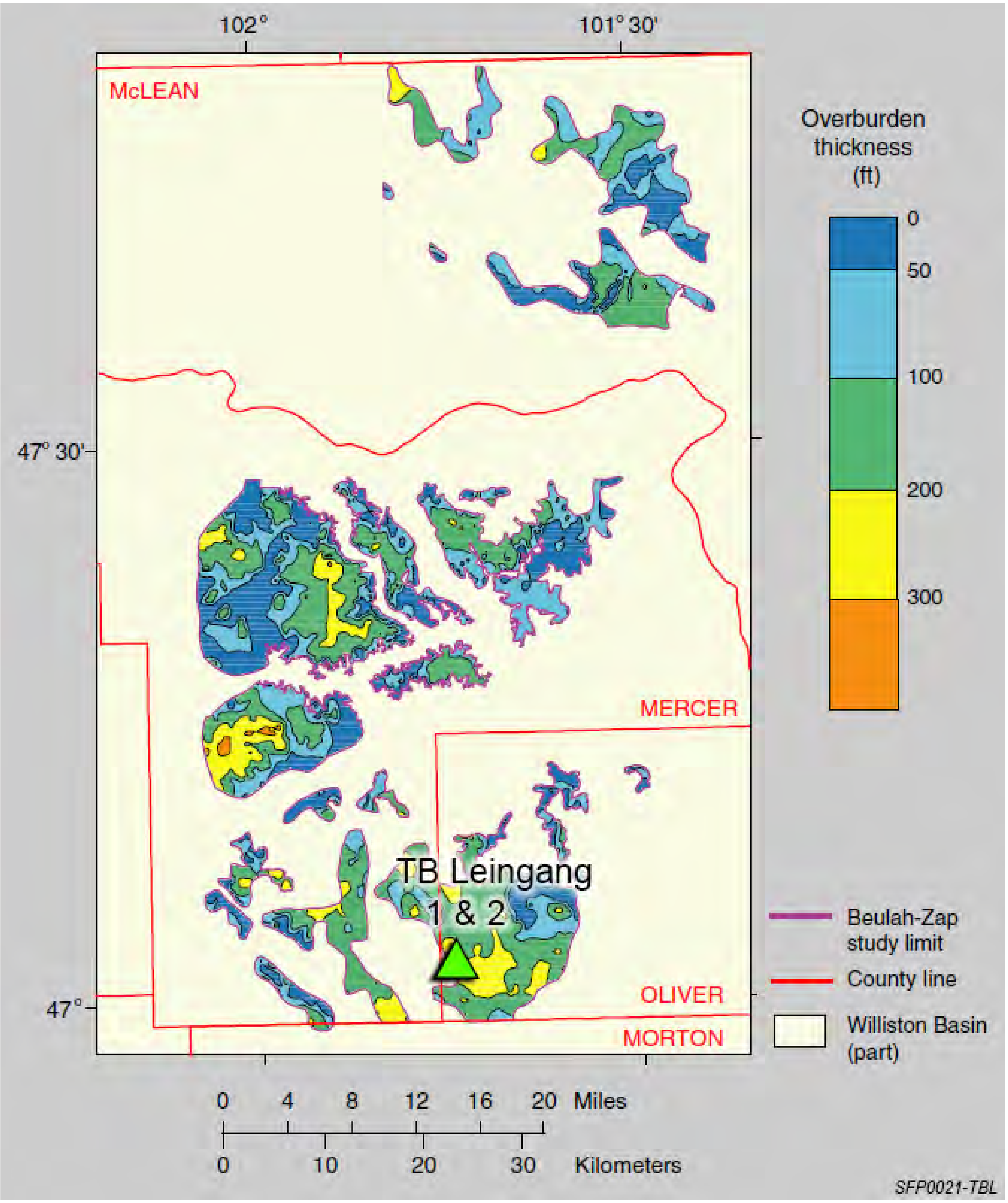


Figure 2-50. Beulah overburden isopach map (modified from Ellis and others, 1999).

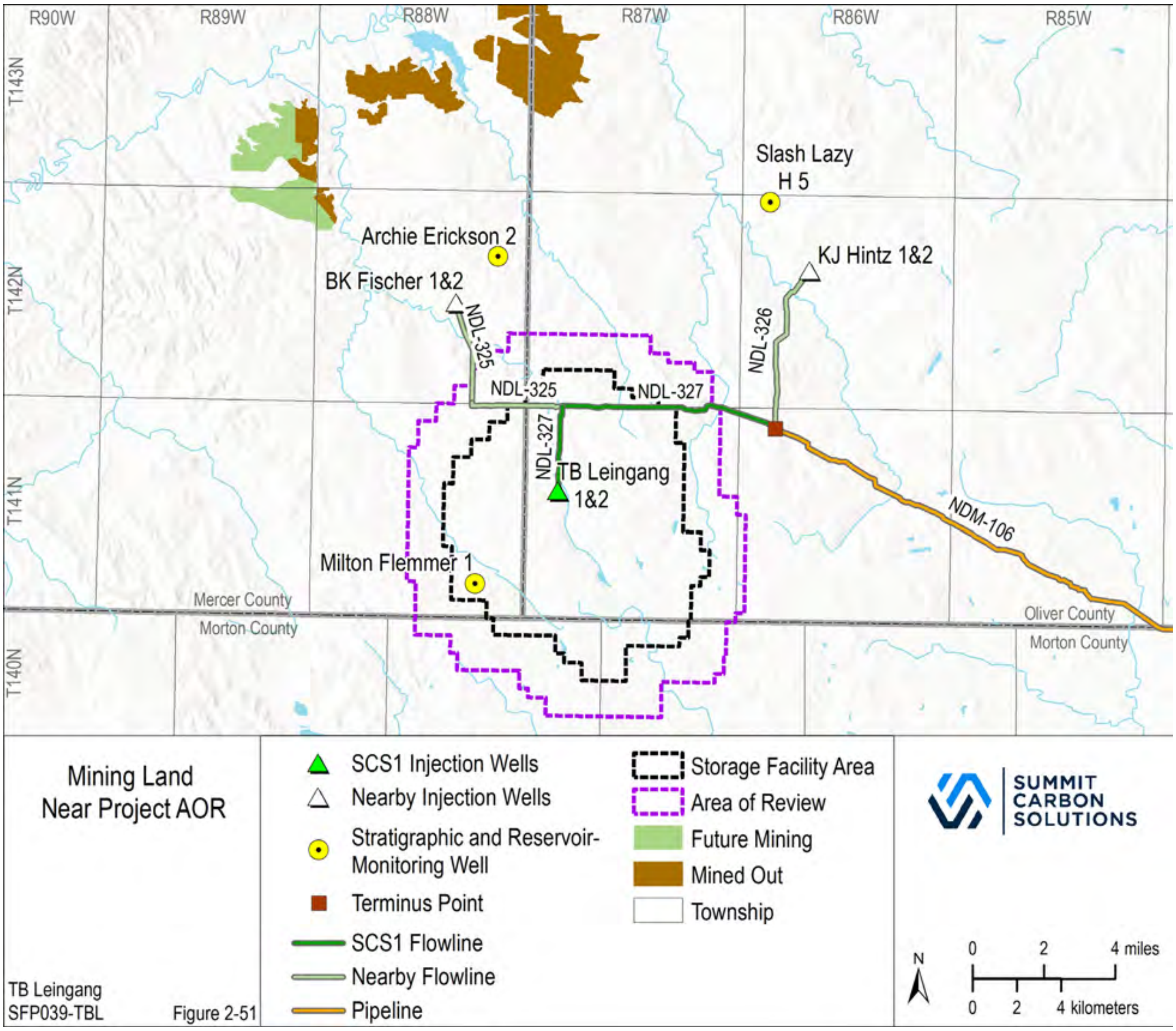


Figure 2-51. Map showing the future mining area for the Coyote Creek Mine and Beulah Mine through 2040.

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SECTION 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

Existing and site-specific subsurface data were analyzed and interpreted (Section 2.2). The data and interpretations were used as inputs to SLB's Petrel software (Schlumberger, 2020) to construct a geologic model of the injection zone (Broom Creek Formation), the upper confining zone (Opeche/Spearfish Formation), and the lower confining zone (Amsden Formation). The geologic model encompasses a 4070-mi^2 (74-mi × 55-mi) area around the TB Leingang 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 facies, 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., 2021). 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 along with the 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 all existing wells that penetrate both the storage reservoir and associated upper and lower confining zones within the geologic model area. Major inputs for the geologic model also included seismic survey data and core sample measurements. The core sample measurements acted as control points during the distribution of the geologic properties throughout the modeled area. The geologic properties distributed throughout the model include acoustic impedance (AI), total porosity, effective porosity, permeability, and facies.

Three 3D seismic AI volumes (Figure 2-8) were upscaled and integrated into the geologic model grid using a volume-weighted method (Figure 2-3). The volumes were used to guide the facies and petrophysical property distributions within the 3D geologic model and determine lateral heterogeneity through a variogram assessment. Horizontal variogram directions and structures were determined from the resampled 3D Beulah seismic AI volume because it covered the largest areal extent and captured multiple dune structures, producing the most reliable variogram calculation.

3.2.2 Structural Framework Construction

SLB's Petrel software was used to interpolate structural surfaces for the undifferentiated Opeche/Spearfish (i.e., Spearfish, Minnekahta, Opeche), Broom Creek, and Amsden Formations. Input data included formation top depths from the online North Dakota Industrial Commission (NDIC) Department of Mineral Resources Oil and Gas Division (DMR-O&G) database; data collected from ten cored wells: ANG 1, Flemmer 1, BNI 1, J-LOC 1, Liberty 1, MAG 1, Coteau 1, Milton Flemmer 1, Archie Erickson 2, and Slash Lazy H 5 (Figure 2-4); three 3D seismic surveys (Figure 2-8); and one 5-mi-long 2D seismic line (Figure 2-8). 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 (Opeche/Spearfish and Amsden Formations)

The upper confining zone (Opeche/Spearfish Formation) and the lower confining zone (Amsden Formation) were each assigned a single facies. Based on their primary lithology determined by well log analysis, the upper confining zone is assigned siltstone, and the lower confining zone is assigned dolostone. The lower Piper Formation was included in the geologic model in addition to the Opeche/Spearfish Formations because the Opeche/Spearfish Formation pinches out within the geologic model, approximately ~36 miles east of the Milton Flemmer 1. The lower Piper is assigned as siltstone. AI, 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 (Figure 2-16). The control points were used in combination with variograms, Gaussian random function simulation algorithms, and secondary trend data to distribute the properties. A 6800-ft major and minor axis length variogram model in the lateral direction and a 160-ft vertical variogram length were used within the lower Piper Formation. An 8200-ft major and 7500-ft minor axis length variogram model along an azimuth of 144° and 90-ft vertical variogram length were used for the Opeche/Spearfish Formation. A major axis length of 6500 ft and a minor axis length of 5300 ft along an azimuth of 180° in the lateral direction and 13-ft vertical variogram length were used for the Amsden Formation. Vertical variogram lengths were determined from the upscaled well logs.

3.2.3.2 Injection Zone (Broom Creek Formation)

Seismic data were resampled to the geologic model grid and used to determine lateral heterogeneity through a variogram assessment. Nonreservoir facies (dolostone, anhydrite) captured a major axis range of 8200 ft and a minor axis range of 6000 ft in the lateral direction. Reservoir facies (sandstone, dolomitic sandstone) captured a major axis range of 5000 ft and a minor axis range of 4500 ft along an azimuth of 45°. Vertical variogram lengths were determined from the upscaled well logs (Table 3-1).

Table 3-1. Lateral and Vertical Variogram Lengths for Facies Distributions Within the Injection Zone

Facies	Azimuth, degrees	Major Length, ft	Minor Length, ft	Vertical Length, ft
Sandstone	45	5000	4500	30
Dolostone	90	8200	6000	35
Dolomitic Sandstone	45	5000	4500	28
Anhydrite	90	8200	6000	17

AI from 3D seismic surveys was upscaled to the resolution of the geologic model grid to serve as control points for facies and petrophysical property distributions. Calculated AI logs, derived from available sonic and bulk density well logs in the geologic model area, were also upscaled to aid in discovering trends between well log data and seismic AI data and serve as additional control points for property distributions. After identification of a trend between the AI data and well logs, an AI property was then distributed throughout the model using the upscaled seismic AI data and upscaled AI logs as control points, the horizontal variogram parameters described above, and Gaussian random function simulation algorithms.

Facies classifications were interpreted from well log data and correlated with descriptions of core taken from the Milton Flemmer 1, Archie Erickson 2, Slash Lazy H 5, Flemmer 1, ANG 1, J-LOC 1, Liberty 1, BNI 1, MAG 1, and Coteau 1 wells. Four facies were modeled within the Broom Creek Formation: 1) sandstone, 2) dolostone, 3) dolomitic sandstone, and 4) anhydrite (Figure 2-11). Facies logs were generated from gamma ray, density, neutron porosity, sonic, and resistivity logs. Seismic facies probability volumes interpreted from the 3D Beulah seismic area were used to guide the facies distribution. Three probability volumes corresponding to the predominant facies of sandstone, dolostone, and dolomitic sandstone were resampled into the geologic model. Upscaled mineral fraction logs were also used to generate a facies trend model, which were guided by the resampled seismic probability, kriging algorithm, and variogram ranges described above. The facies logs were upscaled to the resolution of the 3D model to serve as control points for geostatistical distribution using sequential indicator simulation and guided by the facies trend model (Figure 2-15).

Prior to distributing the porosity and permeability properties, total porosity (PHIT), effective porosity (PHIE; total porosity less occupied or isolated pore space), and intrinsic permeability (KINT) well logs were calculated and compared with core porosity and permeability measurements to ensure good agreement with the ten cored wells: Milton Flemmer 1, Archie Erickson 2, Slash Lazy H 5, Flemmer 1, ANG 1, J-LOC 1, Liberty 1, BNI 1, MAG 1, and Coteau 1. The Gaussian random function simulation algorithm was used to distribute the PHIE property using calculated PHIE well logs. The PHIE well logs were upscaled to the resolution of the 3D model and were used as control points and as the variogram structures described previously. The PHIE was cokriged with the AI seismic volumes and conditioned to the distributed facies (Figure 3-1). A KINT property was distributed using the same variogram structures and Gaussian random-function algorithm but was paired with PHIE volume cokriging (Figure 3-2).

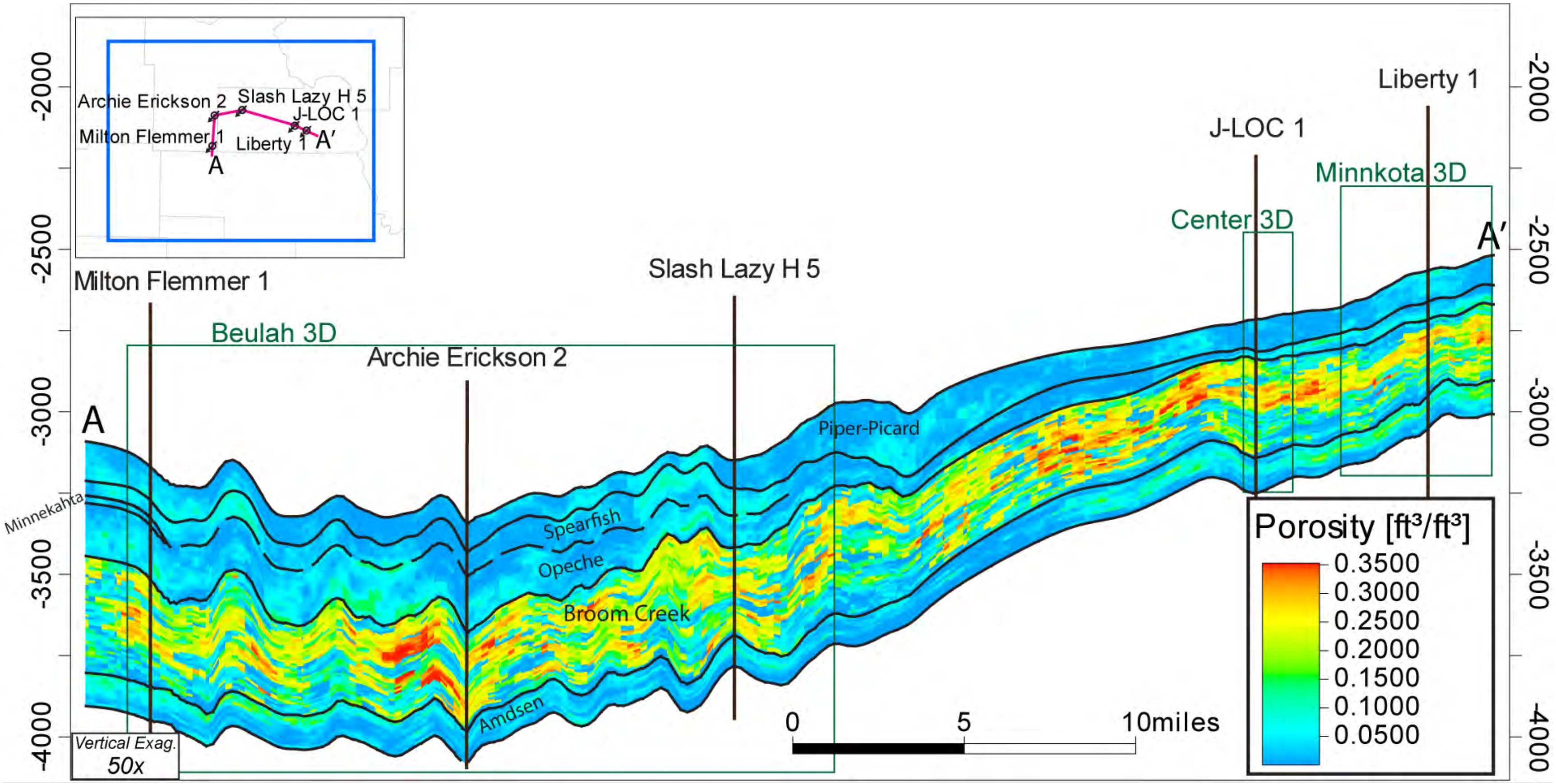


Figure 3-1. Distributed PHIE property along a roughly W-E cross section. The distributed PHIE property was used to distribute permeability throughout the model. Units on the y-axis represent feet below mean sea level (50× vertical exaggeration shown).

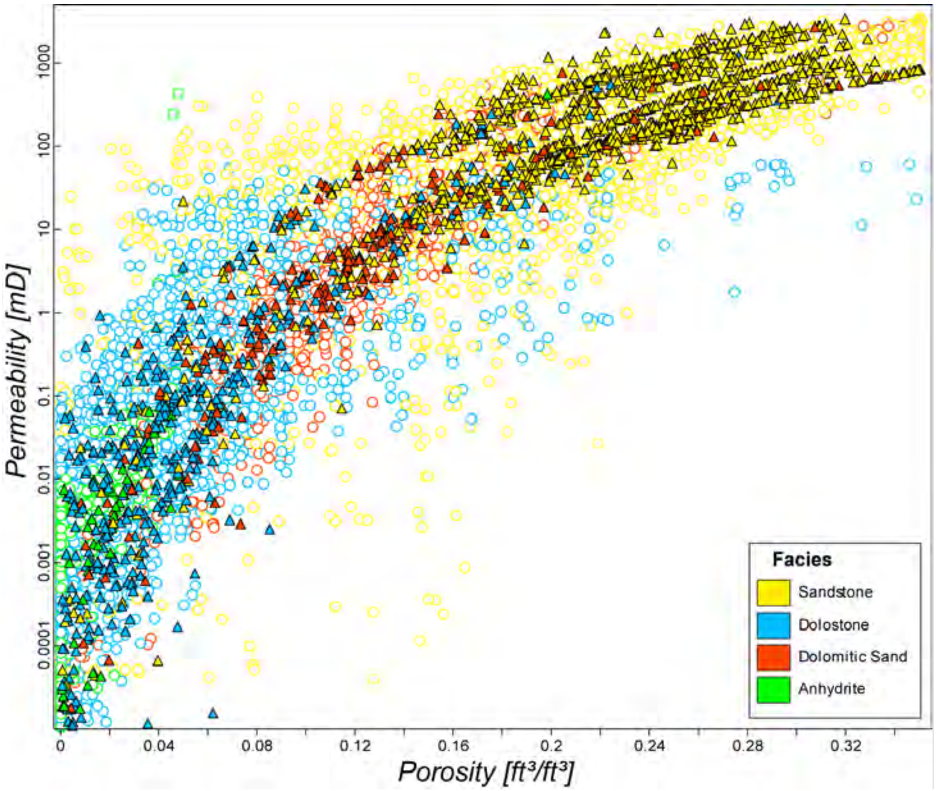


Figure 3-2. Illustration of the relationship between the modeled porosity and permeability of the Broom Creek Formation facies. Upscaled well log values are represented by triangles, while circles represent distributed values. Values are colored according to facies classification.

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's GEM, a compositional reservoir simulation module. Calculated values based on measured temperature and pressure data, along with the reference datum depth, were used to initialize the reservoir equilibrium conditions for performing numerical simulation. Figures 3-3 and 3-4 display a 3D and aerial view, respectively, of the simulation model with the permeability property and injection wells (TB Leingang 1 and 2) for TB Leingang. BK Fischer 1 and 2 and KJ Hintz 1 and 2 were also included to represent adjacent injection sites.

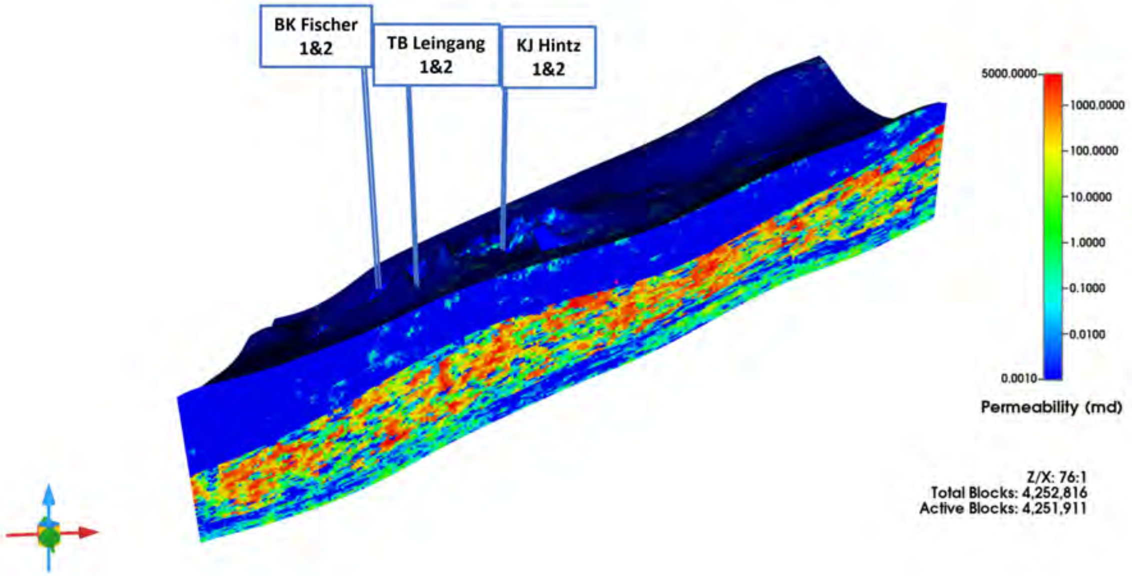


Figure 3-3. 3D view of the simulation model with the permeability property and injection wells displayed. The low-permeability layers (light blue and green) at the top and bottom of the figure should be noted. These layers represent the Opeche/Spearfish Formation (upper confining zone) and the Amsden Formation (lower confining zone). The varied permeability of the Broom Creek Formation is shown between these layers.

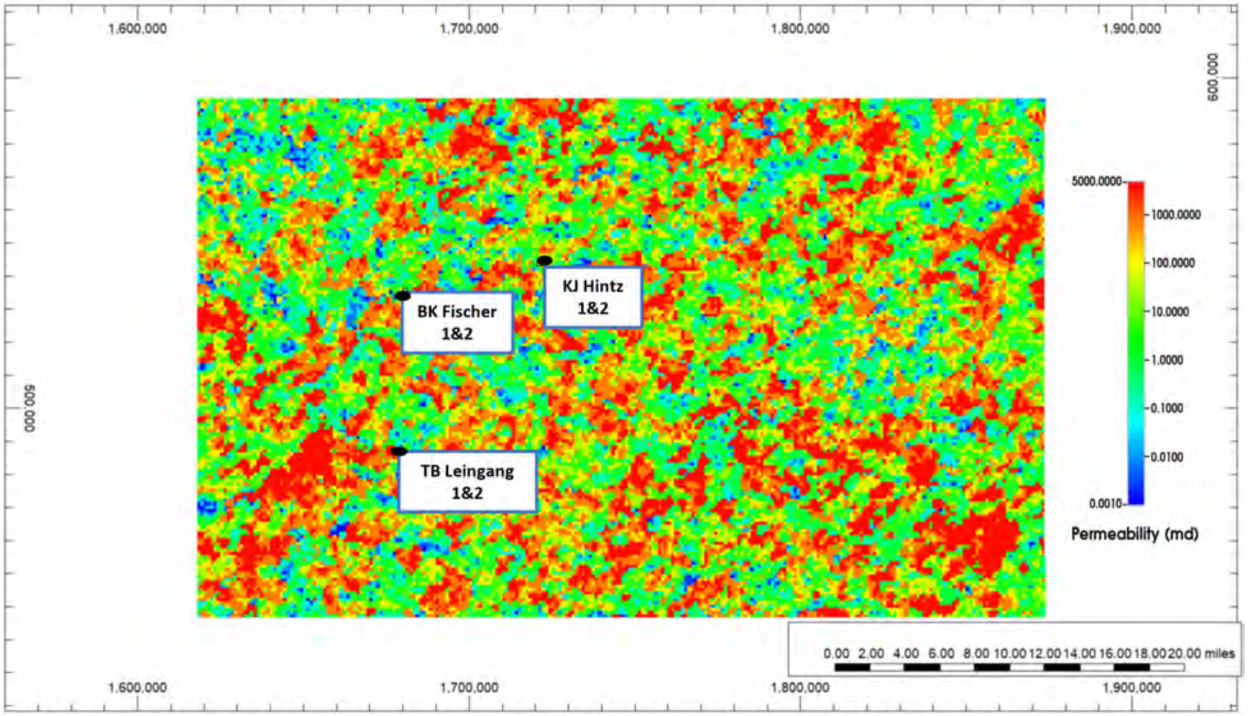


Figure 3-4. Aerial view of the simulation model with the permeability property of Broom Creek Formation (Layer 26, 5668 ft TVD at TB Leingang 1 top perforation, estimated prior to wellsite selection) and the injection wellsites displayed.

The simulation model encompasses an area of 48.5 mi by 29.7 mi. TB Leingang is located approximately 17.4 mi from the north edge of the model and approximately 13.6 mi from the west edge of the model. The simulation model boundaries were assigned partially closed conditions as the Broom Creek Formation pinches out in the northern and eastern parts of the modeled area. Distances from the edge of the model to the pinch-out are assumed to be 56,500 ft (~10.7 mi) to the east, 19,400 ft (~3.7 mi) to the northeast, and 184,800 ft (35 mi) to the west. Therefore, the volume modifiers are 28.25, 283, 10, 185, and 286 for east, north, northeast, west, and south, respectively. These modifiers are multipliers to a block's bulk volume when rock and pore volume are considered. A fluid sample from the Broom Creek Formation collected from Milton Flemmer 1 was analyzed by Minnesota Valley Testing Laboratories, and the measured total dissolved solids (TDS) of 105,000 mg/L was used as input for the numerical simulation. The reservoir was assumed to be 100% brine-saturated with the initial TDS as indicated from Milton Flemmer 1 TDS analysis. Table 3-2 shows the general reservoir properties extracted from the model and used for numerical simulation analysis.

Table 3-2. Summary of Reservoir Properties in the Simulation Model

Formation	Pore Volume (PV) Weighted Average Permeability, mD	Average Porosity, %*	Initial Pressure, P_i, psi	Salinity, mg/L	Boundary Condition
Opeche/Spearfish	0.019	3.8	2741 (at 5882 ft, TVD**)		Partially closed
Broom Creek	1105.5	21.3		105,000	
Amsden	6.67	6.7			

* Porosity and permeability values are reported as PV weighted mean. Permeability averages were calculated after a 2.5 multiplier was applied.

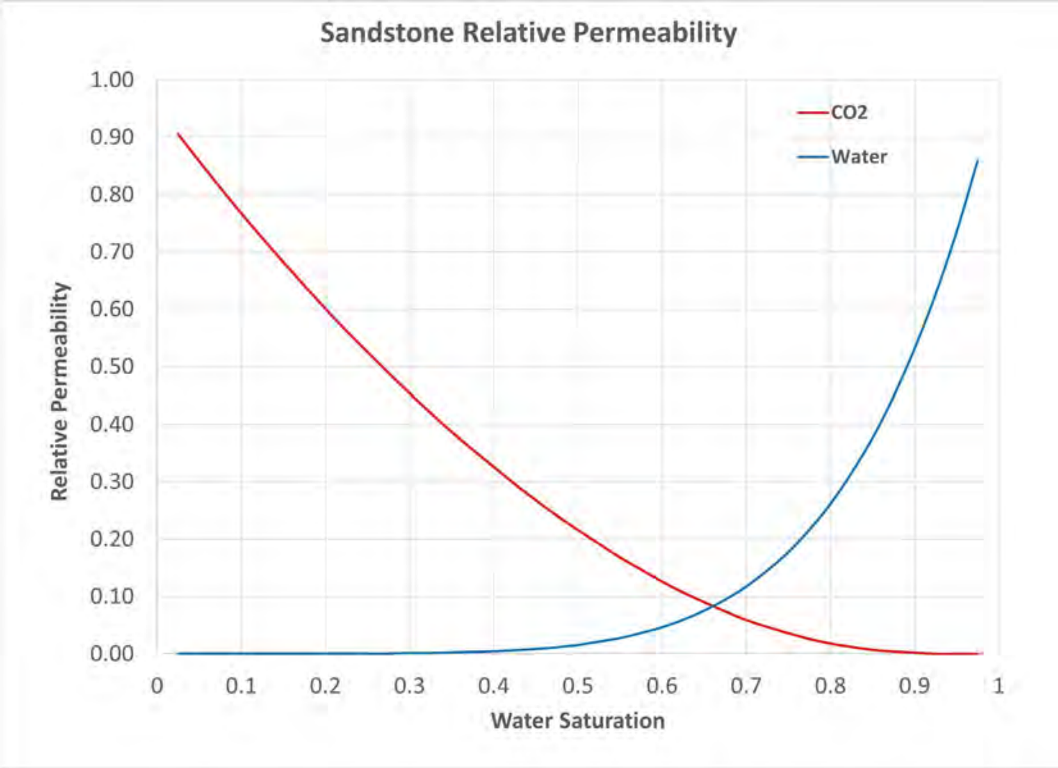
** True vertical depth.

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 Opeche/Spearfish, Broom Creek, and Amsden Formations were used to generate relative permeability and the capillary pressure curves for the five representative facies in the simulation model (sandstone, siltstone, dolostone, dolomitic sandstone, and anhydrite) (Figures 3-5 through 3-9). Samples tested within the Opeche/Spearfish, Broom Creek, and Amsden Formations included all five facies.

Capillary pressure curves calculated from MICP data were modified to the model scale based on the permeability and porosity values of the simulation model for the five representative facies and used in the numerical simulations. These modified capillary pressure curves are also shown in Figures 3-5 through 3-9. The capillary entry pressure values applied in the model were determined by deriving a ratio between the reservoir quality index of core samples of the modeled region from MICP data and modeled properties to scale the capillary entry pressure value derived from core testing (Table 3-3). The capillary pressure curves for siltstone and anhydrite were also modified based on the simulation model domain. This resulted in two different ratios derived first from MICP data (same MICP sample for both facies) and second from the porosity and permeability properties for each of these facies in the model. These results demonstrated that there are two different capillary pressure curves for siltstone and anhydrite facies, Figures 3-6 and 3-9. It is worth noting that the relative permeability and capillary data selection are based on a broader data selection from the modeled region. All site-specific data in the modeled region, collected from Milton Flemmer 1, Archie Erickson 2, Slash Lazy H 5, and J-LOC 1, are screened, and the data from the most representative samples that are close to the reservoir properties are selected in dynamic flow simulations.

The calculated temperature and pressure based on reported temperature and pressure gradients derived from data recorded in the Milton Flemmer 1 wellbore (Tables 2-2 and 2-3) were used to initialize the numerical simulation model for the proposed injection site. In combination with depth, a temperature gradient of 0.017°F/ft was used to calculate subsurface temperatures throughout the simulation model area. A pressure reading recorded from the Broom Creek Formation was used to derive a pore pressure gradient of 0.466 psi/ft (Table 2-3).

A fracture gradient of 0.718 psi/ft was calculated from a microfracture in situ stress test using a SLB MDT (modular dynamics testing) tool (Figure 2-6, Table 2-4). The calculated maximum BHP constraints of 3663 and 3669 psi for TB Leingang 1 and TB Leingang 2, respectively, were derived by multiplying the fracture gradient by the depth of the top perforation in the injection



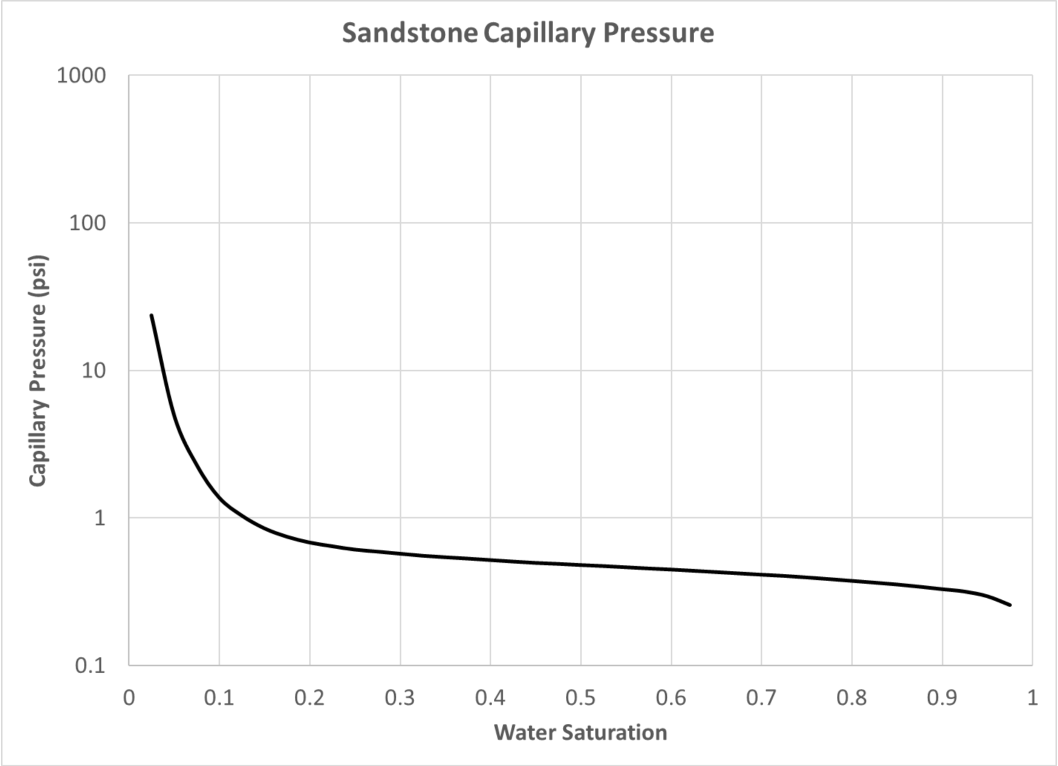
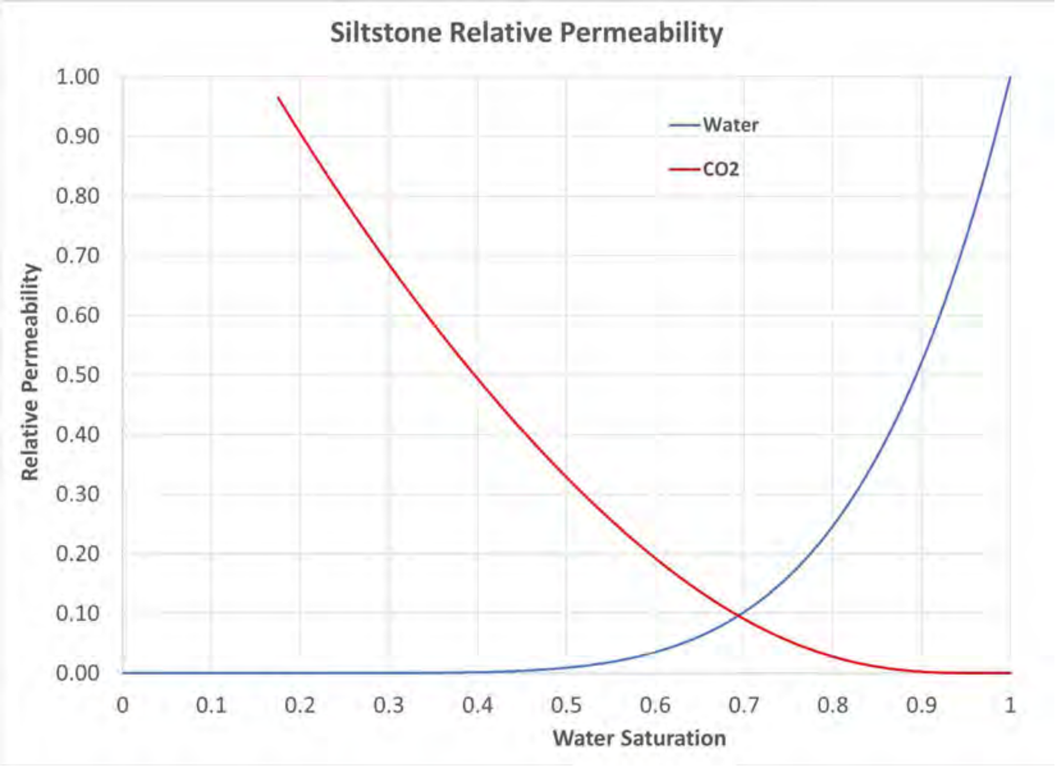


Figure 3-5. Relative permeability (top) and capillary pressure curves (bottom) for the sandstone facies of the Broom Creek Formation.



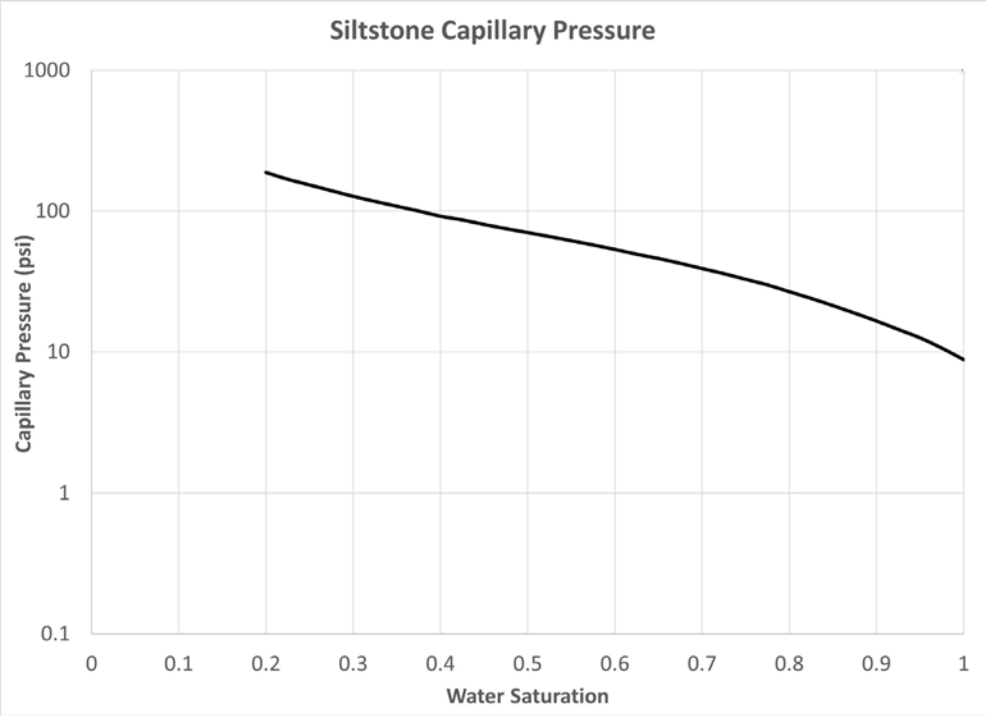
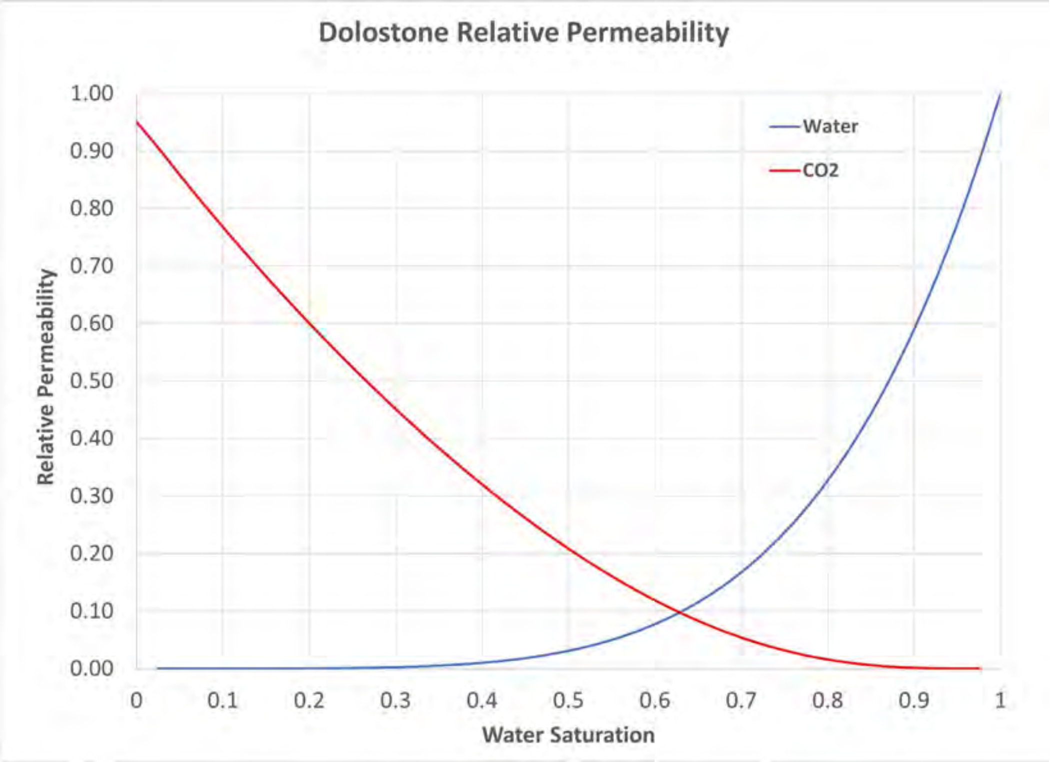


Figure 3-6. Relative permeability (top) and capillary pressure curves (bottom) for the siltstone facies of the Opeche/Spearfish Formation.



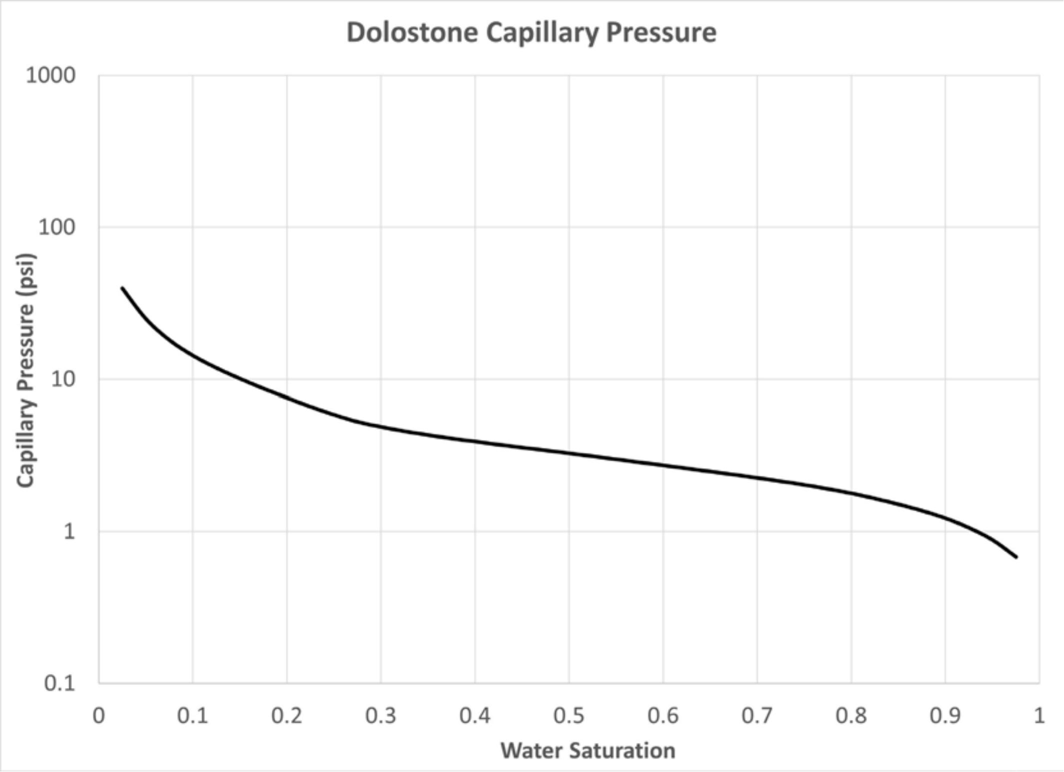
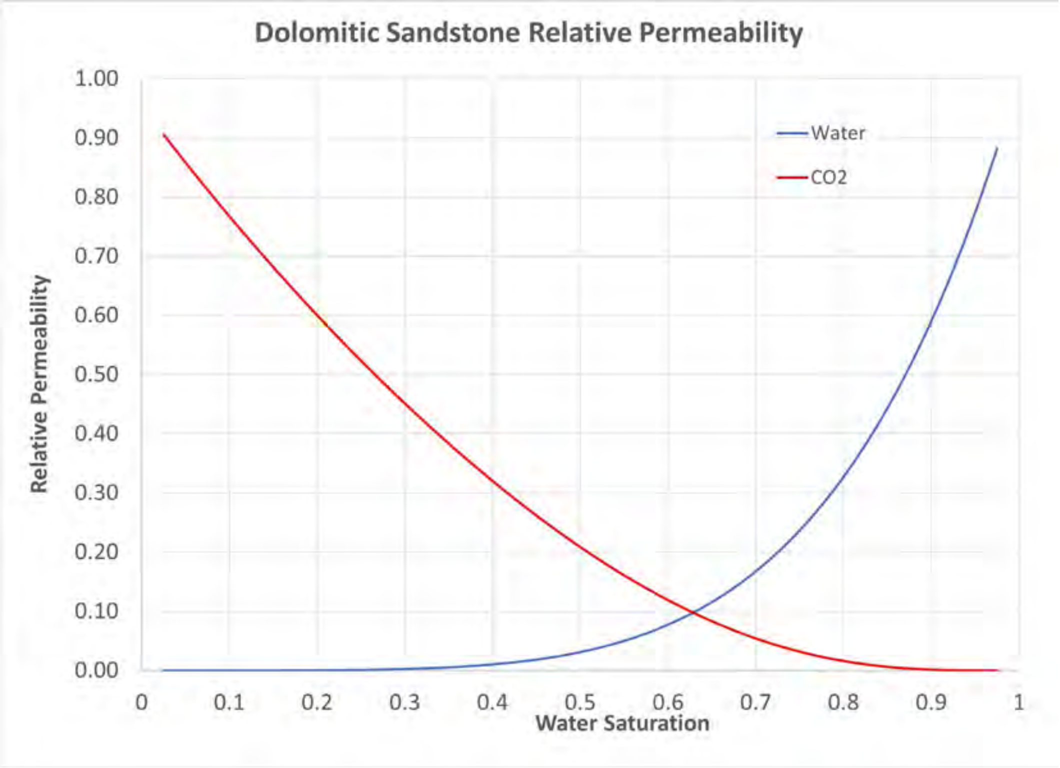


Figure 3-7. Relative permeability (top) and capillary pressure curves (bottom) for the dolostone facies of the Broom Creek and Amsden Formations.



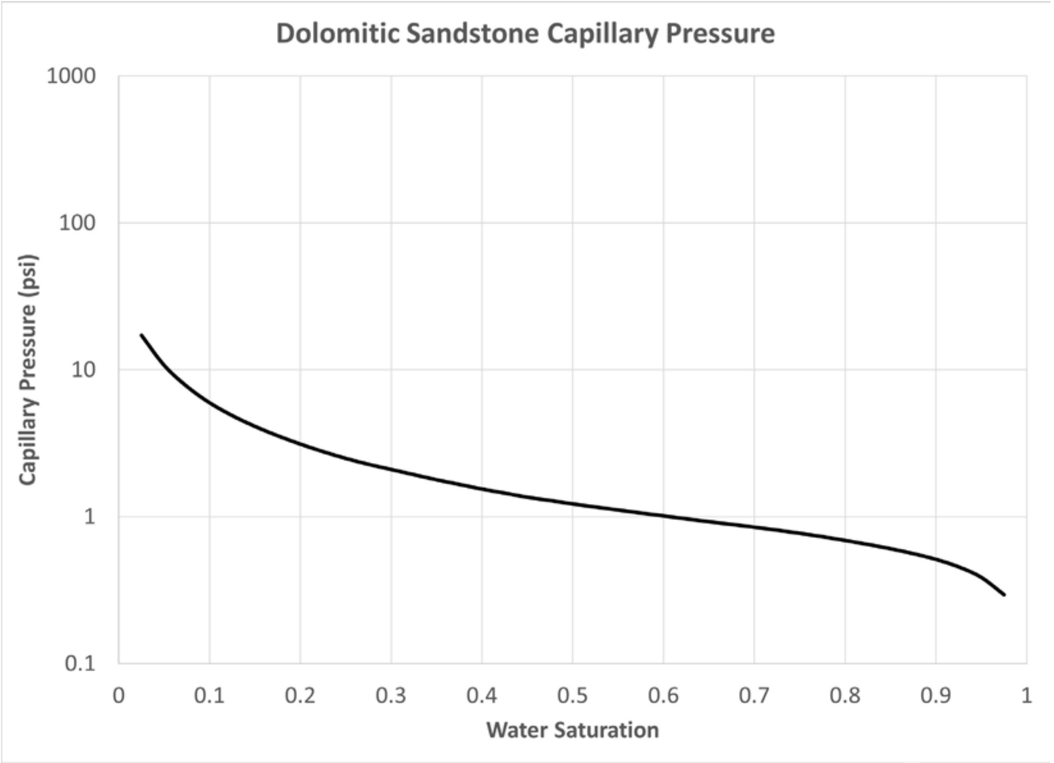
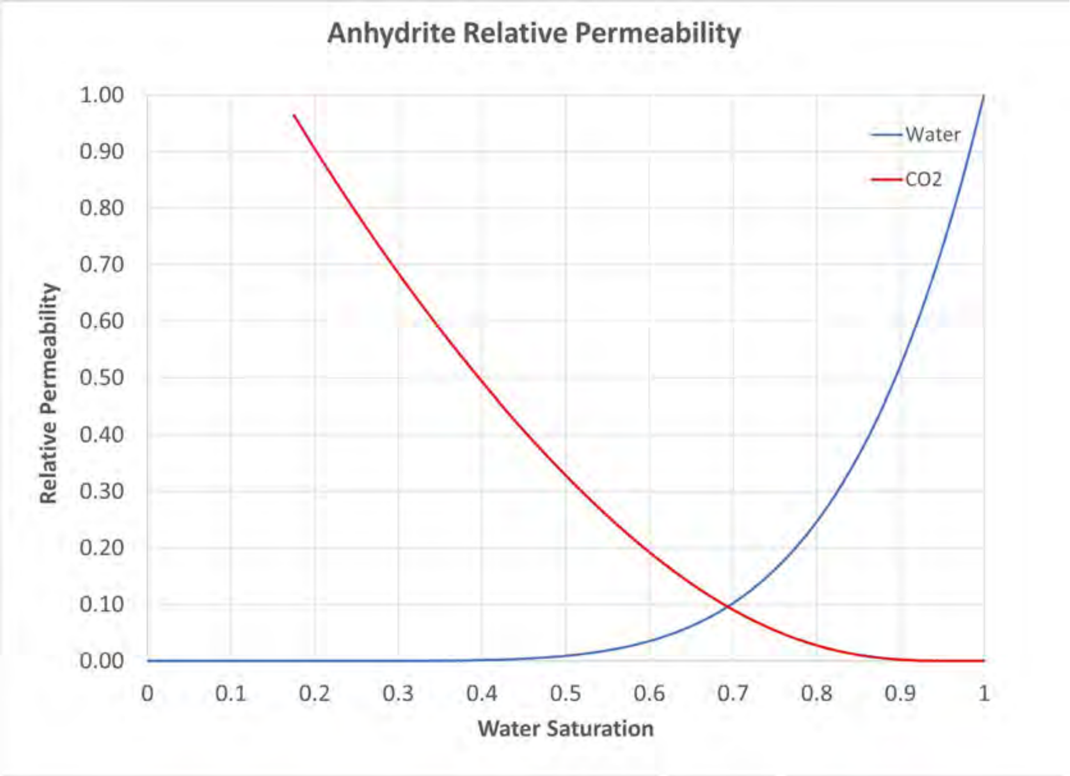


Figure 3-8. Relative permeability (top) and capillary pressure curves (bottom) for the dolomitic sandstone facies of the Broom Creek and Amsden Formations.



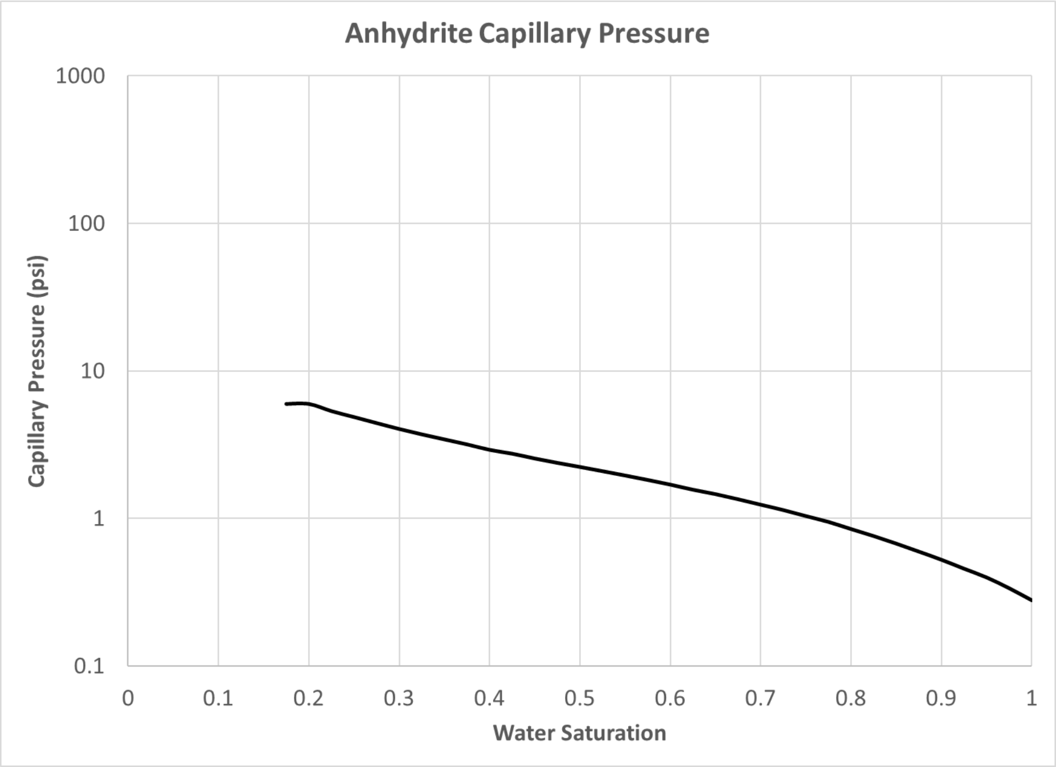


Figure 3-9. Relative permeability (top) and capillary pressure curves (bottom) for the anhydrite facies of the Broom Creek and Amsden Formations.

Table 3-3. Core and Model Properties (porosity [Phi], Permeability [K], and Reservoir Quality Index [RQI]) Showing the Multiplication Factor Used to Calculate Capillary Entry Pressure (Pce) Used in the Simulation Model

	Core					Model				
	Phi, fraction	K, mD	Pce A/Hg, psi	Pce B/CO_2, psi	RQI	Phi, fraction	K, mD	Pce B/CO_2, psi	RQI	Multiplication Factor
Sandstone Sample	0.267	1147	3.04	0.2006	2.058	0.238	1379.000	0.173	2.393	0.860
Siltstone Sample	0.017	0.00002	2630	168.1	0.001	0.048	0.016	9.987	0.018	0.059
Dolostone Sample	0.048	0.00478	274	18.08	0.010	0.086	13.430	0.458	0.391	0.025
Dolomitic-Sands Sample	0.087	0.00683	400	25.6	0.009	0.155	272.100	0.171	1.315	0.007
Anhydrite Sample	0.017	0.00002	2630	168.1	0.001	0.028	9.842	0.308	0.589	0.002

zone of the model (5668 ft TVD for TB Leingang 1 and 5678 ft TVD for TB Leingang 2), and then multiplying this product by 90% as a safety factor. These values were used as the injection constraint in the numerical simulation of the expected injection scenario. The top perforations were placed within the uppermost sandstone of the Broom Creek just below the capping anhydrite, which will act as a barrier to CO_2 flow because of the anhydrite's low porosity and permeability. Perforation depths for the TB Leingang 1 and TB Leingang 2 were calculated prior to final injection site selection and are based on expected ground-level elevation.

The simulation model permeability was tuned globally by applying a permeability multiplier to match the reservoir properties estimated from the well-testing data in the Broom Creek Formation near the Milton Flemmer 1 well. The permeability multiplier was calculated based on the area of study during the injectivity test, the radius of investigation, and the permeability thickness (transmissibility) values from the pressure transient analysis. Ultimately, a global multiplier of 2.5 was applied before numerical simulations to provide a more conservative input for simulation.

The CO_2 stream used to conduct numerical simulations of CO_2 injection was composed of 98.25% (by volume) CO_2 and 1.75% trace quantities of other constituents, including 1.44% nitrogen (N_2), 0.31% oxygen (O_2), and 0.001% hydrogen sulfide (H_2S). This is the anticipated average CO_2 injection stream based on compositional studies of CO_2 from potential sources. Other constituents such as sulfur, hydrocarbons, glycol, amine, aldehydes, NO_x, and NH_3 may also be present but in a negligible amount that would impact neither fluid flow dynamics nor geochemical reactions in the storage formation and were not include. Approximately 6 mi northwest from TB Leingang is the injection site identified for BK Fischer and approximately 9.4 mi northeast is KJ Hintz, as shown in Figures 2-1 and 3-4. TB Leingang is included in the numerical model and simulated injecting simultaneously with BK Fischer and KJ Hintz. TB Leingang consists of two Broom Creek injection wells (TB Leingang 1 and 2), which are proposed to inject at the maximum allowable BHP (90% of the product when multiplying the fracture gradient by top perforation depth) with a secondary maximum allowable WHP constraint of 2100 psi for a total 20-year CO_2 injection period. The well constraints and wellbore model inputs for the simulation model are shown in Table 3-4. The wells (BK Fischer 1 and 2 and KJ Hintz 1 and 2) at nearby sites are also operated under the same conditions with their corresponding maximum BHPs and WHP (2100 psi).

Results using the 7-in. tubing simulation case are presented in this section and used for purposes of boundary delineations (storage facility area, AOR), as the resulting areal extent of these boundaries was greater and, therefore, represents a more conservative 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 of the wellbore model parameters suggested that, at the given injection volume rates and BHP conditions, the wellhead temperature (WHT) played a prominent role in determining WHP response. Sensitivity simulations of different WHTs indicated that injection at a higher WHT would require a higher WHP. For evaluating the expected injection design, a WHT value of 60°F was chosen to most closely represent the expected operational temperature.

Table 3-4. Well Constraints and Wellbore Model in the Simulation Model*

Well Constraint, maximum BHP	Secondary Well Constraint, WHP	Tubing Size	Wellhead Temp.	Downhole Temperature**
3663 psi (TB Leingang 1)	2100 psi (TB Leingang 1 and 2)	7 in.	60°F	136.4°F at 5668 ft TVD (TB Leingang 1)
3669 psi (TB Leingang 2)				136.5°F at 5678 ft TVD (TB Leingang 2)
3633 psi (BK Fischer 1)	2100 psi (BK Fischer 1 and 2)			127.6°F at 5841 ft TVD (BK Fischer 1)
3624 psi (BK Fischer 2)				127.4°F at 5828 ft TVD (BK Fischer 2)
3828 psi (KJ Hintz 1)	2100 psi (KJ Hintz 1 and 2)			116°F at 5426 ft TVD (KJ Hintz 1)
3808 psi (KJ Hintz 2)				115.5°F at 5397 ft TVD (KJ Hintz 2)

* A WHT temperature of 60°F was used for wellbore modeling, and an average ambient surface temperature of 40°F was used for reservoir modeling.

** The formula used to calculate downhole/reservoir temperature in both wellbore and reservoir modeling is Depth × Reservoir Temperature Gradient + 40ºF = Downhole/Reservoir Temperature.

3.4 Simulation Results

The maximum WHP constraint of 2100 psi was one of the constraints on the injection wells for the entire 20 years of simulated injection. The maximum BHP constraint of 3663 psi for TB Leingang 1 and 3669 psi for TB Leingang 2 (equal to 90% of the product when multiplying the fracture gradient by top perforation depth) was approached near Year 20 of injection but was never reached (Figure 3-10), translating to a cumulative combined 124.4 MMt of CO_2 injected into the Broom Creek Formation by TB Leingang 1 and 2 (Figure 3-11). Simulations of CO_2 injection with the given well constraints, listed in Table 3-4, predicted the injection rate would decline from a maximum initial injection rate of approximately 3.65 MMt/yr per well to a final rate of approximately 2.85 MMt/yr per well (with a 20-year combined average of approximately 3.11 MMt/yr per injection well) (Figure 3-12).

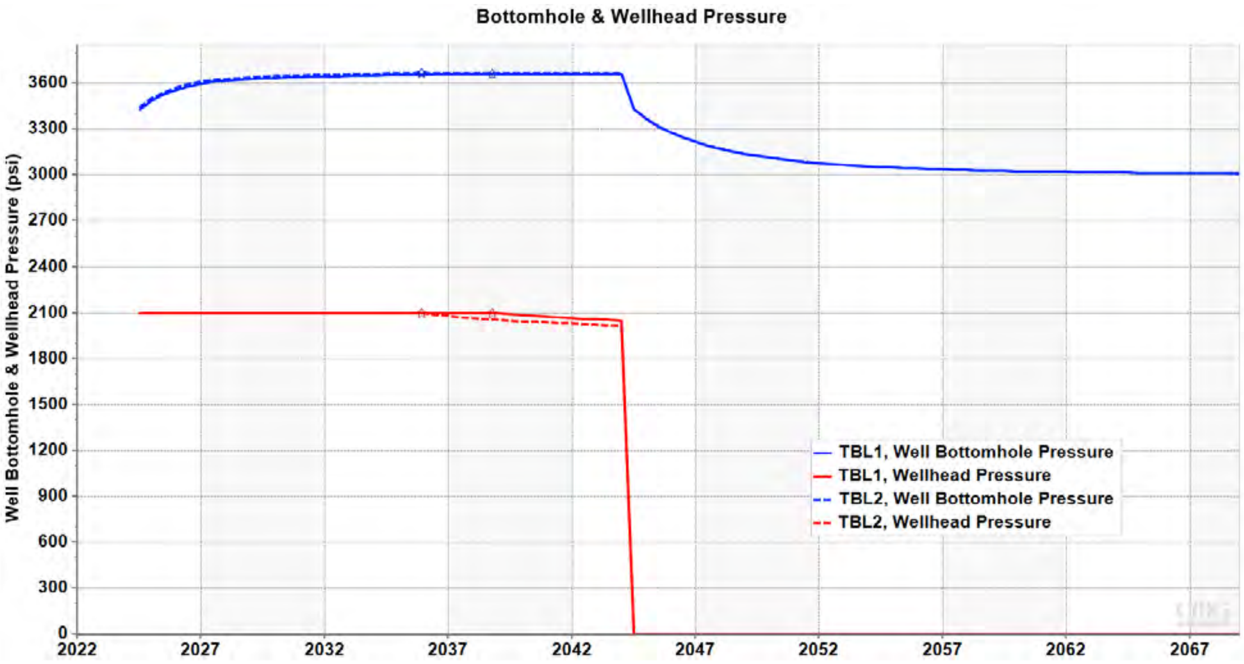


Figure 3-10. Predicted WHP and BHP responses.

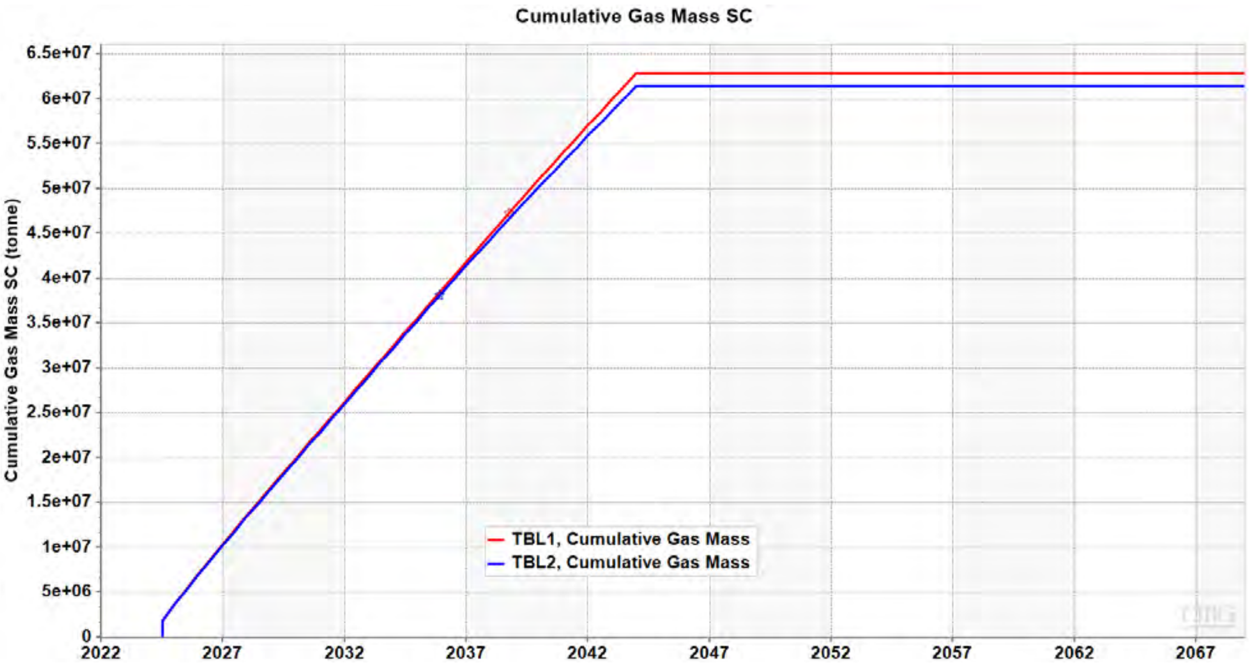


Figure 3-11. Cumulative injected gas mass over 20 years of injection with well pressure constraints.

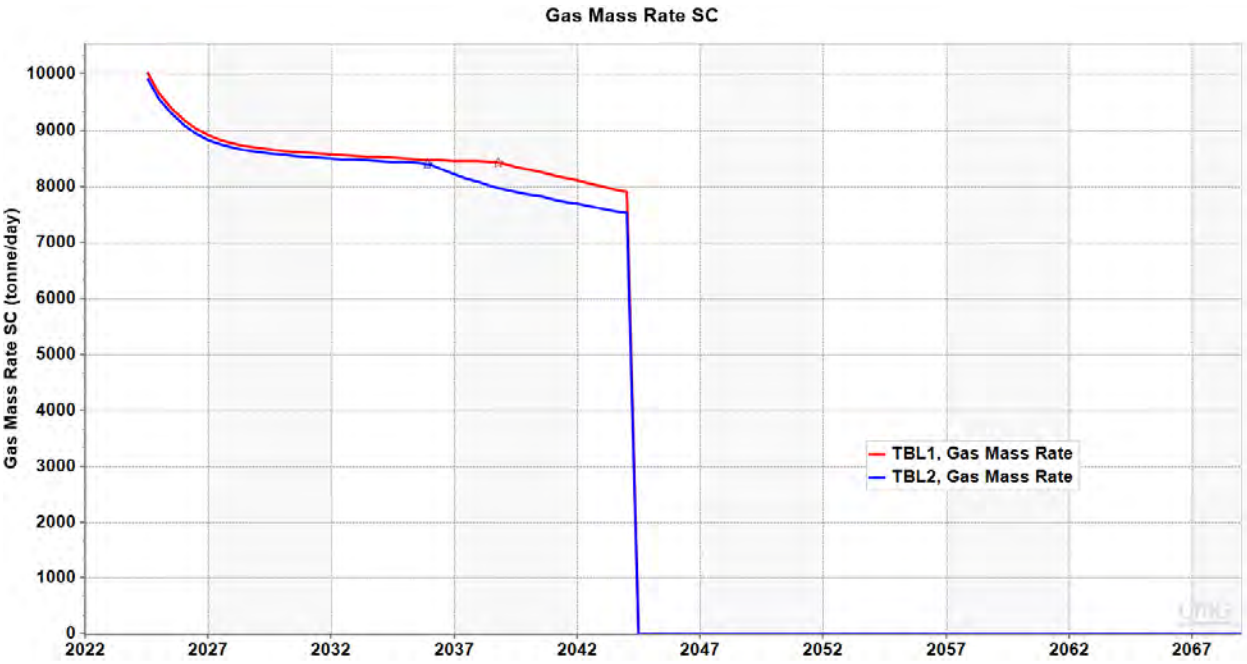


Figure 3-12. Predicted mass injection rate over 20 years of injection with well pressure constraints.

WHP and BHP responses depend on several factors, including predicted injection rate, injection tubing parameters (tubing internal radius and relative roughness), and surface injection temperature. For the designed tubing size of 7 in., the wells are operated at the maximum WHP of 2100 psi during the 20-year injection period (Figure 3-10).

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 3-13).

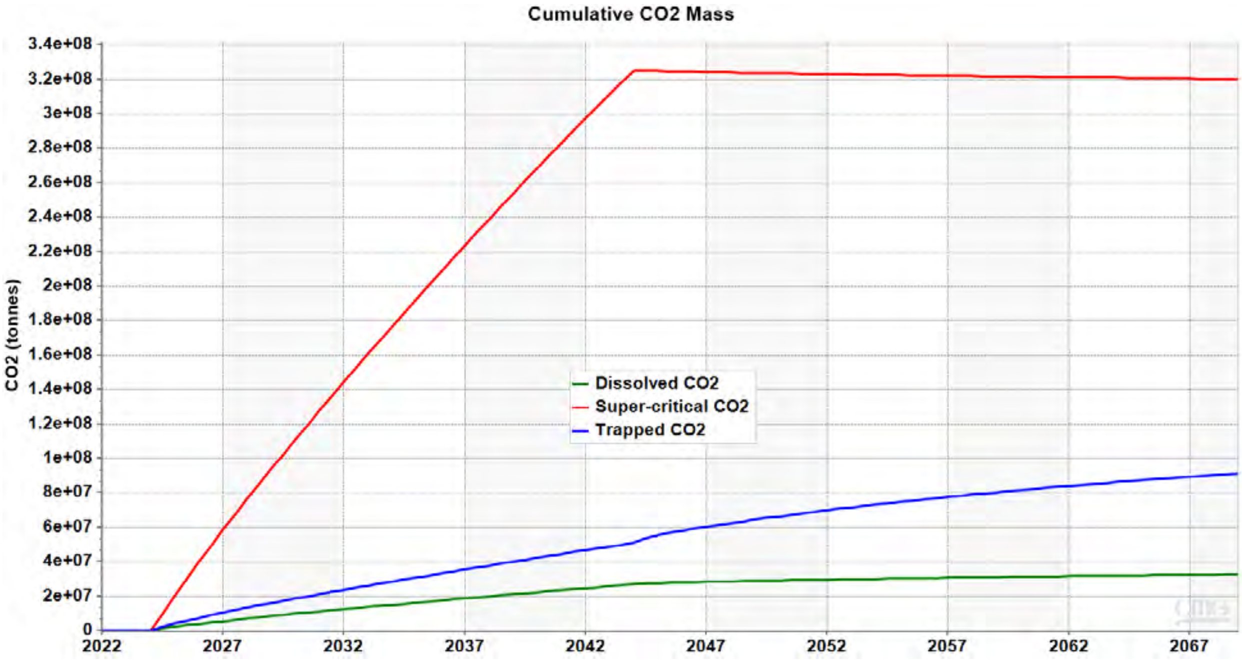


Figure 3-13. Simulated total supercritical free-phase CO_2, trapped CO_2, and dissolved CO_2 in brine for the three adjacent project sites (comprising six injection wells, namely, TB Leingang 1 and 2, BK Fischer 1 and 2, and KJ Hintz 1 and 2).

The pressure fronts (Figures 3-14a–d) show the distribution of average pressure increase throughout the Broom Creek Formation after 5, 10, and 20 years of injection as well as 10 years postinjection. A maximum increase of approximately 1024 psi was estimated in the near-wellbore area at the end of the 20-year injection period (Figure 3-14c).

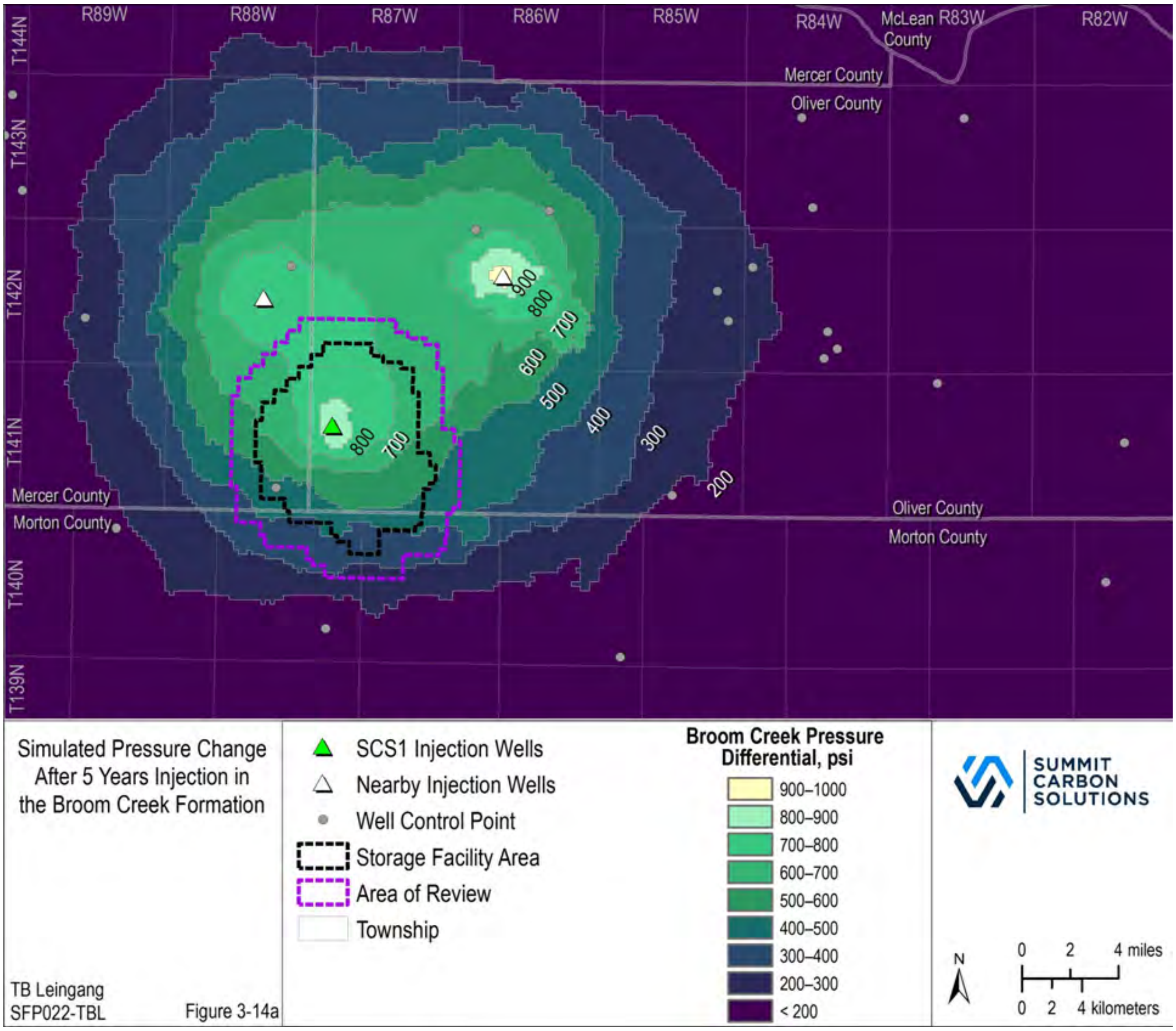


Figure 3-14a. Average pressure increase within the Broom Creek Formation after 5 years of simulated CO_2 injection operation.

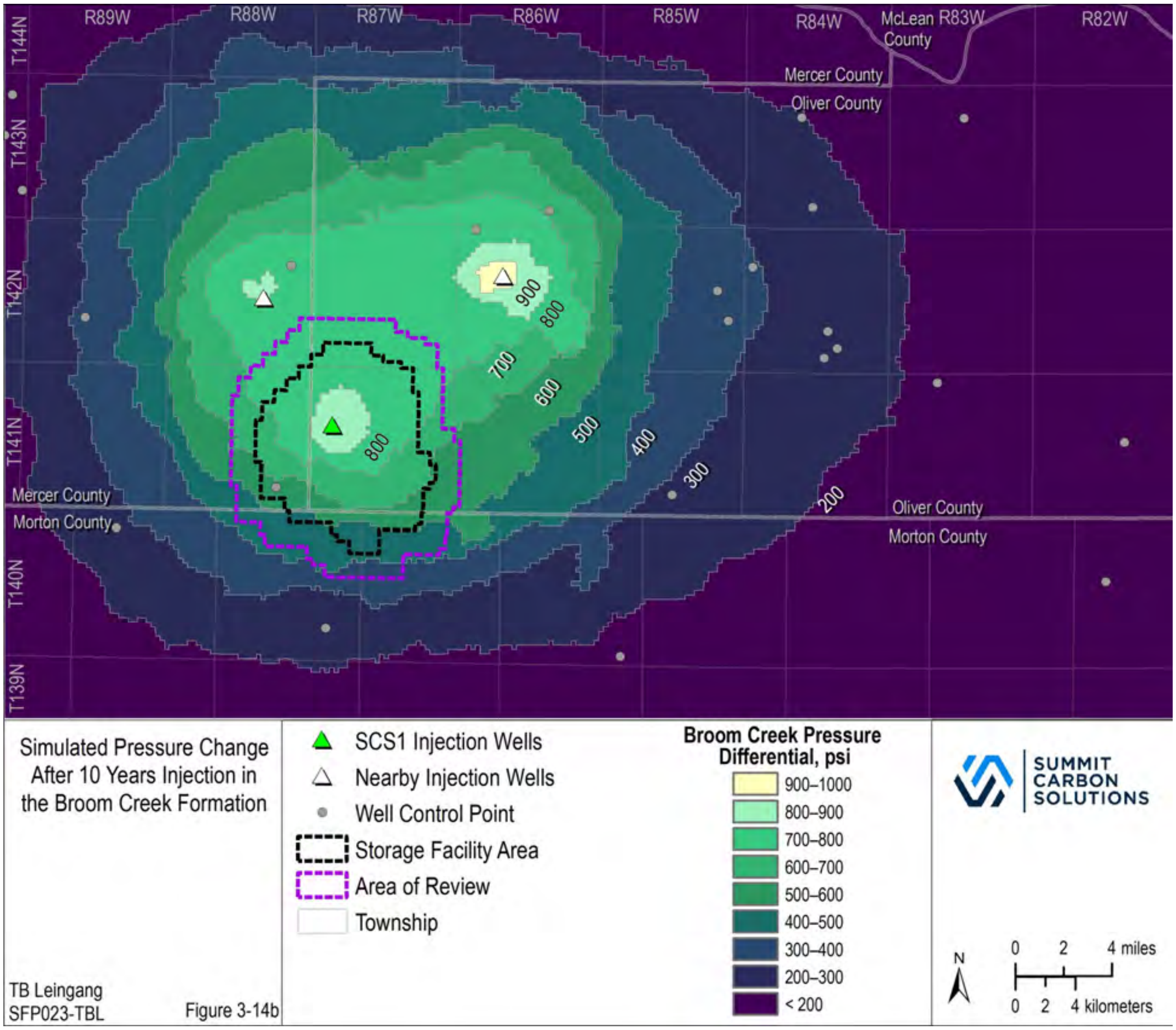


Figure 3-14b. Average pressure increase within the Broom Creek Formation after 10 years of simulated CO_2 injection operation.

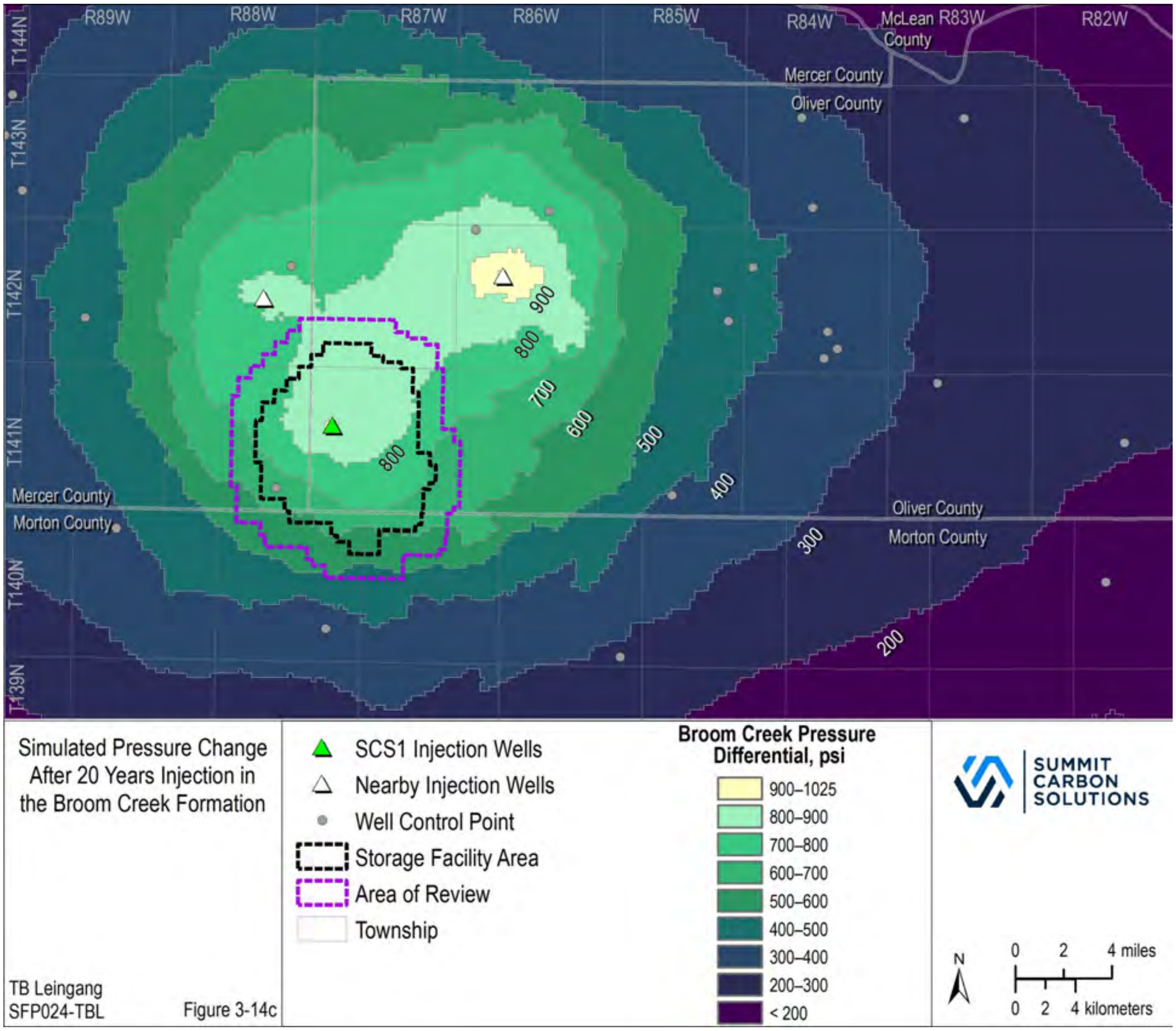


Figure 3-14c. Average pressure increase within the Broom Creek Formation after 20 years of simulated CO_2 injection operation (end of injection operation).

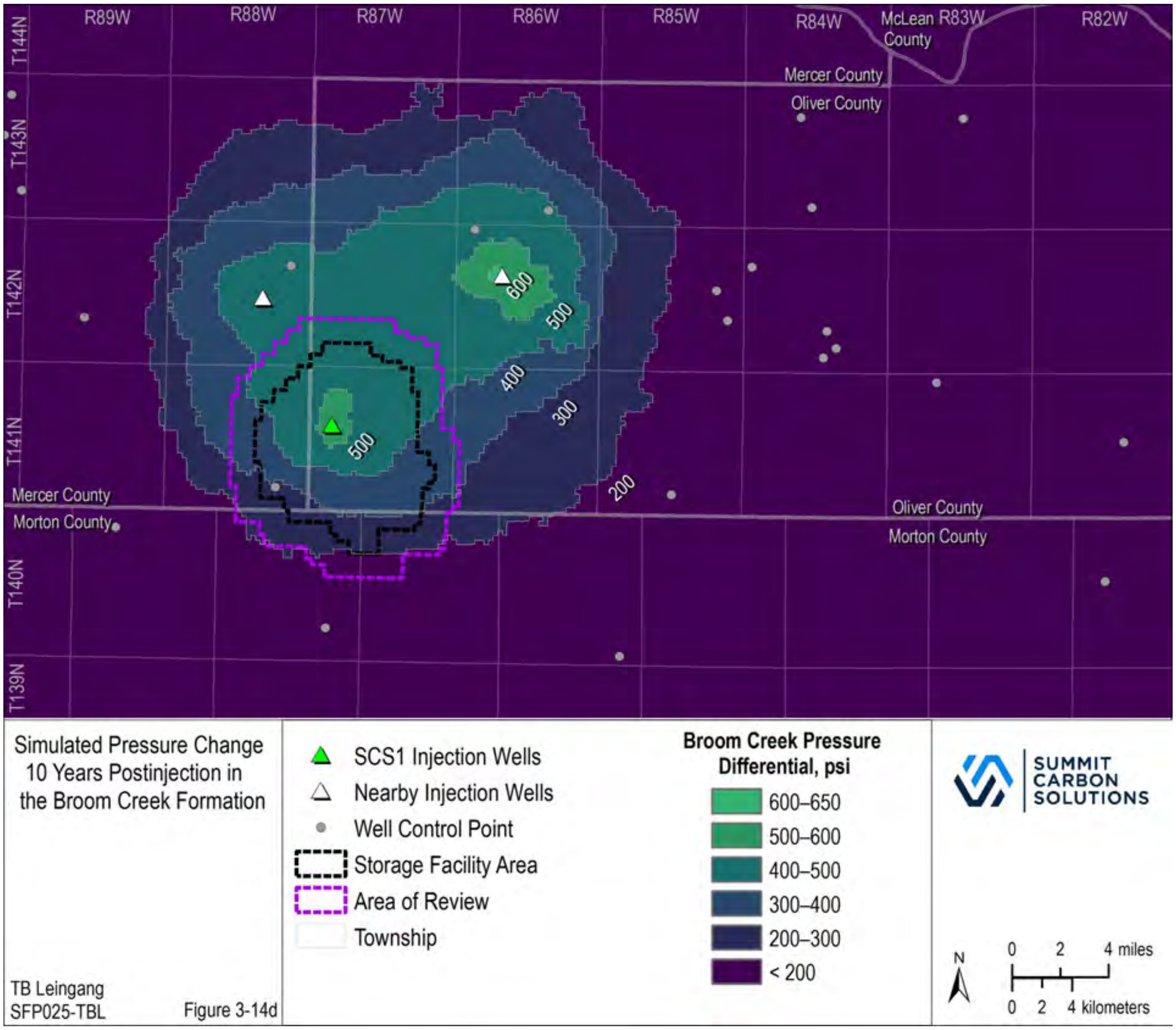


Figure 3-14d. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection.

Long-term CO_2 migration potential was also investigated through 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 supercritical fluids, ultimately immobilize the CO_2 plume and limit the plume's lateral migration and spreading. Figures 3-15a–c show the CO_2 saturation at the end of injection in west-to-east and north-to-south cross-sectional views.

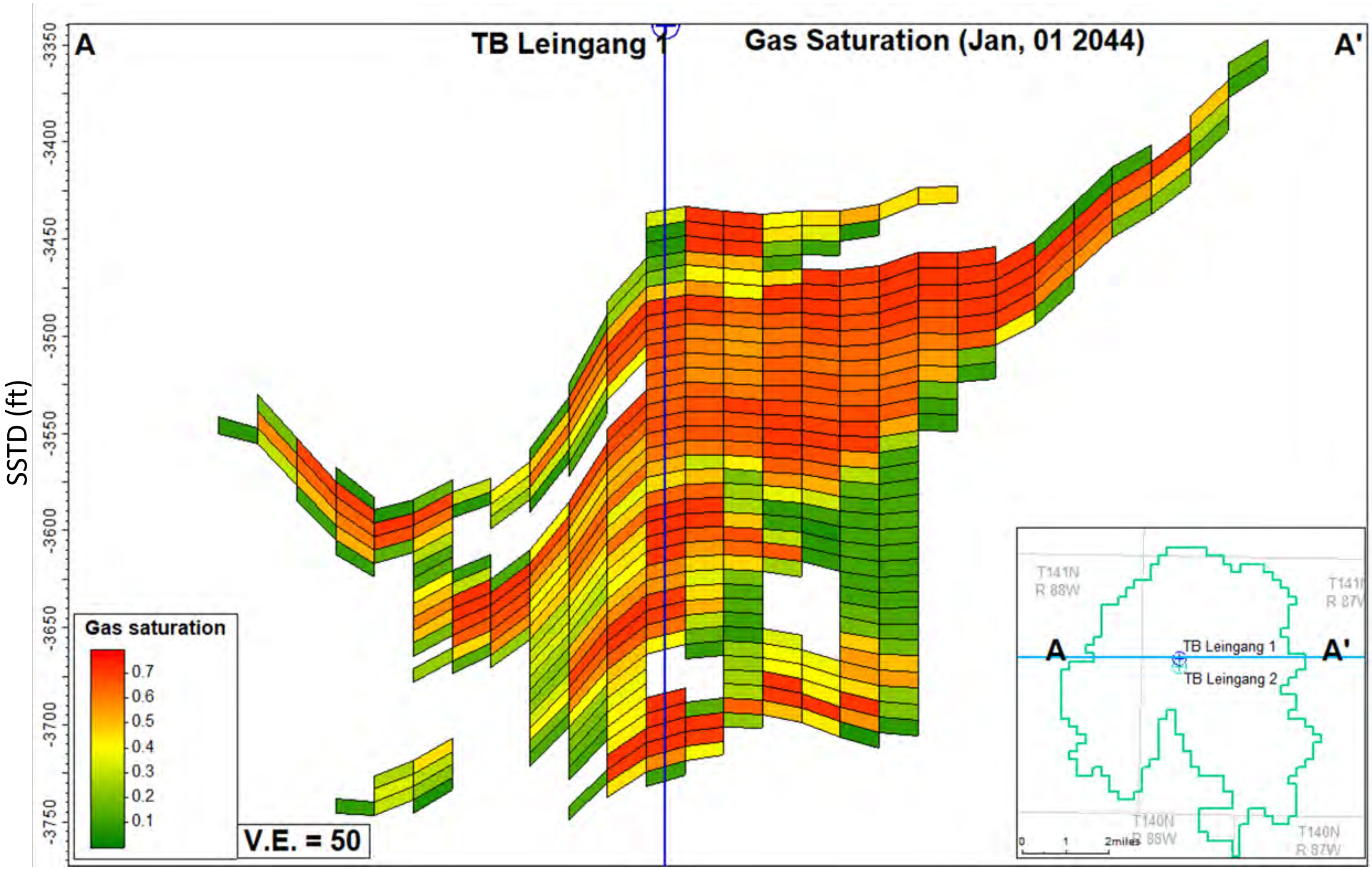


Figure 3-15a. West-to-east cross section (J-layer 65) showing the CO_2 plume at the end of injection. White cells or "empty" intervals contain CO_2 saturation that is less than 5%. 50× vertical exaggeration is shown. Please note the plume geometry south of the injection wells as shown in the map insert is the result of low-permeability zones creating baffles to CO_2 flow. The distribution of these low-permeability zones is supported by the 3D seismic inversion results.

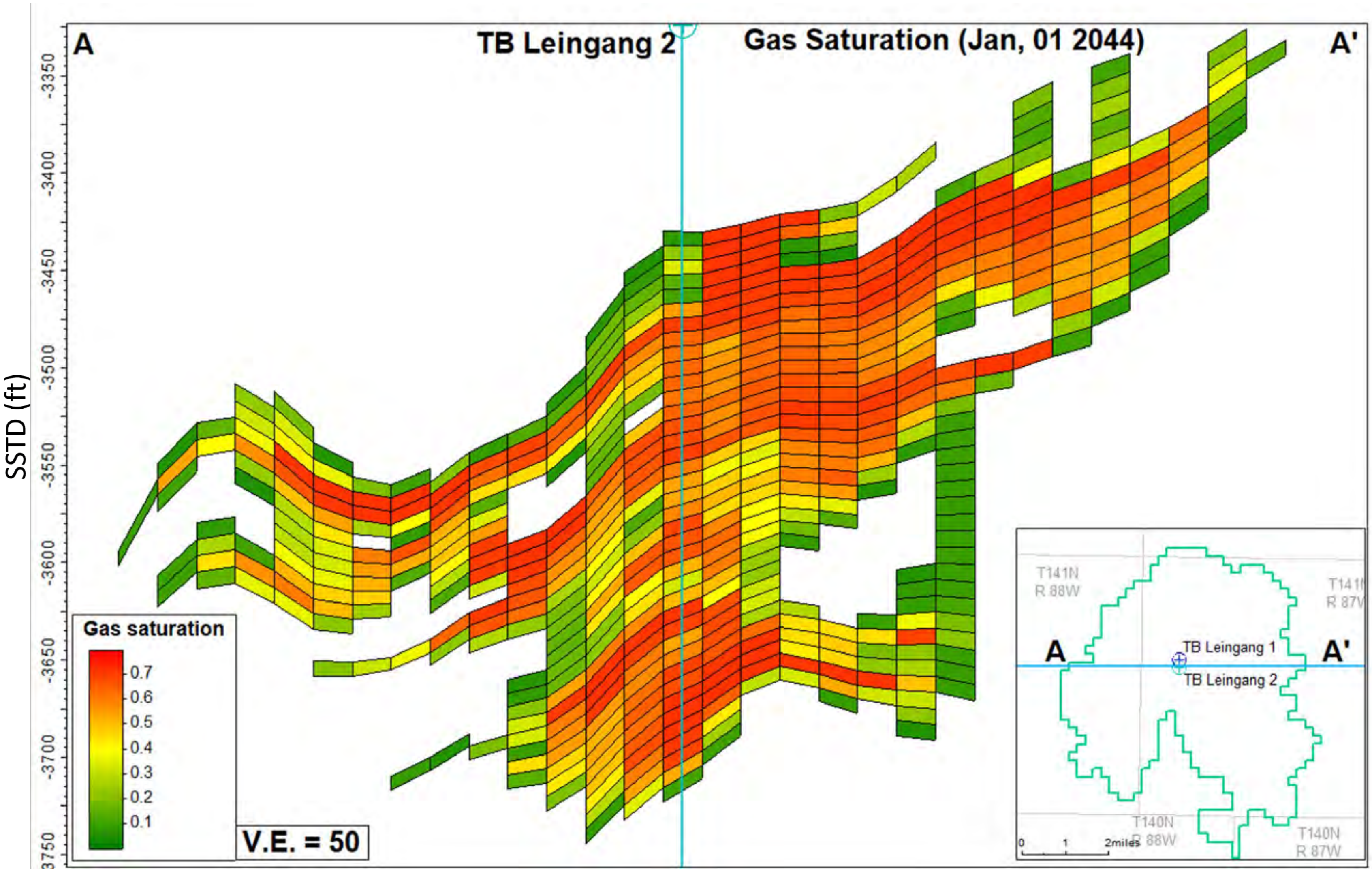


Figure 3-15b. West-to-east cross section (J-layer 64) showing the CO_2 plume at the end of injection. White cells or "empty" intervals contain CO_2 saturation that is less than 5%. 50× vertical exaggeration is shown.

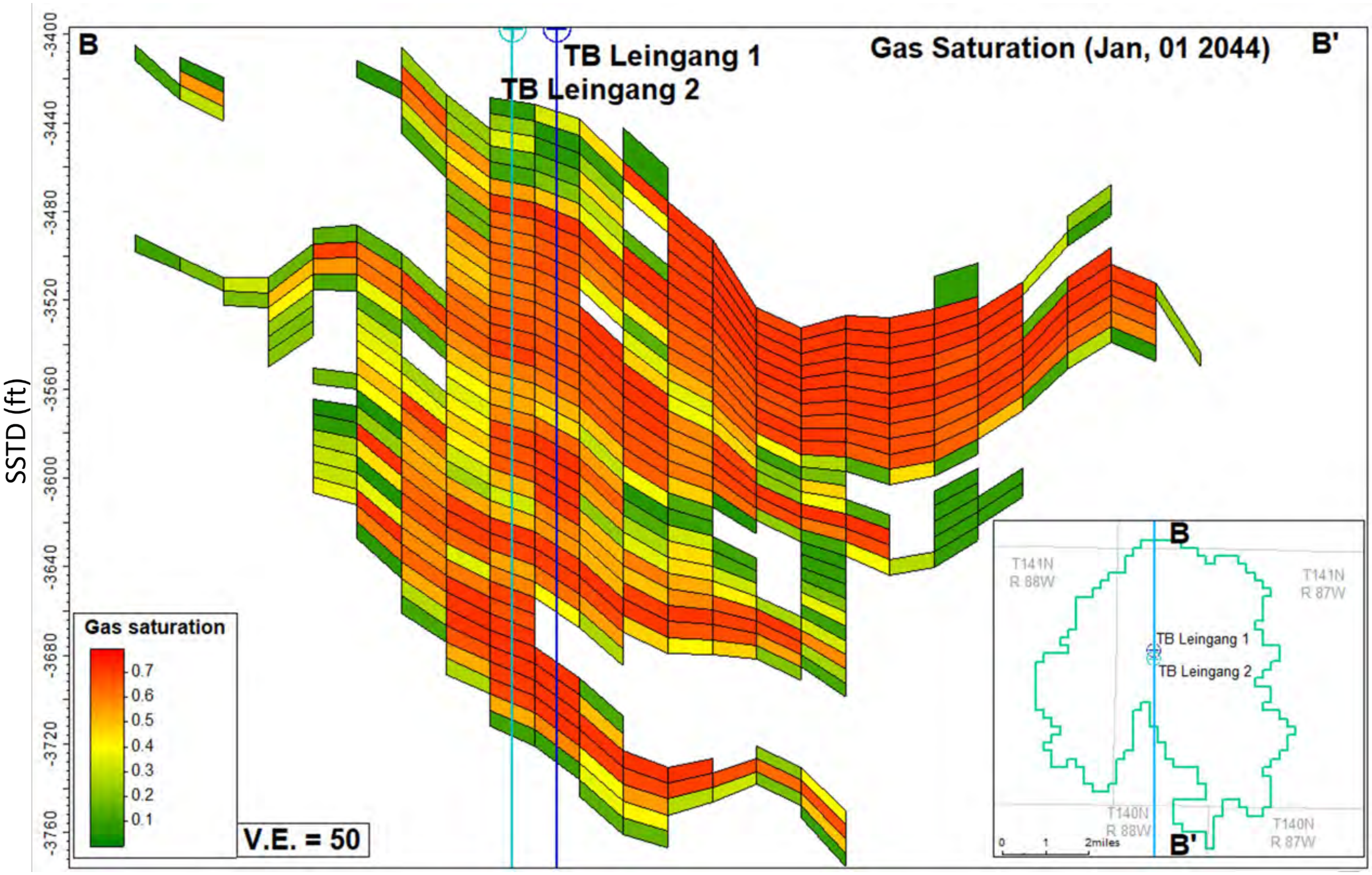


Figure 3-15c. North-to-south cross section (I-layer 72) showing the CO_2 plume at the end of injection. White cells or "empty" intervals contain CO_2 saturation that is less than 5%. 50× vertical exaggeration is shown**.**

3.4.1 *Maximum Injection Pressure and Rates*

An additional case was run to determine if a well would ultimately be limited by the maximum WHP of 2100 psi or maximum calculated downhole pressure of 90% of the fracture propagation pressure at the perforated depth (3663 psi [TB Leingang 1] and 3669 psi [TB Leingang 2]). The estimated fracture propagation pressure gradient of 0.718 psi/ft was used for the calculated maximum BHP as the only injection constraint to evaluate maximum storage potential for each injection well.

When a single injection well reaches the maximum BHP condition of 3663 or 3669 psi in the simulation, the corresponding predicted average WHPs are reaching approximately 5500 and 5120 psi, respectively, for TB Leingang 1 and TB Leingang 2 (Figure 3-16). The predicted maximum daily injection rate could reach approximately 26,016 and 24,570 tonnes/day, respectively, for TB Leingang 1 and TB Leingang 2.

A total volume of 184.8 and 176.7 MMt of gas was injected over 20 years, respectively, resulting in the calculated daily averaged maximum gas injection rate of 25,315 and 24,205 tonnes/day (the total volume divided by 20 years × 365 days), respectively, for TB Leingang 1 and TB Leingang 2 (see Table 11-1).

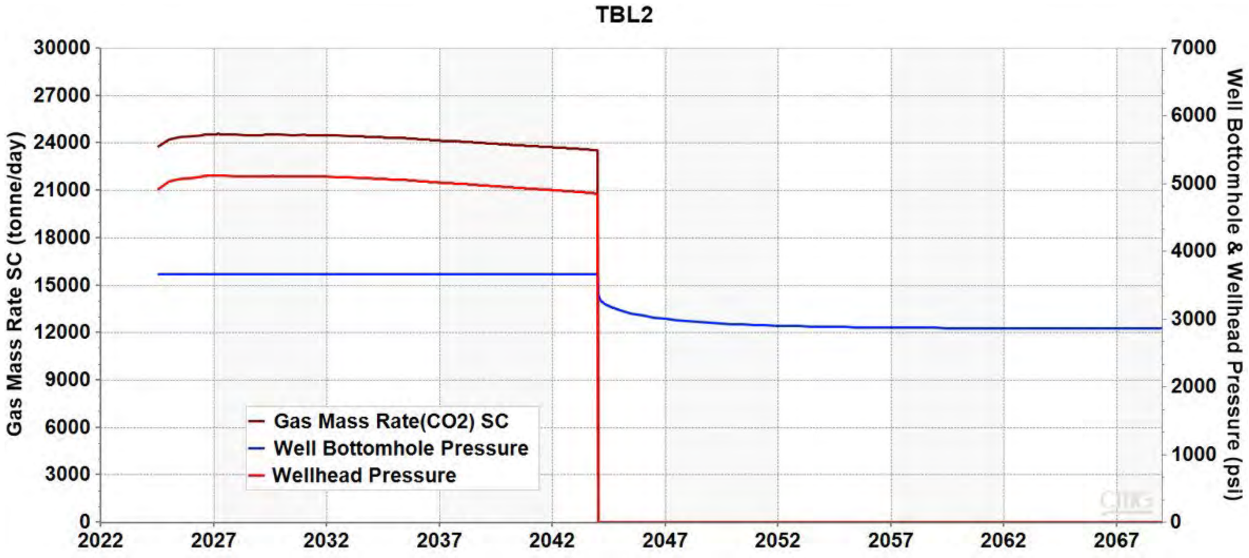


Figure 3-16. Maximum pressure and gas rate response when the well was operated at max BHP only (without any WHP limits) for TB Leingang 1 (top) and TB Leingang 2 (bottom).

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 this permit, the CO_2 plume was assessed in 1-year time steps until the rate of total areal extent change slowed to less than 0.2 square mi per 1-year time step to define the stabilized plume extent boundary 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 (N.D.A.C.) defines an AOR as "the region surrounding the geologic sequestration project [storage project] where underground sources of drinking water [USDWs] may be endangered by the [CO_2] injection activity" (N.D.A.C. § 43-05-01-01[4]). 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 TB Leingang 1 simulation 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:

$$\Delta P_{i,f} = P_u + \rho_i g\,(z_u - z_i) - P_i \qquad \text{[Eq. 1]}$$

Where:

P_u is the initial fluid pressure in the USDW (Pa).
ρ_i is the storage reservoir fluid density (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).
(* amsl = above mean sea level)

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 underpressured relative to the USDW; and if $\Delta P_{i,f} < 0$, then the reservoir is overpressured relative to the USDW.

In scenarios where the storage reservoir and USDW are in hydrostatic equilibrium ($\Delta P_{i,f} = 0$), EPA Method 2 (*pressure front based on displacing fluid initially present in the borehole*) can be used to calculate the critical pressure threshold. Method 2 was originally presented by Nicot and others (2008) and Bandilla and others (2012). Method 2 calculates the critical threshold pressure increase (ΔP_c), which is the fluid pressure increase sufficient to drive formation fluids into the lowermost USDW. This ΔP_c is determined using Equations 2 and 3, assuming 1) hydrostatic conditions, 2) initially linear densities in the borehole, and 3) constant density once the injection zone fluid is lifted to the top of the borehole (i.e., uniform density approach):

$$\Delta P_C = \frac{1}{2}\, g\, \xi\, (z_u - z_i)^2 \qquad \text{[Eq. 2]}$$

Where ξ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \qquad \text{[Eq. 3]}$$

Where:

ΔP_C is the critical threshold pressure increase (Pa).
g is the acceleration of gravity (m/s^2).

z_u is the elevation of the base of the lowermost USDW (m amsl).
z_i is the elevation of the top of the injections zone (m amsl).
ρ_i is the fluid density in the injection zone (kg/m^3).
ρ_u is the fluid density in the USDW (kg/m^3).

3.5.2 Risk-Based AOR Delineation

The methods described by EPA (2013) for estimating the AOR under the Class VI rule (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 overpressured 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 overpressured 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.

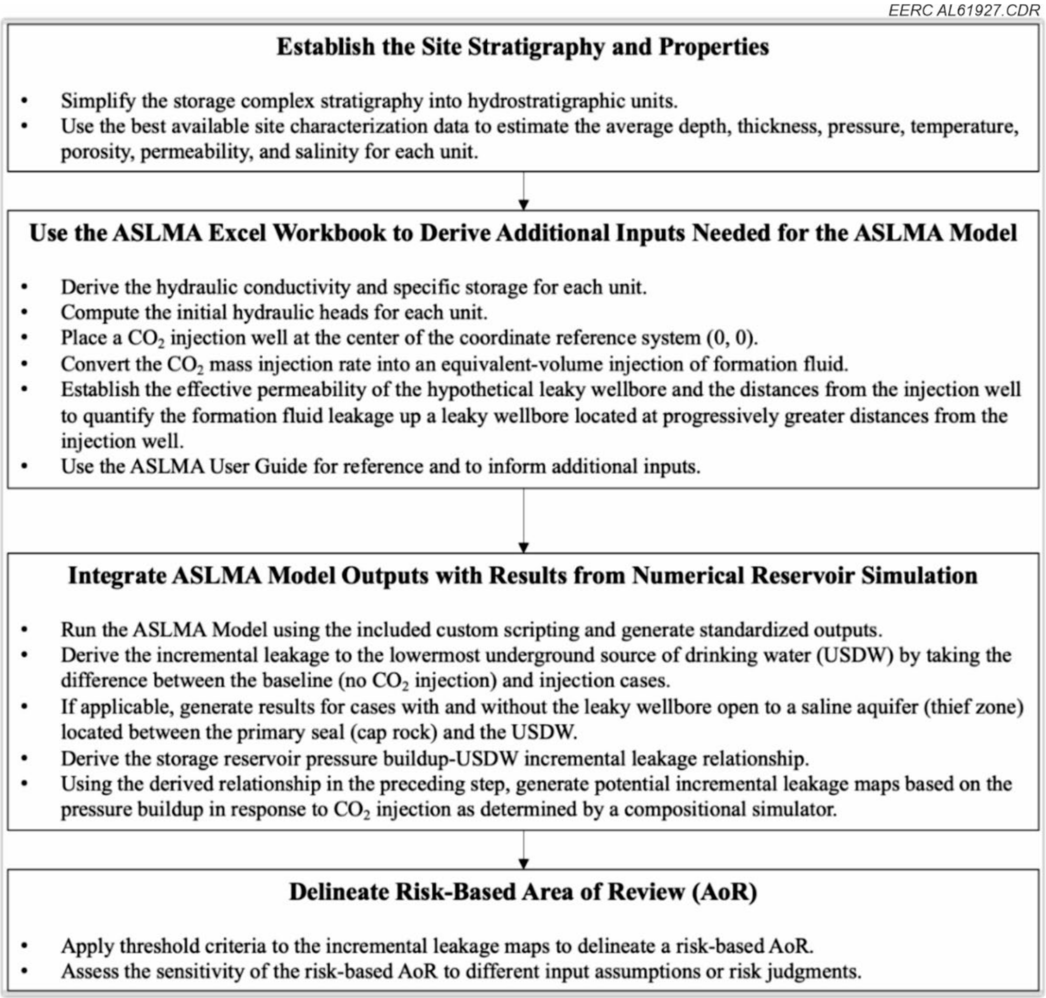
A computational framework for estimating a risk-based AOR was proposed by Oldenburg and others (2014, 2016), who compared formation fluid leakage through a hypothetical open flow path in the baseline scenario (no CO_2 injection) to the incrementally larger leakage that would occur in the CO_2 injection 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”).

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 overpressured 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 3-17).

An important distinction between EPA Methods 1 and 2, which both calculate a critical pressure threshold (either $\Delta P_{i,f}$ for Method 1 or ΔP_c for Method 2) and the risk-based AOR approach is that the risk-based approach 1) calculates and maps the potential incremental flow of formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR.



Establish the Site Stratigraphy and Properties

- Simplify the storage complex stratigraphy into hydrostratigraphic units.
- Use the best available site characterization data to estimate the average depth, thickness, pressure, temperature, porosity, permeability, and salinity for each unit.

Use the ASLMA Excel Workbook to Derive Additional Inputs Needed for the ASLMA Model

- Derive the hydraulic conductivity and specific storage for each unit.
- Compute the initial hydraulic heads for each unit.
- Place a CO_2 injection well at the center of the coordinate reference system (0, 0).
- Convert the CO_2 mass injection rate into an equivalent-volume injection of formation fluid.
- Establish the effective permeability of the hypothetical leaky wellbore and the distances from the injection well to quantify the formation fluid leakage up a leaky wellbore located at progressively greater distances from the injection well.
- Use the ASLMA User Guide for reference and to inform additional inputs.

Integrate ASLMA Model Outputs with Results from Numerical Reservoir Simulation

- Run the ASLMA Model using the included custom scripting and generate standardized outputs.
- Derive the incremental leakage to the lowermost underground source of drinking water (USDW) by taking the difference between the baseline (no CO_2 injection) and injection cases.
- If applicable, generate results for cases with and without the leaky wellbore open to a saline aquifer (thief zone) located between the primary seal (cap rock) and the USDW.
- Derive the storage reservoir pressure buildup-USDW incremental leakage relationship.
- Using the derived relationship in the preceding step, generate potential incremental leakage maps based on the pressure buildup in response to CO_2 injection as determined by a compositional simulator.

Delineate Risk-Based Area of Review (AoR)

- Apply threshold criteria to the incremental leakage maps to delineate a risk-based AoR.
- Assess the sensitivity of the risk-based AoR to different input assumptions or risk judgments.

Figure 3-17. Workflow for delineating a risk-based AOR for an SFP (modified from Burton-Kelly and others, 2021).

3.5.3 Critical Threshold Pressure Increase Estimation

For the purposes of delineating AOR for this permit, constant fluid densities for the lowermost USDW (Fox Hills Formation) and injection zone (Broom Creek Formation) were used in the calculations. Respective fluid densities were used to represent the injection zone fluids (ρ_i), which are estimated based on the in situ estimated brine salinity, temperature, and pressure at the Milton Flemmer 1 stratigraphic test well.

Application of EPA Method 1 (Eq. 1) using model data from the TB Leingang 1 simulation well shows that the injection zone is overpressured 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 3-5, with similar results when applied to each column of the grid cells in the Broom Creek Formation simulation model.

Table 3-5. EPA Method 1 Critical Threshold Pressure Increase Calculated at the TB Leingang 1 Simulation Well

Location Depth,* ft	m	P_i Injection Zone Pressure, MPa	P_u USDW Base Pressure, MPa	ρ_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	psi
5830.3	1777	19.00	4.32	1063	142.3	-1088.8	-1.87	-271

* Ground surface elevation is 688 m amsl. Depth provided is the midpoint of the Broom Creek Formation in feet below ground surface.

In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value 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 3-6. They illustrate the state of overpressure in the storage complex because Aquifer 1 has a greater initial hydraulic head than Aquifer 2 and Aquifer 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 3-6. Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex

Hydrostratigraphic Unit	Depth to Top,* m	Thickness, m	Pressure, MPa	Temperature, °C	Salinity, ppm	Brine Density, kg/m^3	Porosity, %	Permeability,		HCON,** m/d	Specific Storage, m^{-1}	Total Head, m
								mD	m^2			
Overlying Units to Ground Surface (not directly modeled)	0	442										
Aquifer 3 (USDW, Fox Hills Fm)	442	104	3.8	19	1563	1001	37.5	280.0	2.76E-13	2.27E-01	5.69E-06	583
Aquitard 2 (Pierre Fm–Inyan Kara Fm)	546	777	9.2	32	1780	1000	4.39	0.025	2.47E-17	2.71E-05	8.98E-06	689
Aquifer 2 (potential thief zone – Inyan Kara Fm)	1323	121	12.9	50	3560	995	13.4	7.2	7.13E-15	1.09E-02	4.90E-06	629
Aquitard 1 (primary upper seal – Swift Fm–Broom Creek Fm)	1444	84	15.6	51	52,500	1029	2.14	0.0021	2.07E-18	3.01E-06	9.16E-06	645
Aquifer 1 (storage reservoir – Broom Creek Fm)	1728	99	19.0	60	105,000	1063	14.1	7.5	7.40E-15	1.13E-02	5.23E-06	736

* Ground surface elevation 688 m amsl.

** Hydraulic conductivity.

TB LEINGANG/MILTON FLEMMER 1

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 3-7. The CO_2 mass injection rate and CO_2 density are then used to derive the daily equivalent-volume injection rate, shown in Table 3-7.

Table 3-7. CO_2 Density and Injection Parameters Used for the ASLMA Model

CO_2 Density, Reservoir Conditions, kg/m^3	Average CO_2 Injection Rate, tonnes per day	Average Equivalent Water Injection Rate, m^3 per day	Injection Period, years
704	17,041	24,197	20

3.5.4.3 Hypothetical Leaky Wellbore

In the simulation model 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 2) throughout the 20-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 3-18) 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 3-18).

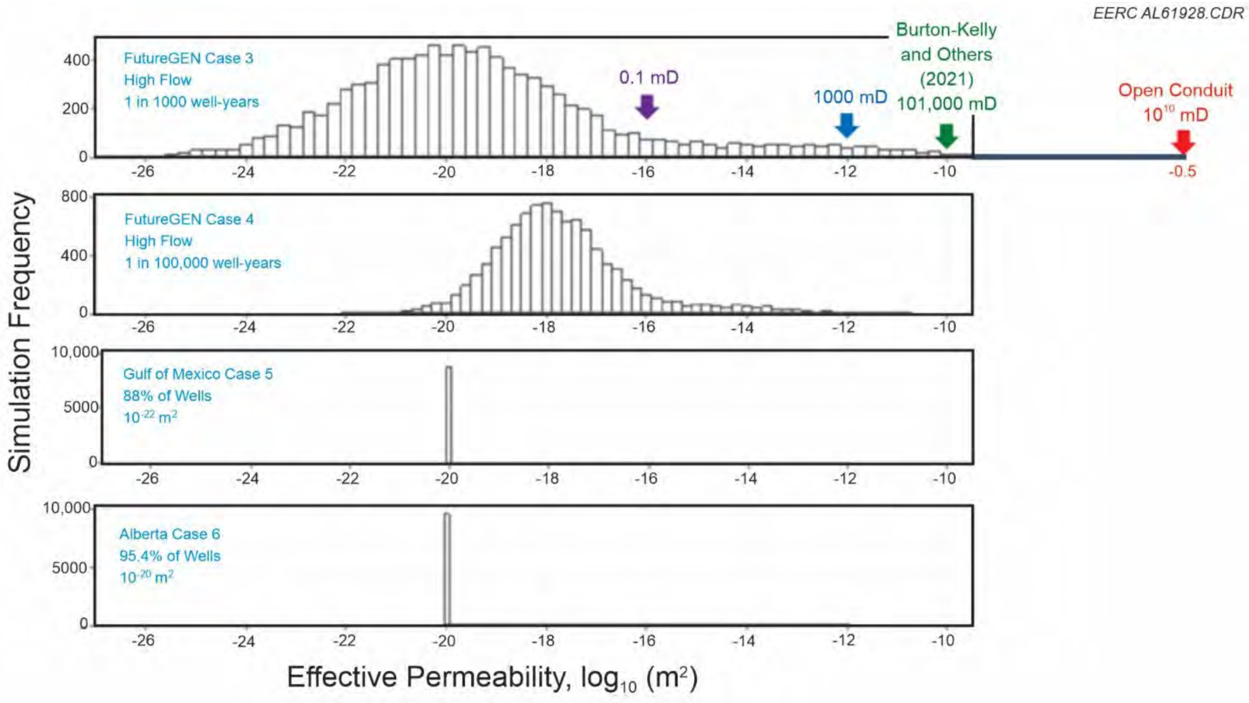


Figure 3-18. Histograms describing the expected frequency of leaky wellbore effective permeabilities under different scenarios. The ASLMA Model used for AOR delineation used a value of approximately 0.1 mD (constructed from data presented by Carey [2017]).

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 Potential Thief Zone

As shown in Table 3-6, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the storage reservoir primary seal and the 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, Aquifer 2 may act as a thief zone and reduce 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 to 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 high-permeability zone encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 were run and the results 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 3-6). For each unit shown in Table 3-6, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: HCON and specific storage (SS). Average porosity and permeability values were derived as follows: Broom Creek, from distributed properties in the geologic model; 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 HCON and SS. The estimated reference case HCON for the storage reservoir (Aquifer 1) potential thief zone (Aquifer 2) and USDW (Aquifer 3) are shown in Table 3-6. 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 3-19 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). 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 3-19) 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 3-8.

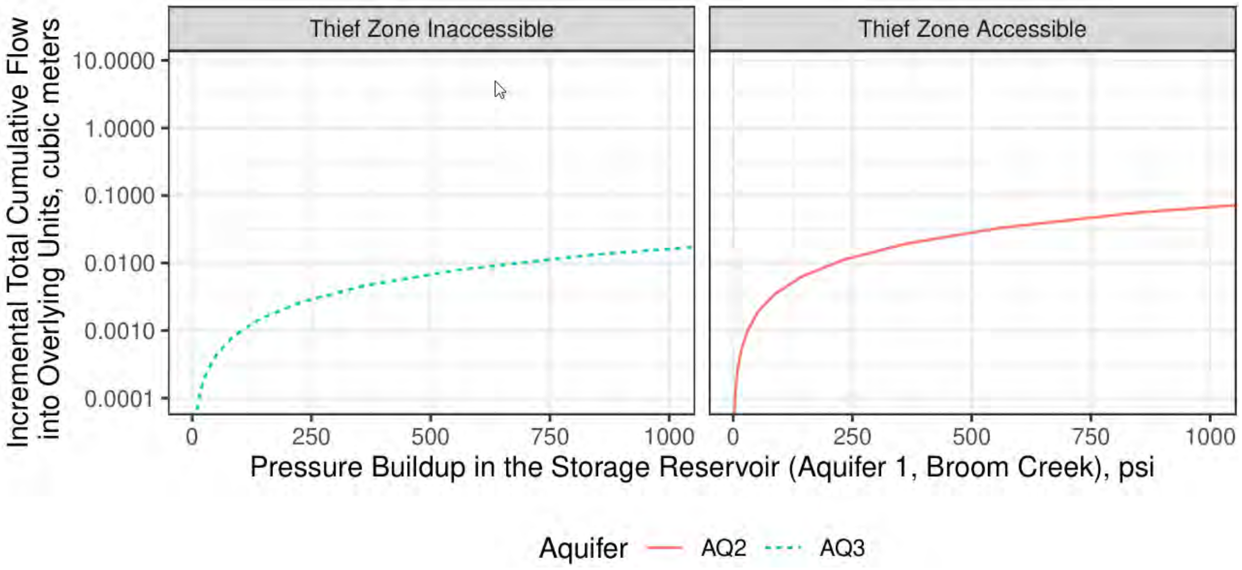


Figure 3-19. Relationship between pressure buildup (x-axis, psi) in the storage reservoir (Aquifer 1, Broom Creek) and incremental total cumulative leakage (y-axis, m^3) into Aquifer 2 (thief zone, Inyan Kara, red solid line) and Aquifer 3 (USDW, Fox Hills, dashed blue line). In the left-hand scenario, the leaky wellbore is closed to Aquifer 2, so all flow is from the storage reservoir to the USDW. In the right-hand scenario, the leaky wellbore is open to Aquifer 2, so the vast majority of flow is from the storage reservoir to the Aquifer 2 thief zone, and the curve showing flow into the Aquifer 3 USDW is not visible on this plot.

3.5.5.2 Incremental Flow Maps and AOR Delineation

The pressure buildup–incremental flow relationship, shown in Figure 3-19, results in the incremental flow map, shown in Figure 3-20, which shows the estimated total cumulative incremental flow potential from a hypothetical leaky well into Aquifer 3 (USDW) over the entire injection period if the modeled leaky wellbore is not open to the thief zone.

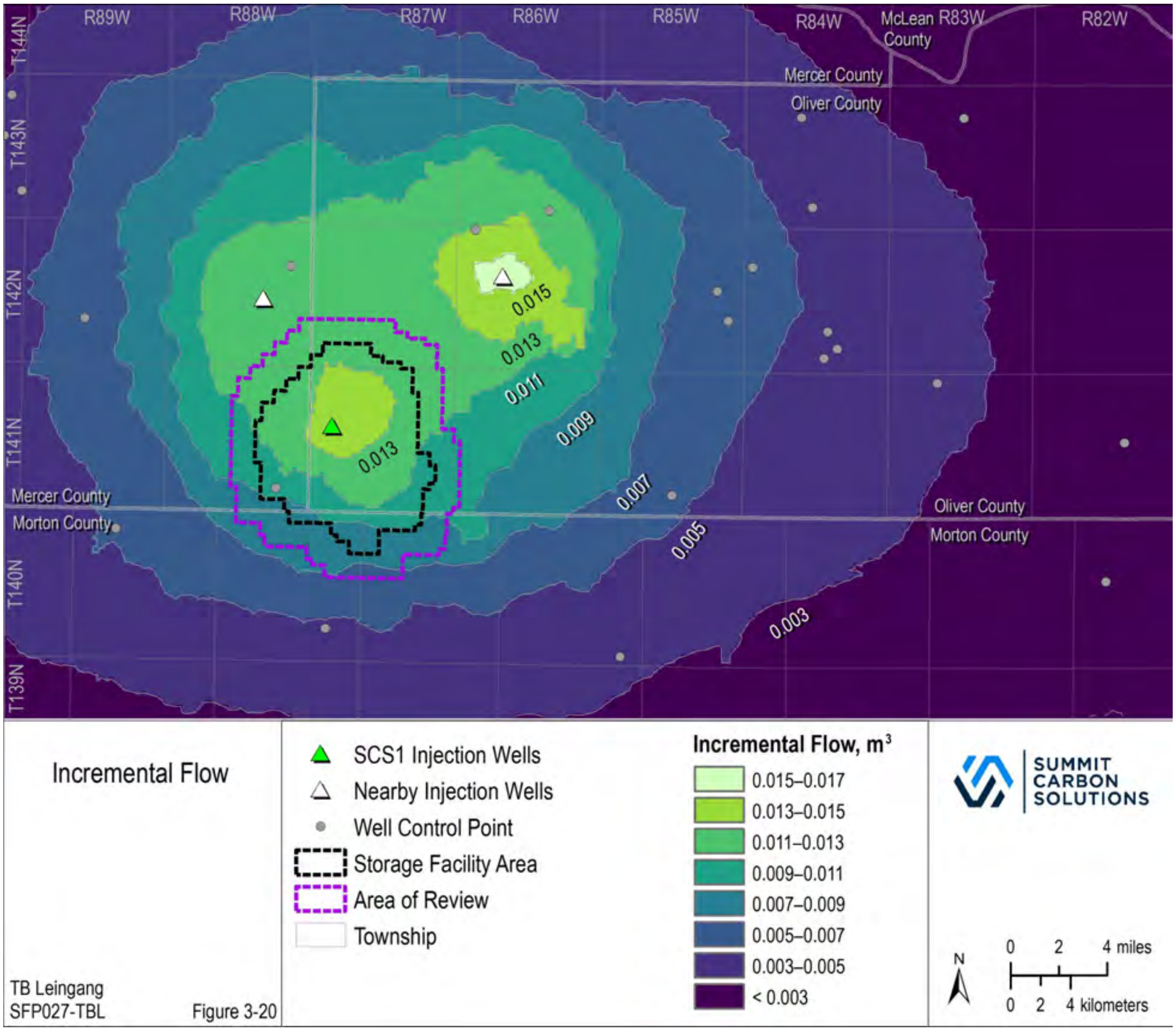


Figure 3-20. Map of potential incremental flow into the USDW at the end of 20 years of CO_2 injection for the scenario where the modeled leaky wellbore is closed to Aquifer 2 (thief zone).

The final step of the risk-based AOR workflow is to apply a threshold criterion to the incremental flow 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 3-19. 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 3-8. 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.

Table 3-8. 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	1004
Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Without* Injection, m^3	0.010
Maximum Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Attributable to* Injection, m^3	0.017

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 TB Leingang area—CO_2 injection is proposed to occur in an area with few available leakage pathways.

- The continued overpressured nature of the Broom Creek Formation with respect to overlying saline aquifers—over relatively short (e.g., 1 year) timescales, overpressured 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-mi buffer (Figure 3-21).

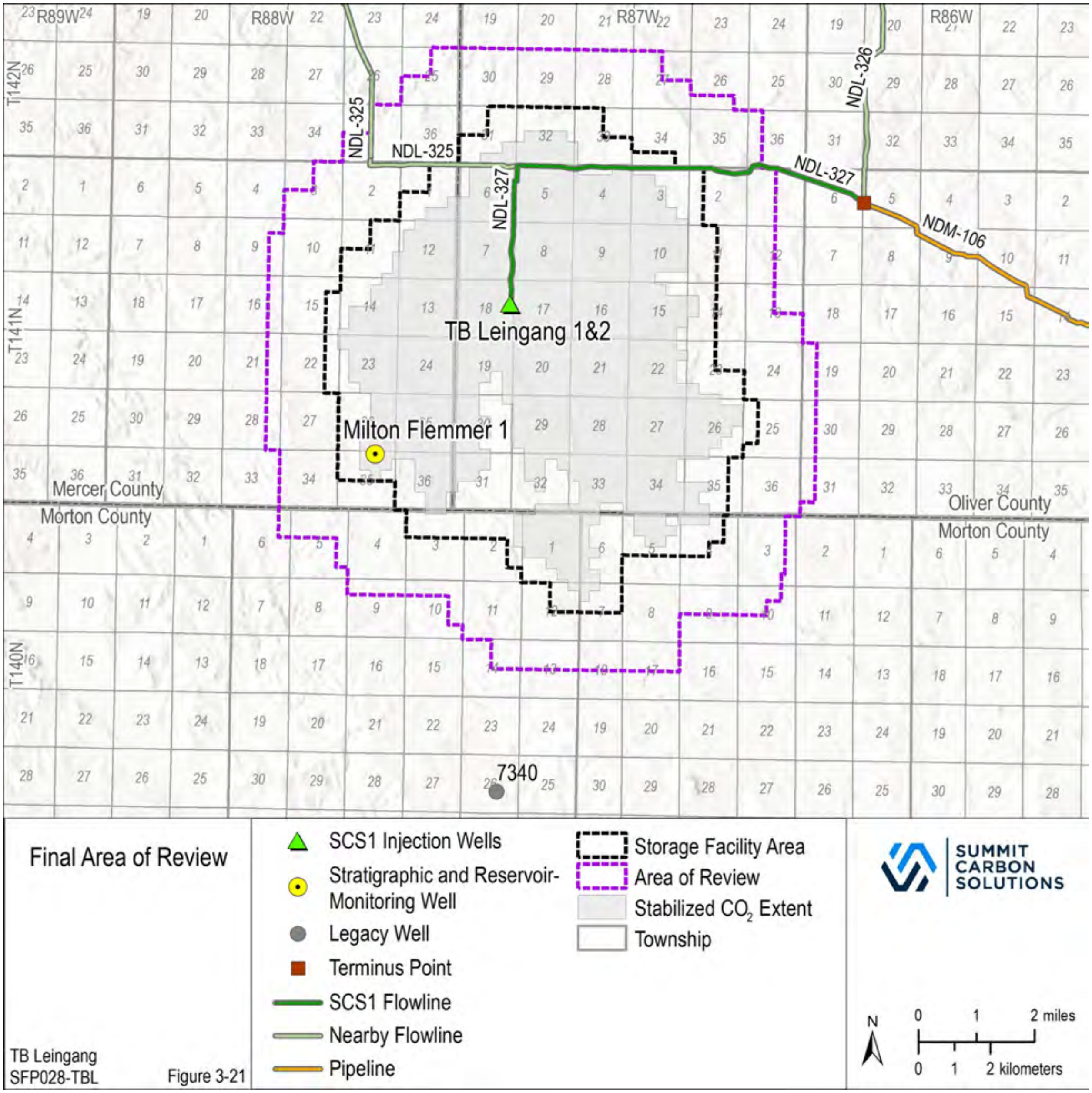


Figure 3-21. Final AOR estimations and stabilized CO_2 extent of the TB Leingang storage facility area in relation to nearby legacy wells. Shown is the storage facility area (black dashed line) and AOR (purple dashed line). The gray circle represents a legacy oil and gas well near the storage facility area.

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SECTION 4.0

AREA OF REVIEW

4.0 AREA OF REVIEW

4.1 Area of Review (AOR) Delineation

North Dakota regulations for geologic storage of CO_2 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 (USDWs)[1] may be endangered by the injection activity" (North Dakota Administrative Code [N.D.A.C.] § 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 that is 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 Milton Flemmer 1 (North Dakota Industrial Commission [NDIC] File No. 38594) 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). The storage reservoir is calculated to be overpressured, with a value of −271 psi calculated using data from the Milton Flemmer 1 well. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period was 1004 psi in the raster cell intersected by the injection well, which corresponds to less than 0.017 m^3 of flow over 20 years (Section 3.5). Based on the computational methods used to simulate CO_2 injection activities and the associated pressure front (Figure 4-1), the resulting AOR for TB Leingang is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations.

In accordance with N.D.A.C. § 43-05-01-05(1)(b)(3), a geologist or engineer reviewed the data of public record for all wells within the storage facility area, including those which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within 1 mi of the storage facility area boundary (Table 4-1).

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[1] The Fox Hills Aquifer underlying western North Dakota, including TB Leingang, 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 TB Leingang 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.

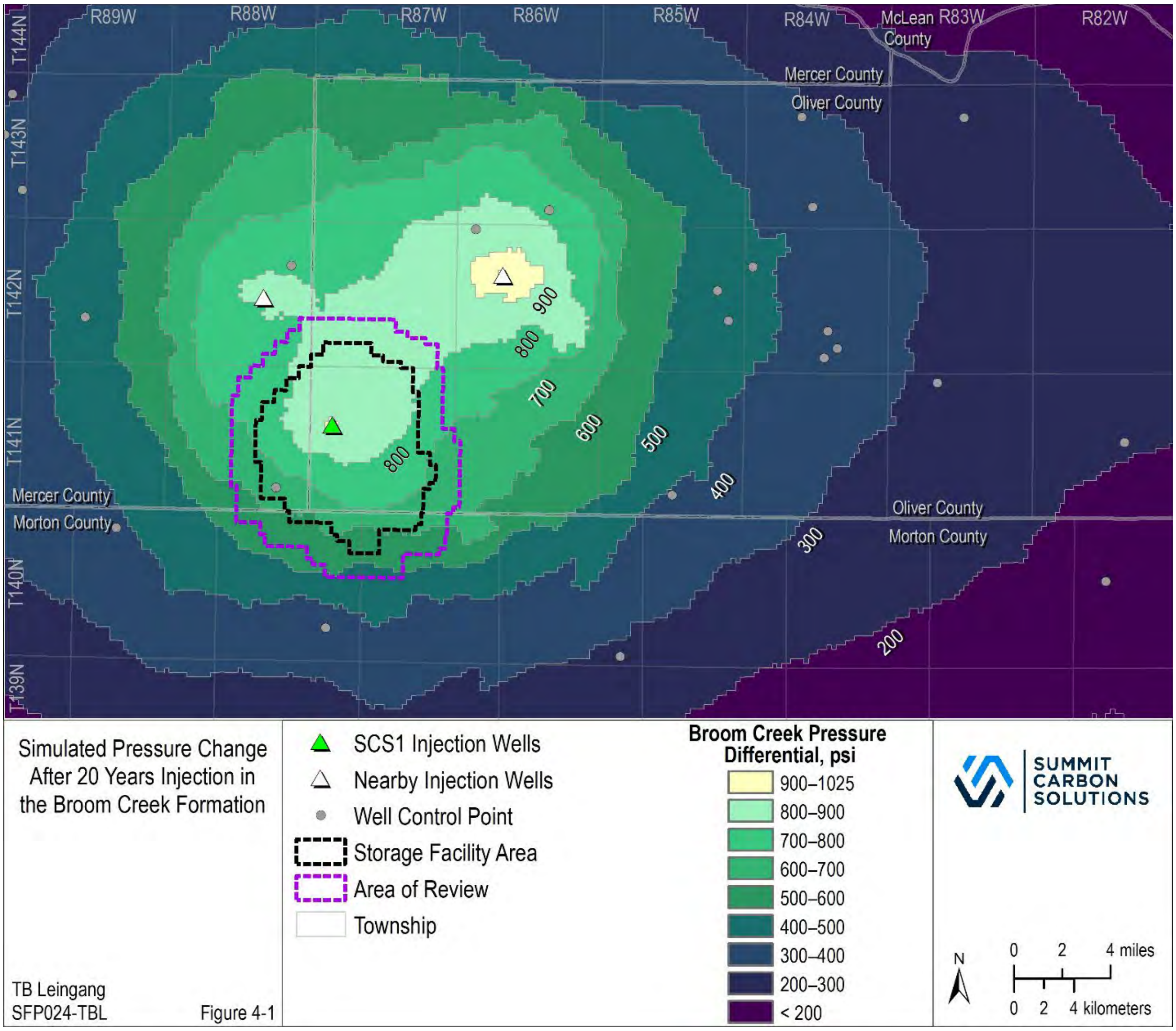


Figure 4-1. Pressure map showing the maximum subsurface pressure influence associated with CO_2 injection in the Broom Creek Formation for TB Leingang. Shown are the storage facility area and AOR boundary in relation to the predicted maximum subsurface pressure influence. Subsurface pressure subsides at the cessation of injection.

This section of the SFP application is accompanied by maps and tables that include information required and in accordance with N.D.A.C. § 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 occupied structures, gravel pits, and wind turbines (Figure 4-2); and location of water wells, springs, and any other wells within the AOR (Figure 4-3). Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation. Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1.

Table 4-1. Investigated and Identified Surface and Subsurface Features in the AOR (Figures 2-50, 4-2, and 4-3)

Surface and Subsurface Features	Investigated and Identified (Figures 4-2 and 4-3)	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) (Figure 2-51)		X
Quarries/Gravel Pits	X	
Man-Made Subsurface Structures and Activities	X	
Location of Proposed Wells	X	
Location of Proposed Cathodic Protection Boreholes*		X
Surface Facilities	X	
Roads	X	
State Boundary Lines		X
County Boundary Lines	X	
Indian Country Boundary Lines		X

* No cathodic protection boreholes are currently included in the site design, and none were identified within the AOR.

An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR (Section 2.5) and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.

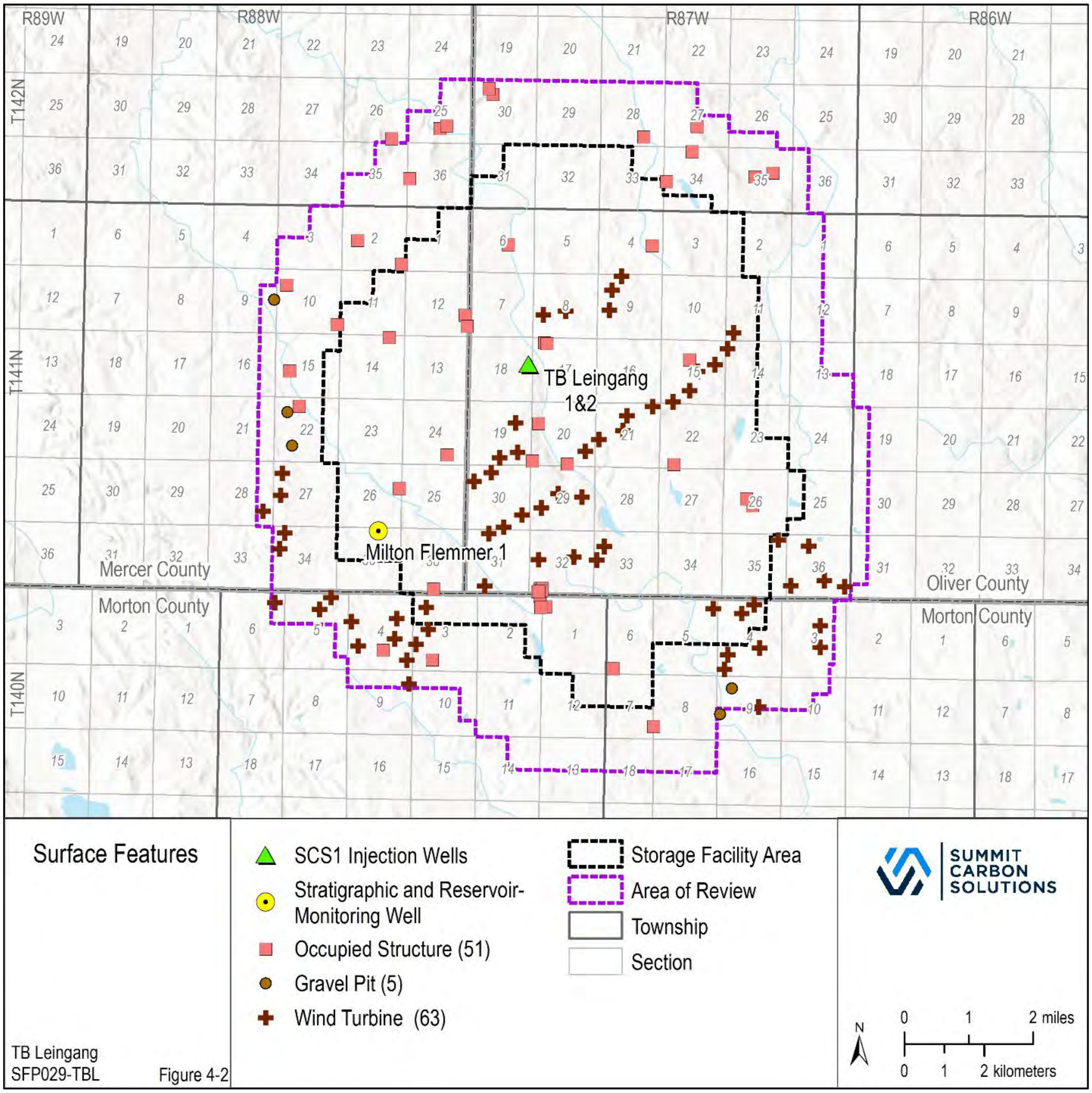


Figure 4-2. Final AOR map showing the TB Leingang storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares represent occupied structures, brown crosses represent wind turbines, and brown circles represent gravel pits (note: gravel pits were identified using the North Dakota Geographic Information System [GIS] Hub landmarks data layer from the North Dakota Department of Transportation [2002]).

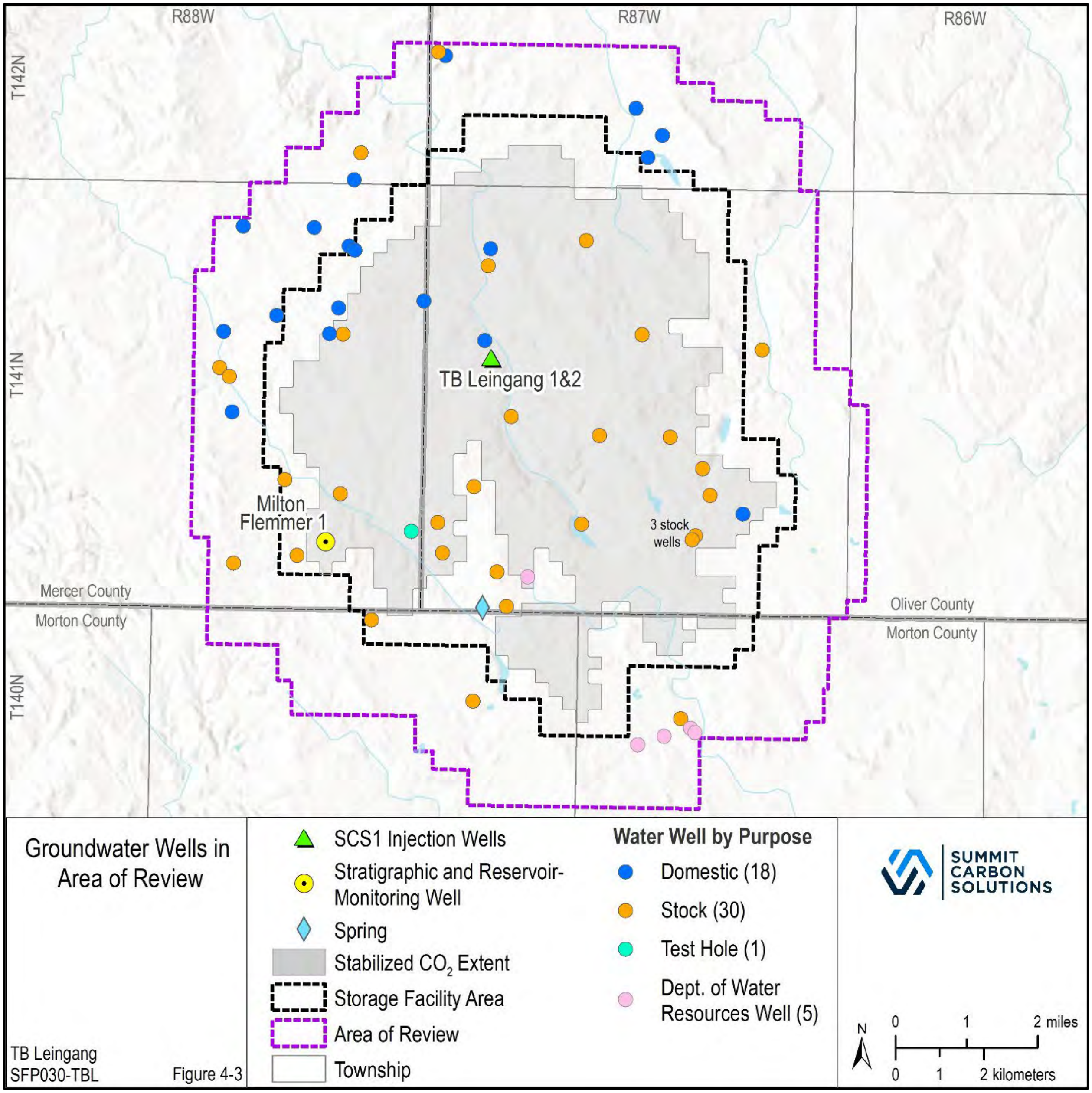


Figure 4-3. Map showing all wells located in the AOR. Shown are the stabilized CO_2 plume extent postinjection (gray-shaded area), storage facility area (dashed black boundary), and AOR (dashed purple boundary). All groundwater wells in the AOR are identified based on data available from the Department of Water Resources (DWR). The only existing well penetrating the Broom Creek Formation and its primary overlying seal (Opeche/Spearfish Formation) within the AOR is the Milton Flemmer 1 well. No other legacy oil and gas wells are present in the AOR (see Figure 2-47 for any nearby legacy wells outside of the AOR). One spring is present in the southern portion of the AOR (note: the spring was identified using the National Map hosted by the U.S. Geological Survey [2023]).

4.2 Corrective Action Evaluation

As identified in Table 4-1, any active and abandoned wells and underground mines in the AOR that may penetrate the confining zone were evaluated pursuant to N.D.A.C. § 43-05-01-05.1(2). Tables 4-2 and 4-3 and Figure 4-4 provide a description of each identified well, including well type, construction, date drilled, location, depth, record of plugging and completion, and any additional pertinent information. 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.

TB LEINGANG/MILTON FLEMMER 1

Table 4-2. Well(s) in AOR Evaluated for Corrective Action*

NDIC Well File No.	Operator	Well Name	Well Type	Spud Date	Surface Casing OD, in.	Surface Casing Depth, ft MD	Long-String Casing OD, in.	Long-String Casing Depth, ft MD	Hole Direction	TD, ft MD	TVD, ft	Status	Plug Date	TWN	RNG	Section	Qtr/Qtr	County	Area	Corrective Action Needed
38594	Summit Carbon Storage #1, LLC	Milton Flemmer 1	Stratigraphic Test	11/18/2021	10.750	2148	7	11,967	Vertical	12,009	12,009	TA	NA	141 N	88 W	35	NW/NE	Mercer	SFA	No

* Abbreviations used in table: outside diameter; total depth; true vertical depth; township; range, quarter; temporarily abandoned; and storage facility area.

Table 4-3. Milton Flemmer 1 (NDIC File No. 38594) Well Evaluation

Well Name: Milton Flemmer 1 (NDIC File No. 38594)

				Formation		
Item	Description	Top Depth, ft MD	Cement Volume	Name	Estimated Top, ft MD	
2	CICR*	4825	6 sacks	Pierre	1799	10¾" Casing Class G cement was used from 0' to 2148' MD
1	CIBP**	6550	6 sacks	10¾" Casing shoe	2148	
				Mowry	4153	7" Casing cemented, including CO_2-resistant cement from 2148’ to 12,009' MD
				Newcastle	4228	
				Skull Creek	4231	
				Inyan Kara	4469	
				Swift	4736	
				Opeche/Spearfish	5587	
				Broom Creek	5818	
				Amsden	6160	
				Icebox	11,060	
				Black Island	11,187	
				Deadwood	11,230	
				Precambrian	11,870	

All depths are in MD based off KB elevation.

Spud Date: 11/18/2021

Total Depth: 12,009' MD (Precambrian Formation)

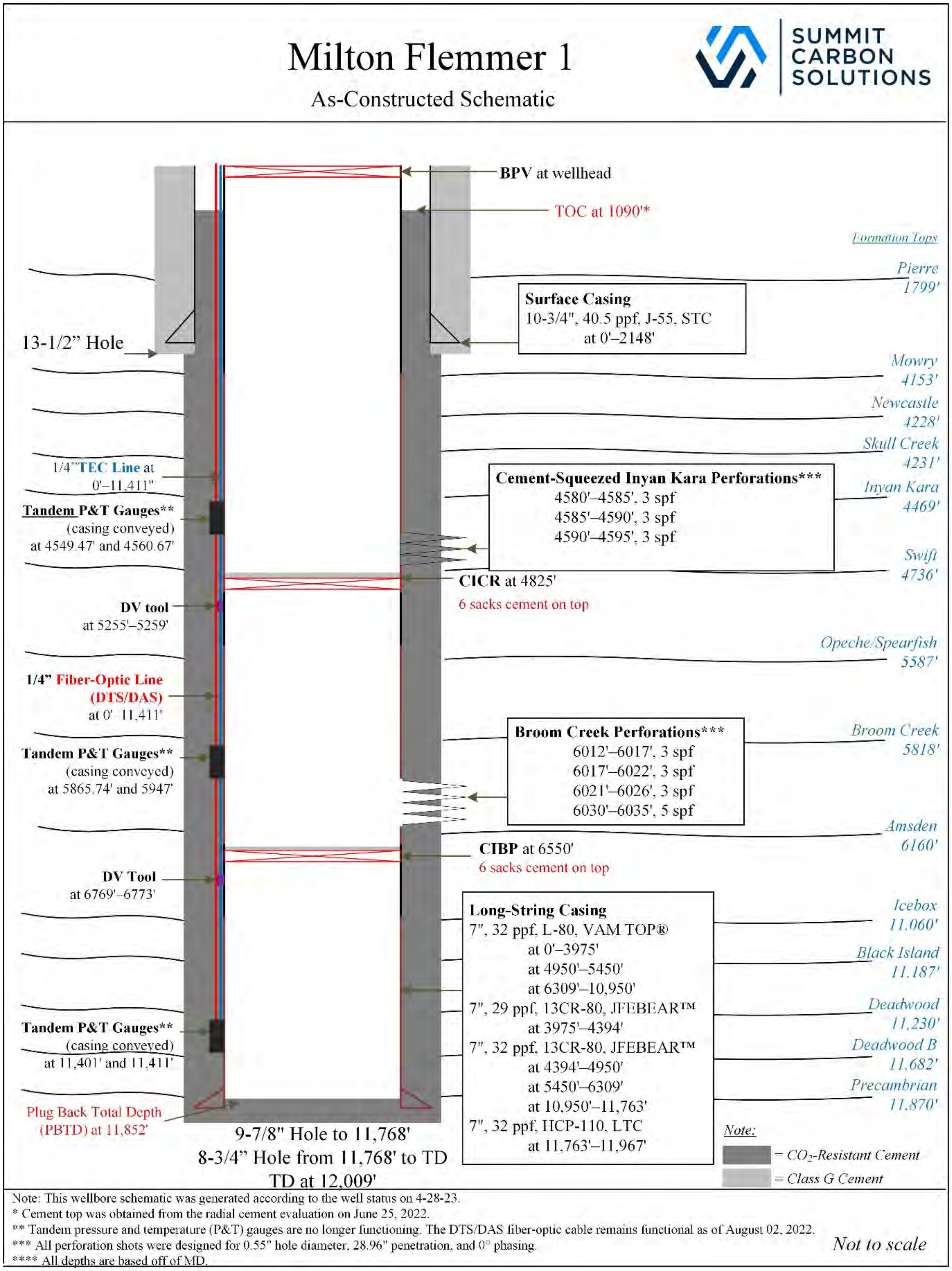
Surface Casing: 10¾" from 0' to 2148'

Cased Hole 7" to 11,967'

Corrective Action: No corrective action is necessary. The well will be the reservoir-monitoring well within the SFA. See Figure 4-4 for depths. The well will be completed as shown in Section 11.

* Cast iron cement retainer.

** Cast iron bridge plug.



Note: This wellbore schematic was generated according to the well status on 4-28-23.
* Cement top was obtained from the radial cement evaluation on June 25, 2022.
** Tandem pressure and temperature (P&T) gauges are no longer functioning. The DTS/DAS fiber-optic cable remains functional as of August 02, 2022.
*** All perforation shots were designed for 0.55" hole diameter, 28.96" penetration, and 0° phasing.
**** All depths are based off of MD.

Figure 4-4. Milton Flemmer 1 (NDIC File No. 38594) well schematic showing the location of cement plugs.

4.3 Reevaluation of AOR and Corrective Action Plan

The AOR and corrective action plan will be reevaluated in accordance with N.D.A.C. § 43-05-01-05.1, with the first reevaluation taking place at a period not to exceed 5 years from the date the permit for CO_2 injection is issued (N.D.A.C. § 43-05-01-10) or when monitoring and operational conditions warrant a reevaluation. Each successive reevaluation shall take place at a period not to exceed 5 years from the date of the previous reevaluation (each referred to as a "Reevaluation Date"). The AOR reevaluations will address the following:

- 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 delineation.

As part of the reevaluation, Summit Carbon Storage #1, LLC (SCS1) will either a) demonstrate to the NDIC Department of Mineral Resources-Oil and Gas Division (DMR-O&G) using monitoring data and modeling results that no plan amendment is necessary or b) submit an amended AOR and corrective action plan for DMR-O&G approval. Plan amendments must be incorporated into the permit and are subject to permit modification requirements.

4.4 Protection of USDWs

4.4.1 Introduction of USDW Protection

The primary confining zone and additional overlying confining zones geologically isolate the Fox Hills and Hell Creek Formations, the lowest USDWs in the AOR, from the underlying injection zone. The Opeche/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 more than 1000 ft thick, providing an additional seal for all USDWs in the region (Table 4-4).

Table 4-4. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on Milton Flemmer 1)

Name of Formation	Lithology	Formation Top Depth MD, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Mudstone	1799	1480	0
Niobrara	Mudstone	3279	418	1480
Carlile	Mudstone	3697	49	1898
Greenhorn	Mudstone	3746	116	1947
Belle Fourche	Mudstone	3862	291	2063
Mowry	Mudstone	4153	75	2354
Skull Creek	Mudstone	4231	238	2432
Swift	Mudstone	4736	458	2937
Rierdon	Mudstone	5193	196	3394
Piper (Kline Member)	Carbonate	5389	94	3590
Piper (Picard Member)	Mudstone	5483	104	3684
Opeche/Spearfish	Mudstone	5587	231	3788

4.4.2 Geology of USDW Formations

The hydrogeology of western North Dakota comprises several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 4-5). These saline and freshwater systems are separated by the Cretaceous Pierre shale of the Williston Basin, a regionally extensive shale between 1000 and 1500 ft thick (Thamke and others, 2014).

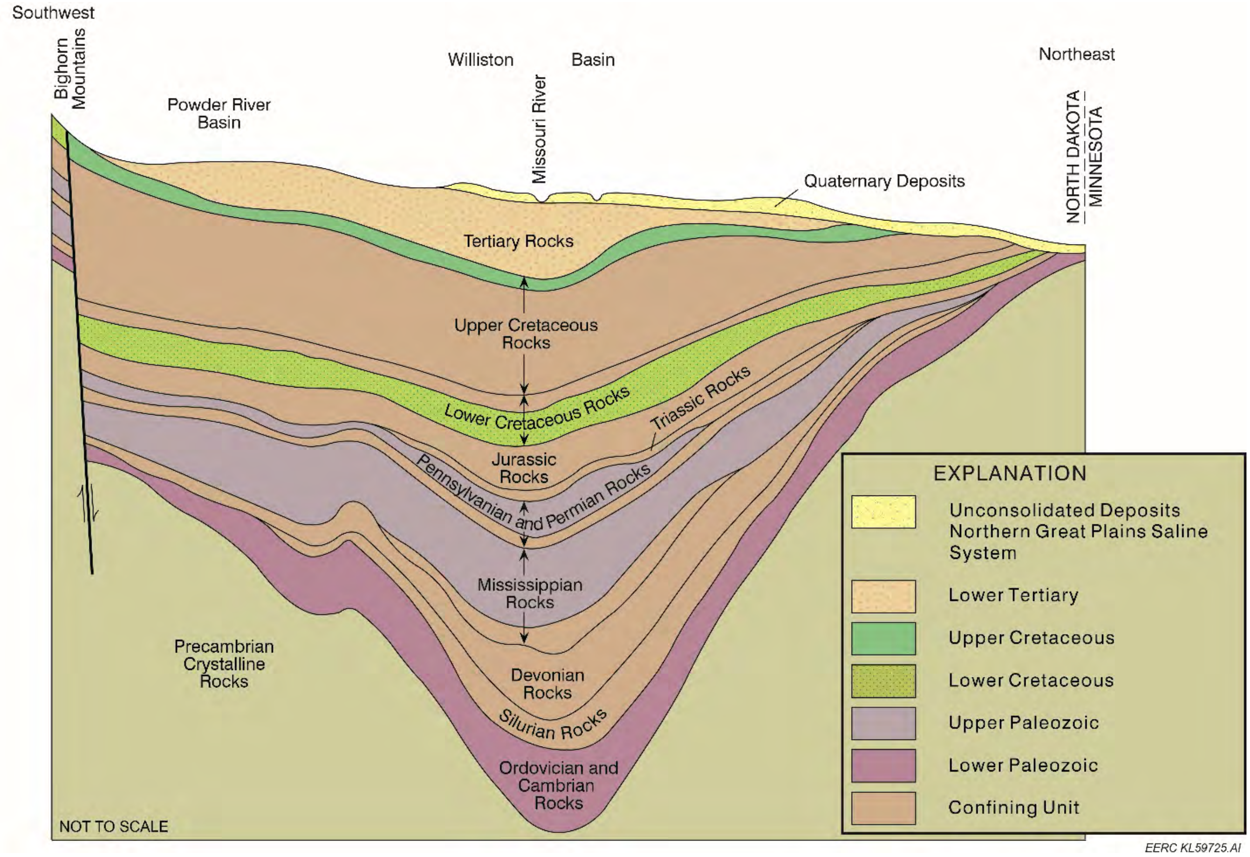
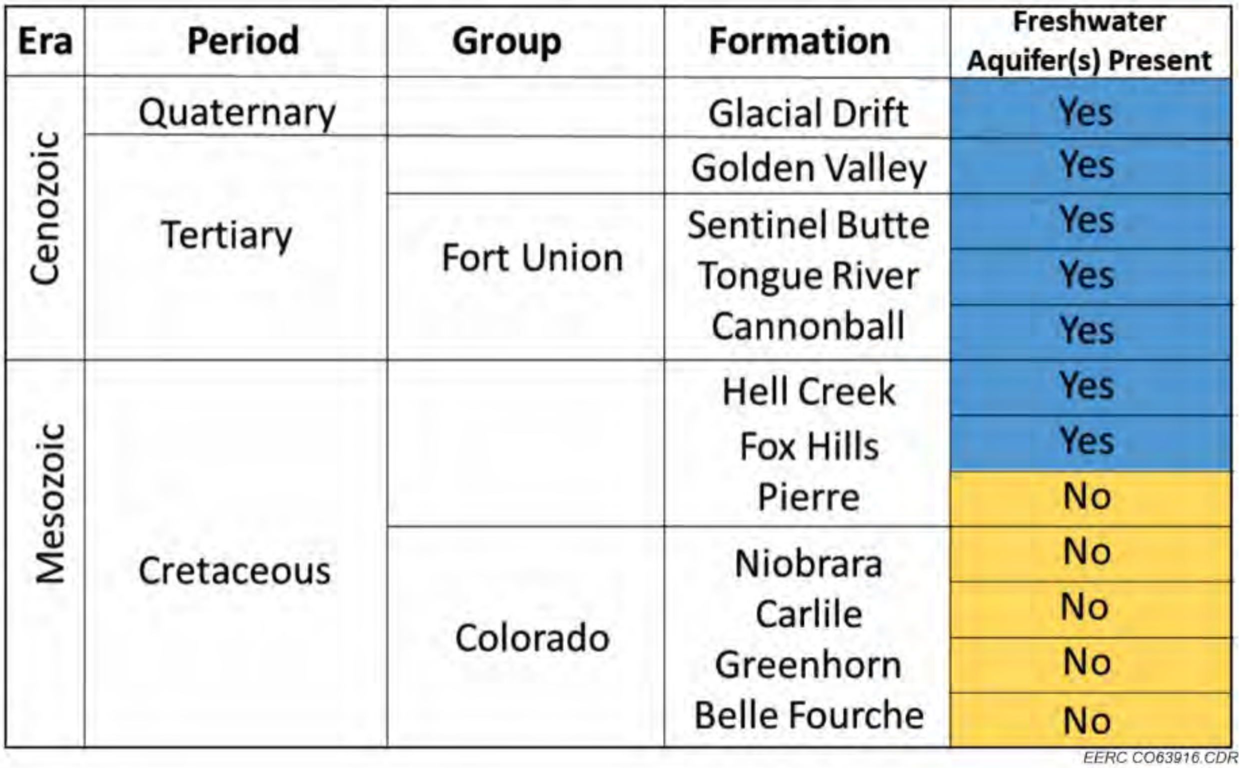


Figure 4-5. Major aquifer systems of the Williston Basin (modified from Downey and Dinwiddie, 1988).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; the overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group; and the Tertiary Golden Valley Formation (Figure 4-6). Above these formations are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the AOR (Croft, 1973).



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

EERC CO63916.CDR

Figure 4-6. Upper stratigraphy of Mercer, Oliver, and Morton Counties showing the stratigraphic relationship of Quaternary, Cretaceous and Tertiary groundwater-bearing formations (modified from Croft, 1973).

The lowest USDW in the AOR 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 of fluvial origin. The underlying Fox Hills Formation is interpreted as interbedded nearshore marine deposits of sand, silt, and shale deposited as part of the final Western Interior Seaway retreat (Fischer, 2013). The Fox Hills Formation in the AOR is approximately 1500 ft deep and 250–300 ft thick (information reported from stratigraphic well installation). 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 AOR (Figure 4-7).

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 1000 ft thick in the AOR (Thamke and others, 2014).

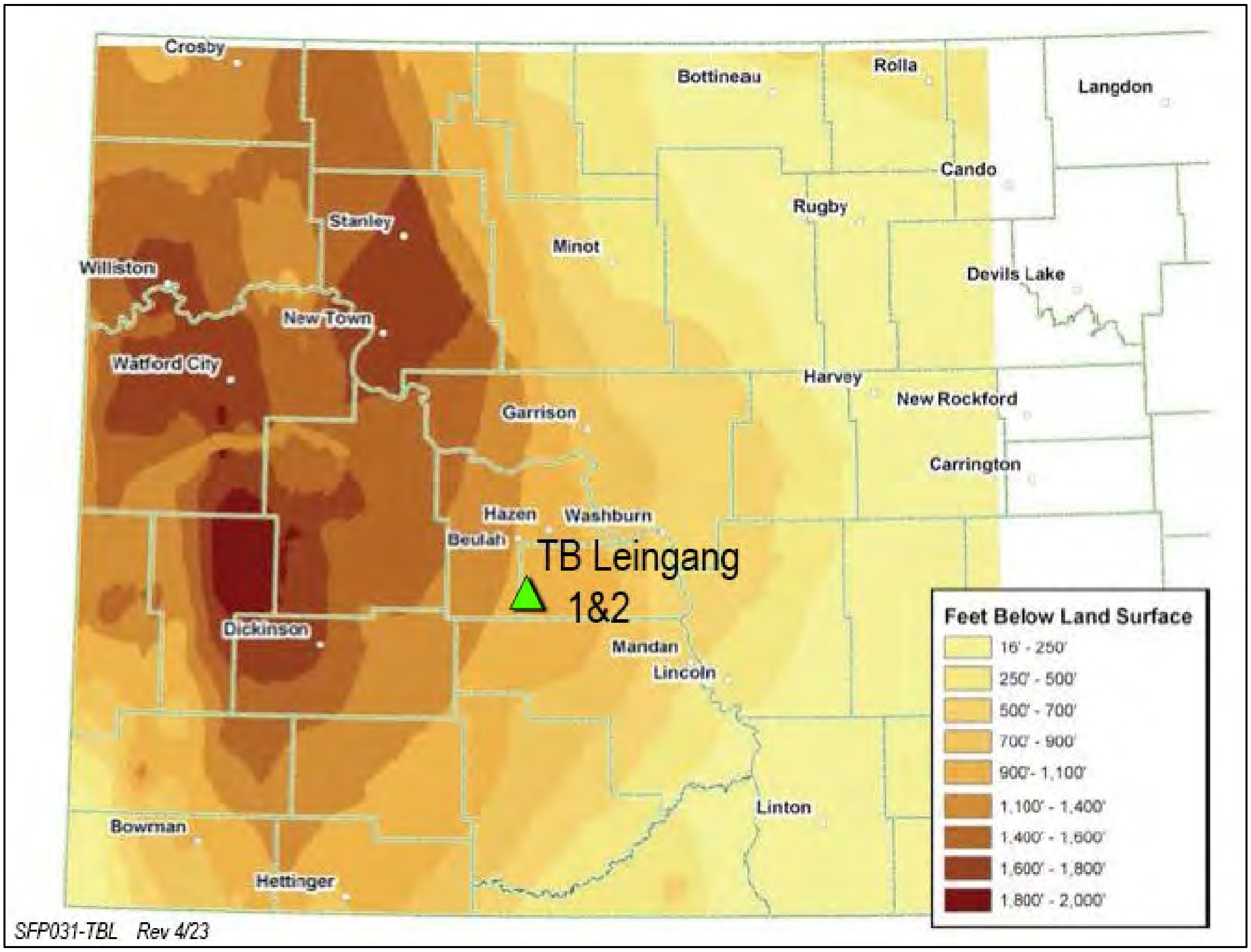


Figure 4-7. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

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 AOR is to the east (Figure 4-8).

Water sampled from the Fox Hills Formation is a sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1500–1600 ppm. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride in excess of 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering.

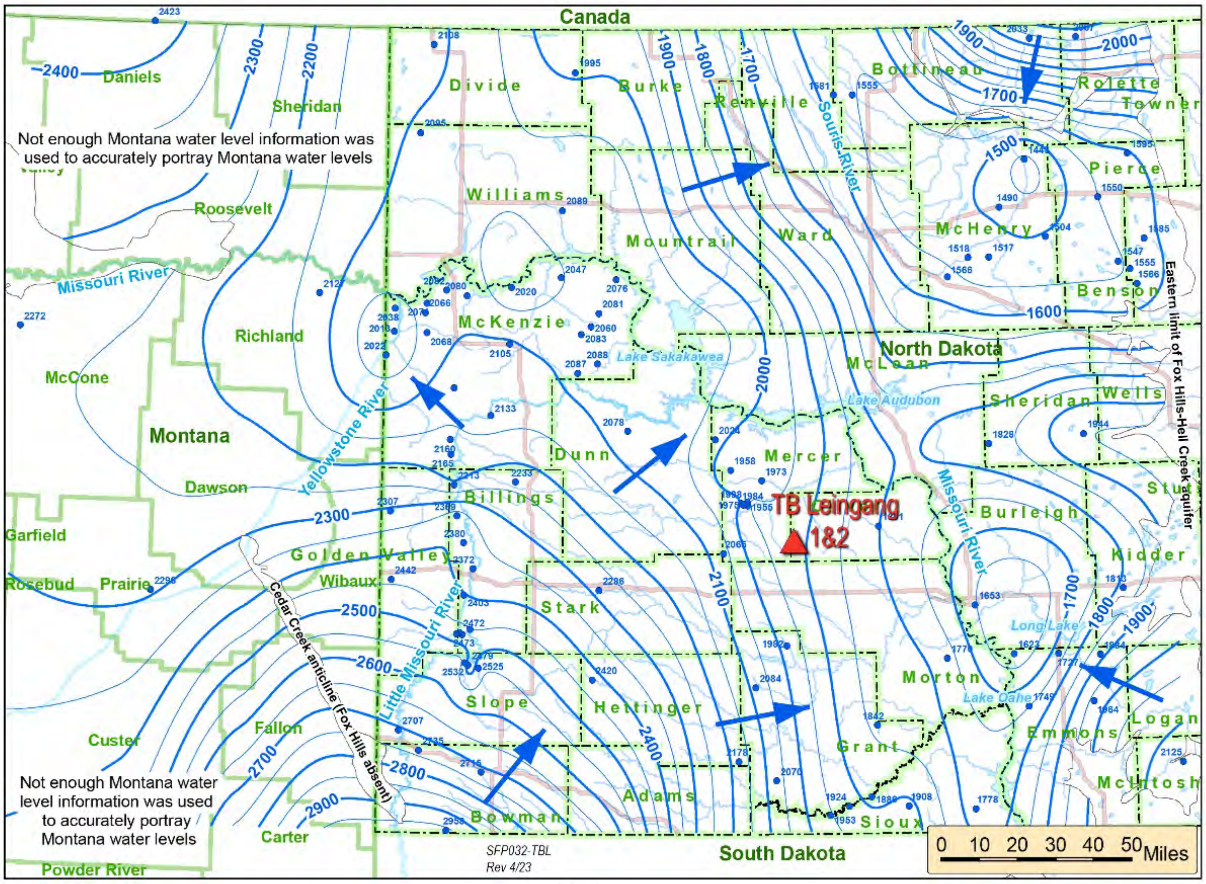


Figure 4-8. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the east through the AOR in Mercer, Oliver, and Morton Counties (modified from Fischer, 2013).

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AOR. A cross section of these formations is presented in Figure 4-9. 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 200 to 500 ft, and it directly underlies surficial glacial deposits in the AOR. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1000 ppm (Croft, 1973).

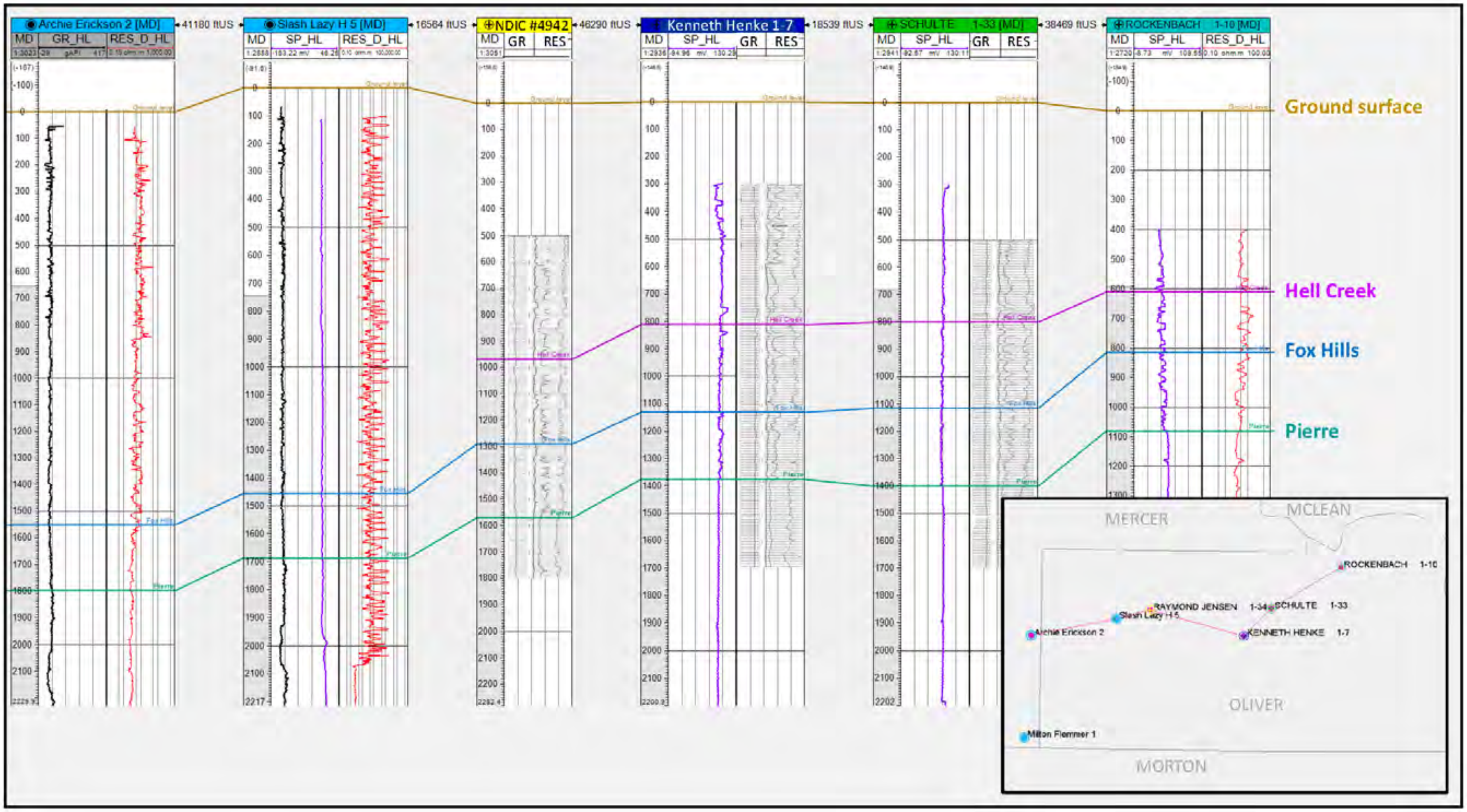


Figure 4-9. West-east cross section of the major aquifer layers in Oliver County. Wells used in the cross section are shown in the inset map and labeled with corresponding well names (NDIC File No. 4942 is Raymond Jensen 1-34).

The Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation in western portions of the AOR. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte Formation is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation range from approximately 400 to 1000 ppm (Croft, 1973). 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 4-5).

The primary seal of the injection zone is the Permian-aged Opeche/Spearfish Formation with the shales of the Permian-aged Spearfish, Jurassic-aged Piper (Picard), Rierdon, and Swift Formations, all of which overlie the Opeche Formation. Above the Swift Formation is the confined saltwater aquifer system of the Inyan Kara Formation that extends across much of the Williston Basin. Above the Inyan Kara Formation are Cretaceous-aged shale formations, namely, the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlisle, Niobrara, and Pierre Formations. The Pierre Formation is the thickest shale formation in the AOR and primary geologic barrier between the USDWs and injection zone. The geologic strata overlying the injection zone consists of multiple impermeable rock layers that are free of transmissive faults or fractures and provide adequate isolation of the USDWs from CO_2 injection activities in the AOR.

Figure 4-10 shows the location of groundwater wells selected to be included in the near-surface baseline and operational monitoring plan, which includes one new Fox Hills monitoring well, and up to four existing groundwater wells. The four existing wells (1 – Fox Hills, 1 – Cannonball-Ludlow, and 2 – Tongue River) were chosen based on depth (>300 ft), location within the AOR, and accessibility. SCS1 field verified each of these wells to confirm accessibility, operational characteristics, and land-use permissions. Table 4-5 correlates DWR well numbers with the well numbers used by SCS1 throughout this permit application.

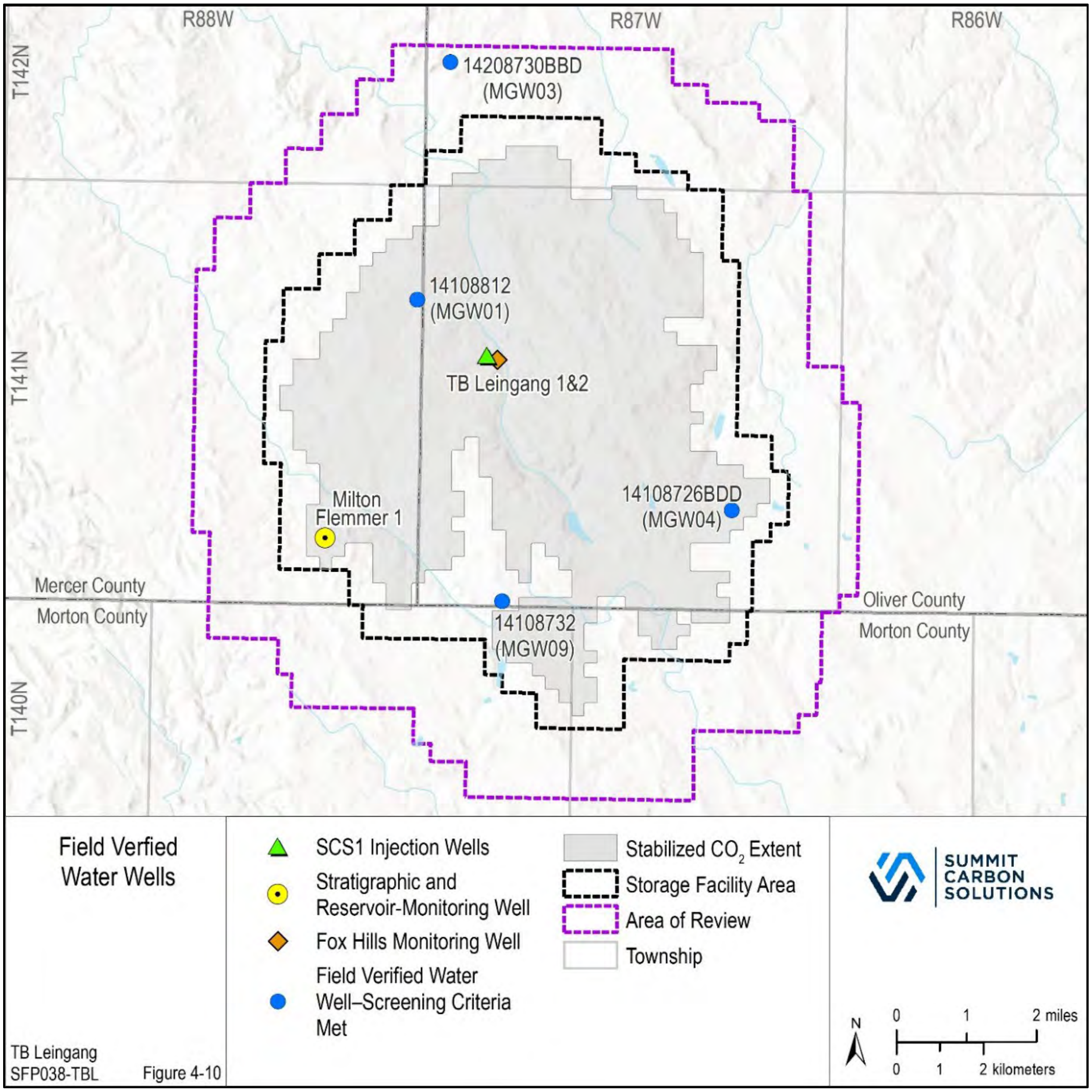


Figure 4-10. Field-verified water wells located within the AOR.

Table 4-5. DWR and SCS1 Well No. Correlation

DWR Well No.	SCS1 Field Verified Location*	SCS1 Well No.	Formation
14208730BBD	142-087-30BAC	MGW03	Cannonball–Ludlow
14108812	141-088-12DAD	MGW01	Fox Hills
14108726BDD	141-087-26CAA	MGW04	Tongue River
14108732	141-087-32CCD	MGW09	Tongue River

* SCS1 Field Verified Location follows an alpha numeric system indicating the township - range - section and quarter-quarter-quarter. This is a similar system used by the DWR but adds the precise quarter-quarter-quarter location from field verification.

SCS1 will work with landowners of the four existing groundwater wells to collect 3–4 samples from each well to establish baseline conditions prior to CO_2 injection and periodically thereafter during subsequent phases of the project as outlined in Section 5.0. The actual number of wells and samples collected from each existing groundwater well location may vary because some of the groundwater wells may not be operated year-round or site accessibility may be limited (e.g., snow cover during winter months).

SCS1 will install one Fox Hills monitoring well adjacent to the CO_2 injection well pad. The Fox Hills monitoring well will be sampled three to four times prior to CO_2 injection to establish a seasonal baseline and periodically thereafter during subsequent phases of the project as outlined in Section 5.0.

4.5 References

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SECTION 5.0

TESTING AND MONITORING PLAN

5.0 TESTING AND MONITORING PLAN

Pursuant to North Dakota Administrative Code (N.D.A.C.) § 43-05-01-11.4(1)(k), this testing and monitoring plan includes 1) a plan for analyzing the captured CO_2 stream, 2) leak detection and corrosion-monitoring plans for surface facilities and all wells associated with the geologic CO_2 storage project, 3) a well-logging and -testing plan, 4) an environmental monitoring plan to verify the injected CO_2 is contained in the storage reservoir, and 5) a quality assurance and surveillance plan (QASP).

This site-specific testing and monitoring plan was informed by the injection scenario (as described in the Project Summary), site characterization activities (Section 2.0), geologic modeling and simulations (Section 3.0), area of review delineation and corrective action evaluation (Section 4.0), and well design (Section 9.0). Activities described in Table 5-1 will be used to establish preinjection (baseline) conditions at the storage site. Pursuant to N.D.A.C. § 43-05-01-11.4, the set of activities described in Table 5-2 will be used to verify that TB Leingang is operating as permitted and is not endangering underground sources of drinking water (USDW). Summit Carbon Storage #1, LLC (SCS1) will specify data-quality measures through the QASP.

SCS1 will review this testing and monitoring plan at a minimum of every 5 years from the start of injection, as required by N.D.A.C. § 43-05-01-11.4(j), to ensure the technologies and strategies deployed remain appropriate for demonstrating containment of CO_2 in the storage reservoir and conformance with predictive modeling and simulations.

A detailed testing and monitoring plan for the baseline and operational phases is provided in the remainder of this section. Section 6.0 describes the testing and monitoring activities associated with the postinjection phase.

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

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Preinjection/Baseline Sampling Frequency
CO_2 Stream Analysis	**Injection composition**	CO_2 stream sampling	CO_2 accounting and ensures stream compatibility with project materials in contact with CO_2	Gas chromatograph and CO_2 stream compositional commercial laboratory results	Downstream of pipeline inspection gauge (PIG) receiver	At least once
Wellbore Mechanical Integrity (external)	**Casing wall thickness**	Ultrasonic logging or other equivalent casing inspection log [CIL] and sonic array logging (inclusive of casing collar locator [CCL], variable-density log [VDL], and radial cement bond log [RCBL]), and gamma ray (GR)	Mechanical integrity demonstration and operational safety assurance	Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL) and GR	CO_2 injection and reservoir-monitoring wells	Once per well
	Radial cement bond					
	Saturation profile (behind casing)	Pulsed-neutron logging (PNL)		PNL tool	CO_2 injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	
	Temperature profile	Temperature logging		Temperature log	CO_2 injection and reservoir-monitoring wells	
		Real-time, continuous data recording via supervisory control and data acquisition (SCADA) system		Distributed temperature sensing (DTS) casing-conveyed fiber-optic cable	Along the outside of the long-string casing of the CO_2 injection and reservoir-monitoring wells	Install at casing deployment
Wellbore Mechanical Integrity (internal)	**Pressure/temperature** (P/T)	Real-time, continuous data recording via SCADA system	Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Between surface and long-string casing annulus on CO_2 injection and reservoir-monitoring wells	Install at well completion
	Annulus pressure	Tubing-casing annulus pressure testing		Pressure testing truck with pressure chart	CO_2 injection and reservoir-monitoring wells	Once per well
	P/T	Real-time, continuous data recording via SCADA system		Digital surface P/T gauge	Between tubing and long-string casing annulus of CO_2 injection and reservoir-monitoring wells	Install at well completion
	Annular fluid level	Real-time, continuous data recording via SCADA system	Prevention of microannulus and monitoring annular fluid volume	Nitrogen (N_2) cushion on tubing-casing annulus with seal pot system	On well pad for each CO_2 injection well	Add initial volumes to TB Leingang 1 and 2
	P/T	Real-time, continuous data recording via SCADA system	Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Tubing of CO_2 injection and reservoir-monitoring wells	Install at well completion
	Saturation profile (tubing-casing annulus)	PNL		PNL tool	CO_2 injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Once per well
Downhole Corrosion Detection	**Saturation profile** (behind casing)	PNL	Corrosion detection of project materials in contact with CO_2 and operational safety assurance	PNL tool	CO_2 injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Once per well
	Casing wall thickness	Ultrasonic logging or other equivalent CIL and sonic array logging (inclusive of CCL, VDL, and RCBL), and GR		Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL), and GR	CO_2 injection and reservoir-monitoring wells	

Continued…

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

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Preinjection/Baseline Sampling Frequency
Near-Surface	**Soil gas composition**	Soil gas sampling (see Figure 5-4)	Assurance near-surface environment is protected	Two soil gas profile stations: MSG01 & MSG04	One station per CO_2 injection and reservoir-monitoring well pad	3–4 seasonal samples per station (with isotopes)
	Soil gas isotopes		Source attribution			
	Water composition	Groundwater well sampling (see Figure 5-4)	Assurance that USDWs are protected	Up to four existing groundwater wells from the Tongue River, Cannonball-Ludlow, and Fox Hills Aquifers (e.g., MGW01, MGW03, MGW04, and MGW09)	Within area of review (AOR)	3–4 seasonal samples per well (water quality with isotopes)
	Water isotopes		Source attribution			
	Water composition		Assurance that lowest USDW is protected	Fox Hills monitoring well	MGW11 adjacent to CO_2 injection well pad	3–4 seasonal samples (water quality with isotopes)
	Water isotopes		Source attribution			
Above-Zone Monitoring Interval (Opeche/Spearfish to Skull Creek)	**Saturation profile**	PNL	Assurance of containment in the storage reservoir and protection of USDWs	PNL Tool	CO_2 injection and reservoir-monitoring wells	Once per well
	Temperature profile	Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable		Install at casing deployment
		Temperature logging		Temperature log		Once per well
Storage Reservoir (direct)	**P/T**	Real-time, continuous data recording via SCADA system	Storage reservoir monitoring and conformance with model and simulation projections	Casing-conveyed (CO_2 injection wells) and tubing-conveyed (monitoring well) downhole P/T gauge	CO_2 injection and reservoir-monitoring wells	Install at casing (CO_2 injection wells) and tubing (monitoring well) deployment
	Temperature profile	Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable		Install at casing deployment
		Temperature logging		Temperature log		Once per well
	Storage reservoir performance	Injectivity testing	Demonstration of storage reservoir performance	Pressure falloff test	CO_2 injection wells	Once per injection well
Storage Reservoir (indirect)	**CO_2 saturation**	3D time-lapse seismic surveys	Site characterization and CO_2 plume tracking to ensure conformance with model and simulation projections	Vibroseis trucks (source) and geophones and distributed acoustic sensing (DAS) fiber-optic cable (receivers)	Within AOR	Collect 3D baseline survey
	Seismicity	Continuous data recording	Seismic event detection and source attribution and operational safety assurance	Seismometer stations and DAS fiber optics	Area around injection wells (within 1 mile)	Install stations

Table 5-2. Overview of Major Components of the Testing and Monitoring Plan – Injection

							Injection Reporting (20 years)		
Monitoring Type	**Parameter**	**Activity Description**	**Primary Purpose(s) of Activity**	**Equipment/Test**	**Location**	**Sampling Frequency**	**Report Content (N.D.A.C. § 43-05-01-18)[1]**	**Reporting Method**	**DMR-O&G Reporting Schedule[2,3]**
CO_2 Stream Analysis Section 5.1	**Injection volume/mass**	Real-time, continuous data recording with automated triggers and alarms via SCADA system	CO_2 accounting, leak detection, and operational safety assurance	Multiple Coriolis mass flowmeters	One flowmeter per injection wellhead placed on flowline after flowline splits on injection pad	Continuous	Monthly average volume (metric tons/Mcf) and mass of CO_2 stream injected over reporting period and cumulative volume injected to date	Form 26 – Carbon Dioxide Storage Report – SFN 18667; NorthSTAR Sundry (e.g., underground injection control [UIC] supplemental information – date of first injection)	Any evidence of injected CO_2 or associated pressure front that may cause an endangerment to USDW or any noncompliance which may endanger health and safety of persons or cause pollution of the environment[6] must be reported with 24 hours. File quarterly[4] Annual report[5]
	Injection flow rate						Monthly average maximum and minimum injection flow rate		
	Injection P/T			Multiple P/T gauges	Upstream of pipeline terminus; Along NDL-327; downstream or upstream of flowmeters; and upstream of injection wellheads		Monthly average pressure (psi) and monthly average temperature (Fahrenheit)		
	Injection composition (see Table 5-3, Stream System Specification)	CO_2 stream sampling	CO_2 accounting and ensures stream compatibility with project materials in contact with CO_2	Gas chromatograph	Downstream of the PIG receiver		Average CO_2 stream composition; any changes to its physical, chemical, and/or relevant characteristics from proposed operating data	Form 26A – Carbon Dioxide Storage Source Report – SFN 18668	
			Verify accuracy of field measurements	CO_2 stream sampling with sample port	Upstream of the gas chromatograph	Quarterly with option to reduce sampling frequency with approval from DMR-O&G	CO_2 stream compositional commercial laboratory results	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	File quarterly[4] if analysis is performed during quarter. Annual report[5]
	Isotopes		Source attribution			Within first year of injection and within 1 year of adding new CO_2 source(s) (other than ethanol)	CO_2 stream isotopic commercial laboratory results		
Surface Facilities Leak Detection Plan Section 5.2	**Mass balance**	Real-time, continuous data recording with automated triggers and alarms via SCADA system	CO_2 accounting, leak detection, and operational safety assurance	Leak detection system (LDS) software, multiple P/T gauges, and Coriolis mass flowmeters	Flowmeter and P/T gauge near each injection wellhead in pump/metering building and flowmeter and P/T gauge at pipeline terminus	Continuous	Any release of CO_2 into the atmosphere or triggering of a surface facilities shutoff device	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	Atmospheric releases or triggering of a shutoff device to be reported within 24 hours[3] after event is confirmed by operator. File quarterly[4] Annual report[5]
	Gas concentrations (e.g., CO_2, CH_4, and H_2S)			Gas detection stations and safety lights	Stations on each injection and reservoir-monitoring wellhead; station inside pump/metering building and safety light mounted on building exterior; multigas detectors worn by field personnel				

Continued . . .

Table 5-2. Overview of Major Components of the Testing and Monitoring Plan – Injection (continued)

							Injection Reporting (20 years)		
Monitoring Type	**Parameter**	**Activity Description**	**Primary Purpose(s) of Activity**	**Equipment/Test**	**Location**	**Sampling Frequency**	**Report Content (N.D.A.C. § 43-05-01-18)[1]**	**Reporting Method**	**DMR-O&G Reporting Schedule[2,3]**
CO_2 Flowline Corrosion Prevention and Detection Plan Section 5.3	**Loss of mass**	Real-time, continuous data recording with automated triggers and alarms via SCADA system	Corrosion detection of project materials in contact with CO_2 and operational safety assurance	Electrical resistance (ER) probe	Flowline NDL-327 begins at the pipeline terminus (NDM-106) and ends at the inlet valve upstream of the emergency shut off valve at each injection wellhead	Continuous	Summary of ER probe monitoring results	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	File quarterly[4] Annual report[5]
		Pipeline inspection		PIG	PIG receiver upstream of the gas chromatograph on NDL-327 flowline	Once every 5 years	Summary of PIG monitoring results		
	Flow conditions (e.g., saturation point of water)	Real-time, continuous data recording with automated triggers and alarms via SCADA system		Real-time model with LDS software and multiple P/T gauges and Coriolis mass flowmeters	Flowmeter and P/T gauge near each injection wellhead and at pipeline terminus	Continuous	Operator statement about flowline operation conditions		
	Cathodic protection	Continuous data recording	Corrosion prevention of project materials	Impressed current cathodic protection (ICCP) system	Anodes buried along the length of NDL-327 flowline				
Wellbore Mechanical Integrity (external) Section 5.4	**Casing wall thickness**	Ultrasonic logging or other equivalent CIL and sonic array logging (inclusive of CCL, VDL, RCBL), and GR	Mechanical integrity demonstration and operational safety assurance	Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL) and GR	CO_2 injection and reservoir-monitoring wells	Repeat when required and when tubing is pulled during workovers	Mechanical integrity test (MIT), injection well test, well workover, and logging results and interpretations	NorthSTAR Sundry (e.g., casing/cement supplemental information; logs and testing – notification of work performed, supplemental information, etc.)	Mechanical integrity failures to be reported within 24 hours after event is confirmed by operator. File quarterly[4] if analysis is performed or log is acquired during quarter. Annual report[5]
	Radial cement bond								
	Saturation profile (behind casing)	PNL		PNL tool	CO_2 injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)			
	Temperature profile	Temperature logging		Temperature log	CO_2 injection and reservoir-monitoring wells	Annually only if DTS fails	MIT (i.e., annual external mechanical integrity demonstration test results) injection well test, well workover, and logging results and interpretations		
		Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable	Along the outside of the long-string casing of the CO_2 injection and reservoir-monitoring wells	Continuous			

Continued…

Table 5-2. Overview of Major Components of the Testing and Monitoring Plan – Injection (continued)

							Injection Reporting (20 years)		
Monitoring Type	**Parameter**	**Activity Description**	**Primary Purpose(s) of Activity**	**Equipment/Test**	**Location**	**Sampling Frequency**	**Report Content (N.D.A.C. § 43-05-01-18)[1]**	**Reporting Method**	**DMR-O&G Reporting Schedule[2,3]**
Wellbore Mechanical Integrity (internal) Section 5.4	**P/T**	Real-time, continuous data recording via SCADA system	Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Between surface and long-string casing annulus on CO_2 injection and reservoir-monitoring wells	Continuous	Wellhead temperatures and pressures (surface casing)	Form 26 – Carbon Dioxide Storage Report – SFN 18667; NorthSTAR Sundry (e.g., casing/cement supplemental information; logs and testing – notification of work performed, supplemental information, etc.)	Mechanical integrity failures to be reported within 24 hours after event is confirmed by operator. Form 26 – Monthly File quarterly[4] Annual report[5]
	Annulus pressure	Tubing-casing annulus pressure testing		Pressure testing truck with pressure chart	CO_2 injection and reservoir-monitoring wells	Repeat during workover operations in cases where the tubing must be pulled and no less than once every 5 years.	Monthly average maximum and minimum annular pressure; MIT or well workover results and interpretations; description of event that exceeds operating procedures		Mechanical integrity failures to be reported within 24 hours after event is confirmed by operator. Form 26 – Monthly File report by quarter[4] in which the analysis is performed. Annual report[5]
	P/T	Real-time, continuous data recording via SCADA system		Digital surface P/T gauge	Between tubing and long-string casing annulus of CO_2 injection and reservoir-monitoring wells	Continuous	Wellhead temperatures and pressures (annulus)		Mechanical integrity failures to be reported within 24 hours after event is confirmed by operator. Form 26 – Monthly File quarterly[4] Annual report[5]
	Annular fluid level		Prevention of microannulus and monitoring annular fluid volume	N2 cushion on tubing-casing annulus with seal pot system	On well pad for each CO_2 injection well		Monthly annulus fluid volumes added		
	P/T		Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Tubing of CO_2 injection and reservoir-monitoring wells		Wellhead temperatures and pressures (tubing) and monthly average, maximum, and minimum injection pressure		
	Saturation profile (tubing-casing annulus)	PNL		PNL tool	CO_2 injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Year 1, Year 3, and at least every 3 years thereafter (e.g., Years 6, 9, 12, etc.)	MIT, injection well test, well workover, and logging results and interpretation		File report by quarter[4] in which the log is acquired. Annual report[5]

Continued . . .

Table 5-2. Overview of Major Components of the Testing and Monitoring Plan – Injection (continued)

							Injection Reporting (20 years)		
Monitoring Type	**Parameter**	**Activity Description**	**Primary Purpose(s) of Activity**	**Equipment/Test**	**Location**	**Sampling Frequency**	**Report Content (N.D.A.C. § 43-05-01-18)[1]**	**Reporting Method**	**DMR-O&G Reporting Schedule[2,3]**
Downhole Corrosion Detection Section 5.6.2	**Saturation profile** (behind casing)	PNL	Corrosion detection of project materials in contact with CO_2 and operational safety assurance	PNL tool	CO_2 injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Year 1, Year 3, and at least once every 3 years thereafter	Logging results and interpretations	NorthSTAR Sundry (e.g., casing/cement supplemental information)	File quarterly[4] in which the log is acquired. Annual report[5]
	Casing wall thickness	Ultrasonic logging or other equivalent CIL and sonic array logging (inclusive of CCL, VDL, and RCBL), and GR		Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL), and GR	CO_2 injection and reservoir-monitoring wells	Repeat when required and when tubing is pulled during workovers			
Near-Surface Sections 5.7.1 and 5.7.2	**Soil gas composition** (see Table 5-7)	Soil gas sampling (see Figure 5-4)	Assurance near-surface environment is protected	Two soil gas profile stations: MSG01 and MSG04	One station per CO_2 injection and reservoir-monitoring well pad	Collect 3–4 seasonal samples annually per station (no isotopes; perform concentration analysis)	Summary of lab results	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	Any CO_2 release of CO_2 to the atmosphere or biosphere requires 24-hour notification. File quarterly[4] Annual report[5]
	Water composition (see Table 5-9)	Groundwater well sampling (see Figure 5-4)	Assurance that USDWs are protected	Up to four existing groundwater wells from the Tongue River, Cannonball–Ludlow, and Fox Hills Aquifers (e.g., MGW01, MGW03, MGW04, and MGW09)	AOR	At start of injection, shift sampling program to MGW11. For MGW01, collect 3–4 seasonal samples annually in Year 2 and reduce to annually thereafter.			
	Water composition		Assurance that lowest USDW is protected	Fox Hills monitoring well	MGW11 adjacent to CO_2 injection well pad; additional wells may be phased in overtime as the CO_2 plume migrates.	3–4 seasonal samples in Years 1–4 and reduce to annually thereafter. (water quality only; no isotopic testing)			
Above-Zone Monitoring interval Opeche/Spearfish to Skull Creek Section 5.7.3.1	**Saturation profile**	PNL	Assurance of containment in the storage reservoir and protection of USDWs	PNL tool	CO_2 injection and reservoir-monitoring wells	Year 1, Year 3, and at least every 3 years thereafter	Logging results and interpretations	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	File by quarter[4] in which the log is acquired. Annual report[5]
	Temperature profile	Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable		Continuous			
		Temperature logging		Temperature log		Annually only if DTS fails			

Continued . . .

Table 5-2. Overview of Major Components of the Testing and Monitoring Plan – Injection (continued)

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Frequency	Injection Reporting (20 years)		
							Report Content (N.D.A.C. § 43-05-01-18)[1]	**Reporting Method**	**DMR-O&G Reporting Schedule[2,3]**
Storage Reservoir (direct) Sections 5.7 and 5.7.3.2	**P/T**	Real-time, continuous data recording via SCADA system	Storage reservoir monitoring and conformance with model and simulation projections	Casing-conveyed downhole P/T gauge	CO$_2$ injection wells	Continuous	Downhole temperatures and pressures	Form 26 – Carbon Dioxide Storage Report – SFN 18667; NorthSTAR Sundry (e.g., logs and testing – supplemental information)	Form 26 - monthly File quarterly[4] Annual report[5]
				Tubing-conveyed downhole P/T gauge	Reservoir-monitoring well				
	Temperature profile			DTS casing-conveyed fiber-optic cable	CO$_2$ injection and reservoir-monitoring wells		Logging results and interpretations		File by quarter[4] in which the analysis is performed or log is acquired. Annual report[5]
		Temperature logging		Temperature log		Annually only if DTS fails			
	Storage reservoir performance	Injectivity testing	Demonstration of storage reservoir performance	Pressure falloff tests	CO$_2$ injection wells	Once every 5 years per well after the start of injection	Injection well test results		
Storage Reservoir, (indirect) Section 5.7.3.3	**CO$_2$ saturation**	3D time-lapse seismic surveys (see Figure 5-6)	Site characterization and CO$_2$ plume tracking to ensure conformance with model and simulation projections	Vibroseis trucks (source) and geophones and DAS fiber-optic cable (receivers)	Within AOR	Repeat 3D seismic survey by the end of Year 2 and in Years 4 and 9 and at least once every 5 years thereafter.	Summary of seismic results and interpretations	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	File by quarter[4] in which the analysis is performed. Annual report[5]
	Seismicity	Continuous data recording	Seismic event detection and source attribution and operational safety assurance	Seismometer stations and DAS fiber optics	Area around injection wells (within 1 mile)	Continuous			Report on seismic events detected within 24 hours. File quarterly[4] Annual report[5]

[1] In addition to the reports, submittals, notifications, and other information described in Table 5-1 and N.D.A.C. § 43-05-01-18, Reporting Requirements, the Director may require other additional information to be reported not outlined in Table 5-1.

[2] SCS1 will notify the Director as soon as possible of any planned changes which may result in noncompliance with permit requirements.

[3] Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements shall be submitted no later than 30 days following each scheduled reporting date. SCS1 shall file with the Director an annual report that summarizes the quarterly reports.

[4] The storage operator shall file with the Director quarterly, or more frequently, if the Director requires. The quarterly report shall also contain events that trigger a shutoff device and any monitoring results.

[5] SCS1 shall file with the Director an annual report that summarizes the quarterly reports and include projections of the response and storage capacity of the storage reservoir including anomalies and assumptions. All anomalies in predicted behavior as indicated in permit conditions or in the assumptions upon which the permit was issued must be explained and, if necessary, the permit conditions amended in accordance with N.D.A.C. § 43-05-01-12. The annual report is due 45 days after the end of the year.

[6] SCS1 shall verbally report noncompliance or malfunction within 24 hours from the time SCS1 became aware of the circumstances. A written submission shall also be provided within 5 days of the time SCS1 became aware and include a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

5.1 CO_2 Stream Analysis

The CO_2 stream will be monitored during injection operations to accurately measure CO_2 volumes transported from the CO_2 flowline to the CO_2 injection wellheads (TB Leingang 1 and 2). A pressure/temperature (P/T) gauge and Coriolis mass flowmeter installed near each of the CO_2 injection wellheads will provide continuous, real-time measurements of the injection volume, flow rate, pressure, and temperature of the CO_2 stream during operations. The equipment will be spliced to a supervisory control and data acquisition (SCADA) system and have automated triggers and alarms for notifying the operations center in the event of any anomalous readings.

Another goal of monitoring the CO_2 stream is to ensure materials and equipment in contact with the stream are protected. Prior to injection, SCS1 determined the composition of each individual CO_2 source and the resultant CO_2 stream to establish a system specification, as shown in Table 5-3. Selected flowline and well materials are designed to meet or exceed the system specification. Any new CO_2 streams from third-party entities not accounted for at the time of permitting must also meet or exceed the system specification once commingled with the existing CO_2 stream as described in Table 5-3.

Table 5-3. CO_2 Stream System Specification

Chemical Content	System Specification
Carbon Dioxide, CO_2	≥98.25%
Inert, N_2	≤1.44%
Oxygen, O_2	≤0.31%
Water, H_2O*	≤20 lb/MMscf
Total Hydrocarbons*	≤1800 ppm by volume
Hydrogen Sulfide, H_2S*	≤10 ppm by volume
Total Sulfur, S*	≤10 ppm by volume
Glycol	≤0.3 gallons/MMscf

* Denotes trace constituents that do not make up notable percentages of stream composition.

N.D.A.C. § 43-05-01-11.4(1)(a) requires "[a]nalysis 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." Key chemical and physical characteristics of interest include composition, corrosiveness, temperature, and density (N.D.A.C. § 43-05-01-11[9][b]). SCS1 plans to sample the CO_2 stream continuously with a gas chromatograph installed on the injection well pad. The gas chromatograph will be spliced to the SCADA system to collect real-time data. Tables 5-1 and 5-2 specify the CO_2 stream-sampling strategy.

For isotopic analysis of the CO_2 stream, a sample port will be placed upstream of the gas chromatograph to collect samples. Figure 5-1 illustrates the anticipated ranges for stable carbon isotopes from various CO_2 source signals. At the time of permitting, the CO_2 stream is expected to be sourced by ethanol (biofuel) facilities. Therefore, the corresponding stable carbon isotope signature of the CO_2 stream is anticipated to be approximately –10 ‰ to –20 ‰, as shown in Figure 5-1. If sources of CO_2 other than ethanol are added that were not originally accounted for at the time of permitting, SCS1 will repeat sampling of the CO_2 stream within a year of adding the new CO_2 source(s) to redetermine its isotopic signature.

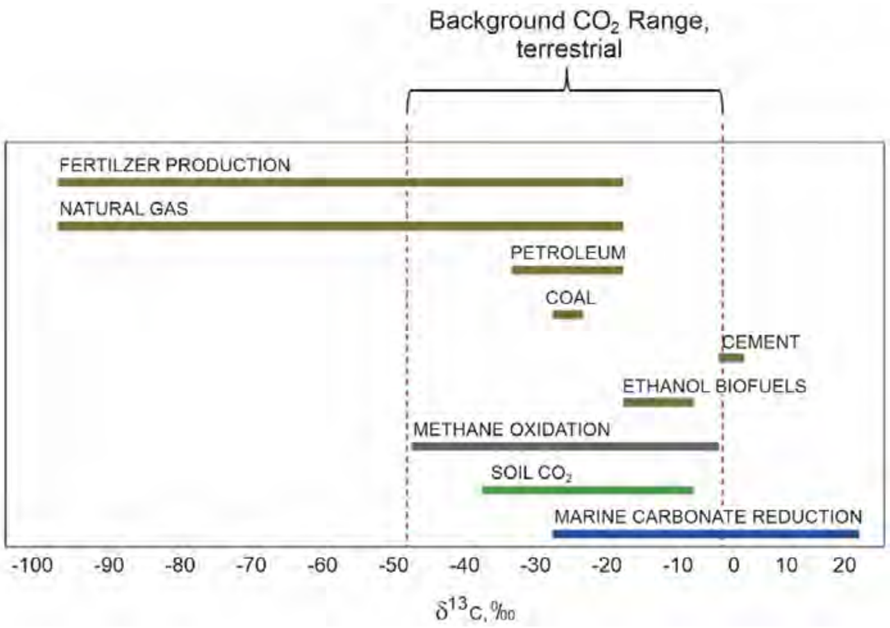


Figure 5-1. Stable carbon isotope signatures of various CO_2 source signals (Dixon and Romanak, 2015).

5.1.1 CO_2 Stream Analysis QASP

SCS1 will follow manufacturer guidelines to regularly calibrate and maintain the gas chromatograph (specification sheet provided in Appendix D, Attachment D-1). The gas chromatograph will measure the CO_2 stream's individual chemical components for concentration analysis using a thermal conductivity detector. The onboard electronics and software will calculate the concentrations of each individual chemical component and output the results in a tabulated format, similar to what is shown in Table 5-3. CO_2 stream analysis with the gas chromatograph will be performed at regularly scheduled intervals determined by SCS1 that meets N.D.A.C. § 43-05-01-11.4(1)(a). Isotopic analyses of the CO_2 stream will be outsourced to commercial laboratories that will employ standard analytical quality assurance/quality control (QA/QC) protocols used by the industry. CO_2 stream sampling will be performed at regularly scheduled intervals determined by SCS1 that meets N.D.A.C. § 43-05-01-11.4(1)(a) and analyzed by a third-party commercial laboratory.

5.2 Surface Facilities Leak Detection Plan

The purpose of this leak detection plan is to specify the monitoring strategies SCS1 will use to quantify any losses of CO_2 from surface facilities during operations. Surface facilities include the CO_2 injection wellheads (TB Leingang 1 and 2), the reservoir-monitoring wellhead (Milton Flemmer 1), and the NDL-327 CO_2 flowline, which begins at the pipeline terminus of NDM-106 and ends at the inlet valve upstream of the automated emergency shutoff valve at each CO_2 injection wellhead. Figure 5-2 illustrates the CO_2 flowline path to CO_2 injection wellsite, and Figure 5-3 is a generalized flow diagram from the pipeline terminus of NDM-106 to the CO_2 injection wellheads, illustrating key surface facilities' connections and monitoring equipment.

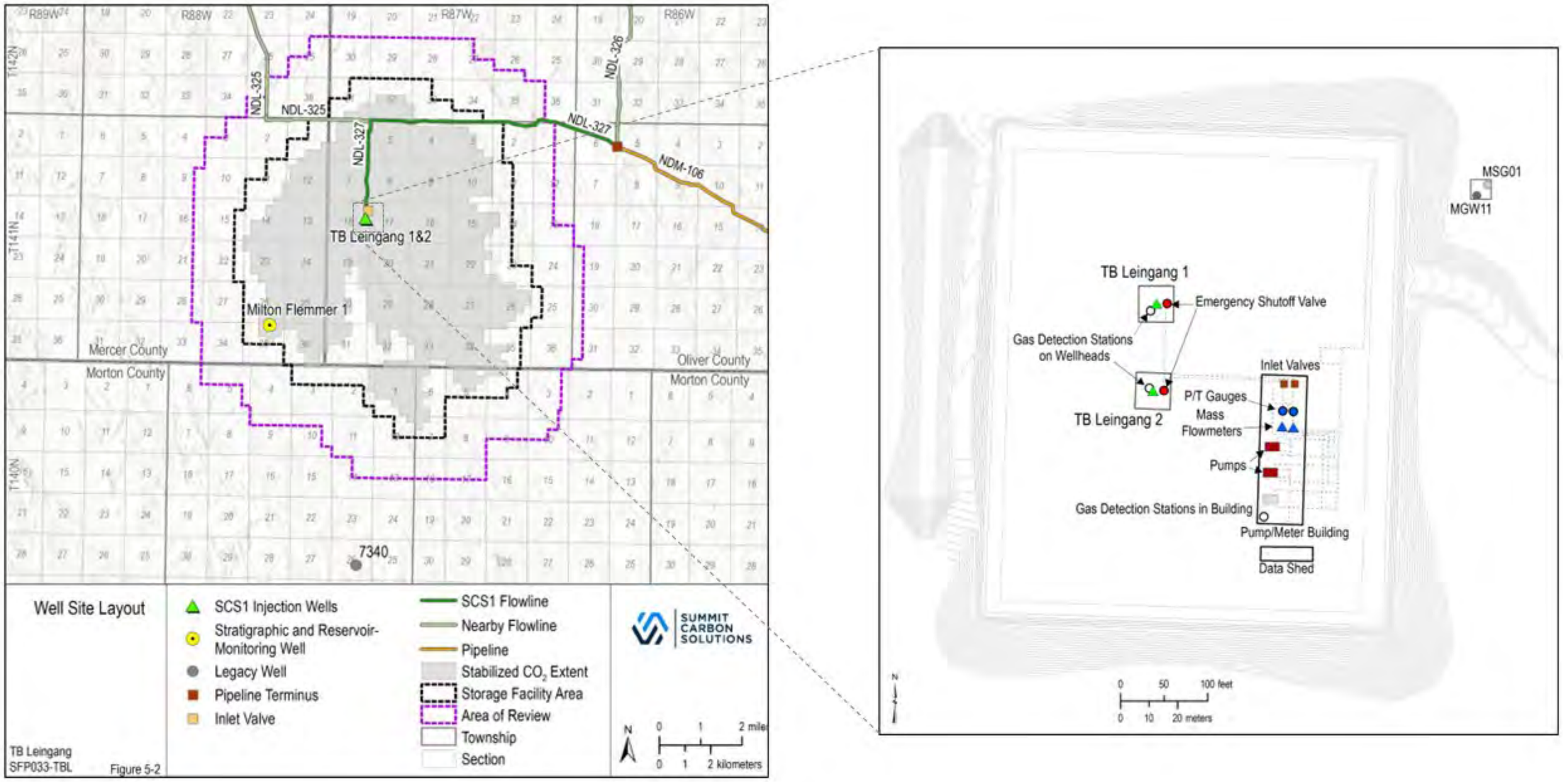


Figure 5-2. Map detailing CO_2 flowline path to CO_2 injection wellsite (left) and layout of surface facilities at the wellsite (right), illustrating key surface facility leak detection and monitoring equipment. Soil gas profile station, MSG01, and groundwater well, MGW11, off-pad monitoring locations are also shown on the surface facilities map inset.

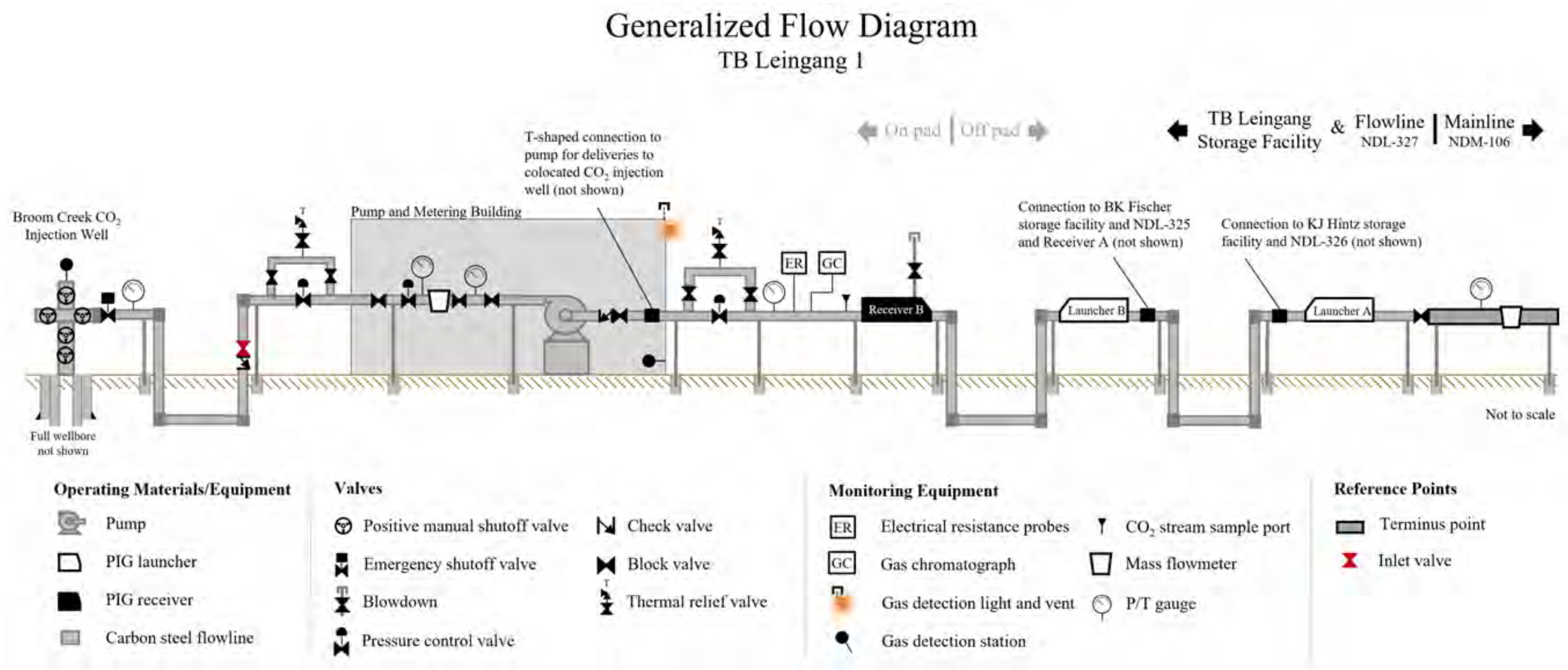


Figure 5-3. Generalized flow diagram from the pipeline terminus to the TB Leingang 1 CO_2 injection well, illustrating key surface facilities' connections and monitoring equipment. The flow diagram is identical for the TB Leingang 2 CO_2 injection well (not shown).

As illustrated in Figure 5-3, leak detection equipment includes 1) P/T gauges along the flowline, 2) a Coriolis mass flowmeter placed near each of the injection wellheads, and 3) gas detection stations placed on the CO_2 injection wellheads pursuant to N.D.A.C. § 43-05-01-14(1) and inside the pump/metering building. The gas detection stations, which will detect gases such as CO_2, methane (CH_4), and hydrogen sulfide (H_2S), will have automated triggers and alarms to alert SCS1 of any anomalous readings. The SCADA system, which will continuously collect data streams from the leak detection equipment in real time, will also monitor for leaks with leak detection software.

Field personnel from SCS1 will have multigas detectors with them for visiting wellsites or conducting flowline inspections. In addition, gas detection safety lights (part of the integrated alarm system) will be placed outside of the pump/metering building to warn field personnel of potential indoor air quality threats.

5.2.1 Data Sharing and Custody Transfer

The entire CO_2 flowline (NDL-327), which begins at the pipeline terminus of NDM-106 and ends at the inlet valve upstream of the automated emergency shutoff valve at each CO_2 injection wellhead, will be owned by SCS1 and operated by SCS Carbon Transport LLC (Figure 5-3). NDL-327 consists of 8.6 miles of 20- to 24-inch flowline within Oliver County.

NDM-106 and NDL-327 to the CO_2 injection wellsite will be operated as one integrated SCADA system with data flowing to a single operations center. SCS1; Summit Carbon Storage #2, LLC; Summit Carbon Storage #3, LLC; SCS Permanent Carbon Storage LLC; and SCS Carbon Transport LLC will share operational data and controls in real time and ensure operational parameters (e.g., flowline pressures) are safely maintained between all injection sites at all times. Data shared will include, but are not limited to, defining the financial and operational responsibilities, mass balance and custody transfers, data access and data sharing, and general operations including leak detection and reporting, emergency response, monitoring, and maintenance of NDL-327 and respective wellsites.

Custody transfer of the CO_2 will occur using flowmeters placed at each individual CO_2 capture facility prior to entering NDM-106 operated by SCS Carbon Transport LLC. Once the transported CO_2 stream reaches the NDM-106 pipeline terminus, the CO_2 will be metered with a Coriolis mass flowmeter to transfer custody from SCS Carbon Transport LLC to SCS1 at the start of the NDL-327 flowline. Separate Coriolis mass flowmeters will also be located at each CO_2 injection well (TB Leingang 1 and 2) and at each injection site associated with SCS2 and SCS3 for performing mass balance calculations and attributing injected CO_2 volumes per well (Figure 5-3).

5.2.2 Surface Facilities Leak Detection Plan QASP

Pursuant to N.D.A.C. § 43-05-01-14(1), the leak detection equipment will be inspected and tested on a semiannual basis. If equipment is defective, SCS1 will repair or replace the equipment within 10 days or, acting with good cause, SCS1 will propose an alternate timeline for approval by the DMR-O&G. Each repaired or replaced detector will be retested, if required. The gas detection stations are described in Appendix D, Attachment D-2. The SCADA system and leak detection software are described in further detail in Appendix D, Attachment D-3, and the personnel multigas detectors are described in Appendix D, Attachment D-4. SCS1 will install the leak detection equipment according to the manufacturer's recommendations.

The flowline will be regularly inspected for any visual or auditory signs of equipment failure. Any release of CO_2 to the atmosphere or near-surface environments from the surface facilities will be reported to DMR-O&G within 24 hours pursuant to N.D.A.C. § 43-05-01-18(9)(e).

5.2.2.1 NDL-327 Flowline Design

The NDL-327 flowline will be manufactured with a high-frequency electrical resistance weld or double submerged arc weld process. Based upon volume requirements and pressure service, the 20/24-inch NDL-327 flowline design is summarized in Table 5-4.

Table 5-4. NDL-327 Flowline Design Specification[1]

Parameter	Design Specification
Maximum Operating Pressure	2183 psig
Maximum Discharge Pressure[2]	2160 psig
Typical Operating Pressure	1250–2150 psig
Design Temperature (above-grade piping)	−50°–120°F
Design Temperature (below-grade piping)	23°–120°F
Anticipated CO_2 Stream Temperature Range	30°–115°F
Maximum Design Flow Rate	936 million scf per day[3]

[1] Abbreviation used in table: pounds per square inch gauge; standard cubic foot

[2] At pump stations or individual capture facilities.

[3] Approximately equivalent to 18 million tonnes of CO_2 annually.

The NDL-327 flowline and associated structures will be designed, constructed, inspected, tested, and operated in accordance with industry standards. The flowline will be constructed of high-strength carbon steel pipe, exceeding the American Petroleum Institute (API) 5L (2018) Pipe Specification. API 5L is the industry standard specification for seamless and welded steel line pipes used in pipeline transportation systems, including the energy industry. These regulations and industry standards specify pipeline and associated facilities materials and qualification and other controls to mitigate the risk of an incident while providing protection for the public and environment.

5.3 CO_2 Flowline Corrosion Prevention and Detection Plan

The purpose of this plan is to prevent and detect any signs of corrosion in the flowline.

5.3.1 Corrosion Prevention

To protect against corrosion, an external fusion-bonded epoxy coating will be applied to the NDL-327 flowline. Flowline installed by trenchless methods, such as road crossings, will also have an abrasion-resistant overcoat installed as a secondary coating, over the fusion-bonded epoxy, prior to installation.

SCS1 will install an impressed current cathodic protection (ICCP) system along the buried flowline to mitigate the threat of external soil corrosion on the line. The ICCP system, which will be continuously monitored, involves the installation of deep anode beds along the flowline that are connected to external power through a rectifier. The power provides the current needed to drive an electrochemical reaction whereby the anodes corrode instead of the flowline. Except for a rectifier, junction box, and small diameter vent pipe posted above the anode beds, the ICCP system will be buried.

Because the CO_2 stream will contain only trace amounts of water (Table 5-3), SCS1 will operate the surface facilities above the saturation point of water to prevent corrosive conditions from forming.

5.3.1.1 Corrosion Prevention QASP

The flowline construction materials will be in accordance with API 5L X-70 PSL 2 (2018) requirements, which includes applying external coatings to the pipe (e.g., fusion-bonded epoxy) and any borings or crossings (e.g., abrasive-resistant overcoats) to prevent corrosion. The flowline's ICCP system will be in accordance with Title 49 of the Code of Federal Regulations (CFR), Part 195 and will be pressure-tested prior to CO_2 injection operations. SCS1 will supply DMR-O&G with a map of cathodic protection borehole locations to meet N.D.A.C. § 43-05-01-05(1)(a) prior to injection.

5.3.2 Corrosion Detection

Real-time, continuous monitoring of the CO_2 flowline with P/T gauges and Coriolis mass flowmeter measurements from the pump/metering building to the terminus of the pipeline combined with continuous analysis of the CO_2 stream with the gas chromatograph will provide strong evidence that noncorrosive conditions are maintained in the flowline during injection operations. The equipment will be spliced to the SCADA system and have automated triggers and alarms for alerting SCS1 of any anomalous readings.

The flowline segment from the terminus of the pipeline to the pipeline inspection gauge (PIG) receiver (shown in Figure 5-3) will allow the passage of internal inspection devices (commonly referred to as "smart PIGs"), which are designed to detect certain internal and external anomalies in the line, such as loss of mass/wall thickness, dents, pitting, cracking, and scratches. The launchers and receiver facilities are designed to launch and receive these internal inspection devices along with other types of PIGs (e.g., maintenance pigs). The launchers and receivers will be located at standalone sites in Oliver and Mercer Counties. The frequency for running PIGs in the flowline during operations is described in Table 5-2.

In addition to the activities described above, SCS1 will install at least one electrical resistance (ER) probe along the CO_2 flowline upstream of the gas chromatograph to continuously monitor for loss of mass throughout the operational phase. The ER probe will be spliced to the SCADA system for real-time monitoring and will be removable for visual inspection and replacement, if required. The SCADA system will have automated triggers and alarms for alerting SCS1 of any anomalous readings.

5.3.2.1 Corrosion Detection QASP

SCS1 will utilize PIG equipment that has been maintained and calibrated according to the manufacturer's recommendations and 40 CFR Part 195 rules and regulations. The ER probe will be exposed to the CO_2 stream and spliced to the SCADA system for continuously measuring losses of mass to calculate a real-time corrosion rate. The ER measurements are mathematically translated into terms of changes in mass, and the results are plotted over time. Changes in the regression of the data trend correspond to changes in the corrosion rate. Changes in mass of the exposed probe material can be attributable to changes in the length or cross-sectional area of the probe material, which may include pitting. The ER probe will be spliced to the SCADA system and programmed with triggers and alarms for alerting the operations center of anomalous ER measurements. Specification sheets for the ER probe and data transmitter are provided in Appendix D, Attachments D-5 and D-6, respectively.

SCS1 will investigate anomalies in flowline operating parameters to ensure noncorrosive conditions are maintained during injection operations, including pulling the ER probe for inspection and replacement, as required by DMR-O&G.

5.4 Wellbore Mechanical Integrity Testing

Pursuant to N.D.A.C. § 43-05-01-11.1, SCS1 will conduct mechanical integrity testing of the CO_2 injection and reservoir-monitoring wellbores to ensure there is no significant leak in the casing, tubing, or packer and that there is no significant fluid movement into an USDW adjacent to the wellbore. Below is a summary of the methods that SCS1 will use to verify mechanical integrity. Tables 5-1 and 5-2 specify the sampling frequency for the set of activities described in this section.

External mechanical integrity in the CO_2 injection wells and reservoir-monitoring well will be demonstrated with the following:

1) Ultrasonic or other equivalent casing inspection log (CIL) and sonic array logging tools [inclusive of variable-density log (VDL), casing collar log (CCL), and radial cement bond log (RCBL)].

2) Pulsed-neutron logging (PNL) to examine the saturation profile behind casing from the Opeche/Spearfish Formation to surface. If repeat PNLs detect evidence of unexpected vertical migration of CO_2, then SCS1 will notify and work with DMR-O&G to identify and take appropriate action, such as pulling tubing and running an ultrasonic or other equivalent CIL tool for attributing the source of the suspected out-of-zone migration.

3) Distributed temperature sensing (DTS) fiber-optic cable installed outside of the long-string casing will continuously monitor the temperature profile of each wellbore from the storage reservoir to surface. A baseline temperature log will be acquired in case the DTS fiber-optic cable fails and temperature logging is required in the future pursuant to N.D.A.C. § 43-02-05-07(3)(b).

Internal mechanical integrity in the CO_2 injection wells and reservoir-monitoring well will be demonstrated with the following:

1) The surface and long-string casing annulus will be continuously monitored with a digital surface P/T gauge.

2) Tubing-casing annulus pressure testing.

3) The tubing-casing annulus pressure will be continuously monitored with a digital surface P/T gauge on each wellhead.

4) A seal pot system with a nitrogen (N_2) cushion will be used to continuously monitor and maintain the packer fluid pressure in the tubing-casing annular space at the surface below 300 psi. The N_2 cushion accommodates for packer fluid level/volume changes due to temperature fluctuations to ensure that the tubing-casing annular space is kept full.

5) The tubing conditions will be continuously monitored with a digital surface P/T gauge on each wellhead.

6) PNL to examine the saturation profile in the tubing-casing annulus from the Opeche/ Spearfish Formation to surface. If repeat PNLs detect evidence of unexpected vertical migration of CO_2, then SCS1 will notify and work with DMR-O&G to identify and take appropriate action, such as performing a tubing-casing annulus pressure test or pulling tubing and performing a casing pressure test or running an ultrasonic or other equivalent CIL tool for attributing the source of the suspected out-of-zone migration.

All digital P/T gauges mentioned in the plan will be spliced to the SCADA system for real-time monitoring. Wellbore schematics illustrating the monitoring equipment for the CO_2 injection wells and reservoir-monitoring well are shown in Figures 11-2, 11-4, and 11-5, respectively, in Section 11.0.

5.4.1 Wellbore Mechanical Integrity Testing QASP

Specification sheets for the ultrasonic, array sonic, and PNL tools are provided in Appendix D, Attachments D-7, D-8, and D-9, respectively, and specification sheets for the DTS fiber-optic cable and interrogator are provided in Appendix D, Attachments D-10 and D-11, respectively.

An example procedure for conducting an annulus pressure test prior to CO_2 injection is provided in Appendix D, Attachment D-12. A diagram of the seal pot system design is provided in Appendix D, Attachment D-13.

Digital surface P/T gauges will be maintained and calibrated according to the manufacturer's recommendations; copies of calibration certificate will be submitted. Pursuant to N.D.A.C. § 43-05-01-14(1), the leak detection equipment (i.e., P/T gauges on wellheads and seal pot system) will be inspected and tested on a semiannual basis. If equipment is defective, SCS1 will repair or replace the equipment within 10 days or, acting with good cause, SCS1 will propose an alternate timeline for approval by DMR-O&G. Each repaired or replaced detector will be retested, if required.

For all well-logging activities, SCS1 will ensure that third-party contractors follow industry standard or better QA/QC protocols. SCS1 will also ensure reports of logging activities are prepared by a qualified geologist or engineer.

SCS1 will contract a third-party entity to conduct a feasibility study to quantify the CO_2 detection capabilities using the proposed PNL method based on the design of the CO_2 injection and reservoir-monitoring wellbores. Results of the feasibility study will be submitted to DMR-O&G prior to injection.

5.5 Baseline Wellbore Logging and Testing Plan (Site Characterization)

Pursuant to N.D.A.C. § 43-05-01-11.2, SCS1 will collect baseline well-logging and -testing measurements from subsurface geologic formations in the CO_2 injection wellbores to 1) verify the depth, thickness, porosity, permeability, lithology, and salinity of the storage complex; 2) ensure conformance with the injection well construction requirements; and 3) establish accurate baseline data for making future time-lapse measurements. Baseline well-logging and -testing measurements will also be collected from the reservoir-monitoring well.

Table 5-5 specifies baseline well-logging and -testing activities completed in the reservoir-monitoring well (Milton Flemmer 1), and Table 5-6 identifies the well-logging and -testing plan for the TB Leingang 1. The plan for the TB Leingang 2 wellbore will be the same as what is presented for the TB Leingang 1 but may exclude dipole sonic logging (assuming dipole sonic logging is successful in the TB Leingang 1).

Tables 5-1 and 5-2 specify well-logging and -testing activities associated with establishing mechanical integrity and monitoring the deep subsurface, including the storage complex. Coring activities are described separately in the Section 9.0 as-drilled wellbore diagrams for TB Leingang 1 and 2 and in the text in Section 2.0 for Milton Flemmer 1.

SCS1 will provide DMR-O&G with an opportunity to witness all well-logging and -testing activities as required under N.D.A.C. § 43-05-01-11.2(6).

Table 5-5. Completed Logging and Testing Activities for Milton Flemmer 1

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

Table 5-6. Logging and Testing Plan for the TB Leingang 1 and TB Leingang 2 Wellbores

	Logging/Testing	Justification	N.D.A.C. § 43-05-01-11.2
Surface Section	Open-hole logs: triple combo, SP, caliper, and temperature	Quantify variability in reservoir properties, such as resistivity and lithology, and measure hole conditions.	(1)(b)(1)
	Cased-hole logs: ultrasonic tool or other CIL and array sonic tools (inclusive of CCL, VDL, and RCBL), GR, and temperature	Identify cement bond quality radially, evaluate the cement top and zonal isolation, and establish external mechanical integrity. Establish baseline temperature profile for temperature-to-DTS calibration.	(1)(b)(2) and (1)(d)
Long-String Section	Open-hole logs: quad combo (triple combo plus dipole sonic*), SP**, GR, and caliper	Quantify variability in reservoir properties, including resistivity, porosity, and lithology, and measure hole conditions. Provide input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve interpretations. Identify mechanical properties, including stress anisotropy. Provide compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.	(1)(c)(1)
	Open-hole log: fracture finder log	Quantify fractures in the Broom Creek Formation and confining layers to ensure safe, long-term storage of CO_2.	(1)(c)(1)
	Open-hole log: magnetic resonance log	Aid in interpreting reservoir permeability and determine the best location for modular formation dynamics testing (MDT) fluid-sampling depths, packer-setting depths, and stress-testing depths.	(1)(c)(1)
	Open-hole log: MDT fluid sampling and testing	Collect fluid sample from the Broom Creek Formation for analysis.	(1), (2), and (3)
	Open-hole log: spectral GR	Identify clays and lithology that could affect injectivity. Also used for core to log depth correlation.	(4)(b)
	Injectivity test	Perform to define the fracture gradient and maximum allowable injection pressure of the storage reservoir.	(4)
	Pressure falloff test	Perform to verify hydrogeologic characteristics of the Broom Creek Formation.	(5)
	Cased-hole log: PNL	Confirm mechanical integrity from Opeche/Spearfish Formation to surface.	11.4(g)(1)
	Cased-hole logs: ultrasonic tool or other CIL and array sonic tools (inclusive of CCL, VDL, and RCBL), GR, and temperature	Confirm cement bond quality radially, evaluate cement top and zonal isolation and demonstrate mechanical integrity. Establish baseline for casing inspection logging and temperature profile for temperature-to-DTS calibration.	(1)(c)(2) and (d)

* Dipole sonic logging may be excluded in TB Leingang 2 assuming that the dipole sonic log is successful in TB Leingang 1.

** A sundry will be submitted requesting a waiver of the SP log and that an alternative method providing equivalent data will be utilized instead upon the DMR-O&G's approval pursuant to N.D.A.C. § 43-05-01-11.2(e).

Wellbore data collected from the reservoir-monitoring well (Milton Flemmer 1) have been integrated with the geologic model to inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations (Section 3.0). 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.

5.5.1 Baseline Wellbore Logging and Testing Plan (Site Characterization) QASP

For all planned well-logging and -testing activities, SCS1 will ensure that third-party contractors follow industry standard or better QA/QC protocols for acquiring and processing the data and that reports of activities are prepared by a qualified geologist or engineer.

5.6 Wellbore Corrosion Prevention and Detection Plan

The purpose of this corrosion prevention and detection plan is to monitor the well materials to ensure they meet the minimum standards for material strength and performance, pursuant to N.D.A.C. § 43-05-01-11.4(1)(c).

5.6.1 Downhole Corrosion Prevention

To prevent corrosion of the well materials in the TB Leingang 1 and 2 wellbores, the following preemptive measures will be implemented: 1) cement opposite of the injection interval and extending to the differential valve (DV) staging tool above the top of the Mowry Formation will be CO_2-resistant; 2) the well casing will also be CO_2-resistant from the bottomhole to just above the Opeche/Spearfish Formation and from below the top of the Swift Formation to just below the top of the Skull Creek Formation; 3) the well tubing will be CO_2-resistant from the injection interval to surface; 4) the packer will be CO_2-resistant; and 5) the packer fluid will be an industry-standard corrosion inhibitor. The tubing-casing annulus will be filled with the packer fluid system that is planned to be a brine-based fluid treated with antimicrobial biocide, corrosion inhibitor, and oxygen scavenger to minimize potential corrosive effects of soluble oxygen.

To prevent corrosion of the well materials in the Milton Flemmer 1 wellbore, the following preemptive measures are implemented: 1) cement opposite the injection interval and extending above the confining zones is CO_2-resistant; 2) the well casing is CO_2-resistant from the cast iron bridge plug set at 6550 feet in the well (to 137 feet above the Opeche/Spearfish Formation and from 214 feet below the top of the Swift Formation to 178 feet above the top of the Mowry Formation); and 3) the packer fluid is an industry-standard corrosion inhibitor. The tubing-casing annulus will be filled with a brine-based packer fluid treated with biocide, corrosion inhibitor, and oxygen scavenger. In addition, SCS1 plans to reevaluate replacement of packer and bottomhole assembly during the 5-year evaluation.

Figures 11-2, 11-4, and 11-5 in Section 11.0 illustrate the downhole corrosion prevention measures in each of the wellbores.

5.6.1.1 Downhole Corrosion Prevention QASP

Specification sheets for the antimicrobial biocide, corrosion inhibitor, and oxygen scavenger treatment are provided in Appendix D, Attachments D-14, D-15, and D-16, respectively.

SCS1 will ensure that third-party contractors follow industry standard or better QA/QC protocols when drilling and completing each of the wells and that the selected well materials at a minimum meet the standards selected and presented in Sections 9.0, 10.0, and 11.0 of this permit application.

5.6.2 Downhole Corrosion Detection

PNLs will be run in the TB Leingang 1 and 2 and Milton Flemmer 1 wellbores to detect saturations of CO_2. Further investigative methods of inspecting for corrosion in the wellbore could include ultrasonic logging or other equivalent CIL when required. Tables 5-1 and 5-2 specify the sampling frequency for acquiring data related to this downhole corrosion detection plan.

5.6.2.1 Downhole Corrosion Detection QASP

If the PNLs detect possible signs of out-of-zone vertical migration, SCS1 will work with DMR-O&G to take appropriate action, such as running an ultrasonic tool or other equivalent CIL to confirm downhole conditions in the wellbore. For any logging activities related to corrosion detection, SCS1 will ensure that third-party contractors follow industry standard or better QA/QC protocols and that reports of logging activities are prepared by a qualified geologist or engineer.

5.7 Environmental Monitoring Plan

To verify the injected CO_2 is contained in the storage reservoir, protect all USDW, and demonstrate hydrogeologic properties of the storage reservoir, multiple environments will be monitored.

As required by N.D.A.C. § 43-05-01-11.4(1)(d) and (h), the near-surface environment, defined as the region from the surface down to the lowest USDW (Fox Hills Aquifer), will be monitored by sampling and analyzing vadose-zone soil gas at two soil gas profile stations, one new Fox Hills monitoring well, and up to four existing groundwater wells.

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 confining zone above the storage reservoir to the confining zone above the next permeable zone above the storage reservoir (i.e., Opeche/Spearfish Formation to the Skull Creek Formation). The AZMI will be continuously monitored with DTS fiber optics in the TB Leingang 1 and 2 wellbores as well as PNLs.

Pursuant to N.D.A.C. § 43-05-01-11.4(1)(g), the storage reservoir will be monitored with both direct and indirect methods. Direct methods include continuous fiber optics (DTS) and downhole P/T measurements in the TB Leingang 1 and 2 and Milton Flemmer 1 and falloff tests and PNLs in the TB Leingang 1 and 2 wellbores. Falloff testing analysis will provide reservoir pressure data and the completion condition including transmissibility, skin factor, and well flowing and static pressure data for technical adequacy to demonstrate no migration from the reservoir. Indirect methods include time-lapse seismic surveys. These efforts will provide assurance that surface and near-surface environments are protected and that the injected CO_2 is safely and permanently contained in the storage reservoir. In addition, SCS1 will install multiple seismometer stations for passively detecting and locating seismic events.

5.7.1 Soil Gas Monitoring

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. Two permanent soil gas profile stations installed adjacent to both the CO_2 injection and Milton Flemmer 1 well pads will be sampled, as shown in Figure 5-4. Figure 5-5 is a typical wellbore schematic of a soil gas profile station.

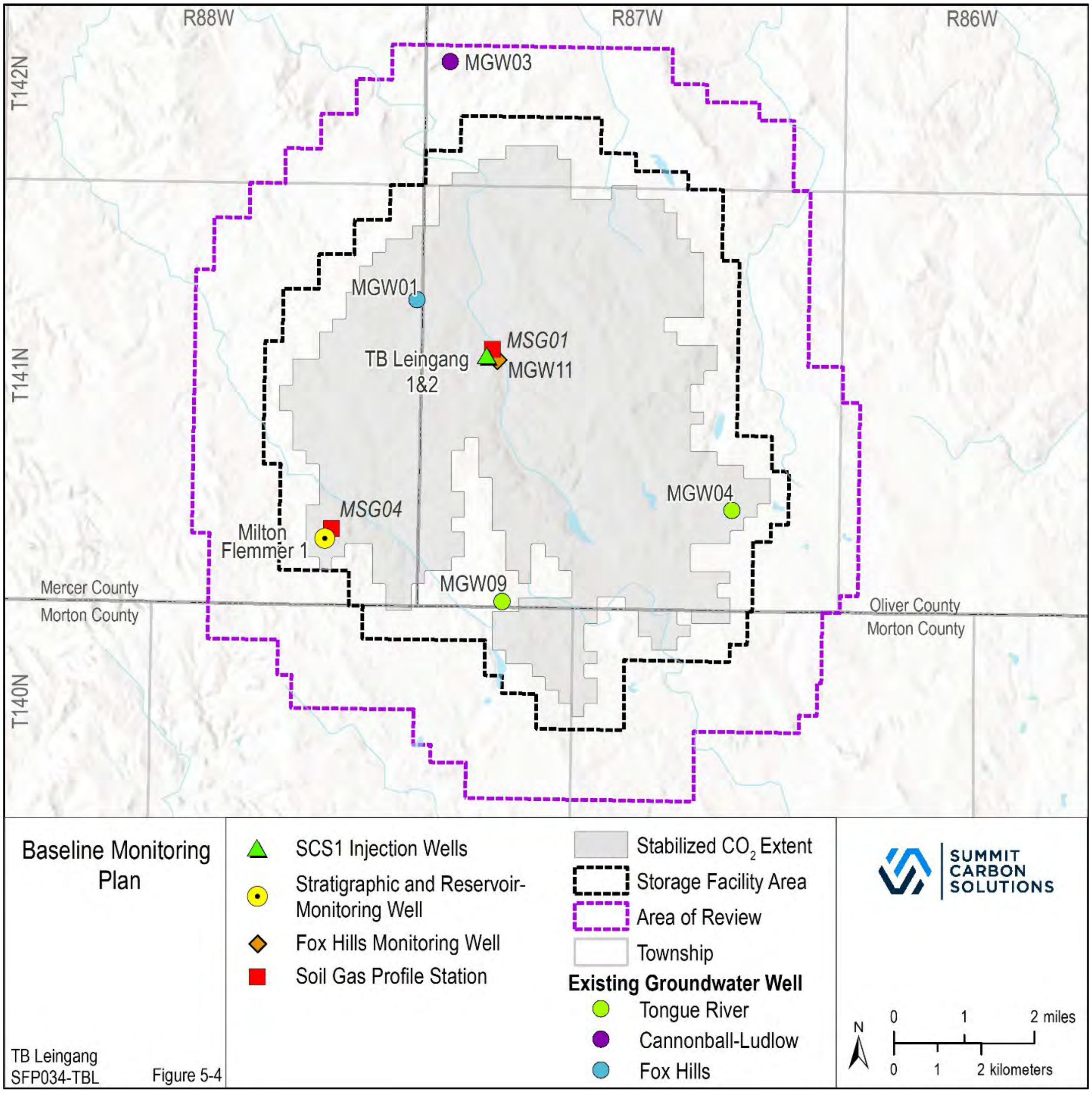


Figure 5-4. SCS1 baseline and operational near-surface sampling locations.

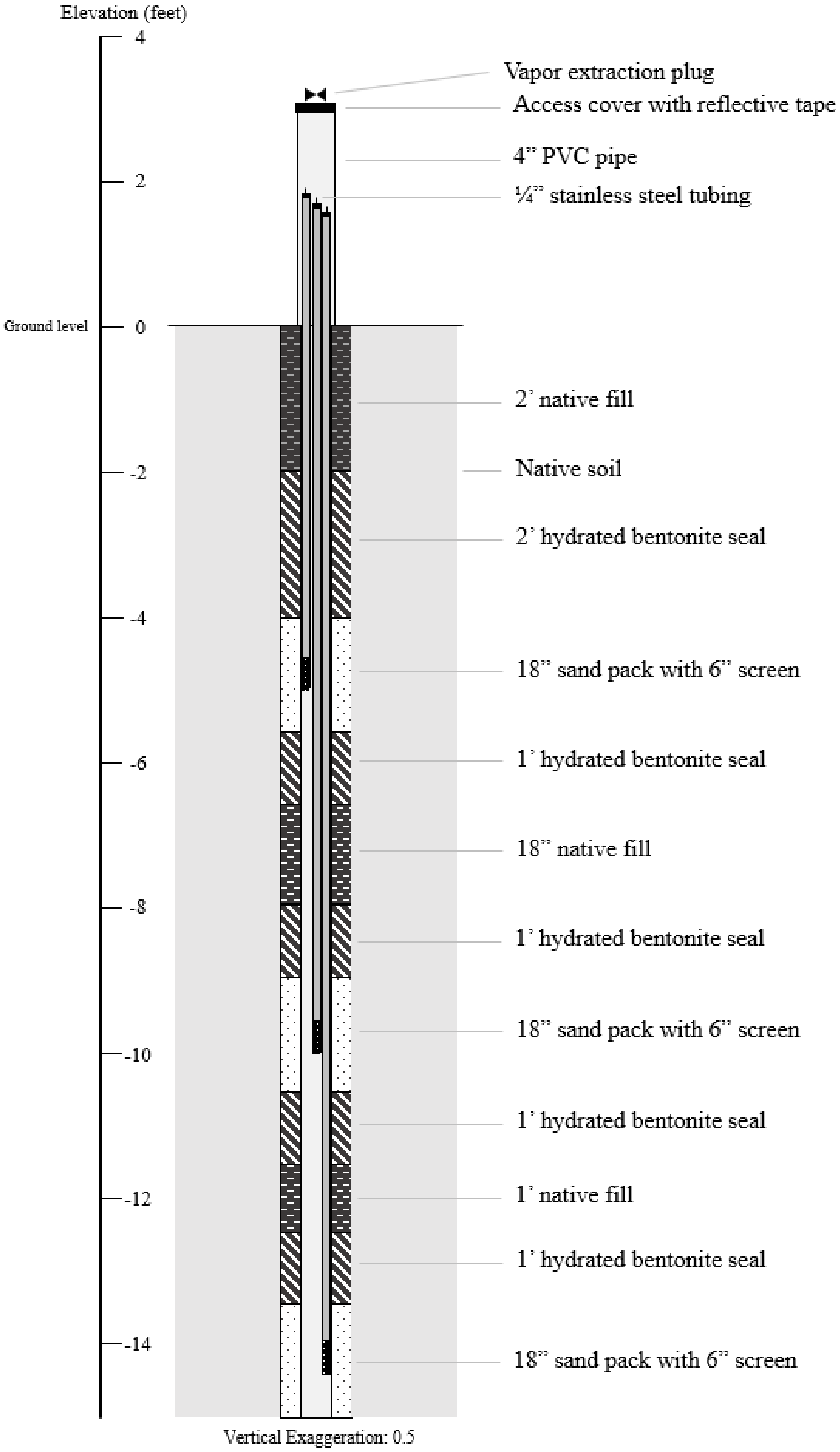


Figure 5-5. A typical wellbore schematic of a soil gas profile station.

The sampling frequency for soil gas is summarized in Tables 5-1 and 5-2. During injection, SCS1 may install additional replacement or alternative soil gas sampling sites based on monitoring data results. SCS1 will notify DMR-O&G if either replacement or alternative soil gas sampling sites are added pursuant to N.D.A.C. § 43-05-01-18(2). The results of the baseline soil gas sampling program will be provided to DMR-O&G prior to injection.

5.7.1.1 Soil Gas Monitoring QASP

Tables 5-7 and 5-8 indicate a minimum set of analytes that will be included for the soil gas analysis.

Table 5-7. Soil Gas Compositional Analysis – Primary Components

Analyte	Units
N_2	Volume %
O_2	Volume %
CO_2	Volume %
Ar	Volume %
CH_4	Volume %

Table 5-8. Stable and Radiocarbon Isotope Soil Gas Measurements

Isotope	Units
$\delta^{13}C$ of CO_2 and CH_4	‰ (per mil)
$\delta^{14}C$ of CO_2 and CH_4	‰ (per mil)
δD of CH_4	‰ (per mil)

At minimum, SCS1 will ensure that third-party service providers apply a standard procedure for sampling the wells, such as the one provided below. Figure 5-5 is a typical wellbore schematic of a soil gas profile station.

Example Soil Gas Profile Station Sampling Procedure

Prior to the collection of each sample, a minimum of three probe casing volumes will be removed, and the representativeness of the gas flow will be determined by analyzing the soil gas over time for CO_2, total volatile organic compounds (VOCs), and O_2 using a handheld multigas meter. The handheld meter will be calibrated daily during sampling based on manufacturer instructions. After these measurements of the soil gas composition stabilize, two soil gas samples will be collected for characterization at each location using an air sampling bag and labeled with the appropriate sample number and site information. The samples will be sent to third-party laboratories for analysis.

Soil Gas Sampling QA/QC Procedures

SCS1 will ensure that third-party service providers selected for soil gas sampling and analysis follow industry standard sampling and analytical QA/QC protocols, including collection of field blanks and duplicate (replicate) samples to identify environmental contamination and evaluate repeatability in sampling and analytical methods, respectively.

5.7.2 Groundwater Monitoring

Groundwater monitoring directly measures the chemical constituents of the water in the pore space between grains of subsurface geologic formations (aquifers) and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. Figure 5-4 identifies the sampling locations associated with the near-surface baseline and operational monitoring plan, which includes one new Fox Hills monitoring well, and up to four existing groundwater wells.

SCS1 will work with landowners of the four existing groundwater wells (MGW01, MGW03, MGW04, and MGW09) to attempt to collect samples as specified in Tables 5-1 and 5-2. The number of samples collected from each existing groundwater well may vary by location, since some of the groundwater wells may not be operated year-round or site accessibility may be limited (e.g., snow cover during winter months). If SCS1 is ever unable to access the wells due to operational status or access concerns, it will document the reason why it was unable to take samples. An attempt was made to identify alternative wells that operate year-round with reduced access concerns but produced no results.

SCS1 will install one Fox Hills monitoring well (MGW11) adjacent to the injection well pad (as shown in Figure 5-4). The Fox Hills monitoring well will be sampled according to the sampling frequency specified in Tables 5-1 and 5-2.

SCS1 reserves the right to evaluate and modify, if necessary, appropriate groundwater sampling locations and frequency based on conformance of the CO_2 plume extent in the subsurface. SCS1 will notify DMR-O&G if alternative or new water wells are added to the sampling program pursuant to N.D.A.C. § 43-05-01-18(2).

Appendix B includes a supplemental baseline dataset of historic geochemistry results for four groundwater wells within the area of review (AOR) boundary. The data were obtained from the Department of Water Resources (DWR) website. The wells are DWR 9433, 9053, 9055, and 9056, as shown in Figure B-1. These shallow groundwater wells were excluded from the baseline and operational monitoring plan primarily because they did not meet the depth criterion used to select wells for inclusion in the testing and monitoring plan.

5.7.2.1 Groundwater Monitoring QASP

State-certified commercial laboratories will be identified by SCS1 to analyze the water samples for the analytes described in Tables 5-9 and 5-10.

Table 5-9. General Analytes for Groundwater Samples

Analyte	Cation (total and dissolved)	Anion (total)
pH	Aluminum	Bromide
Conductivity	Antimony	Chloride
Alkalinity	Arsenic	Fluoride
TDS	Barium	Nitrate
Total Organic Carbon (TOC)	Beryllium	Nitrite
Dissolved Organic Carbon (DOC)	Boron	Sulfate
	Cadmium	
	Calcium	
	Chromium	
	Cobalt	
	Copper	
	Iron	
	Lead	
	Lithium	
	Magnesium	
	Manganese	
	Mercury	
	Molybdenum	
	Nickel	
	Potassium	
	Selenium	
	Silicon	
	Silver	
	Sodium	
	Strontium	
	Thallium	
	Phosphorus	
	Vanadium	
	Zinc	

Table 5-10. Stable and Radiocarbon Isotope Measurements in Groundwater

Isotope	Units
δD H_2O	‰ (per mil)
$\delta^{18}O$ H_2O	‰ (per mil)
$\delta^{13}C$ Dissolved Inorganic Carbon (DIC)	‰ (per mil)
^{3}H H_2O	‰ (per mil)
$\delta^{14}C$ DIC	‰ (per mil)

SCS1 will select third-party service providers to collect groundwater samples and ensure that standard industry QA/QC procedures are followed. At minimum, SCS1 will ensure that third-party service providers apply a standard procedure for sampling the wells, such as the one provided below.

Example Groundwater Well Sampling Procedure

Groundwater samples will be collected by a third party from the dedicated Fox Hills monitoring well as well as other shallower groundwater wells, specified by SCS1 and with landowner approval, using a submersible pump. The standard procedure for sampling the wells is provided below:

1. Purge the well, removing a minimum of three casing volumes.

2. Wait for field measurements to stabilize and collect the sample.

    a. Record the location of the sample point.
    b. Collect field readings: temperature, conductivity, and pH.

    Fill appropriate sample containers for analysis with minimum headspace and refrigeration/cooling (chill each sample to ≤6°C) to reduce microbial activity.

3. Collect a duplicate sample from about 1 in every 10 samples for QA/QC purposes.

Groundwater Sampling QA/QC Procedures

SCS1 will ensure that third-party service providers selected for groundwater sampling and analysis follow industry standard sampling and analytical QA/QC protocols, including collection of field blanks and duplicate (replicate) samples to identify environmental contamination and evaluate repeatability in sampling and analytical methods, respectively.

5.7.3 Deep Subsurface Monitoring

Pursuant to N.D.A.C. § 43-05-01-11.4(1)(g), SCS1 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 direct and indirect storage reservoir monitoring methods described in this subsection of the permit application will be used to characterize the CO_2 plume's saturation and pressure within the AOR for the baseline and operational phases.

5.7.3.1 Above-Zone Monitoring Interval

Monitoring of the AZMI during injection operations includes monitoring of the temperature and saturation profiles from the Opeche/Spearfish Formation through the Skull Creek Formation. Temperature in the AZMI will be continuously monitored via DTS fiber-optic cable installed in the TB Leingang 1 and 2 and Milton Flemmer 1 wellbores. The plan for acquiring saturation data from PNLs is described in Tables 5-1 and 5-2.

5.7.3.2 Above-Zone Monitoring Interval QASP

SCS1 will ensure that all continuous monitoring devices (e.g., fiber optics) are inspected and maintained in accordance with the manufacturer's recommendations. For any logging activities, SCS1 will ensure that third-party contractors follow industry standard or better QA/QC protocols and that reports of logging activities are prepared by a qualified geologist or engineer.

Time-lapse data from the PNLs will be used to ensure CO_2 is not detected in the AZMI as an assurance-monitoring technique for evaluating the performance of the storage complex and protecting USDW.

5.7.3.3 Direct Reservoir Monitoring

DTS fiber optics installed in the TB Leingang 1 and 2 and Milton Flemmer 1 wellbores will directly monitor the temperature of the storage reservoir. P/T readings from the casing-conveyed gauges in the CO_2 injection wells will also monitor conditions in the storage reservoir. To track the pressure front from CO_2 injection in the storage reservoir, pressure will be measured continuously from the downhole tubing-conveyed P/T gauge installed in the Milton Flemmer 1 well. To track the CO_2 plume in the storage reservoir, the DTS fiber-optic cable and temperature measurements from the downhole P/T gauge installed in the Milton Flemmer 1 well be used to estimate the timing of arrival of the CO_2 plume at the reservoir-monitoring well. The pressure and temperature data will be used to ensure the monitoring data from the Broom Creek Formation (from Amsden Formation through Opeche/Spearfish Formation) is conforming to the geologic model and numerical simulations. Pressure falloff tests will be performed in the CO_2 injection to demonstrate the performance of the storage reservoir.

5.7.3.4 Direct Reservoir Monitoring QASP

SCS1 will ensure that all continuous monitoring devices (e.g., fiber optics and downhole P/T gauges) are inspected and maintained in accordance with the manufacturer's recommendations. Downhole P/T gauges will be calibrated within one year of initial installation; copies of calibration certificate will be submitted. Example specification sheets for the casing-conveyed downhole P/T gauges in the CO_2 injection wells and tubing-conveyed P/T gauge in the reservoir-monitoring well are provided in Appendix D, Attachments D-17 and D-18, respectively. For any logging activities, SCS1 will ensure that third-party contractors follow industry standard or better QA/QC protocols and that reports of logging activities are prepared by a qualified geologist or engineer.

5.7.3.5 Indirect Reservoir Monitoring

SCS1 will acquire 3D time-lapse seismic surveys to track the extent of the CO_2 plume within the storage reservoir. The 200-mi^2 3D Beulah seismic survey referenced in Section 2.0 will serve as the baseline survey. To demonstrate conformance between the reservoir model simulation and site performance, localized 3D seismic surveys will be collected to monitor the extent of the CO_2 plume, as shown in Figure 5-6 and detailed in Table 5-2.

SCS1 will reevaluate the testing and monitoring plan, inclusive of the design and frequency of the repeat 3D seismic surveys, at least once every 5 years, as required. If necessary, the time-lapse seismic monitoring strategy will be adapted based on updated simulations of the predicted extents of the CO_2 plume, including expanding the 3D survey area to capture additional data as the CO_2 plume expands in the storage reservoir.

SCS1 plans to install multiple seismometer stations to continuously monitor for seismic events with a magnitude of >1.5 within the AOR boundary during injection. The 3D seismic survey data (e.g., velocity modeling) collected within the AOR boundary will provide supporting evidence for confidently locating seismic events. A traffic light system for detecting larger magnitude events (e.g., >2.7) is presented with the Indirect Reservoir Monitoring QASP section of this application.

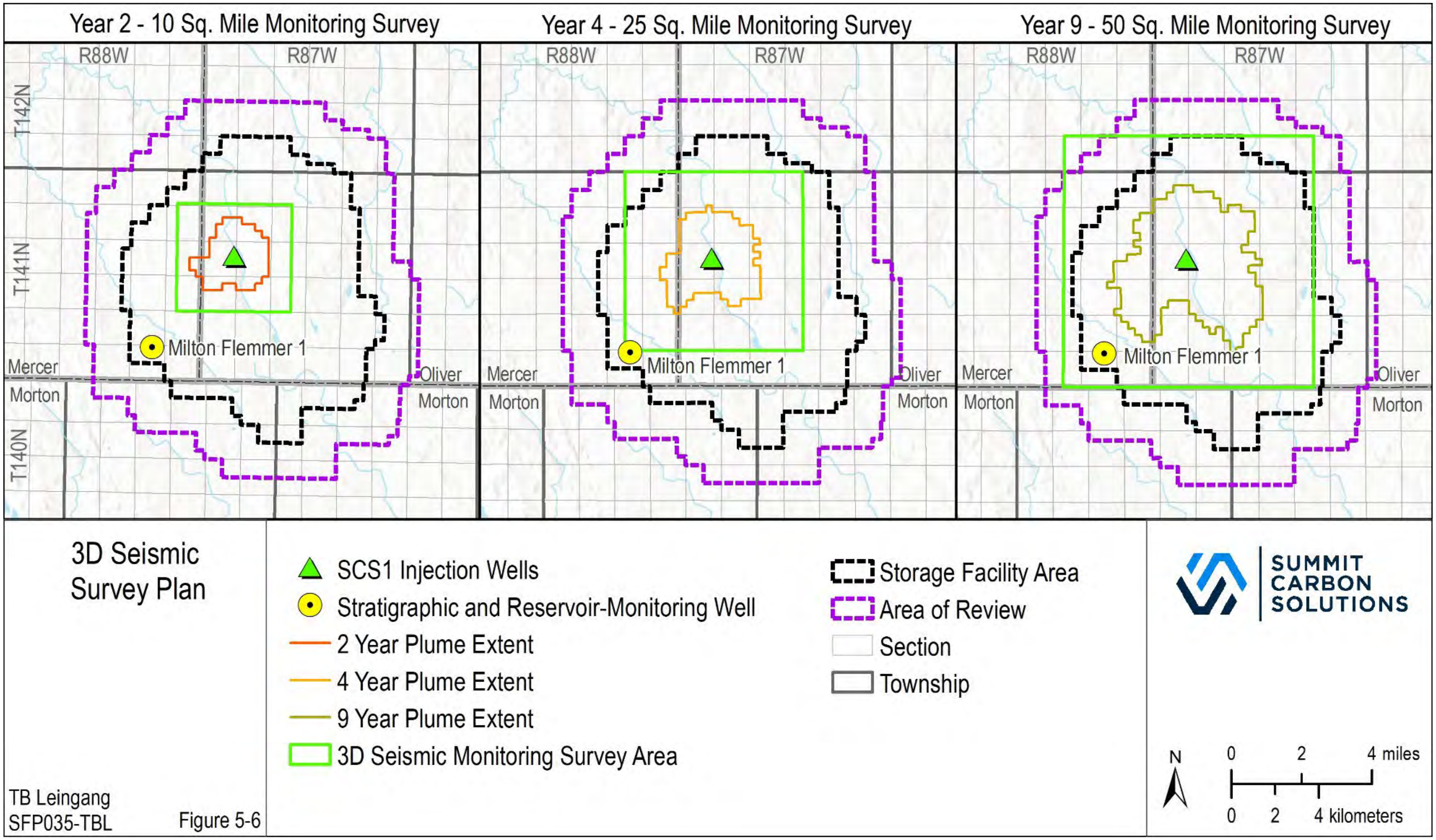


Figure 5-6. Simulated extent of the CO_2 plume at the end of Years 2, 4, and 9. The green boxes show the planned 3D seismic monitoring survey extents.

5.7.3.5.1 Indirect Reservoir Monitoring QASP

The geophysical monitoring that is planned for the project includes 3D time-lapse seismic surveys. Time-lapse seismic surveys provide a measurement of the change in acoustic properties of the storage formation as injected CO_2 saturates the storage interval.

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 seismic quality (Lumley and others, 1997, 2000) that can be quantified once the processed data are analyzed by an experienced seismic interpreter.

For seismic survey acquisitions, SCS1 will follow the required permitting process pursuant to North Dakota Century Code (N.D.C.C.) § 38-08.1-04 and N.D.A.C. § 43-02-12-04. Seismic acquisition and processing are performed by highly specialized companies and crews that provide the equipment, procedures, and QA/QC protocols based on the technology selected for acquisition and parameters for processing the data. SCS1 will work with third-party contractors to select the appropriate equipment, procedures, QA/QC protocols, acquisition and processing parameters, and seismic interpreters for all repeat surveys.

5.7.3.5.2 Seismicity Monitoring

The Williston Basin is a tectonically stable region of the North American Craton. A total of 13 events have been detected in North Dakota since 1870. While few seismic events have been recorded in the region, SCS1 plans to maintain a surface array during injection to ensure the safe operation of both the storage facility and associated infrastructure. This seismic monitoring will be conducted with a surface array of seismometer stations.

5.7.3.5.3 Seismicity Monitoring QASP

SCS1 will work with third-party contractors and landowners to ensure proper design and installation of the passive seismicity monitoring array. The design and installation of the seismometer station array is performed by specialized contractors including the following activities:

- Project management support to design seismometer array, model network performance, coordinate permitting and equipment installation, testing and maintenance, and ensuring optimum execution of project.

- Field operation to deploy surface seismic station instrumentation, power and communication systems, data quality, and commissioning.

- Data acquisition, system configuration, and processing setup.

- Continuous support and monitoring for data verification and QA/QC.

- Continuous near-real-time reporting, including analyst review and alert notifications for events at or above predetermined magnitude thresholds over the seismic area.

SCS1 will follow a traffic light system if a seismic event is recorded by either the local or public national array during injection operations.

Traffic Light System

If an event is recorded by either the local private array or the public national array to have occurred within 3 miles of an injection well, SCS1 will implement its Emergency Remedial and Response Plan (Section 7.0) subject to detected earthquake magnitude limits defined below:

- For an event >2.7 located within 3 miles of injection, SCS1 will closely monitor seismic activity and may implement a pause to operations or continue operations at a reduced rate, should analysis indicate a causal relationship between injection operations and detected seismicity. If the event is not related to the storage facility operation, the operator will resume normal injection rates.

- For an event >4.0 located within 3 miles of injection, SCS1 will stop injection and perform an inspection in surface facilities and wells. If there is no damage, the operator will reduce the injection rate by not less than 50% and perform a detailed analysis to determine if a causal relationship exists. If the event is not related to the storage facility operation, the operator will resume normal injection rates. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity. Such plans are dependent on the pressures and seismicity observed and may include but not be limited to:
  - Pausing operations until reservoir pressures fall below a critical limit.
  - Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

- For an event >4.5 located within 3 miles of injection, the operator will stop injection. The operator will inform the regulator of seismic activity and inform them that operations have stopped pending a technical analysis. The operator will initiate an inspection of surface infrastructure for damage from the earthquake. A detailed analysis is conducted to determine if a causal relationship exists between injection operations and observed seismic activity. If the event is not related to the storage facility operation, and previously approved by the regulators, the operator will resume normal injection rates in steps, increasing the surveillance. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity before resuming injection operations. Such plans are dependent on the pressures and seismicity observed and may include but not be limited to:
  - Pausing operations until reservoir pressures fall below a critical limit.
  - Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

5.8 Reporting Requirements

SCS1 shall retain the following records for a period of at least 10 years from the date of sample, measurement, or report:

- All data collected for the application of the storage facility permit, injection well permit, and operation of injection well permit.
- Data on the nature and composition of all injected fluids collected pursuant to N.D.A.C. § 43-05-01-11.4(1).
- All records from the closure period, including well plugging reports, postinjection site care data, and the final assessment.
- Upon project completion, SCS1 shall deliver any required records described in N.D.A.C. § 43-05-01-18(11).

SCS1 shall retain the following records for a period of at least 10 years from the date of sample, measurement, or report (N.D.A.C. § 43-05-01-18[12]):

- Monitoring data collected pursuant to N.D.A.C. § 43-05-01-11.4(b-i).
- Calibration and maintenance records.
- All original strip chart records for continuous monitoring instrumentation.
- Copies of all reports required by the storage facility permit.

5.8.1 Surface Facilities Leak Detection Reporting

Leak detection equipment at the wellhead of TB Leingang 1, TB Leingang 2, and Milton Flemmer 1 will be inspected and tested on a semiannual basis. If detection equipment is found to be defective, it will be repaired or replaced within 10 days of operator being aware of failure. An extension of time to repair or replacement of a leak detector may be granted by DMR-O&G upon SCS1 showing good cause. Semiannual inspection records will be maintained by SCS1 for at least 10 years and will be made available to DMR-O&G upon request pursuant to N.D.A.C. § 43-05-01-14(1).

5.9 Adaptive Management Approach

SCS1 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 DMR-O&G for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by

DMR-O&G. 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.

5.10 References

American Petroleum Institute, 2018, Line Pipe: API Specification 5L, Forty-Sixth Ed., April 2018, Errata 1, May 2018, 210 p.

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.

Dixon, T., and Romanak, K.D., 2015, Improving monitoring protocols for CO_2 geological storage with technical advances in CO_2 attribution monitoring: International Journal of Greenhouse Gas Control, v. 41, p. 29–40, doi: 10.1016/j.ijggc.2015.05.029.

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.

SECTION 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 Summit Carbon Storage #1, LLC (SCS1) will perform following the cessation of CO_2 injection to achieve final closure and issuance of a certificate of project completion. An overview of postinjection testing and monitoring activities is provided in Table 6-1. The postinjection testing and monitoring data will provide evidence that the injected CO_2 plume is stable (i.e., CO_2 migration will be unlikely to cross the storage facility area [SFA] boundary).

Pursuant to North Dakota Administrative Code (N.D.A.C.) § 43-05-01-19(1)(d), SCS1 proposes to submit the PISC monitoring results annually to the Department of Mineral Resources Oil and Gas Division (DMR-O&G).

Table 6-1. Overview of Postinjection Testing and Monitoring Activities[1]

Monitoring Type/SFP Reference	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Frequency (10 years minimum)
Wellbore Mechanical Integrity (external)/ Section 6.2.1	Material wall thickness	Ultrasonic or other equivalent casing inspection log (CIL) and sonic array logging	Mechanical integrity confirmation and operational safety assurance	Ultrasonic or other equivalent CIL and sonic array tools	Milton Flemmer 1	Repeat when required and when tubing is pulled during workovers.
	Radial cement bond					
	Temperature profile	Continuous data recording		Distributed temperature sensing (DTS) fiber		Continuous
		Temperature logging		Temperature log		Annually only if DTS fiber fails
	Saturation profile	Pulsed-neutron log (PNL)		PNL tool		Repeat PNL in Year 4 and Year 9 of postinjection. Run log from Opeche/Spearfish Formation to surface.
Wellbore Mechanical Integrity (internal)/ Section 6.2.1	Pressure/temperature	Continuous data recording via supervisory control and data acquisition (SCADA) system		Digital surface pressure gauge on the casing annulus (between surface and long-string sections)	Milton Flemmer 1	Continuous
		Tubing-casing annulus pressure testing		Surface pressure/temperature (P/T) gauge on tubing-casing annulus		Repeat during workover operations in cases where the tubing must be pulled and no less than every 5 years.
		Continuous data recording via SCADA system		Digital surface P/T gauge on tubing-casing annulus		Continuous
		Continuous data recording via SCADA system		Digital surface P/T gauge on tubing		Continuous
	Saturation profile	PNL		PNL tool		Repeat PNL in Year 4 and Year 9 of postinjection. Run log from Opeche/Spearfish Formation to surface.
Downhole Corrosion Detection/ Section 6.2.1	Saturation profile	PNL	Corrosion detection of project materials in contact with CO_2	PNL tool	Milton Flemmer 1	Repeat PNL in Year 4 and Year 9 of postinjection. Run log from Opeche/Spearfish Formation to surface.
	Material wall thickness	Ultrasonic or other equivalent CIL		Ultrasonic or other approved CIL tools		Repeat when required and when tubing is pulled during workovers.[2]

[1] Pursuant to N.D.A.C. § 43-05-01-19(1)(d), SCS1 proposes to submit monitoring results annually. The annual report is due 45 days after the end of the year.

[2] If PNL indicates out-of-zone migration, the operator will work with DMR-O&G to take appropriate action.

Continued…

Table 6-1. Overview of Postinjection Testing and Monitoring Activities (continued)

Monitoring Type/SFP Reference	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Frequency (10 years minimum)
Near Surface/ Section 6.2.2	Soil gas composition (e.g., CO_2, N_2, and O_2)	Soil gas sampling	Protection of near-surface environment	Field meter and sample bags	MSG01 and MSG04	Collect 3–4 seasonal samples at each station (MSG01 and MSG04) in Year 1 and Year 3 of postinjection and every 3 years thereafter (e.g., Years 6 and 9) and perform concentration analysis on all samples.
	Water composition (e.g., pH, total dissolved solids [TDS], and conductivity)	Groundwater sampling	Protection of underground sources of drinking water (USDWs)	Field meter and sample containers	MGW01	Collect 3–4 seasonal samples in Year 1 and Year 3 of postinjection and at least once every 3 years thereafter until facility closure (anticipated in Year 10 of postinjection).
					MGW04	Collect 3–4 seasonal samples in Year 4 of postinjection and prior to facility closure.
					MGW03 and MGW09	Collect 3–4 seasonal samples prior to facility closure (anticipated in Year 10 of postinjection).
					MGW11	Collect samples from MGW11 annually until facility closure (anticipated in Year 10 of postinjection).
Above-Zone Monitoring Interval/ Section 6.2.3	Temperature profile	Continuous data recording via SCADA system	Assurance of containment in storage reservoir	DTS casing-conveyed fiber-optic cable	Milton Flemmer 1	Continuous
		Temperature logging		Temperature log		Annually only if DTS fiber fails
	Saturation profile	PNL		PNL tool		Repeat PNL in Year 4 and Year 9 of postinjection. Run log from Opeche/Spearfish Formation to surface.
Storage Reservoir (direct)/ Section 6.2.3	Pressure/temperature	Continuous data recording via SCADA system	Pressure front tracking	Tubing-conveyed P/T gauge	Milton Flemmer 1	Continuous
	Temperature profile	Continuous data recording via SCADA system	CO_2 plume tracking	DTS casing-conveyed fiber-optic cable		Continuous
Storage Reservoir (indirect)/ Section 6.2.3	CO_2 saturation	Time-lapse seismic monitoring	CO_2 plume tracking	Time-lapse seismic surveys with source and receivers	Within area of review (AOR) boundary (CO_2 plume extents)	Actual design to be determined based on reevaluations of the testing and monitoring plan (Section 5.0) and migration of the CO_2 plume over time. Collect multiple repeat time-lapse seismic surveys during postinjection, with the first survey occurring by Year 4 of postinjection.

[1] Pursuant to N.D.A.C. § 43-05-01-19(1)(d), SCS1 proposes to submit monitoring results annually. The annual report is due 45 days after the end of the year.

[2] If PNL indicates out-of-zone migration, the operator will work with DMR-O&G to take appropriate action.

Based on the current simulations of 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 (SFA) boundary (Section 3.0), confirming nonendangerment of USDWs within the AOR. Based on these projections, a minimum 10-year postinjection monitoring period is planned to confirm CO_2 plume extent and postinjection stabilization pursuant to North Dakota Century Code (N.D.C.C.) § 38-22-17. Monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume and nonendangerment of USDWs. The nature and duration of that extension will be determined based on an update of this plan and DMR-O&G approval.

In addition to the foregoing postinjection monitoring program, the CO_2 injection wells will be plugged as described in the plugging plan (Section 10.0). All surface equipment not associated with long-term monitoring will be removed, and all surface land associated with the project will be reclaimed as close as is practicable to its predisturbance condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site and be submitted to DMR-O&G as part of a facility closure report. After application by the storage operator, NDIC shall consider issuing a certificate of project completion after notice and hearing pursuant to N.D.C.C. § 38-22-17.

6.1 Predicted Postinjection Subsurface Conditions

6.1.1 Pre- and Postinjection Pressure Differential

Model simulations were performed to predict the change in pressure in the Broom Creek Formation during and after the cessation of CO_2 injection. The simulations were conducted for 20 years of CO_2 injection in the Broom Creek Formation at an average total rate of 6.22 MMt/yr, followed by a postinjection period of 10 years.

Figure 6-1 illustrates the predicted pressure differential at the cessation of CO_2 injection. At the time that CO_2 injection ceases, the models predict an increase in the pressure of the reservoir, with a maximum pressure differential of 938 psi at the TB Leingang well pad. There is insufficient pressure increase caused by CO_2 injection to move more than 1 m^3 of formation fluids from the storage reservoir to the lowest USDW. The details of the pressure evaluation are provided as part of the AOR delineation discussion within Section 3.0 of this application.

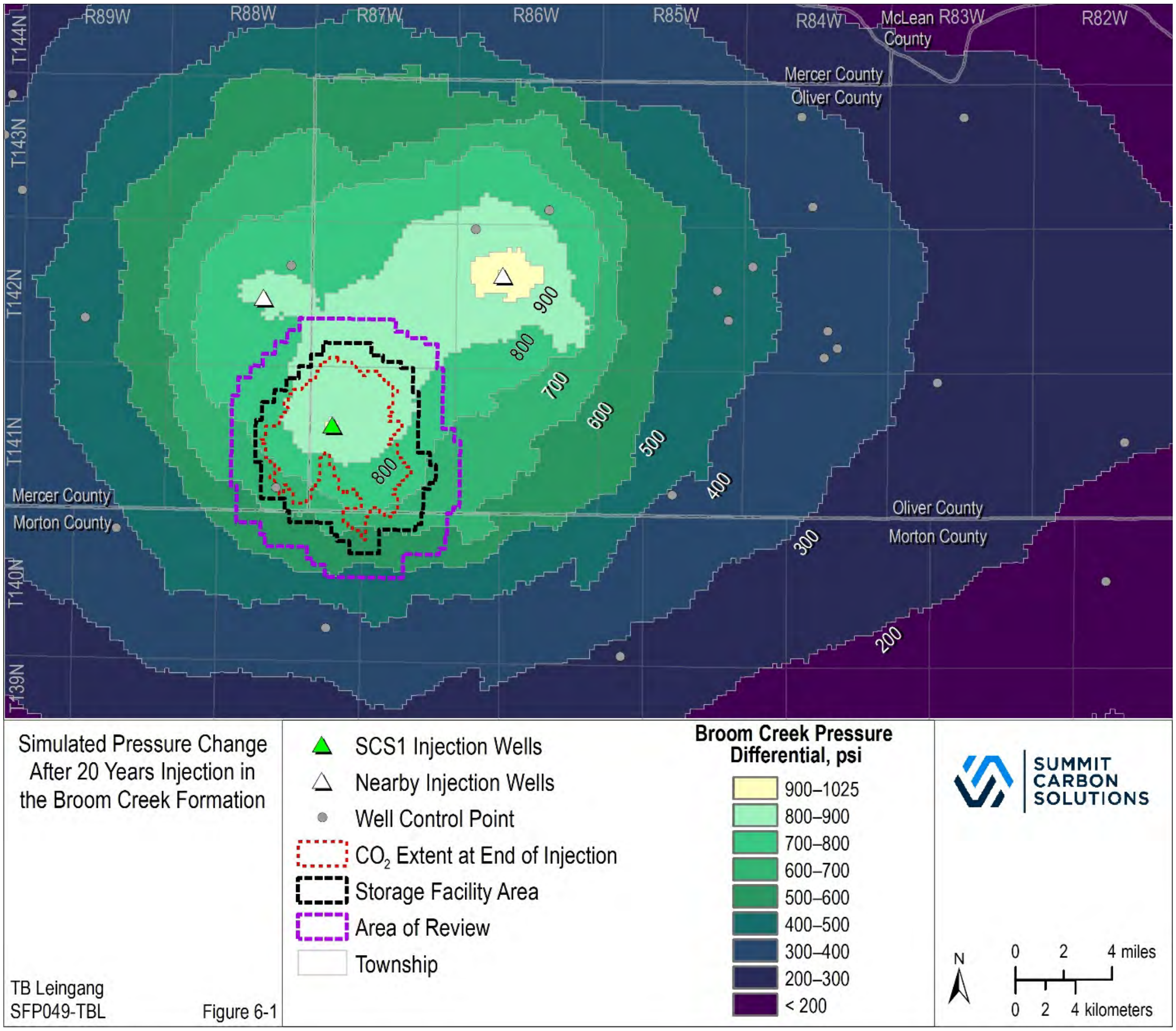


Figure 6-1. Predicted pressure increase in the storage reservoir following 20 years of injection of an average 6.22 MMt/yr of CO_2.

Figure 6-2 illustrates the predicted gradual pressure decrease in the storage reservoir over a 10-year period following the cessation of CO_2 injection. The pressure at the TB Leingang CO_2 injection well pad at the end of the 10-year period is anticipated to decrease 600–650 psi as compared to the pressure in the storage reservoir at the time CO_2 injection ends. This trend of decreasing pressure is anticipated to continue over time until the pressure of the storage reservoir approaches the original reservoir pressure conditions.

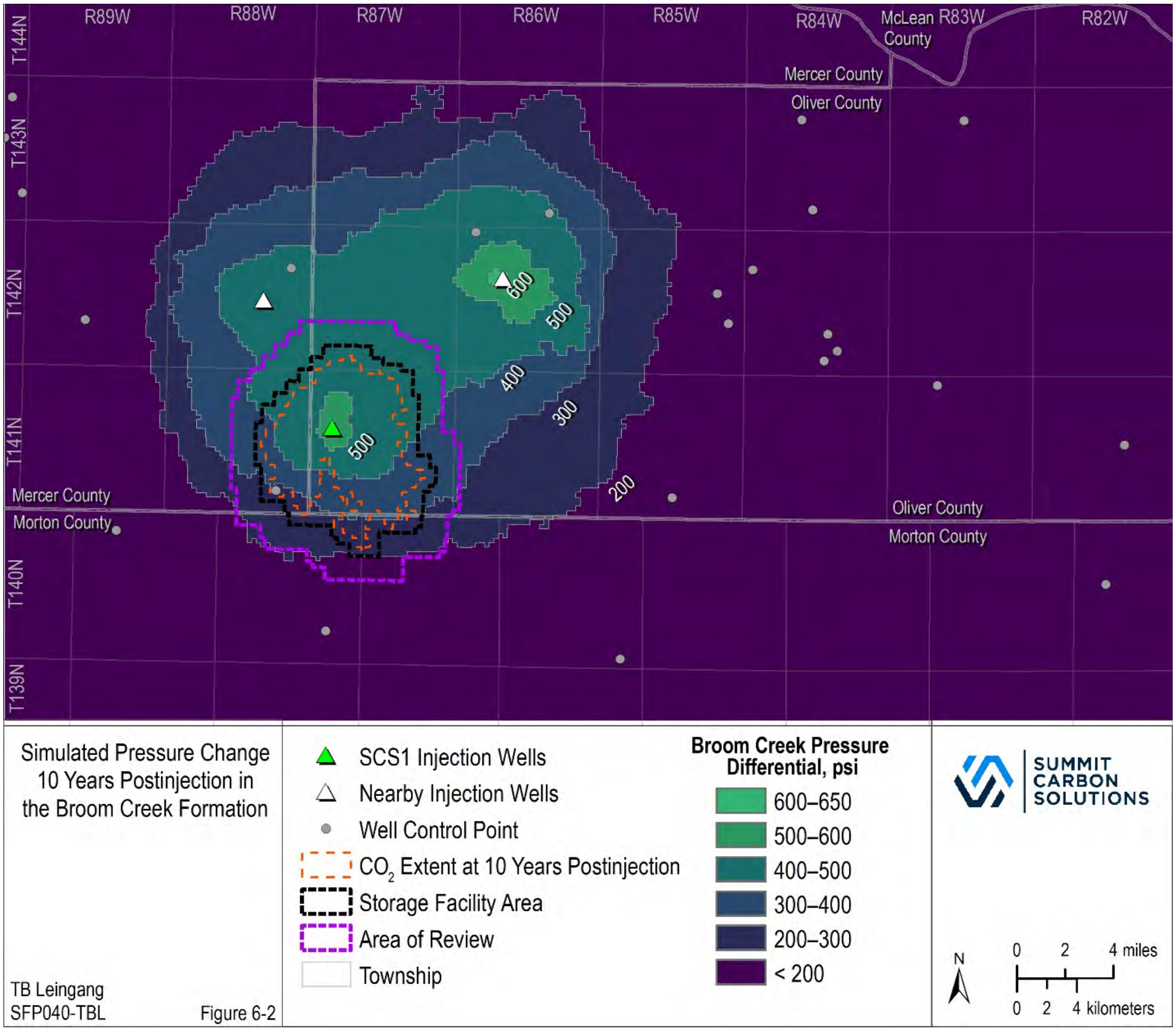


Figure 6-2. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection.

6.1.2 Predicted Extent of CO_2 Plume

Figure 6-2 illustrates the extent of the CO_2 plume following the planned 10-year PISC period, which is based on numerical simulation predictions. The results of these simulations predict that the CO_2 plume extent will expand to an area of 30-mi^2 by the end of the 10-year PISC period.

If SCS1 demonstrates at the end of the 10-year PISC period that the CO_2 plume at the site is unlikely to extend beyond the SFA boundary, then the CO_2 plume will meet the definition of stabilization as presented in N.D.C.C. § 38-22-17(5)(d) as part of qualifying the storage site for receipt of a certificate of project completion.

6.2 Postinjection Testing and Monitoring Plan

This postinjection testing and monitoring plan assumes that the CO_2 injection wells will be plugged at cessation of injection. Planned postinjection monitoring activities include 1) a mechanical integrity testing and corrosion detection plan for the reservoir-monitoring well (Milton Flemmer 1) and 2) an environmental monitoring plan for the near surface and deep subsurface for evidence that the injected CO_2 plume is essentially stationary within the storage reservoir and USDWs are nonendangered.

6.2.1 Mechanical Integrity Testing and Corrosion Detection

The postinjection mechanical integrity testing and corrosion detection plan for the Milton Flemmer 1 is provided in Table 6-1. The supervisory control and acquisition (SCADA) system will be used to collect real-time and continuous measurements from the surface and downhole gauges in the Milton Flemmer 1.

SCS1 will follow the Wellbore Mechanical Integrity Testing Quality Assurance and Surveillance Plan (QASP) and Downhole Corrosion Detection QASP described within Section 5.0 of this application for the set of mechanical integrity and corrosion detection postinjection monitoring activities presented in Table 6-1.

6.2.2 Soil Gas and Groundwater Monitoring

Figure 6-3 identifies the locations of the soil gas profile stations and groundwater wells that are included in this monitoring effort. The two stations (MSG01 and MSG04), the Fox Hills monitoring well drilled for this project (MGW11), and existing shallow groundwater wells (MGW01, MGW03, MGW04, and MGW09) will be sampled according to the plan outlined in Table 6-1. SCS1 may specify alternate groundwater sampling locations and sampling frequencies for the PISC period, if obtaining samples from MGW01, MGW03, MGW04, or MGW09 is not feasible.

Analytes and sampling procedures for all soil gas and groundwater monitoring activities conducted during the PISC period are anticipated to be the same as what is presented in the Soil Gas Monitoring QASP and Groundwater Monitoring QASP within Section 5.0 of this application. SCS1 anticipates that the final target list of analytical parameters will likely be reduced for the PISC period based on an evaluation of the monitoring results that are generated during the 20-year injection period of the storage operations.

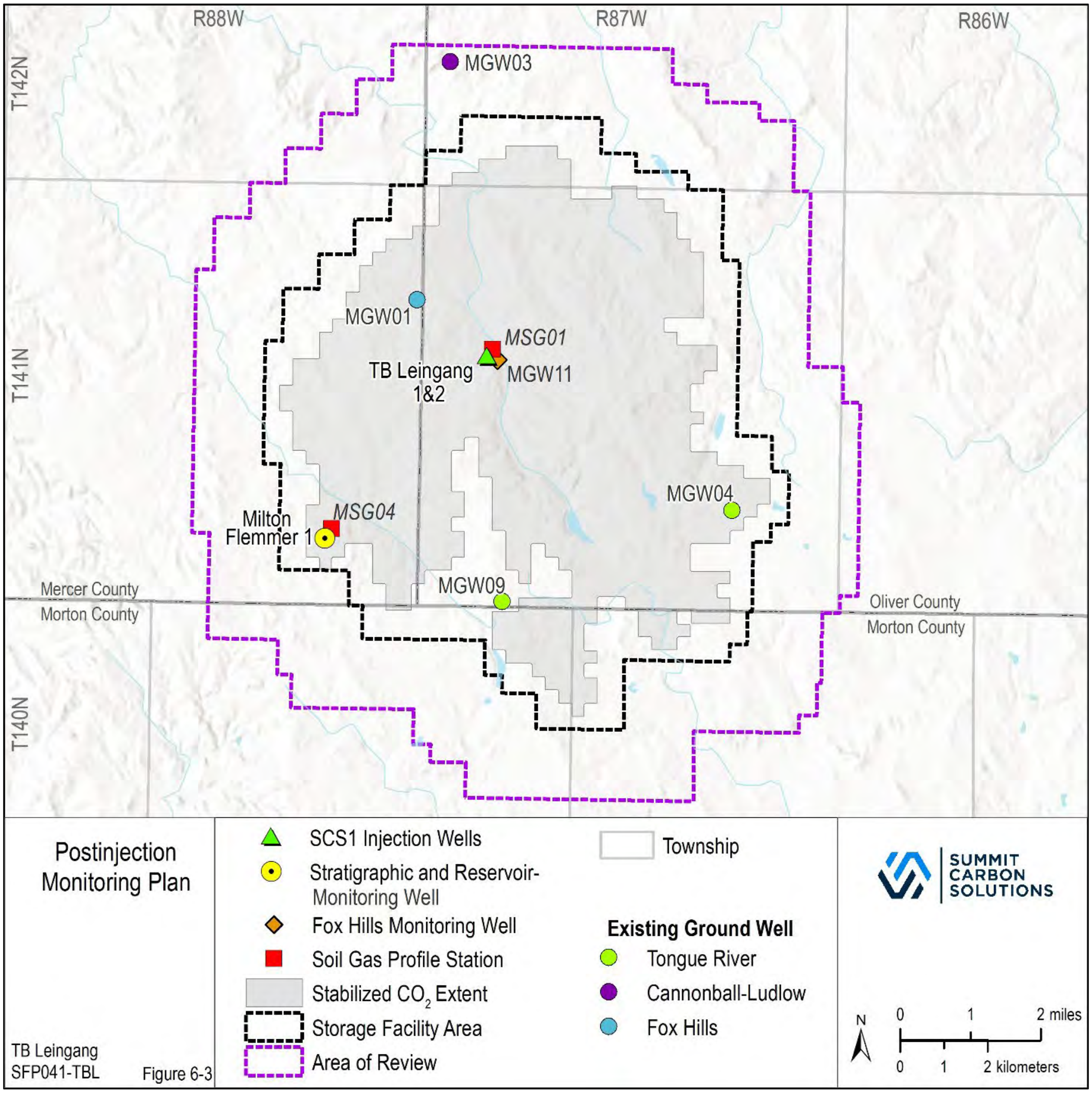


Figure 6-3. Soil gas station and groundwater well sampling locations included in the PISC period.

6.2.3 Deep Subsurface Monitoring

Table 6-1 describes the deep subsurface monitoring strategy during the PISC period. Monitoring methods include a combination of geophysical monitoring (e.g., time-lapse 3D/2D seismic) and formation monitoring (i.e., downhole P/T) for tracking CO_2 saturation and associated pressure, respectively, over the entire storage complex.

The design and frequency of the time-lapse seismic survey will depend on how the CO_2 plume is migrating during the operational phase of the project and the results of the adaptive management approach discussion described in Section 5.0 of this application. The seismic survey design will be reevaluated and updated according to monitoring data results gathered in the operational phase.

SCS1 will follow the Above-Zone Monitoring Interval QASP, Direct Reservoir Monitoring QASP, and Indirect Reservoir Monitoring QASP described within Section 5.0 of this application for the set of deep subsurface postinjection monitoring activities presented in Table 6-1.

6.3 Postinjection Site Care Plan

At the start of the PISC period, Flowline NDL-327, if not in use or projected use at this time, will be permanently disconnected, purged, and capped at both ends below grade, in accordance with the abandonment of flowlines pursuant to N.D.A.C. § 43-02-03-34.1. Main line valves (MLVs), launcher receivers, and other associated flowline infrastructure at grade or buried at a depth of 3 feet or less will be removed, whereas the NDL-327 flowlines themselves will be abandoned in place as the pipe bury depth will be 4 feet top of pipe and will be permanently disconnected, purged, and capped pursuant to N.D.A.C. § 43-02-03-34.1. The cost estimate for flowline segment NDL-327 abandonment can be found in Table 12-3b.

As required by N.D.A.C. § 43-05-01-19(5), PISC activities will include the P&A (plugging and abandonment) of the CO_2 injection wells (TB Leingang 1 and 2) and reclamation of the injection well pad. Storage facility equipment, appurtenances, and structures not associated with monitoring will be removed, and the surface will be reclaimed to the DMR-O&G's specifications to return the land as close as is practicable to its original condition. Injection well pad reclamation activities may occur contemporaneously with flowline removal and do not include the soil gas profile station (MSG01) and the Fox Hills monitoring well (MGW11).

SCS1 intends to use the Milton Flemmer 1 wellbore for deep subsurface monitoring during the PISC period. The postinjection testing and monitoring activities for the Milton Flemmer 1 and near-surface sampling are described earlier in Section 6.2. Section 12.0 includes cost estimates for performing these proposed testing and monitoring activities.

6.3.1 Schedule for Submitting Postinjection Monitoring Results

Where possible, PISC-monitoring data and results will be submitted to DMR-O&G within 45 days following the end of the calendar year in which 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 analytical results, and simulation results from updated geologic models and numerical simulations.

6.4 Facility Closure Plan

SCS1 will notify DMR-O&G prior to its intent to close the site, and the facility closure plan will describe a set of activities that will be performed, following approval by DMR-O&G, at the end of the PISC period. Facility closure activities will include the plugging of all wells that are not planned for continued use in monitoring the closed site; the decommissioning and removal of aboveground storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring or another deemed use; and the reclaiming of the surface land of the site as close as is practicable to its predisturbance condition.

As part of the final assessment, SCS1 will work with DMR-O&G to determine which wells and monitoring equipment will remain and transfer to the state for continued postinjection monitoring. P&A of the Milton Flemmer 1 and well pad reclamation costs are factored into Section 12.0, but DMR-O&G may choose to retain this reservoir-monitoring well into the postclosure period. The Fox Hills monitoring well drilled adjacent to the CO_2 injection wells (MGW11) and the soil gas profile stations (MSG01 and MSG04) may also transfer ownership to the state or a third party, pending DMR-O&G review and approval of the PISC plan and final assessment pursuant to N.D.A.C. § 43-05-01-19.11. Cost estimates for the PISC and closure periods can be found in Section 12.0 of this permit application in the scenario such that transfer to the state or a third-party entity does not occur.

6.4.1 Submission of Facility Closure Report, Survey, and Deed

A facility closure report will be prepared and submitted to DMR-O&G within 90 days following the execution of the PISC and facility closure plan. This report will provide DMR-O&G 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 facility closure report will also document the following:

- Plugging records of the CO_2 injection wells and reservoir-monitoring well.
- Location of the sealed CO_2 injection wells and reservoir-monitoring well on a plat survey that has been submitted to the county recorder's office.
- Notifications to state and local authorities as required by N.D.A.C. § 43-05-01-19.
- Records regarding the nature, composition, and volume of the injected CO_2.
- Postinjection monitoring records.

At the same time, SCS1 will also provide DMR-O&G with a copy of an accurate plat certified by a registered surveyor that has been submitted to the county recorder's office designated by DMR-O&G. The plat will indicate the location of the injection well relative to permanently surveyed benchmarks pursuant to N.D.A.C. § 43-05-01-19.

Lastly, SCS1 will record a notation on the deed (or any other title search document) to the property on which the injection well was located pursuant to N.D.A.C. § 43-05-01-19.11.

SECTION 7.0

EMERGENCY AND REMEDIAL RESPONSE PLAN

7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

Summit Carbon Storage #1, LLC (SCS1) requires all employees, contractors, and agents to follow the company emergency and remedial response plan (ERRP) for TB Leingang. The purpose of the ERRP is to provide guidance for quick, safe, and effective response to an emergency to protect the public, all responders, company personnel, and the environment.

This 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 underground sources of drinking water (USDW) during the construction, operation, and postinjection site care phases 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, this ERRP describes the emergency response team and command structure, injection 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 company's nearest operational office and at the geologic storage facility.

7.1 Background

SCS1 is the owner and operator of TB Leingang, located in Oliver County, approximately 16 miles south of Beulah, North Dakota. SCS1 is requesting a commercial permit for the operation of the storage facility for the injection of a CO_2 stream that will range from 95% CO_2 to ≤99.9% CO_2. This CO_2 stream range will provide flexibility to receive CO_2 from a variety of industrial sources (Table 7-1). This anticipated average CO_2 stream composition will ensure the safe and economical operation of the storage facility, including such factors as consistency with the design and materials of transport and storage equipment.

Table 7-1. Anticipated Average CO_2 Stream Composition

Chemical Content	System Specification
Carbon Dioxide, CO_2	≥98.25%
Inert, N_2	≤1.44%
Oxygen, O_2	≤0.31%
Water, H_2O*	≤20 lb/MMscf
Total Hydrocarbons*	≤1800 ppm by volume
Hydrogen Sulfide, H_2S*	≤10 ppm by volume
Total Sulfur, S*	≤10 ppm by volume
Glycol	≤0.3 gallons/MMscf

* Denotes trace constituents that do not make up notable percentages of stream composition.

Figure 7-1 identifies the planned pipeline, flowlines, injection wells (TB Leingang 1 and TB Leingang 2), and stratigraphic and reservoir-monitoring well (Milton Flemmer 1). The well locations, including latitudes and longitudes, are listed in Table 7-2. At the time SCS1 filed this application, it has not applied for any other permits from state, federal, or local agencies.

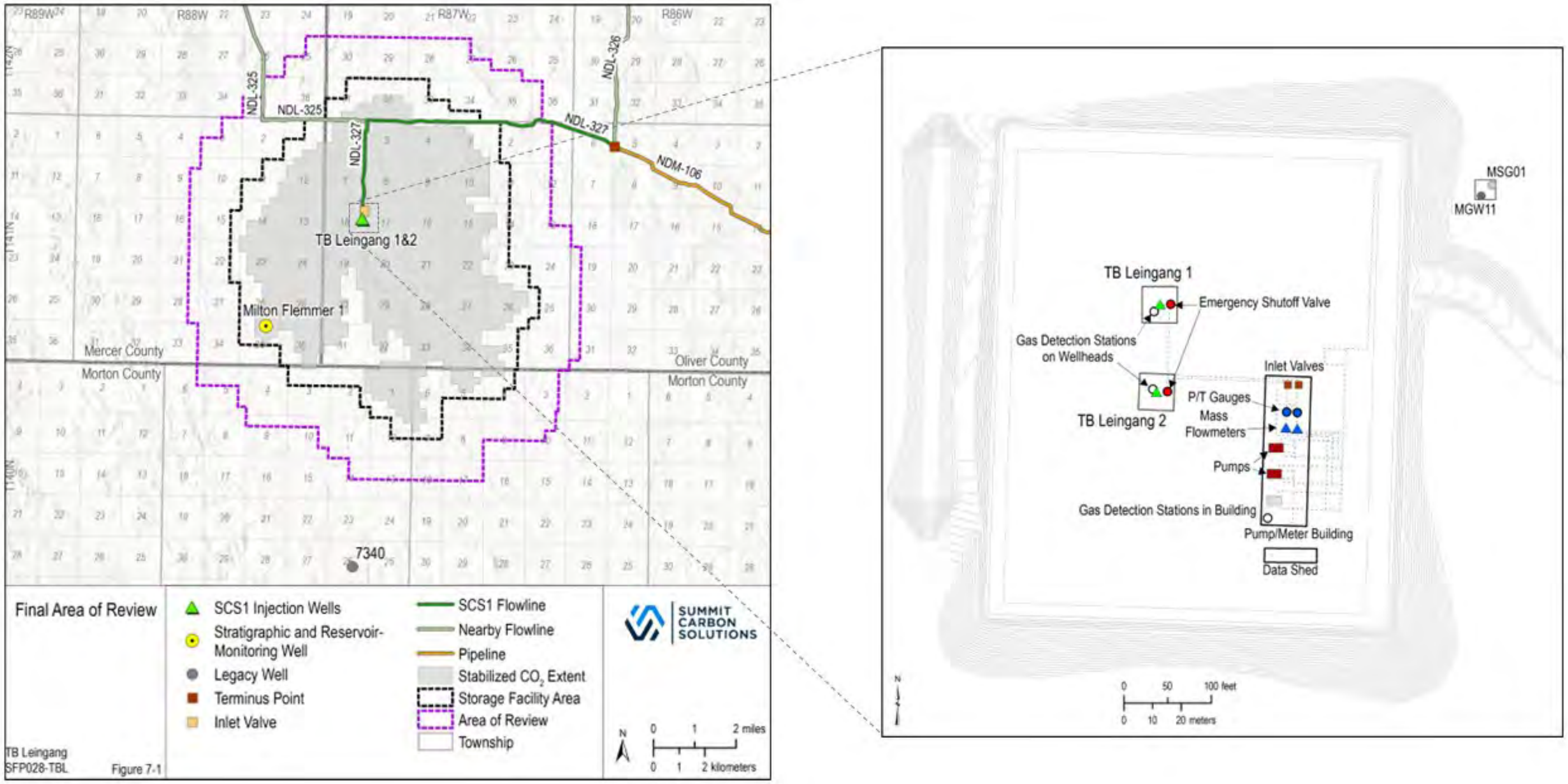


Figure 7-1. Site map detailing the on-pad CO_2 flowline(s) and the CO_2 injection wellsite. Also shown are the flowline(s) and pipeline associated with the Midwest Carbon Express (MCE) Project. Inset map illustrates a layout of surface facilities with key leak detection and monitoring equipment identified.

Table 7-2. Well Names and Location Information for the Injection Wells and Reservoir-Monitoring Well of the Geologic Storage Operations

Well Name	Purpose	NDIC[1] File No.	Quarter/ Quarter	Section	Township	Range	Latitude[2]	Longitude[2]
TB Leingang 1	CO_2 injection	40158	SE4/NE4	18	141N	87W	47.03321400	−101.74547500
TB Leingang 2	CO_2 injection	40178	SE4/NE4	18	141N	87W	47.032939	−101.745481
Milton Flemmer 1	Reservoir monitoring	38594	NW4/NE4	35	141N	88W	46.994917	−101.792939

[1] North Dakota Industrial Commission.

[2] North American Datum 83 (NAD 83) geographic coordinate system.

The primary SCS1 contacts for the geologic storage project and their contact information are listed in Table 7-3.

Table 7-3. Primary SCS1 Contacts

		Contact Information
Individual	**Title**	**Office Phone Number**
Wade Boeshans	Executive Vice President	515.531.2608
Jay Volk	Sequestration – Director of Health, Safety & Environmental	515.207.3563
Jeff Skaare	Director of Land & Legal Affairs	515.531.2615

Contact names and information for key local emergency organizations/agencies are provided in Figures 7-2 through 7-5 and Table 7-4.

7.2 Local Resources and Infrastructure

Land use near TB Leingang comprises primarily agricultural activities. Local resources in the vicinity of the geologic storage project that may be impacted as a result of an emergency event include existing groundwater wells, a spring (Figure 4-3), and five gravel pits (Figure 4-2).

The infrastructure in the area of review (AOR) that may be impacted as a result of an emergency event include 1) TB Leingang 1 and 2 (CO_2 injection wells), SCS1 flowline NDL-327, and Milton Flemmer 1 (stratigraphic and reservoir-monitoring well); 2) portions of the Bison Wind Farm (Figure 4-2); 3) surface features and occupied structures (Figure 4-2); and 3) public roads (Figures 7-3 through 7-5). Additional infrastructure nearby includes BK Fischer (SCS2), comprising two CO_2 injection wells and respective NDL-326 flowline; Archie Erickson 2 (stratigraphic and reservoir-monitoring well); KJ Hintz (SCS3), comprising two CO_2 injection wells and respective NDL-325 flowline, and Slash Lazy H 5 (stratigraphic and reservoir-monitoring well); and the MCE pipeline (Figures 7-3 through 7-5).

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 phases.

Storage Facility Area	Location	County	EMS District	Fire District	Law Enforcement	LEPC Jurisdiction
TB Leingang	Monitoring Site Milton Flemmer 1	Mercer	Glen Ullin EMS	Glen Ullin Fire Department	Mercer County Sheriff’s Department	Mercer County LEPC
	Injection Site TB Leingang 1 and 2	Oliver	Beulah EMS Mercer County Ambulance	Beulah Rural Fire Dept.	Oliver County Sheriff’s Department	Oliver County LEPC
	TB Leingang SFA	Mercer/ Oliver/ Morton				
			New Salem Ambulance Service	New Salem Fire Department	Morton County Sheriff’s Department	Mercer County LEPC
			Glen Ullin EMS	Glen Ullin Fire Department	Mercer County Sheriff’s Department	Morton County LEPC
BK Fisher	Monitoring Site Archie Erickson 2	Mercer	Beulah EMS Mercer County Ambulance	Beulah Rural Fire Dept.	Mercer County Sheriff’s Department	Mercer County LEPC
	Injection Site BK Fisher 1 and 2					
	BK Fisher SFA	Mercer/ Oliver				
					Oliver County Sheriff’s Department	Oliver County LEPC
KJ Hintz	Monitoring Site Slash Lazy H 5	Oliver	Hazen EMS Mercer County Ambulance	Hazen Fire & Rescue	Oliver County Sheriff’s Department	Oliver County LEPC
	Injection Site KJ Hintz 1 and 2					
	KJ Hintz SFA					
				New Salem Fire Dept.		
			Beulah EMS Mercer County Ambulance	Oliver Fire Dept.		
			Oliver EMS	Beulah Rural Fire Dept.		

Figure 7-2. Off-site emergency notification list. Emergency management service (EMS) districts, fire districts, law enforcement agencies, and Local Emergency Planning Committee (LEPC) jurisdictions with response jurisdictions intersecting with the TB Leingang storage facility area (SFA) will be provided a copy of this ERRP.

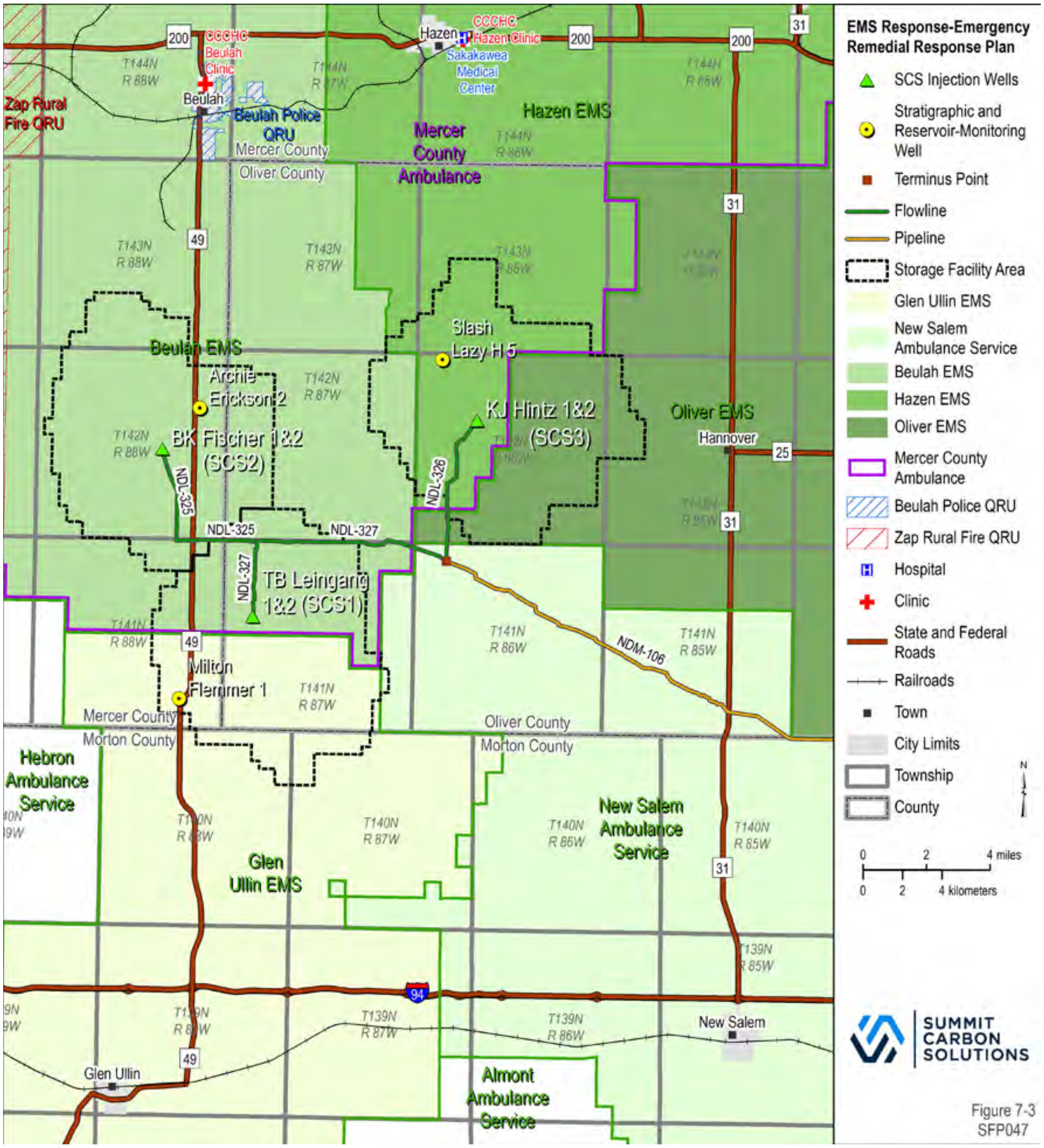


Figure 7-3. Map showing emergency management service (EMS) response zones including, and within the vicinity of, TB Leingang. Also included on this map are the planned CO_2 injection wells, stratigraphic and reservoir-monitoring wells, flowline(s), MCE pipeline, and state and federal roads.

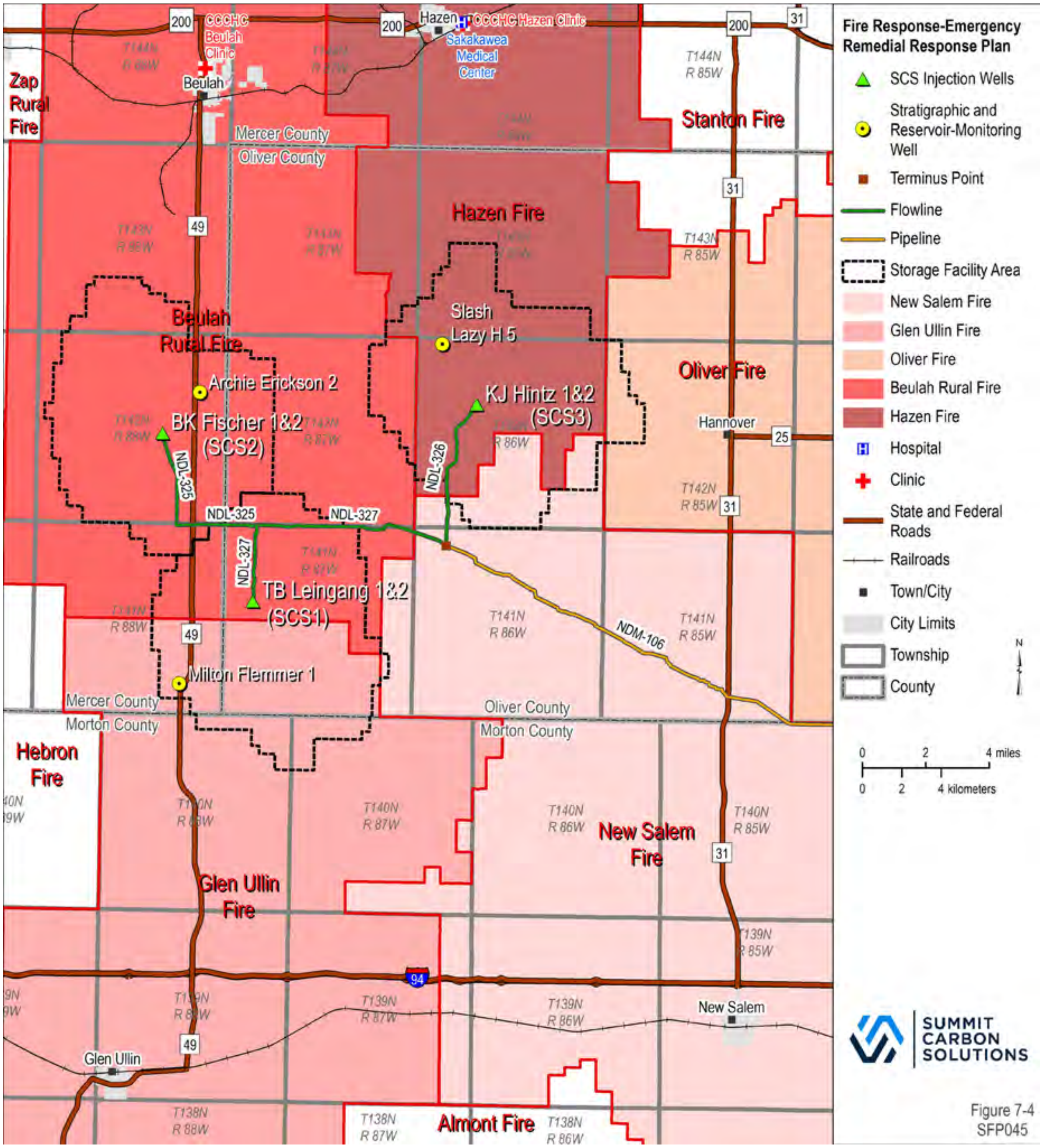


Figure 7-4. Map showing fire response zones including, and within the vicinity of, TB Leingang. Also included on this map are the planned CO_2 injection wells, stratigraphic and reservoir-monitoring wells, flowline(s), MCE pipeline, and state and federal roads.

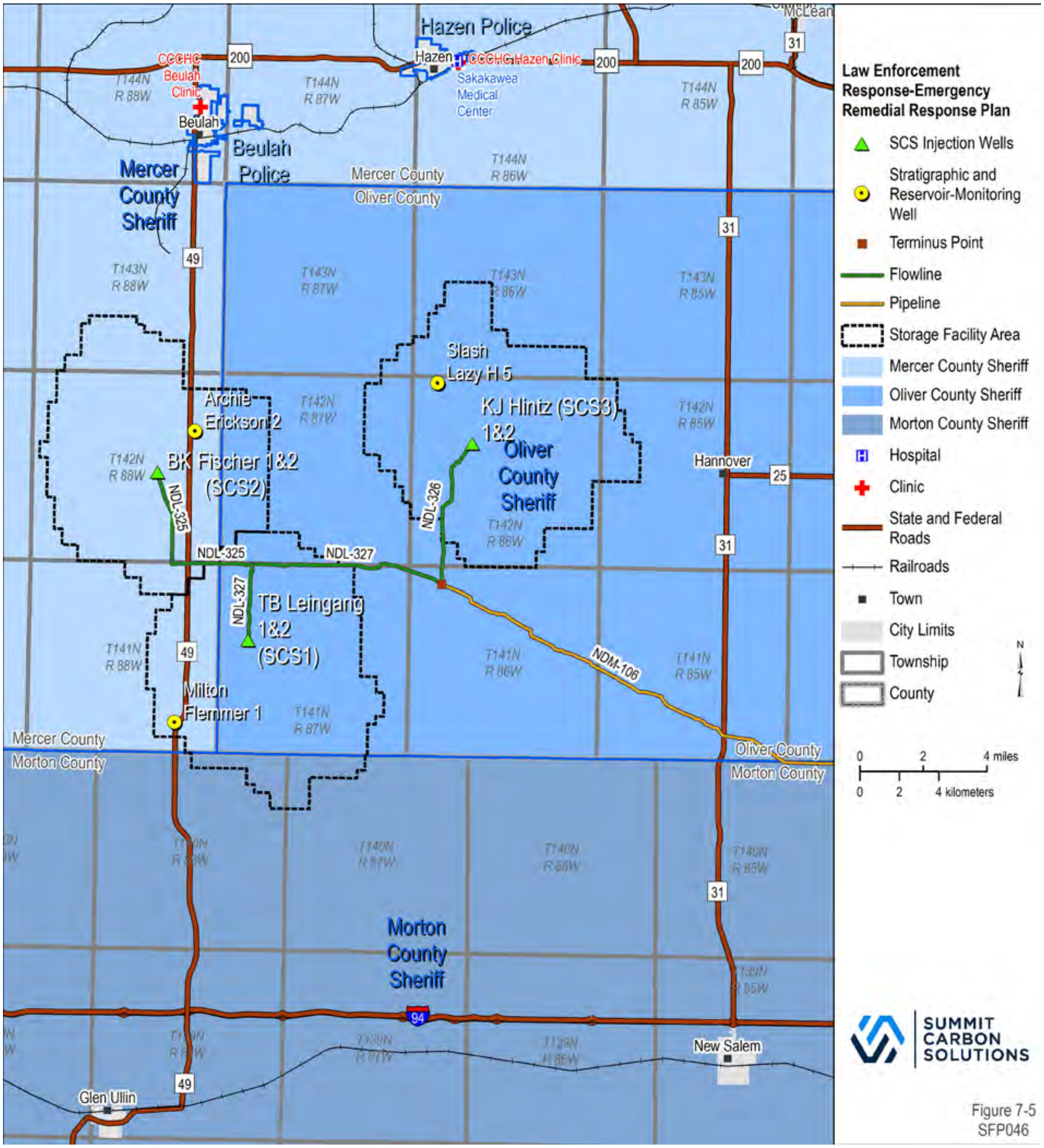


Figure 7-5. Map showing law enforcement response zones including, and within the vicinity of, TB Leingang. Also included on this map are the planned CO_2 injection wells, stratigraphic and reservoir-monitoring wells, flowline(s), MCE pipeline, and state and federal roads.

Table 7-4. Off-Site Emergency Notification/PSAP Phone List

Agency	Phone	Alternate Contact/Notes
Almont Ambulance Service	701.943.2355	
Beulah Police Department	701.873.5252	Quick response unit (QRU)
Beulah Rural Fire Department	701.873.2121	
Coal Country Community Health Center – Beulah Clinic	701.873.4445	
Coal Country Community Health Center – Hazen Clinic	701.748.2256	
Coal Country Community Health Center – Center Clinic	701.794.8798	
Emergency Manager – Mercer County	701.745.3333	
Emergency Manager – Morton County	701.667.3307	
Emergency Manager – Oliver County	701.745.3302	
Glen Ullin Ambulance	701.348.3507	
Glen Ullin Fire Department	701.348.3113	
Hazen Police Department	701.748.2414	
Hazen Fire & Rescue	701.745.3332	
Hebron Ambulance Service District	701.878.4600	
Hebron Fire Department	701.878.4353	State radio dispatch at 701.328.9921/800.472.2121
Mercer County Ambulance – Beulah EMS	701.748.7241	
Mercer County Ambulance – Hazen EMS	701.748.5558	
Mercer County Sheriff's Department	701.745.3333	
Morton County Sheriff's Department	701.667.3330	
ND Department of Emergency Services	1.833.997.7458	
ND Highway Department	701.327.9921	
ND Highway Patrol	State radio dispatch 701.328.9921/ 800.472.2121	Office: 701.328.2447
ND Poison Control	1.800.222.1222	
New Salem Ambulance Services	701.843.7828	
New Salem Fire Department	701.843.7111	
Oliver County Ambulance Service	701.794.3555	
Oliver Fire Department	701.794.3450	
Oliver County Sheriff's Department	701.794.3450	Mercer County Dispatch 701.745.3333
Sanford AirMed	844.424.7633	Sanford AirMed Dispatch Sioux Falls, SD 1.800.437.6886
Sanford Emergency and Trauma Center – Bismarck	701.323.6150	
Sakakawea Medical Center – Hazen	701.748.2225	Emergency services
Stanton Fire Department	701.748.2591	
Zap Rural Fire Department	Mercer County Dispatch 701.745.3333	QRU
Western Plains Public Health	701.667.3370/ 1.888.667.3370	Formerly Custer Health District

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. Injection operations
2. Storage capacity
3. Containment – lateral migration of CO_2
4. Containment – pressure propagation
5. Containment – vertical migration of CO_2 or formation water brine via injection wells, other wells, or inadequate confining zones
6. Natural disasters (induced seismicity)

Based on a review of these technical risk categories, SCS1 developed, to include in this ERRP, a list of the geologic storage project events that could potentially result in the movement of injection fluid or formation fluid in a manner that may endanger a USDW and, in turn, require an emergency response. These events and means for their detection are provided in Table 7-5.

In addition to the foregoing technical project risks, the occurrence of a natural disaster (e.g., naturally occurring earthquake, tornado, lightning strike, etc.) also represents an event for which an emergency response action may be warranted. For example, an earthquake or weather-related disaster (e.g., tornado or lightning strike) has the potential to result in injection well problems (integrity loss, leakage, or malfunction) and may also disrupt surface and subsurface storage operations. These events are also addressed in this ERRP.

7.4 Emergency Response Actions

7.4.1 General Emergency Response Actions

The response actions that will be taken to address the events listed in Table 7-5, 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), as found in Section 7.5, will be immediately notified and will make an initial assessment of the severity of the event (i.e., does it represent an emergency event?). The QI must make this assessment as soon as practical but must do so within 24 hours of the notification. This protocol will ensure SCS1 has taken all reasonable and necessary steps to identify and characterize any release pursuant to North Dakota Administrative Code (N.D.A.C.) § 43-05-01-13(2)(b).

- If an emergency event exists, the QI or designee shall notify, within 24 hours of the emergency event determination, the Department of Mineral Resources Oil and Gas Division (DMR-O&G) Director (see Sections 7.5 and 7.6, N.D.A.C. § 43-05-01-13[2][c]). The QI shall also implement the emergency communications plan (N.D.A.C. § 43-05-01-13[2][d]).

Table 7-5. Potential Project Emergency Events and Their Detection

Potential Emergency Events	Detection of Emergency Events
Failure of CO_2 Flowline NDL-327	• Computational flowline continuous monitoring and leak detection system (LDS). – Instrumentation at the flowline for each injection well on the well pad collects pressure, temperature, and flow data. – Pressure, temperature, and flow measurements will be measured at the MCE terminus point. – The LDS software uses the pressure readings and flow rates in and out of the line to produce a real-time model and predictive model. – By monitoring deviations between the real-time model and the predictive model, the software detects flowline leaks. • Frozen ground at the leak site may be observed. • CO_2 monitors located inside and outside of the process buildings detect a release of CO_2 from the flowline, connection, and/or wellhead.
Integrity Failure of Injection or Monitoring Well	• Pressure monitoring reveals wellhead pressure exceeds the shutdown pressure specified in the permit. • Annulus pressure indicates a loss of external or internal well containment. • Mechanical integrity test results identify a loss of mechanical integrity. • CO_2 monitors located inside and outside of the enclosed wellhead building detect a release of CO_2 from the wellhead.
Monitoring Equipment Failure of Injection Well	• Failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure is detected.
Storage Reservoir Unable to Contain the Formation Fluid or Stored CO_2	• Elevated concentrations of indicator parameter(s) in soil gas, groundwater, and/or surface water sample(s) are detected.

Following these actions, the company will:

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

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

- Vent CO_2 from the surface facilities.

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

- If warranted, initiate the evacuation of the injection facilities, and communicate with local emergency authorities to initiate evacuation plans of nearby residents (Figure 7-2 and Table 7-4).

- Perform the necessary actions to determine the cause of the event; identify and implement the appropriate emergency response actions in consultation with the DMR-O&G Director. Table 7-6 provides details regarding the specific actions that will be taken to determine the cause and, if required, mitigation of each of the events listed in Table 7-5.

Table 7-6. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions

Failure of CO_2 Flowline NDL-327	• The CO_2 release and its location will be detected by the LDS and/or CO_2 wellhead monitors, which will trigger a Pipeline Control* alarm, alerting system operators to take necessary action. • If warranted, initiate an evacuation plan in tandem with an appropriate workspace and/or ambient air-monitoring program, situated near the location of the failure, to monitor the presence of CO_2 and its natural dispersion following the shutdown of the flowline. • Inspect the flowline failure to determine the root cause. • Repair/replace the damaged flowline and, if warranted, put in place the measures necessary to eliminate such events in the future.
Integrity Failure of Injection or Monitoring Well	• Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure. • Identify and implement appropriate remedial actions to repair damage to downhole equipment or wellhead (in consultation with the DMR-O&G Director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the DMR-O&G Director).
Monitoring Equipment Failure of Injection Well	• Monitor well pressure, temperature, and annulus pressure (manually, if necessary) to determine the cause and extent of failure. • Identify and, if necessary, implement appropriate remedial actions (in consultation with the DMR-O&G Director).

* Pipeline Control refers to the controller monitoring MCE, SCS1, SCS2, and SCS3 flowline operations (see Section 7.5.8).

Continued . . .

Table 7-6. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Storage Reservoir Unable to Contain the Formation Fluid or Stored CO_2	• Collect a confirmation sample(s) of groundwater from the Fox Hills monitoring well(s) and soil gas profile station(s), and analyze the samples for indicator parameters (Section 5.0). • If the presence of indicator parameters is confirmed, develop (in consultation with the DMR-O&G 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 and, if warranted, initiate an evacuation plan in tandem with an appropriate workspace and/or ambient air-monitoring program situated at the appropriate incident boundary to monitor the presence of CO_2 and its natural dispersion following the termination of CO_2 injection. c. If surface release of CO_2 to surface waters is confirmed, implement the appropriate surface water-monitoring program to determine if water quality standards are exceeded. 2. Proceed with efforts, if necessary, to: a. Remediate the USDW to achieve compliance with drinking water standards (e.g., install a system to intercept/extract brine or CO_2 or “pump and treat” the impacted drinking water to mitigate CO_2/brine impacts), and/or b. Manage surface waters using natural attenuation (i.e., natural processes, such as biological degradation, active in the environment that can reduce contaminant concentrations), or c. Activate treatment to achieve compliance with applicable water quality standards. • Continue all remediation and monitoring at an appropriate frequency (as determined by company management designee and the DMR-O&G Director) until unacceptable adverse impacts have been fully addressed.

Continued . . .

Table 7-6. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Natural Disasters (seismicity)	• Identify when the event occurred and the epicenter and magnitude of the event. • If the magnitude is greater than 2.7 (Section 5.0), then: 1. Determine whether there is a connection with injection activities. 2. Demonstrate all project wells have maintained mechanical integrity. 3. If a loss of CO_2 containment is determined, proceed as described above to evaluate and, if warranted, mitigate the loss of containment.
Natural Disasters	• Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate the extent of any impacts. • If impacts or endangerment are detected, identify and implement appropriate response actions in accordance with the facility response plan (in consultation with the DMR-O&G Director).

7.4.2 Incident-Specific Response Actions

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

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

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

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

    - Pipeline Control will call the appropriate public safety answering point (PSAP) and nearby fire departments, law enforcement, and other appropriate agencies. Table 7-4 provides a listing of PSAPs. Personnel on-scene during an incident may call 911 directly.

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

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

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

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

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

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

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

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

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

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

- Assemble the LRT at the command post.

- Coordinate response efforts with on-scene fire department.

3. Operational Failure Causing a Hazardous Condition

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

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

- Pipeline Control will call the appropriate PSAP and nearby fire departments, law enforcement, and other appropriate agencies (Figure 7-2 and Table 7-4). Personnel on-scene during an incident may call 911 directly.

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

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

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

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

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

7.5 Response Personnel/Equipment and Training

7.5.1 Response Personnel and Equipment

Designated company personnel will undergo hazardous waste operations and emergency response training (HAZWOPER) 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 emergency services to implement this ERRP, as shown in Figures 7-2 through 7-5.

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 is required (such as a drilling rig, logging equipment, or potable water hauling, etc.), one of the primary contacts listed in Table 7-3 is responsible for procurement of this equipment. One of the primary contacts listed in Table 7-3 is also responsible to maintain a list of contractors and equipment vendors (see Section 7.6).

The company will provide personnel, training, equipment, instruments, tools, and material as needed to respond to an emergency incident:

- All local company personnel are available for callout as needed for duty on a 24-hour basis to support public safety agencies.

- Additional personnel, if required, will be acquired from agency responders from public safety agencies and/or response contractors.

- If public authorities are involved, they will be given full cooperation and assistance. In no event shall such cooperation and assistance violate safety rules or consist of actions that would endanger the public or employees.

- Company employees, contractors, and agency responders will be equipped with tools, supplies, and equipment available to be used in cases of emergency conditions existing on or near the injection facility and associated flowline(s). CO_2/O_2 monitoring devices should be used in the event of an accidental/uncontrolled release of CO_2. Self-contained breathing apparatus may be required pending results from on-site-specific hazards and monitoring results.

7.5.2 Staff Training and Exercise Procedures

The company will integrate the training of the emergency response personnel of the geologic storage project into the standard operating procedures and facility operations training programs. Periodic training will be provided, at least annually, to protect all necessary facility- and project-personnel. The training efforts will be documented in accordance with the requirements of company plans which, at a minimum, will include a record of the trainee's name, date of training, type of training (e.g., initial or refresher), and instructor name. The company 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.

7.5.3 Emergency Response Procedures

This section describes organization features and duties of the company's QI, LRT, and CST. The company's initial response to an incident will be provided by the LRT, once activated by the QI. The IC will activate a CST if an incident exceeds the local capabilities. In some cases, the initial responders to an incident may include local law enforcement, ambulance, and/or local fire department(s). The company will work with these agencies to manage a coordinated response effort.

The ICS will be used to manage emergency response activities. Because ICS is a management tool that is readily adaptable to incidents of varying magnitude, it will be used for all emergency incidents. Staffing levels will be adjusted to meet specific response team needs based on incident size, severity, and type of emergency. Local agencies are also trained to use ICS and may fill roles during a coordinated response effort. ICS principles include the following:

- Common terminology
- Manageable span of control
- Management by objectives
- Incident action planning
- Comprehensive resource management
- Established incident facilities
- Integrated communications

As a component of an ICS, the unified command (UC) is a structure that brings together the company and agencies at the command level. The UC links the organizations responding to the incident and provides a forum for the responsible party and responding agencies to make consensus decisions. Under the UC, the various responding agencies and company personnel may blend together throughout the organization to create an integrated response team. The ICS process requires the UC to set clear objectives to guide the on-scene response resources. The primary entities of a UC may be two or more of the following:

- Federal on-scene coordinator
- State on-scene coordinator
- Local on-scene coordinator
- Company IC (responsible party IC)

7.5.4 Qualified Individual (QI)

The QI is defined by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) as a company employee who has been given authority to fund response efforts without consulting company leadership for further authorization and knows how to commence the response procedures of this plan. The QI is responsible for activating the ICS response organization, including the LRT and CST.

The QI will be an English-speaking company employee who is available on a 24-hour basis with the full authority to activate and deploy the necessary emergency response contractors. The QI or alternate QI will activate personnel and equipment, act as a liaison with the UC, and obligate any funds required to carry out all the required or direct emergency response activities.

7.5.4.1 Communicating to Appropriate Operator Personnel

If notification of an event relating to a potential emergency requires immediate response, the emergency notification flowchart in Figure 7-6 provides guidance regarding notification of appropriate operator personnel, contractors, and emergency and public officials.

7.5.5 Local Response Team (LRT)

The first company person on scene will function as the IC and person in charge until relieved by an authorized person who will then assume the position of IC. The number of positions/personnel required to staff the LRT will depend on the size and complexity of the incident. The duties of each position may be performed by the IC directly or delegated as the situation demands. The IC is always responsible for directing response activities and will assume the duties of all the primary positions until the duties can be delegated to other qualified personnel.

The LRT will fill the necessary positions and request additional support from the CST (defined below) to fill/back up any additional positions necessitated by the incident. Detailed job descriptions of the response team positions are provided within this plan.

7.5.6 Company Support Team (CST)

The QI and IC may decide to mobilize a CST if there are any response operations outside the LRT's capabilities. The members of the LRT will typically become members of the CST.

The CST, once fully staffed, is designed to cover all aspects of a comprehensive and prolonged incident response. The number of positions/personnel required to staff the CST will depend on the size and complexity of the incident. During a prolonged response, additional personnel may be cascaded in to fill additional ICS positions or relieve responding personnel.

The CST is staffed by trained personnel from various company locations and by various contract resources as the situation requires.

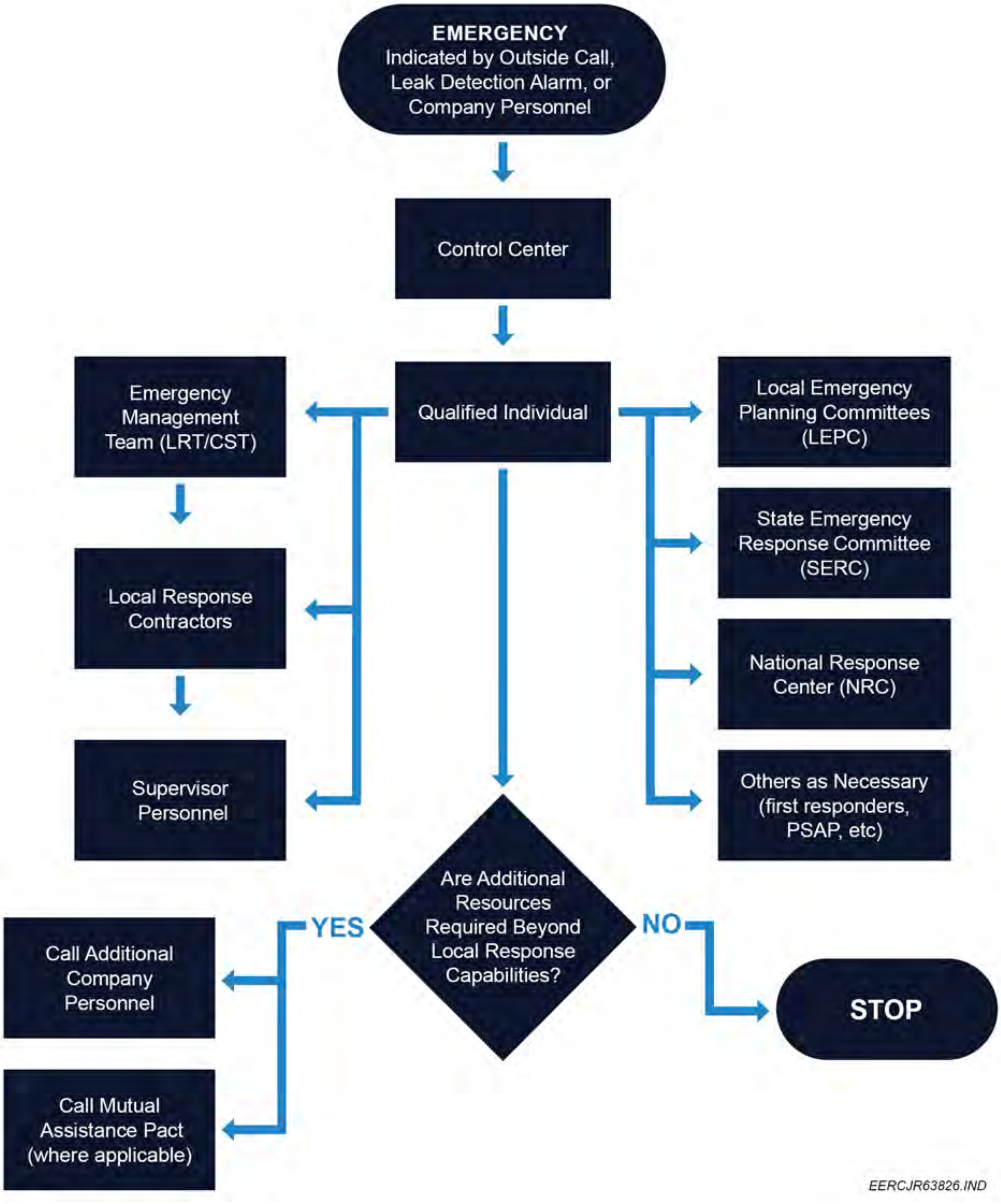


Figure 7-6. Emergency notification flowchart.

7.5.7 Preplanning Emergency Response Activities with Public Safety Answering Point, Fire, Police, and Other Public Officials

To enhance cooperation during an incident response, the company will liaise with agency responders and public officials, including participating in emergency tabletop exercises, coordinating meetings to discuss hazards and emergency response, and conducting facility tours or open houses. These and other public outreach activities will be included in the Public Awareness Program that will be developed and implemented prior to commencing operation of the pipeline.

7.5.8 Required Controller Actions

Pipeline Control actions during emergency response actions will be detailed in the control room management plan that will be developed and implemented prior to commencing pipeline operations. Generally, the actions will include:

- Identifying abnormal operating conditions, including potential pipeline ruptures.
- Confirmation of abnormal conditions.
- Specific steps to take in response to certain abnormal conditions, including closing valves, notifications internal to the company, and notifications external to agency responders.
- Specific steps to take following pipeline shutdown to reestablish pipeline operations.

7.6 Emergency Communications Plan

In the event of an emergency, the facility response plan contains an ICS which specifies the organization of a facility response team, team member roles, and team member responsibilities. The company organizational structure is still in development. The company will provide updated specific identification and contact information for each member of the facility response team. In the event of an emergency, as outlined in N.D.A.C. § 43-05-01-13(2), DMR-O&G will be notified within 24 hours (Table 7-7).

Table 7-7. DMR-O&G UIC Program Management Contact

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

The QI or QI designee is responsible for establishing and maintaining communications with appropriate off-site persons and/or agencies as provided in Figure 7-2 and Table 7-4. Table 7-8 lists available contractors and service providers.

Lastly, the facility response plan contact list also includes addresses and contact information for the neighboring facilities and occupied residences located within a 1-mi radius of the geologic storage project. Because indicated local and regional emergency agencies (Figure 7-2 and Table 7-4) are provided a copy of the facility response plan, the QI or QI 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 company to focus time and resources on response measures.

Table 7-8. Potential Contractor and Service Providers

Company	Service	Location	Phone
4th Dimension Surveying & Consulting	Land surveying and drone mapping	Williston, ND	701.580.5267
Baranko Brothers, Inc.	Excavation, dirt work/hauling	Dickinson, ND	701.690.7279
Barr Engineering	Engineering services	Bismarck, ND	701.255.5460
Basin Concrete, Inc.	Trucking and rentals	Williston, ND	701.774.3085
Dakota Outlaw Services	Fencing	Glen Ullin, ND	701.870.5303
Dryland Enterprises LLC	Waste hauler	Belfield, ND	701.559.3232
Environmental Solutions	Cuttings disposal	Belfield, ND	701.300.1156
Farmers Union Oil (Cenex)	Propane, seed, soil fertility testing	Beulah, ND	701.873.4363
Flowserve	Injection pump manufacturer	Irving, TX	972.443.6500
Industrial Contractors Inc.	Mechanical	Bismarck, ND	701.258.9908
J&S Sanitation	Sanitation	Beulah, ND	701.873.5577
Lake View Services LLC	Crane services and dirt work/hauling	Beulah, ND	701.873.2719
Meadowland Services	Spraying	Zap, ND	701.880.0996
Minnesota Valley Testing Laboratories, Inc.	Formation fluids collection and analysis	Bismarck, ND	701.204.5478
Neuberger Oil	Fuel	Beulah, ND	701.873.2188
Pale Horse Services, Inc	Cuttings hauling and rentals	Dickinson, ND	701.690.6408
Roughrider Disposal LLC	Cuttings disposal	Fairfield, ND	701.638.8053
Roughrider Electric	Power provider	Hazen, ND	701.748.2293
Siemens	Variable-frequency drive and motor manufacturer	Alpharetta, GA	800.333.7421
Unruh Trucking	Fresh water hauling	Zap, ND	701.891.2875
Waste Management	Trash	Bismarck, ND	701.214.9741
Western Steel Builders	Metal building contractor	Hazen, ND	701.748.6305
Wild Well Control	Well control emergency responders	Greeley, CO	281.784.4700
YES LLC	Electrical	Dickinson, ND	701.483.8330

7.7 ERRP Review and Updates

This ERRP shall be reviewed:

- At least annually following its approval by DMR-O&G.
- Within 1 year of an AOR reevaluation.
- Within a prescribed period (to be determined by DMR-O&G) following any significant changes to the project, (e.g., injection process, the injection rate).
- As required by DMR-O&G.

If the review indicates that no amendments to the ERRP are necessary, the company will provide the documentation supporting the “no amendment necessary” determination to the DMR-O&G Director.

If the review indicates that amendments to the ERRP are necessary, SCS1 will make and submit amendments to DMR-O&G as soon as reasonably practicable. In no event, however, shall it do so more than 1 year following the commencement of a review.

SECTION 8.0

WORKER SAFETY PLAN

8.0 WORKER SAFETY PLAN

Summit Carbon Storage #1, LLC (SCS1) requires all employees and contractors to follow the SCS1 Worker Safety Plan (WSP) for TB Leingang. SCS1 maintains and implements a safety program that meets all state and federal requirements for worker safety protections, including the Occupational Safety and Health Administration (OSHA) and the National Fire Protection Association (NFPA). The safety program is described in this WSP. SCS1 will periodically review the WSP, and if substantive changes are warranted, the revised WSP will be provided to the Department of Mineral Resources, Oil and Gas Division (DMR-O&G). Controlled copies of the WSP are available at SCS1's nearest operational office and at the geologic storage facility (North Dakota Administrative Code [N.D.A.C.] § 43-05-01-13).

The WSP outlines steps to protect the health and safety of employees, contractors, and visitors while working near and around CO_2. Specific topics included in the WSP are, but are not limited to, the following:

- A list of safety training programs, including annual CO_2 safety training, annual safe-working procedures training, and annual Emergency and Remedial Response Plan (ERRP) training, as well as the review frequency for the safety training programs and, if necessary, updates. A record of training completions, including the trainee's name, date and type of training, and the signatures (or other acceptable acknowledgment/documentation) of the trainee and trainer are maintained and available upon request.

- A site-specific list of potential hazards of working near and around CO_2.

- Processes for determining causes of incidents and implementing appropriate emergency response actions.

- Requirements for employees to perform duties in ways that prevent the discharge of CO_2.

- Personal protective equipment (PPE) policies for employees while performing their duties, including guidelines for selecting, using, and maintaining PPE.

- New-hire, contractor, and visitor protocols to ensure all on-site individuals are appropriately trained and are aware of the potential hazards of CO_2.

- Drug, alcohol, and controlled substances policy complying with all governmental laws and regulations in the workplace and consequences for those who violate the policy.

- Reporting guidelines for all injuries; equipment or property damages; leaks, spills, or releases; or other health, safety, and environmental (HSE)-related incidents.

Only SCS1 employees and contractor personnel who have been properly trained can participate in the on-site activities of drilling, construction, operations, and equipment repair.

SECTION 9.0

WELL CASING AND CEMENTING PROGRAM

9.0 WELL CASING AND CEMENTING PROGRAM

Summit Carbon Storage #1, LLC (SCS1) plans to construct two CO_2 injection wells TB Leingang 1 (API 33-065-00026, North Dakota Industrial Commission [NDIC] File No. 40158) and TB Leingang 2 (API 33-065-00027, NDIC File No. 40178) and reenter and convert the Milton Flemmer 1 stratigraphic test well (API 33-057-00041, NDIC File No. 38594) into a reservoir-monitoring well. The following information represents the current proposed state for TB Leingang 1 (Figures 9-1 and 9-2, Tables 9-1 through 9-4) and TB Leingang 2 (Figures 9-3 and 9-4, Tables 9-5 through 9-8), the current, as-constructed state for Milton Flemmer 1 (Figure 9-5, Tables 9-9 through 9-12), and a radial cement bond log (RCBL) evaluation summary for Milton Flemmer 1 (Figure 9-6).

9.1 TB Leingang 1: Proposed Injection Well Casing and Cementing Programs

The proposed state of TB Leingang 1 is provided in Figure 9-1. TB Leingang 1 is a deviated well. The well surface location, well trajectory, and bottomhole target location are provided in Figure 9-2. This fieldwork information may change based on field conditions and operational challenges. The information below is the best knowledge available at the time of drafting this permit application.

Table 9-1 provides well information for TB Leingang 1. Tables 9-2 through 9-4 provide the casing and cement programs for TB Leingang 1 and have been updated according to the proposed drilling estimate for 2025. The tables demonstrate compliance with North Dakota Administrative Code (N.D.A.C.) § 43-05-01. In addition, the materials used for construction satisfy the requirements of N.D.A.C. § 43-05-01-11 for a CO_2 injection well.

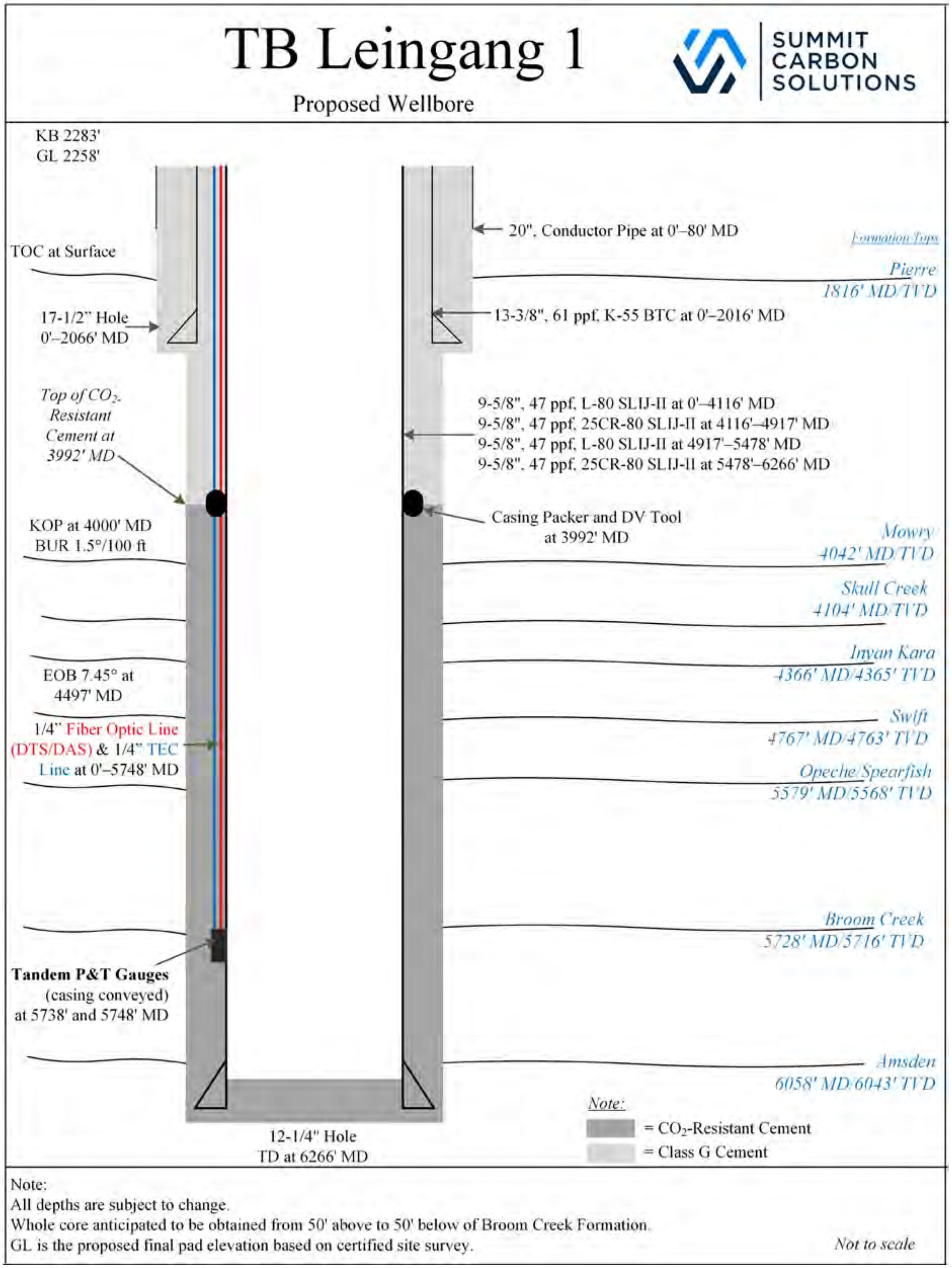
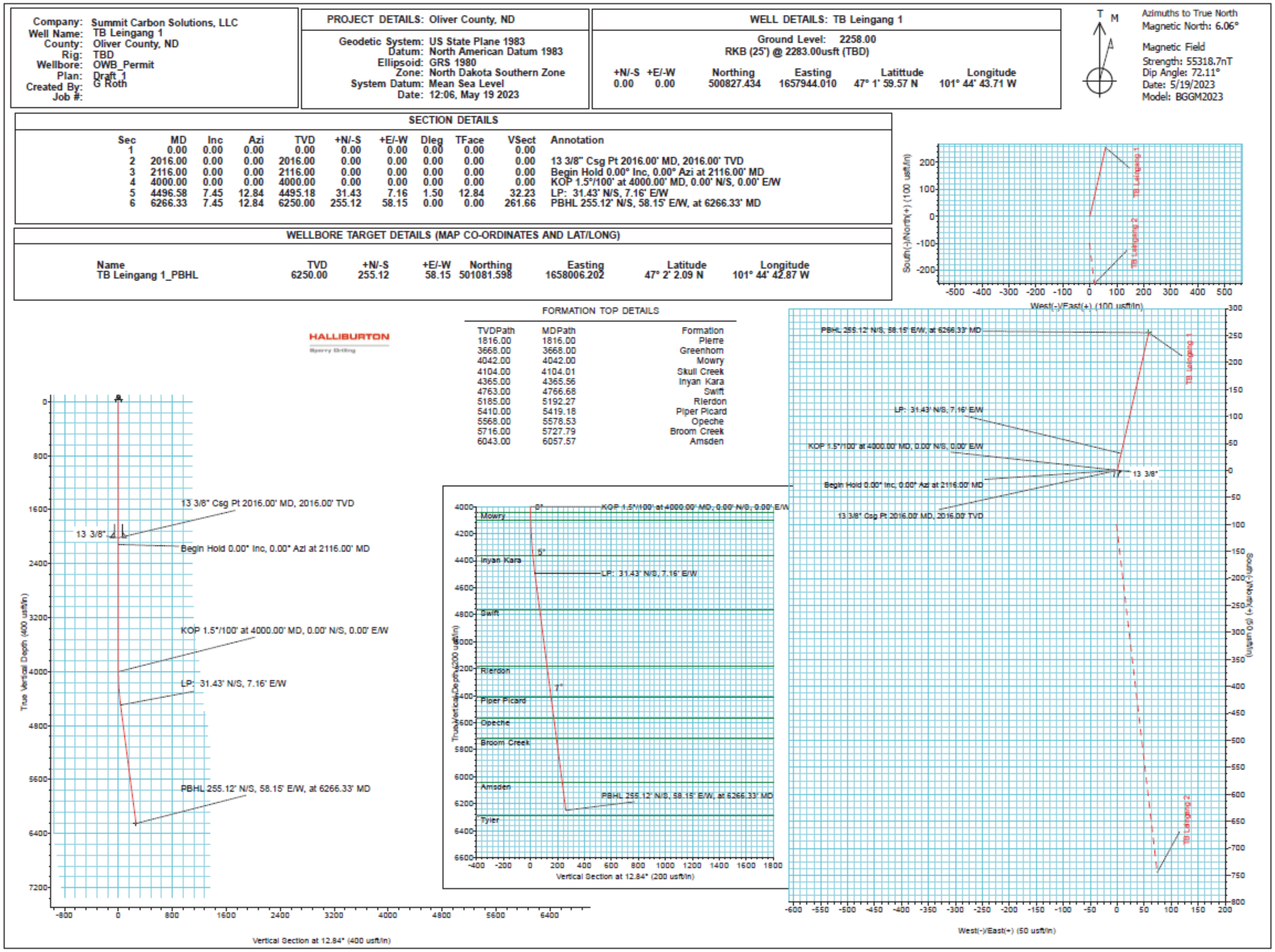


Figure 9-1. TB Leingang 1 proposed wellbore schematic.



Company: Summit Carbon Solutions, LLC
Well Name: TB Leingang 1
County: Oliver County, ND
Rig: TBD
Wellbore: OWB_Permit
Plan: Draft 1
Created By: G Roth
Job #:

PROJECT DETAILS: Oliver County, ND

Geodetic System: US State Plane 1983
Datum: North American Datum 1983
Ellipsoid: GRS 1980
Zone: North Dakota Southern Zone
System Datum: Mean Sea Level
Date: 12:06, May 19 2023

WELL DETAILS: TB Leingang 1

Ground Level: 2258.00
RKB (25') @ 2283.00usft (TBD)

+N/-S	+E/-W	Northing	Easting	Latittude	Longitude
0.00	0.00	500827.434	1657944.010	47° 1' 59.57 N	101° 44' 43.71 W

Azimuths to True North
Magnetic North: 6.06°

Magnetic Field
Strength: 55318.7nT
Dip Angle: 72.11°
Date: 5/19/2023
Model: BGGM2023

SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect	Annotation
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	2016.00	0.00	0.00	2016.00	0.00	0.00	0.00	0.00	0.00	13 3/8" Csg Pt 2016.00' MD, 2016.00' TVD
3	2116.00	0.00	0.00	2116.00	0.00	0.00	0.00	0.00	0.00	Begin Hold 0.00° Inc, 0.00° Azi at 2116.00' MD
4	4000.00	0.00	0.00	4000.00	0.00	0.00	0.00	0.00	0.00	KOP 1.5°/100' at 4000.00' MD, 0.00' N/S, 0.00' E/W
5	4496.58	7.45	12.84	4495.18	31.43	7.16	1.50	12.84	32.23	LP: 31.43' N/S, 7.16' E/W
6	6266.33	7.45	12.84	6250.00	255.12	58.15	0.00	0.00	261.66	PBHL 255.12' N/S, 58.15' E/W, at 6266.33' MD

WELLBORE TARGET DETAILS (MAP CO-ORDINATES AND LAT/LONG)

Name	TVD	+N/-S	+E/-W	Northing	Easting	Latitude	Longitude
TB Leingang 1_PBHL	6250.00	255.12	58.15	501081.598	1658006.202	47° 2' 2.09 N	101° 44' 42.87 W

FORMATION TOP DETAILS

TVDPath	MDPath	Formation
1816.00	1816.00	Pierre
3668.00	3668.00	Greenhorn
4042.00	4042.00	Mowry
4104.00	4104.01	Skull Creek
4365.00	4365.56	Inyan Kara
4763.00	4766.68	Swift
5185.00	5192.27	Rierdon
5410.00	5419.18	Piper Picard
5568.00	5578.53	Opeche
5716.00	5727.79	Broom Creek
6043.00	6057.57	Amsden

Figure 9-2. TB Leingang 1 proposed wellbore trajectory.

Table 9-1. TB Leingang 1: Proposed Well Information

Well Name:	**TB Leingang 1**	**NDIC File No.:**	**40158**	**API No.:**	33-065-00026
County:	Oliver	**State:**	ND	**Operator:**	SUMMIT CARBON STORAGE #1, LLC
Location:	Sec. 18 T141N R87W	**Footages*:**	2160 ft FNL, 519 ft FEL	**Total Depth:**	6266 ft, MD

* From the north line (FNL), from the east line (FEL).

Table 9-2. TB Leingang 1: Proposed Casing Program

Section	Hole Size, in.	Casing OD,* in.	Weight, lb/ft	Grade	Connection**	Top Depth,*** ft	Bottom Depth,*** ft	Objective
Surface	17.5	13.375	61	K-55	BTC	0	2016	Protects underground source of drinking water (USDW) Fox Hills Formation
Long-String	12.25	9.625	47	L-80	SLIJ-II	0	4116	Long-string casing
	12.25	9.625	47	25Cr-80	SLIJ-II	4116	4917	CO_2-resistant across Inyan Kara Formation
	12.25	9.625	47	L-80	SLIJ-II	4917	5478	Long-string casing
	12.25	9.625	47	25Cr-80	SLIJ-II	5478	6266	CO_2-resistant across Broom Creek Formation

* Outside diameter.

** BTC: buttress, SLIJ-II: VAM SLIJ-II: gastight premium connection.

*** Depths are in measured depth (MD) based on proposed wellbore trajectory and formation top prognosis.

Table 9-3. TB Leingang 1: Proposed Casing Properties

Section	OD, in.	Grade	Weight, lb/ft	Connection	ID,* in.	Drift ID,* in.	Collapse, psi	Burst, psi	Yield Strength, klb	
									Body	Connection
Surface	13.375	K-55	61	BTC	12.515	12.359	1537	3088	963	1170
Long-String	9.625	L-80	47	SLIJ-II	8.681	8.525	4756	6858	1087	780
	9.625	25Cr-80	47	SLIJ-II	8.681	8.525	4756	6858	1087	780

* Inside diameter.

Table 9-4. TB Leingang 1: Proposed Cement Program

Section	Casing OD, in.	Cement Class/Type	Lead/Tail/ Single	Stage	Slurry Weight, ppg	Slurry Yield, ft^3/sack	Interval,* ft	Excess, %	Volume, sacks
Surface	13.375	Class G	Single	NA	12.5	2.220	0–2016	100	1305
Long-String	9.625	Class G	Single	Stage 2	12.2	2.214	0–3992	100	880
	Stage 2 Through DV Tool at 3992 ft, MD**								
	9.625	CO_2-resistant	Single	Stage 1	13	1.541	3992–6266	100	935

* The cement top will be confirmed once the RCBL is performed. Depths are in MD based on proposed wellbore trajectory and formation top prognosis.

** Differential valve.

9.2 TB Leingang 2: Proposed Injection Well Casing and Cementing Programs

The proposed state of TB Leingang 2 is provided in Figure 9-3. TB Leingang 2 is a deviated well. The well surface location, well trajectory, and bottomhole target location are provided in Figure 9-4. This fieldwork information may change based on field conditions and operational challenges. The information below is the best knowledge available at the time of drafting this permit application.

Table 9-5 provides well information for TB Leingang 2. Tables 9-6 through 9-8 provide the casing and cementing programs for TB Leingang 2 and have been updated according to the proposed drilling estimate for 2025. The tables demonstrate compliance with N.D.A.C. § 43-05-01. In addition, the materials used for construction satisfy the requirements of N.D.A.C. § 43-05-01-11 for a CO_2 injection well.

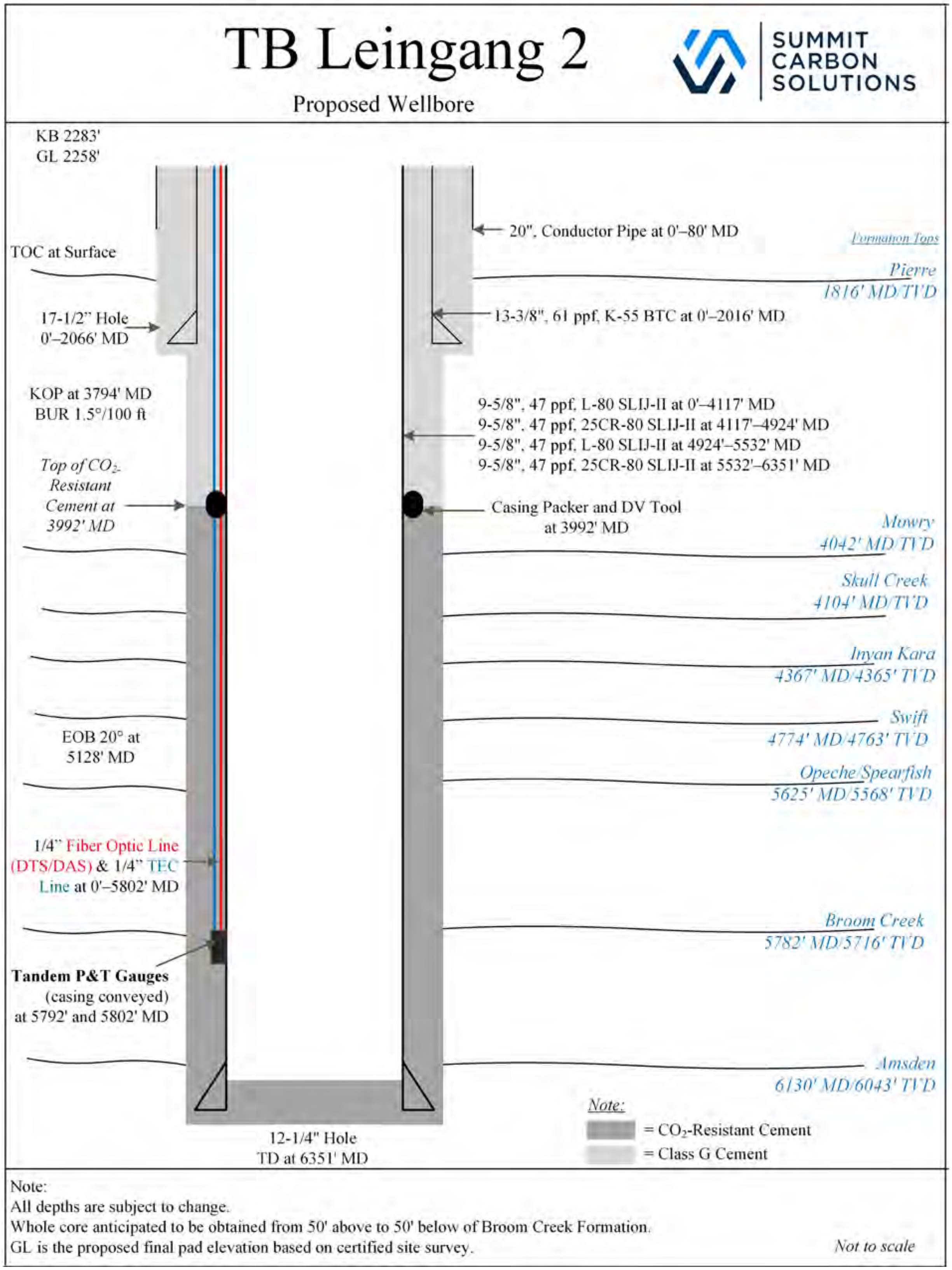
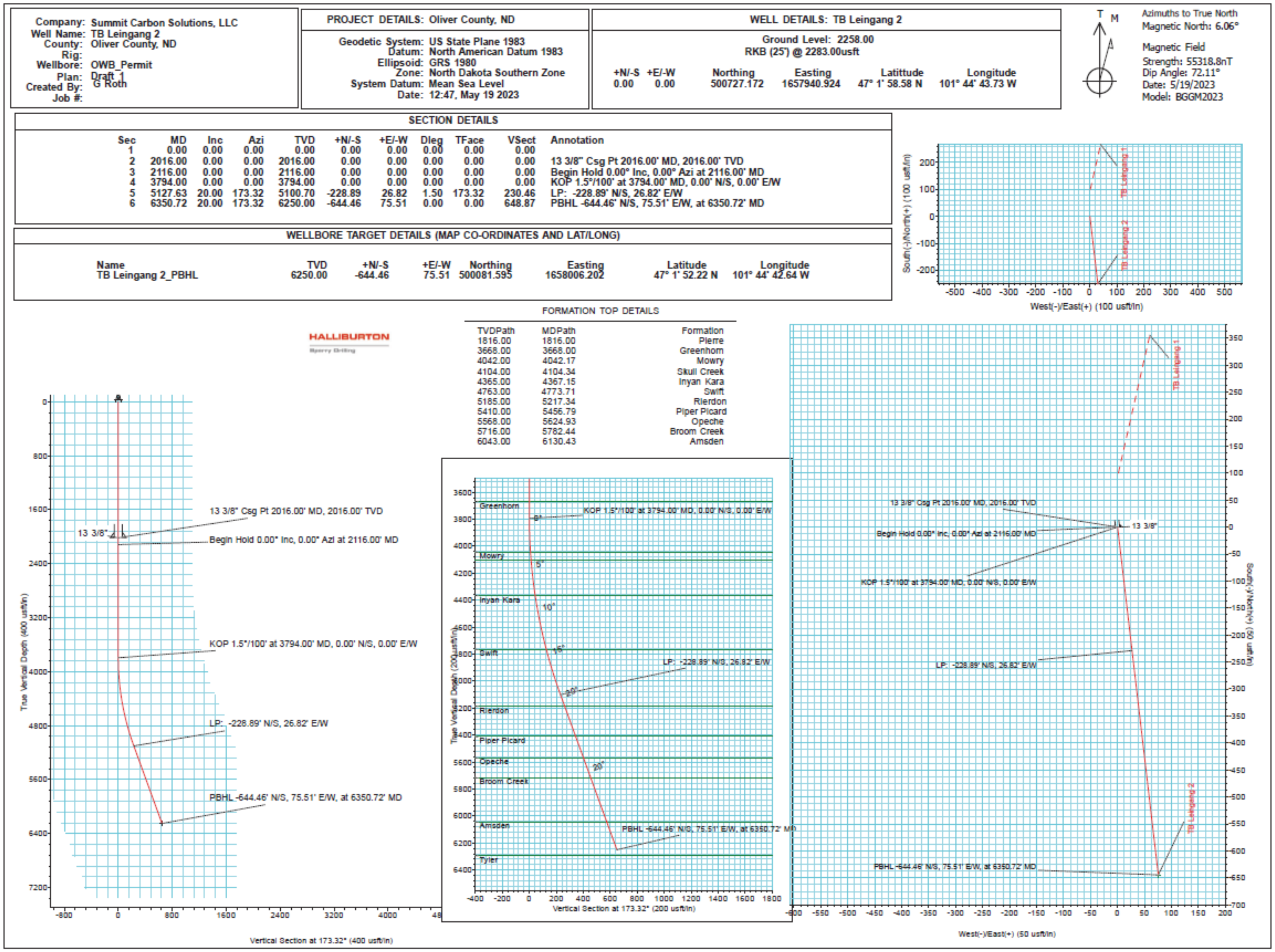


Figure 9-3. TB Leingang 2 proposed wellbore schematic.



Company: Summit Carbon Solutions, LLC
Well Name: TB Leingang 2
County: Oliver County, ND
Rig:
Wellbore: OWB_Permit
Plan: Draft 1
Created By: G Roth
Job #:

PROJECT DETAILS: Oliver County, ND

Geodetic System: US State Plane 1983
Datum: North American Datum 1983
Ellipsoid: GRS 1980
Zone: North Dakota Southern Zone
System Datum: Mean Sea Level
Date: 12:47, May 19 2023

WELL DETAILS: TB Leingang 2

Ground Level: 2258.00
RKB (25') @ 2283.00usft

+N/-S	+E/-W	Northing	Easting	Latittude	Longitude
0.00	0.00	500727.172	1657940.924	47° 1' 58.58 N	101° 44' 43.73 W

Azimuths to True North
Magnetic North: 6.06°

Magnetic Field
Strength: 55318.8nT
Dip Angle: 72.11°
Date: 5/19/2023
Model: BGGM2023

SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect	Annotation
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	2016.00	0.00	0.00	2016.00	0.00	0.00	0.00	0.00	0.00	13 3/8" Csg Pt 2016.00' MD, 2016.00' TVD
3	2116.00	0.00	0.00	2116.00	0.00	0.00	0.00	0.00	0.00	Begin Hold 0.00° Inc, 0.00° Azi at 2116.00' MD
4	3794.00	0.00	0.00	3794.00	0.00	0.00	0.00	0.00	0.00	KOP 1.5°/100' at 3794.00' MD, 0.00' N/S, 0.00' E/W
5	5127.63	20.00	173.32	5100.70	-228.89	26.82	1.50	173.32	230.46	LP: -228.89' N/S, 26.82' E/W
6	6350.72	20.00	173.32	6250.00	-644.46	75.51	0.00	0.00	648.87	PBHL -644.46' N/S, 75.51' E/W, at 6350.72' MD

WELLBORE TARGET DETAILS (MAP CO-ORDINATES AND LAT/LONG)

Name	TVD	+N/-S	+E/-W	Northing	Easting	Latitude	Longitude
TB Leingang 2_PBHL	6250.00	-644.46	75.51	500081.595	1658006.202	47° 1' 52.22 N	101° 44' 42.64 W

FORMATION TOP DETAILS

TVDPath	MDPath	Formation
1816.00	1816.00	Pierre
3668.00	3668.00	Greenhorn
4042.00	4042.17	Mowry
4104.00	4104.34	Skull Creek
4365.00	4367.15	Inyan Kara
4763.00	4773.71	Swift
5185.00	5217.34	Rierdon
5410.00	5456.79	Piper Picard
5568.00	5624.93	Opeche
5716.00	5782.44	Broom Creek
6043.00	6130.43	Amsden

Figure 9-4. TB Leingang 2 proposed wellbore trajectory.

Table 9-5. TB Leingang 2: Proposed Well Information

Well Name:	TB Leingang 2	**NDIC File No.:**	40178	**API No.:**	33-065-00027
County:	Oliver	**State:**	ND	**Operator:**	SUMMIT CARBON STORAGE #1, LLC
Location:	Sec. 18 T141N R87W	**Footages:**	2260 ft FNL, 521 ft FEL	**Total Depth:**	6351 ft, MD

Table 9-6. TB Leingang 2: Proposed Casing Program

Section	**Hole Size, in.**	**Casing OD, in.**	**Weight, lb/ft**	**Grade**	**Connection**	**Top Depth,* ft**	**Bottom Depth,*ft**	**Objective**
Surface	17.5	13.375	61	K-55	BTC	0	2016	Protects USDW Fox Hills Formation
Long-String	12.25	9.625	47	L-80	SLIJ-II	0	4117	Long-string casing
	12.25	9.625	47	25Cr-80	SLIJ-II	4117	4924	CO_2-resistant across Inyan Kara Formation
	12.25	9.625	47	L-80	SLIJ-II	4924	5532	Long-string casing
	12.25	9.625	47	25Cr-80	SLIJ-II	5532	6351	CO_2-resistant across Broom Creek Formation

* Depths are in MD based on proposed wellbore trajectory and formation top prognosis.

Table 9-7. TB Leingang 2: Proposed Casing Properties

									Yield Strength, klb	
Section	**OD, in.**	**Grade**	**Weight, lb/ft**	**Connection**	**ID, in.**	**Drift ID, in.**	**Collapse, psi**	**Burst, psi**	**Body**	**Connection**
Surface	13.375	K-55	61	BTC	12.515	12.359	1537	3088	963	1170
Long-String	9.625	L-80	47	SLIJ-II	8.681	8.525	4756	6858	1087	780
	9.625	25Cr-80	47	SLIJ-II	8.681	8.525	4756	6858	1087	780

Table 9-8. TB Leingang 2: Proposed Cement Program

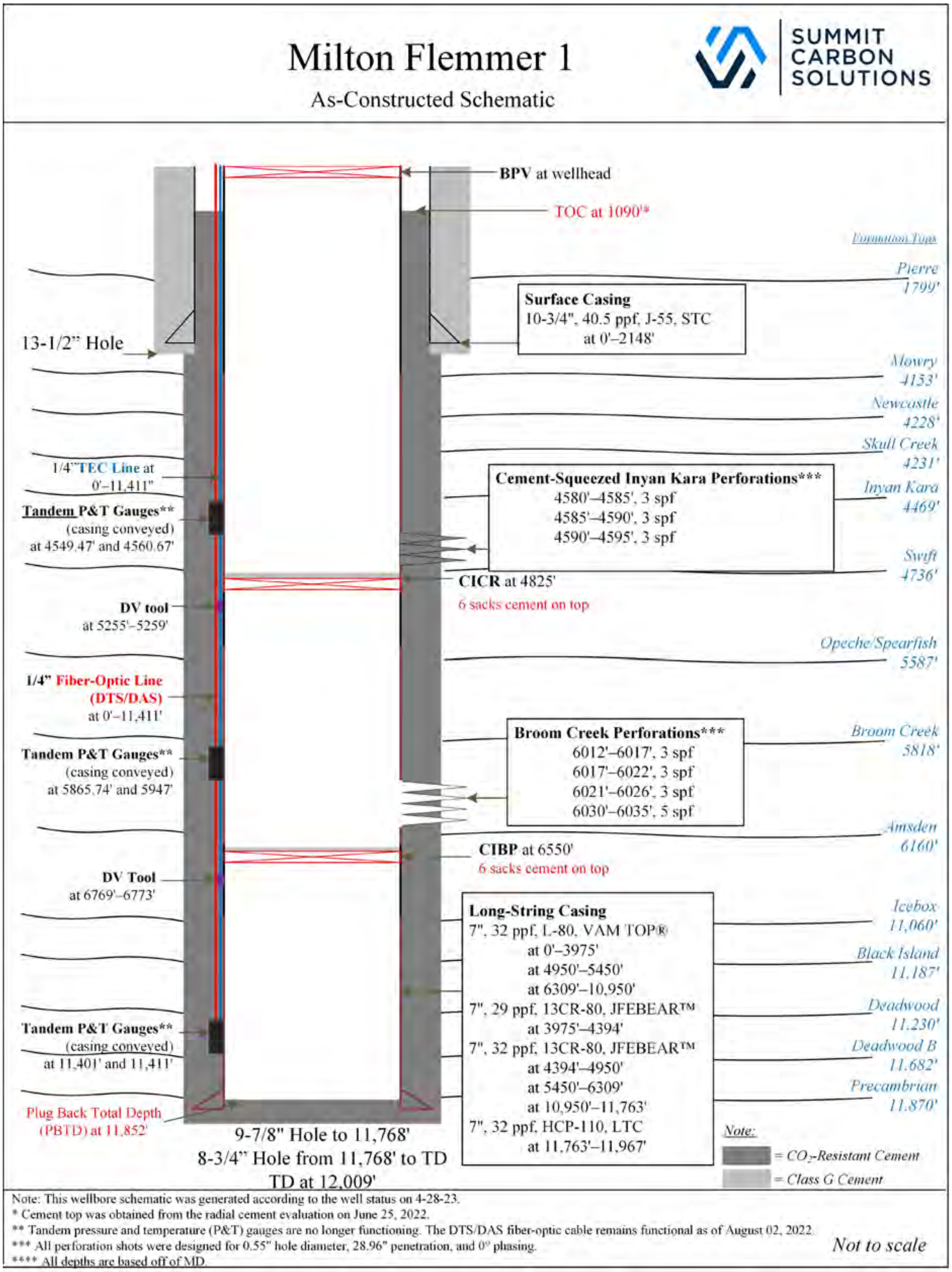
Section	**Casing OD, in.**	**Type/ Name**	**Lead/Tail/Single**	**Stage**	**Slurry Weight, ppg**	**Slurry Yield, ft^3/sack**	**Interval,* ft**	**Excess**	**Volume, sacks**
Surface	13.375	Class G	Single	NA	12.5	2.220	0–2016	100	1305
Long-String	9.625	Class G	Single	Stage 2	12.2	2.214	0–3992	100	880
	Stage 2 Through DV Tool at 3992 ft, MD								
	9.625	CO_2-resistant	Single	Stage 1	13	1.541	3992–6351	100	970

* The cement top will be confirmed once the RCBL is performed. Depths are in MD based on proposed wellbore trajectory and formation top prognosis.

9.3 Milton Flemmer 1: As-Constructed CO_2 Monitoring Well Casing and Cementing Programs

The Milton Flemmer 1 well was permitted and drilled as a stratigraphic test well in November 2021 by the original operator, Summit Carbon Solutions, LLC (SCS). The Milton Flemmer 1 well was constructed and operated in compliance with N.D.A.C. § 43-05-01 requirements, bonded in accordance with N.D.A.C. § 43-02-03-15, and temporarily abandoned (TA) in accordance with N.D.A.C. § 43-02-03-55. As of December 2023, SCS has transferred ownership and operation of the Milton Flemmer 1 (API 33-057-00041, NDIC File No. 38594) well to SCS1 in accordance with N.D.A.C. § 43-02-03-15. Future plans for the Milton Flemmer 1 include utilizing the well as a reservoir-monitoring well. The as-constructed state of Milton Flemmer 1 is shown in Figure 9-5. The isolation scanner log, generally called an ultrasonic imaging tool (USIT), was deployed to determine the cement bond quality radially and provide a casing-inspection log. The isolation scanner log result is provided in Figure 9-6.

Table 9-9 provides well information for Milton Flemmer 1. Tables 9-10 through 9-12 provide the casing and cementing programs for Milton Flemmer 1 and have been updated according to the drilling performed in November 2021.



Note: This wellbore schematic was generated according to the well status on 4-28-23.

* Cement top was obtained from the radial cement evaluation on June 25, 2022.

** Tandem pressure and temperature (P&T) gauges are no longer functioning. The DTS/DAS fiber-optic cable remains functional as of August 02, 2022.

*** All perforation shots were designed for 0.55" hole diameter, 28.96" penetration, and 0° phasing.

**** All depths are based off of MD.

Figure 9-5. Milton Flemmer 1 as-constructed wellbore schematic.

Table 9-9. Milton Flemmer 1: As-Constructed Well Information

Well Name:	Milton Flemmer 1	**NDIC File No.:**	38594	**API No.:**	33-057-00041
County:	Mercer	**State:**	ND	**Original Operator:**	SUMMIT CARBON SOLUTIONS, LLC
				Current Operator:	SUMMIT CARBON STORAGE #1, LLC
Location:	Sec. 35, T141N, R88W	**Footages:**	306 ft FNL, 1839 ft FEL	**Total Depth:**	12,009 ft, MD

Table 9-10. Milton Flemmer 1: As-Constructed Casing Program

Section	Hole Size, in.	Casing OD, in.	Grade	Weight, lb/ft	Connection*	Top Depth,** ft	Bottom Depth,** ft	Objective
Surface	13.50	10.75	J-55	40.5	STC	0	2148	Protects USDW Fox Hills
Long-String	9.875	7.00	L-80	32	VAM TOP	0	3975	Long-string casing
	9.875	7.00	13Cr-80	29	JFE BEAR	3975	4394	CO_2-resistant across Inyan Kara Formation
	9.875	7.00	13Cr-80	32	JFE BEAR	4394	4950	CO_2-resistant across Inyan Kara Formation
	9.875	7.00	L-80	32	VAMTOP	4950	5450	Long-string casing
	9.875	7.00	13Cr-80	32	JFE BEAR	5450	6309	CO_2-resistant across Broom Creek Formation
	9.875	7.00	L-80	32	VAM TOP	6309	10,950	Long-string casing
	9.875	7.00	13Cr-80	32	JFE BEAR	10,950	11,763	CO_2-resistant across Deadwood Formation
	9.875 and 8.75***	7.00	HCP-110	32	LTC	11,763	11,967	Long-string casing

* STC: short-thread and coupled; LTC: long-thread and coupled; VAM TOP and JFE BEAR: gastight premium connection.

** Depths are in MD.

*** 9.875 in. hole to 11,768 ft, MD and 8.75 in. hole from 11,768 ft, MD to 12,009 ft, MD.

Table 9-11. Milton Flemmer 1: As-Constructed Casing Properties

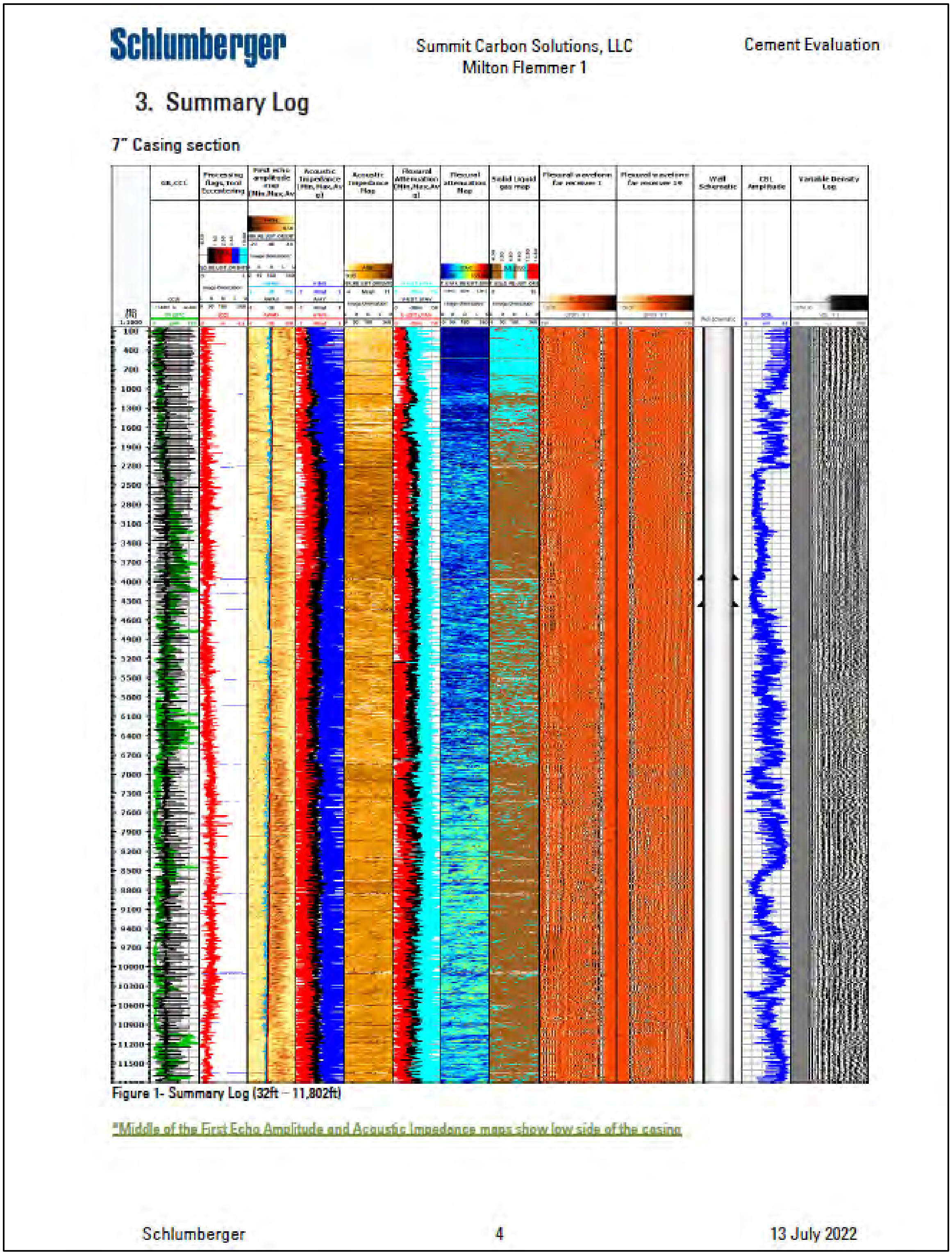
Section	OD, in.	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.	Collapse, psi	Burst, psi	Yield Strength, klb	
									Body	Connection
Surface	10.75	J-55	40.5	STC	10.050	9.894	1580	3130	629	420
Long-String	7.00	L-80	32	VAM TOP	6.094	5.969	8610	9060	745	745
	7.00	13Cr-80	29	JFE BEAR	6.184	6.059	7030	8160	676	676
	7.00	13Cr-80	32	JFE BEAR	6.094	5.969	8600	9060	745	745
	7.00	HCP-110	32	LTC	6.094	5.969	10,760	12,460	1025	897

Table 9-12. Milton Flemmer 1: As-Constructed Cement Program

Section	Casing OD, in.	Type	Lead/Tail/ Single	Stage	Slurry Weight, ppg	Interval,* ft, MD	Volume, sacks
Surface**	10.75	VariCem GS1	Lead	NA	11.5	0–2148	370
	10.75	VariCem GS1	Tail	NA	13.0		205
Long-String	7.00	EconoCem GWS 1	Lead	Stage 3	12.2	0–5255	270
	7.00	CorrosaCem	Tail	Stage 3	12.2		1000
	Stage 3 Through DV Tool at 5255–5259 ft, MD						
	7.00	CorrosaCem	Single	Stage 2	13.5	5255–6769	845
	Stage 2 Through DV Tool at 6769–6773 ft, MD						
	7.00	CorrosaCem	Single	Stage 1	13.0	6769–11,967	1440

* The cement intervals are based on the designed volumes in the cementing post job report. According to Halliburton, it is not possible to distinguish where CorrosaCem ends and EconoCem GWS 1 begins, but the isolation scanner illustrates isolation in the CO_2 injection zone (Figure 9-6), confining zones, and USDWs.

** On December 8, 2021, a top job was performed on the surface section. The job was a single-type Class G cement, with a slurry weight of 15.8 ppg. The interval for this job ranged from 0 to 110 feet.



Schlumberger

Summit Carbon Solutions, LLC
Milton Flemmer 1

Cement Evaluation

3. Summary Log

7" Casing section

Figure 1- Summary Log (32ft – 11,802ft)

*Middle of the First Echo Amplitude and Acoustic Impedance maps show low side of the casing

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Figure 9-6. Milton Flemmer 1 cement evaluation—RCBL from Milton Flemmer 1 verifies the cement bond quality. Using a high-resolution image, the analyst can assess isolation in the CO_2 injection zone, confining zones, and USDWs.

SECTION 10.0

PLUGGING PLAN

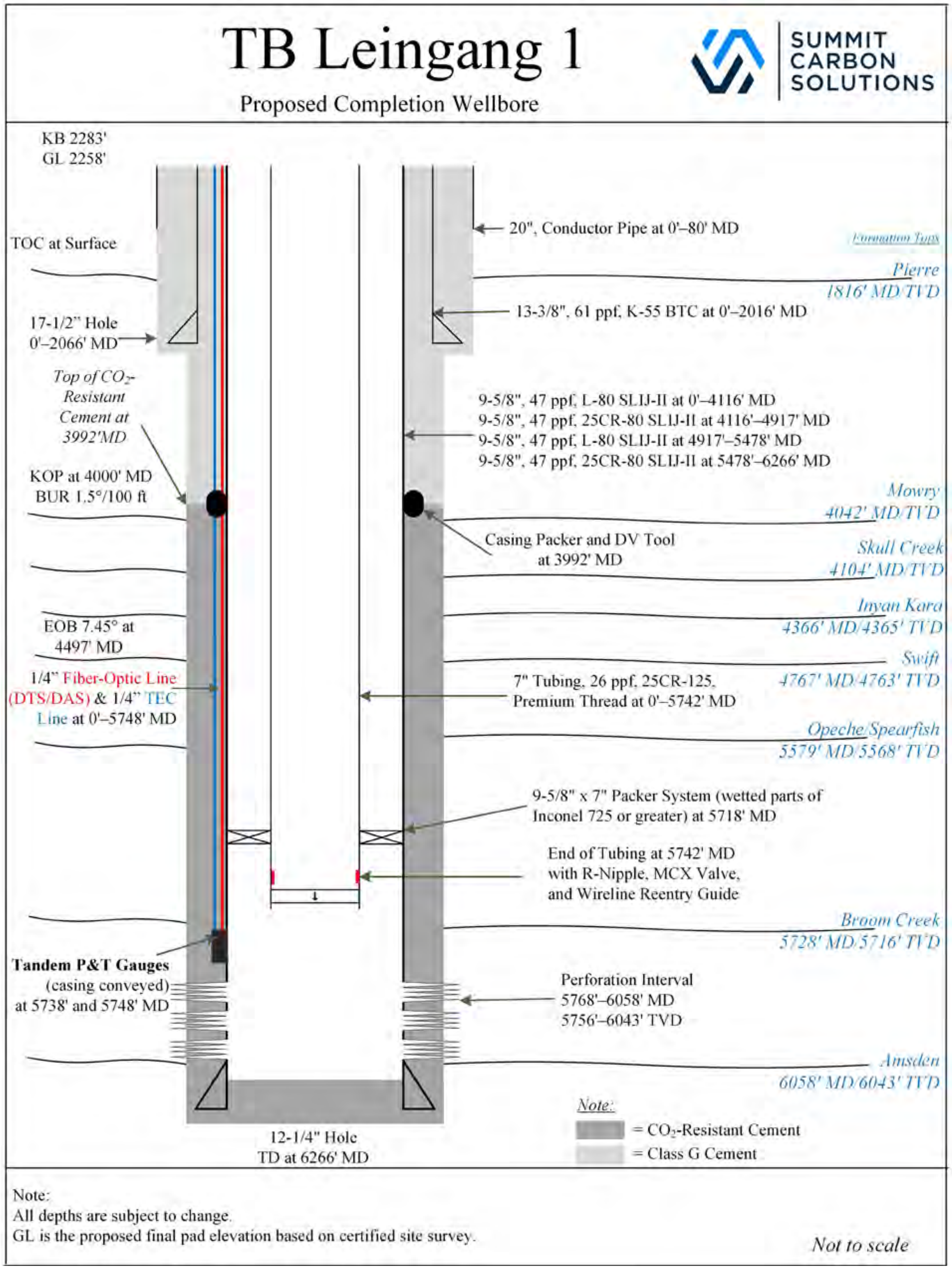
10.0 PLUGGING PLAN

The proposed plug and abandonment (P&A) procedures for the TB Leingang 1 and TB Leingang 2 wells are intended to be interpreted as proposed conditions and do not reflect the current as-proposed state for the wells. The proposed plugging procedure for the Milton Flemmer 1 does not reflect the current as-constructed state but the anticipated construction state at the time of abandonment during site closure. Plugging operations will likely occur at different times in the life cycle of the injector wells (TB Leingang 1 and TB Leingang 2) and the reservoir-monitoring well (Milton Flemmer 1). The injection wells (TB Leingang 1 and TB Leingang 2) are planned for P&A once the CO_2 injection operation ceases. The reservoir-monitoring well (Milton Flemmer 1) is planned for P&A after verification and the Department of Mineral Resources, Oil and Gas Division (DMR-O&G) has approved that the CO_2 plume has stabilized.

A proposed P&A procedure will be provided to DMR-O&G. Final procedures and requirements will be determined and approved at the time of abandonment. A CO_2-resistant cement plug will be placed across the CO_2 storage reservoir in addition to cement across other zones, as deemed necessary for isolation of oil-bearing zones, nitrogen zones, etc. After approval, ample notification will be given to allow a DMR-O&G 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 and complete isolation of the injection zone as per North Dakota underground injection control (UIC) Class VI requirements.

10.1 TB Leingang 1: Proposed Injection Well P&A Program

The TB Leingang 1 CO_2 injection well proposed completion schematic is provided in Figure 10-1. The proposed schematic is based on current information. The proposed P&A program may change based on the best knowledge available at the time of execution. The proposed P&A program may also change based on well response during the actual P&A procedures.



Note:
All depths are subject to change.
GL is the proposed final pad elevation based on certified site survey.

Figure 10-1. TB Leingang 1 proposed completion wellbore schematic.

DMR-O&G will be contacted, and an intent to P&A for TB Leingang 1 will be filed in NorthSTAR for approval. Final adjustments to the proposed P&A procedure will be made based on current wellbore conditions and DMR-O&G field inspector recommendations. Currently, the proposed P&A procedure for the well is as follows.

Proposed P&A Procedure

1. The procedures described below are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications, as per DMR-O&G approval, due to unforeseen circumstances will be described in the plugging report.

2. After injection operations have been terminated, the well will be flushed with kill fluid, which should be calculated from downhole gauges for proper fluid weight. A sufficient volume will be pumped to kill the well while remaining below the fracture pressure and ensuring control of the well.

3. Contact DMR-O&G supervisor and/or DMR-O&G field inspector 24 hours (hr) prior to moving onto location.

4. Dig out surface casing valve, and bleed off. Confirm most recent date of pull test. Pull test deadman anchors, if required. May require installing new deadman anchors depending on results.

5. Move in and rig up (MIRU) workover rig and surface equipment onto the TB Leingang 1 well. All CO_2 flowlines and valves will be marked and noted by the rig supervisor prior to MIRU.

6. Conduct and document a safety meeting. Check pressure at wellhead, and ensure pressure is off prior to starting work. Additional kill fluid may be needed.

7. Nipple-up (NU) lubricator, and install backpressure valve (BPV) in tubing hanger. Nipple-down (ND) Christmas tree, NU blowout preventer (BOP). Recover BPV, and install test plug. Test BOP for functionality. Pressure-test BOP to 80% of working pressure. Document BOP test.

8. Recover test plug. Connect a 7-in. work joint to the tubing hanger, and POOH (pull out of hole) until tubing hanger is unseated.

9. Release tubing from packer following the packer manufacturer instructions. Trip out of hole (TOOH) with 7-in. corrosion-resistant alloy (CRA) tubing string, and lay down.

   Contingency: If unable to release tubing from packer, rig up (RU) electric line, and make a cut on the tubing string just above the packer. Pull the tubing string out of hole, and proceed to the next step. If problems are noted, update the cement remediation plan.

10. Pick up (PU) 2⅞-in. work string, and stand in derrick. PU bit and scraper, and trip in hole (TIH) to top of packer. Perform reverse circulation, pump down casing annulus and up the work string to clean hole. TOOH with work string, bit, and scraper.

11. PU cast iron cement retainer (CICR) and stinger, and TIH to depth. Set CICR 20 ft above packer.

12. Spot cement equipment and RU, preparing to squeeze across Broom Creek Formation perforations and balance plugs.

13. Conduct and document a safety meeting prior to pumping cement. Ensure all materials are on location and accounted for. Confirm volumes, tests, procedures, operating equipment, and setting times with cement provider. Ensure **CO_2-resistant cement** is used for Broom Creek and Inyan Kara intervals. All other cement plugs should be of Class G grade or equivalent.

14. Pressure-test lines prior to pumping. Sting in and establish injection rate. Proceed with squeezing Broom Creek Formation perforations per cementer's planned procedures with 260 sacks (sx) of 15.2 pounds per gallon (ppg), 0.92 ft^3/sx **CO_2-resistant cement** and under displace 5 barrels of cement. Sting out of retainer, and finish displacing the last 5 barrels on top of the cement retainer. Check for flow. Pull work string above the plug.

15. Pressure-test casing to 1000 psi for 30 minutes or as approved by DMR-O&G. Record mechanical integrity test on casing. Circulate wellbore clean. TOOH with stinger and work string standing in derrick, and rig down (RD) stinger.

    Contingency: If pressure test failed, a cast iron bridge plug (CIBP) will be set below each subsequent plug until casing test passes.

16. If needed, RU logging unit. Confirm external mechanical integrity by running one of the tests listed below as options, and RD logging truck:

    - Activated neutron log
    - Noise log
    - Production logging tool (PLT)
    - Tracers
    - Temperature log
    - DTS (distributed temperature sensing) survey (no required logging unit)

    Note: If external failure in long-string casing is identified, the operator will adjust the P&A plan with DMR-O&G's approval.

17. If pressure test failed, set a CIBP prior to pumping balanced plug. TIH with work string and diffuser to depth of Plug 2. Pump 270 sx of 15.2 ppg, 0.92 ft^3/sx **CO_2-resistant cement** balanced plug as designed from cementer's proposed procedures across Inyan Kara interval.

18. Pull up work string above the top of the plug, and test casing. Circulate wellbore clean.

19. Set a CIBP prior to pumping Plug 3 if previous test failed. TOOH to depth of Plug 3. Pump 95 sx of 15.8 ppg, 1.15 ft^3/sx Class G cement at 2116 ft. Pull up work string above the top of the plug, and circulate wellbore clean.

20. TOOH laying down work string to 90 ft. Pump 40 sx of 15.8 ppg, 1.15 ft^3/sx Class G cement plug at 90 ft. Lay down all work string.

    Contingency: Perform top job as necessary to ensure good cement on both sides.

21. RD all equipment, and move out.

22. 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.

23. Dig out deadman anchors. Report photos of steel cap to DMR-O&G.

24. Within 60 days, submit Form 7 plugging report after plugging operations are complete (N.D.A.C. § 43-05-01-11.5[4]).

25. Submit notice of intent to reclaim to DMR-O&G 30 days in advance prior to reclamation (N.D.A.C. § 43-05-01-18[10][d]).

The proposed P&A plan for TB Leingang 1 is summarized in Table 10-1 and provided in Figure 10-2. These values are estimated; final volume and thickness of plugs will be determined by design at time of plugging.

Table 10-1. Summary of P&A Plan for TB Leingang 1

Cement Plug No.	Cement Type	Weight, ppg	Yield, ft^3/sx	Interval, ft, MD	Thickness, ft	Volume, sx	Notes
Plug 4	Class G	15.8	1.15	0–90	90	40	Surface plug
Plug 3	Class G	15.8	1.15	1866–2116	250	95	Isolate Fox Hills Formation at base of surface casing
Plug 2	CO_2-resistant	15.2	0.92	4166–4766	600	270	Isolate Inyan Kara Formation from Fox Hills Formation
Plug 1	CO_2-resistant	15.2	0.92	5698–6266	568	260	Squeeze perforations and mechanically isolate Broom Creek Formation

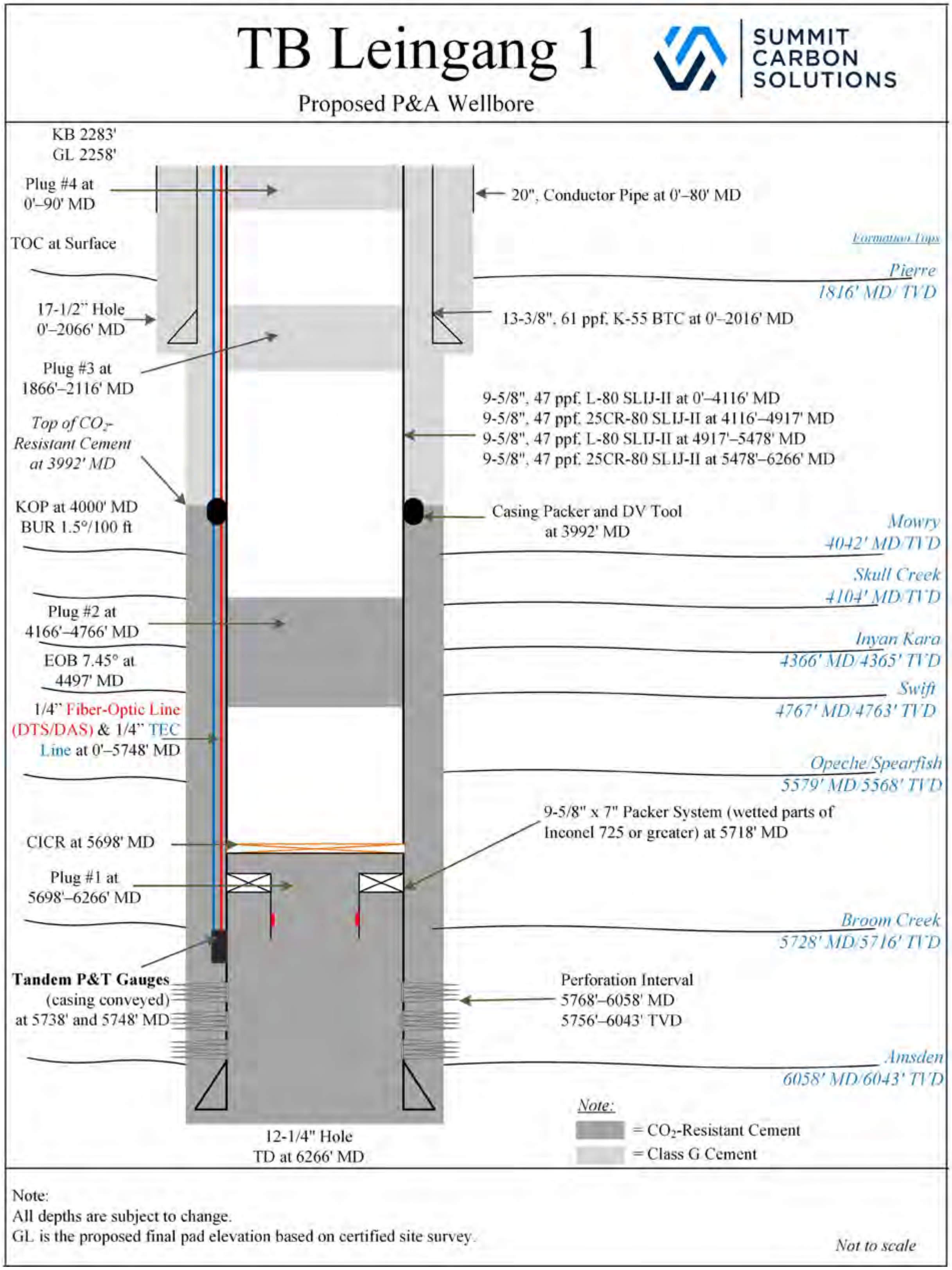


Figure 10-2. TB Leingang 1 proposed P&A wellbore schematic.

10.2 TB Leingang 2: Proposed Injection Well P&A Program

The TB Leingang 2 CO_2 injection well proposed completion schematic is provided in Figure 10-3. The proposed schematic is based on current information. The proposed P&A program may change based on the best knowledge available at the time of execution. The proposed P&A program may also change based on well response during the actual P&A procedures.

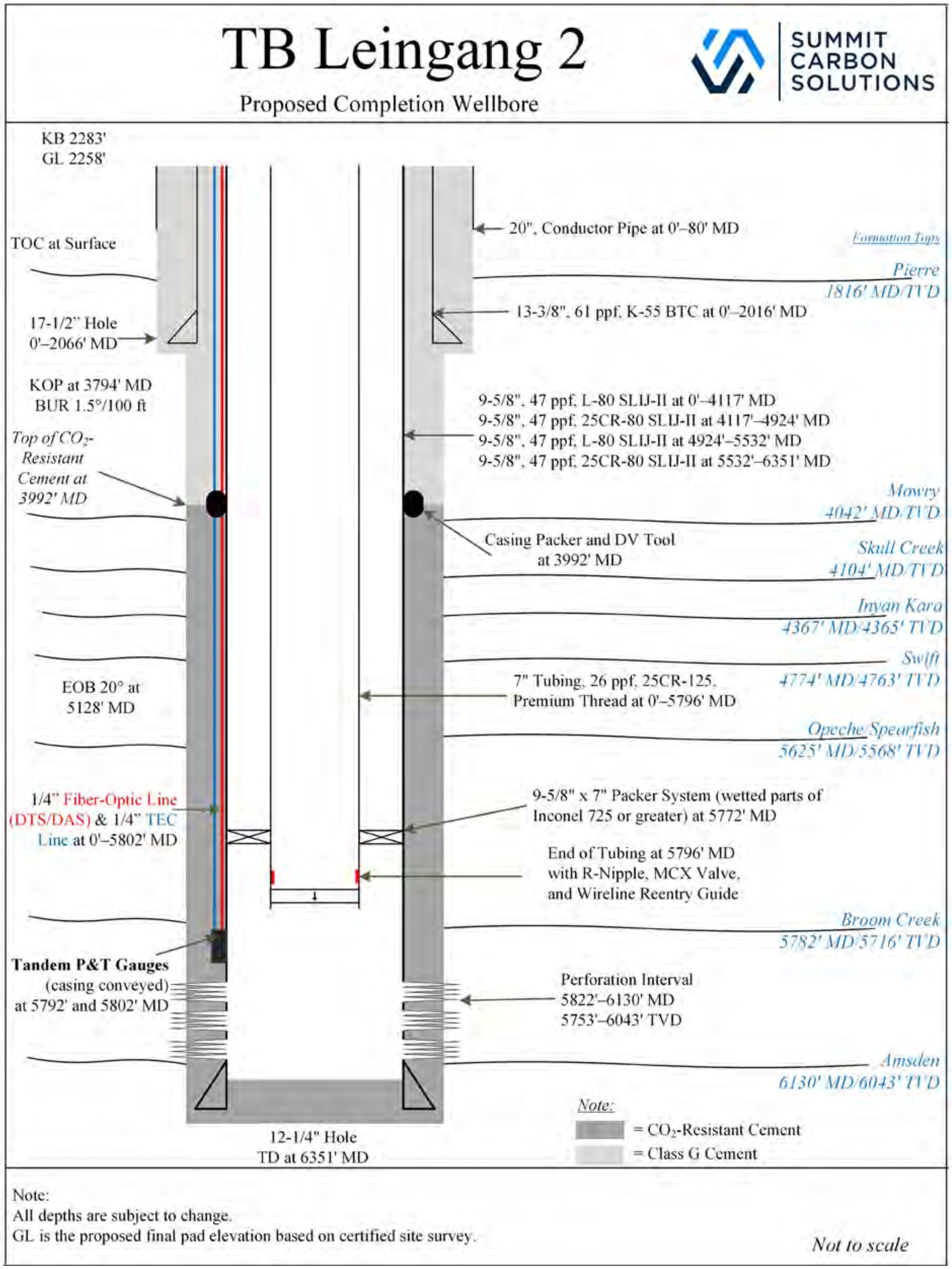


Figure 10-3. TB Leingang 2 proposed completion wellbore schematic.

DMR-O&G will be contacted, and an intent to P&A for TB Leingang 2 will be filed in NorthSTAR for approval. Final adjustments to the proposed P&A procedure will be made based on current wellbore conditions and DMR-O&G field inspector recommendations. Currently, the proposed P&A procedure for the well is as follows.

Proposed P&A Procedure:

1. The procedures described below are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications, as per DMR-O&G approval, due to unforeseen circumstances will be described in the plugging report.

2. After injection operations have been terminated, the well will be flushed with kill fluid, which should be calculated from downhole gauges for proper fluid weight. A sufficient volume will be pumped to kill the well while remaining below the fracture pressure and ensuring control of the well.

3. Contact DMR-O&G supervisor and/or DMR-O&G field inspector 24 hr prior to moving onto location.

4. Dig out surface casing valve, and bleed off. Confirm most recent date of pull test. Pull test deadman anchors if required. May require installing new deadman anchors depending on results.

5. MIRU workover rig and surface equipment onto the TB Leingang 2 well. All CO_2 flowlines and valves will be marked and noted by the rig supervisor prior to MIRU.

6. Conduct and document a safety meeting. Check pressure at wellhead, and ensure pressure is off prior to starting work. Additional kill fluid may be needed.

7. NU lubricator, and install BPV in tubing hanger. ND Christmas tree, NU BOP. Recover BPV, and install test plug. Test BOP for functionality. Pressure-test BOP to 80% of working pressure. Document BOP test.

8. Recover test plug. Connect a 7-in. work joint to the tubing hanger, and POOH until tubing hanger is unseated.

9. Release tubing from packer following the packer manufacturer instructions. TOOH with 7-in. CRA tubing string, and lay down.

   Contingency: If unable to release tubing from packer, RU electric line, and make a cut on the tubing string just above the packer. Pull the tubing string out of hole, and proceed to the next step. If problems are noted, update the cement remediation plan.

10. PU 2⅞-in. work string, and stand in derrick. PU bit and scraper, and TIH to top of packer. Perform reverse circulation, pump down casing annulus and up the work string to clean hole. TOOH with work string, bit, and scraper.

11. PU CICR and stinger, and TIH to depth. Set CICR 20 ft above packer.

12. Spot cement equipment, and RU. Prepare to squeeze across Broom Creek Formation perforations and balance plugs.

13. Conduct and document a safety meeting prior to pumping cement. Ensure all materials are on location and accounted for. Confirm volumes, tests, procedures, operating equipment, and setting times with cement provider. Ensure **CO_2-resistant cement** is used for Broom Creek and Inyan Kara intervals. All other cement plugs should be of Class G grade or equivalent.

14. Pressure-test lines prior to pumping. Sting in, and establish injection rate. Proceed with squeezing Broom Creek Formation perforations per cementer's planned procedures with 280 sx of 15.2 ppg, 0.92 ft^3/sx **CO_2-resistant cement** and under displace 5 barrels of cement. Sting out of retainer, and finish displacing the last 5 barrels on top of the cement retainer. Check for flow. Pull work string above the plug.

15. Pressure-test casing to 1000 psi for 30 minutes or as approved by DMR-O&G. Record mechanical integrity test on casing. Circulate wellbore clean. TOOH with stinger and work string standing in derrick, and RD stinger.

    Contingency: If pressure test failed, a CIBP will be set below each subsequent plug until casing test passes.

16. If needed, RU logging unit. Confirm external mechanical integrity by running one of the tests listed below as options, and RD logging truck:

    - Activated neutron log
    - Noise log
    - PLT
    - Tracers
    - Temperature log
    - DTS survey (no required logging unit)

    Note: If external failure in long-string casing is identified, the operator will adjust the P&A plan with DMR-O&G's approval.

17. If pressure test failed, set a CIBP prior to pumping balanced plug. TIH with work string and diffuser to depth of Plug 2. Pump 270 sx of 15.2 ppg, 0.92 ft^3/sx **CO_2-resistant cement** balanced plug as designed from cementer's proposed procedures across Inyan Kara interval.

18. Pull up work string above the top of the plug and test casing. Circulate wellbore clean.

19. Set a CIBP prior to pumping Plug 3 if previous test failed. TOOH to depth of Plug 3. Pump 95 sx of 15.8 ppg, 1.15 ft^3/sx Class G cement at 2116 ft. Pull up work string above the top of the plug and circulate wellbore clean.

20. TOOH laying down work string to 90 ft. Pump 40 sx of 15.8 ppg, 1.15 ft^3/sx Class G cement plug at 90 ft. Lay down all work string.

    Contingency: Perform top job as necessary to ensure good cement on both sides.

21. RD all equipment and move out.

22. Dig out wellhead and cut off casing 5-ft below GL. Weld ½-in. steel cap on casing with well name, date inscribed, and information that it was used for CO_2 injection.

23. Dig out deadman anchors. Report photos of steel cap to DMR-O&G.

24. Within 60 days, submit Form 7 plugging report after plugging operations are complete (N.D.A.C. § 43-05-01-11.5[4]).

25. Submit notice of intent to reclaim to DMR-O&G 30 days in advance prior to reclamation (N.D.A.C. § 43-05-01-18[10][d]).

The proposed P&A plan for TB Leingang 2 is summarized in Table 10-2 and provided in Figure 10-4. These values are estimated; final volume and thickness of plugs will be determined by design at time of plugging.

Table 10-2. Summary of P&A Plan for TB Leingang 2

Cement Plug No.	Cement Type	Weight, ppg	Yield, ft^3/sx	Interval, ft, MD	Thickness, ft	Volume, sx	Notes
Plug 4	Class G	15.8	1.15	0–90	90	40	Surface plug
Plug 3	Class G	15.8	1.15	1866–2116	250	95	Isolate Fox Hills Formation at base of surface casing
Plug 2	CO_2-resistant	15.2	0.92	4168–4768	600	270	Isolate Inyan Kara Formation from Fox Hills Formation
Plug 1	CO_2-resistant	15.2	0.92	5752–6351	599	280	Squeeze perforations and mechanically isolate Broom Creek Formation

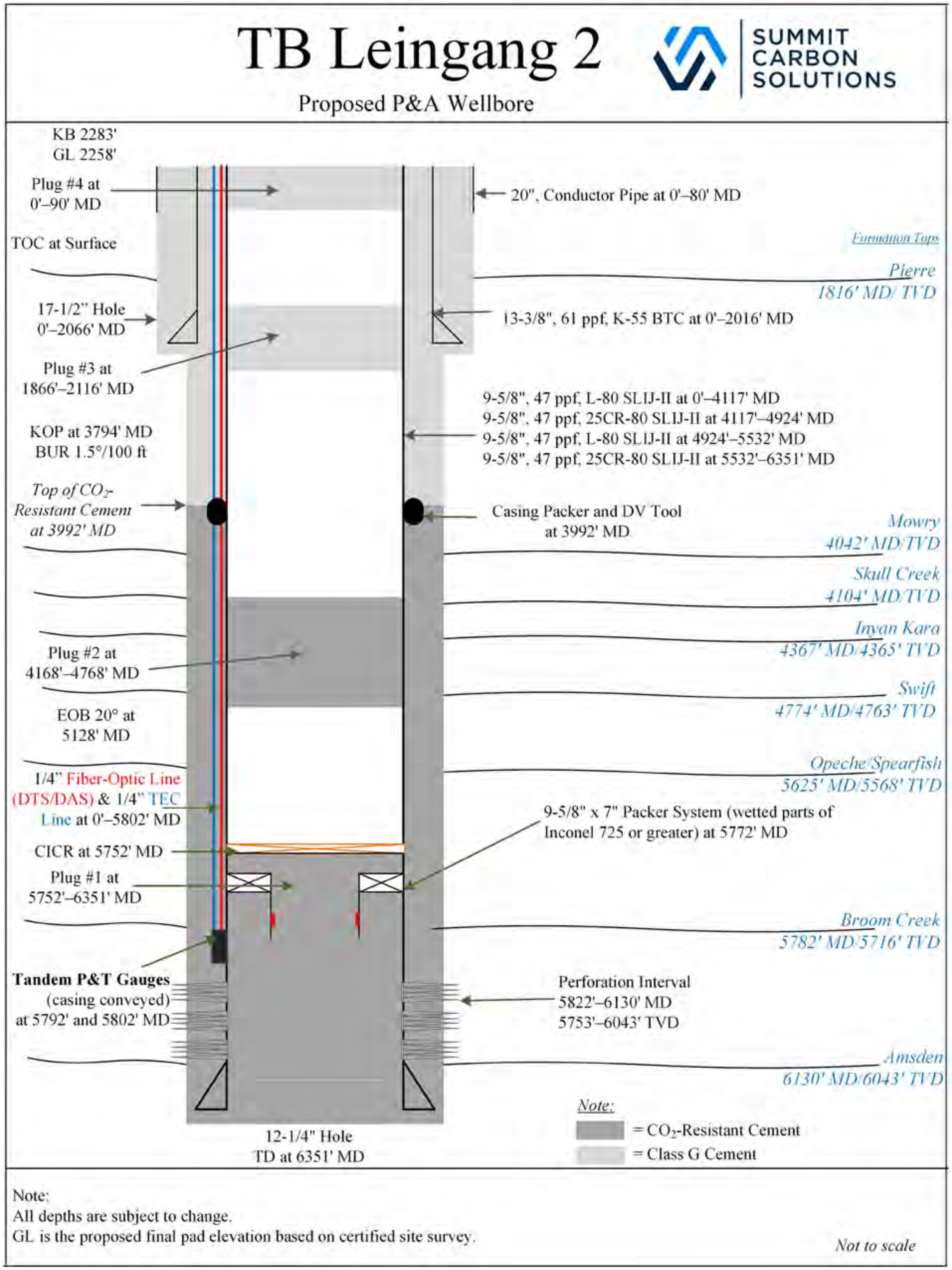
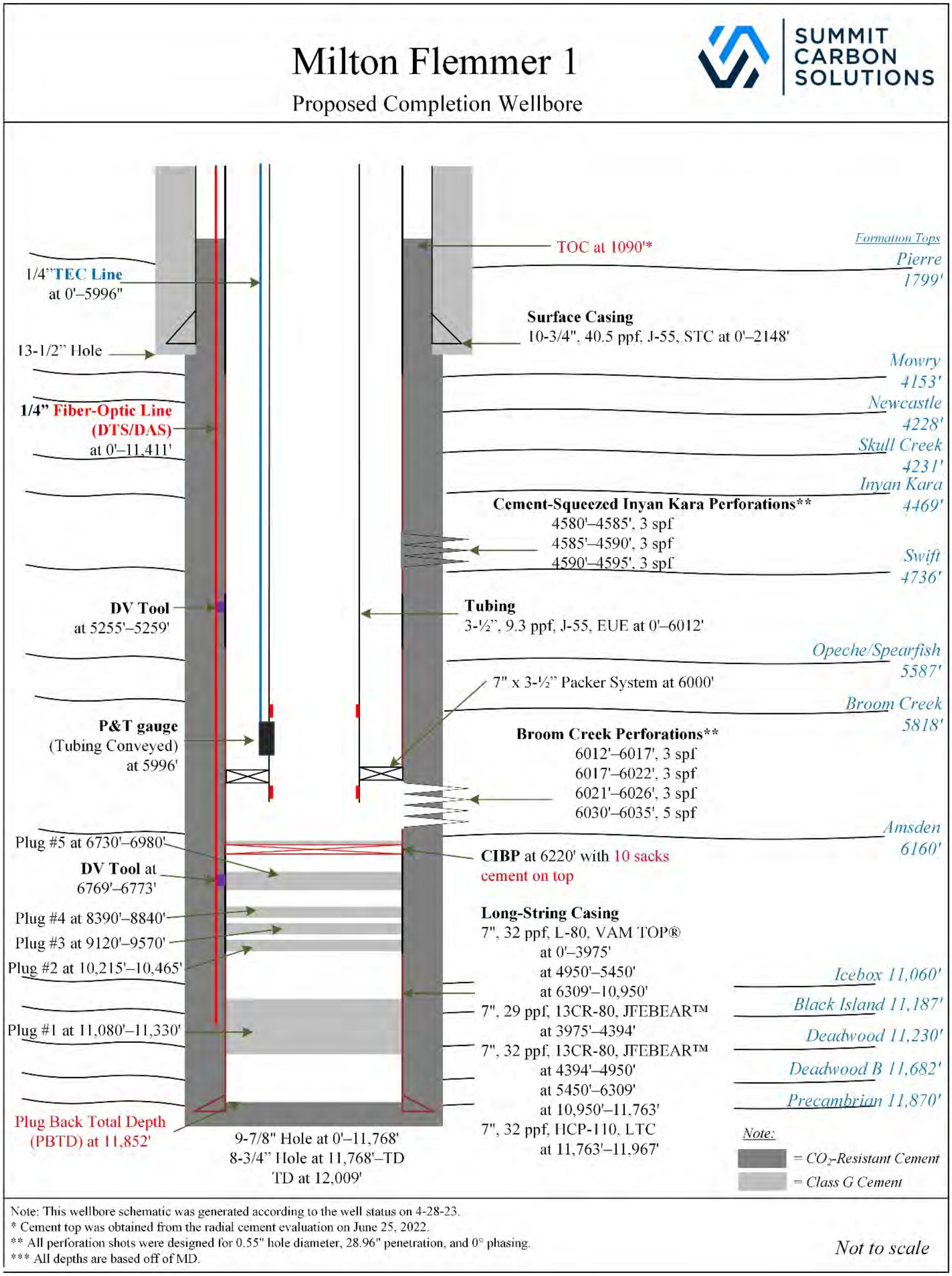


Figure 10-4. TB Leingang 2 proposed P&A wellbore schematic.

10.3 Milton Flemmer 1: Proposed Reservoir-Monitoring Well P&A Program

The Milton Flemmer 1 wellbore will be P&A when the CO_2 plume has stabilized and monitoring of the plume extent is no longer necessary. A proposed reservoir-monitoring well completion schematic of Milton Flemmer 1 is provided in Figure 10-5. Described in Section 11.3, proposed completion procedure of Milton Flemmer 1, including plugback procedures, will be conducted prior to injection operations. The proposed P&A program may change based on the best knowledge available at the time of execution. The proposed P&A program may also change based on well response during the actual P&A procedures.



Note: This wellbore schematic was generated according to the well status on 4-28-23.
* Cement top was obtained from the radial cement evaluation on June 25, 2022.
** All perforation shots were designed for 0.55" hole diameter, 28.96" penetration, and 0° phasing.
*** All depths are based off of MD.

Figure 10-5. Milton Flemmer 1 proposed completion wellbore schematic.

DMR-O&G will be contacted, and an intent to P&A for Milton Flemmer 1 will be filed in NorthSTAR for approval. Final adjustments to the proposed P&A procedure will be made based on current wellbore conditions and DMR-O&G field inspector recommendations. Currently, the proposed P&A procedure for the well is as follows.

Proposed P&A Procedure:

1. The procedures described below are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications, as per DMR-O&G approval, due to unforeseen circumstances will be described in the plugging report.

2. After monitoring operations have been terminated, the well will be flushed with kill fluid, which should be calculated from downhole gauges for proper fluid weight. A sufficient volume will be pumped to kill the well while remaining below the fracture pressure and ensuring control of the well.

3. Contact DMR-O&G supervisor and/or DMR-O&G field inspector 24 hr prior to moving onto location.

4. Dig out surface casing valve, and bleed off. Confirm most recent date of pull test. Pull test deadman anchors, if required. May require installing new deadman anchors depending on results.

5. MIRU workover rig and surface equipment onto the Milton Flemmer 1 well.

6. Conduct and document a safety meeting. Check pressure at wellhead, and ensure pressure is off prior to starting work. Additional kill fluid may be needed.

7. Fill tubing with kill fluid. Bleeding off occasionally may be necessary to remove all air from the system. Monitor tubing and annulus pressure.

8. If both casing and tubing are dead, ND wellhead and NU BOP. Install test plug. Test BOP for functionality. Pressure-test BOP to 80% of working pressure. Document BOP test.

   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 fluid until the well is under control. After casing and tubing pressure are zero, ND Christmas tree, NU BOPs, and perform a function test. Prepare to recover packer with work string in case the packer needs to be unlatched.

9. Unseat tubing hanger. Release 3½-in. tubing, and POOH and lay down tubing, cable, and sensors.

   Contingency: If unable to release tubing from the packer, RU electric line, and make a cut on the tubing string just above the packer. Pull the tubing string out of hole, and proceed to the next step. If problems are noted, update the cement remediation plan.

10. Make up (MU) bottomhole assembly (BHA) to include 6-in. bit, mud motor, drill collars, and jars. Tally and TIH BHA and 2⅞-in. work string and tag packer.

11. Drill out packer. Tally and continue to PU work string and tag CIBP at 6220 ft. Circulate hole clean with 9.8-ppg working fluid.

12. TOOH laying down BHA.

13. Spot and RU cementing equipment. Conduct and document a safety meeting prior to pumping cement. Confirm equipment and setting times with cement provider. Ensure **CO_2-resistant cement** is used for Broom Creek and Inyan Kara intervals. All other cement plugs should be of Class G grade or equivalent.

14. RU Wireline. PU CICR. Run in hole (RIH) with CICR, and set at 5620 ft.

15. Prepare to perform cement squeeze Broom Creek Formation perforations with **CO_2-resistant cement**. Tally, TIH, and sting into CICR. Establish injection rate. Mix and pump 145 sx of 15.2 ppg, 0.92 ft^3/sx CO_2-resistant cement, squeeze 135 sx into retainer, sting out and spot 10 sx on top.

16. TOOH with stinger and work string, standing in derrick, and RD stinger.

17. TIH open ended to 4870 ft. Prepare to pump Inyan Kara Formation balanced plug with CO_2-resistant cement. Mix and pump 135 sx of 15.2 ppg, 0.92 ft^3/sx **CO_2-resistant cement** across Inyan Kara.

18. TOOH laying down work string to 2250 ft. Mix and pump 50 sx of 15.8-ppg, 1.15 ft^3/sx Class G cement across surface casing shoe.

19. TOOH. As per cement bond log (CBL), top of cement (TOC) is picked at 1090 ft. Perforate 2-hole squeeze shot at 90 ft. Close BOP blind rams, and break circulation out of surface casing.

20. Pump 45 sx of 15.8 ppg, 1.15 ft^3/sx Class G cement plug to perforations at 90 ft until cement returns observed at surface. Lay down all work string.

    Contingency: Perform top job as necessary to ensure good cement in both 7-in. casing and 7-in. × 10¾-in. annulus.

21. ND BOP, RD all equipment, and move out.

22. Dig out wellhead and cut off casing 5-ft below GL. Weld ½-in. steel cap on casing with well name, date inscribed, and information that it was used for CO_2 monitoring.

23. Dig out deadman anchors. Report photos of steel cap to DMR-O&G.

24. Within 60 days, submit Form 7 plugging report after plugging operations are complete (N.D.A.C. § 43-05-01-11.5[4]).

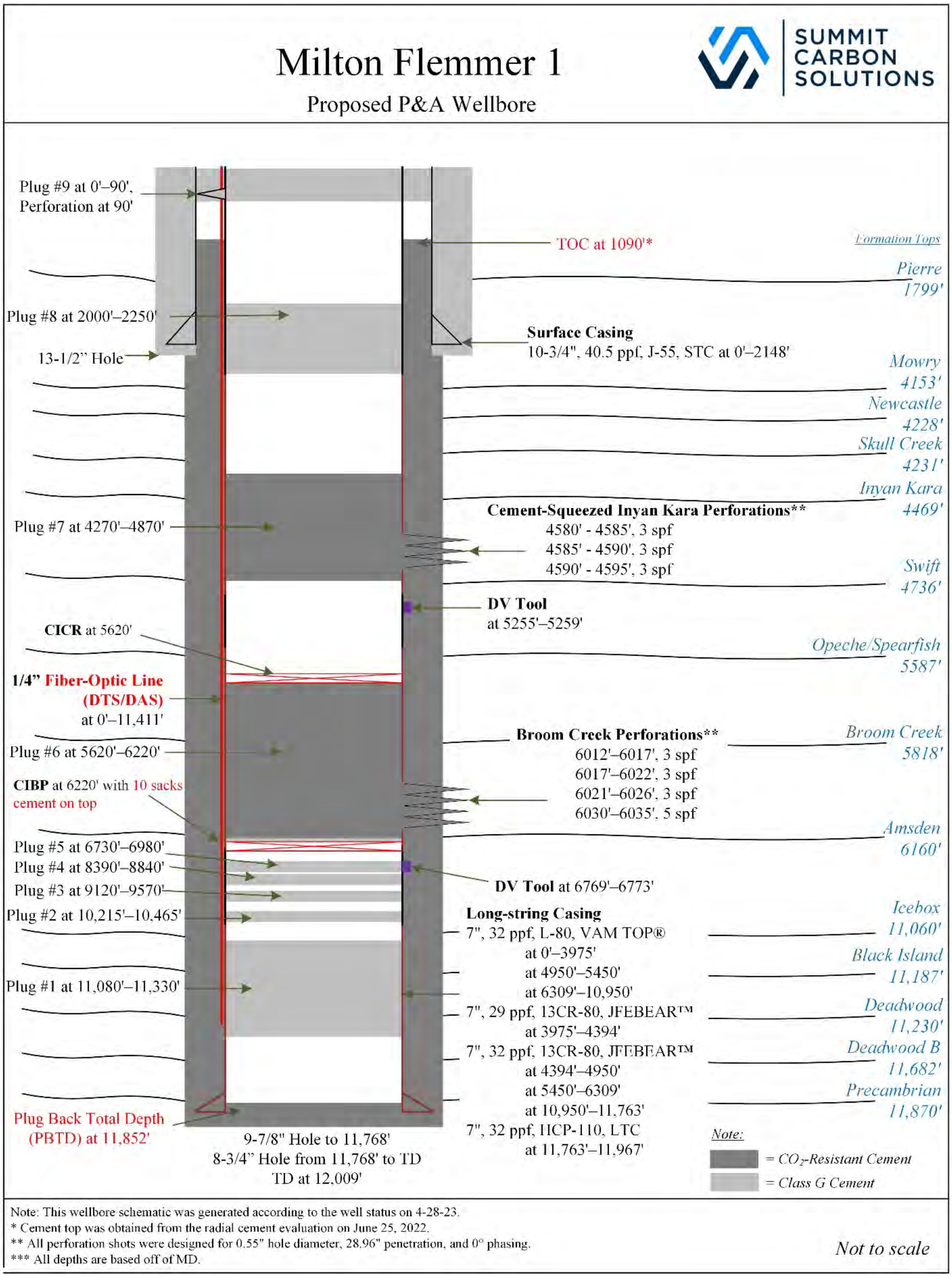
25. Submit notice of intent to reclaim to DMR-O&G 30 days in advance prior to reclamation (N.D.A.C. § 43-05-01-18[10][d]).

The proposed P&A plan for Milton Flemmer 1 is summarized in Table 10-3 and provided in Figure 10-6. These values are estimated; final volume and thickness of plugs will be determined by design at time of plugging.

Table 10-3. Summary of P&A Plan for Milton Flemmer 1

Cement Plug No.	Cement Type	Weight, ppg	Yield, ft^3/sx	Interval, ft, MD	Thickness, ft	Volume, sx	Notes
Plug 9	Class G	15.8	1.15	0–90	90	45	Surface plug
Plug 8	Class G	15.8	1.15	2000–2250	250	50	Isolate Fox Hills Formation at base of surface casing
Plug 7	CO_2-resistant	15.2	0.92	4270–4870	600	135	Isolate Inyan Kara Formation from Fox Hills Formation
Plug 6	CO_2-resistant	15.2	0.92	5620–6220	600	145	Squeeze perforations and mechanically isolate Broom Creek Formation
Plug 5*	Class G	15.8	1.15	6730–6980	250	50	Isolate the Madison Group
Plug 4*	Class G	15.8	1.15	8390–8840	450	85	Isolate the Duperow and Bakken
Plug 3*	Class G with 35% silica	15.6	1.50	9120–9570	450	65	Isolate the Interlake and Dawson Bay
Plug 2*	Class G with 35% silica	15.6	1.50	10,215–10,465	250	40	Isolate the Red River
Plug 1*	Class G with 35% silica	15.6	1.50	11,080–11,330	250	40	Isolate the Deadwood

* Described in Section 11.3, plugs are set during plugback conversion of monitoring well prior to injection operations.



Note: This wellbore schematic was generated according to the well status on 4-28-23.
* Cement top was obtained from the radial cement evaluation on June 25, 2022.
** All perforation shots were designed for 0.55" hole diameter, 28.96" penetration, and 0° phasing.
*** All depths are based off of MD.

Figure 10-6. Milton Flemmer 1 proposed P&A wellbore schematic.

SECTION 11.0

INJECTION WELL AND STORAGE OPERATIONS

11.0 INJECTION WELL AND STORAGE OPERATIONS

This section of the storage facility permit (SFP) application presents the engineering criteria for completing and operating the injection wells in a manner that protects underground sources of drinking water (USDWs). The information presented in Table 11-1 meets the permit requirements for injection well and storage operations (North Dakota Administrative Code [N.D.A.C.] § 43-05-01-05 and § 43-05-01-11.3). Planned well logging, testing, and monitoring activities can be found in Sections 5.0 and 6.0.

Table 11-1. TB Leingang 1 and TB Leingang 2: Proposed Injection Well Operating Parameters

Item	Values	Description/Comments	
Injected Volume			
Total Injected Mass/Volume	124.4 MMt 6.22 MMt/yr 2,351,294 MMcf	Based on a maximum wellhead pressure (WHP) constraint of 2100 psi and maximum bottomhole pressure (BHP) constraint	
Injection Rates	**TB Leingang 1**	**TB Leingang 2**	**Description/Comments**
Average Injection Rate	8616 tonnes/day (163 MMscf/day) 3.145 MMt/yr 1,188,878 MMcf 62.9 MMt	8425 tonnes/day (159.2 MMscf/day) 3.075 MMt/yr 1,162,416 MMcf 61.5 MMt	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Average Maximum Injection Rate*	25,315 tonnes/day (478.5 MMscf/day) 9.24 MMt/yr 3,492,920 MMcf 184.8 MMt	24,205 tonnes/day (457.5 MMscf/day) 8.835 MMt/yr 3,339,821 MMcf 176.7 MMt	Based on maximum BHP with only one well injecting at a time: TB Leingang 1: 3663 psi TB Leingang 2: 3669 psi
Depth	**TB Leingang 1**	**TB Leingang 2**	**Description/Comments**
Depth (true vertical depth [TVD]) of the top perforation used in the BHP calculation	5668 ft	5678 ft	Depths are for simulation modeling, taken prior to final site survey
Pressure	**TB Leingang 1**	**TB Leingang 2**	**Description/Comments**
Formation Fracture Pressure at Top Perforation	4070 psi	4077 psi	Based on geomechanical analysis of formation fracture gradient as 0.718 psi/ft
Average Surface Injection Pressure	2100 psi	2100 psi	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Maximum Surface Injection Pressure*	5500 psi	5120 psi	Based on maximum BHP with only one well injecting at a time (using the designed 7-inch tubing): TB Leingang 1: 3663 psi TB Leingang 2: 3669 psi

Continued . . .

Table 11-1. TB Leingang 1 and TB Leingang 2: Proposed Injection Well Operating Parameters (continued)

Pressure	TB Leingang 1	TB Leingang 2	Description/Comments
Average BHP	3621 psi	3633 psi	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Calculated Maximum BHP	3663 psi	3669 psi	Based on 90% of the formation fracture pressure: 4070 psi for TB Leingang 1 4077 psi for TB Leingang 2

*Maximum injection pressure during operations will be limited to the surface equipment pressure ratings and maximum BHP constraint.

11.1 TB Leingang 1: Proposed Completion Procedure to Conduct Injection Operations

As described in Section 9.1, the TB Leingang 1 well will be drilled and completed as a CO_2 injector (Figures 11-1 and 11-2 and Tables 11-2, 11-3, and 11-4). The following proposed completion procedure outlines the steps necessary to complete and test the well for injection purposes. The procedures described below are subject to change during execution as necessary to ensure successful completion and/or testing.

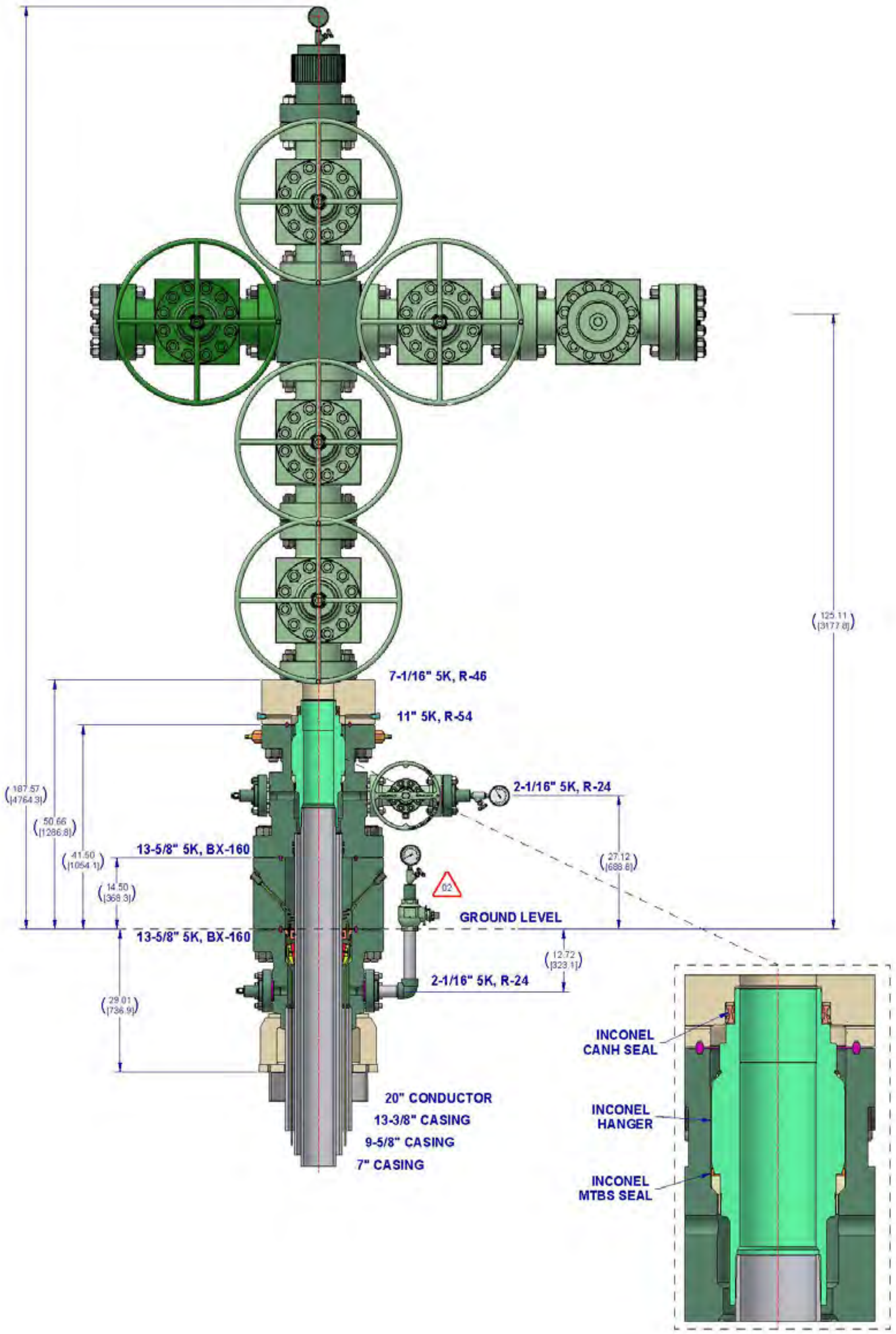


Figure 11-1. TB Leingang 1 proposed CO_2-resistant wellhead schematic. Lowest manual valve of injection tree will be of Class HH material, and the tubing hanger mandrel will be of CRA (corrosion-resistant alloy) material, while the rest of the tree will consist of Class FF and equivalent.

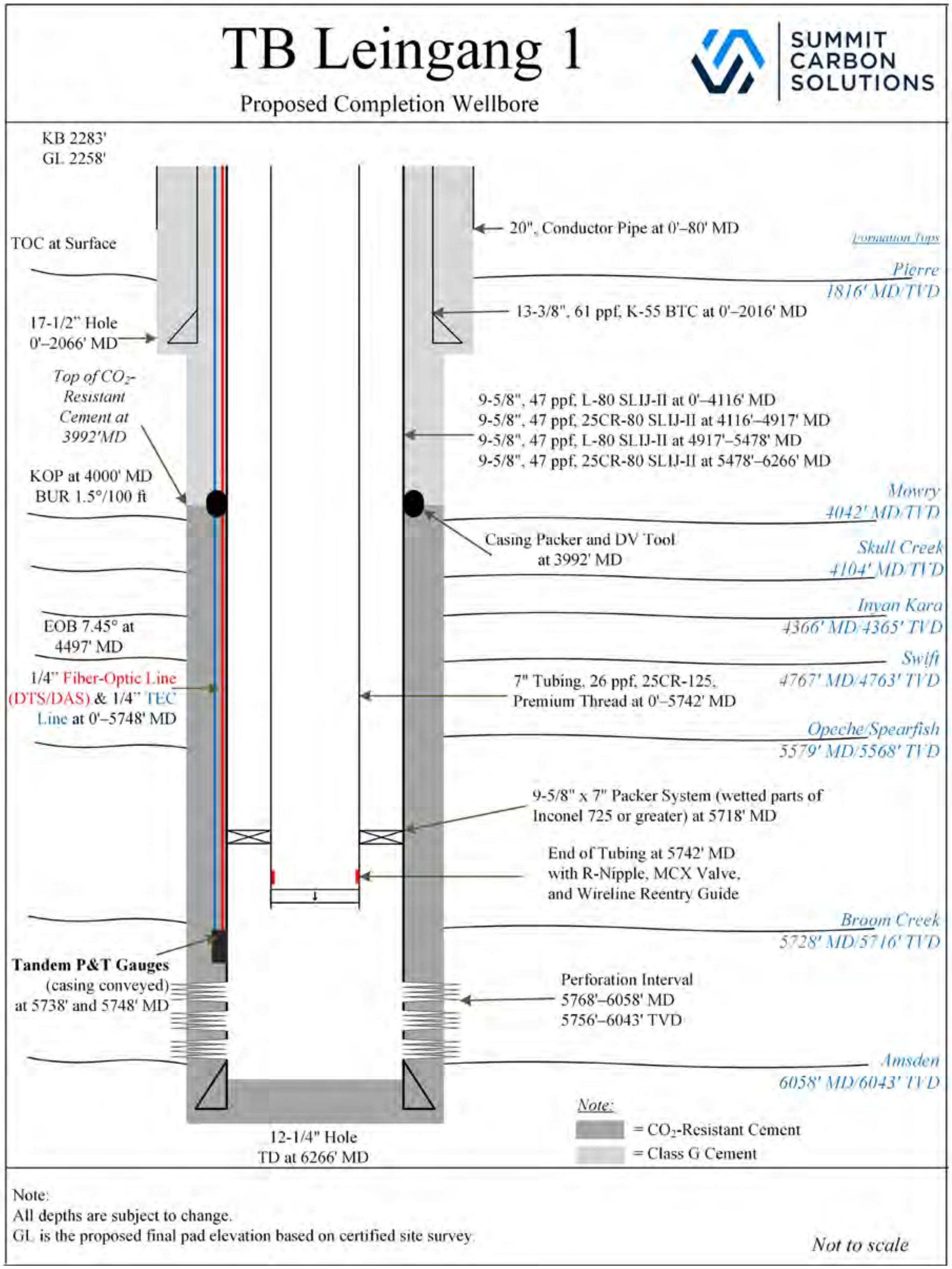


Figure 11-2. TB Leingang 1 proposed completion wellbore schematic.

Table 11-2. TB Leingang 1: Tubing Properties

OD ,* in.	Grade	Weight, lb/ft	Connection	ID,** in.	Drift ID, in.	Collapse, psi	Burst, psi	Tension, klb
7.000	25Cr-125	26	Sentinel	6.276	6.151	6233	10,239	943

* Outer diameter.
** Inside diameter.

Table 11-3. TB Leingang 1: Tubing Accessories

Description	OD, in.	Depth,* ft, MD	Material	ID, in.	Drift ID, in.
Ratch Latch Assembly	7.765	5714	CRA	5.980	5.950
Packer	8.220	5718	CRA	5.980	5.950
Pup Joint	7.000	5725	25Cr-125	6.276	6.151
LN Profile	7.954	5731	CRA	5.875	5.875
Pup Joint	7.000	5733	25Cr-125	6.276	6.151
LN Profile	7.733	5739	CRA	5.750	5.750
Wireline Reentry Guide	8.250	5741	CRA	6.230	6.200
MCX Valve**	5.620	TBD	CRA	2.620	–

* Estimated, top connection depth will be adjusted with actual tally; TBD: to be determined.
** MCX valve will be run with slickline after installation of tubing assembly.

Table 11-4. Cased-Hole Logging Plan for the TB Leingang 1

	Logging	Justification	Frequency	N.D.A.C. § 43-05-01-
Long-String Section Without Tubing	Sonic array logging (inclusive of radial cement bond log [RCBL], variable-density log [VDL], casing collar locator [CCL]), gamma ray (GR), and temperature log	Identify cement bond quality radially and evaluate cement top and zonal isolation. Establish baseline temperature profile for distributed temperature sensing (DTS) fiber-optic cable calibration.	Baseline and repeat when required and when tubing is pulled during workovers	11.2(1)(c)(2) and (d)
	Ultrasonic logging tool (or other approved casing inspection log [CIL])	Acquire baseline and demonstrate external mechanical integrity prior to injection.		11.2(1)(c)(2) and (d)
Through-Tubing	Pulsed-neutron log (PNL)	Confirm internal and external mechanical integrity from Opeche/Spearfish Formation to surface.	Baseline and Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)	11.4(g)(1)
	Temperature logging	Confirm external mechanical integrity and acquire baseline temperature profile.	Baseline and annually only if DTS fails	11.2(1)(c)(2) and (d)

Site Well Work Preparations

- Contact the Department of Mineral Resources, Oil and Gas Division (DMR-O&G), and provide a schedule to perform DMR-O&G-approved well work.
- Work road and location as needed for safe operations.
- Install rig anchors, and test to 20,000 lbf (pound-force), or as required by rig contractor. If installed, confirm recent anchor test date and that tension has been performed according to contractor policy.
- Confirm actual casing depths and casing-conveyed gauges with the contractor representative and designated contractor field engineer.
- Conduct safety meetings prior to shifts and treatments/operations.
- Move in (MI) pipe racks, pipe wranglers, tanks, and portable toilet.
- MI and unload 7-in., 25Cr-125 injection string and 2⅞-in. PH6 work string.
- Fill tanks with compatible testing fluid for all well work.

1. Move in and rig up (MIRU) workover (WO) rig capable of 200,000 lb and equipment, check the casing pressure, and release pressure if any. Ensure no pressure buildup before proceeding to the next step.

2. Remove nightcap and nipple up (NU) a blowout preventer (BOP) with variable rams capable of 2⅞ to 7-in.

3. Test BOP to maximum anticipated surface pressure (MASP).

4. Tally and pick up 2⅞-in. PH6 work string and 8½-in. bit to drill out differential valve (DV) tool and clean out residual cement down to float collar. Pull out of hole (POOH).

5. Run in the hole and work string with bit and scraper in front of the injection zone and at the depth where the packer will be set.

6. Tag plug back total depth (PBTD).

7. Circulate the wellbore with completion fluid, estimated at 9.8 ppg, compatible with the formation. Circulate until clean returns.

8. Trip out of hole (TOOH) work string with bit and scraper.

9. Close blind rams and test casing for 30 min to 1000 psi or as approved by DMR-O&G. If the pressure decreases more than 10% in 30 min, 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. Document all test results.

10. MIRU logging truck.

11. Conduct safety meeting to discuss logging and perforating operations.

12. Install and test lubricator.

13. Perform logs as per cased-hole logging plan shown in Table 11-4.

    Note: Run radial cement bond log (RCBL) with 500-psi pressure. If the RCBL result shows poor cement bonding or a low top of cement, the results should be communicated to DMR-O&G, and an action plan will be prepared.

14. Perforate the Broom Creek Formation (ensure shots do not penetrate fiber-optic cable or downhole gauges. Perforations should be at least 10 ft away from gauge and fiber-optic cable). Actual perforation depths and design will be determined by designated geologists and engineers and will be based on the log analysis review and selected contractor.

    Note: DTS/DAS (distributed temperature sensing/distributed acoustic sensing) fiber-optic cable and casing-conveyed gauges 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. TOOH with perforating guns.

16. Tally and pick up retrievable testing packer with surface read-out downhole gauges, and run in the hole with work string to the top of the perforations.

17. Set packer above, at least 50 ft, top perforations to isolate and test the annulus to ensure seal and no communication with backside.

18. RU pump truck. Perform an injectivity test/step rate test (SRT) and pressure falloff test with fluid compatible with the formation. The SRT and pressure falloff test will be designed at a later time.

    Note: 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. Ensure correct acid and additives are used and the acid formula is determined based on not only acid/formation compatibility test result but also installed CRA material.

19. Release packer. TOOH, lay down (LD) retrievable packer, and LD work string.

20. Prepare rig floor to install injection string assembly (injection tubing and packer).

21. RU wireline. Pick up (PU) wireline-set permanent packer to desired depth.

22. Set injection packer within 50 ft above the top perforations, according to manufacturer recommendations and DMR-O&G requirements.

    Note: Avoid setting packer within 10 ft of casing-conveyed gauges.

23. Tally, PU, and run completion assembly in accordance with program. Displace the well with inhibited packer fluid prior to latching 7-in., 25Cr-125 injection string into permanent packer.

24. Test packer to 1000 psi for 30 min. Ensure good seal.

25. Install tubing hanger.

26. Install backpressure valve (BPV), and nipple down (ND) BOP.

27. NU injection tree. Recover BPV.

28. Install test plug, and pressure-test injection tree to pressure rating. Recover test plug.

29. RDMO (rig down and move out) WO rig and equipment.

30. Schedule mechanical integrity test (MIT) with DMR-O&G inspector. Perform and record MIT with DMR-O&G representative present. Document MIT and submit to DMR-O&G.

11.2 TB Leingang 2: Proposed Completion Procedure to Conduct Injection Operations

As described in Section 9.1, the TB Leingang 2 well will be drilled and completed as a CO_2 injector (Figures 11-3 and 11-4 and Tables 11-5, 11-6, and 11-7). The following proposed completion procedure outlines the steps necessary to complete and test the well for injection purposes. The procedures described below are subject to change during execution as necessary to ensure successful completion and/or testing.

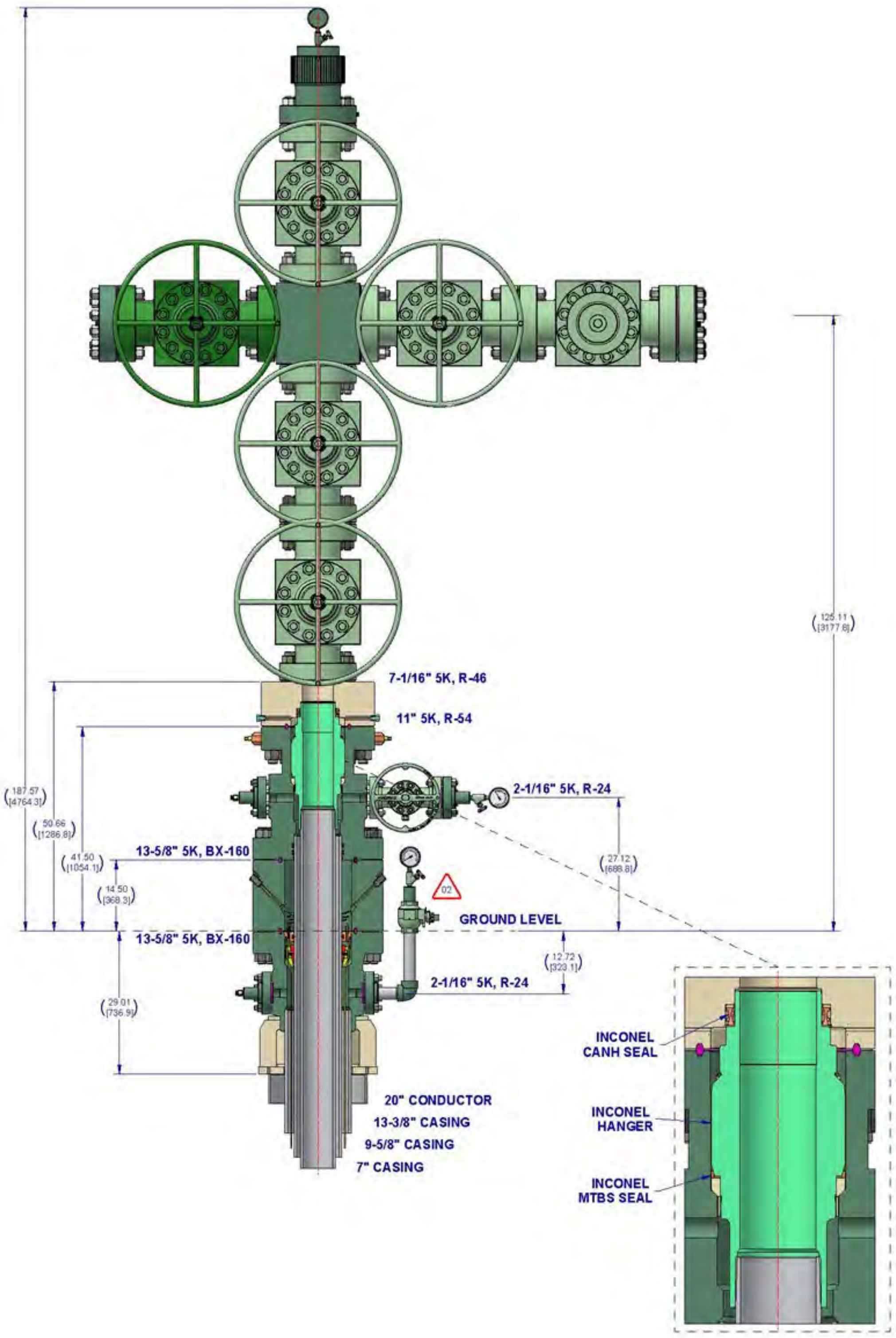


Figure 11-3. TB Leingang 2 proposed CO_2-resistant wellhead schematic. Lowest manual valve of injection tree will be of Class HH material, and tubing hanger mandrel will be of corrosion-resistant material, while the rest of the tree will consist of Class FF and equivalent.

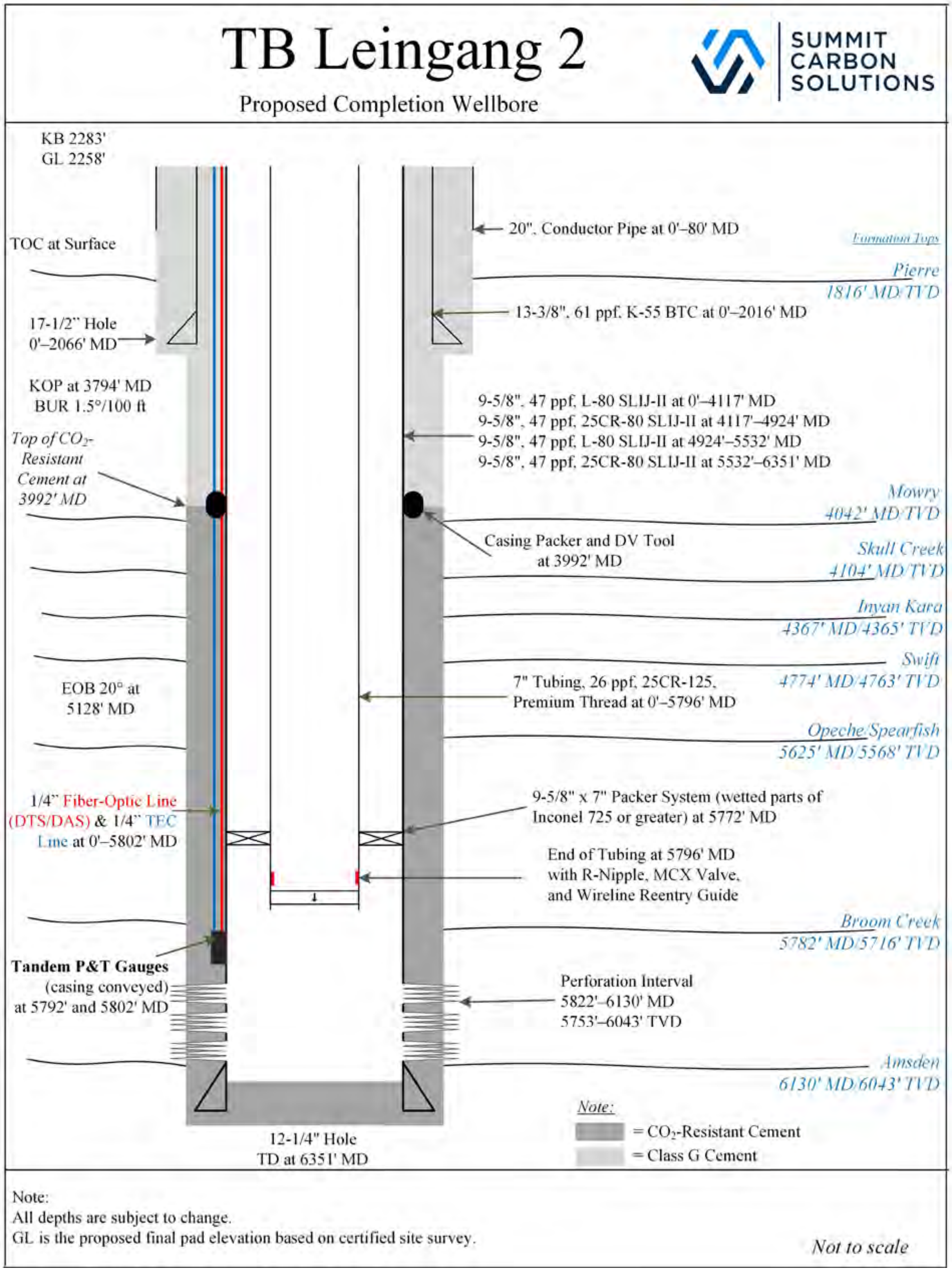


Figure 11-4. TB Leingang 2 proposed completion wellbore schematic.

Table 11-5. TB Leingang 2: Tubing Properties

OD, in.	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.	Collapse, psi	Burst, psi	Tension, klb
7.000	25Cr-125	26	Sentinel	6.276	6.151	6233	10,239	943

Table 11-6. TB Leingang 2: Tubing Accessories

Description	OD, in.	Depth,* ft, MD	Material	ID, in.	Drift ID, in.
Ratch Latch Assembly	7.765	5768	CRA	5.980	5.950
Packer	8.220	5772	CRA	5.980	5.950
Pup Joint	7.000	5779	25Cr-125	6.276	6.151
LN Profile	7.954	5785	CRA	5.875	5.875
Pup Joint	7.000	5767	25Cr-125	6.276	6.151
LN Profile	7.733	5793	CRA	5.750	5.750
Wireline Reentry Guide	8.250	5795	CRA	6.230	6.200
MCX Valve**	5.620	TBD	CRA	2.620	–

* Estimated, top connection depth will be adjusted with actual tally, TBD: to be determined.

** MCX valve will be run with slickline after installation of tubing assembly.

Table 11-7. Cased-Hole Logging Plan for the TB Leingang 2

	Logging	Justification	Frequency	N.D.A.C. § 43-05-01-
Long-String Section Without Tubing	Sonic array logging (inclusive of RCBL, VDL, CCL), GR, and temperature log	Identify cement bond quality radially and evaluate cement top and zonal isolation. Establish baseline temperature profile for DTS fiber-optic cable calibration.	Baseline and repeat when required and when tubing is pulled during workovers	11.2(1)(c)(2) and (d)
	Ultrasonic logging tool (or other approved CIL)	Acquire baseline and demonstrate external mechanical integrity prior to injection.		11.2(1)(c)(2) and (d)
Through-Tubing	PNL	Confirm internal and external mechanical integrity from Opeche/Spearfish Formation to surface.	Baseline and Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)	11.4(g)(1)
	Temperature logging	Confirm external mechanical integrity and acquire baseline temperature profile.	Baseline and annually only if DTS fails	11.2(1)(c)(2) and (d)

Site Well Work Preparations

- Contact DMR-O&G, and provide a schedule to perform DMR-O&G-approved well work.
- Work road and location as needed for safe operations.
- Install rig anchors, and test to 20,000 lbf, or as required by rig contractor. If installed, confirm recent anchor test date and that tension has been performed according to contractor policy.
- Confirm actual casing depths and casing-conveyed gauges with the contractor representative and designated contractor field engineer.
- Conduct safety meetings prior to shifts and treatments/operations.
- MI pipe racks, pipe wranglers, tanks, and portable toilet.
- MI and unload 7-in., 25Cr-125 injection string and 2⅞-in. PH6 work string.
- Fill tanks with compatible testing fluid for all well work.

1. MIRU WO rig capable of 200,000 lb and equipment, check the casing pressure, and release pressure if any. Ensure no pressure buildup before proceeding to the next step.

2. Remove nightcap, and NU a BOP with variable rams capable of 2⅞ to 7-in.

3. Test BOP to MASP.

4. Tally and pick up 2⅞-in. PH6 work string and 8½-in. bit to drill out DV tool and clean out residual cement down to float collar. POOH.

5. Run in the hole and work string with bit and scraper in front of the injection zone and at the depth where the packer will be set.

6. Tag PBTD.

7. Circulate the wellbore with completion fluid, estimated at 9.8 ppg, compatible with the formation. Circulate until clean returns.

8. TOOH work string with bit and scraper.

9. Close blind rams and test casing for 30 min to 1000 psi or as approved by DMR-O&G. If the pressure decreases more than 10% in 30 min, 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. Document all test results.

10. MIRU logging truck.

11. Conduct safety meeting to discuss logging and perforating operations.

12. Install and test lubricator.

13. Perform logs as per cased-hole logging plan shown in Table 11-7.

Note: Run RCBL with 500-psi pressure. If the RCBL result shows poor cement bonding or a low top of cement, the results should be communicated to DMR-O&G and an action plan will be prepared.

14. Perforate the Broom Creek Formation (ensure shots do not penetrate fiber-optic cable or downhole gauges. Perforations should be at least 10 ft away from gauge and fiber-optic cable). Actual perforation depths and design will be determined by designated geologists and engineers and will be based on the log analysis review and selected contractor.

    Note: DTS/DAS fiber-optic cable and casing-conveyed gauges 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. TOOH with perforating guns.

16. Tally and pick up retrievable testing packer with surface read-out downhole gauges, and run in the hole with work string to the top of the perforations.

17. Set packer above, at least 50 ft, top perforations to isolate and test the annulus to ensure seal and no communication with backside.

18. RU pump truck. Perform an injectivity test/SRT and pressure falloff test with fluid compatible with the formation. The SRT and pressure falloff test will be designed at a later time.

    Note: 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. Ensure correct acid and additives are used and the acid formula is determined based on not only acid/formation compatibility test result but also installed CRA material.

19. Release packer. TOOH, LD retrievable packer, and LD work string.

20. Prepare rig floor to install injection string assembly (injection tubing and packer).

21. RU wireline. PU wireline-set permanent packer to desired depth.

22. Set injection packer within 50 ft above the top perforations, according to manufacturer recommendations and DMR-O&G requirements.

    Note: Avoid setting packer within 10 ft of casing-conveyed gauges.

23. Tally, PU, and run completion assembly in accordance with program. Displace the well with inhibited packer fluid prior to latching 7-in., 25Cr-125 injection string into permanent packer.

24. Test packer to 1000 psi for 30 min. Ensure good seal.

25. Install tubing hanger.

26. Install BPV and ND BOP.

27. NU injection tree. Recover BPV.

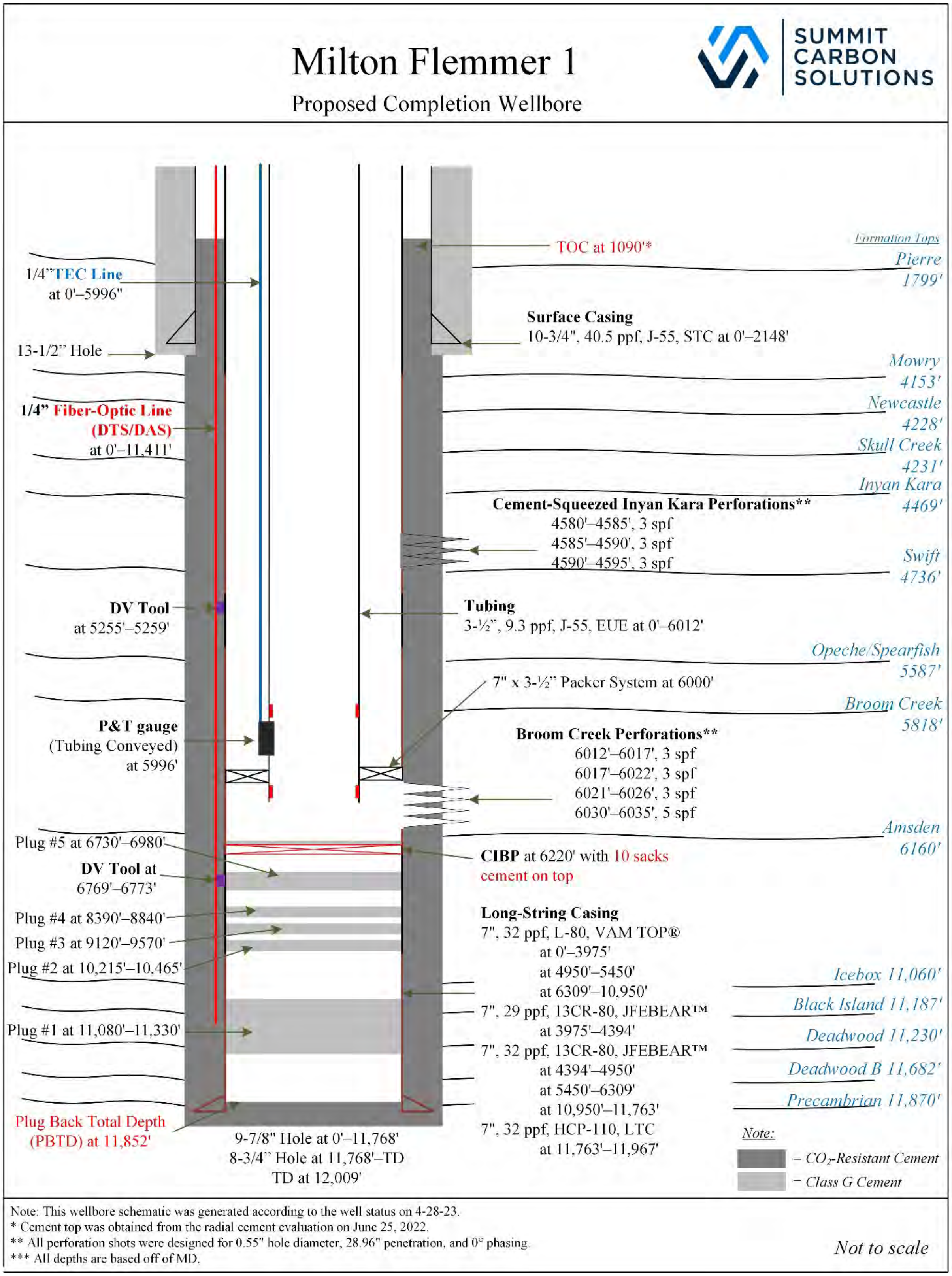
28. Install test plug, and pressure-test injection tree to pressure rating. Recover test plug.

29. RDMO WO rig and equipment.

30. Schedule MIT with DMR-O&G inspector. Perform and record MIT with DMR-O&G representative present. Document MIT and submit to DMR-O&G.

11.3 Milton Flemmer 1: Proposed Completion Procedure for Monitoring-Well Operations

Milton Flemmer 1 will be constructed as a reservoir-monitoring well (Figures 11-5 and 11-6 and Tables 11-8, 11-9, and 11-10) to support deep subsurface monitoring of TB Leingang 1 and TB Leingang 2, the CO_2 injection wells. Monitoring of the CO_2 plume extent and the storage reservoir pressure will be conducted continuously through casing-conveyed fiber-optic cable installed outside the long-string casing 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 care (PISC) period (see Section 6.0).



Milton Flemmer 1

Proposed Completion Wellbore

Note: This wellbore schematic was generated according to the well status on 4-28-23.
* Cement top was obtained from the radial cement evaluation on June 25, 2022.
** All perforation shots were designed for 0.55" hole diameter, 28.96" penetration, and 0° phasing.
*** All depths are based off of MD.

Not to scale

Figure 11-5. Milton Flemmer 1 proposed completion wellbore schematic.

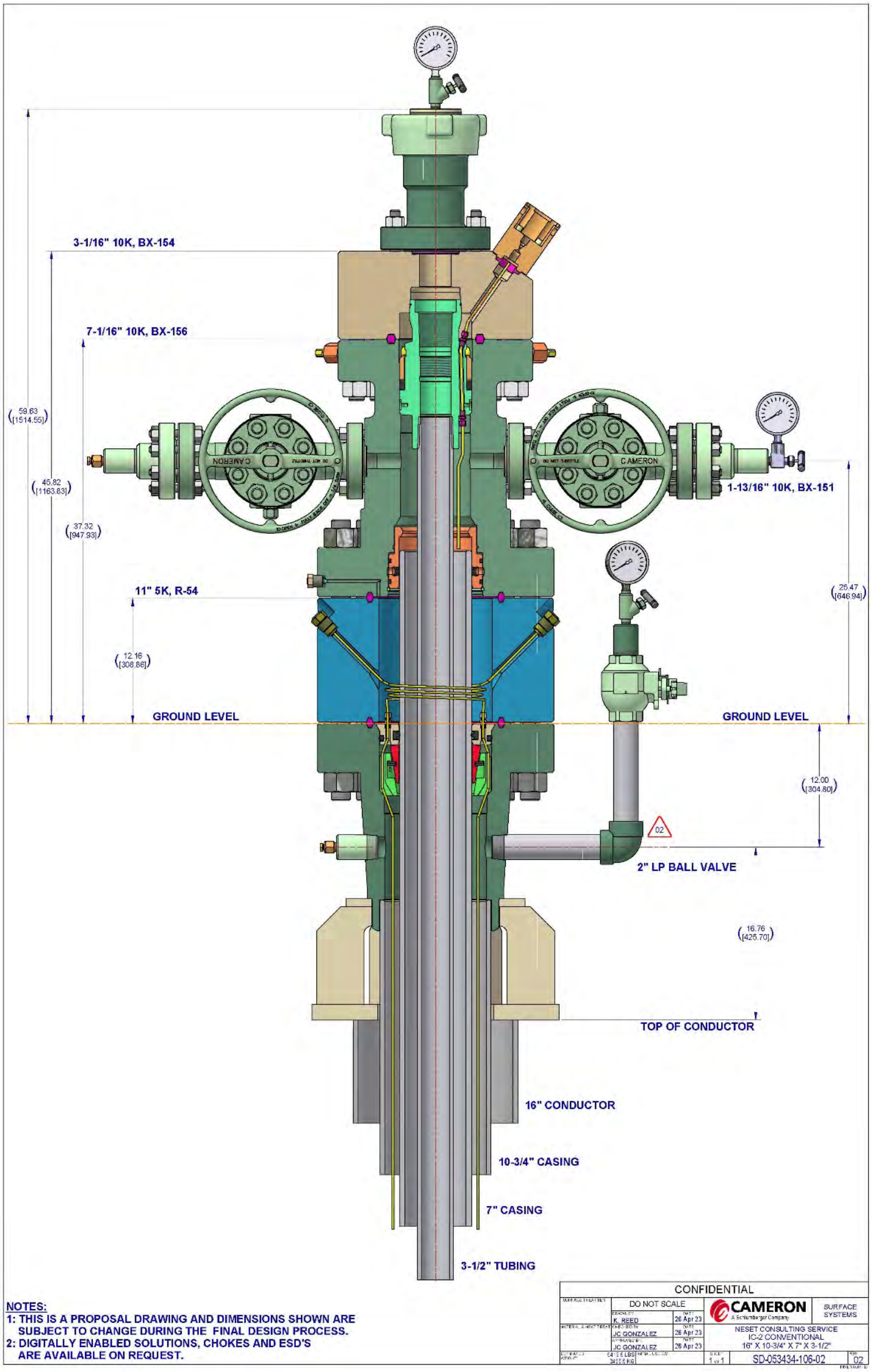


Figure 11-6. Milton Flemmer 1 proposed wellhead schematic.

Table 11-8. Milton Flemmer 1: Tubing Properties

OD, in.	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.	Collapse, psi	Burst, psi	Tension, klb
3.5	J-55	9.3	EUE 8R	2.992	2.867	7400	6990	142

Table 11-9. Milton Flemmer 1: Tubing Accessories

Description	OD, in.	Depth,* ft, MD	Material	ID, in.	Length, ft
Crossover	3.500	5995	N-80	2.992	0.50
LN Profile	3.770	5995	N-80	2.992	0.97
Gauge Side Pocket Mandrel	4.725	5996	N-80	2.993	4.00
Ratchet Latch Assembly	5.190	6000	LAS**	3.850	2.78
Packer	5.875	6000	LAS**	4.880	4.62
Pup Joint	3.500	6005	J-55	2.992	6.00
Crossover	3.500	6011	N-80	2.992	0.50
LN Profile	3.770	6011	N-80	2.635	1.17
Pop Assembly	4.545	6012	N-80	–	0.50

* Estimated, top connection depth will be adjusted with actual tally.

** Low-alloy steel.

Table 11-10. Cased-Hole Logging Plan for the Milton Flemmer 1

	Logging		**Justification**	**Frequency**	**N.D.A.C. § 43-05-01-**
Long-String Section Without Tubing	Sonic array logging (inclusive of RCBL,VDL, CCL), GR, and temperature		Baseline already acquired to identify cement bond quality radially and evaluate cement top and zonal isolation.	Repeat when required and when tubing is pulled during workovers	11.2(1)(c)(2) and (d)
	Ultrasonic logging tool (or other approved CIL)		Baseline already acquired. Run log to demonstrate external mechanical integrity.		11.2(1)(c)(2) and (d)
Through-Tubing	PNL	Confirm internal and external mechanical integrity from Opeche/Spearfish Formation to surface.	Baseline and Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)		11.4(g)(1)
	Temperature logging	Confirm external mechanical integrity and acquire baseline temperature profile.	Baseline and annually only if the DTS fails		11.2(1)(c)(2) and (d)

The following proposed completion procedure outlines the steps necessary to complete and convert the well prior to injection operations.

Site Well Work Preparations

- Contact DMR-O&G, and provide a schedule to perform DMR-O&G-approved well work.
- Work road and location as needed for safe operations.
- Test deadman anchors.
- Confirm actual casing depths and perforation depths.
- Conduct safety meetings prior to shifts and treatments.
- MI mud pump, mud tank, power swivel, pipe racks, pipe wranglers, upright and catch tanks, and portable toilet.
- MI and unload 3½-in., J-55 EUE tubing string and 2⅞-in. PH6 work string.
- Fill tanks with 9.8-ppg water plus KCl (potassium chloride) working fluid for all well work.

  Note: Broom Creek Formation perforations are open; ensure working fluid is compatible with formation, estimated at a pressure gradient of 0.466 psi/ft. The well will be plugged back to the Amsden Formation prior to running completions assembly.

1. MIRU WO rig and equipment, check the casing pressure, and release pressure if any. Ensure no pressure buildup before proceeding to the next step.

2. Fill casing with 9.8-ppg working fluid.

3. Remove nightcap, and NU a BOP with blind and correct pipe rams.

4. Test BOP to MASP.

5. PU power swivel. Tally and MU 6-in. bit, mud motor, drill collars, and jars.

6. Tally, PU 2⅞-in. PH6 work string and bottomhole assembly (BHA). Trip in hole (TIH) to cast iron cement retainer (CICR) with cement on top at 4825 ft.

7. Close blind rams and pressure test casing with working fluid to 1000 psi for 30 min to verify Inyan Kara Formation perforations are sealed off. If the pressure decreases more than 10% in 30 min, 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. Document all test results.

8. If the pressure test is successful, proceed to drill out CICR and cement at 4825 ft.

   Note: Broom Creek Formation perforations below are open; ensure completion fluid is compatible with formation pressure.

9. Circulate the wellbore with completion fluid, compatible with the formation, estimated at a pressure gradient of 0.466 psi/ft.

10. Continue picking up work string. Tag cast iron bridge plug (CIBP) at 6550 ft. Circulate hole clean. Drill out CIBP and circulate hole clean. TOOH with work string.

11. Check bit and PU scraper. TIH with 6-in. bit and scraper, and perform scrape pass perforations at 6012–6035 ft and to PBTD.

12. Circulate wellbore clean. TOOH laying down BHA.

13. PU retrievable packer. TIH with retrievable packer and set at 6200 ft. Test casing below 6200 ft to 1000 psi for 15 min. TOOH with work string and retrievable packer.

14. Spot and RU cementing equipment. Confirm equipment and setting times with cement provider.

15. TIH to 11,330 ft. Conduct and document a safety meeting prior to testing lines and pumping cement. Pressure test lines prior to pumping.

16. Mix and pump 40 sacks (sx) Class G cement with 35% silica flour at 15.6 ppg, 1.50 ft^3/sx balanced plug (Deadwood Isolation). Pull above and roll hole clean.

17. TOOH to 10,465 ft. Mix and pump 40 sx Class G cement with 35% silica flour at 15.6 ppg, 1.50 ft^3/sx balanced plug (Red River Isolation). Pull above and roll hole clean.

18. TOOH to 9570 ft. Mix and pump 65 sx Class G cement with 35% silica flour at 15.6 ppg, 1.50 ft^3/sx balanced plug (Interlake and Dawson Bay Isolation). Pull above and roll hole clean.

19. TOOH to 8840 ft. Mix and pump 85 sx Class G cement at 15.8 ppg, 1.15 ft^3/sx balanced plug (Duperow and Bakken Isolation). Pull above and roll hole clean.

20. TOOH to 6980 ft. Mix and pump 50 sx Class G cement at 15.8 ppg, 1.15 ft^3/sx balanced plug (Madison Group Isolation). Pull above and roll hole clean.

21. PU CIBP. TIH and set CIBP at 6220 ft. Dump 10 sx on top. PU permanent packer and set packer at 6000 ft, at least 10 ft above the top perforation.

22. Prepare rig floor to install tubing and monitoring assembly (3½-in. tubing and tubing-conveyed gauge(s). Gauges will be ported to the inside of the tubing, allowing readings of downhole pressure and temperature.

23. Tally and PU and run monitoring assembly in accordance with program.

24. Displace the well with inhibited packer fluid. Latch onto packer.

25. Test backside/annulus of tubing/casing to 1000 psi for 30 min. Document annular pressure test.

26. PU BOP. Install tubing hanger and double studded adapter with cable exit ports.

27. ND BOP.

28. Install cable exit unit and monitoring wellhead.

29. RDMO WO rig and equipment.

30. Schedule MIT with DMR-O&G inspector. Perform and record MIT with DMR-O&G representative present. Document MIT and submit to DMR-O&G.

31. Install pressure and temperature surface interrogator. Well is ready for monitoring operations.

SECTION 12.0

FINANCIAL ASSURANCE DEMONSTRATION PLAN

12.0 FINANCIAL ASSURANCE DEMONSTRATION PLAN

This financial assurance 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 (N.D.A.C.) § 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 corrective actions and monitoring and reporting.

The FADP describes actions the operator of Summit Carbon Storage #1, LLC (SCS1) has taken and shall take to assure state and federal regulators that sufficient financial support is in place to cover the cost of any corrective action (N.D.A.C. § 43-05-01-05.1) that may be required at the geologic storage facility during any of its phases of operation, including: injection well plugging (N.D.A.C. § 43-05-01-11.5); postinjection site care (PISC) and facility closure (N.D.A.C. § 43-05-01-19); emergency and remedial response plan (ERRP) (N.D.A.C. § 43-05-01-13); and endangerment to underground sources of drinking water (USDW).

This FADP provides cost estimates for each of the above actions (Section 12.0) based on the information that is provided in the SFP application and describes the financial instruments that will be established (Section 12.3). The FADP was prepared to account for the entire operation of TB Leingang.

As the FADP was prepared, U.S. Environmental Protection Agency (EPA) guidance (2011) was also considered to assess the effectiveness of multiple qualifying financial instruments in the context of SCS1, e.g., key aspects of long-term public confidence, optimization of stakeholder interests, and practicality of implementation. Further, because of the structure of entity ownership, the FADP financial instruments were considered in evaluating the assurance approach during each of the operational periods.

SCS1 will establish a financial instrument(s) 30–60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations. The applicant will provide a surety bond to ensure funds are available for PISC and facility closure activities in accordance with N.D.A.C. § 43-05-01-09.1(1)(a). It will also provide a third-party pollution liability insurance policy to cover emergency and remedial response costs, including endangerment to USDWs, in accordance with N.D.A.C. § 43-05-01-13, and a financial instrument to cover the costs of plugging the injection wells under N.D.A.C. § 43-05-01-11.5. No estimates have been provided for corrective action (N.D.A.C. § 43-05-01-05.1) because no action is required at this time.

The details contained in this FADP, along with supporting documentation, establish the approach the applicant proposes to use to meet the financial responsibility requirements and ensure that each of these instruments sufficiently addresses the activities and costs associated with the corrective action plan, injection well-plugging program, PISC and facility closure, ERRP, and endangerment of USDWs. The estimated total costs of these activities are presented in Table 12-1.

Table 12-1. Potential Future Costs Covered by Financial Assurance

Phase	Activity	Total Cost	Covered by Surety	Covered by Pollution Liability Policy	Details in Supporting Table
Preinjection, Active Injection, and PISC	Corrective Action on Wells in Area of Review (AOR)	$0	$0	$0	N/A
Cessation of Injection	Plugging of Injection Wells	$1,166,000	$1,166,000	$0	Table 12-2
PISC	PISC Storage Facility Monitoring and Injection Well Site Reclamation	$4,225,000	$4,225,000	$0	Table 12-3a
PISC	Flowline Plugged and Abandoned (P&A)	$243,000	$243,000	$0	Table 12-3b
PISC	Site Closure and Remediation	$887,000	$887,000	$0	Table 12-4
Active Injection/PISC	ERRP	$11,100,000	$0	$11,100,000	Table 12-6
Active Injection/PISC	Endangerment of USDWs	$2,695,000	$0	$2,695,000	Table 12-7
	Total	**$20,316,000**	**$6,521,000**	**$13,795,000**	

If there are any changes, updated information related to the financial instruments will be provided on an annual basis to the Department of Mineral Resources Oil and Gas Division (DMR-O&G) for review and evaluation as required under N.D.A.C. § 43-05-01-09.1.

12.1 Facility Information

The facility name, facility contact, and injection well locations are provided below:

Facility Name:	Summit Carbon Storage #1, LLC
Facility Contact:	Wade Boeshans
Injection Well Locations:	TB Leingang 1 and 2; NE¼ of Section 18 T141N, R87W

12.2 Approach to Financial Responsibility Cost Estimates

In accordance with the requirements contained in N.D.A.C. § 43-05-01-09.1, the FADP provides financial assurance sufficient to cover the activities identified in the corrective action plan, injection well-plugging program, PISC and facility closure, ERRP, and endangerment of USDWs (Table 12-1). The following provides a summary description of the considerations and assessment approach for each activity.

12.2.1 Corrective Action

According to N.D.A.C. § 43-05-01-05.1, corrective action involves inventorying and characterizing existing wells in the proposed AOR. The objective of a corrective action assessment is to describe the actions SCS1 will take, prior to and over the course of the project operation, on existing wells to proactively prevent the movement of fluid into or between USDWs. A detailed description of how the AOR was delineated can be found in Section 3.0 of this SFP application. SCS1 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 to ensure they meet the minimum completion standards for geologic storage of CO_2 and require no corrective action.

SCS1 has determined no wells in the proposed AOR require corrective action prior to or during the project operation, PISC, or postclosure period (Section 4.2). The only identified wellbore within the AOR boundary is the stratigraphic test and reservoir-monitoring wellbore, Milton Flemmer 1. SCS1 will employ a proactive monitoring approach to track the CO_2 plume extent and associated pressure front throughout the life of the project to ensure nonendangerment of USDWs, which includes acquiring time-lapse seismic and continuously monitoring reservoir pressure in the Broom Creek Formation at the CO_2 injection wells and reservoir-monitoring well (Section 5.7). For the avoidance of doubt, if injection or monitoring wells proposed as part of the SCS1 site operation require corrective action, such associated activities and costs relating thereto would be accounted for as part of the project's operating budget.

12.2.2 Plugging of Injection Wells

SCS1 will include the costs associated with plugging injection wells during site program closure within the project cost, the FADP, and the proposed instruments that SCS1 will use for plugging (N.D.A.C. § 43-05-01-11.5[2]). The injection wells will be plugged at cessation of the injection operation as discussed in Section 6.0 of this SFP application. The estimate covers the aggregated plugging and abandonment (P&A) cost of SCS1 injector wells TB Leingang 1 and 2, including rig mobilization, workover rig and rentals, labor, cementing, logging, trucking, supervision, and project management (Table 12-2). The specifics of the plugging program of the TB Leingang 1 and 2 wells can be found in Section 10.0. Reservoir-monitoring well plugging is separately accounted for as part of facility closure.

Table 12-2. Injection Well Plugging

Activity	Total Cost
Plugging TB Leingang 1	$583,000
Plugging TB Leingang 2	$583,000
Total	**$1,166,000**

12.2.3 Implementation of the PISC Plan and Facility Closure Activities

PISC and facility closure cost estimates include site monitoring and periodic reevaluation of the AOR, facilities maintenance and power costs, and overhead and support costs during the 10-year PISC period. Details of the activities and actions contained in the PISC and Facility Closure Plan can be found in Section 6.0 of this SFP application.

The total combined cost for the implementation of the PISC and facility closure activities is estimated to be $5,355,000, including $4,225,000 for implementing the PISC (Table 12-3a), $243,000 for flowline P&A (Table 12-3b), and $887,000 for facility closure activities (Table 12-4). The PISC includes the following: a) formation monitoring (i.e., pulsed-neutron logs [PNL]),

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 logging), and c) coordinated repeat time-lapse seismic. The largest element of the PISC cost estimate relates to seismic studies, which are required to be carried out at 5-year intervals to validate models, which are expected to cover an area up to 65 mi^2. Additionally, at the start of the PISC period, determined by cessation of injection

Table 12-3a. Cost Estimate[1] for PISC Activities for TB Leingang Assuming a 10-year PISC Period

Activity	Frequency	Unit Cost	Total
Injection Pad Reclamation			
Reclamation Costs of the Injection Well Pad and Aboveground Structure Removal	Perform prior to facility closure (anticipated in Year 10 of postinjection).	$255,000	$255,000
Wellbore Monitoring (Milton Flemmer 1)			
Overhead and Management	Overhead and management on monitoring activities for the whole duration of the PISC period.	$60,000	$600,000
PNL (saturation monitoring)	Repeat PNL in Year 4 and Year 9 during the PISC period.	$45,000	$90,000
Ultrasonic Logging (or other approved CIL [casing inspection log])	Repeat when required (assumes two occurrences).	$43,000	$86,000
Annulus Pressure Testing (internal mechanical integrity)	Repeat during workover operations in cases where the tubing must be pulled (assumes two occurrences).	$8,000	$16,000
Monitoring Surface Equipment Maintenance and Power	Quarterly inspections of wellhead and surface monitoring equipment.	$5,000	$50,000
Near-Surface Monitoring			
MSG01 and MSG04 – Sampling and Analysis	Collect three to four seasonal samples at each station (MSG01 and MSG04) in Years 1 and 3 of postinjection and every 3 years thereafter (e.g., Years 6 and 9), and perform concentration analyses on all samples.	$2,150	$34,000
Existing Groundwater Wells (MGW01) – Sampling and Analysis	Collect three to four seasonal samples in Years 1 and 3 of postinjection and at least once every 3 years thereafter until facility closure (anticipated in Year 10 of postinjection).	$1,500	$24,000
Existing Groundwater Wells (MGW04) – Sampling and Analysis	Collect three to four seasonal samples in Year 4 of postinjection and prior to facility closure (anticipated in Year 10 of postinjection).	$1,500	$12,000
Existing Groundwater Wells (MGW03 & MGW09) – Sampling and Analysis	Collect three to four seasonal samples prior to facility closure (anticipated in Year 10 of postinjection).	$1,500	$9,000
Dedicated Fox Hills Well (MGW11) – Sampling and Analysis	Collect annually until facility closure (anticipated in Year 10 of postinjection).	$1,500	$15,000
Storage Complex Monitoring			
Time-Lapse Seismic Survey Acquisition and Processing	Collect multiple repeat time-lapse seismic surveys during postinjection, with the first survey occurring by Year 4 of postinjection (two occurrences).	$1,517,000	$3,034,000
Total for PISC Activities			4,225,000

[1] Does not include interpretation and reporting. Costs are based on 2023 pricing and do not account for inflation.

operations, SCS1 will plug and abandon the TB Leingang 1 and 2 injection wells (Table 12-2) and conduct reclamation of injection well pad and aboveground structures, if no other beneficial use is determined at that time. SCS1 would leave intact for the period of the PISC the reservoir-monitoring well and the dedicated Fox Hills monitoring well (MGW11). These costs for plugging and surface facility reclamation are included in Table 12-4.

12.2.3.1 Plugging and Abandonment of Flowlines

The application must demonstrate that a financial instrument is in place sufficient to cover the costs associated with abandonment of $100,000 or an amount determined by the Director of the DMR-O&G. This document describes the abandonment cost of the flowline and associated structures to be $243,000 (Table 12-3b).

The FADP describes actions the operator has taken and shall take to assure state and federal regulators that sufficient financial support is in place to cover the cost of abandonment which includes:

a) Disconnect and physically isolate the pipeline from any operating facility or other pipeline.
b) Cut off the pipeline or the part of the pipeline to be abandoned below surface at pipeline level.
c) Purge the pipeline with fresh water, air, or inert gas in a manner that effectively removes all fluid.
d) Remove cathodic protection from the pipeline.
e) Permanently plug or cap all open ends by mechanical means or welded means.

Table 12-3b. Cost Estimate for Flowline Segment NDL-327 Abandonment

Activity	**Timing**	**Description**	**Total**
Closure and Reclamation Costs			
Isolation of Flowline from Operating Facility or Other Pipeline	Prior to facility closure	Disconnect and physically isolate the pipeline from any operating facility or other pipeline.	$20,000
Cut of Flowline to Be Abandoned	Prior to facility closure	Cut off the pipeline or the part of the pipeline to be abandoned below surface at pipeline level.	$50,000
Purge Flowline	Prior to facility closure	Purge the pipeline with fresh water, air, or inert gas in a manner that effectively removes all fluid.	$10,000
Cathodic Protection Removal	Prior to facility closure	Remove cathodic protection from the flowline.	$10,000
Remove Launcher/Receivers	Prior to facility closure	Remove three launcher and/or receiver (three sites) associated with NDL-327.	$150,000
Site Reclamation	Prior to facility closure	Main line valves (MLVs)/launcher receiver sites based on 0.06 ac/Site 3 sites (seed, seeding, soil prep, and mobilization).	$3,000
Total for Flowline P&A Activities			$243,000

12.2.3.2 Facility Closure

SCS1 will prepare and apply for facility closure to the DMR-O&G and, upon authorization from the DMR-O&G, will proceed with plugging the reservoir-monitoring wells and well pad reclamation as discussed in Section 6.0 of this SFP application. The specifics of the plugging program of the reservoir-monitoring well can be found in Section 10.0. The estimate covers the aggregated P&A and reclamation cost of SCS1 reservoir-monitoring well, Milton Flemmer 1, including rig mobilization, Fox Hills monitoring well P&A, soil gas profile station P&A, workover rig and rentals, equipment and labor, cementing, logging, trucking, dirt work, supervision, and project management (Table 12-4). SCS1 is planning that the Fox Hills monitoring well (MGW11) will remain in place because the groundwater monitoring locations may be wanted by DMR-O&G or SCS1 for future use; however, SCS1 has set aside funds in case P&A is required.

Table 12-4. Cost Estimate[1] for Site Closure and Remediation Activities for TB Leingang CO_2 Storage Project

Activity	Timing	Description	Total
Closure and Reclamation Costs			
Plugging of Milton Flemmer 1	During facility closure	Plugging activities described in Section 10 plugging plan	$613,500
Reclamation Costs of Milton Flemmer 1 Well Pad	During facility closure	Wellhead removal, sump removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, general labor	$255,000
Fox Hills Monitoring Well P&A[2]	During facility closure	Pipe removal, pad reclamation (rock removal and soil coverage), reseeding, general labor of MGW11	$16,000
MSG Station(s) P&A[2]	During facility closure	P&A of MSG01 and MSG04	$2,500 ($1,250 per well)
Total for Closure Activities			$887,000

[1] Does not include interpretation and reporting. Costs are based on 2023 pricing and do not account for inflation.

[2] P&A assumed unless DMR-O&G requests transfer of ownership.

12.2.4 Implementation of Emergency and Remedial Response Actions

12.2.4.1 Emergency Response Actions

The ERRP and associated detailed assessment can be found in Section 7.0 of this SFP application. The ERRP assessment supports a determination that the likelihood of release of significant volumes of CO_2 from underground storage into the soil or the atmosphere or significant volumes of saltwater into the environment are considered remote. Multiple factors were considered in the development of the ERRP, including:

a) Extensive and independently verified analysis of the integrity of the storage mechanism.
b) Selection of qualified and experienced storage facility operator.
c) Selection of qualified and experienced drilling contractor.

Risk mitigation measures include:

a) Continuous monitoring of transportation and injection systems.
b) Routine measurement and reporting of CO_2 volumes.
c) Physical security, barriers, and signage around injection facilities.
d) Primary and secondary containment for leaked fluids at injection well pads.

A review of the ERRP technical risk categories for SCS1 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:

a) Loss of injectivity
b) Lower storage capacity than modeled
c) Containment loss – lateral migration of CO_2
d) Containment loss – pressure propagation
e) Containment loss – vertical migration of CO_2 or formation water brine via injection wells, other wells, or inadequate confining zones
f) Natural disasters

If it is determined that one or more of these events has occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7.0) of this SFP application. SCS1 planned response actions are summarized in Table 7-6.

12.2.4.2 Estimation of Costs of Emergency Response Actions

Estimating the costs of implementing the emergency response actions in Table 7-6 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). 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 hypotheticals with other release and loss containment events, 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.

12.2.4.2.1 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 12-5. The impacted media in Table 12-5 include surface and groundwater/USDW, vadose zone, indoor settings, and atmosphere; the remedial measures include a combination of active (e.g., air sparging) and passive (e.g., dispersion, natural attenuation) systems.

Table 12-5. 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 (soil gas)	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

However, it is important to note that, at this time, no methodology is widely accepted for designing intervention and remediation plans for CO_2 geologic storage projects. In an effort to establish SCS1's site-specific financial assurance obligation, three areas were evaluated, as follows:

1) Cost estimates specific to remediation within SCS1's AOR,
2) Methodologies and estimates from permitted North Dakota storage facilities, and
3) Existing literature (Manceau and others, 2014; Bielicki and others, 2014).

12.2.4.2.2 Estimation of Costs for Implementing Emergency Event Responses

SCS1 has compiled cost estimates regarding a conservative hypothetical emergency event scenario to provide for future financial assurance. This conservative outer-limit cost estimate was calculated and used as a basis for this FADP.

Emergency Remedial Response Scenarios

The applicant formed a team to evaluate and quantify project risks based upon the scenarios described in the ERRP. The team consisted of members with relevant professional qualifications and experience in subsurface analysis, drilling engineering, facilities engineering, operations, well control events, and finance. The team evaluated and considered hypothetical scenarios for costs estimates in this document and identified site-specific financial risks.

Following the identification of financial risks, the applicant compiled cost estimates associated with a conservative hypothetical scenario wherein a failure of well integrity in an injection well causes a loss of containment in which a significant volume of CO_2 and briny water migrates to the surface during injection operations through one of the injection wells. The conservative hypothetical scenario response action includes potential responses including but not limited to securing the location, diagnostics, well control and containment activities, remediation of injection well integrity, evaluation of environmental impacts, installation of monitoring equipment, and execution of surface remediation. The remediation plan would be discussed with DMR-O&G. The scenario contemplates a reactive response approach, e.g., mobilization of response personnel and equipment upon discovery of such an event to diagnose and develop a remediation plan. This approach is considered appropriate because of the remoteness of the residual risk. Specific postoccurrence action is not determinable until occurrence; thus actual response to such an event would be based on its severity. Because of the remote likelihood, this single conservative scenario was compiled to account for the outer-limit cost estimate to satisfy event response. The scenario used for cost estimating assumed the optimal operating conditions (10 years of operation) requiring outer-limit response and remediation costs. This conservative outer-limit cost estimate was calculated and used as a basis for this FADP.

Endangerment of Drinking Water Sources

As discussed in the ERRP section, the risk of endangerment to USDWs is considered remote. However, as part of the reactive response scenario contemplated in the ERRP cost estimate, the applicant assessed the specific response actions and cost data to represent the likely impact of such an event on sources of drinking water. Because of precautions taken in the design for spill control and pollution prevention, the well pad design incorporates a berm that, in combination with the response strategy, would minimize this portion of environmental repair. Thus, the applicant assessed the second reactive scenario, which contemplates a subsurface leak scenario. This subsurface leak scenario has primary costs related to groundwater delineation, and an extended period (10 years) of quarterly monitoring and reporting after emergency remedial actions are taken.

Selected Elements of Analysis of Inherent Risks

From the surface to the lowermost USDW—the Fox Hills Aquifer—the groundwater is considered a protected aquifer with <10,000 ppm TDS (total dissolved solids). The Fox Hills base is estimated at a depth of approximately 1000 ft and is followed by a thick section of clays with a thickness of approximately 2600 ft. These clays act as a seal until the next major permeable zone, the Inyan Kara. The Inyan Kara is an underpressured formation that is classified as an exempt aquifer under N.D.A.C. § 43-02-05-03. It is west of the 83W range line, and this formation is mostly targeted for water disposal wells in its surrounding areas. Approximately 1083 ft of cap rock acts as a main seal between the Inyan Kara zone and the Broom Creek.

Inside the AOR, 18 domestic wells, 30 stock wells, one test hole, and 3 Department of Water Resources wells are located in shallow aquifers, providing water for the associated farms' livestock, irrigation, and localized consumption (Figure 4-3). One existing well that penetrates the Fox Hills Formation (MGW01) and one new Fox Hills monitoring well (MGW11) will monitor the lowest USDW within the AOR, as shown in Figure 5-4 and discussed in the testing and monitoring strategy (Section 5.7).

No producible minerals, oil, natural gas, or other reserves are reported in the AOR for the Broom Creek Formation or overlying formations. As described in the AOR and corrective action section (Section 4.0) for the SCS1 storage reservoir, one deep well penetrates the storage complex (the Milton Flemmer 1) within or in proximity to the plume boundaries and the identified pressure front. These wells are identified in Section 4.2.

12.2.4.2.3 Cost Estimates

The tables in Section 12 provide a detailed estimate, in current dollars (2023), of the cost for performing corrective actions on wells in the AOR, plugging the injection wells, PISC and facility closure, endangerment to USDWs, flowline abandonment, and ERRP. Table 12-1 is a summary of the cost estimates underlying the FADP, and it identifies proposed financial instrument(s) that will provide the appropriate assurance to regulatory agencies of the applicant's intent and ability to fulfill its responsibilities.

The values included in the FADP are based on cost estimates provided during the permit application development process and are based on the hiring of a third party to perform the services or procurement of goods associated with performance. For that reason, the estimate includes costs such as project management and oversight, general and administrative costs, and overhead during the postinjection period. These values are subject to change during the course of the project to account for inflation of costs and any changes to the project that affect the cost of the covered activities. SCS1 will adjust the value of the financial instruments if the cost estimates change, and it will submit any adjustment to DMR-O&G for approval (N.D.A.C. § 43-05-01-09.1[3]) and N.D.A.C. § 43-05-01-19).

Tables 12-6 and 12-7 provide additional information for the future cost estimates that were provided in Table 12-1.

Table 12-6. Cost Estimate for Emergency and Remedial Response Plan*

Activity/Item		Cost
General Incident Response and Diagnostics		$600,000
Well Control and Containment Activities		$8,100,000
Well Integrity and Site Remediation Activities		$2,400,000
	Total	**$11,100,000**

* These costs are based on activities in response to a hypothetical scenario with remote risk of occurrence.

Table 12-7. Cost Estimate for Endangerment of USDWs*

Description		Total Estimated Amount
General Response, Delineation, and Water Replacement		$1,890,000
Quarterly Groundwater Monitoring (10 years) and Reporting		$750,000
P&A of Groundwater-Monitoring Wells		$55,000
	Total	**$2,695,000**

* These costs are based on activities in response to a hypothetical scenario with remote risk of occurrence. Costs are based on estimates of current (2023) contract rates.

12.3 Financial Instruments

The applicant will establish a financial instrument(s) 30–60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations (N.D.A.C. § 43-05-01-09.1). The applicant will provide financial assurance in the form of a surety bond to ensure funds are available for PISC and facility closure activities (N.D.A.C. § 43-05-01-09.1[1][a] and N.D.A.C. § 43-05-01-19). The applicant will also obtain a pollution liability policy(s) to cover emergency and remedial response costs and endangerment of USDWs under N.D.A.C. § 43-05-01-13 and a financial instrument (surety bond) to cover the costs of plugging the injection wells (N.D.A.C. § 43-05-01-11.5). No estimates have been provided for corrective action (N.D.A.C. § 43-05-01-05.1) because no action is required at this time.

This application presents the estimated total costs ($20,316,000) of these activities and a breakdown apportionment across proposed financial instruments in Table 12-1. Section 12.2 of this FADP provides additional details of the financial responsibility cost estimates for each activity.

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 on the basis of 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 a time that DMR-O&G determines that the storage operator has fulfilled its financial obligations.

The third-party insurance, which identifies SCS1 as the covered party, will be provided by one or a combination of the companies meeting the creditworthiness and other requirements of N.D.A.C. § 43-05-01-09.1. However, the greatest hypothetical exposure evaluated would be an acute upward migration through an CO_2 injection well, which has an estimated cost of $13,795,000 for emergency and remedial response actions, as well as coverage identified in the endangerment of USDWs.

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 injection operations; however, 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 actual third-party insurance companies will be determined closer to the proposed injection start date and will meet both of the following criteria, as specified in N.D.A.C. §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.

12.4 References

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Manceau, J.C., Hatzignatiou, D.G., de Lary, L., Jensen, N.B., and Réveillère, 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.

U.S. Environmental Protection Agency, 2011, Geologic sequestration of carbon dioxide—underground injection control (UIC) Program Class VI financial responsibility guidance: www.epa.gov/sites/default/files/2015-06/documents/uicfinancialresponsibilityguidancefinal072011v.pdf (accessed November 2023).

APPENDIX A

WELL AND WELL FORMATION FLUID SAMPLING LAB ANALYSIS

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

Page: 1 of 1

Report Date: 28 Feb 22
Lab Number: 22-W258
Work Order #:82-0330
Account #: 74217
Date Sampled: 15 Feb 22 15:10
Date Received: 16 Feb 22 8:23
Sampled By: MVTL Field Service

Jean Datahan
Neset Consulting
6844 Hwy 40
Tioga ND 58852

Project Name: Flemmer Well
Sample Description: Broom Creek

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	16 Feb 22	RAA
pH	* 6.8	units	N/A	SM4500-H+-B-11	16 Feb 22 17:00	RAA
Conductivity (EC)	113190	umhos/cm	N/A	SM2510B-11	16 Feb 22 17:00	RAA
pH - Field	6.47	units	NA	SM 4500 H+ B	15 Feb 22 15:10	JSM
Temperature - Field	16.9	Degrees C	NA	SM 2550B	15 Feb 22 15:10	JSM
Total Alkalinity	101	mg/l CaCO3	20	SM2320B-11	16 Feb 22 17:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	16 Feb 22 17:00	RAA
Bicarbonate	101	mg/l CaCO3	20	SM2320B-11	16 Feb 22 17:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	16 Feb 22 17:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	16 Feb 22 17:00	RAA
Conductivity - Field	126070	umhos/cm	1	EPA 120.1	15 Feb 22 15:10	JSM
Total Organic Carbon	< 250 @	mg/l	0.5	SM5310C-11	21 Feb 22 19:07	NAS
Sulfate	2400	mg/l	5.00	ASTM D516-11	18 Feb 22 10:43	SD
Chloride	42400	mg/l	2.0	SM4500-Cl-E-11	16 Feb 22 15:48	SD
Nitrate-Nitrite as N	114	mg/l	0.20	EPA 353.2	17 Feb 22 11:44	SD
Ammonia-Nitrogen as N	0.49	mg/l	0.20	EPA 350.1	22 Feb 22 11:43	SD
Mercury - Dissolved	< 0.002	mg/l	0.0002	EPA 245.1	23 Feb 22 12:18	MDE
Total Dissolved Solids	105000	mg/l	10	USGS I1750-85	18 Feb 22 14:38	RAA
Calcium - Total	3060	mg/l	1.0	6010D	24 Feb 22 9:19	SZ
Magnesium - Total	505	mg/l	1.0	6010D	24 Feb 22 9:19	SZ
Sodium - Total	39500	mg/l	1.0	6010D	24 Feb 22 9:19	SZ
Potassium - Total	680	mg/l	1.0	6010D	24 Feb 22 9:19	SZ
Iron - Total	< 5 @	mg/l	0.10	6010D	28 Feb 22 10:36	SZ
Manganese - Total	< 2.5 @	mg/l	0.05	6010D	28 Feb 22 10:36	SZ
Barium - Dissolved	< 5 @	mg/l	0.10	6010D	28 Feb 22 10:36	SZ
Copper - Dissolved	< 2.5 @	mg/l	0.05	6010D	28 Feb 22 10:36	SZ
Strontium - Dissolved	86.5	mg/l	0.10	6010D	28 Feb 22 10:36	SZ
Arsenic - Dissolved	< 0.04 @	mg/l	0.0020	6020B	24 Feb 22 11:43	MDE
Cadmium - Dissolved	0.0238	mg/l	0.0005	6020B	24 Feb 22 11:43	MDE
Chromium - Dissolved	< 0.04 @	mg/l	0.0020	6020B	24 Feb 22 11:43	MDE
Lead - Dissolved	< 0.01 @	mg/l	0.0005	6020B	24 Feb 22 11:43	MDE
Molybdenum - Dissolved	0.5756	mg/l	0.0020	6020B	24 Feb 22 11:43	MDE
Selenium - Dissolved	0.1832	mg/l	0.0050	6020B	24 Feb 22 11:43	MDE
Silver - Dissolved	< 0.01 @	mg/l	0.0005	6020B	24 Feb 22 11:43	MDE

* Holding time exceeded

SL

Approved by: Claudette K Carroll 3Mar22

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
\# = Due to concentration of other analytes
\+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL

2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Chain of Custody Record

Project Name: **Flemmer Well**	**Event:**	**Work Order Number:** 82-0330
Report To: **Neset Consulting** Attn: Jean Datahan Address: 6844 Hwy 40 Tioga, ND 58852 Phone: 701-664-1492 Email: jeandatahan@nestconsulting.com	CC:	Collected By: Jeremy Meyer

Lab Number	Sample ID	Date	Time	Sample Type	1 Liter Raw	500 mL Nitric	500 mL Nitric (filtered)	250 mL Sulfuric	3 VOC	3 TOC	1 Liter Amber	1 Liter Amber HCL	Temp (°C)	Spec. Cond.	pH	Analysis Required
W257	Deadwood	15 feb 22	1500	GW	X	X	X	X		X			18.54	215,710	4.94	See Attachment
W258	Broom Creek	15 feb 22	1510	GW	X	X	X	X		X			16.90	126,067	6.47	

Comments:

Relinquished By		Sample Condition	
Name	Date/Time	Location	Temp (°C)
1	16 feb 22 0823	[✓ Log In] Walk In #2	Roi 0.4 TM562 / [✓ TM805]
2			

Received By	
Name	Date/Time
	16 feb 22 0823

Summit Carbon Solutions 2021-2022

Metal Digestion
pH
Conductivity (EC)
pH - Field
Temperature - Field
Total Alkalinity
Phenolphthalein Alk
Bicarbonate
Carbonate
Hydroxide
Conductivity - Field
Total Organic Carbon
Sulfate
Chloride
Nitrate-Nitrite as N
Ammonia-Nitrogen as N
Mercury - Dissolved
Total Dissolved Solids
Calcium - Total
Magnesium - Total
Sodium - Total
Potassium - Total
Iron - Total
Manganese - Total
Barium - Dissolved
Copper - Dissolved
Molybdenum - Dissolved
Strontium - Dissolved
Arsenic - Dissolved
Cadmium - Dissolved
Chromium - Dissolved
Lead - Dissolved
Selenium - Dissolved
Silver - Dissolved

2-1L Raw
500 N
500 N (f)
250 Sulf
TOC

Carbon Capture Sites South of Beulah.

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

Page: 1 of 2

Report Date: 21 Jan 22
Lab Number: 22-W53
Work Order #:82-0078
Account #: 74217
Date Sampled: 12 Jan 22 5:40
Date Received: 12 Jan 22 8:13
Sampled By: Client

Temp at Receipt: 6.5C ROI

Jean Datahan
Neset Consulting
6844 Hwy 40
Tioga ND 58852

Sample Description: Inyan Kara
Sample Site: Milton Flemmer 1

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	12 Jan 22	RAA
pH	* 8.7	units	N/A	SM4500-H+-B-11	12 Jan 22 11:34	RAA
Conductivity (EC)	5057	umhos/cm	N/A	SM2510B-11	13 Jan 22 17:00	RAA
pH - Field	8.68	units	NA	SM 4500 H+ B	12 Jan 22 5:40	JSM
Temperature - Field	12.2	Degrees C	NA	SM 2550B	12 Jan 22 5:40	JSM
Total Alkalinity	433	mg/l CaCO3	20	SM2320B-11	13 Jan 22 17:00	RAA
Phenolphthalein Alk	23	mg/l CaCO3	20	SM2320B-11	13 Jan 22 17:00	RAA
Bicarbonate	388	mg/l CaCO3	20	SM2320B-11	13 Jan 22 17:00	RAA
Carbonate	45	mg/l CaCO3	20	SM2320B-11	13 Jan 22 17:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	13 Jan 22 17:00	RAA
Conductivity - Field	5191	umhos/cm	1	EPA 120.1	12 Jan 22 5:40	JSM
Total Organic Carbon	84.0	mg/l	0.5	SM5310C-11	20 Jan 22 17:13	NAS
Sulfate	1410	mg/l	5.00	ASTM D516-11	14 Jan 22 9:13	SD
Chloride	718	mg/l	2.0	SM4500-Cl-E-11	14 Jan 22 10:57	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	13 Jan 22 10:30	SD
Ammonia-Nitrogen as N	2.25	mg/l	0.20	EPA 350.1	18 Jan 22 10:37	SD
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Jan 22 12:45	AC
Total Dissolved Solids	3560	mg/l	10	USGS I1750-85	14 Jan 22 14:00	RAA
Calcium - Total	13.8	mg/l	1.0	6010D	18 Jan 22 14:00	SZ
Magnesium - Total	< 5 @	mg/l	1.0	6010D	18 Jan 22 14:00	SZ
Sodium - Total	1310	mg/l	1.0	6010D	18 Jan 22 14:00	SZ
Potassium - Total	6.8	mg/l	1.0	6010D	18 Jan 22 14:00	SZ
Iron - Total	< 0.5 @	mg/l	0.10	6010D	17 Jan 22 14:16	SZ
Manganese - Total	< 0.25 @	mg/l	0.05	6010D	17 Jan 22 14:16	SZ
Strontium - Dissolved	< 0.5 @	mg/l	0.10	6010D	21 Jan 22 9:16	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	18 Jan 22 14:13	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

Report Date: 21 Jan 22
Lab Number: 22-W53
Work Order #:82-0078
Account #: 74217
Date Sampled: 12 Jan 22 5:40
Date Received: 12 Jan 22 8:13
Sampled By: Client

Temp at Receipt: 6.5C ROI

Jean Datahan
Neset Consulting
6844 Hwy 40
Tioga ND 58852

Sample Description: Inyan Kara
Sample Site: Milton Flemmer 1

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Barium - Dissolved	0.0488	mg/l	0.0020	6020B	18 Jan 22 14:13	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	18 Jan 22 14:13	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	18 Jan 22 14:13	MDE
Copper - Dissolved	0.0021	mg/l	0.0020	6020B	18 Jan 22 14:13	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	18 Jan 22 14:13	MDE
Molybdenum - Dissolved	0.0138	mg/l	0.0020	6020B	18 Jan 22 14:13	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	18 Jan 22 14:13	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	18 Jan 22 14:13	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

APPENDIX B

FRESHWATER WELL FLUID SAMPLING

B-1. FRESHWATER WELL FLUID SAMPLING

Table B-1 summarizes the results from existing groundwater wells for ranges of pH, electrical conductivity (EC), total dissolved solids (TDS), and total alkalinity measured from 4 monitoring sites within TB Leingang area of review (AOR). Monitoring sites were selected to supplement forthcoming groundwater sampling to establish baseline conditions. Figure B-1 is a map showing the locations of the selected monitoring sites. Water chemistry results are included below.

Table B-1. Summary of Water Chemistries[1] at Four Sampling Locations Within the Area of Review (AOR) at TB Leingang

Number of Wells	Water Samples	Data Vintage	Sampling Horizon	pH	EC, mS/cm	TDS, mg/L	Total Alkalinity, mg/L $CaCO_3$
1	1	1968	Tongue River	8.4	2460	1680	1370
3	3	1967–68	Unknown	7.2–9.3	2850–4330	1960–4260	NA

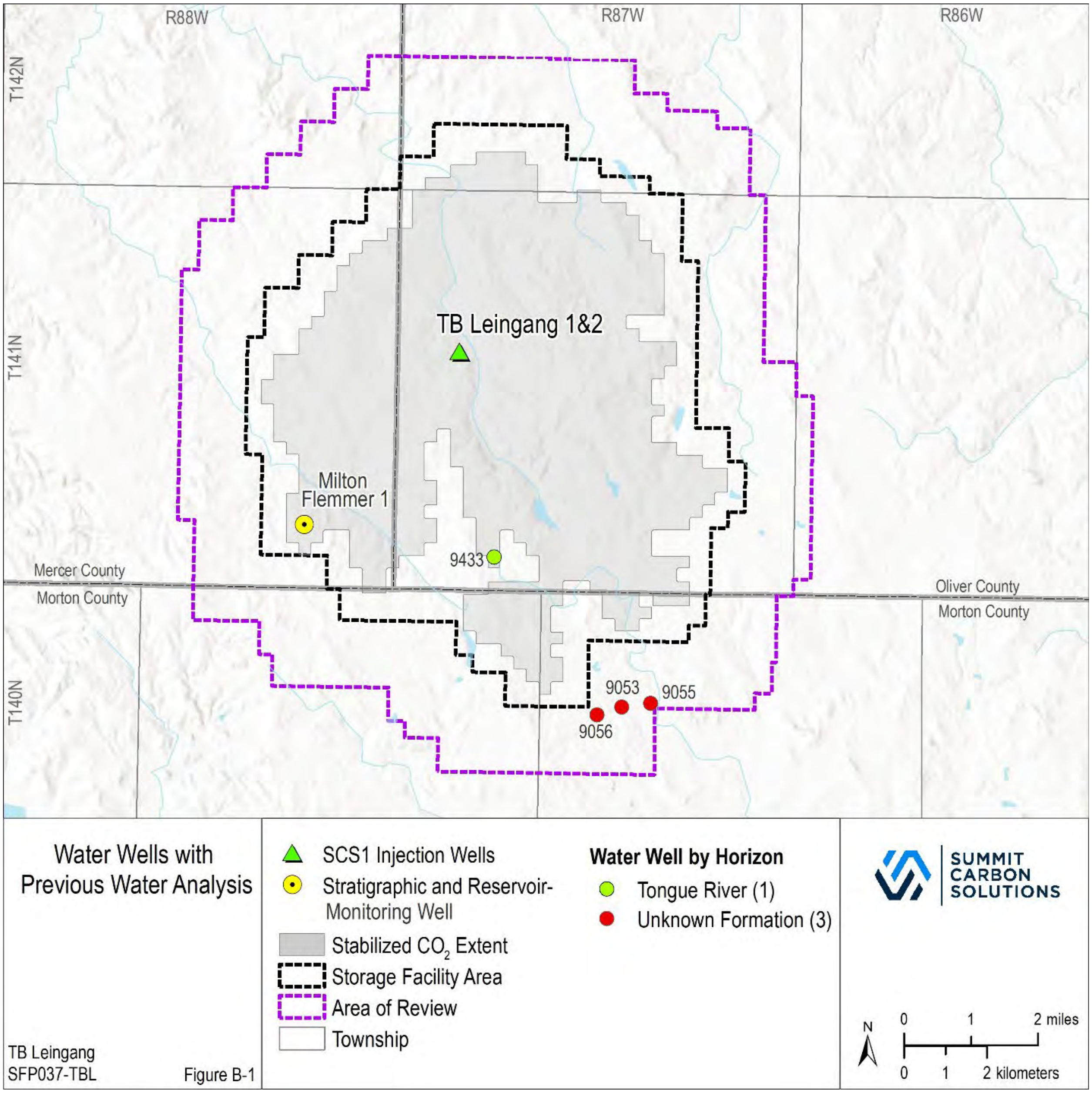


Figure B-1. Locations of the four sampled fresh water wells within the AOR.

APPENDIX C

GEOCHEMICAL INTERACTIONS

C.1 GEOCHEMICAL INTERACTIONS

C.1.1 Geochemical Interaction of Injection Zone (Broom Creek Formation)

Geochemical simulation was 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 GEM, the compositional simulation software package from Computer Modelling Group Ltd. (CMG). 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 bottomhole pressure (BHP) and maximum wellhead pressure (WHP) constraints of 3663 and 2100 psi, 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 anticipated average CO_2 stream composition is 98.25% CO_2, 1.44% N_2, and 0.31% O_2, with a trace amount of H_2S. The CO_2 stream, shown in Table C-1 that was used for geochemical modeling, contains a higher amount of O_2 (2%). The modeled stream containing ~95% CO_2 and 2% O_2 was used to represent a conservative scenario where the oxygen concentration is highest, potentially triggering more geochemical reactions in the formation. This simulation scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figures C-1 and C-2).

The case with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (78% of bulk reservoir volume) and average formation brine composition (22% of bulk reservoir volume). X-ray diffraction (XRD) data from the Milton Flemmer 1 well core samples were used to inform the mineralogical composition of the Broom Creek Formation (Table C-2). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Ionic composition of the Broom Creek Formation water, derived from the state-certified analysis reported in Appendix A, is listed in Table C-3.

Table C-1. CO_2 Stream Composition Used for Geochemical Modeling

Component	mol%
CO_2	94.999
N_2	3
O_2	2
H_2S	1.0E-3

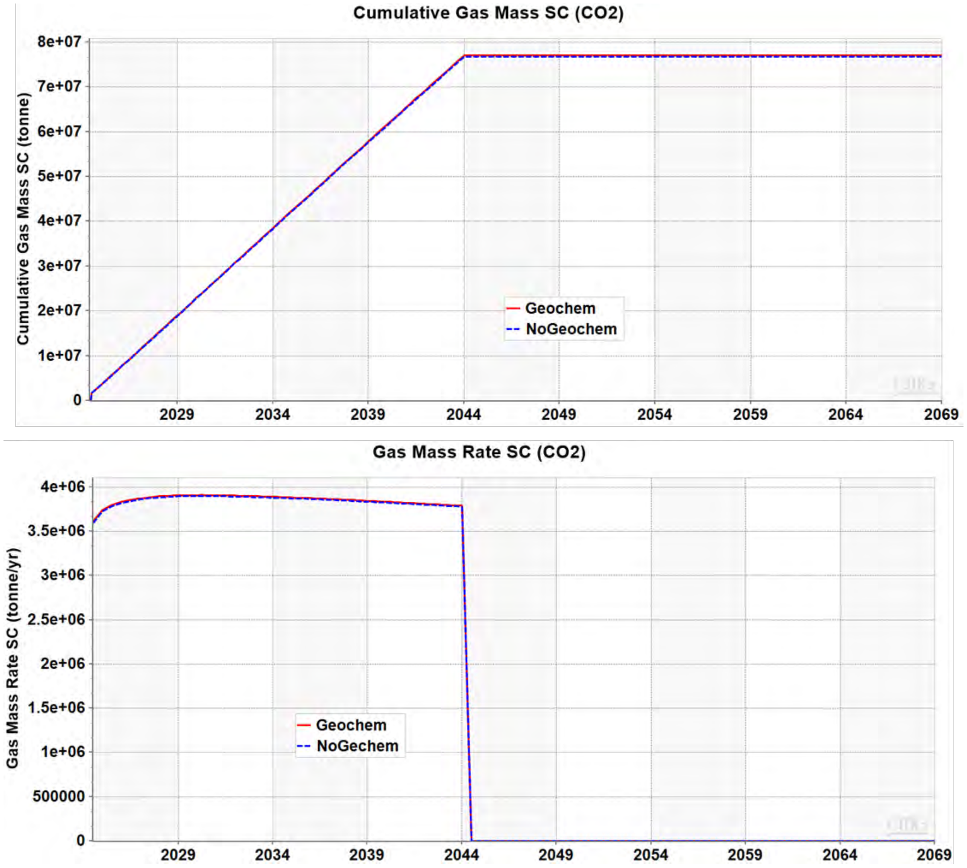


Figure C-1. Top graph shows cumulative injection vs. time; bottom graph shows gas injection rate vs. time. There is no observable difference in injection volume and gas rate due to geochemical reactions.

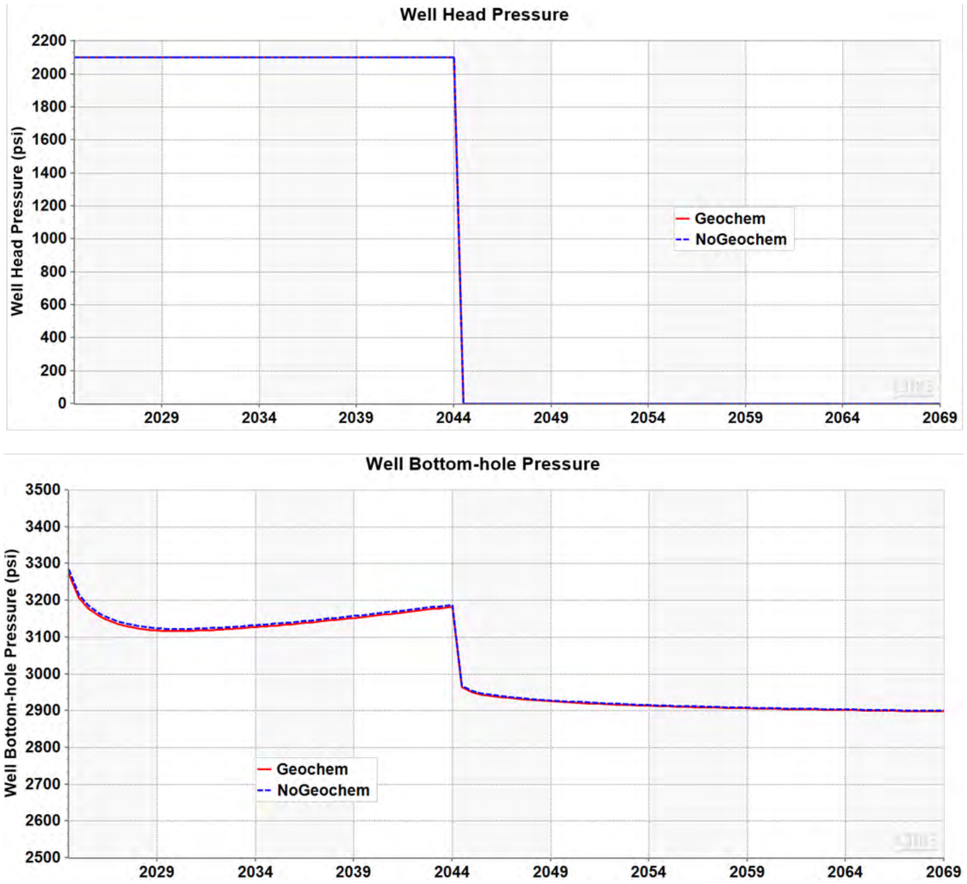


Figure C-2. Top graph shows WHP vs. time; bottom graph shows BHP vs. time. There is no observable difference in pressures due to geochemical reactions.

Table C-2. Averaged XRD data for (Milton Flemmer 1) Broom Creek Core Sample

Mineral Data	wt%
Illite	3.07
K-Feldspar	4.35
Albite	1.32
Quartz	53.17
Dolomite	21.16
Anhydrite	16.79
Siderite	0.12
Hematite	0.02

Table C-3. Milton Flemmer 1 Broom Creek Formation Water Ionic Composition

Component	mg/L	Molality
Na^+	39,500	1.787216
K^+	680	0.018091
Ca^{2+}	3060	0.079421
Mg^{2+}	505	0.021613
Fe^{2+}	5	9.31E-05
SO_4^{2-}	2400	2.60E-02
Cl^-	42,400	1.244033
HCO_3^-	101	1.72E-03
H^+	0.00015976	1.65E-07
Al^{3+}	1E-10	3.86E-15
OH^-	0.00852419	5.21E-07
SiO_2(aq)	1.00E-10	1.73E-15
CO_3^{2-}	0.00001	1.73E-10
Fe^{3+}	1.00E-10	1.86E-15

The results do not show an evident difference in the CO_2 gas molality fraction between both cases as seen in Figures C-1 and C-2 for volume injected and injection pressure simulation results. As a result of geochemical reactions in the reservoir, cumulative volume and injection rate have no observable difference between the geochemical and nongeochemical cases. The resulting BHP and WHP from the two cases are nearly identical, with no appreciable differences.

Figure C-3 shows the location of the cross sections and Layer 30 used in Figures C-4a and C-4b to depict the geochemical modeling results. Figures C-4a and C-4b show the concentration of CO_2, in molality, in the reservoir after 20 years of injection plus 25 years of postinjection for the geochemistry model and nongeochemistry model, respectively.

The pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure C-5a. The pH of the Broom Creek Formation native brine sample is 6.8, whereas the fluid pH declines to approximately 4.3 in the CO_2-flooded areas near the well as a result of CO_2 dissolution in the native formation brine (Figure C-5b).

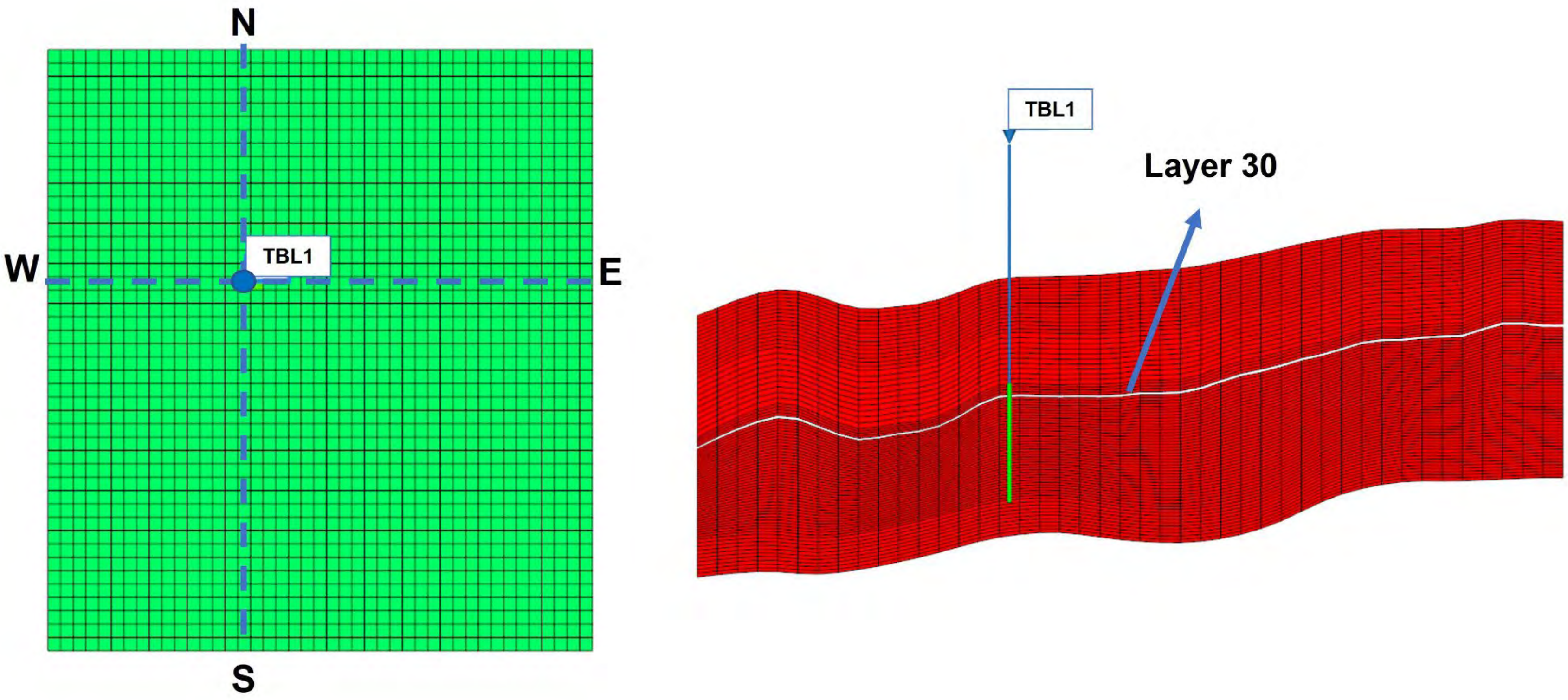


Figure C-3. Index map of west–east and south–north cross sections and simulation Layer 30 at 3469 ft (SSTVD, subsea true vertical depth).

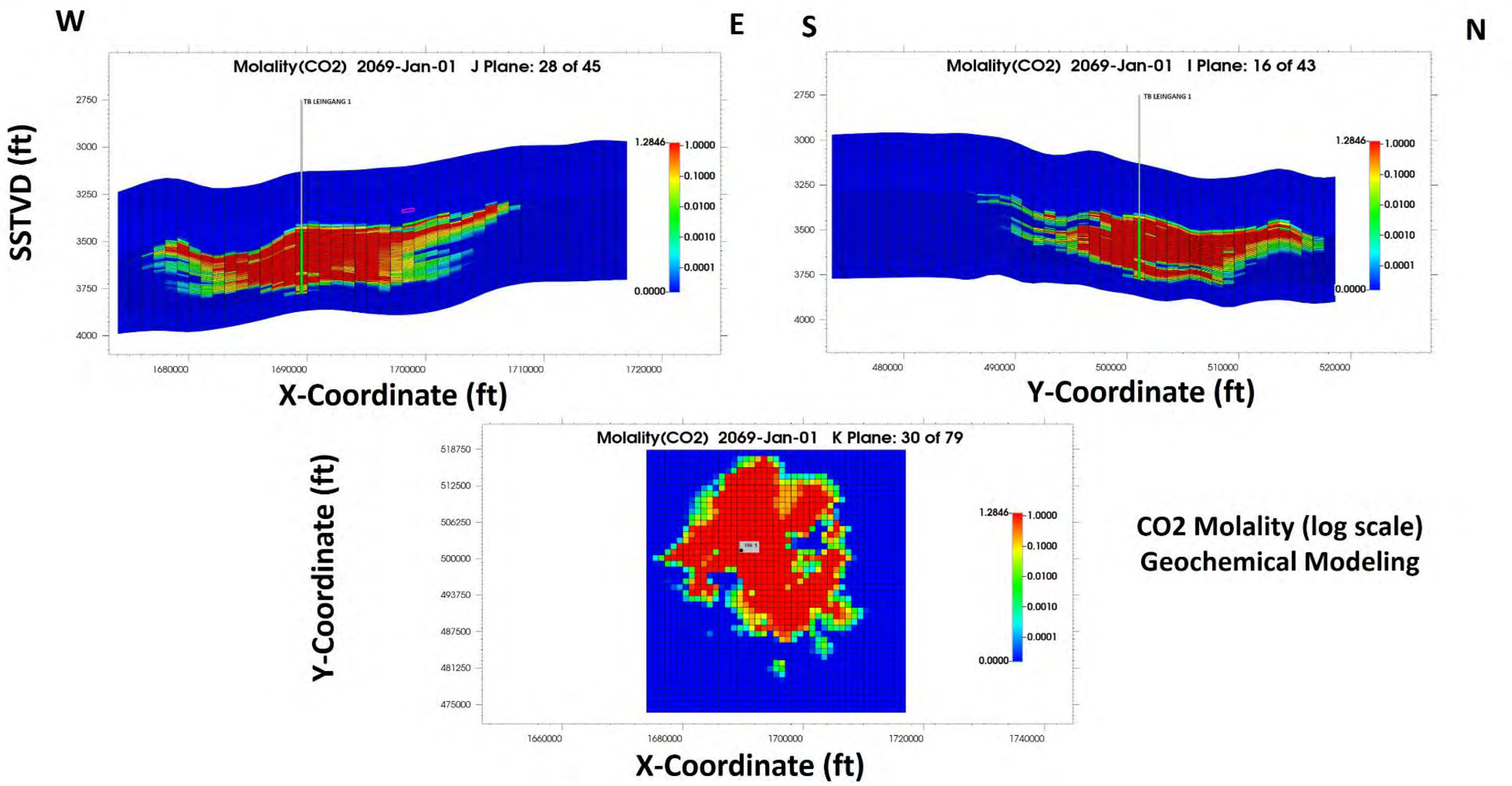


Figure C-4a. CO_2 molality for the geochemistry case simulation results after 20 years of injection plus 25 years postinjection showing the distribution of CO_2 molality in log scale. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD).

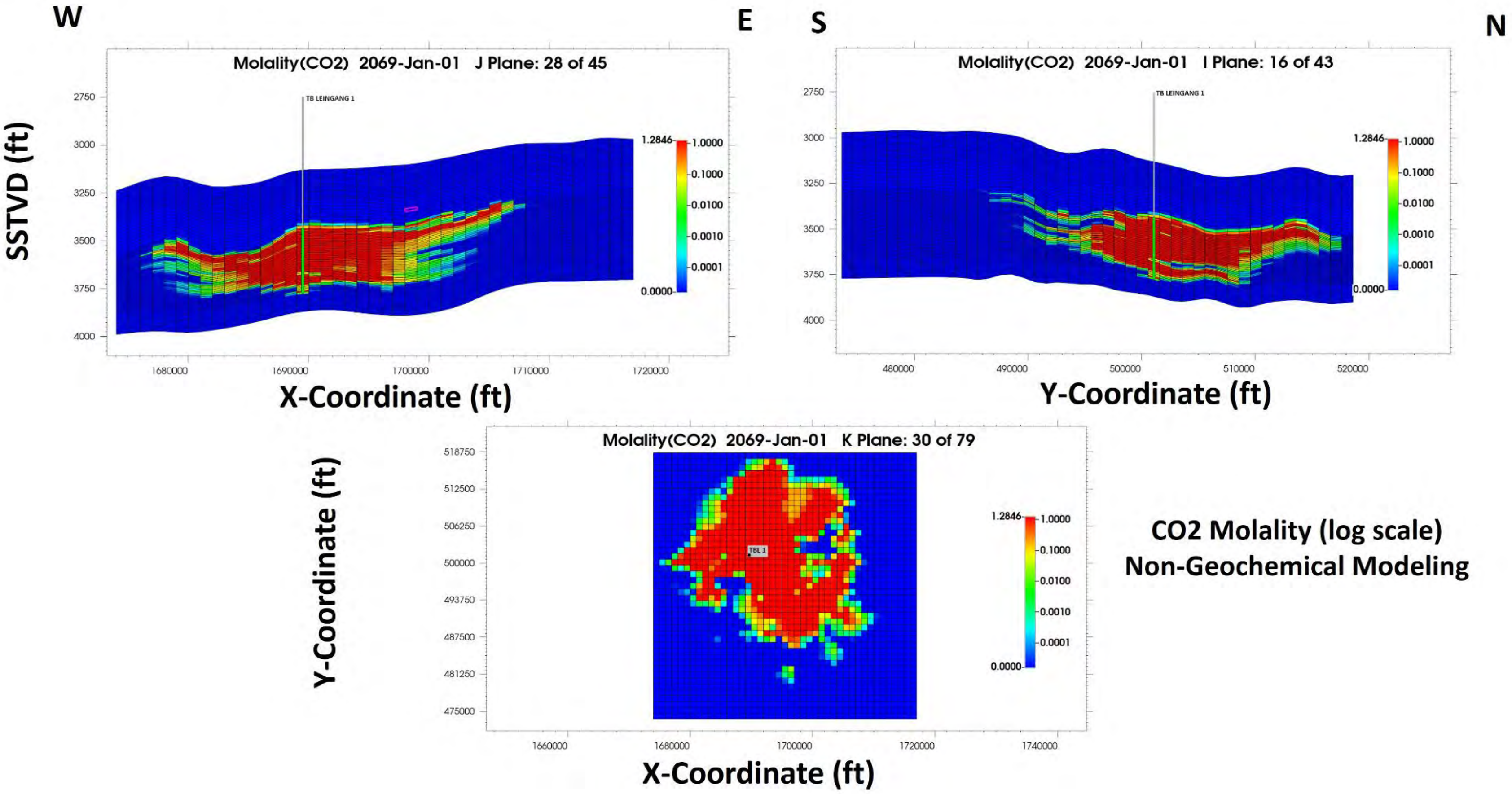


Figure C-4b. CO_2 molality for the nongeochemistry case simulation results after 20 years of injection plus 25 years postinjection showing the distribution of CO_2 molality in log scale. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD).

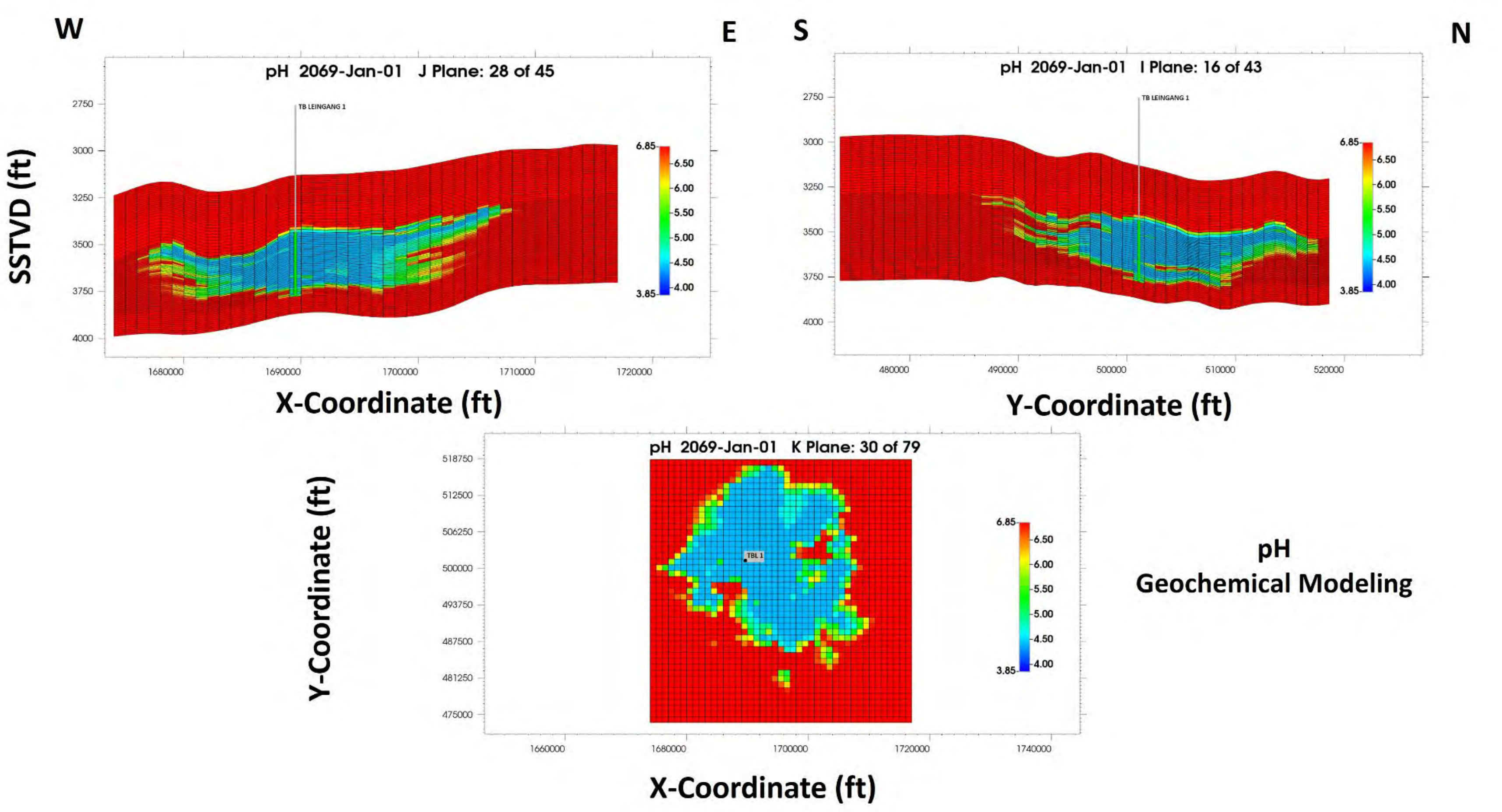


Figure C-5a. Geochemistry case simulation results after 20 years of injection plus 25 years postinjection showing the pH of formation brine in log scale. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD).

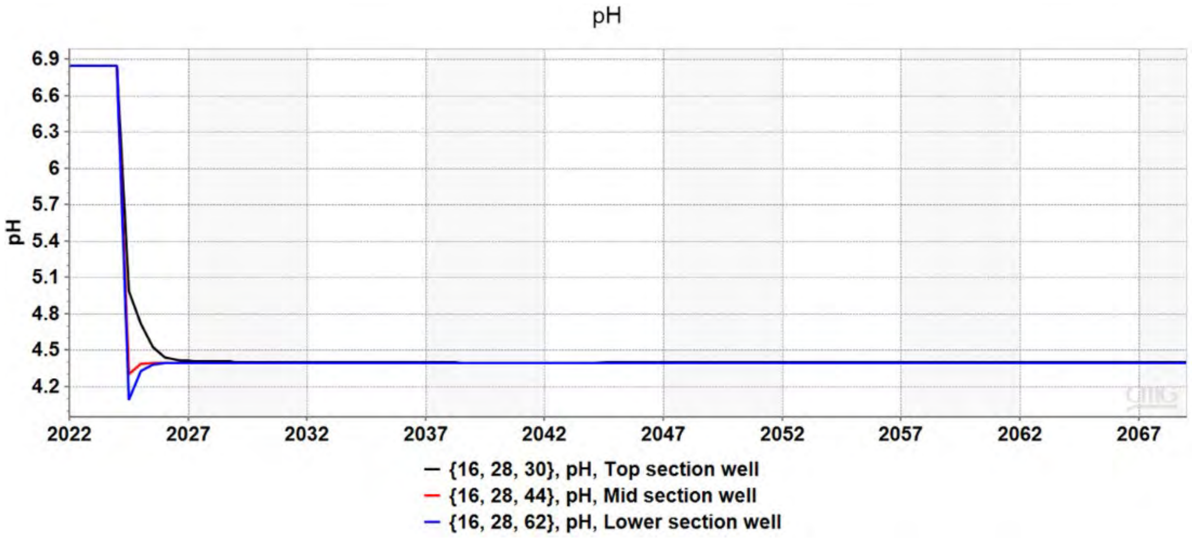


Figure C-5b. Geochemistry case simulation results through 20 years of injection plus 25 years postinjection showing the pH of the Broom Creek Formation brine at the wellbore vs. time for Layer 30 at 3469 ft (SSTVD), Layer 44 at 3574.4 ft (SSTVD), and Layer 62 at 3710 ft (SSTVD).

Figures C-6a and C-6b show the cross section for O_2 molality in the Broom Creek Formation. Figure C-6a shows the cross section for the concentration of O_2, in molality, in the reservoir after 20 years of injection plus 25 years postinjection for the geochemistry model scenario, and Figure C-6b shows the same information for the nongeochemistry simulation case for comparison. The results do not show an evident difference in the O_2 gas molality fraction between both cases. After being injected, the 2% molar oxygen content in the injection stream is dissolved in the brine and likely to cause oxidative reactions of the minerals, which may induce dissolution/precipitation of reactive minerals and formation of secondary minerals in the reservoir. The simulation results showed no significant precipitation caused by the high concentration of O_2 that would affect the CO_2 injection volume, as demonstrated by the comparison in injection rates between the case with and without geochemical modeling shown in Figure C-2.

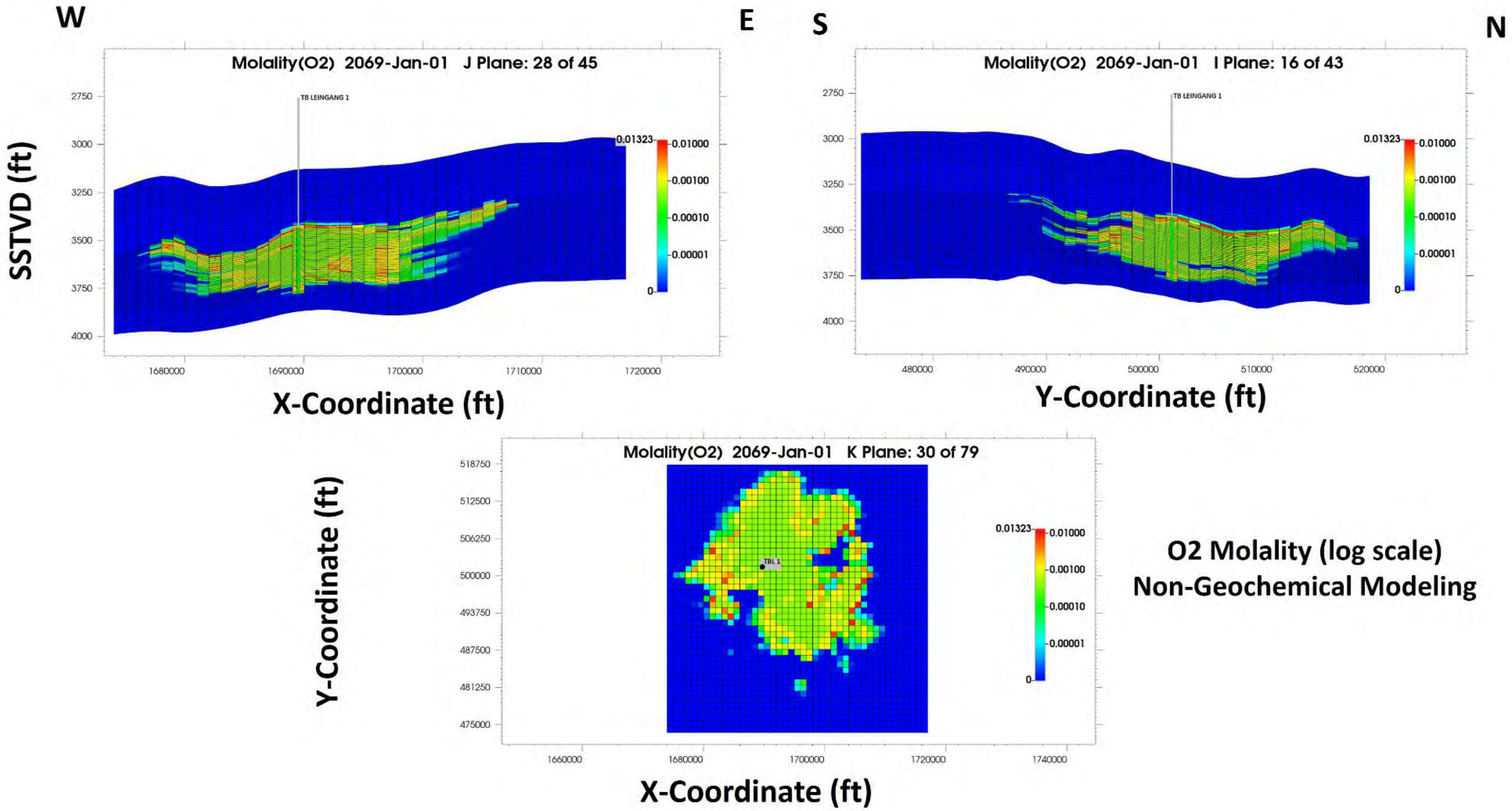
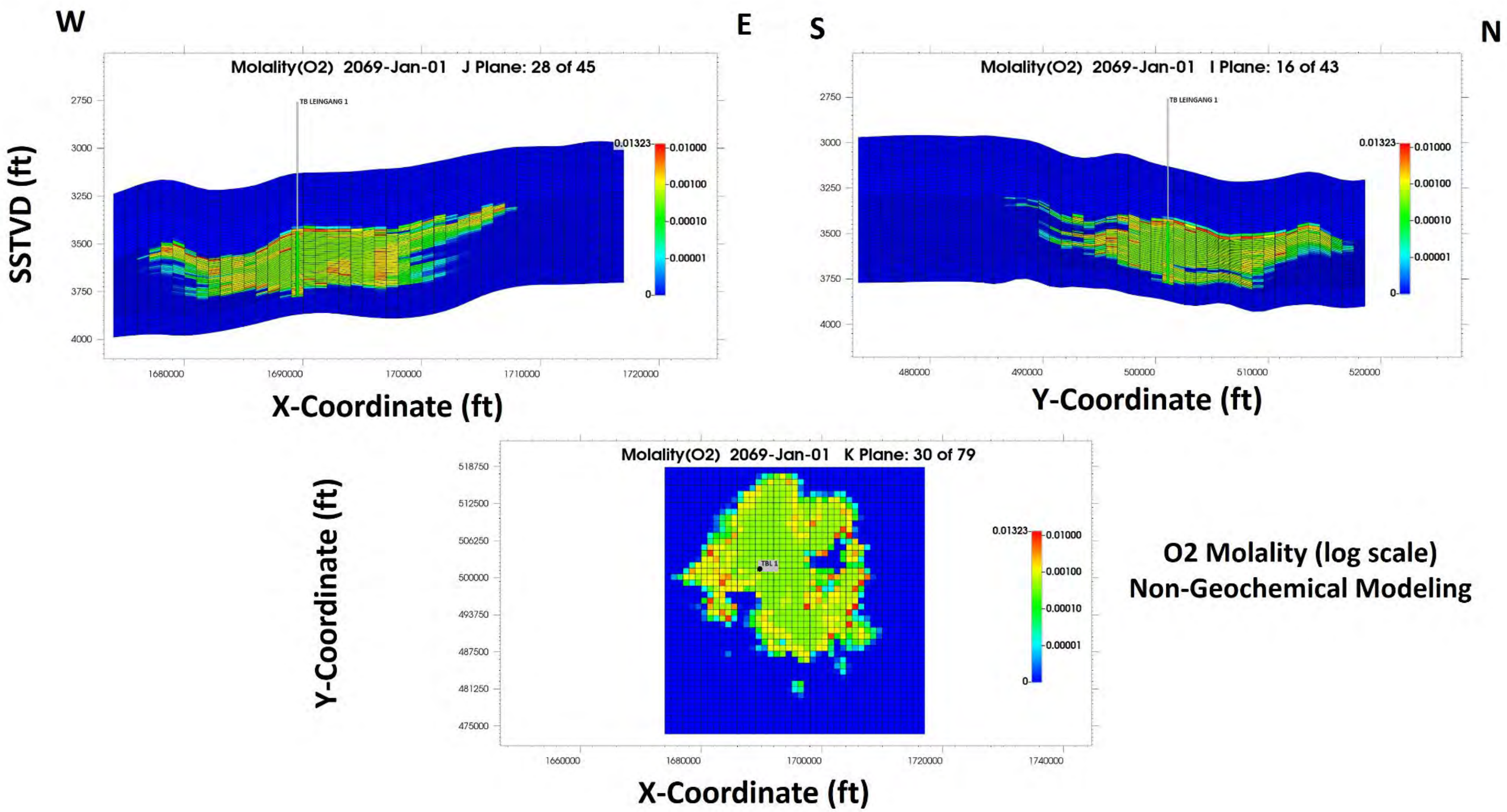


Figure C-6a. Cross section for O_2 molality for the geochemistry case simulation results after 20 years of injection plus 25 years postinjection showing the distribution of O_2 in the gas phase in log scale. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD).



O2 Molality (log scale)
Non-Geochemical Modeling

Figure C-6b. Cross section for O_2 molality for the nongeochemistry case simulation results after 20 years of injection plus 25 years postinjection showing the distribution of O_2 in the gas phase in log scale. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD).

Figure C-7 shows the mass of mineral dissolution and precipitation due to CO_2 injection in the Broom Creek Formation. Dolomite is the most prominent dissolved mineral, while anhydrite is the most prominent precipitated mineral. All other minerals showed very limited variations.

Simulation results show that, during CO_2 injection, the supercritical CO_2 (free-phase CO_2 gas) remains dominant. CO_2 dissolution in the formation water and residual trapping of CO_2 slowly increased over time, while CO_2 mineralization is negligible at the plot scale in Figure C-7 it can be observed at the plot scale in Figure C-8. Once CO_2 injection ceases in 2044, injected concentrated CO_2 begins to expand, resulting in more CO_2 that is capillary-trapped or dissolved into fresh brine, as evidenced by the crossover in Figure C-8. Figures C-9 and C-10, respectively, 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, anhydrite. Considering the apparent net dissolution of minerals in the system, as indicated in Figure C-7, there is an associated net increase in porosity in the affected areas, as shown in Figure C-11. Del Porosity Mineral (DPORMNR) output calculates the porosity change due to mineral dissolution/precipitation. It is calculated as Initial Porosity – Porosity at Time “t.” Negative values of this output indicate net mineral dissolution (porosity increase), while positive values indicate net mineral precipitation (porosity decrease). However, the porosity change is small, less than 0.01% porosity units, equating to a maximum increase in average porosity from 22.00% to 22.01% after the 20-year injection period plus 25 years postinjection.

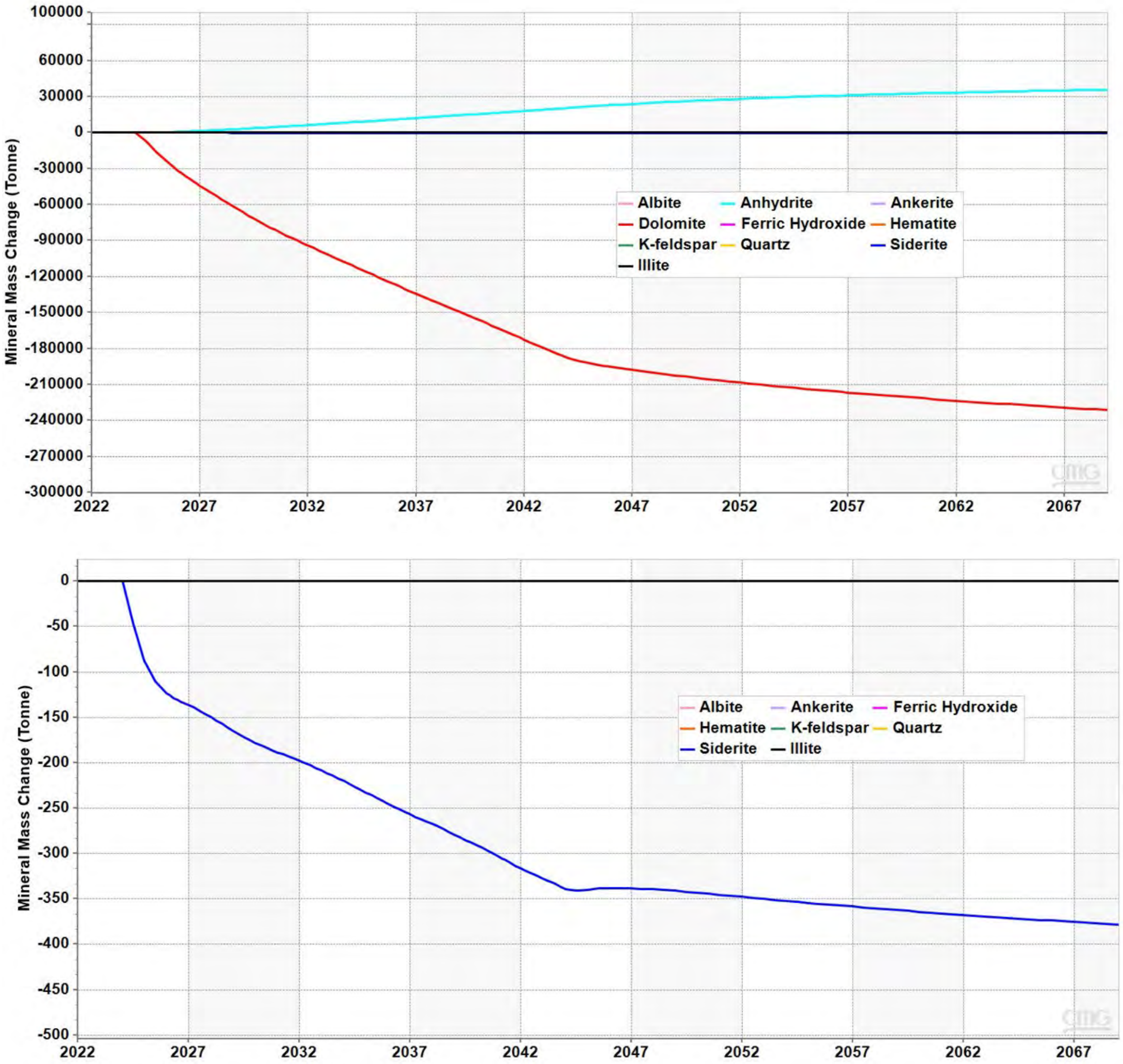


Figure C-7. Modeled change in the mineral masses (minus values show dissolution and positive values show precipitation) due to CO_2 injection (top: all minerals; bottom: zoomed in after removing anhydrite and dolomite). Dissolution of dolomite with precipitation of anhydrite was observed. All of the other minerals showed very small values and account as net zero in this figure.

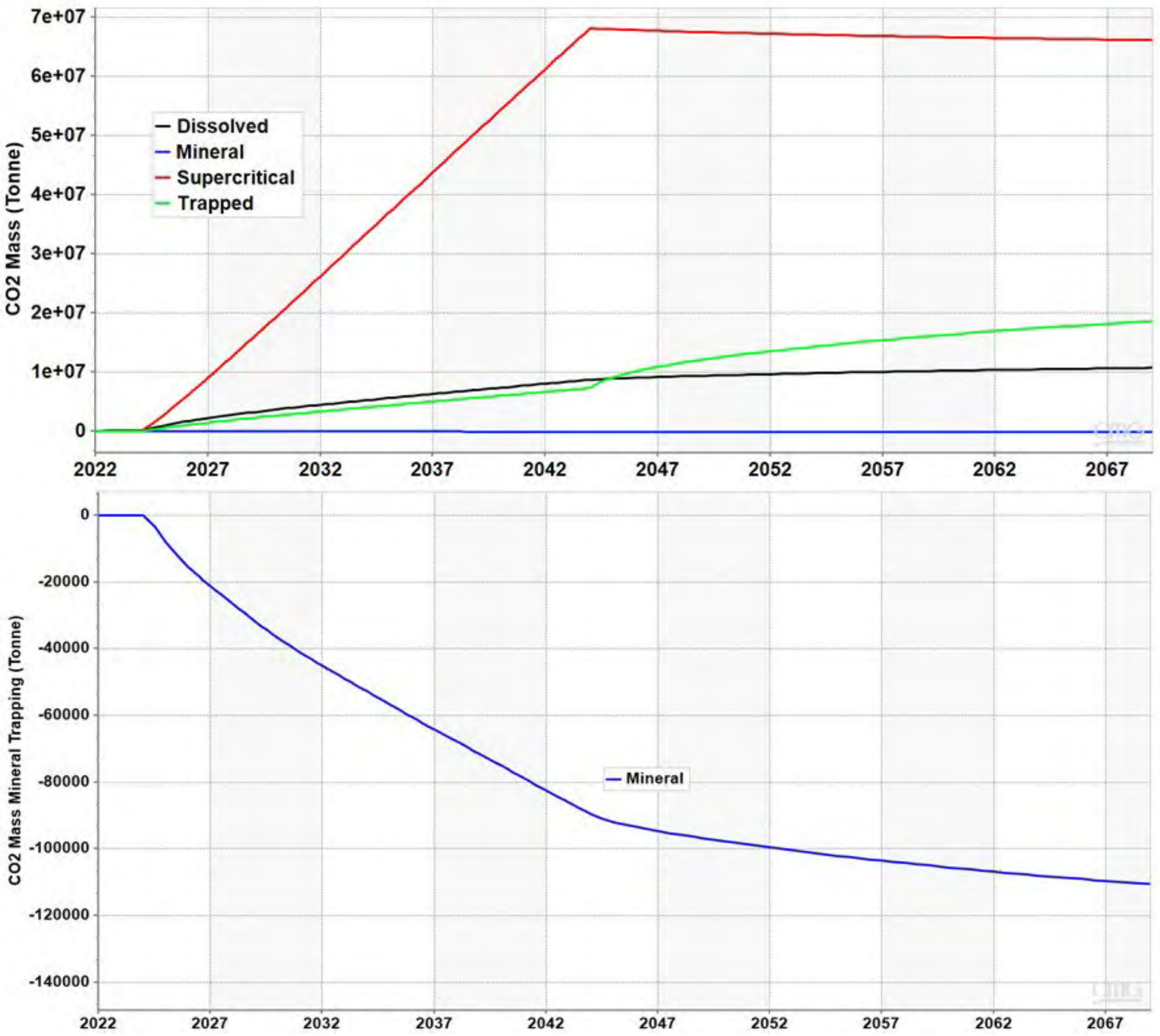


Figure C-8. Top image: mineral mass changes, in metric tons (tonnes), for the different CO_2-trapping mechanisms present during CO_2 injection with geochemical modeling in the injection zone for the Broom Creek Formation; bottom image: CO_2 mineral trapping.

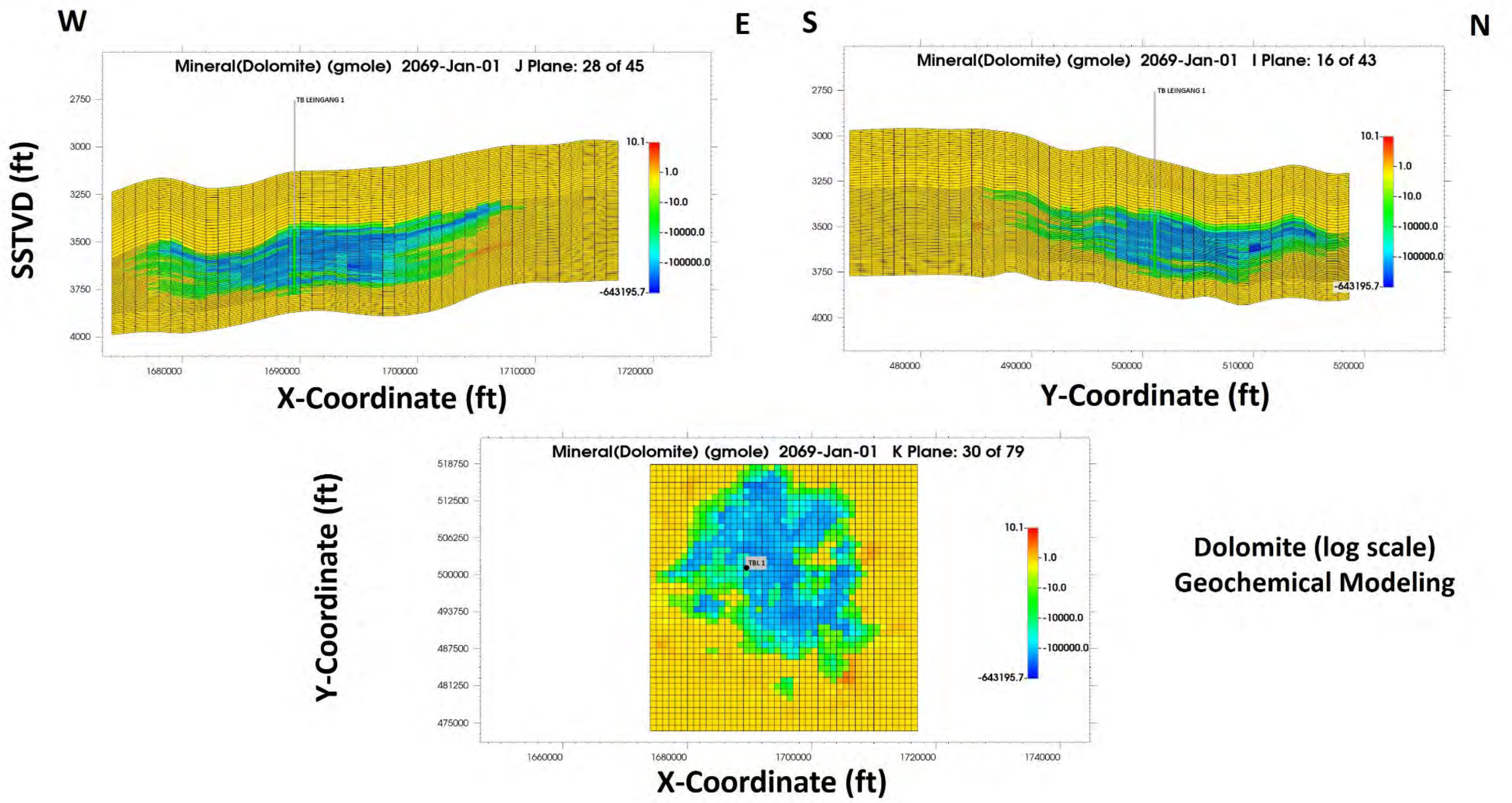


Figure C-9. Modeled change in molar distribution of dolomite, the most prominent dissolved mineral after 20 years of injection plus a 25-year postinjection period. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD).

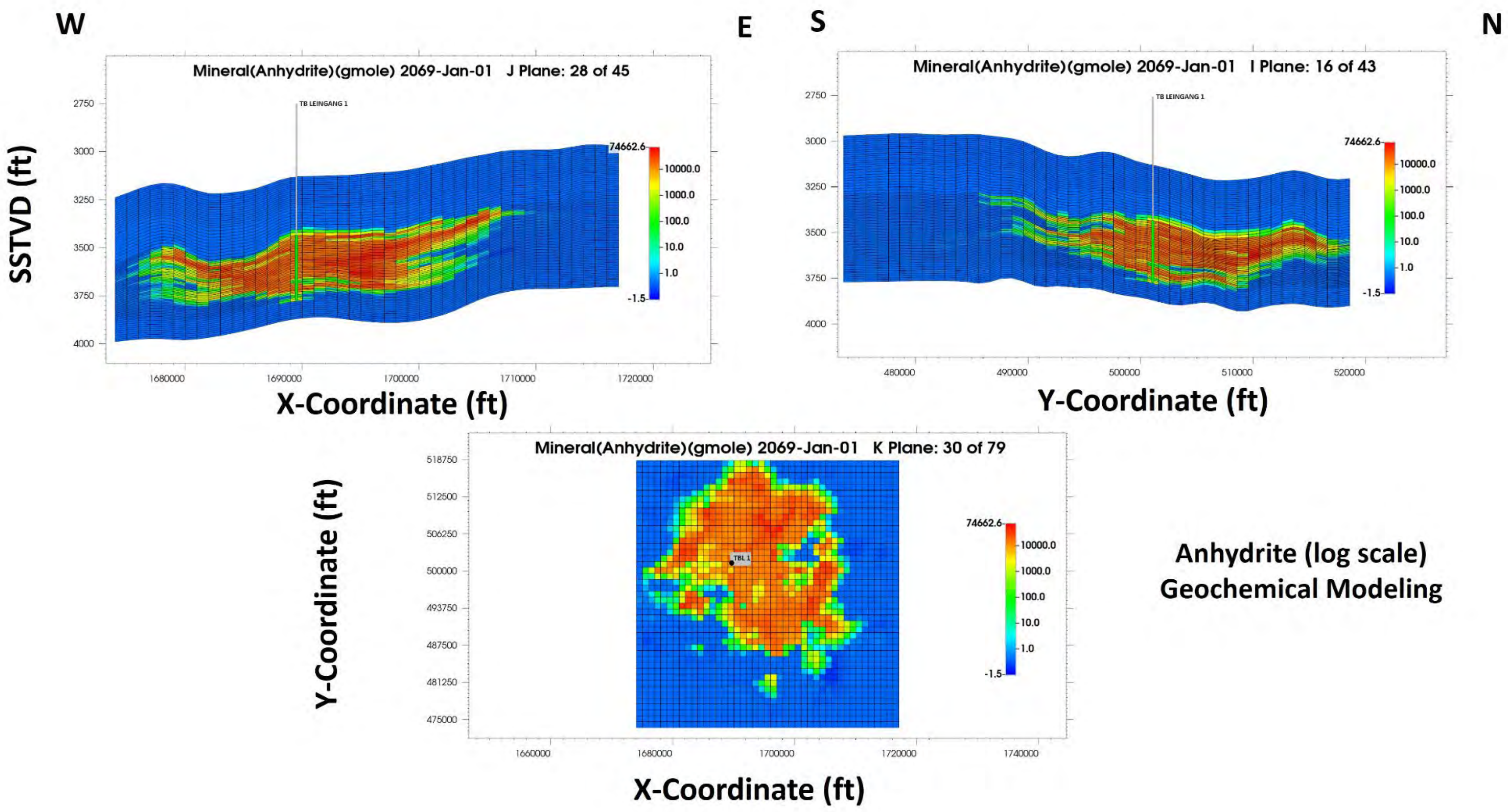
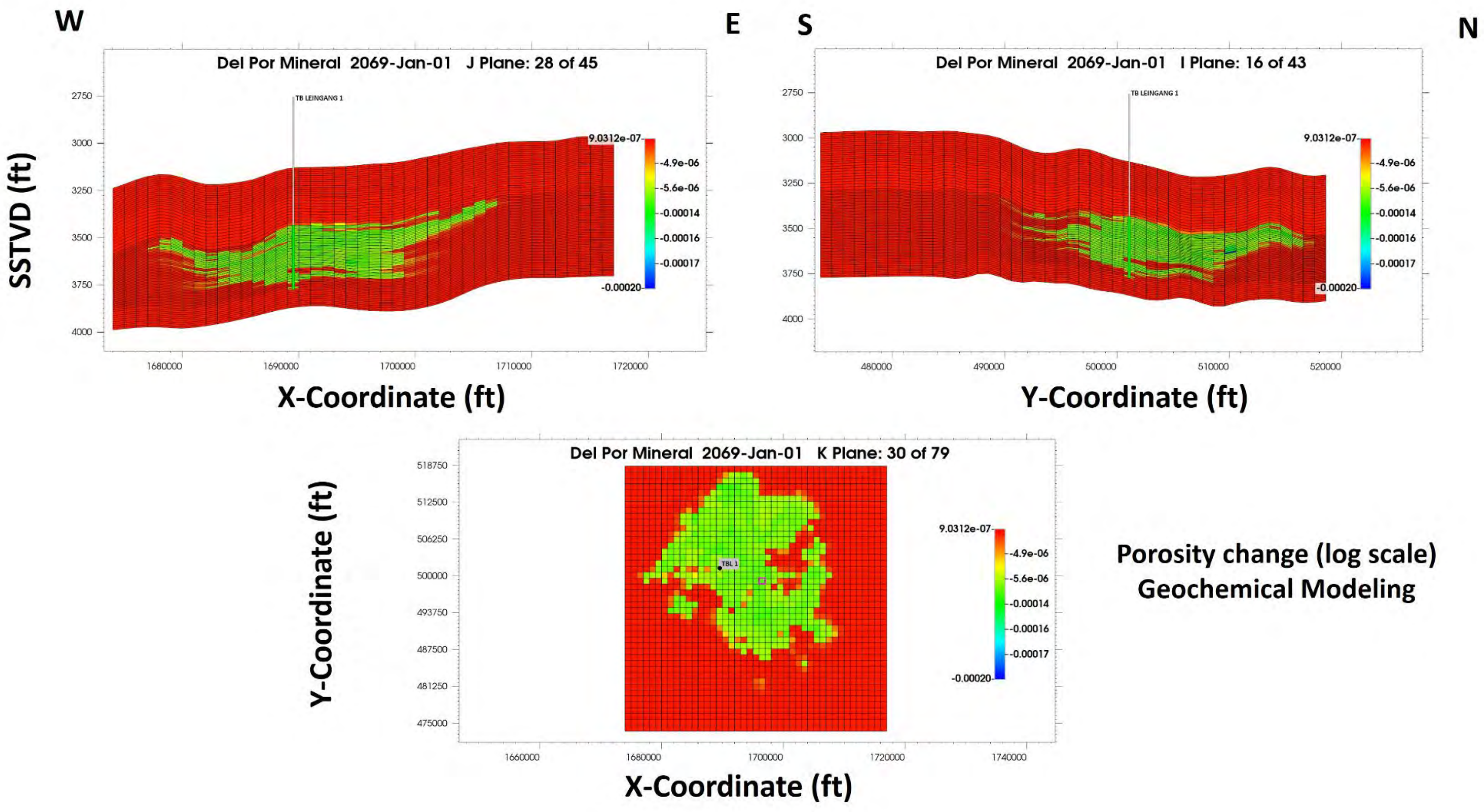


Figure C-10. Modeled change in molar distribution of anhydrite, the most prominent precipitated mineral after 20 years of injection plus a 25-year postinjection period. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD).



Porosity change (log scale)
Geochemical Modeling

Figure C-11. Modeled change in porosity due to net geochemical dissolution after 20 years of injection plus a 25-year postinjection period. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD).

C.1.2 Geochemical Interaction of the Upper Confining Zone (Cap Rock, Opeche/Spearfish Formation)

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected multicomponent CO_2 stream on the Opeche/Spearfish Formation. Note: PHREEQC's unit of measure is metric. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to the injection stream mixture at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Opeche/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 average mineralogical composition calculated from the XRD results of the two deepest samples from the Opeche/Spearfish Formation was honored (Table C-4). Formation brine composition was assumed to be the same as the known composition from the Broom Creek Formation injection zone below (Table C-5).

The anticipated average CO_2 stream composition is 98.25% CO_2, 1.44% N_2, and 0.31% O_2, with a trace amount of H_2S. The CO_2 stream, shown in Table C-1 that was used for geochemical modeling, contains a higher amount of O_2 (2%). The modeled stream containing ~95% CO_2 and 2% O_2, Table C-1, was used to represent a conservative scenario where the higher oxygen concentration may trigger more geochemical reactions in the formation. The exposure level, expressed in moles per year, of the CO_2 stream to the confining layer 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). Again, this conservative overestimation 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 postinjection. The simulation was performed at elevated reservoir pressure and temperature conditions obtained from the dynamic reservoir simulation.

Table C-4. Averaged Mineral Composition of the Opeche/Spearfish Derived from XRD Analysis of Milton Flemmer 1 Core Samples at Depths* of 5824.8 and 5819.5 ft MD

Minerals, wt%	
Anhydrite	59.56
Quartz	25.20
Dolomite	9.14
K-Feldspar	4.82
Illite	1.29

*Core Depths. Please reference Table 2-2a for the core to log depth shifts in the Milton Flemmer 1.

Table C-5. Formation Water Chemistry from Broom Creek Formation Fluid Sample from Milton Flemmer 1

pH	6.47	TDS	105,000 mg/L
Total Alkalinity	101 mg/L $CaCO_3$	Calcium	3060 mg/L
Bicarbonate	101 mg/L $CaCO_3$	Magnesium	505 mg/L
Sulfate	2400 mg/L	Iron	5 mg/L
Chloride	42,400 mg/L	Lead	0.01 mg/L
Sodium	39,500 mg/L	Strontium	86.5 mg/L
Potassium	680 mg/L	Barium	5 mg/L

Results showed geochemical processes at work. Figures C-12 through C-16 show results from geochemical modeling. Figure C-12 shows a change in fluid pH over time as CO_2 diffuses into the system. For the cell at the CO_2 interface, Cell 1 (C1), the pH starts declining from an initial pH of 6.47, decreasing to a level of 5.05 after 10 years of injection, and slowly stabilizes at 5.03 by the end of 25 years postinjection. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH begins to change after Year 8 and goes down to 5.45 by the end of simulation. For the cell occupying the space 2 to 3 meters into the cap rock, C3, the pH begins to change after Year 43.

Figure C-13 shows the modeled change in mineral dissolution and precipitation in grams per cubic meter of rock for C1 and C2. In C1 and C2, K-feldspar starts to dissolve from the beginning of the simulation period, while illite and quartz start to precipitate at the same time. The net change due to precipitation or dissolution in C2 is less than 5 kg per cubic meter, with little dissolution or precipitation taking place during the later years of simulation. Any effects in C3 are too small to represent at this scale.

Figure C-14 represents the initial fractions of potentially reactive minerals in the Opeche/Spearfish Formation based on XRD data shown in Table C-4. The expected dissolution of these minerals in weight percentage is also shown for C1 and C2 of the model. In C1 and C2, K-feldspar is the primary mineral that dissolves. Dissolution (%) in C2 is minimal (<0.2%) and not significant to represent at the scale in Figure C-14.

Figure C-15 represents minerals expected to be precipitated in weight (%) shown for C1 and C2 of the model. In C1 and C2, illite, quartz, and calcite are the minerals to be precipitated.

Figure C-16 shows the modeled change in porosity of the cap rock for C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.1% change during the life of the simulation. Initially, C1 experiences up to a 0.14% increase in porosity upon first CO_2 exposure because of dissolution and initial model equilibration, but the change is temporary. No significant porosity changes were observed for C2 and C3. These results suggest that geochemical change from exposure to CO_2 is minor; therefore, the ability of the Opeche/Spearfish Formation to maintain its sealing integrity will not be compromised by geochemical processes.

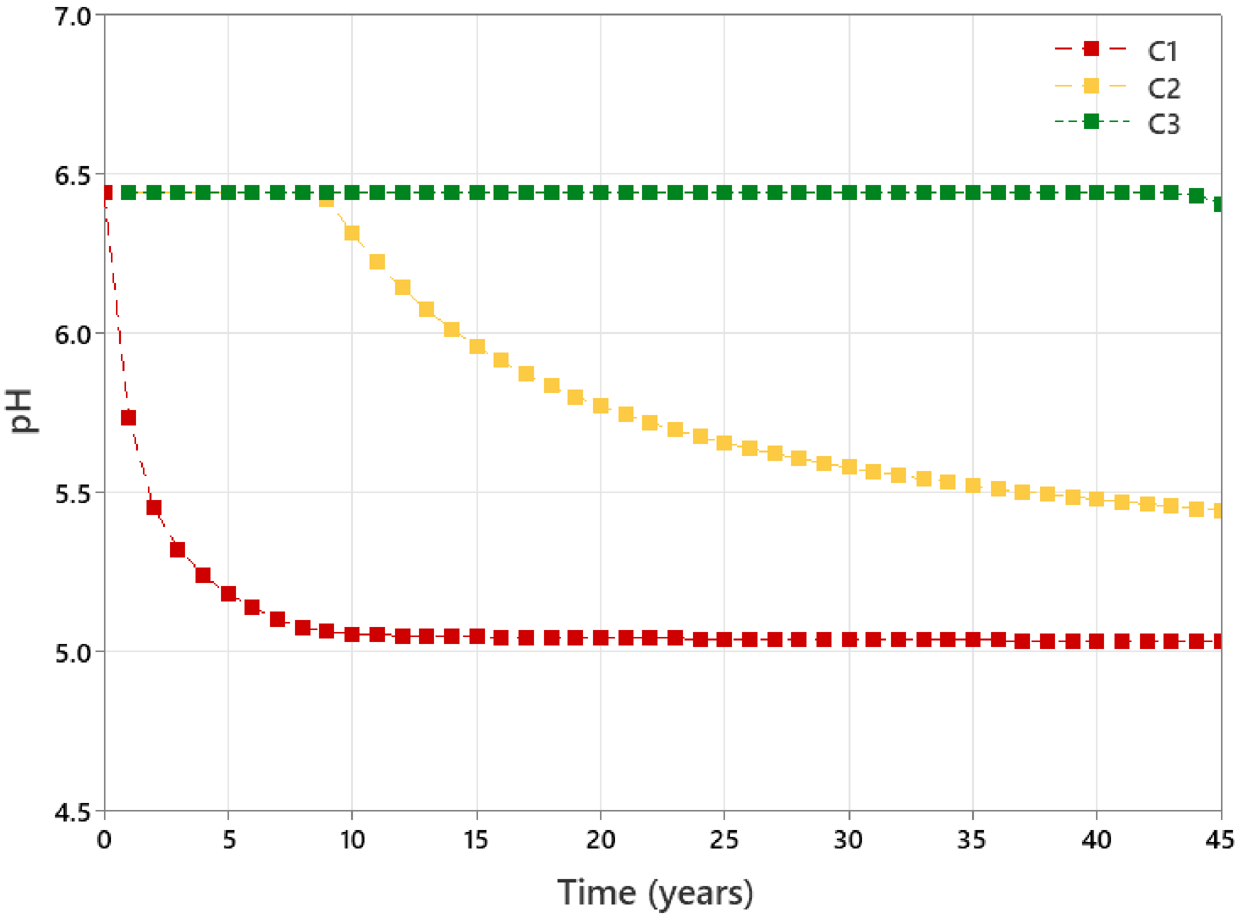


Figure C-12. Modeled change in fluid pH vs. time. Red line shows pH for the center of C1, 0.5 meters above the Opeche/Spearfish Formation cap rock base. Yellow line shows C2, 1.5 meters above the cap rock base. Green line shows C3, 2.5 meters above the cap rock base.

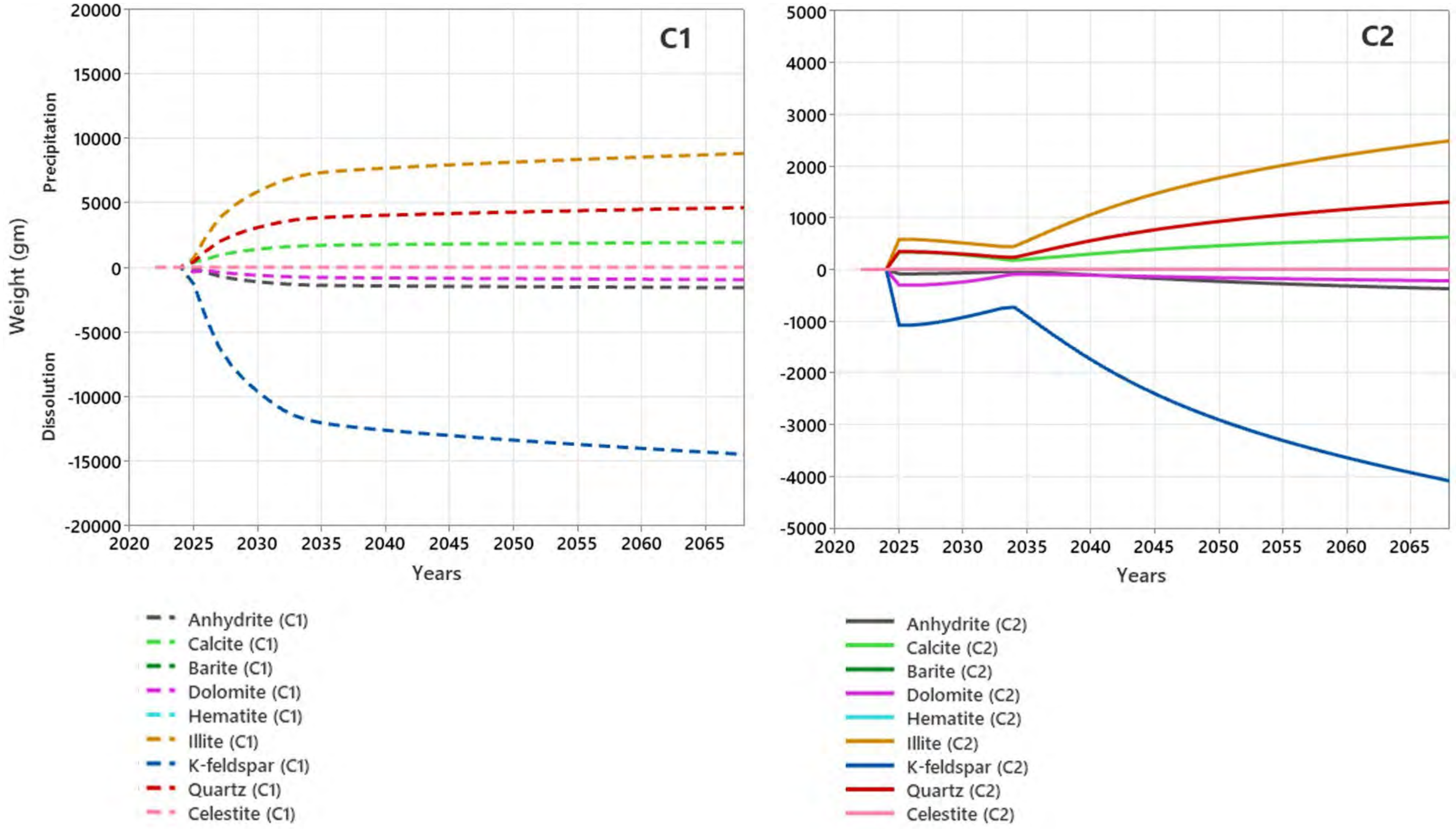


Figure C-13. Modeled dissolution and precipitation of minerals in the Opeche/Spearfish Formation cap rock. Dashed lines show results calculated for C1, 0.5 meters above the cap rock base. Solid lines show results for C2, 1.5 meters above the cap rock base, and these changes are smaller compared to the changes observed for C1. Results from C3, 2.5 meters above the cap rock base, are not shown because they are less than the dissolution and precipitation occurring in C2.

TB LEINGANG/MILTON FLEMMER 1

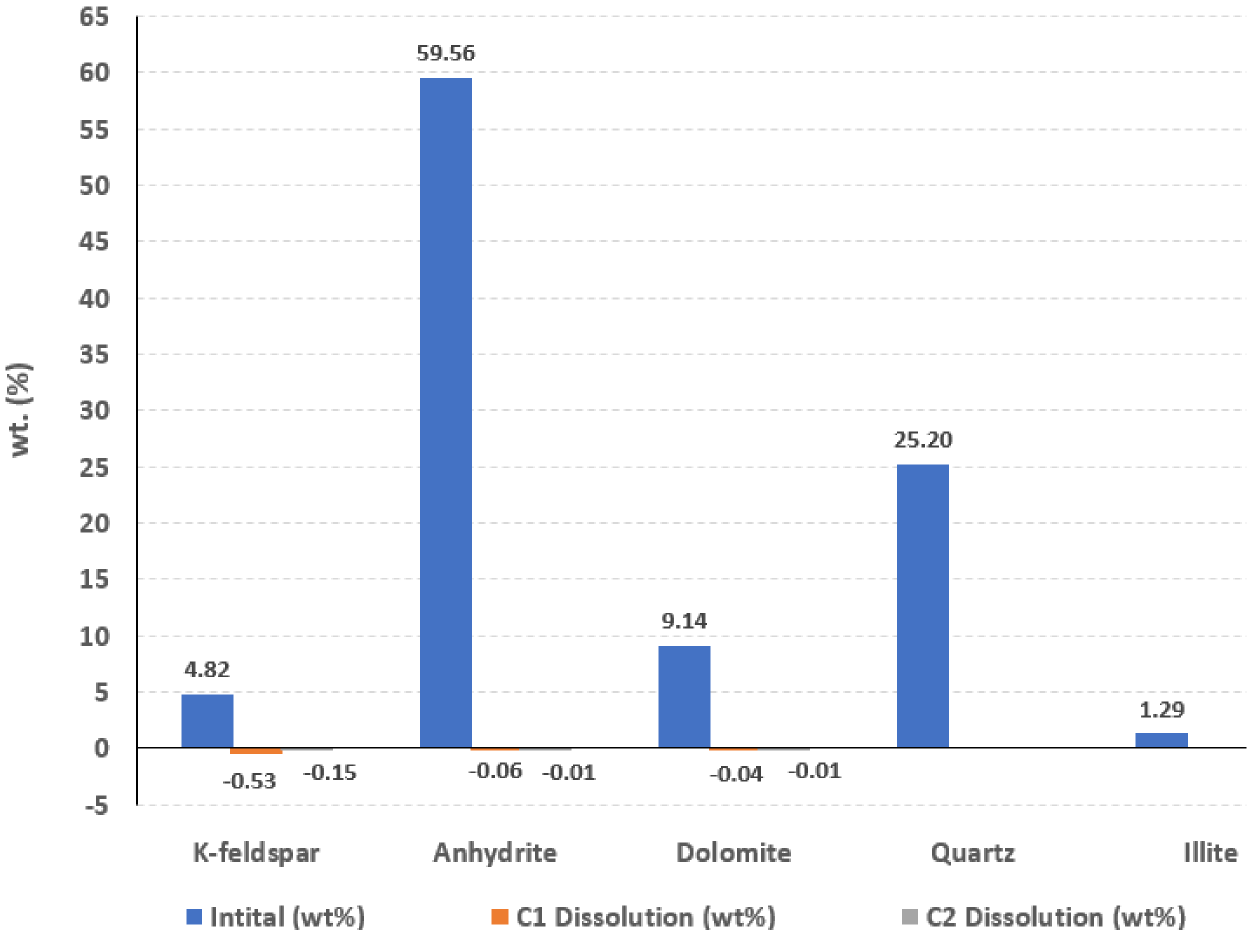


Figure C-14. Weight percentage (wt%) of potentially reactive minerals present in the Opeche/Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in C1 (orange) and C2 (gray, too small to see in the figure) after 20 years of injection plus 25 years postinjection. Negative values represent total wt% associated with dissolution.

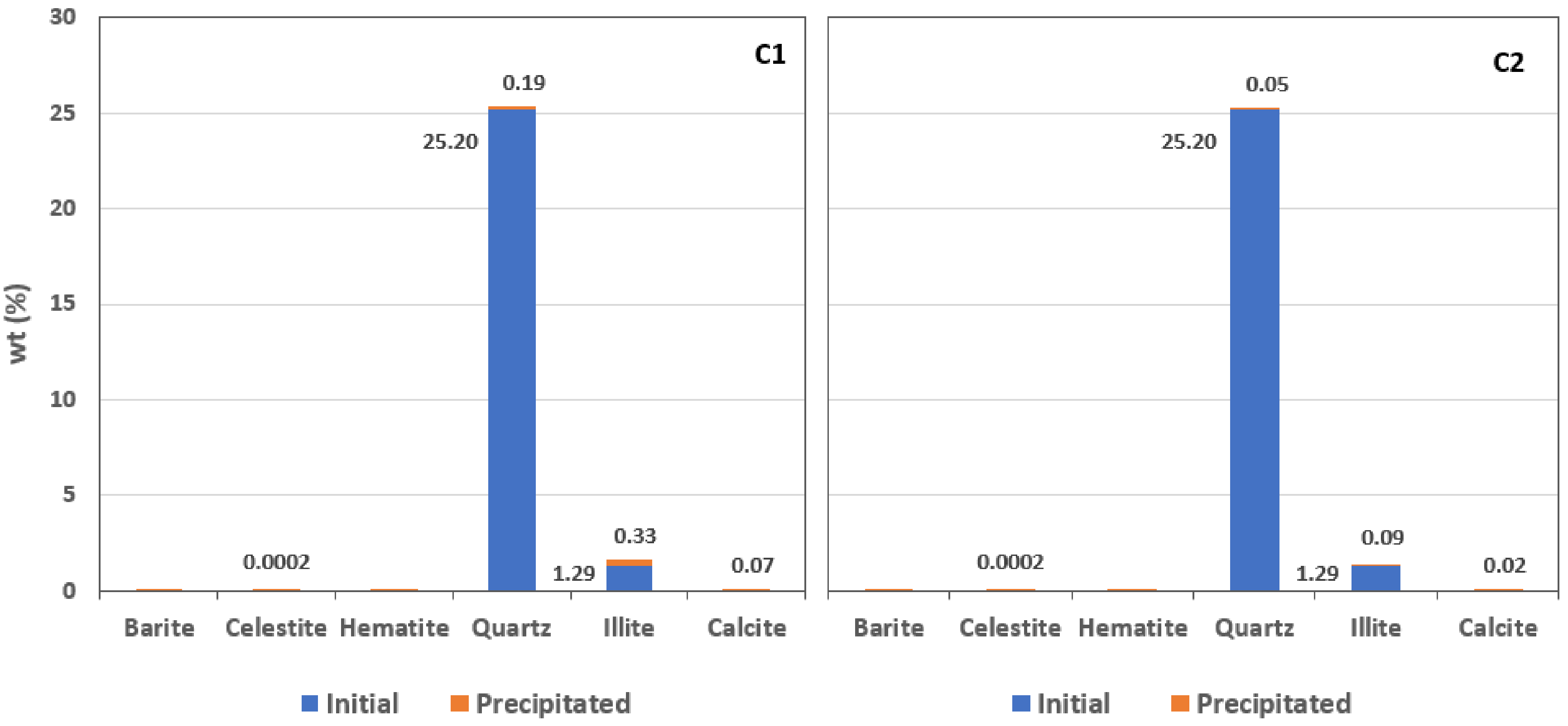


Figure C-15. Weight percentage (wt%) of initial (blue) and precipitated (orange) minerals of the Opeche/Spearfish Formation in C1 and C2 normalized based on total solids (initial – dissolution + precipitation) present in C1 and C2 after 20 years of injection and 25 years postinjection. Secondary minerals, barite and hematite, precipitated in C1 and C2, are too small (<10^{-4}%) to be seen in the figure.

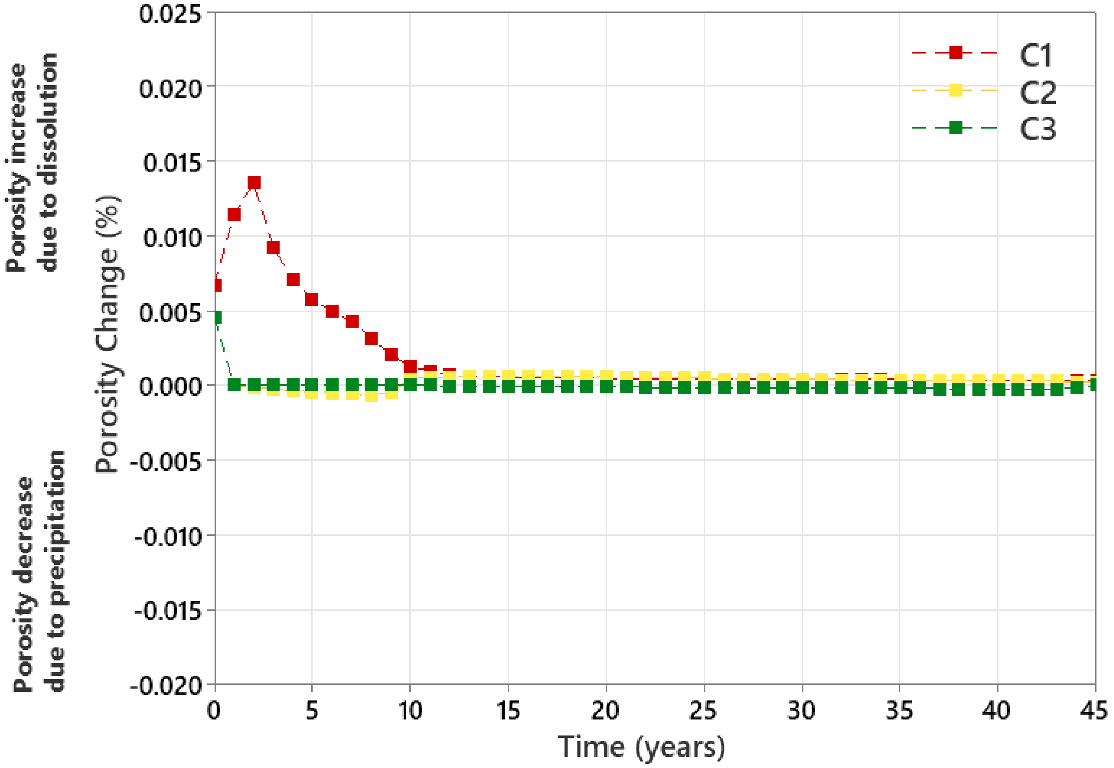


Figure C-16. Modeled change in percent porosity of the Opeche/Spearfish Formation cap rock. Red line shows porosity change calculated for C1, 0.5 meters above the cap rock base. Yellow line shows C2, 1.5 meters above the cap rock base. Green line shows C3, 2.5 meters above the cap rock base. Long-term 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.

C1.3 Geochemical Interaction of the Lower Confining Zone (Amsden Formation)

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 seven cells, each cell 1 meter in thickness. The formation was exposed to CO_2 stream components at the top boundary of the simulation, and CO_2 was allowed to enter the system by advection and dispersion processes. Direct fluid flow into the Amsden 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 center of each cell below the confining layer–CO_2 exposure boundary. The average mineralogical composition calculated from the results of two samples from the Amsden Formation was honored (Table C-6). The formation brine composition was assumed to be the same as the known composition from the overlying Broom Creek Formation injection zone (Table C-5). A CO_2 stream containing ~95% CO_2 and 2% O_2, described in Table C-1, was used in the geochemical modeling to represent a conservative scenario, where higher oxygen concentration may trigger more geochemical reactions in the formation. The maximum formation temperature and pressure, projected from CMG simulation results, described in Section 3.0, were used to represent the potential maximum pore pressure and temperature level.

Table C-6. Averaged Mineral Composition of the Amsden Formation Derived from XRD Analysis of Milton Flemmer 1 Core Samples at Depths* of 6169 and 6177 ft MD

Minerals, wt%	
Illite	10.0
K-Feldspar	9.05
Albite	5.03
Quartz	24.2
Dolomite	50.9
Others	0.82

*Core Depths. Please reference Table 2-2a for the core to log depth shifts in the Milton Flemmer 1.

The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change. This simulation was run for 45 years to represent 20 years of injection plus 25 years postinjection.

Modeling results show geochemical processes at work. Figures C-17 through C-22 show results from the geochemical modeling. Figure C-17 shows change in fluid pH over 45 years (representing 20 years of injection and 25 years postinjection) as CO_2 enters the system. Initial change in pH in all of the cells, for C1 to C7, is related to initial equilibration of the model. For the cell at the CO_2 interface, C1, the pH declines to a level of 5.7 after 7 years of injection, further declining to 4.8 by the end of the modeled injection period, and hits 4.5 by the end of simulation period. Progressively lower or slower pH changes occur for each cell that is more distant from the CO_2 interface. The pH for C7 did not decline over the 45 years of simulation time. Figure C-18 shows that CO_2 does not penetrate more than 6 meters (represented by C7) over the 20 years of injection and 25 years postinjection.

Figure C-19 shows the modeled changes in mineral dissolution and precipitation in grams per cubic meter over 45 years of simulation time. For C1, albite and K-feldspar start to dissolve from the beginning of the simulation period while quartz and illite start to precipitate. Anhydrite and hematite, the secondary minerals, precipitate in minor amounts. C2 shows the same trends, but the process begins approximately 6 years after Cell C1.

Figure C-20 represents the initial fractions of potentially reactive minerals in the Amsden Formation based on the XRD data in Table C-6. The expected dissolution of the minerals in weight percentage is also shown for C1 and C2 of the model. In C1 and C2, albite and K-feldspar are the primary minerals that dissolve, and their initial fractions have almost completely dissolved. No dissolution is observed for illite and quartz. The minerals that experience dissolution in the model are almost completely replaced by the precipitation of other minerals.

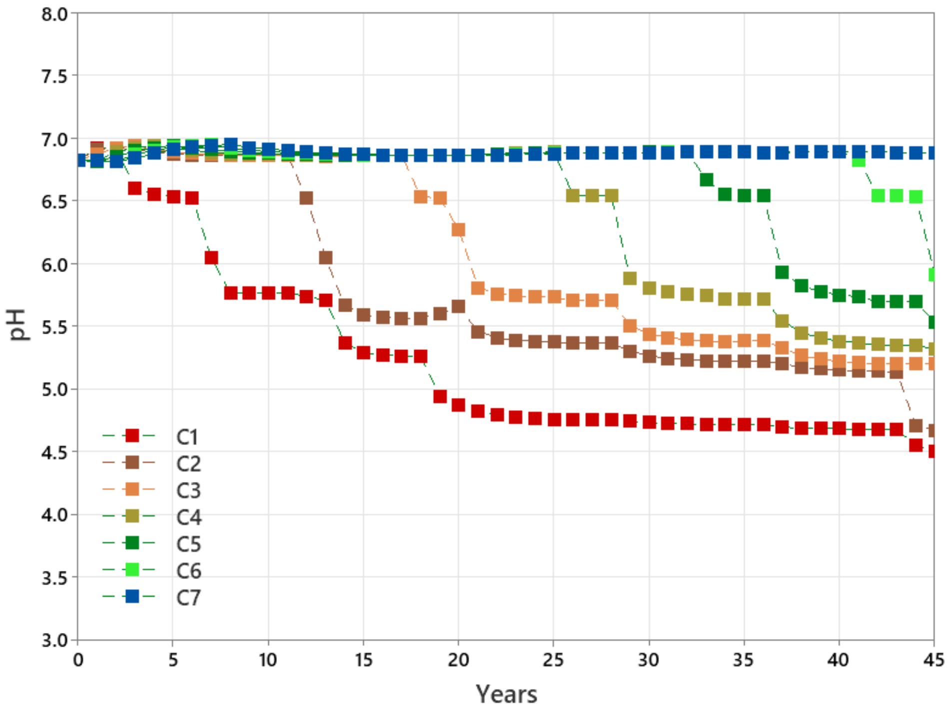


Figure C-17. Modeled change in fluid pH for C1–C7 in the Amsden Formation underlying confining layer.

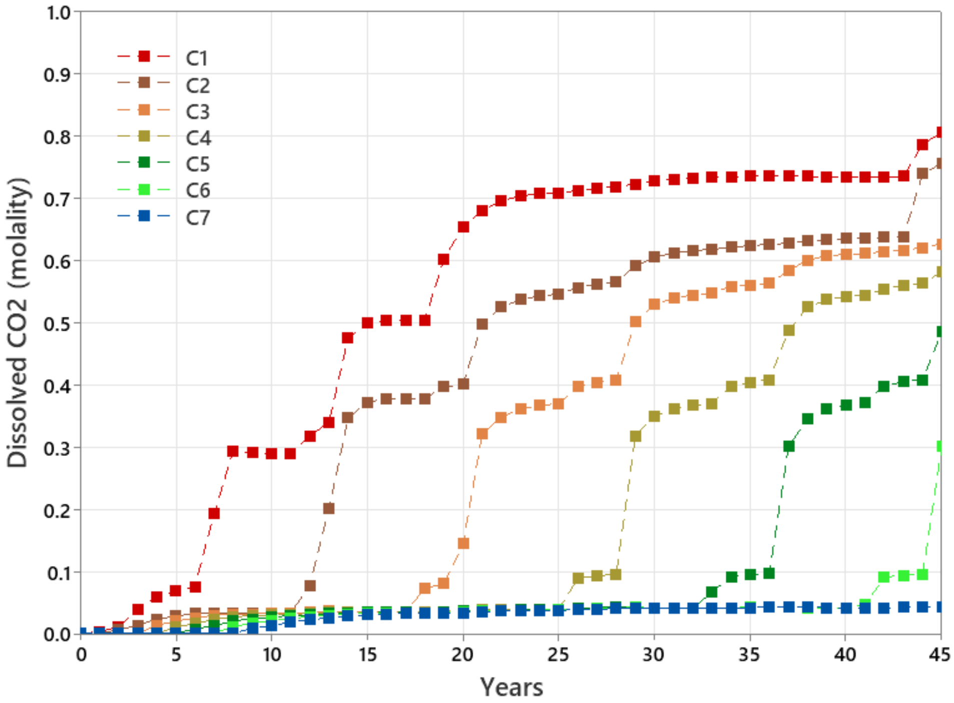


Figure C-18. Modeled CO_2 concentration (molality) for C1–C7 in the Amsden Formation underlying confining layer.

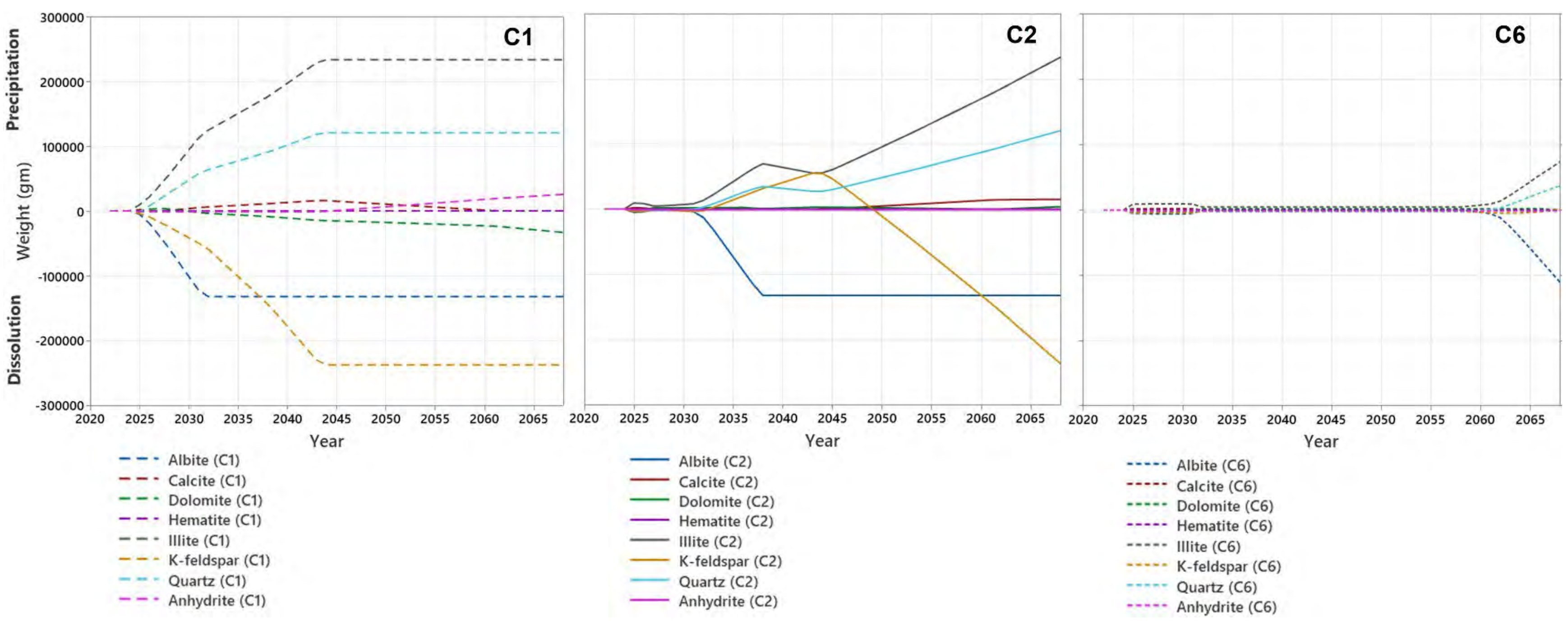


Figure C-19. Modeled dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for C1, 0 to 1 meter below the Amsden Formation top. Solid lines show results for C2, 1 to 2 meters below the Amsden Formation top. Dotted lines show results for C6, 5 to 6 meters below the Amsden Formation top. C6 shows minimal dissolution and precipitation at the end of 25 years postinjection because of the smaller amount of CO_2 penetration in C6 by the end of 45 years of simulation.

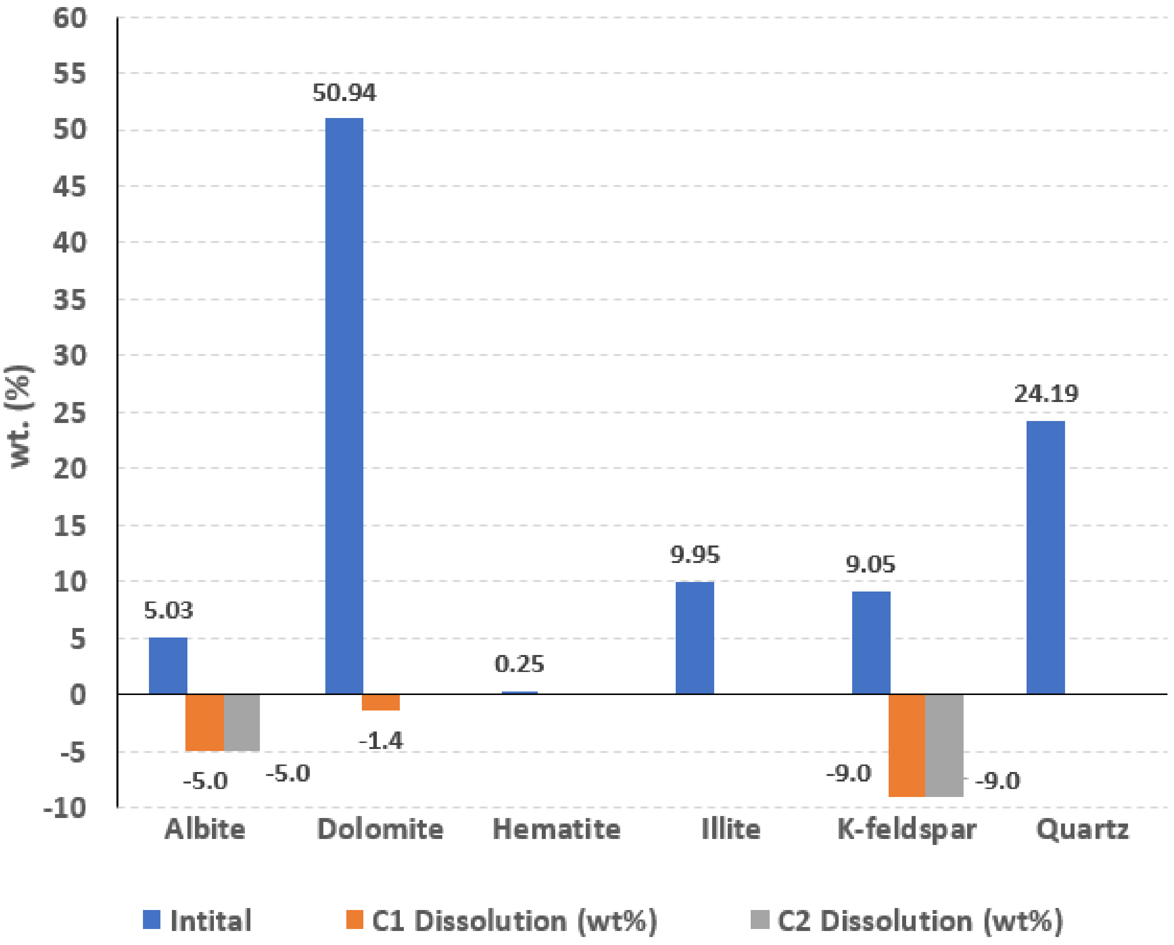


Figure C-20. Weight percentage (wt%) of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in C1 (orange) and C2 (gray) after 20 years of injection plus 25 years postinjection. Negative values represent total wt% associated with dissolution.

Figure C-21 represents this replacement, with the minerals expected to be precipitated in weight percentage (wt%) shown for C1 and C2 of the model. In C1 and C2, illite and quartz are the key primary minerals expected to be precipitated. Anhydrite and hematite precipitate as secondary minerals in C1 and calcite in C2.

The modeled change in porosity (% units) of the Amsden Formation underlying confining layer is displayed in Figure C-22 for C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 2% change during the life of the simulation. C1 shows an initial porosity increase, but this change is temporary, and the cell returns to its near-initial porosity after Year 18. For C2 and C3, a cyclic pattern of porosity increase and subsequent decrease with low amplitude is observed. No significant porosity changes were observed in C2–C3 after 20 years of modeled injection. Cells C4–C7 showed similar results, with porosity change being less than 0.1% at each time step (not shown in Figure C-22).

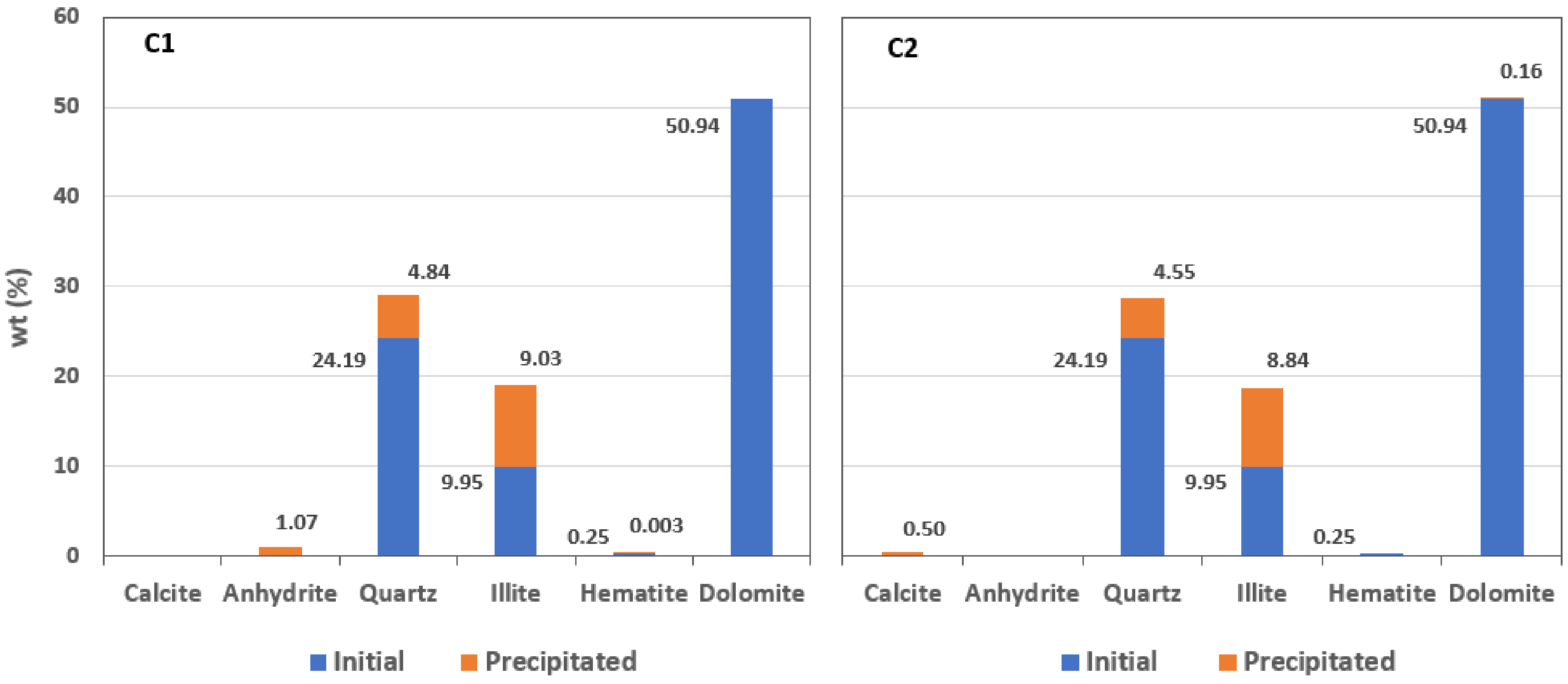


Figure C-21. Weight percentage (wt%) of initial (blue) and precipitated (orange) minerals of the Amsden Formation in C1 and C2, normalized based on total solids (initial – dissolution + precipitation) present in C1 and C2 after 20 years of injection and 25 years postinjection. Very little hematite and anhydrite precipitation is observed in C1. Hematite precipitation in C2 is too small to be seen in the figure.

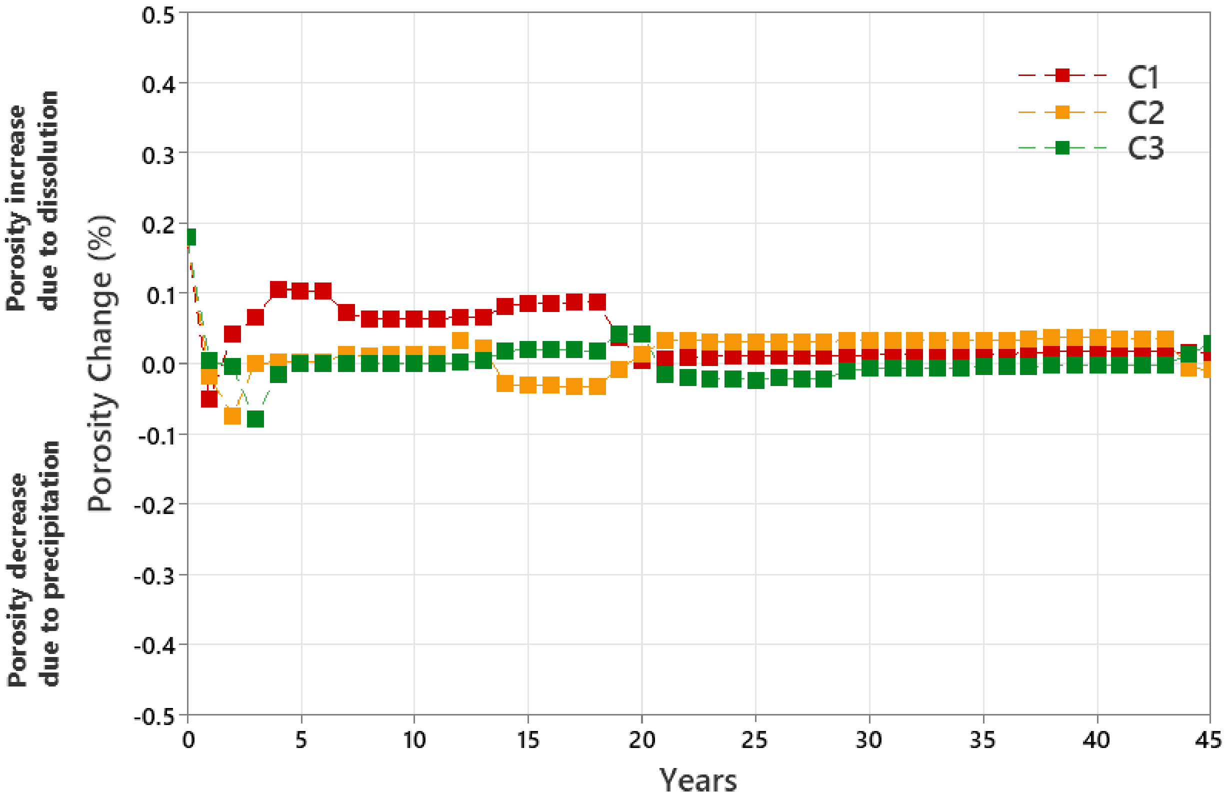


Figure C-22. Modeled change in percent porosity in the Amsden Formation underlying confining layer. Red line shows porosity change for C1, 0 to 1 meter below the Amsden Formation top. Orange line shows C2, 1 to 2 meters below the Amsden Formation top. Green line shows C3, 2 to 3 meters below the Amsden Formation 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.

C.1.4 REFERENCES

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.

APPENDIX D

MONITORING EQUIPMENT SPECIFICATION INFORMATION

Attachment D-1 – Gas Chromatograph Specification Sheet

Envent
Knowledge by **Analysis**

Envent Model 132S

Process Gas Chromatograph

The Model 132S Process Gas Chromatograph (GC) is a simple approach to energy measurement, created and designed for many different applications. Envent provides a Process Gas Chromatograph platform that is efficiently manufactured to ensure industry leading delivery, while providing a GC that allows for ease of serviceability.

Features

- High performance GC columns packed in our Envent GC Lab
- Reduced carrier usage due to efficient column design
- Environmental chamber tested prior to shipment

Field-Serviceability

- Easy access Electronics Enclosure with single board technology
- Easy access GC Detector/Column Oven for easy GC valve diaphragm replacement and column change
- Typical downtime for diaphragm and column change: approx. 30 minutes
- No modules to maintain or un-planned downtime due to non-serviceability and high cost of competitor's module technology
- Returns ownership to the measurement technician rather than the GC manufacturer

Natural Gas Applications

- Energy Measurement
- Pipeline Monitoring
- Custody Transfer
- Biogas/Landfill
- Power Generation
- Turbine Control

Gas Processing Applications

- Cryogenic gas plant
- NGL/LPG (methanol ethanol)
- LNG
- Fractionation/ Hydrocarbon Purity
- Gas Sweetening
- Methanol in NGL
- Methanol in Natural Gas

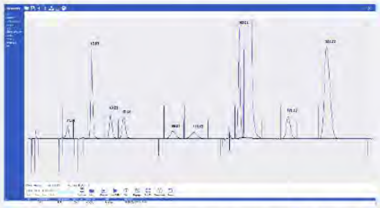
Electronics

- Non-incendive electronic circuit design approved for Class I Division 2 electrical areas
- Eliminates the need for explosion proof enclosures or purge-air
- Includes all CPU, Memory, and I/O functions on a single board that operates together with the Envent Gas Chromatograph software
- Low-cost, simplified electronic troubleshooting approach

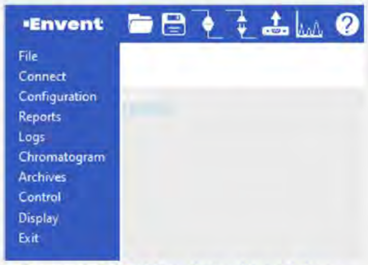
Software

- Archived custody stream chromatogram/chart storage
- Auto-storage of most recent calibration chromatogram/chart
- 18 months of archived analysis reports
- 6 months of archived calibration reports

132S Process Configuration



Envent **G**as **C**hromatograph **S**oftware (GCS)



Envent GCS User Interface Menu

www.enventengineering.com

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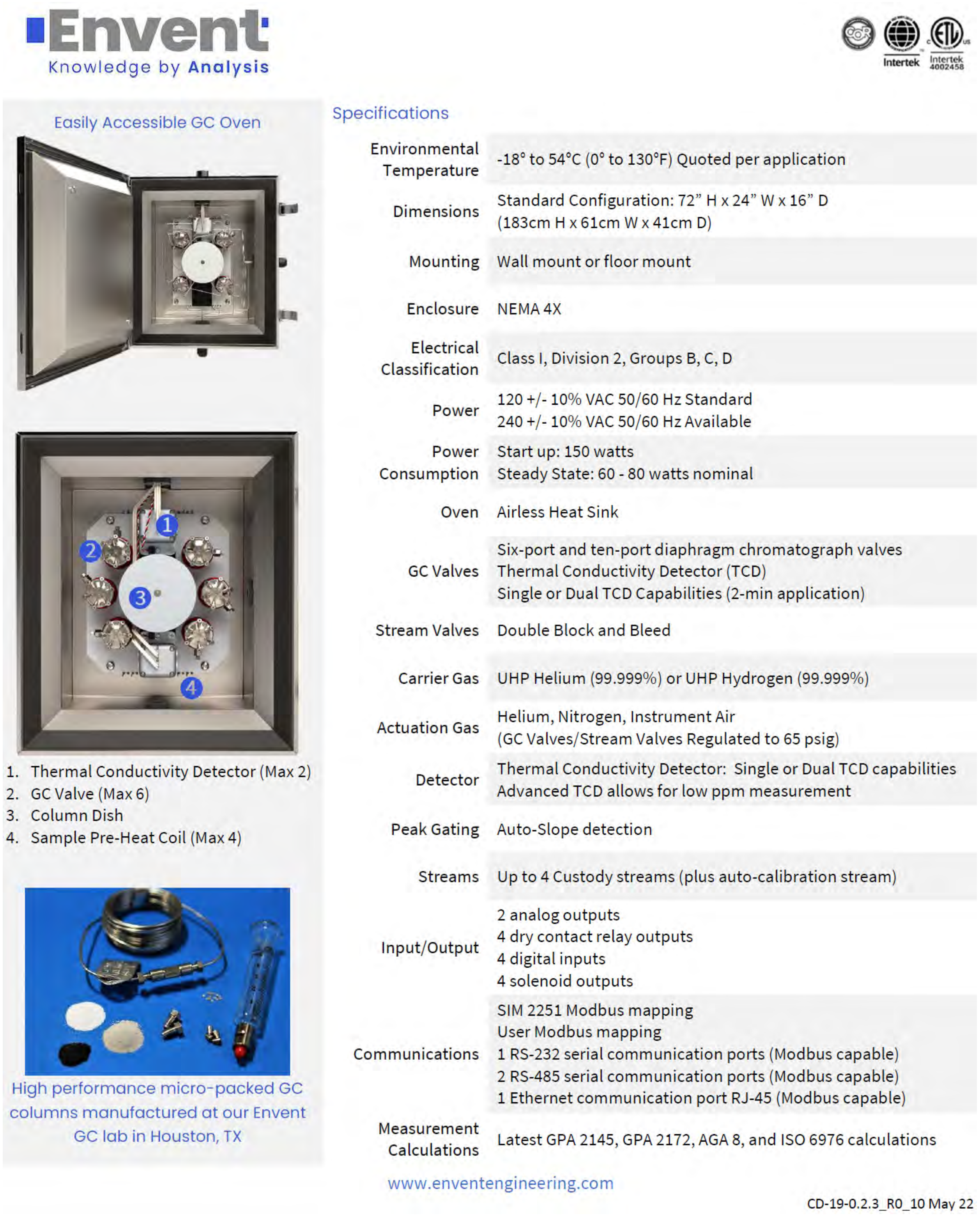
Attachment D-1 – Gas Chromatograph Specification Sheet (continued)



Envent
Knowledge by **Analysis**

Intertek
Intertek 4002458

Easily Accessible GC Oven

1. Thermal Conductivity Detector (Max 2)
2. GC Valve (Max 6)
3. Column Dish
4. Sample Pre-Heat Coil (Max 4)

High performance micro-packed GC columns manufactured at our Envent GC lab in Houston, TX

Specifications

Environmental Temperature	-18° to 54°C (0° to 130°F) Quoted per application
Dimensions	Standard Configuration: 72” H x 24” W x 16” D (183cm H x 61cm W x 41cm D)
Mounting	Wall mount or floor mount
Enclosure	NEMA 4X
Electrical Classification	Class I, Division 2, Groups B, C, D
Power	120 +/- 10% VAC 50/60 Hz Standard 240 +/- 10% VAC 50/60 Hz Available
Power Consumption	Start up: 150 watts Steady State: 60 - 80 watts nominal
Oven	Airless Heat Sink
GC Valves	Six-port and ten-port diaphragm chromatograph valves Thermal Conductivity Detector (TCD) Single or Dual TCD Capabilities (2-min application)
Stream Valves	Double Block and Bleed
Carrier Gas	UHP Helium (99.999%) or UHP Hydrogen (99.999%)
Actuation Gas	Helium, Nitrogen, Instrument Air (GC Valves/Stream Valves Regulated to 65 psig)
Detector	Thermal Conductivity Detector: Single or Dual TCD capabilities Advanced TCD allows for low ppm measurement
Peak Gating	Auto-Slope detection
Streams	Up to 4 Custody streams (plus auto-calibration stream)
Input/Output	2 analog outputs 4 dry contact relay outputs 4 digital inputs 4 solenoid outputs
Communications	SIM 2251 Modbus mapping User Modbus mapping 1 RS-232 serial communication ports (Modbus capable) 2 RS-485 serial communication ports (Modbus capable) 1 Ethernet communication port RJ-45 (Modbus capable)
Measurement Calculations	Latest GPA 2145, GPA 2172, AGA 8, and ISO 6976 calculations

www.enventengineering.com

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Continued . . .

Attachment D-2 – Gas Detection Station Specification Sheet

ULTIMA® X5000 Gas Monitor

The future looks bright.

MSA The Safety Company

Simple retrofits have identical footprint and wiring to ULTIMA X Gas Monitor series.

Bluetooth® wireless technology allows mobile device to act as HMI screen and controller.

Intuitive display features new design equipped with organic LED (OLED) display, with full word text in 9 languages. Bright green, yellow, and red status LEDs for extreme visibility.

Industry-first, touch-button interface provides intuitive, tool-free user experience.

Instrument status indicators illuminate power, fault, and alarm conditions.

X/S Connect App

Reduce setup time by at least 50% with the X/S Connect App.

GET IT ON Google Play

Download on the App Store

Advanced Sensor Technology

POWERED BY XCell® SENSORS WITH TruCal® TECHNOLOGY

- Patented XCell H_2S and CO Sensors with TruCal technology extend calibration cycles for as long as 2 years, actively monitor sensor integrity, and compensate for environmental factors and electrochemical sensor drift.
  - **Diffusion Supervision** sends acoustic signal every 6 hours to check that sensor inlet isn't obstructed so gas can reach the sensor.
  - Worry-free operation—automatically self-checks four times per day.
- 3-year warranty and 5-year expected life for XCell Sensors.
- **Dual sensor capability** doubles sensing power with half the footprint of a single gas sensor transmitter.
- **SafeSwap** enables safe and quick XCell Sensor replacement without powering off gas detector.

SafeSwap®

Applications

- Chemical
- Oil and gas
- Petrochemical
- Utilities
- Wastewater
- General industry

Continued…

Attachment D-2 – Gas Detection Station Specification Sheet (continued)

ULTIMA X5000 Gas Monitor: Sensor Specifications

MSA
The Safety Company

Electrochemical Sensors													
Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	*T90*			*Min.*	*Max.*				
Ammonia - 100	0 - 100 ppm	25 - 100 ppm	0.1 ppm	< 20 Sec	< 60 Sec	< ±1%	< 1% FS / Month	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 2
Ammonia - 1000	0 - 1000 ppm	190 - 1000 ppm	10 ppm	< 20 Sec	< 300 Sec	< ±15%	< 1% FS / Month	-30°C (-22°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 2
Carbon Monoxide - 100	0 - 100 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide - 1000	0 - 1000 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide - 500	0 - 500 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide H_2 Resistant	0 - 100 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Chlorine - 5	0 - 5 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< ±1%	< 1% FS / Month	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 2
Chlorine - 10	0 - 10 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< ±1%	< 1% FS / Month	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 2
Chlorine - 20	0 - 20 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< ±1%	< 1% FS / Month	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 2
Chlorine Dioxide	0 - 3 ppm	0.5-3.0 ppm	0.01 ppm	< 12 Sec	< 30 Sec	< +15%	< 1% FS / Month	-40°C (-40°F)	50°C (122°F)	XCell	5 Years	3 Years	Div/Zone 2
Ethylene Oxide	0 - 10 ppm	1 - 10 ppm	0.1 ppm	< 50 Sec	< 140 Sec	< ±15%	< 2% FS/Month	-20°C (-4°F)	40°C (104°F)	Echem	2 Years	1 Year	Div/Zone 2
Hydrogen	0 - 1000 ppm	250 - 1000 ppm	10 ppm	< 40 Sec	< 185 Sec	< ±10%	< 1% FS / Month	-30°C (-22°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 1
Hydrogen Chloride	0 - 50 ppm	25 - 50 ppm	1 ppm	< 30 Sec	< 120 Sec	< ±35%	< 1% FS / Month	-30°C (-22°F)	40°C (104°F)	Echem	2 Years	1 Year	Div/Zone 2
Hydrogen Cyanide	0 - 50 ppm	25 - 50 ppm	1 ppm	< 8 Sec	< 30 Sec	< ±15%	< 1% FS / Month	-20°C (-4°F)	40°C (104°F)	Echem	2 Years	1 Year	Div/Zone 1
Hydrogen Fluoride	0 - 10 ppm	5 - 10 ppm	0.1 ppm	< 60 Sec	< 90 Sec	< ±15%	< 2% FS / Month	0°C (32°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 2
Hydrogen Sulfide - 10	0 - 10 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	< 23 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 50	0 - 50 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	< 23 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 100	0 - 100 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	< 23 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 500	0 - 500 ppm	20 - 500 ppm	1 ppm	< 20 Sec	< 60 Sec	< ±10%	< 1% FS / Month	-40°C (-40°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 1
Nitrogen Dioxide	0 - 10 ppm	1.5 - 10 ppm	0.1 ppm	< 30 Sec	< 60 Sec	< ±10%	< 1% FS / Month	-40°C (-40°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 2
Nitrogen Oxide	0 - 100 ppm	2.5 - 100 ppm	0.5 ppm	< 5 Sec	< 20 Sec	< ±15%	< 1% FS / Month	-30°C (-22°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 1
Oxygen	0 - 25%	5 - 25%	0.10%	< 6 Sec	< 11 Sec	< ±1% Vol	< 0.2 % Vol / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Oxygen (FM)	0 - 25%	5 - 25%	0.10%	< 6 Sec	< 11 Sec	< ±1% Vol	< 0.2 % Vol / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Oxygen, Low	0 - 25%	2 - 25%	0.10%	< 10 Sec	< 30 Sec	< ±10%	< 1% FS / Month	-30°C (-22°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 1
Sulfur Dioxide - 100	0 - 100 ppm	25 - 100 ppm	1 ppm	< 10 Sec	< 30 Sec	< ±15%	< 1% FS / Month	-30°C (-22°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 2
Sulfur Dioxide - 25	0 - 25 ppm	5 - 25 ppm	0.1 ppm	< 3 Sec	< 6 Sec	< ±1%	< 1% FS / Month	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 2

**Typical response at standard temperature and pressure test conditions*

Continued…

Attachment D-2 – Gas Detection Station Specification Sheet (continued)

ULTIMA X5000 Gas Monitor: Sensor Specifications

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XCell Catalytic Bead Sensors

Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	T90			Min.	Max.				
Methane (5.0%)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Propane (2.1%)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Heptane (1.05%)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Nonane (0.8%)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen (4.0%)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Methane (4.4% EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Propane (1.7% EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Heptane (0.85% EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Nonane (0.7% EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1

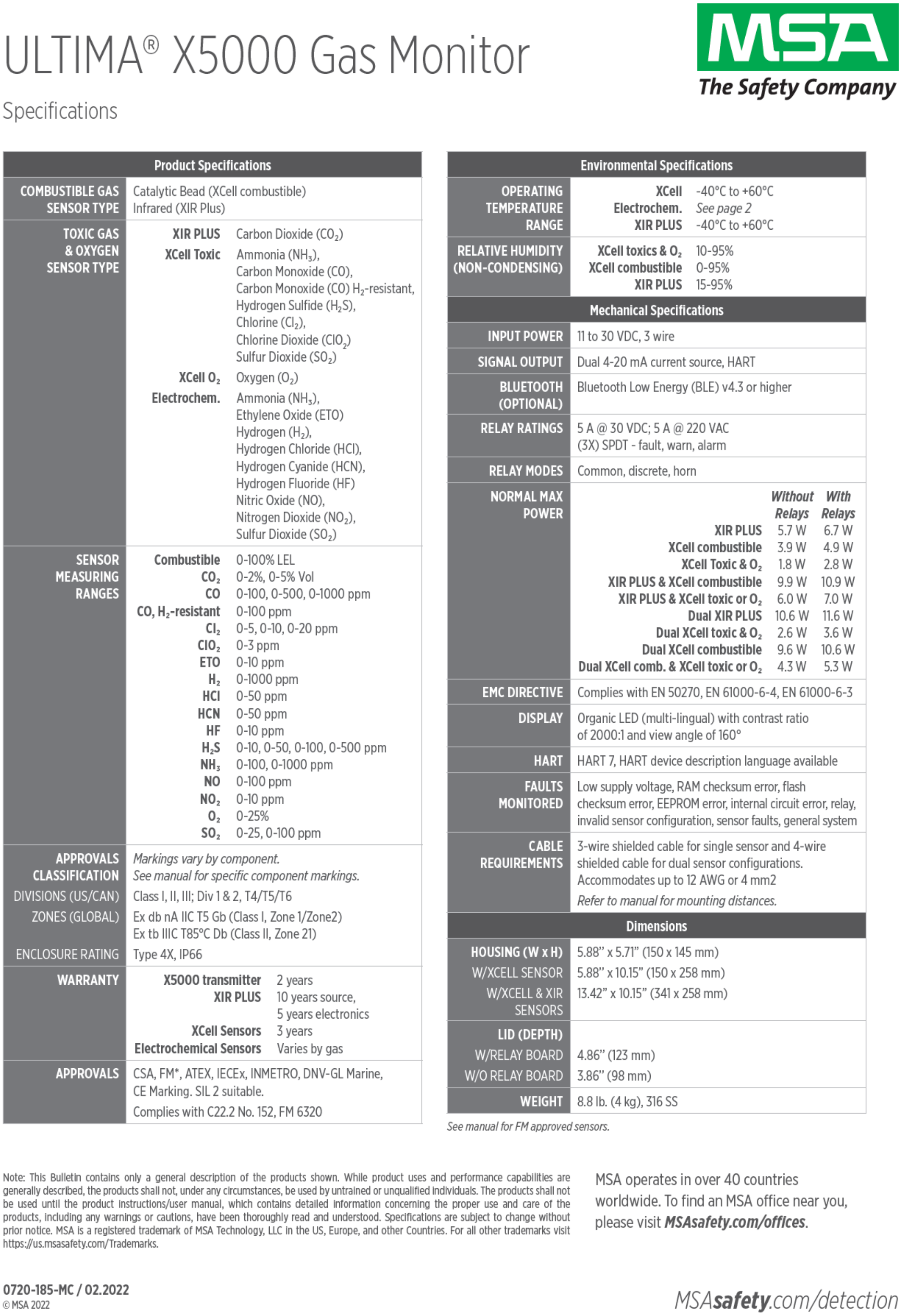
ULTIMA XIR Plus Infrared Sensors

Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Life	Warranty	Classification
				T50	T90			Min.	Max.			
XIR+ 0-100% LEL Ethanol	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Ethylene Oxide	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Gasoline Hexane	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Hexane	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Isopropanol	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Methane (5%)	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Methyl Methacrylate	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Propane (2.1%)	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Ethanol EN	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Ethylene Oxide EN	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Gasoline Hexane EN	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Methane (4.4%) EN	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Propane (1.7%) EN	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ Carbon Dioxide (2%)	0 - 2% Vol	0.4 - 2%	0.05%	< 3 Sec	< 6 Sec	< ±1%	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ Carbon Dioxide (5%)	0 - 5% Vol	1 - 5%	0.05%	< 3 Sec	< 6 Sec	< ±1%	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1

**Typical response at standard temperature and pressure test conditions*

Continued…

Attachment D-2 – Gas Detection Station Specification Sheet (continued)



ULTIMA® X5000 Gas Monitor

MSA
The Safety Company

Specifications

Product Specifications		
COMBUSTIBLE GAS SENSOR TYPE		Catalytic Bead (XCell combustible) Infrared (XIR Plus)
TOXIC GAS & OXYGEN SENSOR TYPE	**XIR PLUS**	Carbon Dioxide (CO_2)
	XCell Toxic	Ammonia (NH_3), Carbon Monoxide (CO), Carbon Monoxide (CO) H_2-resistant, Hydrogen Sulfide (H_2S), Chlorine (Cl_2), Chlorine Dioxide (ClO_2) Sulfur Dioxide (SO_2)
	XCell O_2	Oxygen (O_2)
	Electrochem.	Ammonia (NH_3), Ethylene Oxide (ETO) Hydrogen (H_2), Hydrogen Chloride (HCl), Hydrogen Cyanide (HCN), Hydrogen Fluoride (HF) Nitric Oxide (NO), Nitrogen Dioxide (NO_2), Sulfur Dioxide (SO_2)
SENSOR MEASURING RANGES	**Combustible**	0-100% LEL
	CO_2	0-2%, 0-5% Vol
	CO	0-100, 0-500, 0-1000 ppm
	CO, H_2-resistant	0-100 ppm
	Cl_2	0-5, 0-10, 0-20 ppm
	ClO_2	0-3 ppm
	ETO	0-10 ppm
	H_2	0-1000 ppm
	HCl	0-50 ppm
	HCN	0-50 ppm
	HF	0-10 ppm
	H_2S	0-10, 0-50, 0-100, 0-500 ppm
	NH_3	0-100, 0-1000 ppm
	NO	0-100 ppm
	NO_2	0-10 ppm
	O_2	0-25%
	SO_2	0-25, 0-100 ppm
APPROVALS CLASSIFICATION		*Markings vary by component.* *See manual for specific component markings.*
DIVISIONS (US/CAN)		Class I, II, III; Div 1 & 2, T4/T5/T6
ZONES (GLOBAL)		Ex db nA IIC T5 Gb (Class I, Zone 1/Zone2) Ex tb IIIC T85°C Db (Class II, Zone 21)
ENCLOSURE RATING		Type 4X, IP66
WARRANTY	**X5000 transmitter**	2 years
	XIR PLUS	10 years source, 5 years electronics
	XCell Sensors	3 years
	Electrochemical Sensors	Varies by gas
APPROVALS		CSA, FM*, ATEX, IECEx, INMETRO, DNV-GL Marine, CE Marking. SIL 2 suitable. Complies with C22.2 No. 152, FM 6320

Environmental Specifications			
OPERATING TEMPERATURE RANGE	**XCell**	-40°C to +60°C	
	Electrochem.	*See page 2*	
	XIR PLUS	-40°C to +60°C	
RELATIVE HUMIDITY (NON-CONDENSING)	**XCell toxics & O_2**	10-95%	
	XCell combustible	0-95%	
	XIR PLUS	15-95%	
Mechanical Specifications			
INPUT POWER		11 to 30 VDC, 3 wire	
SIGNAL OUTPUT		Dual 4-20 mA current source, HART	
BLUETOOTH (OPTIONAL)		Bluetooth Low Energy (BLE) v4.3 or higher	
RELAY RATINGS		5 A @ 30 VDC; 5 A @ 220 VAC (3X) SPDT - fault, warn, alarm	
RELAY MODES		Common, discrete, horn	
NORMAL MAX POWER		***Without Relays***	***With Relays***
	XIR PLUS	5.7 W	6.7 W
	XCell combustible	3.9 W	4.9 W
	XCell Toxic & O_2	1.8 W	2.8 W
	XIR PLUS & XCell combustible	9.9 W	10.9 W
	XIR PLUS & XCell toxic or O_2	6.0 W	7.0 W
	Dual XIR PLUS	10.6 W	11.6 W
	Dual XCell toxic & O_2	2.6 W	3.6 W
	Dual XCell combustible	9.6 W	10.6 W
	Dual XCell comb. & XCell toxic or O_2	4.3 W	5.3 W
EMC DIRECTIVE		Complies with EN 50270, EN 61000-6-4, EN 61000-6-3	
DISPLAY		Organic LED (multi-lingual) with contrast ratio of 2000:1 and view angle of 160°	
HART		HART 7, HART device description language available	
FAULTS MONITORED		Low supply voltage, RAM checksum error, flash checksum error, EEPROM error, internal circuit error, relay, invalid sensor configuration, sensor faults, general system	
CABLE REQUIREMENTS		3-wire shielded cable for single sensor and 4-wire shielded cable for dual sensor configurations. Accommodates up to 12 AWG or 4 mm2 *Refer to manual for mounting distances.*	
Dimensions			
HOUSING (W x H)		5.88” x 5.71” (150 x 145 mm)	
W/XCELL SENSOR		5.88” x 10.15” (150 x 258 mm)	
W/XCELL & XIR SENSORS		13.42” x 10.15” (341 x 258 mm)	
LID (DEPTH)			
W/RELAY BOARD		4.86” (123 mm)	
W/O RELAY BOARD		3.86” (98 mm)	
WEIGHT		8.8 lb. (4 kg), 316 SS	

See manual for FM approved sensors.

MSA operates in over 40 countries worldwide. To find an MSA office near you, please visit ***MSAsafety.com/offices***.

0720-185-MC / 02.2022

*MSA**safety**.com/detection*

Attachment D-3 – SCADA System and Leak Detection Software

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 CO_2 geologic storage project injection operations in real time. This supervisory system collects data at an assigned time interval and stores the data in the historian server. Using Summit Carbon Storage #1, LLC (SCS1) process control selections, the SCADA system 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 SCS1 control room, which is staffed 24/7, of near or excessive violations of set parameters within the system.

Leak Detection Software

The leak detection system (LDS) will monitor the CO_2 flowline from the point of transfer to each of the injection wellheads. Instrumentation at both ends of the CO_2 flowline and each injection well collects pressure, temperature, and flow data. The LDS software uses the pressure readings and flow rates in and out of the line to produce a real-time model and predictive model. By monitoring deviations between the real-time model and the predictive model, the software is able to detect leaks along the CO_2 flowline.

Attachment D-4 – Personnel Multigas Detector Specifications

IBRID MX6

An easy and flexible way to do gas detection

Get ready to see hazardous levels of oxygen, toxic and combustible gas, and volatile organic compounds (VOCs) like never before.

The MX6 iBrid™ is more than an intelligent hybrid of Industrial Scientific's best monitoring technologies. It's the first gas monitor to feature a full-color LCD display screen.

The display improves safety with clear readings in low-light, bright-light or anywhere in between. Whether the work is outside, inside or underground, it's easy to see what gas hazards lurk in the immediate work environment.

And a color display is more than eye-catching. It allows the user to step through instrument settings and functions with an intuitive menu and the instrument's five-way navigation button. It even supports the option of on-board graphing for easily interpreted direct readings and recorded data.

Plus, the MX6 iBrid is our most rugged instrument ever. It is compatible with our DSX™ Docking Station and iNet

MX6 IBRID COLOUR SCREEN

The MX6 clearly shows real-time readings in PPM or % by volume.

An intuitive menu provides easy access to features and setup.

Datalog trends and direct readings can be viewed graphically.

Calibration progress and results are shown for each sensor.

A "calibration due" warning appears for each relevant sensor.

Bright red numerals and a flashing backlight show alarm conditions.

Alarms shown with "Go/No Go" text and flashing backlight.

Color-coded text shows test or calibration results at a glance.

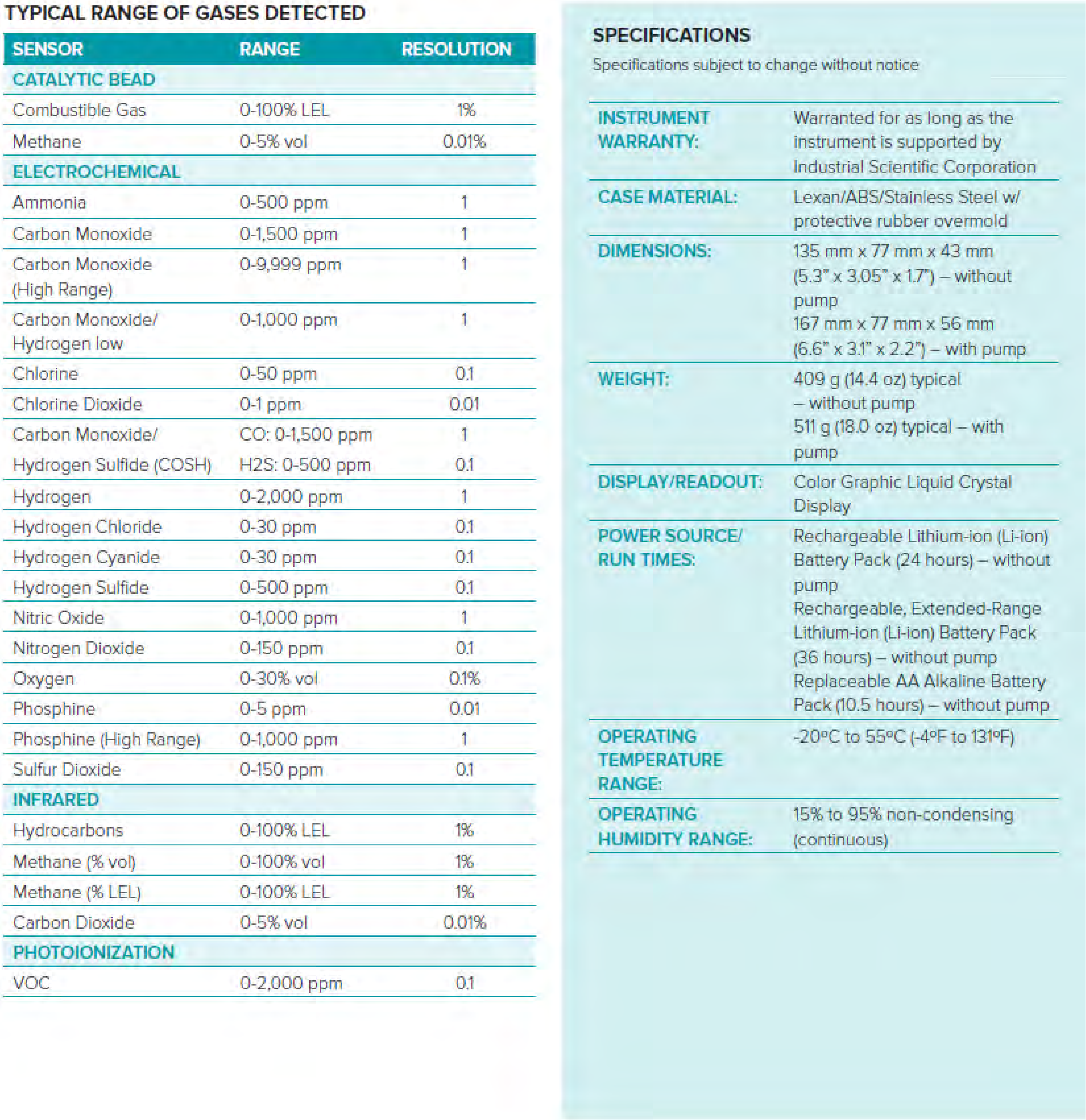
KEY FEATURES

- 24 "Plug-and-Play" fieldreplaceable sensors including PID and Infrared options
- Up to 6 gases monitored simultaneously
- Simple, user-friendly, customizable menudriven navigation
- Five-way navigation button
- Durable, concussionproof overmold
- Optional integral sampling pump with strong 30.5 meter (100 feet) sample draw
- Full-color graphic LCD is highly visible in a variety of lighting conditions
- Powerful, 95 dB audible alarm

iNet READY

Continued…

Attachment D-4 – Personnel Multigas Detector Specifications (continued)



TYPICAL RANGE OF GASES DETECTED

SENSOR	RANGE	RESOLUTION
CATALYTIC BEAD		
Combustible Gas	0-100% LEL	1%
Methane	0-5% vol	0.01%
ELECTROCHEMICAL		
Ammonia	0-500 ppm	1
Carbon Monoxide	0-1,500 ppm	1
Carbon Monoxide (High Range)	0-9,999 ppm	1
Carbon Monoxide/ Hydrogen low	0-1,000 ppm	1
Chlorine	0-50 ppm	0.1
Chlorine Dioxide	0-1 ppm	0.01
Carbon Monoxide/ Hydrogen Sulfide (COSH)	CO: 0-1,500 ppm H2S: 0-500 ppm	1 0.1
Hydrogen	0-2,000 ppm	1
Hydrogen Chloride	0-30 ppm	0.1
Hydrogen Cyanide	0-30 ppm	0.1
Hydrogen Sulfide	0-500 ppm	0.1
Nitric Oxide	0-1,000 ppm	1
Nitrogen Dioxide	0-150 ppm	0.1
Oxygen	0-30% vol	0.1%
Phosphine	0-5 ppm	0.01
Phosphine (High Range)	0-1,000 ppm	1
Sulfur Dioxide	0-150 ppm	0.1
INFRARED		
Hydrocarbons	0-100% LEL	1%
Methane (% vol)	0-100% vol	1%
Methane (% LEL)	0-100% LEL	1%
Carbon Dioxide	0-5% vol	0.01%
PHOTOIONIZATION		
VOC	0-2,000 ppm	0.1

SPECIFICATIONS

Specifications subject to change without notice

INSTRUMENT WARRANTY:	Warranted for as long as the instrument is supported by Industrial Scientific Corporation
CASE MATERIAL:	Lexan/ABS/Stainless Steel w/ protective rubber overmold
DIMENSIONS:	135 mm x 77 mm x 43 mm (5.3" x 3.05" x 1.7") – without pump 167 mm x 77 mm x 56 mm (6.6" x 3.1" x 2.2") – with pump
WEIGHT:	409 g (14.4 oz) typical – without pump 511 g (18.0 oz) typical – with pump
DISPLAY/READOUT:	Color Graphic Liquid Crystal Display
POWER SOURCE/ RUN TIMES:	Rechargeable Lithium-ion (Li-ion) Battery Pack (24 hours) – without pump Rechargeable, Extended-Range Lithium-ion (Li-ion) Battery Pack (36 hours) – without pump Replaceable AA Alkaline Battery Pack (10.5 hours) – without pump
OPERATING TEMPERATURE RANGE:	-20ºC to 55ºC (-4ºF to 131ºF)
OPERATING HUMIDITY RANGE:	15% to 95% non-condensing (continuous)

Attachment D-5 – Electrical Resistance (ER) Probe Specification Sheet

Roxar Retrievable ER Probes
FA-T218-A

Product Data Sheet
06.07.2015

Roxar Electrical Resistance (ER) Probes

2” Retrievable System

High Accuracy ER Probes

Corrosion is a serious industrial problem, and corrosion control is important in order to avoid damage and loss of integrity in a plant or production site. Efficient corrosion mitigation requires fast and reliable tools for control and verification of protection programs, such as the use of corrosion inhibitors.

Electrical Resistance (ER) Probes are probably the most commonly used technology used for internal corrosion monitoring. ER Probes provide a high resolution and sensitivity compared to other technologies available, and changes in corrosion rates can be identified within hours or days [1].

ER Probes measure corrosion and corrosion rates as an increase in electrical resistance over time for a steel element in the probe face. The increase in electrical resistance is proportional to the accumulated corrosion of the probe element over the exposure period. Since resistance is also dependent on temperature, a reference element (not exposed to corrosion) is buried inside the probe body for temperature correction.

ER Probes can generally be used in most common environments, like oil, gas and water. The ER Probes described in this data sheet are of the 2” high pressure retrievable type, typically used in upstream, high pressure applications.

Quality of information and measurement accuracy depend on measurement frequency and instruments used. For best results, it is recommended that Roxar ER Probes are used with Roxar CorrLog or Roxar CorrLog Wireless high accuracy instruments, covering a wide range of configuration options.

Operating conditions vary from case to case, and it is important to choose the right probe for the specific application. For this reason, a range of ER Probes is available with flush or projecting design.

The useful life of an ER Probe is normally defined as half the measurement element thickness.

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[1] *Depending on probe type, measurement frequency and corrosion rates.*

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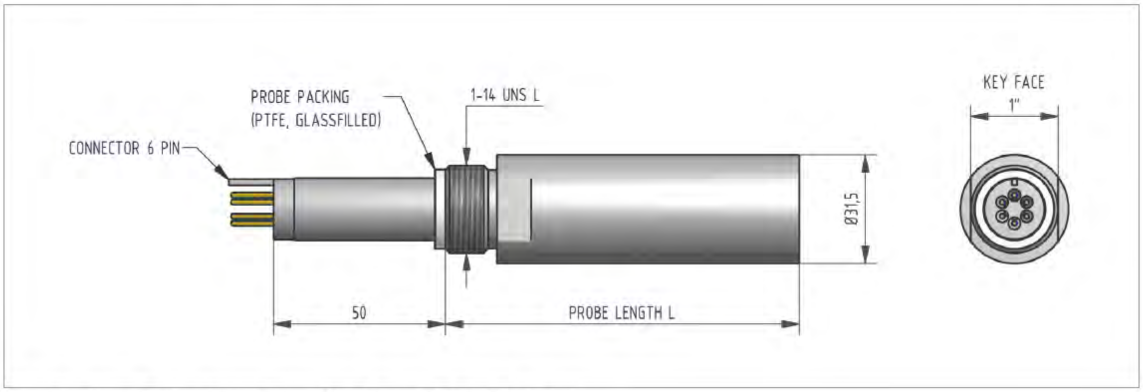
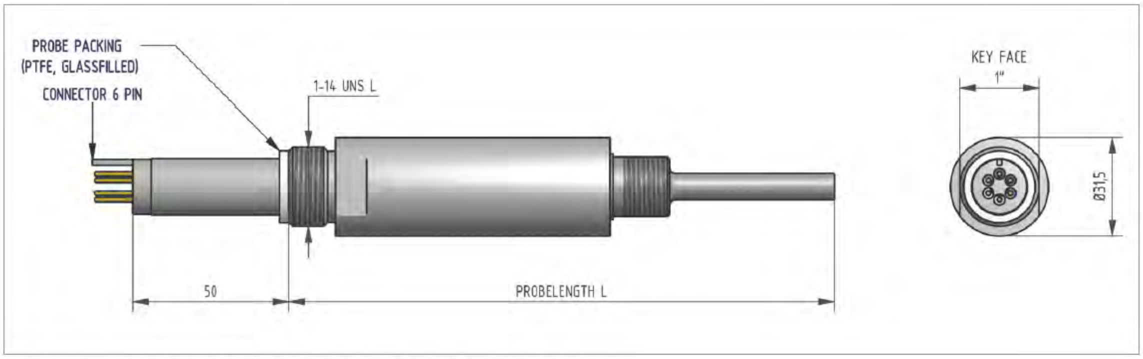
EMERSON.
Process Management

Continued…

Attachment D-5 – ER Probe Specification Sheet (continued)



Drawing shows flush probe outline and basis for probe length calculations.



Drawing shows tubular probe outline and basis for probe length calculations.

A special reinforced probe design is available for conditions where velocities are high, sometimes in combination with a need for long probes. Need for reinforced design probes is normally evaluated based on wake frequency calculations. Picture shows reinforced probe body with reinforced hollow plug.

Continued…

Attachment D-5 – ER Probe Specification Sheet (continued)

Repro D Probe

Repro D Probe front

The design of the Repro D Probe ensures a high resistance, and thus, highly accurate measurements, even if probe has a thick element. This design is therefore suitable for corrosion monitoring where corrosion rates are assumed to be from moderate to high, maintaining a high measurement resolution and accuracy. Repro D Probe is available with element thicknesses 1, 2 and 4 mm (40, 80 and 160 mil).

Repro E Probe

Repro E Probe front

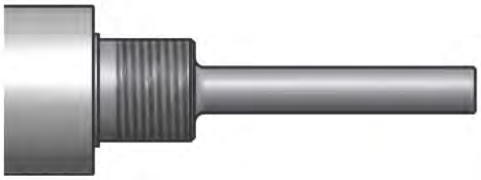
The simple design of the probe makes it suitable in conditions where conductive deposits could cause short circuits between sections of the probe element for more sophisticated probe element designs (e.g. in sour production environments).

Repro F Probe

Repro F Probe front

The Repro F Probe has an element with an optimized shape, and is available with a 0,1 mm (4 mil) measurement element. The design gives the probe a very high sensitivity, however, a limited life for many field applications. The probe is mostly recommended for conditions where corrosion is expected to be low, or for test/research applications where fast response is required.

Tubular T10 and T20 Probes



Roxar Tubular Probe front

Roxar tubular element probes are designed with a tubular shaped element protruding into the flow. The probes are available with 0.25 and 0.5 mm (10 and 20 mil) elements.

Protective shields for the tubular elements are available (T10 probe left, T20 probe right)

Continued…

Attachment D-5 – ER Probe Specification Sheet (continued)

Specifications - Roxar Retrievable ER Probes

Item	Description
Mounting:	2” high pressure access fitting (mechanical or hydraulic system)
Probe body material:	316 SS (other materials available upon request)
Pressure rating:	Standard: 6,000 psi (420 bar) Optional: 10,000 psi (690 bar)
Connector:	6 pin Amphenol male
Temperature rating:	Operating Temperature up to 145˚C (293˚F) (Welded element tubular probes are option at higher temperature rating, please ask Roxar for details).

Model Code Selector - Roxar Retrievable ER Probes

Model	Product Description		
THCMPR	Corrosion Monitoring Probe		
Code	**Measuring Method**		
1	Electrical Resistance		
Code	**Probe Body Type**		
01	Standard Design Fixed Length		
02	Reinforced Design Fixed Length for Access Fitting Flareweld		
03	Reinforced Design Fixed Length for Access Fitting MECH ≤300#, HYD ≤1500#		
04	Reinforced Design Fixed Length for Access Fitting MEC ≥4/600#, HYD 2500#		
99 [5]	Other Design		
Code	**Probe Body Material**		
2C6A	Stainless Steel A 479 Gr. 316L, bar	EN 10204 3.1 NACE MR0175	
2D6A	Duplex A 276 / A 479 UNS S31803, bar	EN 10204 3.1 NACE MR0175	
2C6C	Stainless Steel A 479 Gr. 316L, bar	EN 10204 3.1 NACE MR0175	NORSOK M630 MDS S01
2D6C	Duplex A 276 / A 479 UNS S31803, bar	EN 10204 3.1 NACE MR0175	NORSOK M630 MDS D47
9X9X [5]	Project Specific Material		
Code	**Element Type and Material**		
00S [1]	Flush	Repro D 1.0 mm	St 52-3N
01S [1]	Flush	Repro D 2.0 mm	St 52-3N
02S [1]	Flush	Repro D 4.0 mm	St 52-3N
03S [1]	Flush	Repro E 0.25 mm	St 52-3N
04S [1]	Flush	Repro E 0.50 mm	St 52-3N

Attachment D-6 – ER Probe Data Transmitter Specification Sheet

Rosemount™ 4390 Series of Corrosion and Erosion Wireless Transmitters

Maximize your process performance with continuous online corrosion and erosion monitoring

Rosemount 4390 Series of Corrosion and Erosion Wireless Transmitters provide continuous, accurate and highly sensitive real time corrosion and erosion monitoring data, enabling maximum performance through process optimization and eliminate the need of costly walk-downs. The transmitter delivers superior corrosion management data by using top of the range instruments thus providing improved data processing, flexible data management solutions and friendly user interface.

- Best-in-class inline corrosion and erosion data monitoring by providing continuous, accurate and highly sensitive monitoring data
- Increase safety at your plant by reducing exposure to personnel in hazardous areas and eliminating walk-downs to gather data
- *Wireless*HART® – seamless compatibility with existing Emerson™ devices
- Self-organizing, self-healing, adaptive mesh network – no wireless expertise is required
- Better cost control by enabling maximum performance through process optimization

Easy to Deploy and Easy to Maintain

Corrosion monitoring system

- The transmitter is compatible with Electrical Resistance Probes (ER probes), Linear Polarization Probes (LPR probes) and Multi Element Sand probes from Emerson and other major vendors
- Various data formats (calculated metal loss data, corrosion and erosion rates or probe raw data) can be selected from the HART® terminal, or from the Emerson Asset Management System (AMS)
- The corrosion wireless transmitter can be seamlessly integrated with Plantweb™ Insight Inline Corrosion Application and provides actionable data right to your desk
- High resolution (24 bit) ensuring reliable and fast corrosion and erosion monitoring
- Optimized power consumption up-to 4 times more compared to previous generation
- 15 times better sampling rate compared to previous generation
- Delivers high reliability in challenging radio environments using Direct Sequence Spread Spectrum (DSSS) technology

For more information, visit
Emerson.com/Corrosion-Erosion
or contact your local Emerson Sales Representative

EMERSON

Continued…

Attachment D-6 – ER Probe Data Transmitter Specification Sheet (continued)

Rosemount 4390 Series of Corrosion and Erosion Wireless Transmitters

Product Specifications	
General	For connection with intrusive corrosion and erosion probes
Connection	Connected to probe via a probe cable - maximum 65 feet (20 m)
Humidity Limits	5 - 95% relative humidity
Instrument Resolution	24 bit
Measurement Intervals	Multiple Element probes and Electrical Resistance (ER) probes can be measured as fast as 1-minute interval Linear Polarization Resistance (LPR) probes can be measured as fast as 4-minutes intervals
Communication	*Wireless*HART 2.4 GHz DSSS (Discrete Sequential Spread Spectrum)
ER Probe	Actual accuracy 10-100 ppm of probe element thickness, depending on probe type and environmental conditions
LPR Probe	Accuracy of 100ppm for the resistance measured on the LPR port
Sand Probe	Actual accuracy 10-100 ppm of probe element thickness, depending on probe type and environmental conditions
Operating Temperature	-40 to 158 °F (-40 to +70 °C)
Power Module	Black power module, type 701PBKKF. Replaceable, non-rechargeable. Intrinsically safe Lithium-Thionyl Chloride power module pack with PBT/PC enclosure. 7.2 V
Housing & Weight	Painted aluminum, IP 66, NEMA® 4x, 5kg
Hazardous Location Protection Type	Intrinsically Safe (Ex ia) device

*See product data sheet for full specifications.

RELATED PRODUCTS

Electrical Resistance Probes (ER)

Linear Polarization Probes (LPR)

Multi Element Sand Probes

Emerson Automation Solutions
North America
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☎ +1 952 949 7001
✉ RFQ.RMD-RCC@Emerson.com

00807-0200-4841 Rev AA

Consider It Solved.

Emerson Automation Solutions supports you with innovative technologies and expertise to address your toughest challenges.

For more information, visit Emerson.com/Corrosion-Erosion

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Attachment D-7 – Example Ultrasonic Tool Specification Sheet

Flexural wave imaging is used by Isolation Scanner service as a significant complement to pulse-echo acoustic impedance measurement. It relies on the pulsed excitation and propagation of a casing flexural mode, which leaks deep-penetrating acoustic bulk waves into the annulus. Attenuation of the first casing arrival, estimated at two receivers, is used to unambiguously determine the state of the material coupled to the casing as solid, liquid, or gas (SLG). Third-interface reflection echoes arising from the annulus/formation interface yield additional characterization of the cased hole environment:

- → acoustic velocity (*P* or *S*) of the annulus material
- → position of the casing within the borehole or a second casing string
- → geometrical shape of the wellbore.

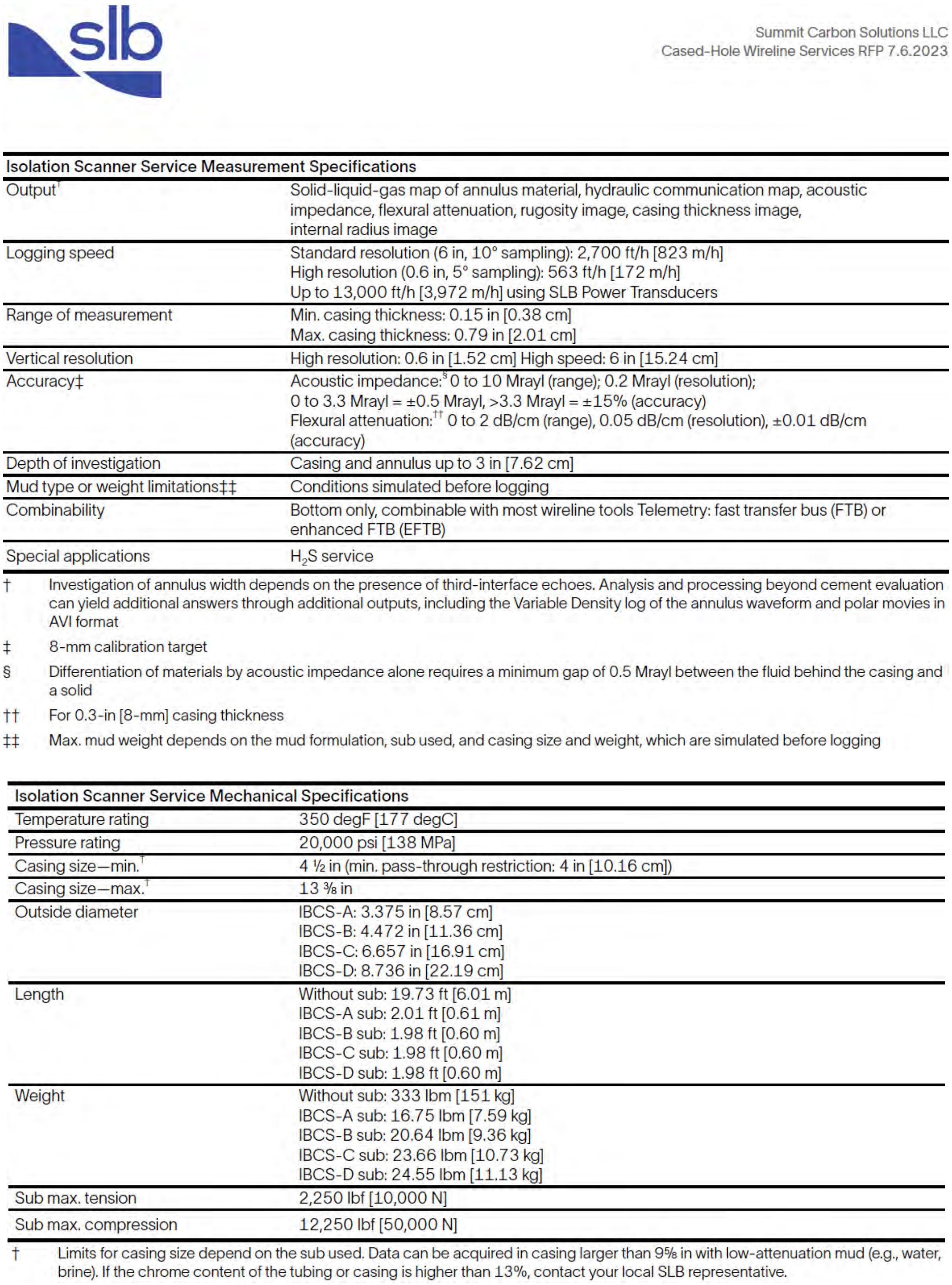
Vertical sampling is selectable to as low as 0.6 in [1.52 cm], and the azimuthal resolution has a maximum of 10°. Because acoustic impedance and flexural attenuation are independent measurements, their combined analysis provides borehole fluid properties, not requiring a separate fluid property measurement.

Applications

- → Differentiate high-performance lightweight cements (foam, LiteCRETE*, and Ultra LiteCRETE* systems) from liquids
- → Map annulus material as SLG
- → Confirm hydraulic isolation
- → Image channels and defects in annular isolating material
- → Visualize position of casing in the borehole
- → Image wellbore shape
- → Determine casing internal diameter and thickness
- → Determine depth for sidetracking and casing milling.

Continued…

Attachment D-7 – Example Ultrasonic Tool Specification Sheet (continued)



Summit Carbon Solutions LLC
Cased-Hole Wireline Services RFP 7.6.2023

Isolation Scanner Service Measurement Specifications	
Output[†]	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image
Logging speed	Standard resolution (6 in, 10° sampling): 2,700 ft/h [823 m/h] High resolution (0.6 in, 5° sampling): 563 ft/h [172 m/h] Up to 13,000 ft/h [3,972 m/h] using SLB Power Transducers
Range of measurement	Min. casing thickness: 0.15 in [0.38 cm] Max. casing thickness: 0.79 in [2.01 cm]
Vertical resolution	High resolution: 0.6 in [1.52 cm] High speed: 6 in [15.24 cm]
Accuracy‡	Acoustic impedance:[§] 0 to 10 Mrayl (range); 0.2 Mrayl (resolution); 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15% (accuracy) Flexural attenuation:[††] 0 to 2 dB/cm (range), 0.05 dB/cm (resolution), ±0.01 dB/cm (accuracy)
Depth of investigation	Casing and annulus up to 3 in [7.62 cm]
Mud type or weight limitations‡‡	Conditions simulated before logging
Combinability	Bottom only, combinable with most wireline tools Telemetry: fast transfer bus (FTB) or enhanced FTB (EFTB)
Special applications	H_2S service

† Investigation of annulus width depends on the presence of third-interface echoes. Analysis and processing beyond cement evaluation can yield additional answers through additional outputs, including the Variable Density log of the annulus waveform and polar movies in AVI format

‡ 8-mm calibration target

§ Differentiation of materials by acoustic impedance alone requires a minimum gap of 0.5 Mrayl between the fluid behind the casing and a solid

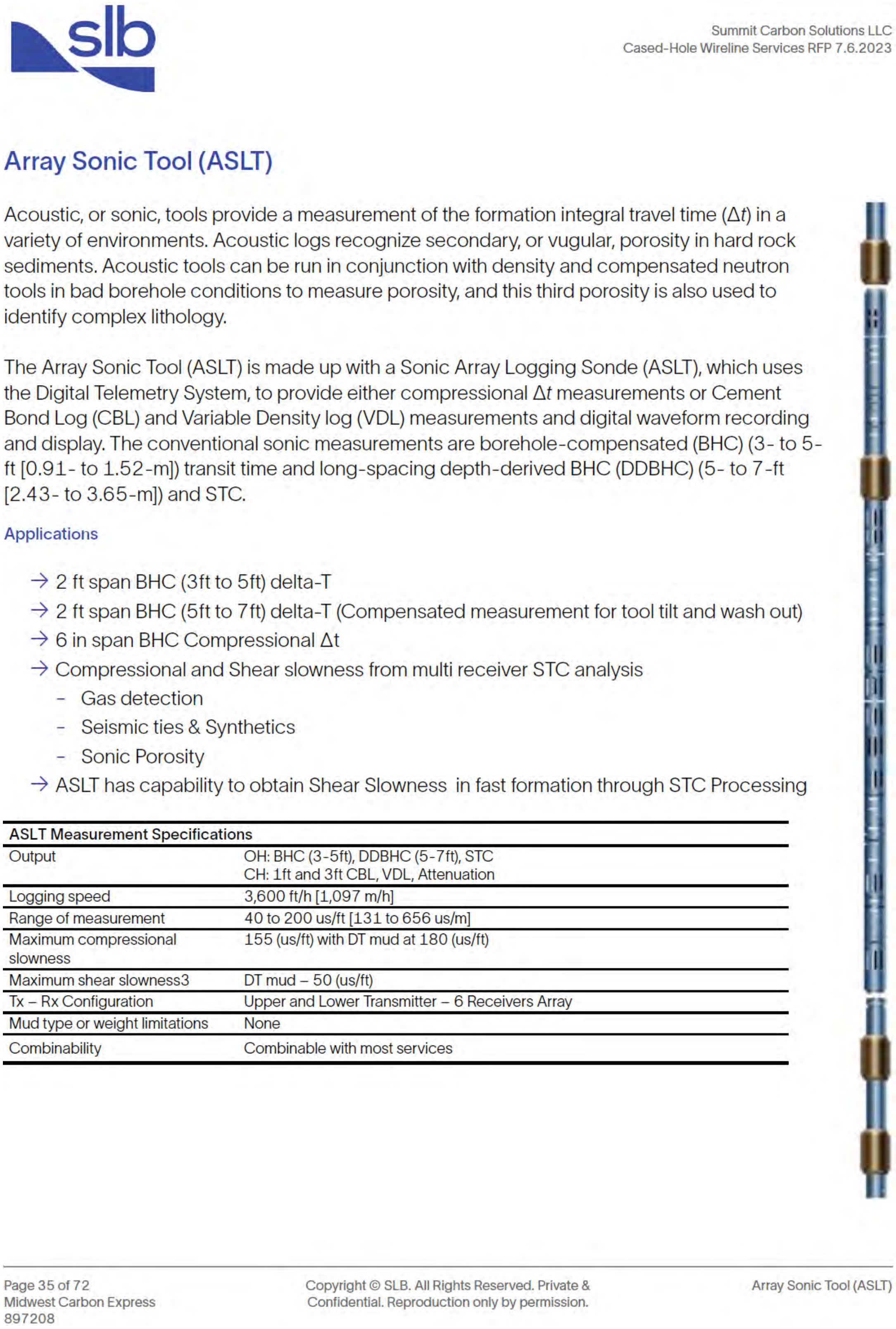
†† For 0.3-in [8-mm] casing thickness

‡‡ Max. mud weight depends on the mud formulation, sub used, and casing size and weight, which are simulated before logging

Isolation Scanner Service Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Casing size—min.[†]	4 ½ in (min. pass-through restriction: 4 in [10.16 cm])
Casing size—max.[†]	13 ⅜ in
Outside diameter	IBCS-A: 3.375 in [8.57 cm] IBCS-B: 4.472 in [11.36 cm] IBCS-C: 6.657 in [16.91 cm] IBCS-D: 8.736 in [22.19 cm]
Length	Without sub: 19.73 ft [6.01 m] IBCS-A sub: 2.01 ft [0.61 m] IBCS-B sub: 1.98 ft [0.60 m] IBCS-C sub: 1.98 ft [0.60 m] IBCS-D sub: 1.98 ft [0.60 m]
Weight	Without sub: 333 lbm [151 kg] IBCS-A sub: 16.75 lbm [7.59 kg] IBCS-B sub: 20.64 lbm [9.36 kg] IBCS-C sub: 23.66 lbm [10.73 kg] IBCS-D sub: 24.55 lbm [11.13 kg]
Sub max. tension	2,250 lbf [10,000 N]
Sub max. compression	12,250 lbf [50,000 N]

† 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). If the chrome content of the tubing or casing is higher than 13%, contact your local SLB representative.

Attachment D-8 – Example Array Sonic Tool Specification Sheet



Array Sonic Tool (ASLT)

Acoustic, or sonic, tools provide a measurement of the formation integral travel time (Δ*t*) in a variety of environments. Acoustic logs recognize secondary, or vugular, porosity in hard rock sediments. Acoustic tools can be run in conjunction with density and compensated neutron tools in bad borehole conditions to measure porosity, and this third porosity is also used to identify complex lithology.

The Array Sonic Tool (ASLT) is made up with a Sonic Array Logging Sonde (ASLT), which uses the Digital Telemetry System, to provide either compressional Δ*t* measurements or Cement Bond Log (CBL) and Variable Density log (VDL) measurements and digital waveform recording and display. The conventional sonic measurements are borehole-compensated (BHC) (3- to 5-ft [0.91- to 1.52-m]) transit time and long-spacing depth-derived BHC (DDBHC) (5- to 7-ft [2.43- to 3.65-m]) and STC.

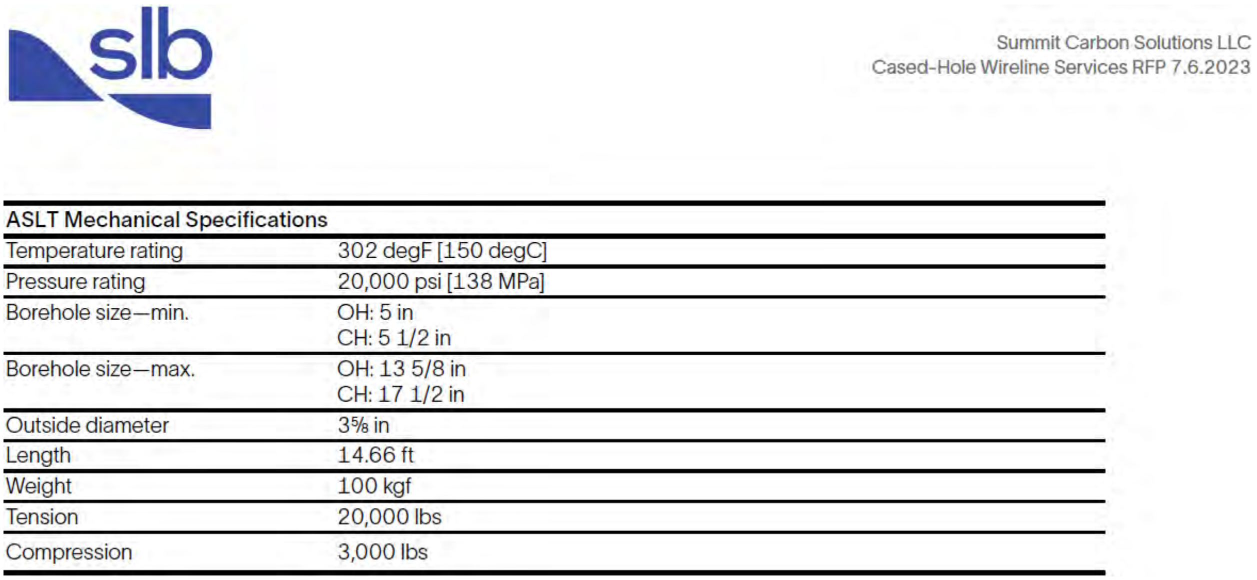
Applications

- → 2 ft span BHC (3ft to 5ft) delta-T
- → 2 ft span BHC (5ft to 7ft) delta-T (Compensated measurement for tool tilt and wash out)
- → 6 in span BHC Compressional Δt
- → Compressional and Shear slowness from multi receiver STC analysis
  - Gas detection
  - Seismic ties & Synthetics
  - Sonic Porosity
- → ASLT has capability to obtain Shear Slowness in fast formation through STC Processing

ASLT Measurement Specifications	
Output	OH: BHC (3-5ft), DDBHC (5-7ft), STC CH: 1ft and 3ft CBL, VDL, Attenuation
Logging speed	3,600 ft/h [1,097 m/h]
Range of measurement	40 to 200 us/ft [131 to 656 us/m]
Maximum compressional slowness	155 (us/ft) with DT mud at 180 (us/ft)
Maximum shear slowness3	DT mud – 50 (us/ft)
Tx – Rx Configuration	Upper and Lower Transmitter – 6 Receivers Array
Mud type or weight limitations	None
Combinability	Combinable with most services

Continued…

Attachment D-8 – Example Array Sonic Tool Specification Sheet (continued)



Summit Carbon Solutions LLC
Cased-Hole Wireline Services RFP 7.6.2023

ASLT Mechanical Specifications	
Temperature rating	302 degF [150 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	OH: 5 in CH: 5 1/2 in
Borehole size—max.	OH: 13 5/8 in CH: 17 1/2 in
Outside diameter	3⅝ in
Length	14.66 ft
Weight	100 kgf
Tension	20,000 lbs
Compression	3,000 lbs

Attachment D-9 – Example Pulsed-Neutron Logging Tool Specification Sheet

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Spectral Pulsed Neutron service

Formation evaluation and reservoir monitoring

The **Spectral Pulsed Neutron (SPN) service** can undertake a broad scope of reservoir evaluation and management applications, including reservoir saturation and produced fluids monitoring, formation evaluation, production profiling, workover and well abandonment evaluation, borehole diagnostics, location of bypassed oil, gas detection and quantification, and identification of water production.

The service uses an advanced, slim-hole, multifunction, pulsed neutron reservoir monitoring tool and is ideally suited for acquiring data through tubing. The tool is flexible with multiple operating modes that are selectable by surface commands. The tool is also very efficient with multiple sensors that enable faster tool movement while performing data acquisition. The SPN service combines multiple acquisition modes, reducing multiple passes down to one pass, without compromising data quality, resulting in logging times reduced by up to 66%.

The Spectral Pulsed Neutron tool employs three high-density high-resolution gamma ray detectors and an advanced digital downhole acquisition system. The reliable high output neutron generator produces gamma ray counts up to 3 times higher than conventional instrumentation providing the most accurate and efficient measurements in the industry. The enhanced detectors and electronics measure both the arrival time and energy of detected gamma rays. The generator is pulsed at distinct frequencies, and the data acquisition system operates in various timing modes to obtain the different gamma ray measurements.

Data acquisition through casing is enabled by the high energy neutrons emitted from the non-chemical pulsed neutron source, even in complicated well completions utilizing multiple tubing and casing strings and sizes. The instrumentation combines multiple nuclear measurements in one system with industry-leading accuracy and precision. Carbon/Oxygen (C/O) and Pulsed Neutron Capture (PNC) measurements acquired with the SPN tool provide formation fluid saturations, porosity, three-phase holdup determination, and oxygen activation measurements for the detection of water flow in annuli and channels.

Extensive physical characterization of the SPN tool is conducted at our Houston Technology Center. The characterization provides forward-

Applications

- Formation evaluation
- Reservoir monitoring and management
- Borehole diagnostics
- Workover applications

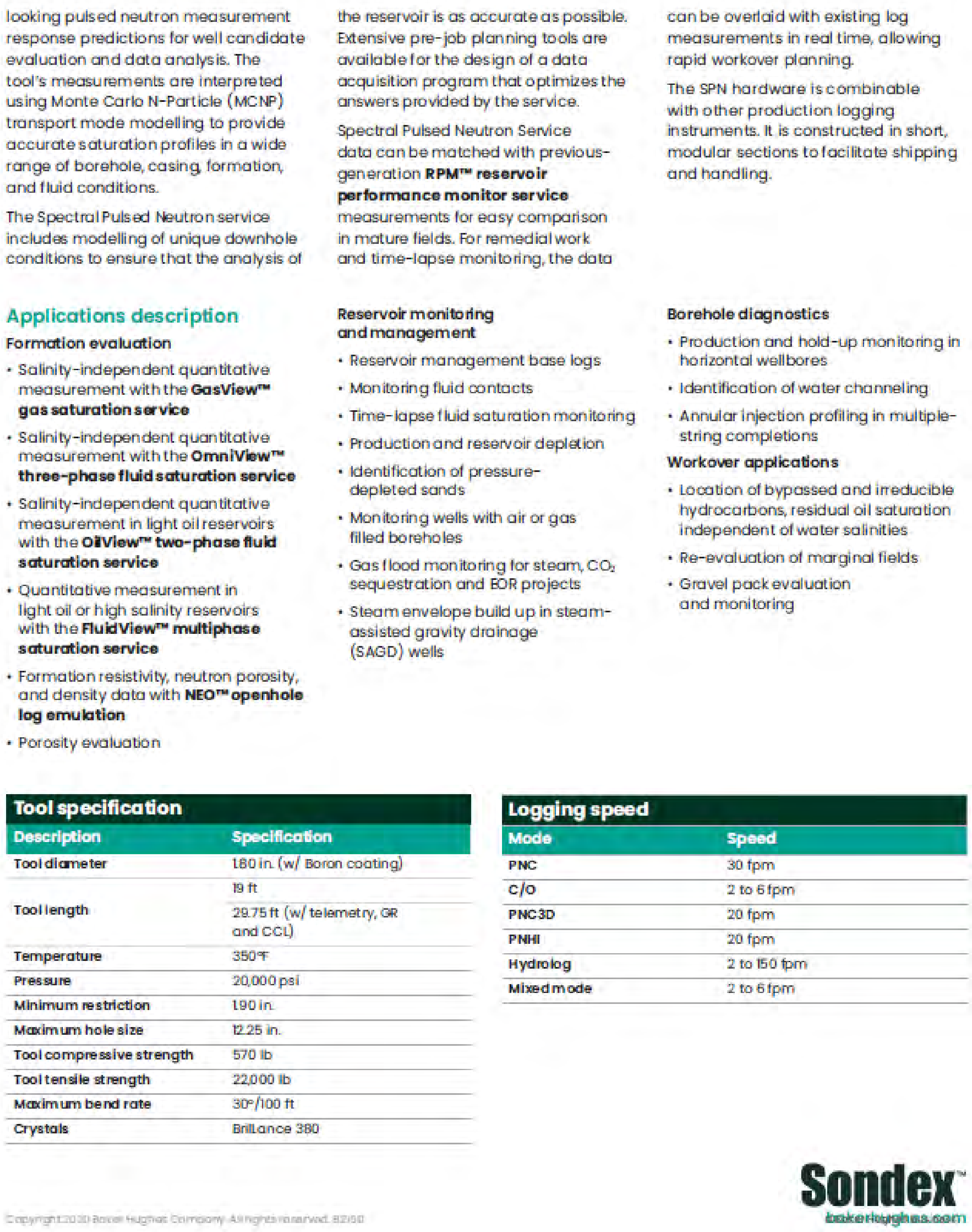
Features and benefits

- Higher count rates and improved signal-to-noise ratio significantly reduces logging times
- Innovative mixed acquisition mode provides a complete pulsed neutron data set all in the same pass
- Multiple modes for operating versatility
- Flexible deployment on e-line
- Pre-job MCNP modelling to provide accurate quantitative fluid saturation

sondex.com

Continued…

Attachment D-9 – Example Pulsed-Neutron Logging Tool Specification Sheet (continued)



looking pulsed neutron measurement response predictions for well candidate evaluation and data analysis. The tool's measurements are interpreted using Monte Carlo N-Particle (MCNP) transport mode modelling to provide accurate saturation profiles in a wide range of borehole, casing, formation, and fluid conditions.

The Spectral Pulsed Neutron service includes modelling of unique downhole conditions to ensure that the analysis of the reservoir is as accurate as possible. Extensive pre-job planning tools are available for the design of a data acquisition program that optimizes the answers provided by the service.

Spectral Pulsed Neutron Service data can be matched with previous-generation **RPM™ reservoir performance monitor service** measurements for easy comparison in mature fields. For remedial work and time-lapse monitoring, the data can be overlaid with existing log measurements in real time, allowing rapid workover planning.

The SPN hardware is combinable with other production logging instruments. It is constructed in short, modular sections to facilitate shipping and handling.

Applications description

Formation evaluation

- Salinity-independent quantitative measurement with the **GasView™ gas saturation service**
- Salinity-independent quantitative measurement with the **OmniView™ three-phase fluid saturation service**
- Salinity-independent quantitative measurement in light oil reservoirs with the **OilView™ two-phase fluid saturation service**
- Quantitative measurement in light oil or high salinity reservoirs with the **FluidView™ multiphase saturation service**
- Formation resistivity, neutron porosity, and density data with **NEO™ openhole log emulation**
- Porosity evaluation

Reservoir monitoring and management

- Reservoir management base logs
- Monitoring fluid contacts
- Time-lapse fluid saturation monitoring
- Production and reservoir depletion
- Identification of pressure-depleted sands
- Monitoring wells with air or gas filled boreholes
- Gas flood monitoring for steam, CO_2 sequestration and EOR projects
- Steam envelope build up in steam-assisted gravity drainage (SAGD) wells

Borehole diagnostics

- Production and hold-up monitoring in horizontal wellbores
- Identification of water channeling
- Annular injection profiling in multiple-string completions

Workover applications

- Location of bypassed and irreducible hydrocarbons, residual oil saturation independent of water salinities
- Re-evaluation of marginal fields
- Gravel pack evaluation and monitoring

Tool specification

Description	Specification
Tool diameter	1.80 in. (w/ Boron coating)
Tool length	19 ft 29.75 ft (w/ telemetry, GR and CCL)
Temperature	350°F
Pressure	20,000 psi
Minimum restriction	1.90 in.
Maximum hole size	12.25 in.
Tool compressive strength	570 lb
Tool tensile strength	22,000 lb
Maximum bend rate	30°/100 ft
Crystals	BrilLance 380

Logging speed

Mode	Speed
PNC	30 fpm
C/O	2 to 6 fpm
PNC3D	20 fpm
PNHI	20 fpm
Hydrolog	2 to 150 fpm
Mixed mode	2 to 6 fpm

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Attachment D-10 – DTS Fiber-Optic Cable Specification Sheet

Cable Engineered by Prysmian

TEF w/ 4 OPTICAL FIBERS 825 ALLOY SHEATH TUBE ROUND ENCAPSULATION

CARBON CAPTURE AND STORAGE (CCS) APPLICATION

Components

A:	2 x Fibercore GIMM CMTDA 50/125 Graded Index Fiber; Colored Blue & Orange
B:	2 x Fibercore SM1250 CMTDA Single Mode Fiber; Colored Red & Black
C:	FIMT: 3.2 mm x 2.8 mm Stainless Steel 316L, Filled with LA4000 EFL $\geq$ 0.30%
D:	Natural Polypropylene; O.D.: 4.57mm (0.180”) Nominal – Belt OD run larger for CCS Application
E:	825 Alloy Tube; Wall Thickness: 0.89 mm (0.035”); O.D.: 6.35 mm (0.250”) Nominal
F:	Yellow Round Profile Polypropylene; OD.: 11 mm (0.433”) Nominal

Print Legend

“FiberSight^{tm}” P/N: 103200010 (Batch Number) (month/year)” Plus Footage Markings

Physical Characteristics

Tube Min Tensile Strength	: 3546 lbs
Tube Min Yield Strength	: 2246 lbs
Cable Breaking Strength, Theoretical	: 4166 lbs Maximum
Fiber Coating	: 245µm ± 15µm
Cable Weight, kg/km (lbs/1000 ft)	: 208 (140) Nominal
Temperature Rating	: 150°C

Optical Characteristics

Optical Attenuation at 850 / 1300nm	: $\leq$ 3.0 dB/km / $\leq$ 1.0 dB/km
Optical Attenuation at 1310 / 1550nm	: $\leq$ 0.5 dB/km / $\leq$ 0.3 dB/km
Point Discontinuity MMF / SMF	: $\leq$ 0.2 dB / $\leq$ 0.1 dB

Rev	DATE	CHANGE DETAIL
0	09/11/23	New Issue
1	10/09/23	SCN 43522

Approvals: Created By: Reviewed By:

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EngDrawing-Rev06-April 2021

Prysmian Group

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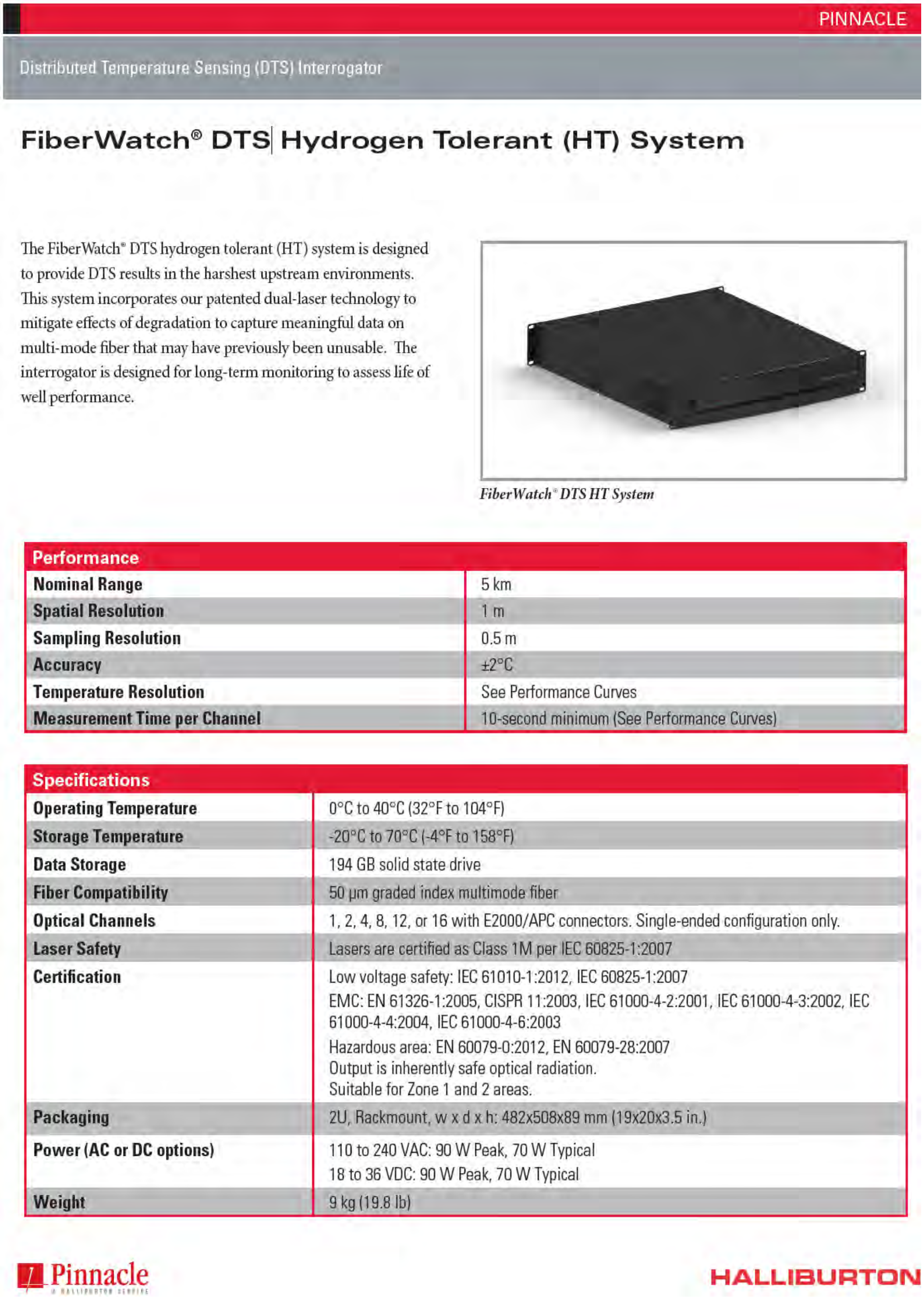
111 Chimney Rock Road
Bridgewater, New Jersey 08807
Phone: 866-786-8823 Fax: 732-469-6363

Project Name:	Halliburton 103200010
Part Number:	20431710
Quote Number:	
File Number:	
Page Number:	Page 1 of 1

Attachment D-11 – DTS Fiber Optics Interrogator Specification Sheet



PINNACLE

Distributed Temperature Sensing (DTS) Interrogator

FiberWatch® DTS | Hydrogen Tolerant (HT) System

The FiberWatch® DTS hydrogen tolerant (HT) system is designed to provide DTS results in the harshest upstream environments. This system incorporates our patented dual-laser technology to mitigate effects of degradation to capture meaningful data on multi-mode fiber that may have previously been unusable. The interrogator is designed for long-term monitoring to assess life of well performance.

FiberWatch® DTS HT System

Performance	
Nominal Range	5 km
Spatial Resolution	1 m
Sampling Resolution	0.5 m
Accuracy	±2°C
Temperature Resolution	See Performance Curves
Measurement Time per Channel	10-second minimum (See Performance Curves)

Specifications	
Operating Temperature	0°C to 40°C (32°F to 104°F)
Storage Temperature	-20°C to 70°C (-4°F to 158°F)
Data Storage	194 GB solid state drive
Fiber Compatibility	50 µm graded index multimode fiber
Optical Channels	1, 2, 4, 8, 12, or 16 with E2000/APC connectors. Single-ended configuration only.
Laser Safety	Lasers are certified as Class 1M per IEC 60825-1:2007
Certification	Low voltage safety: IEC 61010-1:2012, IEC 60825-1:2007 EMC: EN 61326-1:2005, CISPR 11:2003, IEC 61000-4-2:2001, IEC 61000-4-3:2002, IEC 61000-4-4:2004, IEC 61000-4-6:2003 Hazardous area: EN 60079-0:2012, EN 60079-28:2007 Output is inherently safe optical radiation. Suitable for Zone 1 and 2 areas.
Packaging	2U, Rackmount, w x d x h: 482x508x89 mm (19x20x3.5 in.)
Power (AC or DC options)	110 to 240 VAC: 90 W Peak, 70 W Typical 18 to 36 VDC: 90 W Peak, 70 W Typical
Weight	9 kg (19.8 lb)

Pinnacle
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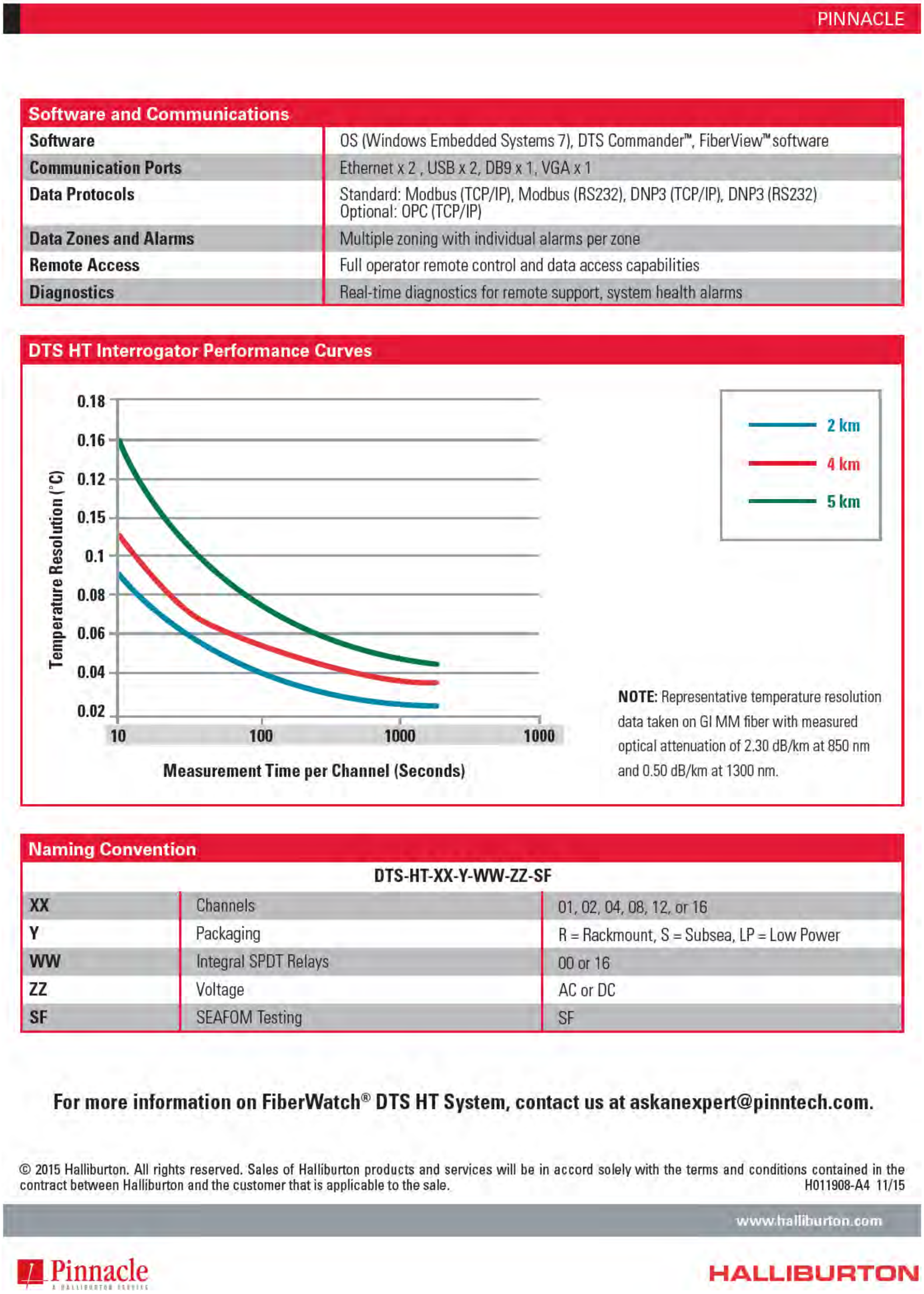
Continued…

Attachment D-11 – DTS Fiber Optics Interrogator Specification Sheet



PINNACLE

Software and Communications

Software	OS (Windows Embedded Systems 7), DTS Commander™, FiberView™ software
Communication Ports	Ethernet x 2 , USB x 2, DB9 x 1, VGA x 1
Data Protocols	Standard: Modbus (TCP/IP), Modbus (RS232), DNP3 (TCP/IP), DNP3 (RS232) Optional: OPC (TCP/IP)
Data Zones and Alarms	Multiple zoning with individual alarms per zone
Remote Access	Full operator remote control and data access capabilities
Diagnostics	Real-time diagnostics for remote support, system health alarms

DTS HT Interrogator Performance Curves

NOTE: Representative temperature resolution data taken on GI MM fiber with measured optical attenuation of 2.30 dB/km at 850 nm and 0.50 dB/km at 1300 nm.

Naming Convention

DTS-HT-XX-Y-WW-ZZ-SF

XX	Channels	01, 02, 04, 08, 12, or 16
Y	Packaging	R = Rackmount, S = Subsea, LP = Low Power
WW	Integral SPDT Relays	00 or 16
ZZ	Voltage	AC or DC
SF	SEAFOM Testing	SF

For more information on FiberWatch® DTS HT System, contact us at askanexpert@pinntech.com.

H011908-A4 11/15

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Attachment D-12 – Example Annulus Pressure Test Procedure

The following is a checklist SCS1 will use as a guide for conducting an initial annulus pressure test. Annulus pressure tests are required prior to commencing injection and are requisite in reestablishing mechanical integrity following a workover that involves tubing removal. If necessary, a detailed annulus pressure test procedure can be provided with the written notification prior to conducting the test.

Pretest Protocol:

- Notify the Department of Mineral Resources (DMR-O&G) in writing at least 30 days prior to annulus pressure testing and again at least 48 hours in advance to witness the test.

- Prepare a well schematic that includes sufficient information to confirm the packer is set opposite a cemented interval of the long-string casing and no more than 50 feet above the uppermost perforation or at a location otherwise approved by DMR-O&G. If the test well was worked over and the tubing or tubing/packer retrieved from the well, provide a workover record to the DMR-O&G inspector for review and verification of packer depth.

- Provide the on-site DMR-O&G inspector with a well schematic confirming the test well packer is in an approved location.

- Provide the on-site DMR-O&G inspector with a calibration certificate for the mechanical or digital device used to record the annulus pressure test verifying calibration within 1 year of the test date.

Test Protocol:

- Install or select the wellhead pressure gauge and continuous recording device to measure pressure and serve as a record of the pressure data witnessed on the wellhead pressure gauge. Select a pressure gauge with an appropriate scale so that the anticipated testing pressure falls within 25% and 75% of the full gauge scale, and that the gauge range is at a minimum twice the testing pressure. The pressure gauge and continuous recording device shall have sufficient accuracy and precision to identify a 10% pressure change.

- Fill the tubing-casing annulus with an approved liquid and confirm the annulus will remain full. Measure and record the liquid type and volume required to fill the annulus. Allow time for the temperature of the well and annulus liquid to equilibrate.

- Confirm that the annulus is liquid-filled.

- Build and maintain the annulus pressure at 1000 psig or a value previously approved by DMR-O&G

- Isolate the well from the pressure source and confirm no leaks occur at shut-off valves. If present, consider disconnecting the seal pot or surge tank to also prevent leaks at their shut-off valves.

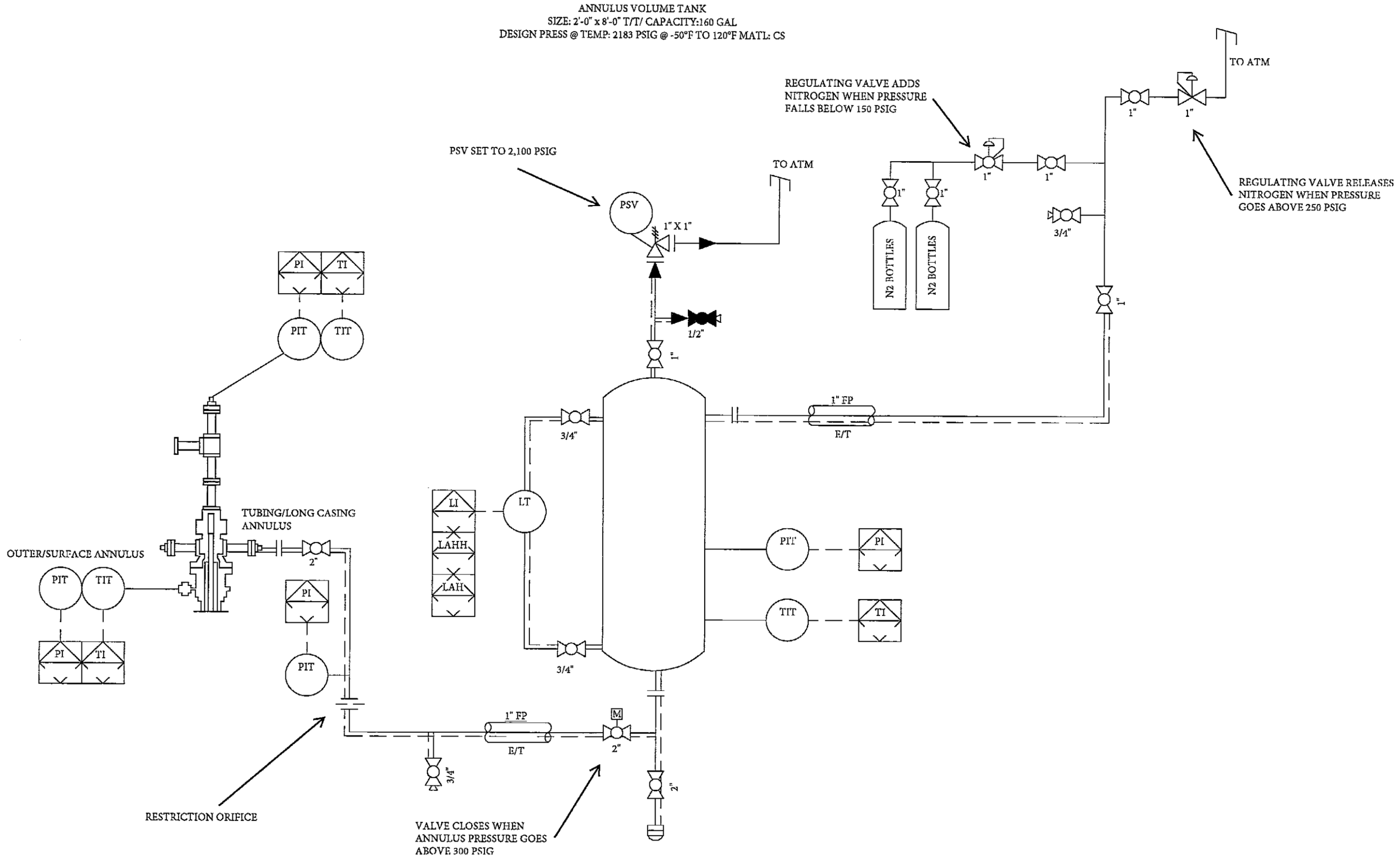
- Maintain a minimum pressure differential of 200 psi between the tubing pressure and annulus pressure. If a lower pressure differential is needed, the storage facility operator must obtain prior DMR-O&G approval.

- Record the annulus pressure for at least 30 minutes.
  - Note the time, the annulus pressure, and the tubing pressure at the start of the test and at least every 5 minutes thereafter to the end of the test.
  - The continuous recording device shall serve as a backup. A copy of the continuous pressure recording shall be submitted with the written reports to DMR-O&G.
  - A net pressure change of more than 10% constitutes a failed test.

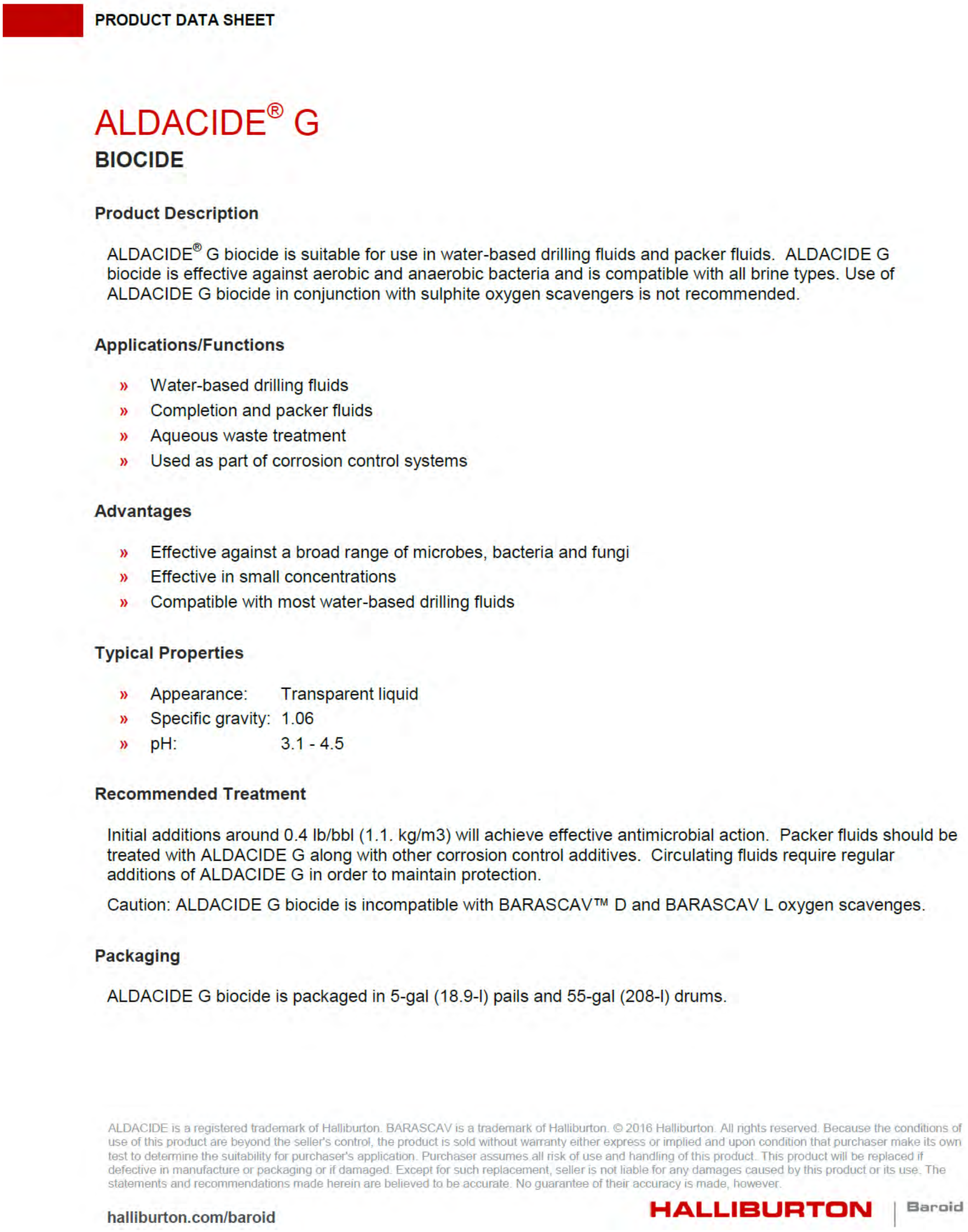
Posttesting Protocol:

- Report to DMR-O&G within 30 days the results of any annulus pressure test.
- Publish the annulus pressure test results in the quarterly report in which the test was performed.

Attachment D-13 – Diagram of the Seal Pot System



Attachment D-14 – Antimicrobial Biocide Specification Sheet



PRODUCT DATA SHEET

ALDACIDE® G

BIOCIDE

Product Description

ALDACIDE® G biocide is suitable for use in water-based drilling fluids and packer fluids. ALDACIDE G biocide is effective against aerobic and anaerobic bacteria and is compatible with all brine types. Use of ALDACIDE G biocide in conjunction with sulphite oxygen scavengers is not recommended.

Applications/Functions

- Water-based drilling fluids
- Completion and packer fluids
- Aqueous waste treatment
- Used as part of corrosion control systems

Advantages

- Effective against a broad range of microbes, bacteria and fungi
- Effective in small concentrations
- Compatible with most water-based drilling fluids

Typical Properties

Appearance:	Transparent liquid
Specific gravity:	1.06
pH:	3.1 - 4.5

Recommended Treatment

Initial additions around 0.4 lb/bbl (1.1. kg/m3) will achieve effective antimicrobial action. Packer fluids should be treated with ALDACIDE G along with other corrosion control additives. Circulating fluids require regular additions of ALDACIDE G in order to maintain protection.

Caution: ALDACIDE G biocide is incompatible with BARASCAV™ D and BARASCAV L oxygen scavenges.

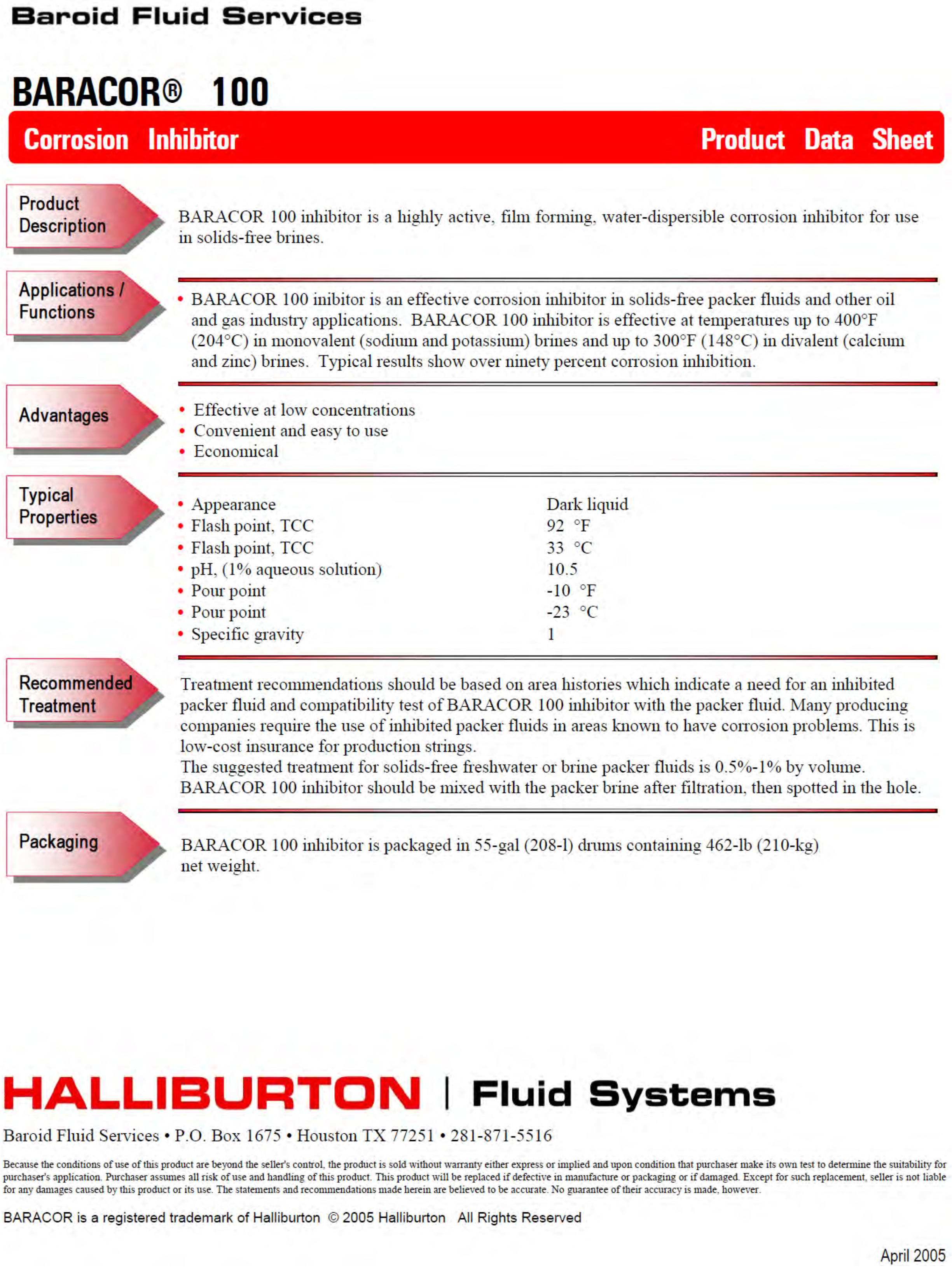
Packaging

ALDACIDE G biocide is packaged in 5-gal (18.9-l) pails and 55-gal (208-l) drums.

halliburton.com/baroid

HALLIBURTON | Baroid

Attachment D-15 – Corrosion Inhibitor Specification Sheet



Baroid Fluid Services

BARACOR® 100

Corrosion Inhibitor Product Data Sheet

Product Description

BARACOR 100 inhibitor is a highly active, film forming, water-dispersible corrosion inhibitor for use in solids-free brines.

Applications / Functions

- BARACOR 100 inibitor is an effective corrosion inhibitor in solids-free packer fluids and other oil and gas industry applications. BARACOR 100 inhibitor is effective at temperatures up to 400°F (204°C) in monovalent (sodium and potassium) brines and up to 300°F (148°C) in divalent (calcium and zinc) brines. Typical results show over ninety percent corrosion inhibition.

Advantages

- Effective at low concentrations
- Convenient and easy to use
- Economical

Typical Properties

• Appearance	Dark liquid
• Flash point, TCC	92 °F
• Flash point, TCC	33 °C
• pH, (1% aqueous solution)	10.5
• Pour point	-10 °F
• Pour point	-23 °C
• Specific gravity	1

Recommended Treatment

Treatment recommendations should be based on area histories which indicate a need for an inhibited packer fluid and compatibility test of BARACOR 100 inhibitor with the packer fluid. Many producing companies require the use of inhibited packer fluids in areas known to have corrosion problems. This is low-cost insurance for production strings.

The suggested treatment for solids-free freshwater or brine packer fluids is 0.5%-1% by volume. BARACOR 100 inhibitor should be mixed with the packer brine after filtration, then spotted in the hole.

Packaging

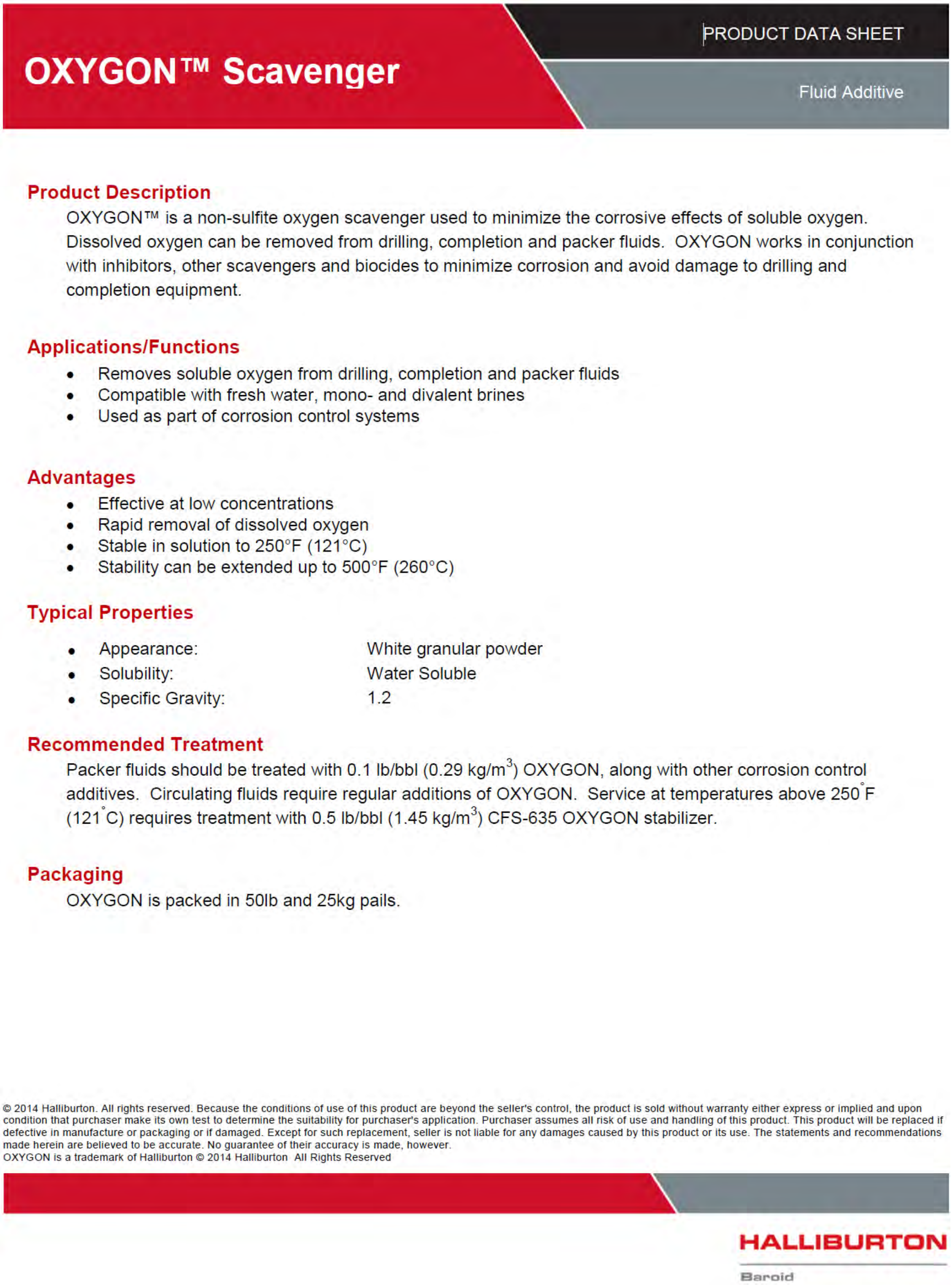
BARACOR 100 inhibitor is packaged in 55-gal (208-l) drums containing 462-lb (210-kg) net weight.

HALLIBURTON | Fluid Systems

Baroid Fluid Services • P.O. Box 1675 • Houston TX 77251 • 281-871-5516

April 2005

Attachment D-16 – Scaling Inhibitor (Oxygen Scavenger) Specification Sheet



PRODUCT DATA SHEET

OXYGON™ Scavenger

Fluid Additive

Product Description

OXYGON™ is a non-sulfite oxygen scavenger used to minimize the corrosive effects of soluble oxygen. Dissolved oxygen can be removed from drilling, completion and packer fluids. OXYGON works in conjunction with inhibitors, other scavengers and biocides to minimize corrosion and avoid damage to drilling and completion equipment.

Applications/Functions

- Removes soluble oxygen from drilling, completion and packer fluids
- Compatible with fresh water, mono- and divalent brines
- Used as part of corrosion control systems

Advantages

- Effective at low concentrations
- Rapid removal of dissolved oxygen
- Stable in solution to 250°F (121°C)
- Stability can be extended up to 500°F (260°C)

Typical Properties

Appearance:	White granular powder
Solubility:	Water Soluble
Specific Gravity:	1.2

Recommended Treatment

Packer fluids should be treated with 0.1 lb/bbl (0.29 kg/m^3) OXYGON, along with other corrosion control additives. Circulating fluids require regular additions of OXYGON. Service at temperatures above 250˚F (121˚C) requires treatment with 0.5 lb/bbl (1.45 kg/m^3) CFS-635 OXYGON stabilizer.

Packaging

OXYGON is packed in 50lb and 25kg pails.

HALLIBURTON

Baroid

Attachment D-17 – Example Casing-Conveyed P/T Gauge Specifications

INTELLIGENT COMPLETIONS | Permanent Monitoring

DataSphere® Array System

RELIABLE MULTI-POINT RESERVOIR MONITORING

OVERVIEW

The DataSphere® Array system is the next step in the evolution of DataSphere permanent monitoring suite. The technology is built upon the reliability of ROC™ gauge hybrid technology and provides greater system customization by deploying multiple discrete sensors across challenging wellbore regions.

A system comprised of conventional gauges can communicate with multiple Array sensor systems distributed across different wellbore intervals. Each Array system provides discrete real-time annular downhole distributed multi-point temperature and pressure monitoring data. The Array system incorporates no cable terminations, which reduces installation time and eliminates risks associated with multiple terminations. Furthermore, the Array system uses internal short circuit protection circuitry that minimizes system line takedowns.

Based on an industry-standard, field-proven resonating quartz crystal sensor, the Array system can be used for distributed, single zone, or multi-zone monitoring applications.

In distributed monitoring, the use of Halliburton conventional downhole gauges can be enhanced by the Array system, allowing operators greater visibility into their operations efficiency in a cost-effective manner.

APPLICATIONS

- ICD efficiency monitoring
- Production monitoring
- Injection monitoring
- Field reservoir monitoring
- SmartWell® completion system optimization
- Artificial lift/gas lift optimization
- Pressure gradient monitoring

FMJ CABLE TERMINATION

When connected to a conventional gauge, the DataSphere Array system uses a high-performance cable termination with a sealing arrangement based on our highly reliable intelligent completion FMJ connector. This cable termination incorporates a pressure-testable dual metal-to-metal ferrule seal arrangement for isolating the downhole cable outer metal sheath from the well fluid.

FEATURES

- Can be deployed standalone
- Up to 50 sensors per array
- ROC-MODBUS communication protocol
- Designed for harsh environments up to 16,000 psi and 175°C
- AWES qualified
- Reduced OD design
- Multi-drop capability on single core tubing encased conductor (TEC)
- Hermetically sealed electron beam-welded design
- Application Specific Integrated Chip (ASIC) technology
- Increased capabilities such as fault protection per sensor
- Designed for a 10 year life at 185°C

BENEFITS

- Quartz-sensors provide high accuracy and resolution and low drift
- Can be deployed across the sandface for greater reservoir inflow/outflow understanding
- Reduces rig time through faster installation times (up to eight hours saved per gauge)
- Reduces need for cable terminations
- Eliminates requirement for gauge mandrels in annular sensing applications
- Validates/disproves reservoir models
- Tool head voltage and gauge current measurement for diagnostics
- Reduces potential leak points by minimizing system connections

HALLIBURTON | Completion Tools

Continued…

Attachment D-17 – Example Casing-Conveyed P/T Gauge Specifications (continued)

INTELLIGENT COMPLETIONS | Permanent Monitoring

TESTING

The individual sensor design has gone through the Design for Reliability process, which includes a Highly Accelerated Lifetime Test (HALT) program. This program is a series of controlled environmental stresses designed to ensure that stringent criteria are met for thermal shock, mechanical shock, vibration and thermal aging. During manufacture, all gauges are also subjected to Environmental Stress Screening (ESS) to highlight any defect in functionality prior to installation at the well site. This method of screening has proven to be far more effective than "burn-in" techniques.

All of the individual sensors that make up the DataSphere Array system are independently calibration-checked in our manufacturing facility. During Factory Acceptance Testing (FAT), the DataSphere Array sensor welds are pressure tested for integrity as the array is being built and spooled onto the final drum.

DataSphere® Array System - Temperature Performance

Accuracy (°C)	0.5
Typical Accuracy (°C)	0.15
Achievable Resolution (°C/sec)	< 0.005
Repeatability (°C)	< 0.01
Drift at 177°C (°C/year)	< 0.1

DATASPHERE ARRAY SYSTEM DESIGNS

- Quartz transducer and hybrid technology
- ASIC technology
- Maximum 175°C operating temperature
- Can be used in conjunction with existing gauges
- Improved shock and vibration performance
- 0.625-in. OD ultra slim design
- Less than 7-in. length per sensor
- Does not need a gauge mandrel to be deployed
- Short-circuit protection per sensor, prevents line takedowns

Temperature and Pressure Sensor > The DataSphere® Array system is comprised of multiple ultra slim, highly accurate quartz-based temperature and pressure sensors.

DataSphere® Array System - Pressure Performance

Pressure Range (psi / bar)	0 to 10,000 / 0 to 690	0 to 16,000 / 0 to 1,100
Accuracy (% FS)	0.015	0.02
Typical Accuracy (% FS)	0.012	0.015
Achievable Resolution (psi/sec)	< 0.006	< 0.008
Repeatability (% FS)	< 0.01	< 0.01
Response Time to FS Step (for 99.5% FS)	< 1 sec	< 1 sec
Acceleration Sensitivity (psi/g – any axis)	< 0.02	< 0.02
Drift at 14 psi and 25°C (%FS/year)	Negligible	Negligible
Drift at Max. Pressure and Temperature (%FS/year)	0.02	0.02

For more information, contact your local Halliburton representative or visit us on the web at www.halliburton.com

HALLIBURTON | Completion Tools

Attachment D-18 – Tubing-Conveyed P/T Gauge Specifications

DataSphere® Opsis™ Permanent Downhole Gauges

RELIABLE, REAL-TIME MONITORING OF DOWNHOLE CONDITIONS

OVERVIEW

In today's challenging environments, there is an increasing need for reliable and accurate reservoir data, driving the need for continuous improvement of monitoring technology. Opsis™ permanent downhole gauges are the latest addition to the DataSphere® permanent monitoring suite, providing real-time downhole data for increased productivity throughout the life of the well.

Opsis gauges feature ASIC (Application Specific Integrated Circuit) technology in combination with field-proven resonating quartz crystal sensors. The result is highly accurate pressure and temperature measurements, even under extreme temperature conditions.

Opsis gauges can be used for single or multi-zone monitoring applications. These gauges may be ported to tubing, annulus, or control line. The addition of feed-through or splitter block assemblies enables the monitoring of multiple zones.

APPLICATIONS

- Life of the well production monitoring
- Life of the field reservoir monitoring
- SmartWell® completion system optimization
- Artificial lift optimization

GAUGE DESIGNS

- Quartz transducer
- ASIC technology
- Maximum 200°C operating temperature
- 0.75-in OD slim line design
- Improved shock and vibration performance

FMJ CABLE TERMINATION

Opsis gauges use a high performance cable termination with a sealing arrangement based on our highly reliable intelligent completion FMJ connector. This cable termination incorporates a pressure-testable dual metal-to-metal ferrule seal arrangement for isolating the downhole cable outer metal sheath from the well fluid.

FEATURES

- ASIC hybrid electronics qualified to 200°C
- Demonstrated downhole gauge reliability 10 years @185°C
- Onboard intelligent gauge diagnostics
- Bellows to isolate quartz crystal from well fluids
- Designed for harsh environments up to 30,000 psi and 200°C
- Extensive qualification testing performed
- Simplified system with multiple sensor options
- Field-testable dual metal-to-metal seal
- Fault-tolerance features for maximum reliability

BENEFITS

- Continuous pressure and temperature data without the need for well intervention
- Enhanced reservoir management
- Increased system reliability using stable pressure/temperature measurements
- Quartz-based sensor for high accuracy, low drift

Continued…

Attachment D-18 – Tubing-Conveyed P/T Gauge Specifications (continued)

COMPLETION SOLUTIONS | Permanent Monitoring

TESTING

Opsis gauges are tested to the full pressure and temperature rating during Factory Acceptance Testing (FAT), and each gauge comes with an independently checked calibration certificate.

New gauge designs are subjected to Reliability Demonstration Testing (RDT) per AWES Recommended Practices.

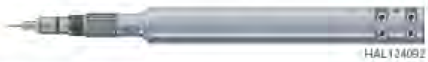
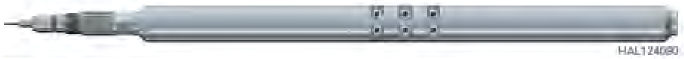
Opsis™ Gauge Temperature Performance

Accuracy (°C)	0.5
Typical Accuracy (°C)	0.15
Achievable Resolution (°C/sec)	<0.005
Repeatability (°C)	<0.01
Drift at 177°C (°C/year)	<0.1

Opsis™ Gauge Pressure Performance

Pressure Range (psi / bar)	0 to 10,000 0 to 690	0 to 16,000 0 to 1,100	0 to 20,000 0 to 1,1380	0 to 25,000 0 to 1,725	0 to 30,000 0 to 2070
Accuracy (% FS) (psi)	0.015 (1.5)	0.02 (3.2)	0.02 (4.0)	0.02 (5.0)	0.025 (7.5)
Typical Accuracy (% FS) (psi)	0.012 (1.2)	0.015 (2.4)	0.015 (3.0)	0.015 (3.75)	0.02 (6.0)
Achievable Resolution (psi/sec)	<0.006	<0.008	<0.008	<0.010	<0.010
Drift at 14 psi and 25°C (% FS)	Negligible	Negligible	Negligible	Negligible	Negligible
Maximum Drift at Maximum Pressure and Temperature (% FS/Year) (psi)	0.02 (2.0)	0.02 (3.2)	0.02 (4.0)	0.02 (5.0)	0.025 (7.5)

Opsis™ Gauge Variants

Configurations	150°C Gauge	175°C Gauge		200°C Gauge	
	10k	16k	20k	25k	30k
Single Sensor					
Single Sensor + Feedthrough					
Dual Sensor					
Dual Sensor + Feedthrough					

Special calibration available upon request
Single sensor non feedthrough variants for 150°C and 175°C have 0.75-in. OD
All feedthrough and dual sensor variants have 1.125-in. OD

APPENDIX E

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

Subject	N.D.C.C./N.D.A.C. 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	N.D.C.C. §§ 38-22-06(3) and (4) N.D.A.C. §§ 43-05-01-08(1) and (2)	**N.D.C.C. § 38-22-06** 3. Notice of the hearing must be given to each mineral lessee, mineral owner, and pore space owner within the storage reservoir and within one-half mile of the storage reservoir's boundaries. 4. Notice of the hearing must be given to each surface owner of land overlying the storage reservoir and within one-half mile of the reservoir's boundaries. **N.D.A.C. § 43-05-01-08** 1. The commission shall hold a public hearing before issuing a storage facility permit. At least forty-five days prior to the hearing, the applicant shall give notice of the hearing to the following: a. Each operator of mineral extraction activities within the facility area and within one-half mile [.80 kilometer] of its outside boundary; b. Each mineral lessee of record within the facility area and within one-half mile [.80 kilometer] of its outside boundary; c. Each owner of record of the surface within the facility area and one-half mile [.80 kilometer] of its outside boundary;	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** Summit Carbon Storage #1, LLC (SCS1) will notify in accordance with N.D.A.C. § 43-05-01-08 of the SFP hearing at least 45 days prior to the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made.	The affidavit has not yet been prepared.
			b. A map showing the extent of the pore space that will be occupied by carbon dioxide over the life of the project;	**1.0 PORE SPACE ACCESS** (p. 1-1) North Dakota law 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 [N.D.C.C.] § 47-31-03). Prior to issuance of the storage facility permit (SFP), North Dakota law mandates the storage operator obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir for geologic storage of CO_2 (N.D.C.C. § 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 (N.D.C.C. §§ 38-22-08[4], [14]). 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 (N.D.C.C. § 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 aboveground activities is not included in pore space amalgamation. Summit Carbon Storage #1, LLC (SCS1) has identified the owners (surface and mineral) (N.D.C.C. §§ 38-22-06[3], [4]; North Dakota Administrative Code [N.D.A.C.] § 43-05-01-08[1]). No mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles of its outside boundary. SCS1 will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made (N.D.C.C. §§ 38-22-06[3], [4]; N.D.A.C. §§ 43-05-01-08[1], [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 (N.D.C.C. § 47-31-03). The review of pertinent county recorder records identified no severance of pore space from the surface estate or leasing of pore space to a third party prior to April 9, 2009. All surface owners and pore space owners and lessees are the same owner of record. The map in Figure 1-1 shows the extent of the pore space that will be occupied by CO_2 at the cessation of injection (20 years) and over the life of the project (the stabilized CO_2 extent) as well as the storage facility area boundary and 0.5 miles outside of the storage facility area boundary (the hearing notification area).	**Figure 1-1.** Map illustrating the pore space CO_2 extent at the cessation of injection (20 years), alongside the stabilized CO_2 extent over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted. (p. 1-2)
			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.** Map illustrating the pore space CO_2 extent at the cessation of injection (20 years), alongside the stabilized CO_2 extent over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted. (p. 1-2)
			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.** Map illustrating the pore space CO_2 extent at the cessation of injection (20 years), alongside the stabilized CO_2 extent

Subject	N.D.C.C./N.D.A.C. 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)
		d. Each owner of record of minerals within the facility area and within one-half mile [.80 kilometer] of its outside boundary; e. Each owner and each lessee of record of the pore space within the storage reservoir and within one-half mile [.80 kilometer] of the reservoir's boundary; and f. Any other persons as required by the commission. 2. The notice given by the applicant must contain: a. A legal description of the land within the facility area. b. The date, time, and place that the commission will hold a hearing on the permit application. c. A statement that a copy of the permit application and draft permit may be obtained from the commission.	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;		over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted. (p. 1-2)
			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.** Map illustrating the pore space CO_2 extent at the cessation of injection (20 years), alongside the stabilized CO_2 extent over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted. (p. 1-2)
			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.** Map illustrating the pore space CO_2 extent at the cessation of injection (20 years), alongside the stabilized CO_2 extent over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted. (p. 1-2)
Geologi	N.D.A.C. § 43-05-01-05	**N.D.A.C. § 43-05-01-05 (1)(b)**	a. Geologic description of the storage reservoir:	**2.1 Overview of Project Area Geology** (p. 2-1)	**Figure 2-1.** Topographic map showing well

<table>
<tr><th>Subject</th><th>N.D.C.C./N.D.A.C. Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description (Page Number)</th></tr>
<tr>
<td></td>
<td>(1)(b)(1)</td>
<td>(1) The name, description, and average depth of the storage reservoirs;</td>
<td>Name
Lithology
Average thickness
Average depth</td>
<td>
<p>TB Leingang is situated approximately 16 miles south of Beulah, North Dakota (Figure 2-1). This project site is on the eastern flank of the Williston Basin.</p>
<p>Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted by the Energy & Environmental Research Center (EERC) via the Plains CO_2 Reduction (PCOR) Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO_2 storage due, in part, to 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).</p>
<p>The CO_2 storage reservoir for this project is the Broom Creek Formation, a predominantly sandstone formation 5818 ft below kelly bushing (KB) elevation at the stratigraphic and reservoir-monitoring well (Milton Flemmer 1, NDIC File No. 38594) (Figure 2-2). Unconformably overlying the Broom Creek Formation is 231 ft of predominantly siltstone with interbedded dolostone and anhydrite of the Spearfish, Minnekahta, and Opeche Formations, hereinafter referred to as the Opeche/Spearfish Formation. The Minnekahta Formation (limestone) is used to distinguish between the Spearfish Formation (above) and Opeche Formation (below). The Minnekahta Formation is interpreted to pinch out within the storage facility area. Where the Minnekahta does not exist, because of the similarity in lithology between the two formations, the Opeche and Spearfish are undifferentiated. The Opeche/Spearfish Formation serves as the primary upper confining zone (Figure 2-2). The Amsden Formation (dolostone, anhydrite, sandstone) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-2). Together, the Opeche/Spearfish, Broom Creek, and Amsden Formations comprise the storage complex for TB Leingang (Table 2-1).</p>
<p>Including the Opeche/Spearfish Formation, there are 1082 ft (thickness in Milton Flemmer 1) of impermeable rock formations between the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. An additional 2670 ft (thickness at Milton Flemmer 1) of impermeable intervals separates the Inyan Kara Formation and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-2).</p>
<p>Table 2-1. Formations Comprising the TB Leingang Storage Complex (simulation model values calculated from model extent shown in Figure 2-3)</p>
<table>
<tr><th>Formation</th><th>Purpose</th><th>Thickness at Milton Flemmer 1, ft</th><th>Depth at Milton Flemmer 1, ft, MD*</th><th>Average Simulation Model Thickness, ft</th><th>Average Simulation Model Depth, ft, TVD**</th><th>Lithology</th></tr>
<tr><td>Opeche/ Spearfish</td><td>Upper confining zone</td><td>231</td><td>5587</td><td>138</td><td>5106</td><td>Siltstone, Dolostone Anhydrite</td></tr>
<tr><td>Broom Creek</td><td>Storage reservoir (i.e., injection zone)</td><td>342</td><td>5818</td><td>280</td><td>5244</td><td>Sandstone, Dolostone, Anhydrite, Siltstone</td></tr>
<tr><td>Amsden</td><td>Lower confining zone</td><td>261</td><td>6160</td><td>257</td><td>5524</td><td>Dolostone, Sandstone, Anhydrite</td></tr>
</table>
<p>* Measured depth.
** True vertical depth.</p>
</td>
<td>
<p>locations and the TB Leingang in relation to the city of Beulah, North Dakota.. (p. 2-2)</p>
<p>Figure 2-2. Stratigraphic column identifying the storage reservoir and confining zones (outlined in red) and the lowest USDW (outlined in blue). The Minnekahta Formation occurs at the stratigraphic test and reservoir-monitoring well location (Milton Flemmer 1) but pinches out within the simulation model area shown in Figure 2-3. (p. 2-3)</p>
<p>Table 2-1. Formations Comprising the TB Leingang Storage Complex (simulation model values calculated from model extent shown in Figure 2-3) (p. 2-4)</p>
</td>
</tr>
</table>

Subject	N.D.C.C./N.D.A.C. 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)
	N.D.A.C. § 43-05-01-05(1)(b)(2)(k)	**N.D.A.C. § 43-05-01-05(1)(b)(2)** (k) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	b. Data on the injection zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs: Depth Areal extent Thickness Mineralogy Porosity Permeability Capillary pressure Facies changes	SOURCE OF DATA **2.2 Data and Information Sources (p. 2-4)** Several sets of data were used to characterize the injection and confining zones to establish their suitability for the storage and containment of injected CO_2. Data sets used for characterization included both existing data (e.g., from published literature, publicly available databases, purchased/leased digital well logs, existing 3D and 2D seismic) and site-specific data acquired specifically to characterize the storage complex. ***2.2.1 Existing Data* (p. 2-4)** Well log data and interpreted formation top depths from 115 wellbores within the 4070-mi^2 (74-mi × 55-mi) area covered by the geologic model were used to characterize the depth, thickness, and extent of the subsurface geologic formations (Figure 2-3). Seismic interpretation products (seismic horizons and acoustic impedance volumes) from legacy 3D seismic data and 2D seismic data shown in Figure 2-3 were used to support generation of the 3D geologic model. In addition to data from Milton Flemmer 1, existing laboratory measurements for core samples from the Broom Creek Formation and its confining zones were available from nine additional wells: ANG 1 (ND-UIC-101), Flemmer 1 (NDIC File No. 34243), BNI 1 (NDIC File No. 34244), J-LOC 1 (NDIC File 37380), Liberty 1 (NDIC File No. 37672), MAG 1 (NDIC File No. 37833), Coteau 1 (NDIC File No. 38379), Archie Erickson 2 (NDIC File No. 38622), and Slash Lazy H 5 (NDIC File No. 38701) (Figure 2-4). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and were integrated with newly acquired site-specific data. ***2.2.2 Site-Specific Data*** (p. 2-6) Site-specific efforts to characterize the storage complex generated multiple data sets, including geophysical well logs, petrophysical data, fluid analyses, whole core, and 3D seismic data. Milton Flemmer 1 was drilled to a depth of 12,009 ft in 2022, specifically to gather subsurface geologic data to support the development of this CO_2 storage facility permit (SFP) application and serve as a future CO_2 reservoir-monitoring well. Downhole logs were acquired, and cores were collected from the associated storage complex (Opeche/Spearfish, Broom Creek, and Amsden Formations). Broom Creek Formation stress tests, a fluid sample, and temperature and pressure measurements were collected in the Milton Flemmer 1 (Figure 2-5). 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 3.0), numerical simulations of CO_2 injection (Section 3.0), geochemical simulation (Appendix C), and geomechanical information (Section 2.4). The site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency for monitoring data collection, 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. DATA ON THE INJECTION ZONE: **2.3 Storage Reservoir (injection zone)** (p. 2-16) The Broom Creek Formation is laterally extensive across the simulation model area and surrounding region (Figure 2-9). The Broom Creek Formation comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone layers (impermeable layers) with minor amounts of siltstone and anhydrite layers. The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by the Opeche/Spearfish Formation (Figure 2-2) (Murphy and others, 2009). The top of the Broom Creek Formation is located at a depth of 5818 ft below KB elevation at Milton Flemmer 1, and the cored interval is made up of 240 ft of sandstone, 81 ft of dolostone, and 21 ft of anhydrite. The thickness of the Broom Creek Formation at Milton Flemmer 1 is 342 ft. Cored wells within the extent of the simulation model show minor anhydrite and siltstone intervals are also present in the Broom Creek Formation. Across the simulation model area, the Broom Creek Formation ranges in thickness from 139 to 492 ft (Figure 2-10a, 2-10b), with an average thickness of 280 ft based on offset-well data and geologic model characteristics. The net sandstone thickness within the simulation model area ranges from 6 to 397 ft, with an average thickness of 140 ft. The top of the Broom Creek Formation was picked 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 Opeche/Spearfish Formation (Figure 2-11). This transition is also noted with a drop in bulk density (RHOB) and dipole sonic compressional slowness values (DTC) and an increase in NEUT and resistivity (RES_D, RES_S). The bottom of the Broom Creek Formation was placed at the base of a relatively low GR package representing a 10-ft package of anhydrite that can be correlated across much of the study area. This rock package	**Figure 2-3**. Map showing the extent of the regional geologic model, distribution of well control points, 2D and 3D seismic, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones. (p. 2-5) **Figure 2-4.** Map showing the spatial relationship between the TB Leingang and ten wells where core samples were collected from the formations comprising the storage complex. (p. 2-6) **Figure 2-9.** Broom Creek Formation in North Dakota. The area within the green dashed line shows the extent originally proposed by Rygh (1990), and the area outside of the green dashed line has been modified based on new well control. (p. 2-16) **Figure 2-10a**. Isopach map of the Broom Creek Formation in the simulation model area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map (thickness of the Broom Creek Formation at Milton Flemmer 1 is 342 ft, see Table 2-6). (p. 2-17)

<table>
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(Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>divides the clean sandstones and dolostone lithologies of the Broom Creek Formation from the dolostone and anhydrite of the Amsden Formation. Seismic data collected as part of site characterization efforts (Figure 2-8) were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and seismic interpretation indicate that the formation is continuous across the area near Milton Flemmer 1 (Figures 2-12 and 2-13). A structure map of the Broom Creek Formation shows no detectable features with associated spill points in the simulation model area (Figures 2-14 and 2-15).

Thirty-two (32) 1-in.-diameter 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 2-6, Figure 2-16). The range in porosity and permeability predominantly captured the sandstone variability as this rock type was prominent in the sampling program over the dolostone.

Core-derived measurements from Milton Flemmer 1 were used as the foundation for the generation of porosity and permeability properties within the 3D geologic model. The 1-in.-diameter core plug sample measurements showed good agreement with the geologic model property distribution at the location of Milton Flemmer 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 geologic model property distribution statistics shown in Table 2-6 are derived from a combination of the 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 because of brine salinity, and high sonic slowness measurements (Figure 2-11). 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 begins to increase in a transition from predominantly sandstone to dolostone (Figure 2-16).

<i>2.3.1 Mineralogy</i> (p. 2-26)
Powder XRD for average bulk composition analysis of 36 finely ground, homogenized samples from the Broom Creek Formation shows quartz as the most common mineral (~52%) followed by carbonates (~22%, primarily dolomite with minor contributions from ankerite and siderite), sulfates (~16%, mostly anhydrite with a minor amount of gypsum), feldspar (~6%, mostly K-feldspar), and clay minerals (~3%, mostly illite) (Figure 2-17a). Minor amounts of oxide/hydroxide (~0.3%), halide (~0.1%), and sulfide (~0.1%) make up the rest of the mineralogy. The major constituents of the Broom Creek Formation are shown in Table 2-7a. These results align with the average elemental composition obtained by XRF which shows silica (Si) as the dominant element followed by calcium (Ca), sulfur (S), magnesium (Mg), aluminum (Al), potassium (K), and other trace elements (Figure 2-17b).

XRF analysis of the Broom Creek Formation (Figure 2-17b) shows a high percentage of SiO_2 (0.4%–97%), CaO (0.1%–40%), and MgO (0%–21%) that confirms the presence of sandstone and dolomite intervals in the Broom Creek Formation. A high percentage of CaO and SO_3 at the top and the base of the formation indicates the presence of anhydrite layers that isolate the Broom Creek Formation from the Opeche/Spearfish Formation from the top and Amsden Formation from the bottom. The Broom Creek Formation consists of a clay content ranging from 0% to 24%, with illite being the dominant clay type.

Table 2-6. Description of CO_2 Storage Reservoir (injection zone) at Milton Flemmer 1
<table>
<tr><th colspan="2">Injection Zone Core Derived Properties</th></tr>
<tr><th>Property</th><th>Description</th></tr>
<tr><td>Formation Name</td><td>Broom Creek</td></tr>
<tr><td>Lithology</td><td>Sandstone, dolostone, anhydrite</td></tr>
<tr><td>Formation Top Depth (MD), ft</td><td>5818</td></tr>
<tr><td>Thickness, ft</td><td>342 (sandstone 240, dolostone 81, anhydrite 21)</td></tr>
</table></td><td>Figure 2-10b. Isopach map of the Broom Creek Formation focused around the three stratigraphic and reservoir-monitoring wells (thickness of the Broom Creek Formation at Milton Flemmer 1 is 342 ft, see Table 2-6). (p. 2-18)

Figure 2-11. Well log display of the interpreted facies of the Opeche/Spearfish, Broom Creek, and Amsden Formations in the Milton Flemmer 1. Tracks from left to right are
1) SSTVD; 2) GR (black) and caliper (dark blue); 3) MD; 4) resistivity – deep (red) and resistivity – shallow (light blue); 5) delta time (black), NEUT (blue), and density (green); and 6) facies.
(p. 2-19)

Figure 2-12. Regional well log stratigraphic cross sections of the upper confining zone and injection zone flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD,
4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. (p. 2-20)</td></tr>
</table>

<table>
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<tr><td></td><td></td><td></td><td></td><td>
<table>
<tr><td>Capillary Entry Pressure (brine/ CO_2), psi</td><td>1.12</td><td></td><td></td></tr>
<tr><td>Geologic Properties</td><td></td><td></td><td></td></tr>
<tr><th>Formation</th><th>Property</th><th>Laboratory Analysis</th><th>Simulation Model Property Distribution</th></tr>
<tr><td>Broom Creek (sandstone)</td><td>Porosity, % *</td><td>15.5
(0.3–26.1)</td><td>22.0
(0.0–35.3)</td></tr>
<tr><td></td><td>Permeability, mD**</td><td>674.71, 13.55
(0.00103–2700)</td><td>458.79, 136.96
(0.0–3401.2)</td></tr>
<tr><td>Broom Creek (dolostone)</td><td>Porosity, %*</td><td>6.1
(1.4–14.6)</td><td>4.4
(0.0–34.9)</td></tr>
<tr><td></td><td>Permeability, mD**</td><td>0.4107, 0.0147
(0.0005–3.34)</td><td>2.07, 0.0221
(0.0–919.6)</td></tr>
</table>
* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses. Values are measured at 2400 psi.
** Permeability values are reported as the arithmetic mean and geometric mean, respectively, followed by the range of values in parentheses and do not have the 2.5 permeability calibration factor applied during simulation. Values are measured at 2400 psi.

<i>Appendix C</i>
<i>C.1.1 Geochemical Information of Injection Zone (Broom Creek Formation)</i>(p. C-1)
Geochemical simulation was 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 GEM, the compositional simulation software package from Computer Modelling Group Ltd. (CMG). 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 bottomhole pressure (BHP) and maximum wellhead pressure (WHP) constraints of 3663 and 2100 psi, 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 anticipated average CO_2 stream composition is 98.25% CO_2, 1.44% N_2, and 0.31% O_2, with a trace amount of H_2S. The CO_2 stream, used for geochemical modeling, described in Table C-1, contains a higher amount of O_2 (2%). The modeled stream containing ~95% CO_2 and 2% O_2 was used to represent a conservative scenario where the oxygen concentration is highest, potentially triggering more geochemical reactions in the formation. This simulation scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figures C-1 and C-2).

The case with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (78% of bulk reservoir volume) and average formation brine composition (22% of bulk reservoir volume). X-ray diffraction (XRD) data from the Milton Flemmer 1 well core samples were used to inform the mineralogical composition of the Broom Creek Formation (Table C-2). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Ionic composition of the Broom Creek Formation water, derived from the state-certified analysis reported in Appendix A, is listed in Table C-3.
As seen in Figures C-1 and C-2, the results do not show an evident difference in the CO_2 gas molality fraction between both cases for volume injected and injection pressure simulation results. As a result of geochemical reactions in the reservoir, cumulative volume and injection
</td><td>Figure 2-13. Regional well log cross sections showing the structure of the Opeche/Spearfish and Broom Creek Formation logs. Displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) neutron porosity (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-21)

Figure 2-14. Structure map of the Broom Creek Formation in the simulation model referenced in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-22)

Figure 2-15. Cross section of the TB Leingang storage complex from the geologic model showing facies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. Geologic model extent is displayed by the blue box in the inset map in the upper-left corner. (p. 2-23)</td></tr>
</table>

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				rate have no observable difference between the geochemical and nongeochemical cases. The resulting BHP and WHP from the two cases are nearly identical, with no appreciable differences. Figure C-3 shows the location of the cross sections and Layer 30 used in Figures C-4a and C-4b to depict the geochemical modeling results. Figures C-4a and C-4b show the concentration of CO_2, in molality, in the reservoir after 20 years of injection plus 25 years of postinjection for the geochemistry model and nongeochemistry model, respectively. The pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure C-5a. The pH of the Broom Creek Formation native brine sample is 6.8, whereas the fluid pH declines to approximately 4.3 in the CO_2-flooded areas near the well as a result of CO_2 dissolution in the native formation brine (Figure C-5b). Figures C-6a and C-6b show the cross section for O_2 molality in the Broom Creek Formation. Figure C-6a shows the cross section for the concentration of O_2, in molality, in the reservoir after 20 years of injection plus 25 years postinjection for the geochemistry model scenario, and Figure C-6b shows the same information for the nongeochemistry simulation case for comparison. The results do not show an evident difference in the O_2 gas molality fraction between both cases. After being injected, the 2% molar oxygen content in the injection stream is dissolved in the brine and likely to cause oxidative reactions of the minerals, which may induce dissolution/precipitation of reactive minerals and formation of secondary minerals in the reservoir. The simulation results showed no significant precipitation caused by the high concentration of O_2 that would affect the CO_2 injection volume, as demonstrated by the comparison in injection rates between the case with and without geochemical modeling shown in Figure C-2. Figure C-7 shows the mass of mineral dissolution and precipitation due to CO_2 injection in the Broom Creek Formation. Dolomite is the most prominent dissolved mineral, while anhydrite is the most prominent precipitated mineral. All other minerals showed very limited variations. Simulation results show that, during CO_2 injection, the supercritical CO_2 (free-phase CO_2 gas) remains dominant. CO_2 dissolution in the formation water and residual trapping of CO_2 slowly increased over time, while CO_2 mineralization is negligible at the plot scale in Figure C-7 but can be observed at the plot scale in Figure C-8. Once CO_2 injection ceases in 2044, injected concentrated CO_2 begins to expand, resulting in more CO_2 that is capillary-trapped or dissolved into fresh brine, as evidenced by the crossover in Figure C-8. Figures C-9 and C-10, respectively, 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, anhydrite. Considering the apparent net dissolution of minerals in the system, as indicated in Figure C-7, there is an associated net increase in porosity in the affected areas, as shown in Figure C-11. Del Porosity Mineral (DPORMNR) output calculates the porosity change due to mineral dissolution/precipitation. It is calculated as Initial porosity – Porosity at time “t.” Negative values of this output indicate net mineral dissolution (porosity increase), while positive values indicate net mineral precipitation (porosity decrease). However, the porosity change is small, less than 0.01% porosity units, equating to a maximum increase in average porosity from 22.00% to 22.01% after the 20-year injection period plus 25 years postinjection.	**Table 2-6.** Description of CO_2 Storage Reservoir (injection zone) at the Milton Flemmer 1 (p. 2-24) **Figure 2-16.** Vertical distribution of core-derived porosity and permeability values in the TB Leingang storage complex from the Milton Flemmer 1. Tracks from left to right are 1) SSTVD; 2) GR (black) and caliper (dark blue); 3) MD; 4) delta time (black), neutron porosity (blue), and bulk density (green); 5) core porosity (2400 psi) and log porosity (light blue); 6) core permeability (2400 psi) and log permeability (black); 7) facies; and 8) upscaled facies (p. 2-25) **Figure 2-17a** Bar charts showing a) average mineralogy (wt%) and b) average elemental composition (wt%) of the Broom Creek Formation at Milton Flemmer 1 (note: elemental data by XRF were determined as oxides of the respective elements). (p. 2-26) **Table 2-7a**. XRD Analysis of the Broom Creek Formation at Milton Flemmer 1. Only major constituents are shown. (p. 2-27)

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					Figure 2-17b. Elemental composition by XRF as a function of depth in the Broom Creek Formation at Milton Flemmer 1. (p. 2-28) **Figure 2-18.** Change in the mineralogy of the target reservoir Broom Creek Formation (highlighted in gray) at Milton Flemmer 1 as a function of depth based on XRD in comparison to core sample total porosity (%) and permeability (mD). Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (i.e., samples too soft/brittle). (p. 2-29) **Figure 2-19**. Thin section (a, b) and SEM (c, d) micrographs of the most porous (a, c) and the least porous (b, d) samples from the Broom Creek Formation at Milton Flemmer 1. The most porous sample has a total porosity and permeability of 33% and >1000 mD, respectively, which notably reduced to 0.37% and 0.000891 mD in the least porous sample. The blue color in the thin sections (a and b) represents porosity. (p. 2-30) **Table C-1** CO_2 Stream Composition Used for Geochemical Modeling (p. C-1)

Subject	N.D.C.C./N.D.A.C. 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 C-1 Top graph shows cumulative injection vs. time; the bottom graph shows the gas injection rate vs. time. There is no observable difference in injection volume and gas rate due to geochemical reactions. (p. C-2) **Figure C-2** Top graph shows WHP vs. time; the bottom graph shows BHP vs. time. There is no observable difference in pressures due to geochemical reactions. (p. C-3) **Table C-2** Averaged XRD data for (Milton Flemmer 1) Broom Creek Core Sample (p. C-3) **Table C-3** Broom Creek Formation Water Ionic Composition (p. C-4) **Figure C-3** Index map of west-east and south-north cross sections and simulation Layer 30 at 3469 ft (SSTVD, subsea true vertical depth). (p. C-5) **Figure C-4a** CO_2 molality for the geochemistry case simulation results after 20 years of injection plus 25 years postinjection, showing the distribution of CO_2 molality in log scale. The top-left image is west-east, and the 1top-right image is a south-north cross section. The

Subject	N.D.C.C./N.D.A.C. 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)
					bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD). (p. C-6) **Figure C-4b** CO_2 molality for the nongeochemistry case simulation results after 20 years of injection plus 25 years postinjection, showing the distribution of CO_2 molality in log scale. The top-left image is west-east, and top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD). (p. C-7) **Figure C-5a** Geochemistry case simulation results after 20 years of injection plus 25 years postinjection showing the pH of formation brine in log scale. The top-left image is west-east, and top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD). (p. C-8) **Figure C-5b** Geochemistry case simulation results through 20 years of injection plus 25 years postinjection showing the pH of the Broom Creek Formation brine at the wellbore vs. time for Layer 30 at 3469 ft (SSTVD), Layer 44 at

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					3574.4 ft (SSTVD), and Layer 62 at 3710 ft (SSTVD). (p. C-9) **Figure C-6a** Cross section for O2 molality for the geochemistry case simulation results after 20 years of injection plus 25 years postinjection showing the distribution of O2 in gas phase in a log scale. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD). (p. C-10) **Figure C-6b** Cross section for O2 molality for the nongeochemistry case simulation results after 20 years of injection plus 25 years postinjection showing the distribution of O_2 in gas phase in a log scale. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD). (p. C-11) **Figure C-7** Modeled change in the mineral masses (minus values show dissolution and positive values show precipitation) due to CO_2 injection (top: all minerals; bottom: zoomed-in after removing anhydrite and

Subject	N.D.C.C./N.D.A.C. 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)
					dolomite). Dissolution of dolomite with precipitation of anhydrite was observed. All of the other minerals showed very small values and account as net zero in this figure. (p. C-13) **Figure C-8** Top image: mineral mass changes, in metric tons (tonnes), for the different CO2-trapping mechanisms present during CO_2 injection with geochemical modeling in the injection zone for the Broom Creek Formation; bottom image: CO_2 mineral trapping. (p. C-14) **Figure C-9** Modeled change in molar distribution of dolomite, the most prominent dissolved mineral after 20 years of injection plus 25-year postinjection period. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD). (p. C-15) **Figure C-10** Modeled change in molar distribution of anhydrite, the most prominent precipitated mineral after 20 years of injection plus 25-year postinjection period. The top-left image is west-

<table>
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<tr><td></td><td></td><td></td><td></td><td></td><td>east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD). (p. C-16)

Figure C-11 Modeled change in porosity due to net geochemical dissolution after 20 years of injection plus 25-year postinjection period. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3469 ft (SSTVD). (p. C-17)</td></tr>
<tr><td></td><td></td><td></td><td>c. Data on the confining zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:
Depth
Areal extent
Thickness
Mineralogy
Porosity
Permeability
Capillary pressure
Facies changes</td><td>SOURCE OF THE DATA:
<i>See discussion above under 2.2.1 Existing Data (p. 2-4)</i>

AND

2.4 Confining Zones (p. 2-31)
The confining zones for the Broom Creek Formation are the overlying Opeche/Spearfish Formation and the underlying Amsden Formation (Figure 2-2, Table 2-7b). Both the overlying and underlying confining formations consist primarily of impermeable rock layers.

Table 2-7b. Properties of Upper and Lower Confining Zones at Milton Flemmer 1
<table>
<tr><th>Confining Zone Properties</th><th>Upper Confining Zone</th><th>Lower Confining Zone</th></tr>
<tr><td>Stratigraphic Unit</td><td>Opeche/Spearfish</td><td>Amsden</td></tr>
<tr><td>Lithology</td><td>Siltstone/anhydrite/dolostone</td><td>Dolostone/anhydrite/sandstone</td></tr>
<tr><td>Formation Top Depth (MD), ft</td><td>5587</td><td>6160</td></tr>
<tr><td>Thickness, ft</td><td>231</td><td>261</td></tr>
<tr><td>Capillary Entry Pressure (brine/CO_2), psi</td><td>750.8</td><td>306.5</td></tr>
<tr><td>Depth below Lowest Identified USDW, ft</td><td>3788</td><td>4361</td></tr>
</table>
<table>
<tr><th>Formation</th><th>Property</th><th>Laboratory Analysis</th><th>Simulation Model Property Distribution</th></tr>
<tr><td>Opeche/Spearfish</td><td>Porosity, %*</td><td>5.2
(0.2–11.2)</td><td>2.1
(0.0–14.6)</td></tr>
</table></td><td>Table 2-7b. Properties of Upper and Lower Confining Zones at Milton Flemmer 1
(p. 2-32)

Figure 2-20. Structure map of the Opeche/Spearfish Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.
(p. 2-33)

Figure 2-21. Isopach map of the Opeche/Spearfish Formation in the simulation model area. A convergent</td></tr>
</table>

<table>
<tr><th>Subject</th><th>N.D.C.C./N.D.A.C. Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application (Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description (Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>
<table>
<tr><td></td><td>Permeability, mD **</td><td>0.009189, 0.001224 (0.0000439–0.0434)</td><td>0.1088, 0.0021 (0.00–6.37)</td></tr>
<tr><td>Amsden</td><td>Porosity, % *</td><td>9.2 (2.9–22.5)</td><td>2.9 (0.0–35.1)</td></tr>
<tr><td></td><td>Permeability, mD **</td><td>81.83, 0.028012 (0.000152–408)</td><td>0.7056, 0.0070 (0.00–156.05)</td></tr>
</table>

* Porosity values recorded at 2400-psi confining pressure. Porosity values from the model are reported as the arithmetic mean followed by the range of values in parentheses.

** Permeability values recorded at 2400-psi confining pressure. Permeability values are reported as the arithmetic mean and geometric mean, respectively, followed by the range of values in parentheses and do not have the 2.5 permeability calibration factor applied during simulation.

2.4.1 Upper Confining Zone (p. 2-32)

In TB Leingang, the upper confining zone, the Opeche/Spearfish Formation, consists of predominantly siltstone with interbedded dolostone and anhydrite (Table 2-7a). The upper confining zone is laterally extensive across the simulation model area (Figure 2-20) and is 5587 ft below KB elevation and 231 ft thick as observed in Milton Flemmer 1 (Figures 2-20 and 2-21). The contact between the underlying Broom Creek Formation 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 Opeche/Spearfish Formation (Figure 2-11).

2.4.1.1 Mineralogy of the Upper Confining Zone (p.2-35)

Powder XRD for average bulk composition analysis of eight finely ground, homogenized samples from the Opeche/Spearfish Formation shows quartz as the most common mineral (~29%) followed by carbonates (~25%, mostly dolomite with a minor contribution from ankerite), sulfates (~17%, mostly anhydrite), potassium- and sodium-feldspar (~7% each), and clay minerals (~15%, mostly illite and chlorite) (Figure 2-22a). Minor amounts of sulfide (~0.1%) and oxide/hydroxide (~0.1%) minerals make up the rest of the mineralogy. The major constituents of the Opeche/Spearfish Formation are also shown in Table 2-7c. XRD data align with the average elemental composition obtained by XRF which show silica (Si) as the dominant element followed by calcium (Ca), sulfur (S), aluminum (Al), magnesium (Mg), potassium (K), iron (Fe), and other trace elements (Figure 2-22b).

Appendix C

C.1.2 Geochemical Interaction of the Upper Confining Zone (Cap Rock, Opeche/Spearfish Formation) (p.C-18)

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected multicomponent CO_2 stream on the Opeche/Spearfish Formation. It should be noted that PHREEQC’s unit of measure is metric. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to the injection stream mixture at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Opeche/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 average mineralogical composition calculated from the XRD results of the two deepest samples from the Opeche/Spearfish Formation was honored (Table C-4). Formation brine composition was assumed to be the same as the known composition from the Broom Creek Formation injection zone below (Table C-5).

The anticipated average CO_2 stream composition is 98.25% CO_2, 1.44% N_2, and 0.31% O_2, with a trace amount of H_2S. The CO_2 stream used for geochemical modeling, described in Table C-1, contains a higher amount of O_2 (2%). The modeled stream containing ~95% CO_2 and 2% O_2, Table C-1, was used to represent a conservative scenario where the higher oxygen concentration may trigger more geochemical reactions in the formation. The exposure level, expressed in moles per year, of the CO_2 stream to the confining layer 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). Again, this conservative overestimation was done to ensure that the degree and pace of geochemical change would not be underestimated. This
</td><td>interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-34)

Figure 2-22a. Bar charts showing a) average mineralogy (wt%) and b) average elemental composition (wt%) of the Opeche/Spearfish Formation at Milton Flemmer 1 (note: elemental data by XRF were determined as oxides of the respective elements). (p. 2-35)

Table 2-7c. XRD Analysis of the Opeche/Spearfish Formation at Milton Flemmer 1. Only major constituents are shown. (p. 2-36)

Figure 2-22b. Elemental composition by XRF as a function of depth in the Opeche/Spearfish Formation at Milton Flemmer 1. (p. 2-36)

Figure 2-23. Thin section (a, b) and SEM (c, d) micrographs of the most porous (a, c) and the least porous (b, d) samples from the Opeche/Spearfish Formation at Milton Flemmer 1. The most porous sample has a total porosity and permeability of 11% and 0.0359 mD, respectively, which is notably reduced to 0.33% and 0.178 mD in the least porous sample.</td></tr>
</table>

Subject	N.D.C.C./N.D.A.C. 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)
				geochemical simulation was run for 45 years to represent 20 years of injection plus 25 years postinjection. The simulation was performed at elevated reservoir pressure and temperature conditions obtained from the dynamic reservoir simulation. Results showed geochemical processes at work. Figures C-12 through C-16 show results from geochemical modeling. Figure C-12 shows a change in fluid pH over time as CO_2 diffuses into the system. For the cell at the CO_2 interface, Cell 1 (C1), the pH starts declining from an initial pH of 6.47, decreasing to a level of 5.05 after 10 years of injection, and slowly stabilizes at 5.03 by the end of 25 years postinjection. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH begins to change after Year 8 and goes down to 5.45 by the end of simulation. For the cell occupying the space 2 to 3 meters into the cap rock, C3, the pH begins to change after Year 43. Figure C-13 shows the modeled change in mineral dissolution and precipitation in grams per cubic meter of rock for C1 and C2. In C1 and C2, K-feldspar starts to dissolve from the beginning of the simulation period, while illite and quartz start to precipitate at the same time. The net change due to precipitation or dissolution in C2 is less than 5 kg per cubic meter, with little dissolution or precipitation taking place during the later years of simulation. Any effects in C3 are too small to represent at this scale. Figure C-14 represents the initial fractions of potentially reactive minerals in the Opeche/Spearfish Formation based on XRD data shown in Table C-4. The expected dissolution of these minerals in weight percentage is also shown for C1 and C2 of the model. In C1 and C2, K-feldspar is the primary mineral that dissolves. Dissolution (%) in C2 is minimal (<0.2%) and not significant to represent at the scale in Figure C-14. Figure C-15 represents minerals expected to be precipitated in weight (%) shown for C1 and C2 of the model. In C1 and C2, illite, quartz, and calcite are the minerals to be precipitated. Figure C-16 shows the modeled change in porosity of the cap rock for C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.1% change during the life of the simulation. Initially, C1 experiences up to a 0.14% increase in porosity upon first CO_2 exposure because of dissolution and initial model equilibration, but the change is temporary. No significant porosity changes were observed for C2 and C3. These results suggest that geochemical change from exposure to CO_2 is minor; therefore, the ability of the Opeche/Spearfish Formation to maintain its sealing integrity will not be compromised by geochemical processes. **C1.3 Geochemical Interaction of the Lower Confining Zone (Amsden Formation) (p. C-24)** 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 seven cells, each cell 1 meter in thickness. The formation was exposed to CO_2 stream components at the top boundary of the simulation, and CO_2 was allowed to enter the system by advection and dispersion processes. Direct fluid flow into the Amsden 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 center of each cell below the confining layer–CO_2 exposure boundary. The average mineralogical composition calculated from the results of two samples from the Amsden Formation was honored (Table C-6). The formation brine composition was assumed to be the same as the known composition from the overlying Broom Creek Formation injection zone (Table C-5). A CO_2 stream containing ~95% CO_2 and 2% O_2, described in Table C-1, was used in the geochemical modeling to represent a conservative scenario, where higher oxygen concentration may trigger more geochemical reactions in the formation. The maximum formation temperature and pressure, projected from CMG simulation results, described in Section 3.0, were used to represent the potential maximum pore pressure and temperature level. The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change. This simulation was run for 45 years to represent 20 years of injection plus 25 years postinjection. Modeling results show geochemical processes at work. Figures C-17 through C-22 show results from the geochemical modeling. Figure C-17 shows change in fluid pH over 45 years (representing 20 years of injection and 25 years postinjection) as CO_2 enters the system. Initial change in pH in all of the cells, for C1 to C7, is related to initial equilibration of the model. For the cell at the CO_2 interface, C1, the pH declines to a level of 5.7 after 7 years of injection, further declining to 4.8 by the end of the modeled injection period, and hits 4.5 by the end of simulation period. Progressively lower or slower pH changes occur for each cell that is more distant from the CO_2 interface. The pH for C7 did not decline over the 45 years of simulation time. Figure C-18 shows that CO_2 does not penetrate more than 6 meters (represented by C7) over the 20 years of injection and 25 years postinjection.	The blue color in the thin sections (a and b) represents porosity. (p. 2-37) **Figure 2-24.** A figure showing a change in the mineralogy of the upper-confining Opeche/Spearfish Formation (highlighted in gray) at Milton Flemmer 1 as a function of depth based on XRD in comparison to core sample total porosity (%) and permeability (mD). Very low total porosity and permeability with a high clay content make the Opeche/Spearfish Formation an ultralow permeable formation. Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (i.e., samples too soft/brittle). (p. 2-38) **Table C-4** Averaged Mineral Composition of the Opeche/Spearfish Derived from XRD Analysis of Milton Flemmer 1 Core Samples at Depths of 5824.8 and 5819.5 ft MD (p. C-18) **Table C-5** Formation Water Chemistry from Broom Creek Formation Fluid Sample from Milton Flemmer 1 (p. C-19) **Figure C-12** Modeled change in fluid pH vs. time. Red line shows pH

<table>
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<tr><td></td><td></td><td></td><td></td><td>Figure C-19 shows the modeled changes in mineral dissolution and precipitation in grams per cubic meter over 45 years of simulation time. For C1, albite and K-feldspar start to dissolve from the beginning of the simulation period, while quartz and illite start to precipitate. Anhydrite and hematite, the secondary minerals, precipitate in minor amounts. C2 shows the same trends, but the process begins approximately 6 years after Cell C1.

Figure C-20 represents the initial fractions of potentially reactive minerals in the Amsden Formation based on the XRD data in Table C-6. The expected dissolution of the minerals in weight percentage is also shown for C1 and C2 of the model. In C1 and C2, albite and K-feldspar are the primary minerals that dissolve, and their initial fractions have almost completely dissolved. No dissolution is observed for illite and quartz. The minerals that experience dissolution in the model are almost completely replaced by the precipitation of other minerals.

Figure C-21 represents this replacement, with the minerals expected to be precipitated in weight percentage (wt%) shown for C1 and C2 of the model. In C1 and C2, illite and quartz are the key primary minerals expected to be precipitated. Anhydrite and hematite precipitate as secondary minerals in C1 and calcite in C2.

The modeled change in porosity (% units) of the Amsden Formation underlying confining layer is displayed in Figure C-22 for C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 2% change during the life of the simulation. C1 shows an initial porosity increase, but this change is temporary, and the cell returns to its near-initial porosity after Year 18. For C2 and C3, a cyclic pattern of porosity increase and subsequent decrease with low amplitude is observed. No significant porosity changes were observed in C2–C3 after 20 years of modeled injection. Cells C4–C7 showed similar results, with porosity change being less than 0.1% at each time step (not shown in Figure C-22).

2.4.2 Additional Overlying Confining Zones (p. 2-39)
Several other formations provide additional confinement above the Opeche/Spearfish Formation. Impermeable rocks above the primary seal include the Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-8a). At Milton Flemmer 1, together with the Opeche/Spearfish Formation, these intervals are 1082 ft thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-25). Above the Inyan Kara Formation, 2670 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and the lowermost USDW, the Fox Hills Formation (Figure 2-26). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-8a).
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 stratigraphically 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 distributed temperature sensor data for the Inyan Kara Formation using the downhole fiber-optic cable provides an additional opportunity for mitigation and remediation (Section 5.0). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at the Milton Flemmer 1 location is approximately 4469 ft below KB elevation, and the interval itself is 267 ft thick.

Table 2-8. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on Milton Flemmer 1)
<table>
<tr><th>Name of Formation</th><th>Lithology</th><th>Formation Top Depth MD, ft</th><th>Thickness, ft</th><th>Depth below Lowest Identified USDW, ft</th></tr>
<tr><td>Pierre</td><td>Mudstone</td><td>1799</td><td>1480</td><td>0</td></tr>
<tr><td>Niobrara</td><td>Mudstone</td><td>3279</td><td>418</td><td>1480</td></tr>
<tr><td>Carlile</td><td>Mudstone</td><td>3697</td><td>49</td><td>1898</td></tr>
<tr><td>Greenhorn</td><td>Mudstone</td><td>3746</td><td>116</td><td>1947</td></tr>
</table></td><td>for the center of C1, 0.5 meters above the Opeche/Spearfish Formation cap rock base. Yellow line shows C2, 1.5 meters above the cap rock base. Green line shows C3, 2.5 meters above the cap rock base. (p. C-20)

Figure C-13 Modeled dissolution and precipitation of minerals in the Opeche/Spearfish Formation cap rock. Dashed lines show results calculated for C1, 0.5 meters above the cap rock base. Solid lines show results for C2, 1.5 meters above the cap rock base, and these changes are smaller compared to the changes observed for C1. Results from C3, 2.5 meters above the cap rock base, are not shown because they are less than the dissolution and precipitation occurring in C2. (p. C-21)

Figure C-14 Weight percentage (wt%) of potentially reactive minerals present in the Opeche/Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in C1 (orange) and C2 (gray, too small to see in the figure) after 20 years of injection plus 25 years of postinjection. Negative values represent total wt%</td></tr>
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<tr><td></td><td></td><td></td><td></td><td>
<table>
<tr><td>Belle Fourche</td><td>Mudstone</td><td>3862</td><td>291</td><td>2063</td></tr>
<tr><td>Mowry</td><td>Mudstone</td><td>4153</td><td>75</td><td>2354</td></tr>
<tr><td>Skull Creek</td><td>Mudstone</td><td>4231</td><td>238</td><td>2432</td></tr>
<tr><td>Swift</td><td>Mudstone</td><td>4736</td><td>458</td><td>2937</td></tr>
<tr><td>Rierdon</td><td>Mudstone</td><td>5193</td><td>196</td><td>3394</td></tr>
<tr><td>Piper (Kline Member)</td><td>Carbonate</td><td>5389</td><td>94</td><td>3590</td></tr>
<tr><td>Piper (Picard Member)</td><td>Mudstone</td><td>5483</td><td>104</td><td>3684</td></tr>
</table>

<i>2.4.3 Lower Confining Zones</i> (p. 2-42)
The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone and anhydrite. The Amsden Formation does include some thin sandstone intervals on the order of 1 to 8 in. thick. The sandstone intervals in the Amsden Formation are isolated from the sandstones of the Broom Creek Formation by thick impermeable dolostone and anhydrite intervals. 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 simulation model area (Figure 2-11). The Amsden Formation is 6160 ft below KB elevation and 261 ft thick at TB Leingang as determined at Milton Flemmer 1 (Figures 2-27 and 2-28).

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 (Figure 2-11). The top of the Amsden in Milton Flemmer 1 is picked at the base of a 10-ft anhydrite bed which can be correlated across much of the study area. This lithologic change is also recognized in the core from Milton Flemmer 1. The lithology of the cored section of the Amsden Formation from Milton Flemmer 1 is predominantly dolostone and anhydrite, with lesser predominant lithologies of sandstone.

<i>2.4.3.1 Mineralogy of the Lower Confining Zone</i> (p. 2-44)
Powder XRD for average bulk composition analysis of six finely ground, homogenized samples from the Amsden Formation shows equal proportions of quartz (~34%) and carbonates (~33%, mostly dolomite with minor contributions from calcite and ankerite) followed by sulfate (~17%, mostly anhydrite) (Figure 2-29a[a]). Feldspar (mostly K-feldspar) and clay minerals (mostly illite) each account for about 7% of the composition of the Amsden Formation with minor amounts of halide (~0.1%), oxide/hydroxide (~0.1%), and sulfide (~0.2%). The major constituents of the Amsden Formation are also shown in Table 2-8b. These data align with the average elemental composition obtained by XRF which show Si as the dominant element followed by calcium (Ca), sulfur (S), magnesium, (Mg), aluminum (Al), potassium (K), iron (Fe), and other trace elements (Figure 2-29a[b]).

XRF analysis of the Amsden Formation (Figure 2-29b) shows that the contact between the Amsden and Broom Creek Formations is dominated by CaO and MgO, indicating the presence of dolomite. As the formation gets deeper, the chemistry changes to more anhydrite-rich, fine to medium-grained sandstones, as shown by the high percentage of SiO_2, CaO, and SO_3. The Amsden Formation contains clay up to 20% with illite being the dominant clay type.

Similar to the Opeche/Spearfish Formation, the higher content of anhydrite (~17%) and clay minerals (~7%) makes the Amsden Formation less porous and more impermeable compared to the target Broom Creek Formation. The thin-section and SEM–EDS micrographs of the most porous sample at the cored depth of 6215.2 ft (6208.2 ft KB elevation) show moderately sorted, fine-grained subangular quartz and feldspar grains with anhydrite cement (Figures 2-30a and c).

The least porous sample, located at the bottom of the section at the core depth of 6219.9 ft (6212.9 ft KB elevation), predominantly consists of anhydrite (~97%) with microfractures (Figures 2-30b and d). Figure 2-31 shows changes in the mineralogy at the Milton Flemmer 1 well as a function of depth next to the core sample porosity and permeability data. The Amsden Formation is highlighted in gray. Although a total porosity of 22% with a permeability of 419 mD was observed at the core depth of 6215.2 ft (6208.2 ft KB elevation), it must be noted that this layer is isolated and confined between ultralow permeable layers (a clay-rich quartz dolomite layer above and an anhydrite-rich layer below).
</td><td>associated with dissolution. (p. C-22)

Figure C-15 Weight percentage (wt%) of initial (blue) and precipitated (orange) minerals of the Opeche/Spearfish Formation in the C1 and C2 normalized based on total solid (initial – dissolution + precipitation) present in the C1 and C2 after 20 years of injection and 25 years of postinjection. Secondary minerals, barite and hematite, precipitated in C1 and C2, are too small (< 10-4%) to be seen in the figure. (p. C-23)

Figure C-16 Modeled change in percent porosity of the Opeche/Spearfish Formation cap rock. Red line shows porosity change calculated for C1, 0.5 meters above the cap rock base. Yellow line shows C2, 1.5 meters above the cap rock base. Green line shows 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. C-24)

Table C-6 Averaged Mineral Composition of the Amsden Formation Derived from XRD
</td></tr>
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					Analysis of Milton Flemmer 1 Core Samples at Depths of 6169 and 6177 ft MD (p. C-25) **Figure C-17** Modeled change in fluid pH for C1–C7 in the Amsden Formation underlying confining layer. (p. C-26) **Figure C-18** Modeled CO_2 concentration (molality) for C1–C7 in the Amsden Formation underlying confining layer. (p. C-26) **Figure C-19** Modeled dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for C1, 0 to 1 meter below the Amsden Formation top. Solid lines show results for C2, 1 to 2 meters below the Amsden Formation top. Dotted lines show results for C6, 5 to 6 meters below the Amsden Formation top. C6 shows minimal dissolution and precipitation at the end of 25 years of postinjection because of smaller amount of CO_2 penetration in C6 by the end of 45 years of simulation. (p. C-27) **Figure C-20** Weight percentage (wt%) of potentially reactive

Subject	N.D.C.C./N.D.A.C. 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)
					minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in C1 (orange) and C2 (gray) after 20 years of injection plus 25 years of postinjection. Negative values represent total wt% associated with dissolution. (p. C-28) **Figure C-21** Weight percentage (wt%) of initial (blue) and precipitated (orange) minerals of Amsden Formation in the C1 and C2 normalized based on total solid (initial – dissolution + precipitation) present in the C1 and C2 after 20 years of injection and 25 years of postinjection. Very little hematite and anhydrite precipitation is observed in C1. Hematite precipitation in C2 is too small to be seen in the figure. (p. C-29) **Figure C-22** Modeled change in percent porosity in the Amsden Formation underlying confining layer. Red line shows porosity change for C1, 0 to 1 meter below the Amsden Formation top. Orange line shows C2, 1 to 2 meters below the Amsden Formation top. Green line shows C3, 2 to 3 meters below

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					the Amsden Formation 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. (p. C-30) **Table 2-8a.** Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on Milton Flemmer 1) (p. 2-39) **Figure 2-25.** 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, 3D seismic, and 2D seismic in creation of this map. (p. 2-40) **Figure 2-26**. 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, 3D seismic, and 2D seismic in creation of this map. (p. 2-41) **Figure 2-27**. Structure map of the Amsden

Subject	N.D.C.C./N.D.A.C. 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)
					Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-42) **Figure 2-28.** Isopach map of the Amsden Formation across the simulation model area. The convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-43). **Figure 2-29a.** Bar charts showing a) average mineralogy (wt%) and b) average elemental composition (wt%) of the Amsden Formation at the Milton Flemmer 1 well. Elemental data by XRF were determined as oxides of the respective elements. (p. 2-44) **Table 2-8b.** XRD Analysis of the Amsden Formation at Milton Flemmer 1. Only major constituents are shown. (p. 2-45) **Figure 2-29a.** Bar charts showing a) average mineralogy (wt%) and b) average elemental composition (wt%) of the Amsden Formation at the Milton Flemmer 1 well. Elemental data by XRF were determined as oxides of

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					the respective elements. (p. 2-44) **Figure 2-29b.** Elemental composition by XRF as a function of depth in the Amsden Formation at Milton Flemmer 1. (p. 2-45) **Figure 2-30.** Thin section (a, b) and SEM (c, d) micrographs of the most porous portion (a, c) and the least porous (b, d) samples of the Amsden Formation at Milton Flemmer 1 well. The most porous sample of the Amsden Formation has a total porosity and permeability of 22% and 419 mD, respectively, which is notably reduced to 0.26% and 0.0008 mD in the least porous sample. The blue color in the thin sections (a and b) represents porosity. (p. 2-46) **Figure 2-31.** A figure showing a change in the mineralogy of the lower confining Amsden Formation (highlighted in gray) at the Milton Flemmer 1 well as a function of depth based on XRD in comparison to core sample total porosity (%) and permeability (mD). Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (samples too soft/brittle). (p. 2-47)
	N.D.A.C. § 43-05-01-05(1)(b)(2)	**N.D.A.C. § 43-05-01-05(1)(b)**	d. A description of the storage reservoir's mechanisms of	***2.2.2.3 Formation Temperature and Pressure*** (p. 2-9)	**Table 2-2b.** Description of Milton Flemmer 1

<table>
<tr><th>Subject</th><th>N.D.C.C./N.D.A.C. Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description (Page Number)</th></tr>
<tr><td></td><td></td><td>(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</td><td>geologic confinement characteristics with regard to preventing migration of carbon dioxide beyond the proposed storage reservoir, including:
Rock properties
Regional pressure gradients
Adsorption processes</td><td>
<p>Temperature measurements from Milton Flemmer 1 were used to derive a temperature gradient for the proposed injection site (Table 2-2b). In combination with depth, the temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for geochemical modeling.</p>
<p>Formation pressure testing at Milton Flemmer 1 was performed with the SLB (formerly Schlumberger) MDT (modular formation dynamics tester) tool. The MDT tool's formation pressure measurements from the Broom Creek Formation are included in Table 2-3. The calculated pressure gradients were used to model formation pressure profiles for use in the numerical simulations of CO_2 injection.</p>
<p>Table 2-2b. Description of Milton Flemmer 1 Temperature Measurements and Calculated Temperature Gradients</p>
<table>
<tr><th>Formation</th><th>Sensor Depth MD, ft</th><th>Sensor Depth TVD, ft</th><th>Temperature, °F</th></tr>
<tr><td>Opeche/Spearfish</td><td>5771.02</td><td>5770.82</td><td>–*</td></tr>
<tr><td>Broom Creek</td><td>5860.03</td><td>5859.81</td><td>132.7</td></tr>
<tr><td></td><td>5882.02</td><td>5881.80</td><td>134.7</td></tr>
<tr><td></td><td>5890.08</td><td>5889.86</td><td>136.2</td></tr>
<tr><td></td><td>5950.02</td><td>5949.79</td><td>137.9</td></tr>
<tr><td></td><td>5974.04</td><td>5973.81</td><td>139.4</td></tr>
<tr><td></td><td>5990.06</td><td>5989.83</td><td>140.4</td></tr>
<tr><td></td><td>6014.00</td><td>6013.77</td><td>141.2</td></tr>
<tr><td></td><td>6020.00</td><td>6019.77</td><td>141.9</td></tr>
<tr><td></td><td>6031.02</td><td>6030.78</td><td>142.6</td></tr>
<tr><td>Mean Broom Creek Temperature, °F</td><td></td><td></td><td>138.56</td></tr>
<tr><td>Broom Creek Temperature Gradient, °F/ft</td><td></td><td></td><td>0.017**</td></tr>
</table>
<p>* Dry test. Temperature measurement is unreliable because it was impacted by tool temperature rather than fluid.
** The temperature gradient is an average of the measured temperature minus the average annual surface temperature (40°F), divided by the associated test depth.</p>
<p>Table 2-3. Description of Milton Flemmer 1 Formation Pressure Measurements and Calculated Pressure Gradients</p>
<table>
<tr><th>Formation</th><th>Sensor Depth MD, ft</th><th>Sensor Depth TVD, ft</th><th>Sensor Formation Pressure, psia</th></tr>
<tr><td>Opeche/Spearfish</td><td>5771.02</td><td>5770.82</td><td>–*</td></tr>
<tr><td>Broom Creek</td><td>5860.03</td><td>5859.81</td><td>2743.45</td></tr>
<tr><td></td><td>5882.02</td><td>5881.80</td><td>2753.45</td></tr>
<tr><td></td><td>5890.08</td><td>5889.86</td><td>2757.04</td></tr>
<tr><td></td><td>5950.02</td><td>5949.79</td><td>2784.61</td></tr>
<tr><td></td><td>5974.04</td><td>5973.81</td><td>2795.56</td></tr>
<tr><td></td><td>5990.06</td><td>5989.83</td><td>2802.94</td></tr>
<tr><td></td><td>6014.00</td><td>6013.77</td><td>2814.05</td></tr>
<tr><td></td><td>6020.00</td><td>6019.77</td><td>2816.57</td></tr>
<tr><td></td><td>6031.02</td><td>6030.78</td><td>2821.66</td></tr>
<tr><td>Mean Broom Creek Pressure, psi</td><td></td><td></td><td>2787.70</td></tr>
<tr><td>Broom Creek Pressure Gradient, psi/ft</td><td></td><td></td><td>0.466**</td></tr>
</table>
</td><td>Temperature Measurements and Calculated Temperature Gradients (p. 2-9)

Table 2-3. Description of Milton Flemmer 1 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-10)</td></tr>
</table>

Subject	N.D.C.C./N.D.A.C. 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)
		maps showing the following:		* Dry test. No fluid was withdrawn because of low permeability. ** 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. 2-31) For TB Leingang, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the upper confining formation (Opeche/Spearfish Formation), which will contain the initially buoyant CO_2 in the reservoir 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.	
	N.D.A.C. § 43-05-01-05(1)(b)(2)(g)	**N.D.A.C. § 43-05-01-05(1)(b)(2)** (g) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir;	e. Identification of all characteristics controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir, including: Structural spill points Stratigraphic discontinuities	*2.2.2.6 Seismic Survey* (p. 2-14) A 208-square-mile 3D seismic survey was conducted from November 2021 to February 2022 south of Beulah, North Dakota (Figure 2-8). The Beulah 3D seismic data provided visualization of deep geologic formations at lateral-spatial intervals as short as 82.5 ft. Additionally, seismic data from nearby 3D surveys to the east, namely, the Center 3D and Minnkota 3D, and a connecting 2D line were used to interpret and evaluate the subsurface (Figure 2-8). The seismic data were used for assessment of the geologic structure and reservoir properties. Data products generated from the interpretation of the Beulah 3D were used as inputs for the geologic model that was used to simulate migration of the CO_2 plume. The Beulah 3D seismic data and the Milton Flemmer 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 Archie Erickson 2, Milton Flemmer 1, and Slash Lazy H 5 dipole sonic logs. The depth-converted surfaces for the storage reservoir and upper and lower confining zones were used as inputs for the geologic model. Detailed information about the structure and varying thickness of the formations away from well control was derived from these surfaces. A prestack seismic inversion was generated from the 3D seismic data and well logs from the Milton Flemmer 1, Archie Erickson 2, and Slash Lazy H 5 stratigraphic test wells. Depth-converted surfaces and poststack seismic inversion results from the Center 3D and Minnkota 3D were also used as inputs for the geologic model. Interpretation of the 3D seismic data suggests there are no major stratigraphic pinch-outs or structural features with associated spill points (e.g., folds, domes, or fault traps) in TB Leingang. 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 3D seismic data in the TB Leingang. ***2.3.2 Mechanism of Geologic Confinement*** (p. 2-31) *See discussion above under 2.3.2 Mechanism of Geologic Confinement*	**Figure 2-8.** Map showing the 2D and 3D seismic surveys used to characterize the TB Leingang and inform the construction of the geologic model. The 3D seismic surveys from west to east are the Beulah 3D, Center 3D, and Minnkota 3D. (p. 2-15) **Figure 2-12.** Regional well log stratigraphic cross sections of the Opeche/Spearfish and Broom Creek Formations flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) neutron porosity (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-20) **Figure 2-13.** Regional well log cross sections

Subject	N.D.C.C./N.D.A.C. 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)
					showing the structure of the Opeche/Spearfish and Broom Creek Formation logs. Displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) neutron porosity (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-21) **Figure 2-14.** Structure map of the Broom Creek Formation in the simulation model referenced in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-22) **Figure 2-15**. Cross section of the TB Leingang storage complex from the geologic model showing facies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. Geologic model extent is displayed by the blue box in the inset map in the upper-left corner. (p.2-23)
	N.D.A.C. § 43-05-01-05(1)(b)(2)(c)	**N.D.A.C. § 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. 2-62) This section discusses local and regional faults, including a regional structural feature, the Stanton Fault, and interpreted basement fault. In the area of review (AOR), none of these known or suspected faults or fractures has sufficient permeability and vertical extent to allow fluid movement out of the storage reservoir. The absence of transmissive faults is supported by fluid sample analysis results from Milton Flemmer 1	**Figure 2-44.** Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from

<table>
<tr><th>Subject</th><th>N.D.C.C./N.D.A.C. Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description (Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>that suggest the injection interval, the Broom Creek Formation (105,000 mg/L), is isolated from the next permeable interval, the Inyan Kara Formation (3560 mg/L) (Appendix A).

This section also discusses the seismic history of North Dakota and the low probability that seismic activity will interfere with containment.</td><td>Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-12.
(p. 2-69)</td></tr>
<tr><td></td><td>N.D.A.C. § 43-05-01-05(1)(b)(2)(j)</td><td>N.D.A.C. § 43-05-01-05(1)(b)(2)
(j) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone in the area of review, and a determination that they would not interfere with containment;</td><td>g. Properties of known or suspected faults and fractures that may transect the confining zone in the area of review:
Location
Orientation
Determination of the probability that they would interfere with containment</td><td><i>See discussion above under 2.5 Faults, Fractures, and Seismic Activity (p. 2-62)</i></td><td>Figure 2-44. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-12.
(p. 2-69)</td></tr>
<tr><td></td><td>N.D.A.C. §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(m)</td><td>N.D.A.C. § 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,</td><td>h. Information on any regional tectonic activity, and the seismic history, including:
The presence and depth of seismic sources;
Determination of the probability that seismicity would interfere with containment;</td><td><i>2.5.4 Seismic Activity</i> (p. 2-67)
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 2-12) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight Precambrian basement faults interpreted by Anderson (2016) in the North Dakota portion of the Williston Basin (Figure 2-44). The earthquake recorded closest to the project area occurred in 1927, located 19.15 miles southwest of the TB Leingang 1 injection well, near Hebron, North Dakota (Table 2-12). The magnitude of this earthquake is estimated to have been 3.2.

Table 2-12. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)
<table>
<tr><th>Map Label</th><th>Date</th><th>Magnitude</th><th>Depth, miles</th><th>Longitude</th><th>Latitude</th><th>City or Vicinity of Earthquake</th><th>Distance to TB Leingang 1 well, miles</th></tr>
<tr><td>A</td><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>109.59</td></tr>
<tr><td>B</td><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>126.30</td></tr>
<tr><td>C</td><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>123.40</td></tr>
<tr><td>D</td><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>50.89</td></tr>
<tr><td>E</td><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>137.75</td></tr>
<tr><td>F</td><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>86.76</td></tr>
<tr><td>G</td><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>149.33</td></tr>
<tr><td>H</td><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>147.41</td></tr>
<tr><td>I</td><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>56.63</td></tr>
<tr><td>J</td><td>May 13, 1947</td><td>3.7**</td><td>U***</td><td>−100.90</td><td>46.00</td><td>Selfridge</td><td>81.94</td></tr>
<tr><td>K</td><td>Oct. 26, 1946</td><td>3.7**</td><td>U</td><td>−103.70</td><td>48.20</td><td>Williston</td><td>121.84</td></tr>
<tr><td>L</td><td>April 29, 1927</td><td>3.2**</td><td>U</td><td>−102.10</td><td>46.90</td><td>Hebron</td><td>19.15</td></tr>
<tr><td>M</td><td>Aug. 8, 1915</td><td>3.7**</td><td>U</td><td>−103.60</td><td>48.20</td><td>Williston</td><td>118.35</td></tr>
</table>
</td><td>Table 2-12. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016)
(p. 2-68)

Figure 2-44. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-12.
(p. 2-69)

Figure 2-45. 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.. (p. 2-70)</td></tr>
</table>

Subject	N.D.C.C./N.D.A.C. 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)
		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: **N.D.A.C. § 43-05-01-05(1)(b)(2)** (m) Information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment;		* Estimated depth. ** Magnitude estimated from reported modified Mercalli intensity (MMI) value. *** Unknown.	
	N.D.A.C. §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(n)	**N.D.A.C. § 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	i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area: Geologic maps Topographic maps Cross sections	**2.1 Overview of Project Area Geology** (p. 2-1) *See discussion above under 2.1 Overview of Project Area Geology* ***4.4.3 Hydrology of USDW Formations*** (p. 4-13) 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 AOR is to the east (Figure 4-8). Water sampled from the Fox Hills Formation is a sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1500–1600 ppm. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride in excess of 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering. Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AOR. A cross section of these formations is presented in Figure 4-9. 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	**Figure 2-1.** Topographic map showing well locations and the TB Leingang in relation to the city of Beulah, North Dakota. (p. 2-2) **Figure 2-9.** Broom Creek Formation in North Dakota. The area within the green dashed line shows the extent originally proposed by Rygh (1990), and the area outside of the green dashed line has been modified based on new well control. (p. 2-16)

Subject	N.D.C.C./N.D.A.C. 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 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: **N.D.A.C. § 43-05-01-05(1)(b)(2)** (n) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the facility area; and		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 200 to 500 ft, and it directly underlies surficial glacial deposits in the AOR. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1000 ppm (Croft, 1973). The Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation in western portions of the AOR. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte Formation is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation range from approximately 400 to 1000 ppm (Croft, 1973). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers.	**Figure 2-12.** Regional well log stratigraphic cross sections of the Opeche/Spearfish and Broom Creek Formations flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) neutron porosity (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-20) **Figure 2-13.** Regional well log cross sections showing the structure of the Opeche/Spearfish and Broom Creek Formation logs. Displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) neutron porosity (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-21) **Figure 2-15**. Cross section of the TB Leingang storage complex from the geologic model showing facies distribution in the Broom Creek Formation. Depths are

Subject	N.D.C.C./N.D.A.C. 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)
					referenced as feet below mean sea level. Geologic model extent is displayed by the blue box in the inset map in the upper-left corner. (p.2-23) **Figure 4-8.** Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the east through the AOR in Mercer, Oliver, and Morton Counties (modified from Fischer, 2013). (p. 4-14) **Figure 4-9.** West-east cross section of the major aquifer layers in Oliver County. Wells used in the cross section are shown in the inset map and labeled with corresponding well names (NDIC File No. 4942 is Raymond Jensen 1-34). (p. 4-15)
	N.D.A.C. § 43-05-01-05(1)(b)(2)(d)	**N.D.A.C. § 43-05-01-05(1)(b)(2)** (d) An isopach map of the storage reservoirs;	j. An isopach map of the storage reservoir(s);	See Figure 2-10a on p. 2-17 and 2-10b on p. 2-18.	**Figure 2-10a**. Isopach map of the Broom Creek Formation in the simulation model area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map.(p. 2-17) **Figure 2-10b**. Isopach map of the Broom Creek Formation focused around the three stratigraphic and reservoir-monitoring wells. (p. 2-18)

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	N.D.A.C. § 43-05-01-05(1)(b)(2)(e)	**N.D.A.C. § 43-05-01-05(1)(b)(2)** (e)An isopach map of the primary and any secondary containment barrier for the storage reservoir;	k. An isopach map of the primary containment barrier for the storage reservoir;	See Figure 2-21 on p. 2-34	**Figure 2-21.** Isopach map of the Opeche/Spearfish Formation in the simulation model area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-34)
			l. An isopach map of the secondary containment barrier for the storage reservoir;	See Figure 2-25 on p. 2-40 and Figure 2-26 on p. 2-41	**Figure 2-25.** 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, 3D seismic, and 2D seismic in creation of this map. (p. 2-40) **Figure 2-26.** 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, 3D seismic, and 2D seismic in creation of this map. (p. 2-41)
	N.D.A.C. § 43-05-01-05(1)(b)(2)(f)	**N.D.A.C. § 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 2-14 on p. 2-22 and Figure 2-20 on page 2-33.	**Figure 2-14.** Structure map of the Broom Creek Formation in the simulation model referenced in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D

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					seismic in the creation of this map. (p. 2-22) **Figure 2-20**. Structure map of the Opeche/Spearfish Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-33)
			n. A structure map of the base of the storage formation;	See Figure 2-27 on p. 2-42	**Figure 2-27.** Structure map of the Amsden Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-42)
	N.D.A.C. § 43-05-01-05(1)(b)(2)(i)	**N.D.A.C. § 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 2-13 on p. 2-21 and Figure 2-15 on p. 2-23.	**Figure 2-13.** Regional well log cross sections showing the structure of the Opeche/Spearfish and Broom Creek Formation logs. Displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) neutron porosity (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-21) **Figure 2-15**. Cross section of the TB Leingang storage

Subject	N.D.C.C./N.D.A.C. 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)
					complex from the geologic model showing facies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. Geologic model extent is displayed by the blue box in the inset map in the upper-left corner. (p.2-23)
			p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-12 on p. 2-20	**Figure 2-12.** Regional well log stratigraphic cross sections of the Opeche/Spearfish and Broom Creek Formations flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) neutron porosity (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-20)
	N.D.A.C. § 43-05-01-05(1)(b)(2)(h)	**N.D.A.C. § 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. 3-16) The maximum WHP constraint of 2100 psi was one of the constraints on the injection wells for the entire 20 years of simulated injection. The maximum BHP constraint of 3663 psi for TB Leingang 1 and 3669 psi for TB Leingang 2 (equal to 90% of the product when multiplying the fracture gradient by top perforation depth) was approached near Year 20 of injection but was never reached (Figure 3-10), translating to a cumulative combined 124.4 MMt of CO_2 injected into the Broom Creek Formation by TB Leingang 1 and 2 (Figure 3-11). Simulations of CO_2 injection with the given well constraints, listed in Table 3-4, predicted the injection rate would decline from a maximum initial injection rate of approximately 3.65 MMt/yr per well to a final rate of approximately 2.85 MMt/yr per well (with a 20-year combined average of approximately 3.11 MMt/yr per injection well) (Figure 3-12). WHP and BHP responses depend on several factors, including predicted injection rate, injection tubing parameters (tubing internal radius and relative roughness), and surface injection temperature. For the designed tubing size of 7 in., the wells are operated at the maximum WHP of 2100 psi during the 20-year injection period (Figure 3-10). 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-	**Figure 3-14a.** Average pressure increase within the Broom Creek Formation after 5 years of simulated CO_2 injection operation. (p. 3-20) **Figure 3-14b.** Average pressure increase within the Broom Creek Formation after 10 years of simulated CO_2 injection operation. (p. 3-21)

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				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 3-13). The pressure fronts (Figures 3-14a–d) show the distribution of average pressure increase throughout the Broom Creek Formation after 5, 10, and 20 years of injection as well as 10 years postinjection. A maximum increase of approximately 1024 psi was estimated in the near-wellbore area at the end of the 20-year injection period (Figure 3-14c). Long-term CO_2 migration potential was also investigated through 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 supercritical fluids, ultimately immobilize the CO_2 plume and limit the plume's lateral migration and spreading. Figures 3-15a–c show the CO_2 saturation at the end of injection in west-to-east and north-to-south cross-sectional views and the areal map showing the stabilized plume at the site. ***6.1.1 Pre- and Postinjection Pressure Differential*** (p. 6-4) Model simulations were performed to predict the change in pressure in the Broom Creek Formation during and after the cessation of CO_2 injection. The simulations were conducted for 20 years of CO_2 injection in the Broom Creek Formation at an average total rate of 6.22 MMt/yr, followed by a postinjection period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the cessation of CO_2 injection. At the time that CO_2 injection ceases, the models predict an increase in the pressure of the reservoir, with a maximum pressure differential of 897 psi at the TB Leingang well pad. There is insufficient pressure increase caused by CO_2 injection to move more than 1 m^3 of formation fluids from the storage reservoir to the lowest USDW. The details of the pressure evaluation are provided as part of the AOR delineation discussion within Section 3.0 of this application.	**Figure 3-14c.** Average pressure increase within the Broom Creek Formation after 20 years of simulated CO_2 injection operation. (p. 3-22) **Figure 6-1.** Predicted pressure increase in the storage reservoir following 20 years of injection of an average 6.465 MMt/yr of CO_2. (p. 6-5) **Figure 6-2.** Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection. (p. 6-6)
	N.D.A.C. § 43-05-01-05(1)(b)(2)(l)	**N.D.A.C. § 43-05-01-05(1)(b)(2)** (l) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream;	r. Geomechanical information on the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide: Fractures Stress Ductility Rock strength In situ fluid pressure	***2.4.4 Geomechanical Information of Confining Zone* (p. 2-48)** *2.4.4.1 Fracture Analysis* Fractures within the overlying confining zone (the Opeche/Spearfish Formation) and the underlying confining zone (Amsden Formation) were assessed during the description of the Milton Flemmer 1 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural fractures and in situ stress were assessed through the interpretation of the image log acquired during the drilling of the Milton Flemmer 1 well. *2.4.4.2 Core-Fracture Analysis* The fractures observed in the Opeche Formation were tectonic, vertical to subvertical, closed, and cemented with anhydrite. The Amsden Formation was determined to be a nonfractured interval. A few discontinuous closed fractures were noted. The presence of stylolites was also noted in the dolomitic intervals of the Amsden Formation. *2.4.4.3 Borehole Image Fracture Analysis* Natural fractures and in situ stresses were assessed through the interpretation of borehole image log, dipole shear sonic slowness (DTS), and DTC logs acquired during the drilling of the Milton Flemmer 1 well. Borehole image logs provide a 360-degree image of the formation of interest and are oriented to provide an understanding of the general orientation of the observed features. The fractures within the upper confining zone formations, specifically Spearfish, Minnekahta, and Opeche, exhibit unique characteristics and are classified individually. Fractures within Opeche Formation were primarily litho-bound resistive fractures, mainly oriented NNW-SSE with the presence of other fracture sets oriented N-S, NW-SE, and NE-SW. They were commonly filled with anhydrite. Some litho-bound conductive fractures were identified and determined to have a N-S and NW-SE orientation. The litho-bound conductive fractures are filled with clay and are interpreted as closed fractures (Figure 2-32a). In the Spearfish formation, one resistive litho-bound fracture and one resistive continuous fracture, oriented N-S and NNE-SSW, were highlighted (Figure 2-32b). In the Minnekahta Formation, one conductive litho-bound fracture, oriented NE-SW was highlighted (Figure 2-32C). The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. They are closed, and the aperture varies from close to centimeter-scale (Figures 2-33 and 2-34). No microfaults were found in the Spearfish, Minnekahta, and Opeche intervals. The Amsden Formation is considered to be a nonfractured interval; however, a few litho-bound conductive and resistive fractures are highlighted with the presence of horizontal compaction features (stylolites). The fractures are oriented E-W, NNE-SSW, and NNW-SSE (Figure	**Figure 2-32a.** Strike orientation per type of fracture that characterizes the Opeche Formation: resistive litho-bound fractures (pink), resistive continuous fractures (brown), and conductive litho-bound fractures (blue). The colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture. (p. 2-49) **Figure 2-32b.** Strike orientation per type of fracture that characterizes the Spearfish Formation: resistive litho-bound fracture (pink) and resistive continuous fracture (brown). The colored dots represent

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				2-35). The fractures vary in orientation and exhibit oblique and vertical trends. The fractures are filled, and the aperture varies from closed to millimeter-scale (Figures 2-36 and 2-37). No microfaults were found in the Amsden interval. Breakout and tensile fractures induced by drilling were identified in several formations such as Precambrian and Ordovician units and Amsden, Broom Creek, and Opeche Formations. Breakouts and tensile fractures have NW-SE and NE-SW orientations, respectively (Figure 2-38). In the confining and injection zones, the tensile fractures were identified at different depths 5804, 5826, 6195, and 6307 ft MD. The tensile fractures are oriented NE-SW, indicating that the maximum horizontal stress (SHmax) has an orientation of N050°. *2.4.4.4 Stress, Ductility and Rock Strength* The dynamic elastic properties (dynamic Young's modulus and Poisson's ratio) for the Opeche/Spearfish, Broom Creek, and Amsden Formations were calculated by using DTC, DTS, and density log collected from Milton Flemmer 1. These dynamic elastic properties were converted to static elastic properties with calibrations of geomechanical lab core measurements. A 1D MEM in the Broom Creek section was built for Milton Flemmer 1 using the available wireline data such as GR logs, caliper logs, density logs (RHOB), dipole sonic logs (DTC, DTS), and image logs. The 1D MEM consists of pore pressure, the vertical in situ stress (Sv, overburden), minimum and maximum horizontal in situ stresses (Shmin, SHmax), static and dynamic Young's moduli (E), static and dynamic Poisson's ratio (v), Bulk modulus (K), shear modulus (G), unconfined compressive strength (UCS), tensile strength (To), and friction angle (FA or FANG) (Tables 2-9 and 2-10). Sv is one of the three principal stresses that act upon a rock. It is defined as the stress applied by the overlaying lithostatic column, at the depth (z), and is estimated using the Plumb and others (1991) equation. Sv is calculated using the RHOB log as an input. For the pore pressure, porosity proxy logging data based on a normal compaction trendline concept were used (for hydraulic static pressure, 1.03 g/cm^3 = 0.44675 psi/ft = 8.6 ppg). For the Broom Creek Formation, the MDT data taken in sand bodies show pore pressure equivalent to 9 ppg equivalent to 0.466 psi/ft, which is slightly overpressured. The pore pressure estimation honored the MDT measurement. Dynamic to static Young's modulus function used a linear conversion where a dynamic Young's modulus log was calculated from the available sonic (DTC, DTS) and density logs. For Poisson's ratio, dynamic and static parameters are assumed to be equal. The Biot factor was estimated using the formula Biot's factor =1 – (K0/Kmineral), where K0 is the bulk modulus of the porous medium and Kmineral is the bulk modulus of solid parts of the porous medium. It is a function of mineral volumes and minerals' bulk modulus. For rock properties, Young's modulus and Poisson's ratio were estimated from well logs and were calibrated with the triaxial core laboratory measurements (Figure 2-39). Unconfined compressive strength (UCS) was calculated using empirical correlations between UCS and DTC for shale, sandstone, and dolostone: the Chang (2006) method was used for shale formation, the McNally (1987) method was used for sandstone formation, and the Golubev and Rabinovich (1976) method was used for dolostone formation. The tensile strength was assumed to be 10% of the calculated UCS. The friction angle (FA or FANG) was estimated using an empirical correlation between the internal angle of friction and DTC: Lal's approach (1999) was used to calculate the FA in the Opeche/Spearfish and Amsden Formations, and Weingarten and Perkins (1995) in Broom Creek Formation. Horizontal stresses (Shmin and SHmax) were estimated using the poroelastic equations (Plumb and others, 2000). The orientations of Shmin and SHmax were estimated with the help of image logs (Figure 2-38). The magnitude of Shmin was calibrated by the closure pressures which were measured with a mini-frac stress test. In addition, the 1D MEM shows that the stress regime observed in the Opeche/Spearfish, Broom Creek, and Amsden Formations is normal (Sv > SHmax > Shmin). The analysis of the pore pressure measured in the Broom Creek Formation attests that it could be considered an overpressured reservoir with a gradient equal to 0.466 psi/ft. Triaxial test (static elastic properties), ultrasonic velocity (dynamic elastic properties), destructive test (compressive strength) at reservoir conditions, and pore volume compressibility (PVC) for reservoir samples were conducted on nine core samples acquired from the Opeche/Spearfish, Broom Creek, and Amsden Formations in the Milton Flemmer 1 well. These values were used to calibrate the static and dynamic Young's modulus and Poisson's ratio generated from well logs (Table 2-11).	the dip value for the corresponding type of fracture and the dip azimuth of the fracture. (p. 2-50) **Figure 2-32c.** Strike orientation per type of fracture that characterizes the Minnekahta Formation: conductive litho-bound fracture (blue). The colored dot represents the dip value for the corresponding type of fracture and the dip azimuth of the fracture**.** (p. 2-51) **Figure 2-33.** Sedimentary and tectonic features in Opeche/Spearfish Formation observed on the borehole image log. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, caliper (HCal); 4) borehole dynamic image log; 5) borehole static image log; and 6) tectonic and sedimentary tadpole orientation in the interval between 5665 and 5743 ft MD. (p. 2-52) **Figure 2-34.** Sedimentary and tectonic features in Opeche/Spearfish Formation observed on the borehole image log. The tracks from left to right show 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) tectonic and sedimentary tadpole

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					orientation in the interval between 5743 and 5700 ft MD. (p. 2-53) **Figure 2-35.** Strike orientation per type of fracture that characterizes the Amsden Formation: resistive litho-bound fractures (red), conductive partially resistive fractures (light green), and conductive litho-bound fractures (dark green). Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture. (p. 2-54) **Figure 2-36.** Sedimentary and tectonic features in Amsden Formation observed on the borehole image log. The tracks from left to right show 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) tectonic and sedimentary tadpole orientation in the interval between 6343 and 6390 ft MD. (p. 2-55) **Figure 2-37**. Sedimentary and tectonic features in Amsden Formation observed on the borehole image log. The tracks from left to right show 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole

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					dynamic image log; 5) borehole static image log; and 6) tectonic and sedimentary tadpole orientation in the interval between 6431 and 6477 ft MD. (p. 2-56) **Figure 2-38.** Orientation of the tensile fractures and breakout in the Milton Flemmer 1 well showing maximum horizontal stress (SHmax) direction about N050° and minimum horizontal stress (Shmin) about N140°. (p. 2-57) **Table 2-9.** Ranges and Averages of the Elastic Properties Estimated from 1D MEM in the Opeche/Spearfish, Broom Creek, and Amsden Formations: Static Young's Modulus (E_Stat), Static Poisson's Ratio (ν_Stat), Static Bulk Modulus (K), Static Shear Modulus (G), Uniaxial Strain Modulus (UCS), Dynamic Young's Modulus (E_Dyn), and Dynamic Poisson's ratio (ν_Dyn) in the Opeche/Spearfish, Broom Creek, and Amsden Formations (p. 2-58) **Table 2-10.** Ranges and Averages of the Sv, Pore Pressure, Shmin, and FA Estimated from 1D MEM in the Opeche/Spearfish, Broom Creek, and Amsden Formations (p. 2-58)

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					Figure 2-39. Geomechanical parameters in the Opeche/Spearfish, Broom Creek, and Amsden Formations. The tracks from left to right show: 1) Measured depth; 2) Formation; 3) GR, (HCal); 4) TNPH (neutron porosity), RHOZ (Bulk Density); 5): Dynamic Young's modulus (E_dyn), static Young's modulus (E_Stat) calibrated with core measurements (E_Core);6): Dynamic Poisson's ratio (PR_dyn) calibrated with core measurements (PR_Core); 7) Cohesion, Bulk modulus (K_dyn), Shear modulus (G_dyn), and Biot's factor; 8) UCS, tensile strength, friction angle; 9) Pore pressure, hydropressure calibrated with MDT pressure data; 10) Vertical Stress (Sv), Maximum horizontal stress (SHmax), Minimum horizontal stress (Shmin), calibrated with the MDT stress test; 11) Pore pressure, Shmin, and Eaton fracture gradients. (p. 2-60) **Table 2-11.** Sample ID, Formation, Lithology, Sample Depth (MD), Vertical Stress, Pore Pressure, Effective Vertical Stress, Horizontal Stress, Static Young's Modulus, Poisson's Ratio, and Compressive Strength in Opeche/Spearfish,

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					Broom Creek, and Amsden Formations (p. 2-61)
	N.D.A.C. § 43-05-01-05(1)(b)(2)(o)	**N.D.A.C. § 43-05-01-05(1)(b)(2)** (o) Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement, are free of transmissive faults or fractures, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	s. Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement: Free of transmissive faults Free of transmissive fractures Effect on pressure dissipation Utility for monitoring, mitigation, and remediation.	***2.4.2 Additional Overlying Confining Zones*** (p. 2-39) *See discussion above under 2.4.2 Additional Overlying Confining Zones (p. 2-39)*	**Table 2-8a.** Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on Milton Flemmer 1) (p. 2-39) **Figure 2-25**. 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, 3D seismic, and 2D seismic in creation of this map. (p. 2-40) **Figure 2-26.** 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, 3D seismic, and 2D seismic in creation of this map. (p. 2-41)
Area of Review Delineation	N.D.A.C. §§ 43-05-01-05(1)(j) and (1)(b)(3)	**N.D.A.C. § 43-05-01-05(1)** j. An area of review and corrective action plan that meets the requirements pursuant to section 43-05-01-05.1;	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.	**4.1 Area of Review (AOR) Delineation** (p. 4-1) North Dakota regulations for geologic storage of CO_2 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 (USDWs)[1] may be endangered by the injection activity" (North Dakota Administrative Code [N.D.A.C.] § 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 that is sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present.	**Figure 4-2.** Final AOR map showing the TB Leingang storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares

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		N.D.A.C. § 43-05-01-05(1)(b) (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following:	The area of review delineation must include the following:	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 Milton Flemmer 1 (North Dakota Industrial Commission [NDIC] File No. 38594) 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). The storage reservoir is calculated to be overpressured, with a value of −271 psi calculated using data from the Milton Flemmer 1 well. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period was 1004 psi in the raster cell intersected by the injection well, which corresponds to less than 0.017 m^3 of flow over 20 years (Section 3.5). Based on the computational methods used to simulate CO$_2$ injection activities and the associated pressure front (Figure 4-1), the resulting AOR for TB Leingang is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations. In accordance with N.D.A.C. § 43-05-01-05(1)(b)(3), a geologist or engineer reviewed the data of public record for all wells within the storage facility area, including those which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within 1 mi of the facility area boundary (Table 4-1). This section of the SFP application is accompanied by maps and tables that include information required and in accordance with N.D.A.C. § 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 occupied structures, gravel pits, and wind turbines (Figure 4-2); and location of water wells, springs, and any other wells within the AOR (Figure 4-3). Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation. Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1. An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR (Section 2.5) 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.	represent occupied structures, brown crosses represent wind turbines, and brown circles represent gravel pits (note: gravel pits were identified using the North Dakota Geographic Information System [GIS] Hub landmarks data layer from the North Dakota Department of Transportation [2002]). (p. 4-4)
	N.D.A.C. §§ 43-05-01-05(1)(b)(3) and (1)(a)	**N.D.A.C. § 43-05-01-05(1)(b)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: **N.D.A.C. § 43-05-01-05(1)** a. A site map showing the boundaries of the storage reservoir and the location of all proposed wells, proposed cathodic protection	a. A map showing the following within the carbon dioxide reservoir area: i. Boundaries of the storage reservoir ii. Location of all proposed wells iii. Location of proposed cathodic protection boreholes iv. Any existing or proposed aboveground facilities;	**2.3 Storage Reservoir (injection zone)** (p. 2-16) See Figure 2-9 on page 2-16. ***5.7.1 Soil Gas Monitoring*** (p. 5-23) See Figure 5-4 on page 5-23. *3.5.5.2 Incremental Leakage Maps and AOR Delineation* (p. 3-40) See Figure 3-21 on page 3-43. **5.2 Surface Facilities Leak Detection Plan** (p. 5-10) See Figure 5-2 on page 5-11. **4.1 Area of Review (AOR) Delineation (p.** See Figure 4-2 on page 4-4	**Figure 2-9.** Broom Creek Formation in North Dakota. The area within the green dashed line shows the extent originally proposed by Rygh (1990), and the area outside of the green dashed line has been modified based on new well control. (p. 2-16) **Figure 5-4.** SCS1 baseline and operational near-surface sampling locations. (p. 5-23) **Figure 3-21.** Final AOR estimations of the TB Leingang storage facility area in relation to nearby legacy wells. Shown is the storage facility area

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		boreholes, and surface facilities within the carbon dioxide storage facility area;			(black dashed line) and AOR (purple dashed line). The gray circle represents legacy oil and gas wells near the storage facility area. (p. 3-43) **Figure 5-2.** Site map detailing the path of the CO_2 flowline to the CO_2 injection wellsite. Inset map (on left) illustrates a generalized injection well pad layout with key monitoring equipment identified. (p. 5-11) **Figure 4-2.** Final AOR map showing the TB Leingang storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares represent occupied structures, brown crosses represent wind turbines and brown circles represent gravel pits (note: gravel pits were identified using the NDGISHUB Landmarks NDDOT [North Dakota Department of Transportation, 2002]). (p. 4-4)
	N.D.A.C. § 43-05-01-05(1)(b)(2)(a)	**N.D.A.C. § 43-05-01-05(1)(b)(2)** (a) All wells, including water, oil, and natural gas exploration and development wells, and other manmade subsurface structures and activities, including coal mines, within the facility area and within one mile [1.61 kilometers] of its outside boundary;	b. A map showing the following within the storage reservoir area and within one mile outside of its boundary: i. All wells, including water, oil, and natural gas exploration and development wells ii. All other manmade subsurface structures and activities, including coal mines;	**4.1 Area of Review (AOR) Delineation** (p. 4-1) See Figure 4-2 on page 4-4 and Figure 4-3 on page 4-5. *2.6 Potential Mineral Zones* (p. 2-70) See Figure 2-47 on page 2-73.	**Figure 4-2**. Final AOR map showing the TB Leingang storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares represent occupied structures, brown crosses represent wind turbines, and brown circles represent gravel pits (note: gravel pits were identified using the North Dakota Geographic Information

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					System [GIS] Hub landmarks data layer from the North Dakota Department of Transportation [2002]). (p. 4-4) **Figure 4-3.** Map showing all wells located in the AOR. Shown are the stabilized CO_2 plume extent postinjection (gray-shaded area), storage facility area (dashed black boundary), and AOR (dashed purple boundary). All groundwater wells in the AOR are identified based on data available from the Department of Water Resources (DWR). The only existing well penetrating the Broom Creek Formation and its primary overlying seal (Opeche/Spearfish Formation) within the AOR is the Milton Flemmer 1 well. No other legacy oil and gas wells are present in the AOR (see Figure 2-47 for any nearby legacy wells outside of the AOR). One spring is present in the southern portion of the AOR (note: the spring was identified using the National Map hosted by the U.S. Geological Survey [2023]).(p. 4-5) **Figure 2-47.** Map showing stratigraphic wells for the project and nearest legacy wells. Gray circles indicate dry wells. The red circle indicates the closest oil

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					and gas producing well (NDIC File No. 7616). (p. 2-73)
	N.D.A.C. § 43-05-01-05(1)(c) and N.D.A.C. § 43-05-01-05.1(1)(a)	**N.D.A.C. § 43-05-01-05(1)** c. The extent of the pore space that will be occupied by carbon dioxide as determined by utilizing all appropriate geologic and reservoir engineering information and reservoir analysis, which must include various computational models for reservoir characterization, and the projected response of the carbon dioxide plume and storage capacity of the storage reservoir. The computational model must be based on detailed geologic data collected to characterize the injection zones, confining zones, and any additional zones; **N.D.A.C. § 43-05-01-05.1(1)** a. The method for delineating the area of review, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	c. A description of the method used for delineating the area of review, including: i. The computational model to be used ii. The assumptions that will be made iii. The site characterization data on which the model will be based;	***3.5.4 Risk-Based AOR Calculations (p. 3-35)*** 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 3-6. They illustrate the state of overpressure in the storage complex because Aquifer 1 has a greater initial hydraulic head than Aquifer 2 and Aquifer 3. Therefore, the storage complex requires different treatment than the default AOR calculations described by EPA (2013). Details on the calculations of initial hydraulic head are provided in Burton-Kelly and others (2021). *3.5.4.2 CO_2 Injection Parameters* The ASLMA Model for the 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 3-7. The CO_2 mass injection rate and CO_2 density are then used to derive the daily equivalent-volume injection rate, shown in Table 3-7. *3.5.4.3 Hypothetical Leaky Wellbore* In the simulation model 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 2) throughout the 20-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 3-18) 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 3-18). 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 Potential Thief Zone*	**Table 3-6.** Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex (p. 3-36) **Table 3-7.** CO_2 Density and Injection Parameters Used for the ASLMA Model (p. 3-37) **Figure 3-19.** 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, so all flow is from the storage reservoir to the USDW. In the right-hand scenario, the leaky wellbore is open to Aquifer 2, so the vast majority of flow is from the storage reservoir to the Aquifer 2 thief zone, and the curve showing flow into the Aquifer 3 USDW is not visible on this plot. (p. 3-40) **Figure 3-18.** Histograms describing the expected frequency of leaky wellbore effective permeabilities under different scenarios. The ASLMA Model used for

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				As shown in Table 3-6, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the storage reservoir primary seal and the 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, Aquifer 2 may act as a thief zone and reduce 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 to 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 high-permeability zone encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 were run and the results 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 3-6). For each unit shown in Table 3-6, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: HCON and specific storage (SS). Average porosity and permeability values were derived as follows: Broom Creek, from distributed properties in the geologic model; 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 HCON and SS. The estimated reference case HCON for the storage reservoir (Aquifer 1) potential thief zone (Aquifer 2) and USDW (Aquifer 3) are shown in Table 3-6. 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* (p. 3-39)** *3.5.5.1 Relating Pressure Buildup to Incremental Leakage with ASLMA Model and Compositional Simulation* Figure 3-19 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). 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 3-19) 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. *3.5.5.2 Incremental Leakage Maps and AOR Delineation* The pressure buildup–incremental flow relationship, shown in Figure 3-19, results in the incremental flow map, shown in Figure 3-20, which shows the estimated total cumulative incremental flow potential from a hypothetical leaky well into Aquifer 3 (USDW) over the entire injection period if the modeled leaky wellbore is not open to the thief zone.	AOR delineation used a value of approximately 0.1 mD (constructed from data presented by Carey [2017]). (p. 3-38) **Table 3-20.** Map of potential incremental flow into the USDW at the end of 20 years of CO_2 injection. (p. 3-41) **Figure 3-21.** Final AOR estimations of the TB Leingang storage facility area in relation to nearby legacy wells. Shown is the storage facility area (black dashed line) and AOR (purple dashed line). The gray circle represents legacy oil and gas wells near the storage facility area. (p. 3-43)
	N.D.A.C. § 43-05-01-05.1(1)(b)(1-4)	**N.D.A.C. § 43-05-01-05.1(1)** b. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) The monitoring and operational conditions that would warrant a	d. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) Any monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next	**4.3 Reevaluation of AOR and Corrective Action Plan** (p. 4-9) The AOR and corrective action plan will be reevaluated in accordance with N.D.A.C. § 43-05-01-05.1, with the first reevaluation taking place at a period not to exceed 5 years from the date the permit for CO_2 injection is issued (N.D.A.C. § 43-05-01-10) or when monitoring and operational conditions warrant a reevaluation. Each successive reevaluation shall take place at a period not to exceed 5 years from the date of the previous reevaluation (each referred to as a “Reevaluation Date”). The AOR reevaluations will address the following: • 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 delineation.	N/A

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		reevaluation of the area of review prior to the next scheduled reevaluation date; (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and (4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	scheduled reevaluation date; (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; (4) How corrective action will be conducted if necessary, including: a. What corrective action will be performed prior to injection b. How corrective action will be adjusted if there are changes in the area of review;	As part of the reevaluation, Summit Carbon Storage #1, LLC (SCS1) will either a) demonstrate to the NDIC Department of Mineral Resources-Oil and Gas Division (DMR-O&G) using monitoring data and modeling results that no plan amendment is necessary or b) submit an amended AOR and corrective action plan for DMR-O&G approval. Plan amendments must be incorporated into the permit and are subject to permit modification requirements.	
	N.D.A.C. § 43-05-01-05(1)(b)(2)(b)	**N.D.A.C. § 43-05-01-05(1)(b)(2)** (b) All manmade surface structures that are intended for temporary or permanent human occupancy within the facility area and within one mile [1.61 kilometers] of its outside boundary;	e. A map showing the areal extent of all manmade surface structures that are intended for temporary or permanent human occupancy within the storage reservoir area, and within one mile outside of its boundary;	***4.1 Area of Review (AOR) Delineation (p. 4-1)*** *See Figure 4-2 on page 4-4.*	**Figure 4-2**. Final AOR map showing the TB Leingang storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares represent occupied structures, brown crosses represent wind turbines, and brown circles represent gravel pits (note: gravel pits were identified using the North Dakota Geographic Information System [GIS] Hub landmarks data layer

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					from the North Dakota Department of Transportation [2002]). (p. 4-4)
	N.D.A.C. § 43-05-01-05(1)(b)(2)	**N.D.A.C. § 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	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. 2-70) See Figure 2-46, Figure 2-47 Figure 2-48, Figure 2-49, and Figure 2-50.	**Figure 2-46.** Drillstem test results indicating the presence of oil in the Spearfish Formation samples (modified from Stolldorf, 2020). (p. 2-71) **Figure 2-47.** Map showing stratigraphic wells for the project and nearest legacy wells. Gray circles indicate dry wells. The red circle indicates the closest oil and gas producing well (NDIC File No. 7616). (p. 2-73) **Figure 2-48.** Beulah net coal isopach map and resource area (modified from Ellis and others, 1999). (p. 2-74) **Figure 2-49.** Beulah overburden isopach map (modified from Ellis and others, 1999). (p. 2-75) **Figure 2-50.** Map showing the future mining area for the Coyote Creek Mine through 2040. (p. 2-76) **Figure 2-51.** Map showing the future mining area for the Coyote Creek Mine and Beulah Mine through 2040. (p. 2-77)

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		one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:			
	N.D.A.C. § 43-05-01-05(1)(b)(3) and N.D.A.C. § 43-05-01-05.1(2)(b)	**N.D.A.C. § 43-05-01-05(1)(b)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: **N.D.A.C. § 43-05-01-05.1(2)** b. Using methods approved by the commission, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone. Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the commission may require;	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.	***2.6 Potential Mineral Zones*** (p. 2-70) See Figure 2-47 on p. 2-73 for nearby legacy wells.	**Figure 2-47**. Map showing stratigraphic wells for the project and nearest legacy wells. Gray circles indicate dry wells. The red circle indicates the closest oil and gas producing well (NDIC File No. 7616). (p. 2-73)
	N.D.A.C. § 43-05-01-05(1)(b)(3)(a)	**N.D.A.C. § 43-05-01-05(1)(b)(3)** (a) A determination that all abandoned wells have been plugged and all operating wells have been constructed in a manner that prevents	h. A review of these wells must include the following: (1) A determination that all abandoned wells have been plugged in a manner that prevents the carbon dioxide or associated	**4.1 Area of Review (AOR) Delineation** (p. 4-1) See Figure 4-2 on page 4-4. **4.2 Corrective Action Evaluation (p. 4-6)** See Table 4-2 on p. 4-7, Table 4-3 on p. 4-7, See Figure 4-4 on p. 4-8	**Figure 4-2**. Final AOR map showing the TB Leingang storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares represent occupied

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	N.D.A.C. § 43-05-01-05(1)(b)(3)(b) N.D.A.C. § 43-05-01-05(1)(b)(3)(c) N.D.A.C. §§ 43-05-01-05(1)(b)(3)(d) and (e)	the carbon dioxide or associated fluids from escaping from the storage reservoir; **N.D.A.C. § 43-05-01-05(1)(b)(3)** (b) A description of each well's type, construction, date drilled, location, depth, record of plugging, and completion; **N.D.A.C. § 43-05-01-05(1)(b)(3)** (c) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all underground sources of drinking water, water wells, and springs within the area of review; their positions relative to the injection zone; and the direction of water movement, where known; **N.D.A.C. § 43-05-01-05(1)(b)(3)** (d) Maps and cross sections of the area of review; **N.D.A.C. § 43-05-01-05(1)(b)(3)** (e) A map of the area of review showing the number or name and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state-approved or United States environmental protection agency-approved	fluids from escaping the storage formation; (2) A determination that all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation; (3) A description of each well: a. Type b. Construction c. Date drilled d. Location e. Depth f. Record of plugging g. Record of completion (4) Maps and stratigraphic cross sections of all underground sources of drinking water within the area of review indicating the following: a. Their positions relative to the injection zone b. The direction of water movement, where known c. General vertical and lateral limits d. Water wells e. Springs (5) Map and cross sections of the area of review; (6) A map of the area of review showing the following: a. Number or name and location of all injection wells b. Number or name and location of all producing wells c. Number or name and location of all abandoned wells	**4.4 Protection of USDWs** (p. 4-9) Table 4-4 on page 4-10, Figure 4-5 on page 4-11, Figure 4-6 on page 4-12, Figure 4-7 on page 4-13, Figure 4-8 on page 4-14, Figure 4-9 on page 4-15, Figure 4-10 on page 4-17, and Table 4-5 on page 4-17. ***2.6 Potential Mineral Zones*** (p. 2-70) See Figure 2-47 on p. 2-73 for nearby legacy wells.	structures, brown crosses represent wind turbines and brown circles represent gravel pits (note: gravel pits were identified using the NDGISHUB Landmarks NDDOT [North Dakota Department of Transportation, 2002]). (p. 4-4) **Table 4-2.** Well(s) in AOR Evaluated for Corrective Action* (p. 4-7) **Table 4-3**. Milton Flemmer 1 (NDIC File No. 38594) Well Evaluation (p. 4-7) **Figure 4-4.** Milton Flemmer 1 (NDIC File No. 38594) well schematic showing the location of cement plugs. (p. 4-8) **Table 4-4**. Description of Zones of Confinement above the Immediate Upper Confining Zone (Opeche/Spearfish Formation) (data based on Milton Flemmer 1) (p. 4-10) **Figure 4-5.** Major aquifer systems of the Williston Basin (modified from Downey and Dinwiddie, 1988). (p. 4-11) **Figure 4-6.** Upper stratigraphy of Mercer, Oliver, and Morton Counties showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-

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	N.D.A.C. § 43-05-01-05(1)(b)(3)(f)	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; **N.D.A.C. § 43-05-01-05(1)(b)(3)** (f) A list of contacts, submitted to the commission, when the area of review extends across state jurisdiction boundary lines;	d. Number of name and location of all plugged wells or dry holes e. Number or name and location of all deep stratigraphic boreholes f. Number or name and location of all state-approved or United States Environmental Protection Agency-approved subsurface cleanup sites g. Name and location of all surface bodies of water h. Name and location of all springs i. Name and location of all mines (surface and subsurface) j. Name and location of all quarries k. Name and location of all water wells l. Name and location of all other pertinent surface features m. Name and location of all structures intended for human occupancy n. Name and location of all state, county, or Indian country boundary lines o. Name and location of all roads (7) A list of contacts, submitted to the Commission, when the area of review extends across state jurisdiction boundary lines.		bearing formations (modified from Croft, 1973). (p. 4-12) **Figure 4-7.** Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013). (p. 4-13) **Figure 4-8.** Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the east through the AOR in Mercer, Oliver, and Morton Counties (modified from Fischer, 2013). (p. 4-14) **Figure 4-9.** West-east cross section of the major aquifer layers in Oliver County. Wells used in the cross section are shown in the inset map and labeled with corresponding well names (NDIC File No. 4942 is Raymond Jensen 1-34). (p. 4-15) **Figure 4-10.** Field-verified water wells located within the AOR. (p. 4-17) **Table 4-5**. DWR and SCS1 Well No. Correlation (p. 4-17) **Figure 2-47**. Map showing stratigraphic wells for the project and nearest legacy wells. Gray circles indicate dry wells. The red circle indicates the closest oil and gas producing well

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					(NDIC File No. 7616). (p. 2-73)
	N.D.A.C. § 43-05-01-05(1)(b)(3)(g)	**N.D.A.C. § 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 (Well and Well Formation Fluid-Sampling Laboratory Analysis) and B (Freshwater Well Fluid Sampling)	N/A
Required Plans	N.D.A.C. § 43-05-01-05(1)(k)	**N.D.A.C. § 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	**12.3 Financial Instruments (p.12-11)** The applicant will establish a financial instrument(s) 30–60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations (N.D.A.C. § 43-05-01-09.1). The applicant will provide financial assurance in the form of a surety bond to ensure funds are available for PISC and facility closure activities (N.D.A.C. § 43-05-01-09.1[1][a] and N.D.A.C. § 43-05-01-19). The applicant will also obtain a pollution liability policy(s) to cover emergency and remedial response costs and endangerment of USDWs under N.D.A.C. § 43-05-01-13 and a financial instrument (surety bond) to cover the costs of plugging the injection wells (N.D.A.C. § 43-05-01-11.5). No estimates have been provided for corrective action (N.D.A.C. § 43-05-01-05.1) because no action is required at this time. This application presents the estimated total costs ($20,316,000) of these activities and a breakdown apportionment across proposed financial instruments in Table 12-1. Section 12.2 of this FADP provides additional details of the financial responsibility cost estimates for each activity. 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 on the basis of 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 a time that DMR-O&G determines that the storage operator has fulfilled its financial obligations. The third-party insurance, which identifies SCS1 as the covered party, will be provided by one or a combination of the companies meeting the creditworthiness and other requirements of N.D.A.C. § 43-05-01-09.1. However, the greatest hypothetical exposure evaluated would be an acute upward migration through an CO_2 injection well, which has an estimated cost of $13,795,000 for emergency and remedial response actions, as well as coverage identified in the endangerment of USDWs. 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 injection operations; however, 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 actual third-party insurance companies will be determined closer to the proposed injection start date and will meet both of the following criteria, as specified in N.D.A.C. §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.	**Table 12-1.** Potential Future Costs Covered by Financial Assurance (p. 12-2) **Table 12-2.** Injection Well Plugging (p. 12-3) **Table 12-3a.** Cost Estimate1 for PISC Activities for TB Leingang Assuming a 10-year PISC Period (p. 12-4) **Table 12-3b.** Cost Estimate for Flowline Segment NDL-327 Abandonment (p. 12-5) **Table 12-4.** Cost Estimate1 for Site Closure and Remediation Activities for TB Leingang CO_2 Storage Project (p. 12-6). **Table 12-6.** Cost Estimate for Emergency and Remedial Response Plan (p. 12-10). **Table 12-7.** Cost Estimate Endangerment of USDWs* (p. 12-10).

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	N.D.A.C. § 43-05-01-05(1)(d)	**N.D.A.C. § 43-05-01-05(1)(d)** d. An emergency and remedial response plan pursuant to section 43-05-01-13;	b. An emergency and remedial response plan;	**7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN** (p. 7-1) Note: Refer to the following key Figures and Tables: Figure 7-2 on page 7-5 with accompanying Figures: Figure 7-3 (p. 7-6), Figure 7-4 (p, 7-7), Figure 7-5 (p. 7-8), Table 7-4 on p. 7-9, and Table 7-5 starting on page 7-11.	**Figure 7-2.** Off-site emergency notification phone list. EMS districts, fire districts, law enforcement agencies, and Local Emergency Planning Committee (LEPC) jurisdictions with jurisdictions intersecting with the TB Leingang storage facility area (SFA) will be provided a copy of this ERRP. (p. 7-5) **Figure 7-3.** Map showing emergency management service (EMS) response zones including, and within the vicinity of, TB Leingang. Also included on this map are the planned CO_2 injection wells, stratigraphic and reservoir-monitoring wells, SCS PCS flowline(s), MCE pipeline, and state and federal roads. (p. 7-6) **Figure 7-4.** Map showing fire response zones including, and within the vicinity of, TB Leingang. Also included on this map are the planned CO_2 injection wells, stratigraphic and reservoir-monitoring wells, SCS PCS flowline(s), MCE pipeline, and state and federal roads. (p. 7-7) **Figure 7-5.** Map showing law enforcement response zones including, and within the vicinity of,

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					TB Leingang. Also included on this map are the planned CO_2 injection wells, stratigraphic and reservoir-monitoring wells, SCS PCS flowline(s), MCE pipeline, and state and federal roads. (p. 7-8) **Table 7-4**. Potential Project Emergency Events and Their Detection (p. 7-9) **Table 7-5**. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (p. 7-11)
	N.D.A.C. § 43-05-01-05(1)(e)	**N.D.A.C. § 43-05-01-05(1)** e. A detailed worker safety plan that addresses carbon dioxide safety training and safe working procedures at the storage facility pursuant to section 43-05-01-13;	c. A detailed worker safety plan that addresses the following: i. Carbon dioxide safety training ii. Safe working procedures at the storage facility;	**8.0 WORKER SAFETY PLAN** (p. 8-1) Summit Carbon Storage #1, LLC (SCS1) requires all employees and contractors to follow the SCS1 Worker Safety Plan (WSP) for TB Leingang. SCS1 maintains and implements a safety program that meets all state and federal requirements for worker safety protections, including the Occupational Safety and Health Administration (OSHA) and the National Fire Protection Association (NFPA). The safety program is described in this WSP. SCS1 will periodically review the WSP, and if substantive changes are warranted, the revised WSP will be provided to the North Dakota Industrial Commission (NDIC). Controlled copies of the WSP are available at SCS1's nearest operational office and at the geologic storage facility (North Dakota Administrative Code [N.D.A.C.] § 43-05-01-13). The WSP outlines steps to protect the health and safety of employees, contractors, and visitors while working near and around CO_2. Specific topics included in the WSP are, but are not limited to, the following: • A list of safety training programs, including annual CO_2 safety training, annual safe-working procedures training, and annual Emergency and Remedial Response Plan (ERRP) training, as well as the review frequency for the safety training programs and, if necessary, updates. A record of training completions, including the trainee's name, date and type of training, and the signatures (or other acceptable acknowledgment/ documentation) of the trainee and trainer are maintained and available upon request. • A site-specific list of potential hazards of working near and around CO_2. • Processes for determining causes of incidents and implementing appropriate emergency response actions. • Requirements for employees to perform duties in ways that prevent the discharge of CO_2. • Personal protective equipment (PPE) policies for employees while performing their duties, including guidelines for selecting, using, and maintaining PPE. • New-hire, contractor, and visitor protocols to ensure all on-site individuals are appropriately trained and are aware of the potential hazards of CO_2.	N/A

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				• Drug, alcohol, and controlled substances policy complying with all governmental laws and regulations in the workplace and consequences for those who violate the policy. • Reporting guidelines for all injuries; equipment or property damages; leaks, spills, or releases; or other health, safety, and environmental (HSE)-related incidents. Only SCS1 employees and contractor personnel who have been properly trained can participate in the on-site activities of drilling, construction, operations, and equipment repair.	
	N.D.A.C. § 43-05-01-05(1)(f)	**N.D.A.C. § 43-05-01-05(1)** f. A corrosion monitoring and prevention plan for all wells and surface facilities pursuant to section 43-05-01-15;	d. A corrosion monitoring and prevention plan for all wells and surface facilities;	**5.3 CO_2 Flowline Corrosion Prevention and Detection Plan (p. 5-14)** The purpose of this plan is to prevent and detect any signs of corrosion in the flowline. ***5.3.1 Corrosion Prevention*** To protect against corrosion, an external fusion-bonded epoxy coating will be applied to the NDL-327 flowline. Flowline installed by trenchless methods, such as road crossings, will also have an abrasion-resistant overcoat installed as a secondary coating, over the fusion-bonded epoxy, prior to installation. SCS1 will install an impressed current cathodic protection (ICCP) system along the buried flowline to mitigate the threat of external soil corrosion on the line. The ICCP system, which will be continuously monitored, involves the installation of deep anode beds along the flowline that are connected to external power through a rectifier. The power provides the current needed to drive an electrochemical reaction whereby the anodes corrode instead of the flowline. Except for a rectifier, junction box, and small diameter vent pipe posted above the anode beds, the ICCP system will be buried. Because the CO_2 stream will contain only trace amounts of water (Table 5-2), SCS1 will operate the surface facilities above the saturation point of water to prevent corrosive conditions from forming. ***5.3.2 Corrosion Detection*** Real-time, continuous monitoring of the CO_2 flowline with P/T gauges and Coriolis mass flowmeter measurements from the pump/metering building to the terminus of the pipeline combined with continuous analysis of the CO_2 stream with the gas chromatograph will provide strong evidence that noncorrosive conditions are maintained in the flowline during injection operations. The equipment will be spliced to the SCADA system and have automated triggers and alarms for alerting SCS1 of any anomalous readings. The flowline segment from the terminus of the pipeline to the pipeline inspection gauge (PIG) receiver (shown in Figure 5-3) will allow the passage of internal inspection devices (commonly referred to as "smart PIGs"), which are designed to detect certain internal and external anomalies in the line, such as loss of mass/wall thickness, dents, pitting, cracking, and scratches. The launchers and receiver facilities are designed to launch and receive these internal inspection devices along with other types of PIGs (e.g., maintenance pigs). The launchers and receivers will be located at standalone sites in Oliver and Mercer Counties. The frequency for running PIGs in the flowline during operations is described in Table 5-2. In addition to the activities described above, SCS1 will install at least one electrical resistance (ER) probe along the CO_2 flowline upstream of the gas chromatograph to continuously monitor for loss of mass throughout the operational phase. The ER probe will be spliced to the SCADA system for real-time monitoring and will be removable for visual inspection and replacement, if required. The SCADA system will have automated triggers and alarms for alerting SCS1 of any anomalous readings. **5.6 Wellbore Corrosion Prevention and Detection Plan (p. 5-21)** The purpose of this corrosion prevention and detection plan is to monitor the well materials to ensure they meet the minimum standards for material strength and performance, pursuant to N.D.A.C. § 43-05-01-11.4(1)(c). ***5.6.1 Downhole Corrosion Prevention*** To prevent corrosion of the well materials in the TB Leingang 1 and 2 wellbores, the following preemptive measures will be implemented: 1) cement opposite of the injection interval and extending to the differential valve (DV) staging tool above the top of the Mowry Formation will	**Figure 5-2.** Site map detailing the path of the CO_2 flowline to the CO_2 injection wellsite. Inset map (on left) illustrates a generalized injection well pad layout with key monitoring equipment identified. (p. 5-11) **Figure 5-3.** Generalized flow diagram from the flange to the TB Leingang 1 CO_2 injection well, illustrating key surface facilities' connections and monitoring equipment. The flow diagram is identical for the TB Leingang 2 CO_2 injection well (not shown). (p. 5-12) **Table 5-3.** Specification for the Commingled CO_2 Stream (p. 5-9)

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				be CO_2-resistant; 2) the well casing will also be CO_2-resistant from the bottomhole to just above the Opeche/Spearfish Formation and from below the top of the Swift Formation to just below the top of the Skull Creek Formation; 3) the well tubing will be CO_2-resistant from the injection interval to surface; 4) the packer will be CO_2-resistant; and 5) the packer fluid will be an industry-standard corrosion inhibitor. The tubing-casing annulus will be filled with the packer fluid system that is planned to be a brine-based fluid treated with antimicrobial biocide, corrosion inhibitor, and oxygen scavenger to minimize potential corrosive effects of soluble oxygen. To prevent corrosion of the well materials in the Milton Flemmer 1 wellbore, the following preemptive measures are implemented: 1) cement opposite the injection interval and extending above the confining zones is CO_2-resistant; 2) the well casing is CO_2-resistant from the cast iron bridge plug set at 6550 feet in the well (to 137 feet above the Opeche/Spearfish Formation and from 214 feet below the top of the Swift Formation to 178 feet above the top of the Mowry Formation); and 3) the packer fluid is an industry-standard corrosion inhibitor. The tubing-casing annulus will be filled with a brine-based packer fluid treated with biocide, corrosion inhibitor, and oxygen scavenger. In addition, SCS1 plans to reevaluate replacement of packer and bottomhole assembly during the 5-year evaluation. Figures 11-2, 11-4, and 11-5 in Section 11.0 illustrate the downhole corrosion prevention measures in each of the wellbores. **5.6.2 Downhole Corrosion Detection** PNLs will be run in the TB Leingang 1 and 2 and Milton Flemmer 1 wellbores to detect saturations of CO_2. Further investigative methods of inspecting for corrosion in the wellbore could include ultrasonic logging or other equivalent CIL when required. Tables 5-1 and 5-2 specify the sampling frequency for acquiring data related to this downhole corrosion detection plan.	
	N.D.A.C. § 43-05-01-05(1)(g)	**N.D.A.C. § 43-05-01-05(1)** g. A leak detection and monitoring plan for all wells and surface facilities pursuant to section 43-05-01-14. The plan must: (1) Identify the potential for release to the atmosphere; (2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.	e. A surface leak detection and monitoring plan for all wells and surface facilities pursuant to N.D.A.C. § 43-05-01-14;	**5.2 Surface Facilities Leak Detection Plan (p. 5-10)** The purpose of this leak detection plan is to specify the monitoring strategies SCS1 will use to quantify any losses of CO_2 from surface facilities during operations. Surface facilities include the CO_2 injection wellheads (TB Leingang 1 and 2), the reservoir-monitoring wellhead (Milton Flemmer 1), and the NDL-327 CO_2 flowline, which begins at the pipeline terminus of NDM-106 and ends at the inlet valve upstream of the automated emergency shutoff valve at each CO_2 injection wellhead. Figure 5-2 illustrates the CO_2 flowline path to CO_2 injection wellsite, and Figure 5-3 is a generalized flow diagram from the pipeline terminus of NDM-106 to the CO_2 injection wellheads, illustrating key surface facilities' connections and monitoring equipment. As illustrated in Figure 5-3, leak detection equipment includes 1) P/T gauges along the flowline, 2) a Coriolis mass flowmeter placed near each of the injection wellheads, and 3) gas detection stations placed on the CO_2 injection wellheads pursuant to N.D.A.C. § 43-05-01-14(1) and inside the pump/metering building. The gas detection stations, which will detect gases such as CO_2, methane (CH_4), and hydrogen sulfide (H_2S), will have automated triggers and alarms to alert SCS1 of any anomalous readings. The SCADA system, which will continuously collect data streams from the leak detection equipment in real time, will also monitor for leaks with leak detection software. Field personnel from SCS1 will have multigas detectors with them for visiting wellsites or conducting flowline inspections. In addition, gas detection safety lights (part of the integrated alarm system) will be placed outside of the pump/metering building to warn field personnel of potential indoor air quality threats. **5.2.2 Surface Facilities Leak Detection Plan QASP** Pursuant to N.D.A.C. § 43-05-01-14(1), the leak detection equipment will be inspected and tested on a semiannual basis. If equipment is defective, SCS1 will repair or replace the equipment within 10 days or, acting with good cause, SCS1 will propose an alternate timeline for approval by the DMR-O&G. Each repaired or replaced detector will be retested, if required. The gas detection stations are described in Appendix D, Attachment D-2. The SCADA system and leak detection software are described in further detail in Appendix D, Attachment D-3, and the personnel multigas detectors are described in Appendix D, Attachment D-4. SCS1 will install the leak detection equipment according to the manufacturer's recommendations. The flowline will be regularly inspected for any visual or auditory signs of equipment failure. Any release of CO_2 to the atmosphere or near-surface environments from the surface facilities will be reported to DMR-O&G within 24 hours pursuant to N.D.A.C. § 43-05-01-18(9)(e).	N/A
	N.D.A.C. § 43-05-01-05(1)(h)	**N.D.A.C. § 43-05-01-05(1)** h. A leak detection and monitoring plan to monitor any movement of the carbon dioxide outside of the	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	**5.7 Environmental Monitoring Plan (p. 5-22)** To verify the injected CO_2 is contained in the storage reservoir, protect all USDW, and demonstrate hydrogeologic properties of the storage reservoir, multiple environments will be monitored.	

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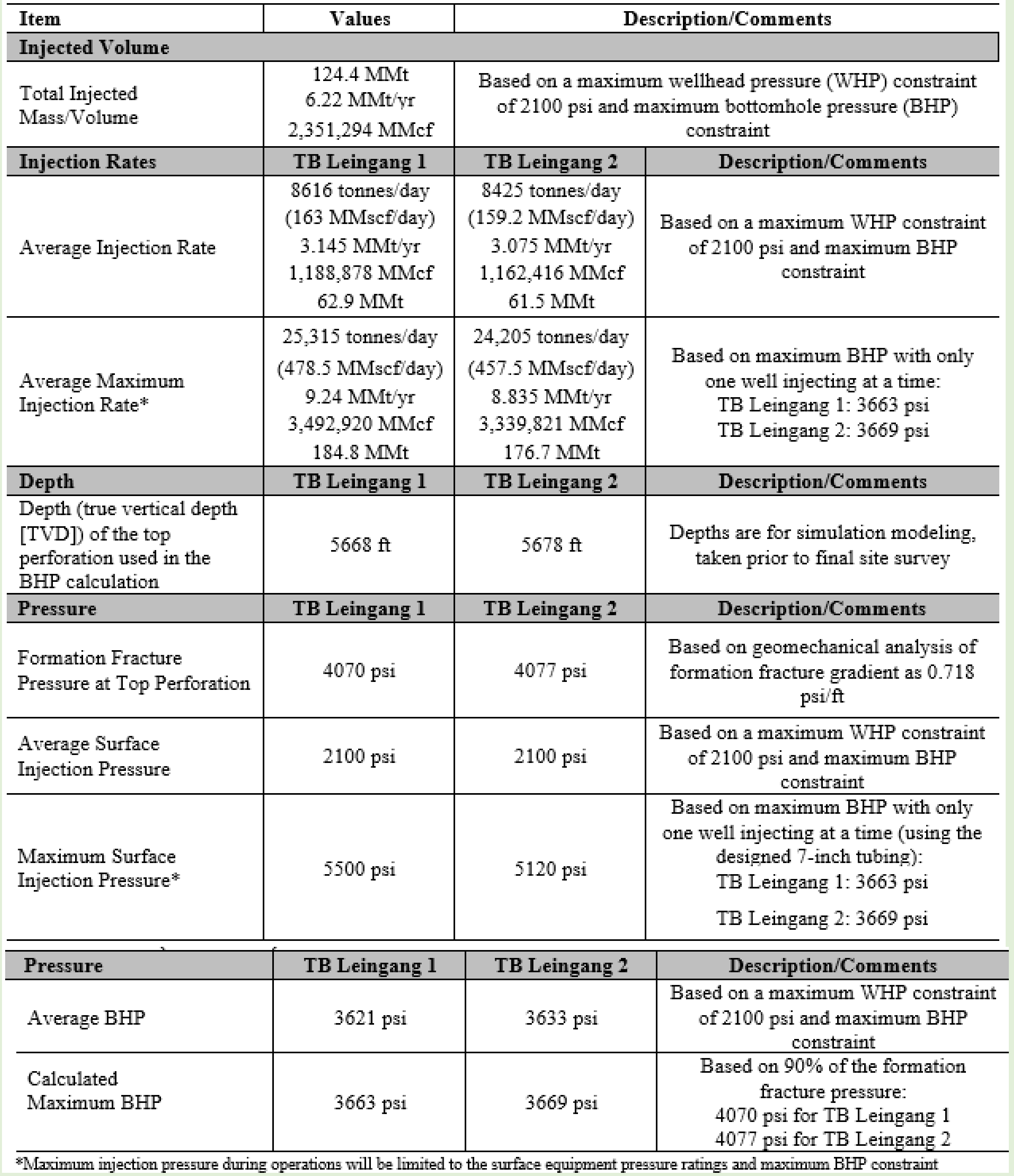
		storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile [1.61 kilometers] of the facility area's outside boundary. Provisions in the plan will be dictated by the site characteristics as documented by materials submitted in support of the permit application but must: (1) Identify the potential for release to the atmosphere; (2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.	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;	As required by N.D.A.C. § 43-05-01-11.4(1)(d) and (h), the near-surface environment, defined as the region from the surface down to the lowest USDW (Fox Hills Aquifer), will be monitored by sampling and analyzing vadose-zone soil gas at two soil gas profile stations, one new Fox Hills monitoring well, and up to four existing groundwater wells. 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 confining zone above the storage reservoir to the confining zone above the next permeable zone above the storage reservoir (i.e., Opeche/Spearfish Formation to the Skull Creek Formation). The AZMI will be continuously monitored with DTS fiber optics in the TB Leingang 1 and 2 wellbores as well as PNLs. Pursuant to N.D.A.C. § 43-05-01-11.4(1)(g), the storage reservoir will be monitored with both direct and indirect methods. Direct methods include continuous fiber optics (DTS) and downhole P/T measurements in the TB Leingang 1 and 2 and Milton Flemmer 1 and falloff tests and PNLs in the TB Leingang 1 and 2 wellbores. Falloff testing analysis will provide reservoir pressure data and the completion condition including transmissibility, skin factor, and well flowing and static pressure data for technical adequacy to demonstrate no migration from the reservoir. Indirect methods include time-lapse seismic surveys. These efforts will provide assurance that surface and near-surface environments are protected and that the injected CO_2 is safely and permanently contained in the storage reservoir. In addition, SCS1 will install multiple seismometer stations for passively detecting and locating seismic events. ***5.7.1 Soil Gas Monitoring*** 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. Two permanent soil gas profile stations installed adjacent to both the CO_2 injection and Milton Flemmer 1 well pads will be sampled, as shown in Figure 5-4. Figure 5-5 is a typical wellbore schematic of a soil gas profile station. The sampling frequency for soil gas is summarized in Tables 5-1 and 5-2. During injection, SCS1 may install additional replacement or alternative soil gas sampling sites based on monitoring data results. SCS1 will notify DMR-O&G if either replacement or alternative soil gas sampling sites are added pursuant to N.D.A.C. § 43-05-01-18(2). The results of the baseline soil gas sampling program will be provided to DMR-O&G prior to injection. ***5.7.2 Groundwater Monitoring*** Groundwater monitoring directly measures the chemical constituents of the water in the pore space between grains of subsurface geologic formations (aquifers) and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. Figure 5-4 identifies the sampling locations associated with the near-surface baseline and operational monitoring plan, which includes one new Fox Hills monitoring well, and up to four existing groundwater wells. SCS1 will work with landowners of the four existing groundwater wells (MGW01, MGW03, MGW04, and MGW09) to attempt to collect samples as specified in Tables 5-1 and 5-2. The number of samples collected from each existing groundwater well may vary by location, since some of the groundwater wells may not be operated year-round or site accessibility may be limited (e.g., snow cover during winter months). If SCS1 is ever unable to access the wells due to operational status or access concerns, it will document the reason why it was unable to take samples. An attempt was made to identify alternative wells that operate year-round with reduced access concerns but produced no results. SCS1 will install one Fox Hills monitoring well (MGW11) adjacent to the injection well pad (as shown in Figure 5-4). The Fox Hills monitoring well will be sampled according to the sampling frequency specified in Tables 5-1 and 5-2. SCS1 reserves the right to evaluate and modify, if necessary, appropriate groundwater sampling locations and frequency based on conformance of the CO_2 plume extent in the subsurface. SCS1 will notify DMR-O&G if alternative or new water wells are added to the sampling program pursuant to N.D.A.C. § 43-05-01-18(2). Appendix B includes a supplemental baseline dataset of historic geochemistry results for four groundwater wells within the AOR boundary. The data were obtained from the Department of Water Resources (DWR) website. The wells are DWR 9433, 9053, 9055, and 9056, as shown in Figure B-1. These shallow groundwater wells were excluded from the baseline and operational monitoring plan primarily because they did not meet the depth criterion used to select wells for inclusion in the testing and monitoring plan. ***5.7.3 Deep Subsurface Monitoring***	

Subject	N.D.C.C./N.D.A.C. 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)
				Pursuant to N.D.A.C. § 43-05-01-11.4(1)(g), SCS1 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 direct and indirect storage reservoir monitoring methods described in this subsection of the permit application will be used to characterize the CO_2 plume's saturation and pressure within the AOR for the baseline and operational phases. *5.7.3.3 Direct Reservoir Monitoring* DTS fiber optics installed in the TB Leingang 1 and 2 and Milton Flemmer 1 wellbores will directly monitor the temperature of the storage reservoir. P/T readings from the casing-conveyed gauges in the CO_2 injection wells will also monitor conditions in the storage reservoir. To track the pressure front from CO_2 injection in the storage reservoir, pressure will be measured continuously from the downhole tubing-conveyed P/T gauge installed in the Milton Flemmer 1 well. To track the CO_2 plume in the storage reservoir, the DTS fiber-optic cable and temperature measurements from the downhole P/T gauge installed in the Milton Flemmer 1 well be used to estimate the timing of arrival of the CO_2 plume at the reservoir-monitoring well. The pressure and temperature data will be used to ensure the monitoring data from the Broom Creek Formation (from Amsden Formation through Opeche/Spearfish Formation) is conforming to the geologic model and numerical simulations. Pressure falloff tests will be performed in the CO_2 injection to demonstrate the performance of the storage reservoir. *5.7.3.5 Indirect Reservoir Monitoring* SCS1 will acquire 3D time-lapse seismic surveys to track the extent of the CO_2 plume within the storage reservoir. The 200-mi2 3D Beulah seismic survey referenced in Section 2.0 will serve as the baseline survey. To demonstrate conformance between the reservoir model simulation and site performance, localized 3D seismic surveys will be collected to monitor the extent of the CO_2 plume, as shown in Figure 5-6 and detailed in Table 5-2. SCS1 will reevaluate the testing and monitoring plan, inclusive of the design and frequency of the repeat 3D seismic surveys, at least once every 5 years, as required. If necessary, the time-lapse seismic monitoring strategy will be adapted based on updated simulations of the predicted extents of the CO_2 plume, including expanding the 3D survey area to capture additional data as the CO_2 plume expands in the storage reservoir. SCS1 plans to install multiple seismometer stations to continuously monitor for seismic events with a magnitude of >1.5 within the AOR boundary during injection. The 3D seismic survey data (e.g., velocity modeling) collected within the AOR boundary will provide supporting evidence for confidently locating seismic events. A traffic light system for detecting larger magnitude events (e.g., >2.7) is presented with the Indirect Reservoir Monitoring QASP section of this application. **5.9 Adaptive Management Approach** SCS1 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 DMR-O&G for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by DMR-O&G. 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.	
	N.D.A.C. § 43-05-01-05(1)(l)	**N.D.A.C. § 43-05-01-05(1)** l. A testing and monitoring plan pursuant to section 43-05-01-11.4;	g. A testing and monitoring plan pursuant to N.D.A.C. Section 43-05-01-11.4;	See Section **5.0 TESTING AND MONITORING PLAN** Note: See Table 5-1 on p. 5-2; Table 5-2 on p. 5-4; Table 5-5 on p. 5-19; Table 5-6 on p. 5-20, for detailed summaries of the testing and monitoring plan.	**Table 5-1.** Overview of Major Components of the Testing and Monitoring Plan – Preinjection (p. 5-2)

Subject	N.D.C.C./N.D.A.C. 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. Overview of Major Components of the Testing and Monitoring Plan – Injection (p. 5-4) **Table 5-5.** Completed Logging and Testing Activities for Milton Flemmer 1 (p. 5-19) **Table 5-6.** Logging and Testing Plan for the TB Leingang 1 Wellbore (p. 5-20)
	N.D.A.C. § 43-05-01-05(1)(i)	**N.D.A.C. § 43-05-01-05 (1)** i. The proposed well casing and cementing program detailing compliance with section 43-05-01-09;	h. The proposed well casing and cementing program;	**9.0 WELL CASING AND CEMENTING PROGRAM** (p. 9-1) Summit Carbon Storage #1, LLC (SCS1) plans to construct two CO_2 injection wells TB Leingang 1 (API 33-065-00026, North Dakota Industrial Commission [NDIC] File No. 40158) and TB Leingang 2 (API 33-065-00027, NDIC File No. 40178) and reenter and convert the Milton Flemmer 1 stratigraphic test well (API 33-057-00041, NDIC File No. 38594) into a reservoir-monitoring well. The following information represents the current proposed state for TB Leingang 1 (Figures 9-1 and 9-2, Tables 9-1 through 9-4) and TB Leingang 2 (Figures 9-3 and 9-4, Tables 9-5 through 9-8), the current, as-constructed state for Milton Flemmer 1 (Figure 9-5, Tables 9-9 through 9-12), and a radial cement bond log (RCBL) evaluation summary for Milton Flemmer 1 (Figure 9-6).	**Figure 9-1**. TB Leingang 1 proposed wellbore schematic. (p. 9-2) **Figure 9-2**. TB Leingang 1 proposed wellbore trajectory. (p. 9-3) **Figure 9-3.** TB Leingang 2-proposed wellbore schematic. (p. 9-7) **Figure 9-4.** TB Leingang 2 proposed wellbore trajectory. (p. 9-8) **Figure 9-5**. Milton Flemmer 1 as-constructed wellbore schematic. (p. 9-12) **Figure 9-6.** Milton Flemmer 1 cement evaluation – RCBL from Milton Flemmer 1 verifies the cement bond quality. Using a high-resolution image, the analyst can assess isolation in the CO_2 injection zone, confining

Subject	N.D.C.C./N.D.A.C. 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)
					zones, and USDWs. (p. 9-15)
	N.D.A.C. § 43-05-01-05(1)(m)	**N.D.A.C. § 43-05-01-05(1)** m. A plugging plan that meets requirements pursuant to section 43-05-01-11.5;	i. A plugging plan;	***Refer to Section 10.1 TB Leingang 1: Proposed Injection Well P&A Program (p. 10-1)*** ***Refer to Section 10.2 TB Leingang 2: Proposed Injection Well P&A Program (p. 10-8)*** ***Refer to Section 10.3 Milton Flemmer 1: Proposed Reservoir-Monitoring Well P&A Program (p. 10-15)***	**Figure 10-1**. TB Leingang 1 proposed completion wellbore schematic. (p. 10-2) **Figure 10-2.** TB Leingang 1 proposed P&A wellbore schematic. (p. 10-7) **Figure 10-3**. TB Leingang 2 proposed completion wellbore schematic. (p. 10-9) **Figure 10-4.** TB Leingang 2 proposed P&A wellbore schematic (p. 10-14) **Figure 10-5.** Milton Flemmer 1 proposed completion wellbore schematic. (p. 10-16) **Figure 10-6.** Milton Flemmer 1 proposed P&A wellbore schematic. (p. 10-21)
	N.D.A.C. § 43-05-01-05(1)(n)	**N.D.A.C. § 43-05-01-05(1)** n. A postinjection site care and facility closure plan pursuant to section 43-05-01-19; and	j. A post-injection site care and facility closure plan.	**6.0 POSTINJECTION SITE AND FACILITY CLOSURE PLAN (p. 6-1)** Note: Refer to Table 6-1 on p. 6-2 for a summary of the postinjection site care monitoring plan.	**Table 6-1.** Overview of Postinjection Testing and Monitoring Activities (p. 6-2)
Storage Facility Operations	N.D.A.C. § 43-05-01-05(1)(b)(4)	**N.D.A.C. § 43-05-01-05(1)(b)** (4) The proposed calculated average and maximum daily injection rates, daily volume, and the total anticipated volume of the carbon dioxide stream using a method acceptable to and filed with the commission;	The following items are required as part of the storage facility permit application: a. The proposed average and maximum daily injection rates;	**11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)**	**Table 11-1.** TB Leingang 1 and TB Leingang 2: Proposed Injection Wells Operating Parameters (p. 11-1)

Subject	N.D.C.C./N.D.A.C. 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 11-1. TB Leingang 1 and TB Leingang 2: Proposed Injection Well Operating Parameters 	
			b. The proposed average and maximum daily injection volume;		
			c. The proposed total anticipated volume of the carbon dioxide to be stored;		
	N.D.A.C. § 43-05-01-05(1)(b)(5)	**N.D.A.C. § 43-05-01-05(1)(b)** (5) The proposed average and maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in pounds per square inch gauge, shall be approved by the commission and specified in the permit. In approving a maximum injection pressure limit, the commission shall consider the results of well tests and other studies that assess the risks of tensile failure and shear failure. The commission shall approve limits that, with a reasonable degree of certainty, will avoid initiating a new fracture or propagating an existing fracture in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water;	d. The proposed average and maximum bottom hole injection pressure to be utilized; e. The proposed average and maximum surface injection pressures to be utilized;		

Item	Values		Description/Comments
Injected Volume			
Total Injected Mass/Volume	124.4 MMt 6.22 MMt/yr 2,351,294 MMcf		Based on a maximum wellhead pressure (WHP) constraint of 2100 psi and maximum bottomhole pressure (BHP) constraint
Injection Rates	**TB Leingang 1**	**TB Leingang 2**	**Description/Comments**
Average Injection Rate	8616 tonnes/day (163 MMscf/day) 3.145 MMt/yr 1,188,878 MMcf 62.9 MMt	8425 tonnes/day (159.2 MMscf/day) 3.075 MMt/yr 1,162,416 MMcf 61.5 MMt	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Average Maximum Injection Rate*	25,315 tonnes/day (478.5 MMscf/day) 9.24 MMt/yr 3,492,920 MMcf 184.8 MMt	24,205 tonnes/day (457.5 MMscf/day) 8.835 MMt/yr 3,339,821 MMcf 176.7 MMt	Based on maximum BHP with only one well injecting at a time: TB Leingang 1: 3663 psi TB Leingang 2: 3669 psi
Depth	**TB Leingang 1**	**TB Leingang 2**	**Description/Comments**
Depth (true vertical depth [TVD]) of the top perforation used in the BHP calculation	5668 ft	5678 ft	Depths are for simulation modeling, taken prior to final site survey
Pressure	**TB Leingang 1**	**TB Leingang 2**	**Description/Comments**
Formation Fracture Pressure at Top Perforation	4070 psi	4077 psi	Based on geomechanical analysis of formation fracture gradient as 0.718 psi/ft
Average Surface Injection Pressure	2100 psi	2100 psi	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Maximum Surface Injection Pressure*	5500 psi	5120 psi	Based on maximum BHP with only one well injecting at a time (using the designed 7-inch tubing): TB Leingang 1: 3663 psi TB Leingang 2: 3669 psi
Pressure	**TB Leingang 1**	**TB Leingang 2**	**Description/Comments**
Average BHP	3621 psi	3633 psi	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Calculated Maximum BHP	3663 psi	3669 psi	Based on 90% of the formation fracture pressure: 4070 psi for TB Leingang 1 4077 psi for TB Leingang 2

*Maximum injection pressure during operations will be limited to the surface equipment pressure ratings and maximum BHP constraint

<table>
<tr><th>Subject</th><th>N.D.C.C./N.D.A.C. Reference</th><th>Requirement</th><th colspan="2">Regulatory Summary</th><th>Storage Facility Permit Application (Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description (Page Number)</th></tr>
<tr><td rowspan="2"></td><td rowspan="2">N.D.A.C. § 43-05-01-05(1)(b)(6)</td><td rowspan="2">N.D.A.C. § 43-05-01-05(1)(b)
(6) The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone pursuant to section 43-05-01-11.2;</td><td>f.</td><td>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 Baseline Wellbore Logging and Testing Plan (p. 5-18)

See Appendix A: WELL AND WELL FORMATION FLUID SAMPLING LABORATORY ANALYSIS

2.0 GEOLOGIC EXHIBITS
<i>Refer to 2.2 Data and Information Services (p. 2-4)</i>
<i>Refer to 2.2.2 Site-Specific Data (p. 2-6)</i>

2.2.2.2 Core Sample Analyses (p. 2-8)

Table 5-6. Logging and Testing Plan for the TB Leingang 1 and TB Leingang 2 Wellbores
<table>
<tr><th></th><th>Logging/Testing</th><th>Justification</th><th>N.D.A.C. § 43-05-01-11.2</th></tr>
<tr><td rowspan="2">Surface Section</td><td>Open-hole logs: triple combo, SP, caliper, and temperature</td><td>Quantify variability in reservoir properties, such as resistivity and lithology, and measure hole conditions.</td><td>(1)(b)(1)</td></tr>
<tr><td>Cased-hole logs: ultrasonic tool or other CIL and array sonic tools (inclusive of CCL, VDL, and RCBL), GR, and temperature</td><td>Identify cement bond quality radially, evaluate the cement top and zonal isolation, and establish external mechanical integrity. Establish baseline temperature profile for temperature-to-DTS calibration.</td><td>(1)(b)(2) and (1)(d)</td></tr>
<tr><td rowspan="7">Long-String Section</td><td>Open-hole logs:
quad combo (triple combo plus dipole sonic*), SP, GR, and caliper</td><td>Quantify variability in reservoir properties, including resistivity, porosity, and lithology, and measure hole conditions. Provide input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve interpretations. Identify mechanical properties, including stress anisotropy. Provide compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.</td><td>(1)(c)(1)</td></tr>
<tr><td>Open-hole log: fracture finder log</td><td>Quantify fractures in the Broom Creek Formation and confining layers to ensure safe, long-term storage of CO_2.</td><td>(1)(c)(1)</td></tr>
<tr><td>Open-hole log: magnetic resonance log</td><td>Aid in interpreting reservoir permeability and determine the best location for modular formation dynamics testing (MDT) fluid-sampling depths, packer-setting depths, and stress-testing depths.</td><td>(1)(c)(1)</td></tr>
<tr><td>Open-hole log: MDT fluid sampling and testing</td><td>Collect fluid sample from the Broom Creek Formation for analysis.</td><td>(1), (2), and (3)</td></tr>
<tr><td>Open-hole log: spectral GR</td><td>Identify clays and lithology that could affect injectivity. Also used for core to log depth correlation.</td><td>(4)(b)</td></tr>
<tr><td>Injectivity test</td><td>Perform to define the fracture gradient and maximum allowable injection pressure of the storage reservoir.</td><td>(4)</td></tr>
<tr><td>Pressure falloff test</td><td>Perform to verify hydrogeologic characteristics of the Broom Creek Formation.</td><td>(5)</td></tr>
</table>
</td><td rowspan="2">Table 5-6. Logging and Testing Plan for the TB Leingang 1 and TB Leingang 2 Wellbores (p. 5-20)</td></tr>
<tr><td>g.</td><td>The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the confining zone;</td></tr>
</table>

<table>
<tr><th>Subject</th><th>N.D.C.C./N.D.A.C. Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description (Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td><table>
<tr><td>Cased-hole log: PNL</td><td>Confirm mechanical integrity from Opeche/Spearfish Formation to surface.</td><td>11.4(g)(1)</td></tr>
<tr><td>Cased-hole logs: ultrasonic tool or other CIL and array sonic tools (inclusive of CCL, VDL, and RCBL), GR, and temperature</td><td>Confirm cement bond quality radially, evaluate cement top and zonal isolation and demonstrate mechanical integrity. Establish baseline for casing inspection logging and temperature profile for temperature-to-DTS calibration.</td><td>(1)(c)(2) and (d)</td></tr>
</table>
* Dipole sonic logging may be excluded in TB Leingang 2 assuming that the dipole sonic log is successful in TB Leingang 1.</td><td></td></tr>
<tr><td></td><td>N.D.A.C. § 43-05-01-05(1)(b)(7)</td><td>N.D.A.C. § 43-05-01-05(1)(b)
(7) The proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment; and</td><td>h. The proposed stimulation program:
1. A description of the stimulation fluids to be used
2. A determination of the probability that stimulation will interfere with containment</td><td>11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)

Refer to Site Well Work Preparations for TB Leingang 1 on page 11-7 and Site Well Work Preparations for TB Leingang 2 on page 11-15.</td><td>N/A</td></tr>
<tr><td></td><td>N.D.A.C. § 43-05-01-05(1)(b)(8)</td><td>N.D.A.C. § 43-05-01-05(1)(b)
(8) The proposed procedure to outline steps necessary to conduct injection operations.</td><td>i. Steps to begin injection operations</td><td>11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)

Refer to Site Well Work Preparations for TB Leingang 1 on page 11-7 and Site Well Work Preparations for TB Leingang 2 on page 11-15.

)</td><td>N/A</td></tr>
</table>