DOE/EA-2197D

Revised Draft Environmental Assessment for North Dakota CarbonSAFE: Project Tundra

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National Energy Technology Laboratory **U.S. Department of Energy**

Responsible Agency: U.S. Department of Energy

Title: Project Tundra, Environmental Assessment (DOE/EA-2197D)

Location: Milton R. Young Power Plant, 3401 24th Street S.W., Center, ND 58530

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Abstract: The United States (U.S.) Department of Energy (DOE) prepared this Environmental Assessment (EA) to analyze the potential environmental, cultural, and socioeconomic impacts of partially funding a proposed project to design, construct, and operate an amine-based post-combustion carbon dioxide (CO_2) capture technology at a coal-fired power plant. DOE proposes to provide cost-shared funding to Minnkota Power Cooperative, Inc. (Minnkota) for the project at Minnkota's Milton R. Young Station (MRY), an existing lignite-fired coal power plant in Oliver County, North Dakota.

Under the Proposed Action, DOE proposes to provide project cost-shared financial assistance to Minnkota. Based on the best available projections, the project's cost is estimated to be approximately $77 million, and the DOE share would be approximately $38.5 million. The project partners are required to obtain funding for the remaining 50 percent of the project cost. It is important to note that the costs are estimates, based on DOE's knowledge of the cost of construction for Carbon Capture, Utilization, and Storage (CCUS) projects. Exact costs are not available, because Minnkota has not been selected to receive DOE funding for the proposed project at this time.

Availability: This EA was released for public review and comment after publication of the Notice of Availability in the Bismarck Tribune on August 19, 2023. DOE received many comments on the Draft EA. Due to the increased level of public interest and number of comments received, DOE prepared a Comment Response document, included as Appendix K, and is reissuing the Draft EA. An additional 30-day comment period will allow interested parties to review the comments and responses, as well as any edits to the Draft EA. Changes to the text of the Draft EA are shown with a line down the left side for ease of comparison. The public is invited to provide written or e-mail comments to DOE on the Draft EA during the comment period, which will occur from April 13 to May 13, 2024. Copies of the Draft EA will be distributed to cognizant agencies, Native American Tribes, public libraries, and interested parties. The Draft EA is available on DOE's National Energy Technology Laboratory website, https://netl.doe.gov/node/6939 and DOE's National Environmental Policy Act (NEPA) website at (https://www.energy.gov/nepa/doe-environmental-assessments). The Draft EA is also available for review at Bismarck Veterans Memorial Public Library, 515 N 5th St, Bismarck, ND 58501, and the North Dakota State Library, 604 E Boulevard Ave, Bismarck, ND 58505. All copies of the document were disseminated electronically, with the exception of hardcopies mailed to the libraries and Native American Tribes. DOE will consider late comments to the extent practicable.

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ACRONYMS AND ABBREVIATIONS

°F	degrees Fahrenheit
AAQS	Ambient Air Quality Standards
ANSI	American National Standards Institute
BCC	Birds of Conservation Concern
BGEPA	Bald and Golden Eagle Protection Act
BIL	Bipartisan Infrastructure Law
BMP	best management practice
BP	Before Present
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CAA	Clean Air Act
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCUS	Carbon Capture, Utilization, and Storage
CEQ	Council on Environmental Quality
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFR	Code of Federal Regulations
CH_4	methane
CJEST	Climate and Economic Justice Screening Tool
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CWA	Clean Water Act
CX	Categorical Exclusion
DOE	U.S. Department of Energy
DoH	North Dakota Department of Health
DOI	U.S. Department of the Interior
DMR	Department of Mineral Resources
EA	Environmental Assessment
EERC	University of North Dakota Energy and Environmental Research Center
EIV	Environmental Information Volume
EO	Executive Order
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
FECM	Office of Fossil Energy and Carbon Management
FEMA	Federal Emergency Management Agency
FIRM	Flood Insurance Rate Map
FOA	Funding Opportunity Announcement
GHG	greenhouse gas
gpm	gallons per minute
GWP	global warming potential
HAP	hazardous air pollutant
HAZOP	hazard and operability
Hg	mercury

HUC	Hydrologic Unit Code
IPaC	Information for Planning and Consultation
IWG	Interagency Working Group
IWG Report	Interagency Working Group on Social Cost of Greenhouse Gases Report
kg	kilogram
KM CDR	Kansai Mitsubishi Carbon Dioxide Recovery
kV	kilovolt
LCA	Life Cycle Analysis
MBTA	Migratory Bird Treaty Act
mD	millidarcy
mg/L	milligrams per liter
MHI	Mitsubishi Heavy Industries
Minnkota	Minnkota Power Cooperative, Inc.
MLRA	Major Land Resource Areas
MMT/yr	million metric tons per year
MRV Plan	Monitoring, Reporting, and Verification Plan
MRY	Milton R. Young Station
MWe	megawatt electric
MWg	megawatts (gross)
MWh	megawatt-hour
N_2O	nitrous oxide
$NaSO_4$	sodium sulfate
NAAQS	National Ambient Air Quality Standards
NPS	National Park Service
NDDEQ	North Dakota Department of Environmental Quality
NDGF	North Dakota Game and Fish Department
NDIC	North Dakota Industrial Commission
NEPA	National Environmental Policy Act
NOAA	National Oceanic and Atmospheric Administration
NOx	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NRCS	Natural Resources Conservation Service
NRHP	National Register of Historic Places
OCED	Office of Clean Energy Demonstrations
OSHA	Occupational Safety and Health Administration
PCOR	Plains CO_2 Reduction
PHA	Process Hazard Analysis
PM_{10}	particulate matter 10 microns or less in diameter
$PM_{2.5}$	particulate matter 2.5 microns or less in diameter
ppm	parts per million
Project	Project Tundra
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psig	pounds per square inch gauge
RCRA	Resource Conservation and Recovery Act

SC-GHG	social cost of greenhouse gas
SC-CH_4	social cost of methane
SC-CO_2	social cost of carbon dioxide
SC-N_2O	social cost of nitrous oxide
SCP	Species of Conservation Priority
SER	significant emission rates
SF_6	sulfur hexafluoride
SHPO	North Dakota State Historical Society, State Historic Preservation Office
SO_2	sulfur dioxide
STPD	short tons per day
SWAP	North Dakota State Wildlife Action Plan
SWPPP	Stormwater Pollution Prevention Plan
TDS	total dissolved solids
TMDL	Total Maximum Daily Load
tpy	tons per year
UDP	Unanticipated Discoveries Plan
U.S.	United States
U.S.C.	United States Code
UIC	Underground Injection Control
USCB	U.S. Census Bureau
USDA	U.S. Department of Agriculture
USDW	underground source of drinking water
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
wet ESP	wet electrostatic precipitator
ZLD	zero liquid discharge

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CHAPTER 1. INTRODUCTION

The United States (U.S.) Department of Energy (DOE) National Energy Technology Laboratory prepared this Environmental Assessment (EA) under the National Environmental Policy Act (NEPA), as amended, and other relevant federal and state laws and regulations. This EA analyzes the potential environmental and social impacts of partially funding Minnkota Power Cooperative, Inc. (Minnkota) for the proposed North Dakota CarbonSAFE: Project Tundra. The project would include new infrastructure and equipment for the capture and geologic storage of carbon dioxide (CO_2) generated by the existing lignite-fired Milton R. Young Station (MRY) in Center, Oliver County, North Dakota, and would utilize Mitsubishi Heavy Industries' (MHI) Kansai Mitsubishi Carbon Dioxide Recovery (KM CDR) amine-based post-combustion carbon capture technology.

1.1 Document Structure

This EA discloses the direct, indirect, and cumulative environmental effects that would result from the Proposed Action and alternatives. The document is organized into four parts:

- Chapter 1: Introduction—This chapter includes information on the project proposal, the purpose of and need for the project, and the agency's proposal for achieving that purpose and need.
- Chapter 2: Proposed Action and Alternatives—This chapter provides a more detailed description of the agency's Proposed Action as well as alternative methods for achieving the stated purpose. Alternatives considered but not analyzed in detail are also discussed in this chapter.
- Chapter 3: Affected Environment and Environment Consequences—This chapter contains a description of current resource conditions in the project area and the environmental effects of the No Action Alternative and implementing the Proposed Action.
- Chapter 4: List of Preparers—This chapter provides a list of preparers for the EA.
- Chapter 5: Distribution List—This chapter provides a list of the recipients of the EA.
- Appendices—The appendices provide information on consultation efforts and other information to support the analyses presented in the EA, including literature citations (Appendix A).

1.2 Background

In 2016, Congress directed the DOE's Office of Fossil Energy and Carbon Management (FECM) to test, mature, and prove Carbon Capture, Utilization, and Storage (CCUS) technologies at commercial scale. DOE developed the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative to fulfill the need for research into safe, efficient, and effective characterization and permitting of commercial-scale CCUS projects. CarbonSAFE projects include storage complexes capable of safely and efficiently storing commercial volumes of CO_2. Storage complexes are geologic reservoirs with permeability and porosity that allow for injection and storage of CO_2, as well as one or more low-permeability seals, which overlay the target storage reservoir(s) and serve as barriers preventing upward migration of CO_2 out of the reservoir(s). Project sites include both the surface footprint and subsurface storage complex over the entire volume of subsurface impacted by the injection. All projects include required monitoring of the target storage reservoir and the surrounding area throughout the project's injection and post-injection phases.

To implement the CarbonSAFE Initiative, DOE established sequential phases of development: Phase I – Integrated CCUS Pre-Feasibility; Phase II – Storage Complex Feasibility; Phase III – Site Characterization and Permitting; and Phase IV – Site Construction. DOE recently added a Phase III.5 in order to accommodate projects that have completed some of the requirements of Phase III prior to applying for DOE funding. DOE issued Funding Opportunity Announcement (FOA) DE-FOA-0001450 (Phase II) in 2017. In 2019, DOE issued DE-FOA-0001999 to request proposals for CarbonSAFE Phase III. DOE conducted a competitive merit review of the proposals and selected projects for Phase III in 2020.

During Phase III, each project team will complete the acquisition, analysis, and development of information to fully characterize a storage complex capable of storing commercial volumes of CO_2 (a minimum of 50 million metric tons of CO_2 within a 30-year period). In addition, Phase III requires the identification of the target storage reservoir(s) within the storage complex, as well as the preparation and submission of the U.S. Environmental Protection Agency's (EPA) Underground Injection Control (UIC) Class VI Permit to Construct for each proposed injection well at the site(s). Once the UIC Class VI Permit(s) to Construct is submitted, any additional activities will include working with the regulators to satisfy their requirements until construction authorization is granted. Finally, Phase III will address pore/surface rights, right(s)-of-way, and all other permitting processes and requirements, liability relief, and finance agreements in support of the business model for eventual commercial operations, as needed. Phase III project participants awarded under DE-FOA-0001999 are required to complete NEPA reviews for a potential Phase IV project, which would include construction of the injection well(s) and obtaining authorization to proceed with commercial scale injection via an Operating Permit from the EPA's UIC Class VI Permitting Process. DOE prepared this EA in response to the requirement to complete the NEPA process as part of the Phase III project. This project has not been selected for a CarbonSAFE Phase IV (construction) project at this time.

"North Dakota CarbonSAFE: Project Tundra" was selected under Phase III and must complete the NEPA process for a potential Phase IV project. DOE assessed this project, as required by NEPA implementing procedures and regulations, as amended, and issued Categorical Exclusions (CXs) prior to the separate, but related, projects in Phase II and Phase III for work conducted in those phases. Copies of all CXs for the previous phases of the proposed project are included in Appendix B. CX documents are also available online at https://netl.doe.gov/nepa.

1.3 Federal Proposed Action

DOE's proposed action is to provide cost-shared financial assistance to Minnkota for the project. Funding for this project is available under two DOE programs, both with funds appropriated by the Infrastructure Investment and Jobs Act, more commonly known as the Bipartisan Infrastructure Law (BIL). Minnkota may apply under either or both FOAs for DOE project funding but may not receive funds from both DOE programs for the same scope of work.

FECM issued DE-FOA-0002711, *Bipartisan Infrastructure Law (BIL): Storage Validation and Testing (Section 40305): Carbon Storage Assurance Facility Enterprise (CarbonSAFE): Phases III, III.5, and IV*, in September 2022. CarbonSAFE Phase IV projects would construct the commercial-scale secure geologic storage facility and prepare it for CO_2 injection. This includes drilling and completion of injection and monitoring wells; completion of risk and mitigation plans; completing all the baseline and any additional monitoring data; completing all other project infrastructure (e.g., CO_2 pipelines, injection facility); and obtaining a Class VI Authorization to Inject or equivalent. DOE funding of Phase IV would not include the operation of the CO_2 injection and storage project. Because the operation of the project can reasonably be expected to occur after the construction is completed, the impacts of operation of the facility are considered to be part of the proposed project for the purposes of the EA.

DOE's Office of Clean Energy Demonstrations (OCED) issued DE-FOA-0002962, *Carbon Capture Demonstration Projects Program*, in February 2023. Projects awarded under this FOA would demonstrate transformational domestic, commercial-scale, integrated carbon capture and storage projects designed to further advance the development, deployment, and commercialization of technologies to capture, transport (if required), and store CO_2 emissions from electric generation facilities or other industrial facilities.

Based on the best available projections, the Phase IV cost is estimated to be approximately $77 million, and the DOE share would be approximately $38.5 million. It is important to note that the costs are estimates, based on DOE's knowledge of the cost of construction for CCUS projects. Exact costs are not available, because Minnkota has not been selected to receive DOE funding for the proposed project at this time. DOE funding of Phase IV would include only the construction of the CO_2 storage facility and its infrastructure; however, because the project cannot proceed without the capture facility, and operation of the storage facility can reasonably be expected to occur after construction is completed, the impacts of these connected actions are included in the analysis of the proposed project's impacts for the purposes of the EA.

1.4 Purpose and Need

The purpose and need for DOE action is to advance the commercial readiness of CCUS by constructing a commercial-scale geologic storage complex and associated CO_2 transport infrastructure. BIL appropriated funds under both the CarbonSAFE Initiative and the Carbon Capture Demonstration Projects Program to further the development, deployment, and commercialization of technologies to capture and geologically store CO_2 emissions securely in the subsurface. Successful implementation of this proposed project will encourage the rapid growth of a vibrant, geographically widespread industry for secure geologic carbon storage by reducing risks and costs for future projects and bringing more storage resources into commercial classifications. Further, this commercial-scale secure geologic storage infrastructure would "support efforts to build a clean and equitable energy economy that achieves zero-carbon electricity by 2035 and puts 'the United States on a path to achieve net-zero emissions, economy-wide, by no later than 2050' to benefit all Americans" (DOE 2023a). If selected, this project would contribute to a diverse portfolio of projects that collectively research, advance and demonstrate the reduction of CO_2 from electricity generation and other industrial sectors.

This project in Oliver County, North Dakota was proposed because a fully characterized storage complex: (1) is able to receive and safely store CO_2 in sufficient quantities to meet the DOE goals of 50 million metric tons over a 30-year period; (2) is located in proximity to one or more CO_2 sources that can supply those quantities; and (3) can be connected to the sources by a transport system that can be built and operated economically.

1.5 National Environmental Policy Act and Related Procedures

DOE prepared this EA in accordance with NEPA, as amended ([Public Law 91–190] [As Amended Through P.L. 118–5, Enacted June 3, 2023]), the President's Council on Environmental Quality (CEQ) regulations for implementing NEPA (40 Code of Federal Regulations [CFR] 1500-1508), and DOE's implementing procedures for compliance with NEPA (10 CFR 1021). This statute and the implementing regulations require that DOE, as a federal agency:

- Assess the environmental impacts of its proposed action;
- Identify any adverse environmental effects that cannot be avoided, should the proposed action be implemented;
- Evaluate alternatives to the proposed action, including a no-action alternative; and
- Describe the cumulative impacts of the proposed action together with other past, present, and reasonably foreseeable future actions.

These provisions must be addressed before a final decision is made to proceed with any proposed federal action that has the potential to cause impacts to the natural or human environment, including providing federal funding to a project. This EA is intended to meet DOE's regulatory requirements under NEPA and provide DOE with the information needed to make an informed decision about providing financial assistance. In accordance with the above regulations, this EA allows for public input into the federal decision-making process; provides federal decision-makers with an understanding of potential environmental effects of their decisions before making these decisions; and documents the NEPA process.

1.6 Laws, Regulations, and Executive Orders

- Clean Air Act (CAA)
- Clean Water Act (CWA)
- Protection of Wetlands (Executive Order [EO]11990)
- Floodplain Management (EO 11988)
- Endangered Species Act (ESA)
- Migratory Bird Treaty Act (MBTA)
- Bald and Golden Eagle Protection Act (BGEPA)
- The Noise Control Act of 1972, as amended
- Federal Actions to Address Environmental Justice in Minority Populations and Low- Income Populations (EO 12898)
- Pollution Prevention Act of 1990
- Resource Conservation and Recovery Act (RCRA)
- Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)
- National Historic Preservation Act

1.7 Public Involvement, Agency Coordination, and Tribal Consultation

DOE coordinated with the following agencies, tribes, and non-governmental agencies through agency consultation letters and/or notification of the availability of the EA. Agency and tribal consultation letters are included in Appendix C.

1.7.1 Federal, State and Local Agencies

The following agencies, tribes, and non-governmental agencies will be provided with consultation letters and/or notification of the availability of the EA.

- Bureau of Indian Affairs
- National Association of State Energy Officials
- National Association of Tribal Historic Preservation Officers
- North Dakota Department of Environmental Quality (NDDEQ)
- North Dakota Game and Fish Department (NDGF)
- North Dakota Industrial Commission (NDIC)
- State and Tribal Government Working Group
- U.S. Army Corps of Engineers
- U.S. Department of the Interior (DOI), Regional Environmental Officer
- U.S. Environmental Protection Agency (EPA), Region 8
- U.S. Fish and Wildlife Service (USFWS)
- U.S. Forest Service (Local Office)

1.7.2 Tribal Governments

- Apache Tribe of Oklahoma
- Fort Belknap Indian Community of the Fort Belknap Reservation of Montana
- Three Affiliated Tribes of the Forth Berthold Reservation, North Dakota

1.7.3 Non-governmental Organizations

- Center for Biological Diversity
- Clean Water Action
- Ducks Unlimited, Inc.
- Earthjustice
- Electric Power Research Institute
- Environmental Defense Fund
- Environmental Defense Institute
- Friends of the Earth
- Greenaction for Health and Environmental Justice
- Institute for Energy and Environmental Research
- National Audubon Society

- The Nature Conservancy
- Sierra Club
- Trout Unlimited
- Utilities Technology Council
- The Wilderness Society
- Western Resource Advocates

CHAPTER 2. PROPOSED ACTION AND ALTERNATIVES

2.1 Introduction

This chapter describes the Proposed Action and No-Action Alternative analyzed in this EA, as well as those alternatives dismissed from further consideration. As described in Chapter 1, CEQ's regulations direct all federal agencies to use the NEPA process to identify and assess the reasonable alternatives to proposed actions that would avoid or minimize adverse effects of these actions upon the quality of the human environment (40 CFR 1502.14).

2.2 Proposed Action

As described in Section 1.3 above, DOE's Proposed Action is to provide cost-shared financial assistance to the proposed Project Tundra. Based on the best available projections, the Phase IV cost is estimated to be approximately $77 million, and the DOE share would be approximately $38.5 million. The project partners are required to obtain funding for the remaining 50 percent of the project cost. It is important to note that the costs are estimates, based on DOE's knowledge of the cost of construction for CCUS projects. Exact costs are not available, because the proposed project has not been selected to receive DOE funding at this time. DOE funding of Phase IV would include only the construction of the CO_2 storage facility and its infrastructure; however, because the project cannot proceed without the capture facility, and operation of the storage facility can reasonably be expected to occur after the construction is completed, the impacts of these connected actions are included in the analysis of the proposed project's impacts for the purposes of the EA.

2.3 No-Action Alternative

Under the No-Action Alternative, DOE would not provide cost-shared funding to the proposed project. The project would be delayed if other funding sources were pursued. Alternatively, the commercial-scale carbon capture and storage project (Project Tundra) may not be constructed. DOE assumes, for the purposes of a meaningful NEPA evaluation of the impacts of funding the project, that the recipient would not pursue the project. Consequently, the commercial-scale geologic storage complex would not be constructed, and the risks would not be reduced for future storage complexes and widespread commercial CCUS would not be advanced.

2.4 Alternatives Considered but Dismissed

NEPA requires DOE to assess the range of reasonable alternatives to the Proposed Action. Because DOE has been instructed by Congress on how to utilize this funding, DOE does not have the authority to utilize these funds for any purpose other than commercial-scale carbon capture and sequestration projects. DOE can only choose to fund or not fund any of the projects applying under a competitive FOA. DOE's **proposed action/purpose** is to provide cost-shared funding, and the only available alternative is not funding the proposed project. Alternatives to the **proposed project** include any other project that meets the goals and objectives of the same FOA. Applicants to DOE's FOAs are assessed for environmental impacts, and the results of those assessments are provided to the selecting official prior to selection, in accordance with 10 CFR 1021.216. In the case of CarbonSAFE Phase IV applications, the selecting official would consider the results of each CarbonSAFE Phase III project's EA or EIS. There are four other projects currently completing the NEPA process in CarbonSAFE Phase III:

- DOE/EA-2194: Wyoming CarbonSAFE
- DOE/EA-2196: Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi: Project ECO_2S
- TBD: San Juan Basin CarbonSAFE
- TBD: Illinois Storage Corridor CarbonSAFE

There are additional projects being selected for CarbonSAFE Phase III, which will also undergo NEPA review. Please see DOE's website (https://netl.doe.gov/node/7677) for a current list of those projects. All CarbonSAFE Phase III projects will be analyzed for potential impacts separately and will not be discussed further in this EA. The CarbonSAFE Initiative Draft EA and EIS documents will continue to be published for review at https://netl.doe.gov/node/6939 and https://netl.doe.gov/library/eis, respectively. DOE's consideration of reasonable alternatives to Project Tundra under NEPA is therefore limited to the No-Action Alternative.

2.5 Project Tundra Description

Minnkota, as the project sponsor and host-site, has proposed to construct Project Tundra, which would be the world's largest post-combustion CO_2 capture and geologic storage project, and would capture and permanently store CO_2 emissions from Minnkota's existing MRY Station, a lignite-fired power plant in Oliver County, North Dakota.

The project consists of the carbon capture facility, a 0.5-mile-long CO_2 flowline; Class VI injection wells (up to three); Class I disposal wells (up to two); one underground source of drinking water (USDW) monitoring well; and deep subsurface monitoring wells (up to two). The project surface facilities are located on Minnkota-owned property. One of the deep subsurface monitoring wells is proposed to be installed approximately two miles northeast of the injection site. The Class I injection wells are proposed for disposal of non-hazardous process wastewater generated by the carbon capture process.

On January 21, 2022, the NDIC approved two geologic storage facilities (MRY-Broom Creek and MRY-Deadwood). Additionally, the design and operating conditions of associated injection wells (Class VI) were also approved as a part of the initial order. For the purposes of this EA, the project includes the surface facilities as described above.

The project would be sized for capture and saline formation geologic storage of an annualized average of 4.0 million metric tons per year (MMT/yr) of CO_2, with a design specification of at least 95 percent CO_2 capture from the processed MRY Unit 1 (250 megawatts gross [MWg] owned by Minnkota) and Unit 2 (455 MWg owned by Square Butte Electric) flue gas, Unit 2 is the principal unit of design. The CO_2 would be compressed and piped via a new 0.5-mile-long CO_2 flowline to an injection site for permanent deep geologic storage. If approved, construction is anticipated to begin in 2024 and to be complete by end of 2028 to first quarter of 2029.

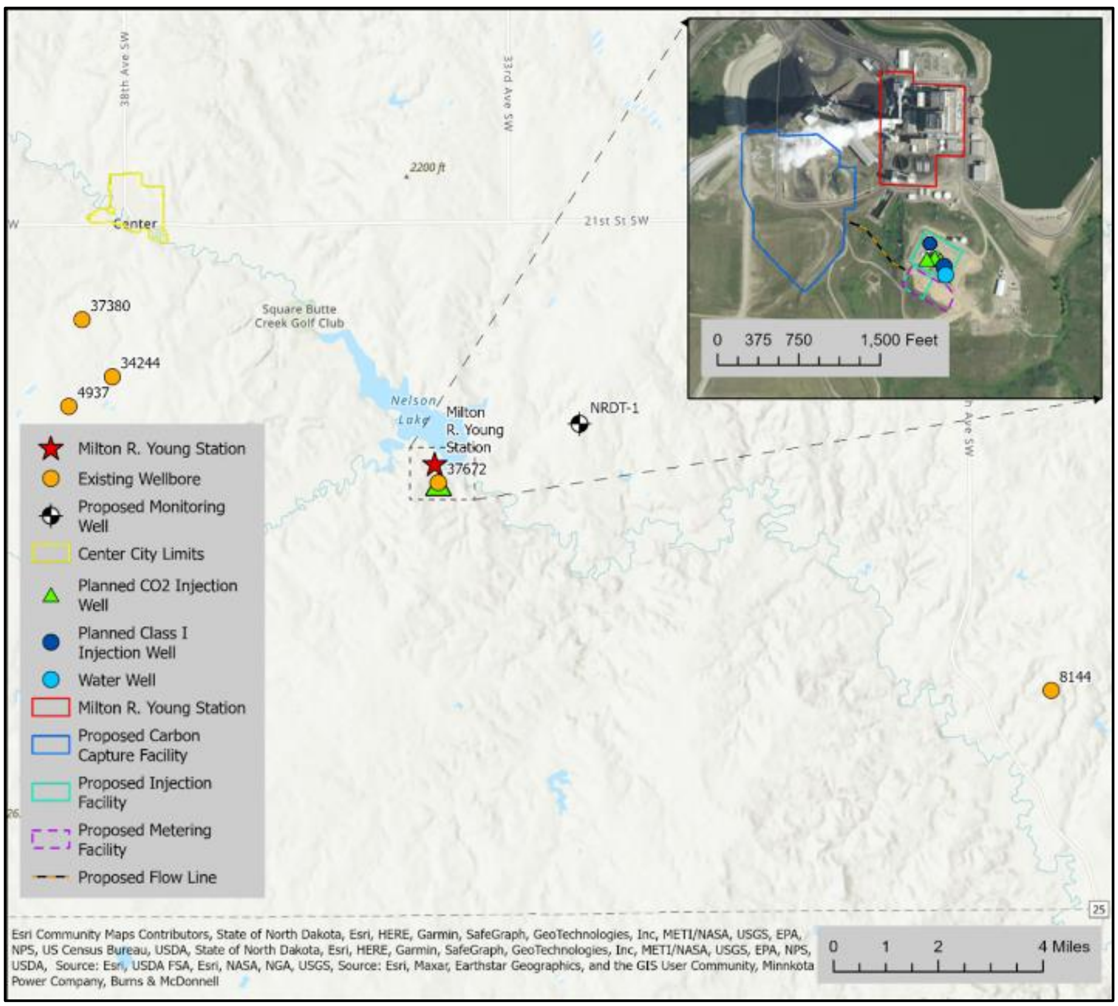
The project would extract steam from the Unit 1 and Unit 2 steam turbines, a necessary component for use in the absorption process. The project would be designed to capture up to 13,000 short tons per day (STPD) of CO_2. During operations, flue gas required to achieve this CO_2 capture rate would require all the flue gas from one unit and a portion of flue gas from the other unit for maximum operation. Various operating scenarios are available and planned to utilize various combinations of flue gas from both units.

The project includes construction of a new water treatment system for operations. Minnkota's existing MRY water system will be upgraded to allow for raw water to be transferred from Nelson Lake to the project water treatment system.

2.5.1 Location and Setting

The proposed project would be located adjacent to MRY near Center, North Dakota (Figure 2-1). The project would be located within the larger MRY associated industrial area that is bound by Nelson Lake to the north and east, coal production and plant waste disposal areas to the south, and agricultural and natural areas to the west.

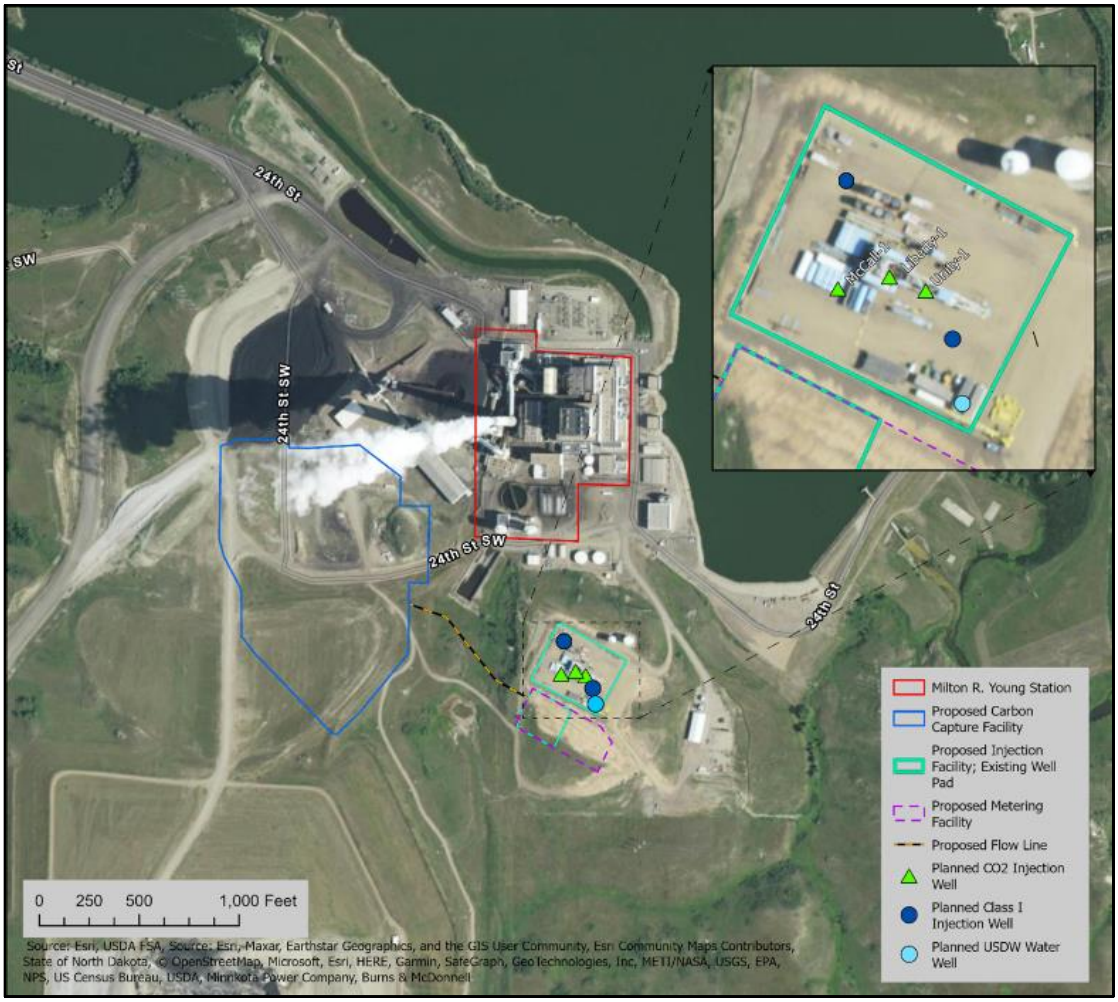
Figure 2-1: Proposed Project Location – MRY Vicinity Map



2.5.2 Facility Configuration and Process Design

The carbon capture facilities would be constructed as a stand-alone facility with a footprint that falls within an irregular area comprised of 25.8 acres west and south of MRY (Figure 2-2). This area is the site of a previously used coal stockpile. Currently, the area comprises equipment and materials storage areas, access roadways, and barren lands. The 0.5-mile-long CO_2 flowline will transport the CO_2 from the carbon capture facility to the injection site.[1] The injection site includes up to three Class VI injection wells referred to as McCall 1, Liberty 1, and Unity 1. The injection site also includes two Class I injection wells and a USDW monitoring well (see Figure 2-2).

Figure 2-2: Proposed Project Plan – Facility Adjacent to MRY Unit No. 1 & Unit No. 2

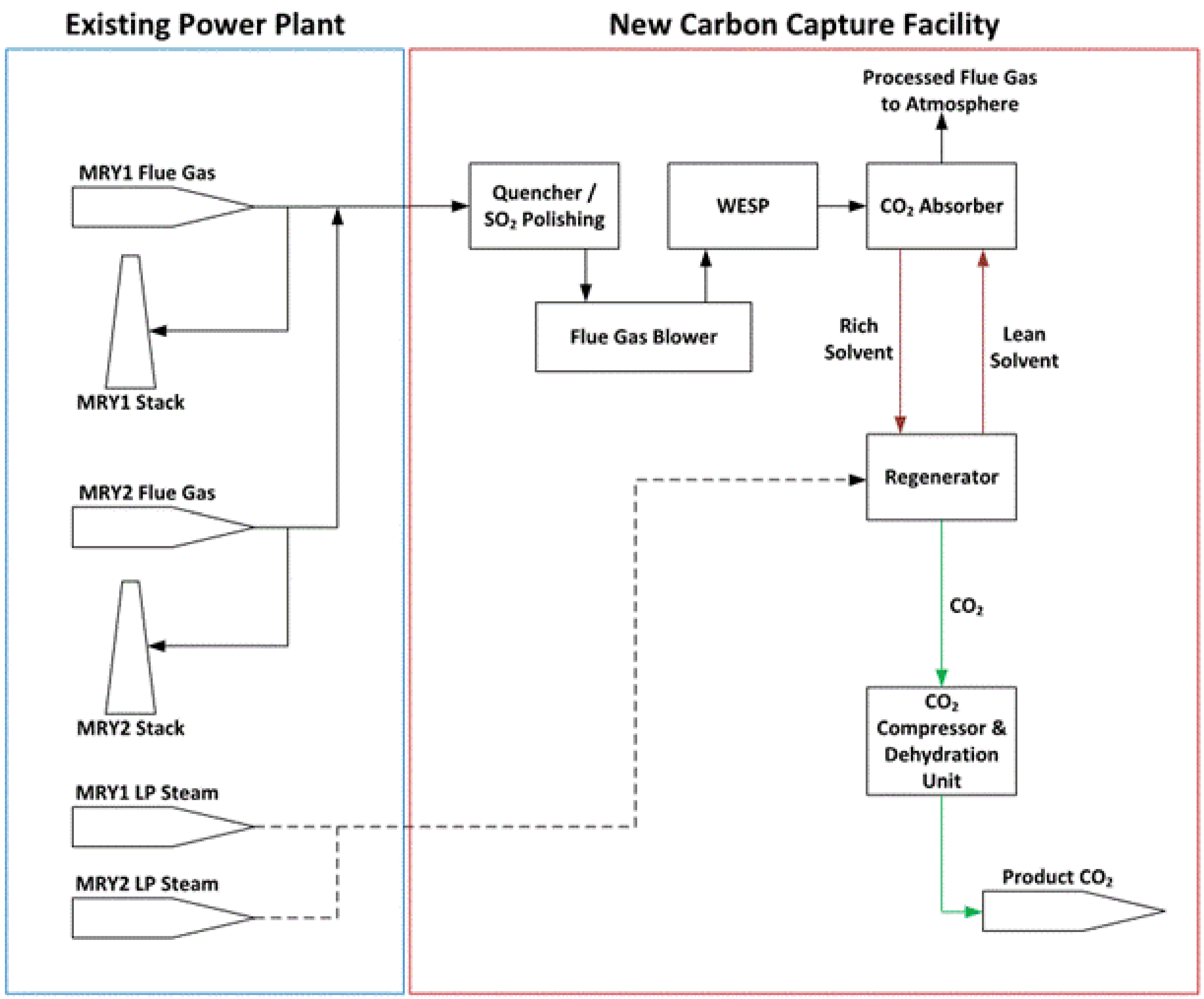


The project is proposing to use MHI's KM CDR technology, which uses an amine-based solvent to capture CO_2. The steam produced from MRY's coal-fired boilers (Unit 1 and Unit 2) will be used to regenerate the amine. The flue gas would be processed by and vented through the carbon capture facility.

[1] All but 790 feet of the 0.5-mile-long CO_2 flowline would be constructed within the proposed carbon capture and injection facility site boundaries.

The stripped CO_2 vapor would then be compressed, purified (dried), and transported by the CO_2 flowline to the injection site for permanent geologic storage. Figure 2-3 diagrams the carbon capture plant process.

Figure 2-3: Carbon Capture Plant Process



The project would include the following major process components:

- **Quencher and sulfur dioxide (SO_2) polishing scrubber.** This unit cools the flue gas and reduces its SO_2 concentration prior to entry into the CO_2 absorber.
- **Wet Electrostatic Precipitator (wet ESP).** The wet ESP reduces the concentration of particulate matter 10 microns or less in diameter (PM_{10}) and particulate matter 2.5 microns or less in diameter ($PM_{2.5}$) in the flue gas prior to entry into the CO_2 absorber.
- **Flue Gas Blower.** The blower provides sufficient pressure of the flue gas to overcome the pressure drop of the wet ESP and the CO_2 absorber columns.

- **CO_2 Absorber**. This unit separates CO_2 from the flue gas stream via absorption into the amine solvent. The absorber includes a stack where processed flue gas and absorber-generated emissions would be emitted.
- **CO_2 Regenerator.** The CO_2 regenerator separates pure CO_2 from the CO_2-rich amine solvent.
- **CO_2 Compression and Dehydration System.** This system compresses and dries the pure CO_2 stream from the CO_2 regenerator so that it can be transported via the CO_2 flowline for geologic storage.
- **Cooling Tower.** The cooling tower enables heat rejection for the capture plant cooling water system.
- **Class I Injection wells.** The Class I wells are used to manage non-hazardous process water from the carbon capture process.
- **Steam extraction.** Heat is required in the regenerator to separate the CO_2 from the CO_2-rich amine solvent. To provide the necessary heat, a portion of the steam currently produced by the coal fired boilers (Unit 1 and Unit 2) would be extracted and sent to the regenerator system to be utilized in the CO_2 capture process.
- **Water Treatment System.** The project will operate its own water treatment system. The existing MRY lake water pump system will be upgraded as necessary to provide raw water to the project water treatment system. The project's water treatment system will not be able to provide demineralized water, which is needed for several sub-processes. MRY will provide demineralized water from the existing MRY water treatment system. The project's water treatment system is designed for efficiency by producing minimal effluent and using minimal water for make-up water requirements. In addition to the water used for cooling duty, other water will be used throughout the project for cleaning and washing down floors and equipment. Information regarding the source of the water for the project and MRY's existing water supply system is provided in Section 2.5.2.1.
- **Solvent Reclaimer System.** The solvent reclaimer system process would use a proprietary non-hazardous amine solvent to separate CO_2 from the flue gas. Throughout the solvent reclaimer system process, amine solvent will be stored in various storage tanks and vessels. These major process components are shown on Figure 2-3. The captured CO_2 stream would be approximately 98 percent pure, dehydrated, and compressed prior to being sent through the flowline to the injection site. The CO_2 would be in a dense fluid phase which is non-corrosive and non-flammable. Equipment and piping for the project would be rated in accordance with American National Standards Institute (ANSI) Class 900 piping. A Process Hazard Analysis (PHA) was conducted for the project to evaluate potential hazardous or undesirable consequences associated with the proposed equipment and piping (Burns & McDonnell Engineering Company, Inc. [Burns & McDonnell] and Hoglin Engineering 2021; Appendix D). The PHA will be updated as needed prior to project construction. Upon commencing operations, the PHA would be certified and re-evaluated on a 5-year basis in accordance with Process Safety Management requirements.

2.5.2.1 Existing Water Supply System Upgrades

MRY currently operates a water supply system for MRY Unit 1 and Unit 2. The Units use water from Nelson Lake for once-through cooling. The lake level is supplemented as necessary by pumping water from the Missouri River. The existing water intake and point of diversion from the Missouri River is located 20 miles to the south-southeast and 25 river miles downstream in the free-flowing section of the river downstream of Garrison Dam at Lake Sakakawea and upstream of water held by Oahe Dam, which is located approximately 13 miles north of MRY.

From the diversion point, water is pumped via pipeline to an isolated bay on Nelson Lake and is separated from the lake by a small dam. Water is stored in the reservoir upstream of the small dam until it is either used at MRY as boiler pretreatment water, or overflows and supplements the water level of Nelson Lake. The intake structure at the Missouri River is referred to as the “river intake” and the intake structure at Nelson Lake is referred to as the “lake intake.” In general, water from the Missouri River is higher quality than Nelson Lake water. Due to its higher quality, Missouri River water is the preferred source for MRY boiler pretreatment water. Nelson Lake water serves as a secondary source of boiler pretreatment water.

In order to meet the project’s increased raw water demand from Nelson Lake, the following upgrades will be made to the MRY water supply system:

- **River Intake.** Variable frequency drives will be added to the Missouri River intake pumps. This will allow the pumps to operate a variety of flow rates based on demand and river level. The structure of the river intake will not be modified as part of this project.
- **Lake Intake.** Lake water is used for cooling and for miscellaneous uses at MRY. The lake water system for miscellaneous uses will be upgraded with modified or replaced pumps to increase pumping capacity to meet the demands of both the MRY system and to provide raw lake water to the new CO_2 capture facility water treatment system. The structure of the lake intake will not be modified as part of this work.
- **Configuration Change.** Currently, the lake water system used by MRY only uses filtration. The new CO_2 capture facility water treatment system will utilize ultra-filtration technology (removes bacteria, protozoa, and some viruses) and nano-filtration technology (removes microbes, most natural organic matter, and some natural minerals) to provide the quality necessary for the project.
- **Beneficial Water Reuse.** Utilizing ultra-filtration and nano-filtration will provide the capture plant cooling system and other uses with higher quality water than more traditional water treatment technologies. The cooling water blowdown stream will also be of higher quality than if using more traditional water treatment technologies. Due to these reasons the cooling water blowdown stream can be recycled back through the facility’s water treatment system.

A new water appropriation of 15,000 acre-feet from the Missouri River has been approved by the North Dakota State Water Commission to supply the water needs. To accommodate the increased water usage, no modifications are required to the existing Missouri River intake structure or water pipeline, nor to the Nelson Lake intake structure. The capacity of the pumping system from the Nelson Lake intake structure will need to be increased to transfer water to the project's water treatment system.

2.5.3 Facility Construction

The final engineering and procurement activities would occur over an approximate one-year timeframe. Construction of the project is expected to begin in 2024 and be complete in late 2028 to first quarter of 2029. The construction contractor will be responsible for ensuring all work is performed according to the design documents and in accordance with the approved safety plan. A construction management team will be hired by the project owner to verify the contractor executes construction per the design, and that all safety and environmental construction protocols are followed.

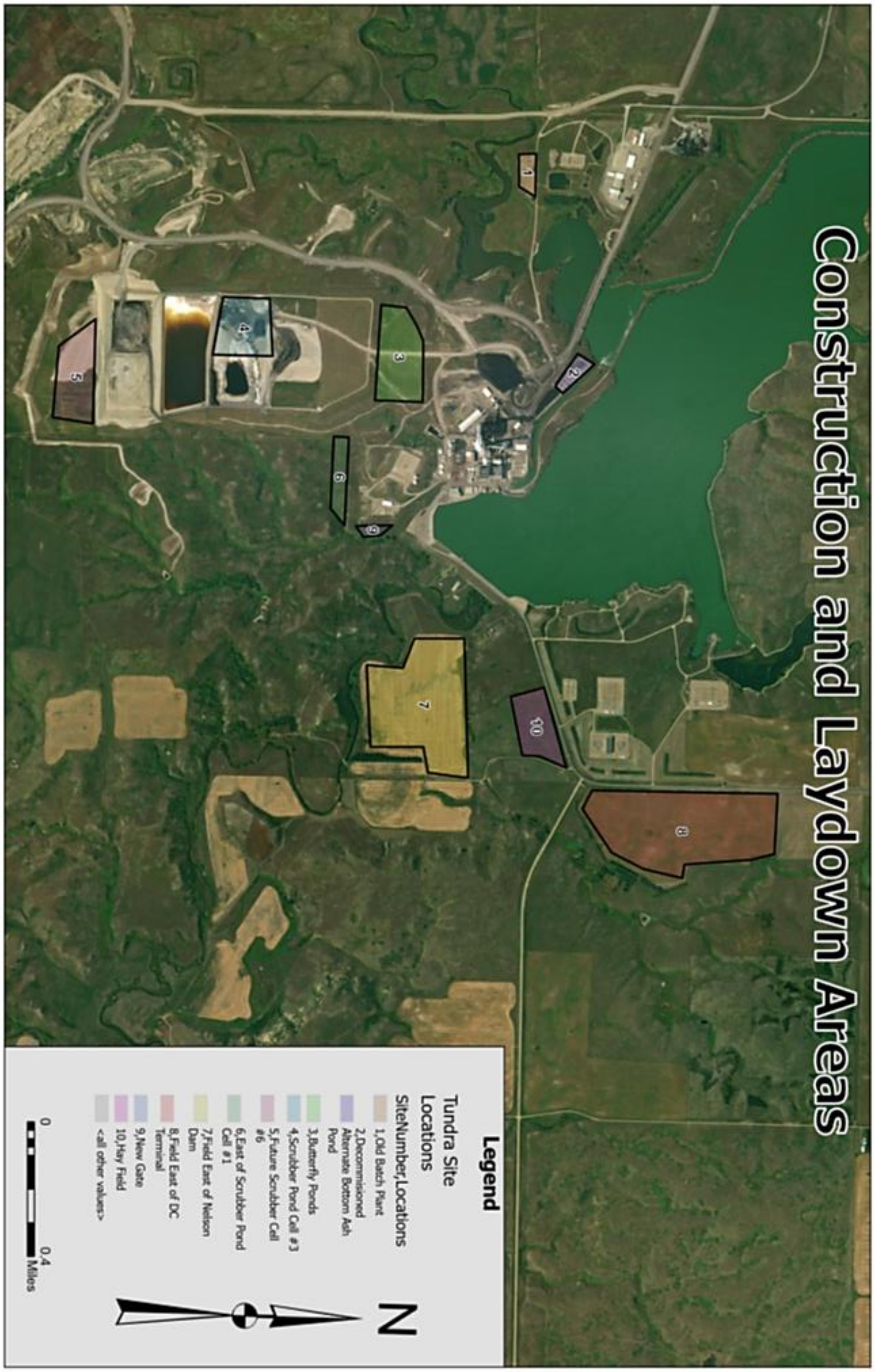
The relocation of the following utilities would be necessary to accommodate the equipment requirements for construction of the project:

- Reroute MRY 230-kilovolt (kV) transmission line around the project;
- Reroute the BNI Coal 69 kV utility service line;
- Reroute and bury a local electric cooperative's 6.9 kV distribution line; and
- Reroute all scrubber blowdown and pond return pipelines.

Equipment required for the project may be fabricated on-site or, alternatively, prefabricated modules may be delivered to the site. All equipment would be installed per the final engineering design specifications. Grading and excavation activities would be performed as needed prior to construction. Best management practices (BMP) would be implemented to verify adherence to appropriate engineering standards and construction requirements.

Project construction would include preparation of laydown and fabrication areas. Figure 2-4 depicts 10 locations on Minnkota-owned property being considered for use as temporary construction and laydown areas. These areas would serve various construction needs including parking, construction trailers, material storage and fabrication, and other activities to support the influx of workers and project construction activities. Minnkota will perform geotechnical studies to determine if the areas are appropriate for the desired use. Additionally, the areas were evaluated for architectural and cultural significance pursuant to Section 106 of the National Historic Preservation Act and for potential effects on threatened or endangered species in accordance with Section 7 of the ESA.

Figure 2-4: Potential Construction and Laydown Areas



Although the areas depicted on Figure 2-4 occupy approximately 221.7 acres, only 97.0 acres of the 221.7 total acres would be needed during construction, including 30.0 acres of land used for agricultural purposes and 67.0 acres of previously disturbed land used for plant operations. Following construction, 90 acres of construction and laydown areas would be restored to original conditions, including the 30.0 acres of agricultural land and 60.0 acres of land previously used for plant operations. The remaining 7.0 acres, within Area 8 on Figure 2-4, would be retained for overflow parking for MRY and project operations. The final construction plan is still being developed and areas may be updated based on site investigations as the construction plan is finalized.

2.5.4 Facility Operations

During the commissioning stages of the project, MRY will use new operators to assist in the troubleshooting and commissioning of the equipment. In addition, maintenance technicians will be utilized to perform maintenance work as needed. This involvement prior to commercial operation will allow for the MRY staff to familiarize themselves with the equipment and be in a better position for reliable operation.

During the initial ramp-up and operation, the project is expected to require additional staffing as necessary to manage the project. After routine operation is established, the expected level of routine staffing will be three operators on shift 24 hours a day, 7 days a week. Instrumentation, electrical, mechanical, maintenance, and laboratory staff will be present for day shift only, unless otherwise necessary. In total, including operations, laboratory, maintenance, engineering, and supervisory personnel, the project is expected to require a staff of 22 full-time equivalents. Two operators would be stationed in the project control room. One of those would be responsible for monitoring the facility operations at all times. One other operator would be conducting routine equipment inspections rounds. A third operator will be responsible for operating the facility's water treatment system. Operation of the project will be in close cooperation and coordination with operation of MRY.

2.5.5 Post-Operations of the Facility

The project has a design life of 20 years. Upon completion of the project's useful life, and before the end of the project, the capture system would be dismantled and removed from the site. Decommissioning would include removal of all equipment from the site, for salvage to the degree possible. The site would then be returned to its previous condition. Dismantling, demolition, removal, and site restoration would be included in the project plan and budget.

Minnkota could opt to replace the project with future technologies but would consider all available options at the end of the project's useful operational life.

2.5.6 Life Cycle Analysis Study

A Life Cycle Analysis (LCA) Study, *Project Tundra Initial Life Cycle Analysis* (Burns & McDonnell 2023), was prepared to quantify the potential life cycle greenhouse gas (GHG) emissions that would result from implementation of the Project Tundra (see Appendix E). The LCA study was conducted in accordance with the requirements outlined in Appendix J of the DOE Office of Clean Energy Demonstration's FOA (Number DE-FOA-0002962; DOE 2023b) regarding carbon capture and storage projects, such as the proposed project. Additional requirements include a contribution analysis showing the impacts from fuel extraction and delivery, plant direct emissions, and CO_2 transport and storage.

The completed analysis looked at the CO_2, methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6) emissions from upstream, the proposed project, and downstream processes. These emissions are ultimately represented by carbon dioxide equivalents (CO_2e) calculated using the 100-year global warming potential (GWP) values published by Appendix J guidance (DOE 2023b). Further details and the results of the LCA are discussed further in Section 3.3.

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CHAPTER 3. AFFECTED ENVIRONMENT AND ENVIRONMENTAL CONSEQUENCES

3.1 Introduction

This section provides relevant environmental, cultural, and socioeconomic baseline information, and identifies and evaluates the individual or cumulative environmental and socioeconomic changes likely to result from constructing and operating the proposed project at MRY. The region of influence for this EA includes MRY and the immediately surrounding areas.

CEQ regulations encourage NEPA analyses to be as concise and focused as possible, consistent with 40 CFR Part 1500.1(b) and 1500.4(b): "…NEPA documents must concentrate on the issues that are truly significant to the action in question, rather than amassing needless detail … prepare analytic rather than encyclopedic analyses." Consistent with the NEPA and CEQ Regulations, this EA focuses on those resources and conditions potentially subject to effects.

The methodology used to identify the existing conditions and to evaluate potential impacts on the physical and human environment involved the following: review of documentation and project information provided by the University of North Dakota Energy and Environmental Research Center (EERC), Minnkota, and their consultants; searches of various environmental and agency databases; and agency consultations. All references are cited, where appropriate, throughout this EA.

Wherever possible, the analyses presented in this chapter quantify the potential impacts associated with the Proposed Action. Where it is not possible to quantify impacts, the analyses present a qualitative assessment of the potential impacts. The subsections presented throughout the remainder of this chapter provide a concise summary of the current affected environment within the region of influence, and an analysis of the potential effects to each resource area considered from implementation of the Proposed Action. Analyses of the no-action alternative is summarized in in Section 3.1.2 and Table 3-1.

3.1.1 Resources Areas Screened from Detailed Analysis

DOE determined that all specific resource areas should be included for discussion in this EA; no resource areas have been dismissed.

3.1.2 No-Action Alternative – Environmental Consequences

Under the No-Action Alternative, the Proposed Action would not occur, the amine based post-combustion carbon capture system would not be implemented, and 13,000 STPD of CO_2 would not be captured for geologic storage. There would be no environmental consequences associated with proposed project construction and no effect on the existing local environment. Minnkota would continue to operate the MRY facility under normal operating conditions.

Table 3-1 summarizes the environmental consequences of the No-Action Alternative.

Table 3-1: No-Action Alternative – Environmental Consequences by Resource Category

Resource Categories	Resource Impacts Under the No Action Alternative
Air Quality	There would be no air emissions associated with proposed project construction and no effect on the existing air emissions from Units 1 or 2 at MRY.
Greenhouse Gases and Climate Change	The beneficial effects of the proposed project (e.g., reduction in CO_2 emissions) would not occur.
Geology and Soils	There would be no changes to the project site, nearby soils, or underlying geologic formations.
Water Resources	No impacts would occur to the project site or nearby surface waters, floodplains, water quality, hydrogeology, or wetlands.
Biological Resources	There would be no changes to the project site or nearby aquatic, wildlife, or vegetative resources.
Health and Safety	There would be no increased potential for adverse impacts to public or employee health and safety from proposed project construction, operation, or decommissioning.
Solid and Hazardous Waste	There would be no increase in the generation of solid waste or hazardous waste from the MRY site.
Infrastructure and Utilities	Construction of utility infrastructure would not occur, and there would be no increase in consumption of water or electricity at the MRY site. Additionally, there would be no increase to wastewater generation and supplemental wastewater treatment would not occur.
Land Use	No land use changes or creation of new impervious surfaces would occur.
Visual Resources	There would be no visual resource changes to the landscape; the area would retain the current visual contrasts.
Cultural and Paleontological Resources	There would be no impacts to cultural and/or paleontological resources or land uses under the No-Action alternative.
Socioeconomic Conditions	There would be no socioeconomic changes, new employment opportunities, or impacts to local businesses.
Noise	There would be no changes to background noise levels or the creation of new sources of noise.
Environmental Justice	There would be no change in effect on environmental justice communities.

3.2 Air Quality

3.2.1 Affected Environment

3.2.1.1 Air Quality

Minnkota currently operates Units 1 and 2 of the lignite coal-fired energy generation facility using coal from the adjacent Center Mine, operated by BNI Energy Inc (BNI 2023). In 2020, Unit 1 was available to produce power 93.9 percent of the time, while Unit 2 was available for power production 93.0 percent of the time. Both units at MRY are equipped with emission control technologies that meet or exceed all current state and federal air quality standards. Notably, between 2006 and 2015, roughly $425 million was invested at MRY to significantly reduce emissions of SO_2, nitrogen oxides (NO_x), mercury (Hg), and other emissions. The power generation units at MRY are classified as an existing major Prevention of Significant Deterioration (PSD) and Title V facility. MRY currently has a Title V Permit to Operate (T5-

F76009), and the permit will expire May 12, 2025. The air emission units include two lignite coal-fired boilers, auxiliary equipment, and associated coal and ash handling equipment.

As described in Section 8.3 of the EPA's *Draft Guidance on Developing Background Concentrations for Use in Modeling Demonstrations*, background air quality concentrations consist of: 1) nearby sources (i.e., sources in the vicinity of the project not adequately represented by ambient monitoring data) and 2) other sources, such as unidentifiable sources, natural resources or other regional transport contributions caused by distant sources. Table 3-2 provides the default background concentration values for criteria pollutants representative of the entire State of North Dakota, including the project area, based on NDDEQ modeling guidance.[2]

Table 3-2: Background Concentrations for the State of North Dakota (ug/m^3)

	Averaging Period				
Pollutant	**1-hour**	**3-hour**	**8-hour**	**24-hour**	**Annual**
SO_2	13	11	---	9	3
NO_2	35	---	---	---	5
PM_{10}	---	---	---	30	15
$PM_{2.5}$	---	---	---	13.7	4.75
CO	1,149	---	1,149	---	---

Table 3-2 reflects the background concentrations identified for the project area after consideration of background values and nearby sources, cumulatively.

3.2.1.2 Air Quality Monitoring Network

Oliver County is located in an air quality attainment area for all six criteria air pollutants: ground-level ozone (1 hour and 8 hour), particulate matter ($PM_{2.5}$ and PM_{10}), carbon monoxide (CO), lead, sulfur oxides, and nitrogen dioxide. According to the EPA's assessment of air quality attainment status, the air quality in the region has been designated as in attainment for all criteria pollutants (40 CFR Part 81).

The Division of Air Quality at the NDDEQ works to safeguard the health and environment of North Dakota and utilizes a permit program to evaluate new construction projects for their impact on air quality. A project may be built once a Permit to Construct is issued. A Permit to Operate program confirms that the project will function in compliance with the CAA and North Dakota Air Pollution Control Rules.

3.2.1.3 Formally Classified Lands

Class I federal lands (i.e., formally classified lands) include areas such as national parks, national wilderness areas, and national monuments, which are granted special air quality protections under Section 162(a) of the federal CAA. There are no Class I areas in the vicinity of the proposed project site. The nearest Class I area to the proposed project site is the Theodore Roosevelt National Park, located about 99 miles west of the project (EPA 2022).

[2] https://deq.nd.gov/publications/AQ/policy/Modeling/ND_Air_Dispersion_Modeling_Guide.pdf

3.2.2 Environmental Consequences

MRY is an existing major PSD and Title V facility. MRY currently has a Title V permit to operate (T5-F76009), and the permit will expire May 12, 2025. Minnkota will submit a renewal request prior to the expiration of its current Title V operating permit. The air emission units include two lignite coal-fired boilers, auxiliary equipment, and associated coal and ash handling equipment. The emissions from the MRY coal-fired boilers will not change as a result of this project. The project would have the consequential benefit of reducing further the emissions of CO_2, SO_2, and particulate matter from the existing MRY Unit 1 and Unit 2 flue gas streams. According to the EPA's assessment of air quality attainment status, the air quality in the region has been designated as in attainment for all criteria pollutants (40 CFR Part 81).

The NDDEQ required an air dispersion modeling analysis be performed for the project to demonstrate compliance with the North Dakota Ambient Air Quality Standards (AAQS) and National Ambient Air Quality Standards (NAAQS). The modeling analysis confirmed that exhausting combinations of MRY Unit 2 and Unit 1 emissions through the carbon capture absorber stack would not cause or contribute to a violation of the NAAQS or North Dakota AAQS. Table 3-3 summarizes the criteria pollutant modeling results and compares them to the appropriate state and federal ambient air quality standards. The ambient background concentrations were added to the modeled design concentrations for each pollutant and averaging period to estimate the total air quality concentration.

Table 3-3 shows the maximum modeled results from the criteria pollutant modeling and confirms that the total concentrations for each pollutant and averaging period modeled would be below the North Dakota AAQS and NAAQS.

Table 3-3: Comparison of Air Quality Concentrations with Ambient Air Quality Standards

Pollutant	Averaging Period	Rank of Model Impacts	AERMOD Modeled Concentration by Case (μg/m³)					Maximum AERMOD Predicted Concentration (μg/m³)	Ambient Background Concentration (μg/m³)	Total Concentration (μg/m³)	USEPA NAAQS/North Dakota AAQS (μg/m³)	% of Criteria
			Case 1 - All Unit 2, Partial Unit 1 (25%)	Case 2 - All Unit 1, Partial Unit 2 (57%)	Case 3 - Unit 1 Min Load Alone	Case 4 - Unit 2 Min Load Alone	Case 5 - Unit 2 Max Load Alone					
NO_2	1-hr[1]	98th	31.18	30.61	28.95	31.76	30.04	31.76	35.00	66.76	188.0	36%
	Annual[2]	H1H	0.84	0.83	0.87	0.93	0.83	0.93	5.00	5.93	100.0	6%
PM_{10}	24-hr[3]	H6H	7.04	6.74	5.60	8.05	6.70	8.05	30.00	38.05	150.0	25%
$PM_{2.5}$	24-hr[4]	98th	4.68	4.48	3.91	5.40	4.43	5.40	13.70	19.10	35.0	55%
	Annual[5]	H1H	0.61	0.58	0.54	0.72	0.58	0.72	4.75	5.47	12.0	46%
SO_2	1-hr[6]	99th	49.68	47.12	39.68	57.31	47.32	57.31	13.00	70.31	196.5	36%
	3-hr[7]	H2H	53.15	50.41	38.40	58.80	48.32	58.80	11.00	69.80	1,300.0	5%
	24-hr[7]	H2H	16.24	15.40	12.31	18.01	15.29	18.01	9.00	27.01	365.0	7%
	Annual[2]	H1H	1.26	1.20	1.06	1.47	1.20	1.47	3.00	4.47	80.0	6%
CO	1-hr[7]	H2H	27.71	26.50	18.88	27.63	25.44	27.71	1149.00	1176.71	40,000.0	3%
	8-hr[7]	H2H	9.20	8.80	7.32	10.36	8.69	10.36	1149.00	1159.36	10,000.0	12%

1 Eighth-highest maximum daily 1-hour concentration (98th percentile) averaged over the 5 years.
2 Maximum annual concentration over the 5 years.
3 Sixth-highest maximum 24-hour concentration averaged over the 5 years.
4 Eight-highest maximum 24-hour concentration averaged over the 5 years.
5 Maximum annual concentration averaged over the 5 years.
6 Fourth-highest maximum daily 1-hour concentration (99th percentile) averaged over the 5 years.
7 Second-highest maximum concentration over the 5 years.

The project's potential emissions of hazardous air pollutants (HAPs) would be greater than 10 tons per year (tpy) for any single HAP and greater than 25 tpy for all HAPs. A case-by-case maximum achievable control technology determination was completed as part of the NDDEQ's permitting process. The air toxics analysis follows the procedure set forth in the North Dakota Air Toxics Policy. The results indicate that the expected Maximum Individual Cancer Risk and Health Index thresholds are in compliance with the Air Toxics Policy.

Construction of the proposed project would result in direct criteria air pollutant emissions from fuel combustion for operation of construction equipment, and indirect criteria air pollutant emissions from consumption of electricity during the construction period (see DOE Appendix J guidance (DOE, 2023b)). Construction of the proposed project would also result in fugitive particulate emissions (PM_{10}, $PM_{2.5}$) from site clearing and excavation, installation of pilings and concrete, and other construction activities. Proposed project construction activities would not exceed air quality monitoring thresholds or ambient air quality standards in offsite areas. Impacts to air quality during proposed project construction would be minor and temporary in nature. The impacts would be minimized by using best practices during construction activities, including, but not limited to, the use of water sprays for fugitive dust suppression and the use of construction equipment with appropriate emission controls.

In December 2023, the NDDEQ approved the project's application for an Air Permit to Construct. The project's Air Permit to Construct, Air Quality Emissions Analysis, and Air Quality Impact Analysis are provided in Appendix J of this Draft EA. NDDEQ staff concluded that the project would comply with all applicable air pollution control rules and is protective of human health and the environment. Project operation would comply with all federal and state air quality regulations. Project maximum potential emissions would be below PSD significant emission rates (SER) for all regulated pollutants. The project owners would apply for and obtain a Title V operating permit for the project. The project would be considered a single source adjacent to MRY. The project would have its own air emission limits in a separate permit. The air emissions limits previously established for other emissions units at MRY are present in the existing Title V permit for the electricity generating facility.

3.3 Greenhouse Gases and Climate Change

3.3.1 Affected Environment

The proposed project would be located at the existing MRY site near Center, Oliver County, North Dakota. The climate in the Center area is typical of the Midwest, with hot summers and cold, moderately snowy winters. In this area, the lowest temperatures of the year typically occur in January whereas the highest temperatures occur in July. The average low temperature for January is 5 degrees Fahrenheit (°F) with an average of 0.44 inch of precipitation (U.S. Climate Data, 2023). The average high temperature for July is 84 °F with an average of 2.83 inches of precipitation (U.S. Climate Data, 2023). Between 2007 and 2019, the average annual precipitation total was 18.51 inches (U.S. Climate Data, 2023). The average annual snowfall in the greater Bismarck Region was 50.5 inches from 1991 to 2020 (NOAA 2020).

Climate change is an inherently cumulative effect caused by releases of GHGs from human activities and natural processes around the world. GHGs are compounds in the atmosphere that absorb and emit radiation, effectively trapping heat (longwave radiation) and causing what is known as the greenhouse effect. The greenhouse effect causes the Earth's atmosphere to warm and thereby creates changes in the planet's climate systems. The primary GHGs in the Earth's atmosphere are water vapor, CO_2, CH_4, and N_2O.

3.3.2 Environmental Consequences

During the construction phase, direct GHG emissions, including CO_2, CH_4, and N_2O, would result from vehicular emissions from traffic from the construction workforce, traffic from construction deliveries, and internal combustion engine emissions from construction equipment. Indirect GHG emissions would result from electricity consumption (e.g., lighting) for project construction.

Direct GHG emissions are expected during the operation of the CO_2 compressor due to releases of CO_2 during startups and discharges as well as fugitive releases from the transportation of CO_2. The CO_2 compressor would be electric, and the project does not include the installation of emergency generators. Therefore, the project would not have any GHG emissions due to fuel consumption. The project would result in indirect GHG emissions including CO_2, CH_4, and N_2O from electricity consumption (e.g., lighting, electric-powered process equipment) and steam consumption (e.g., process heat).

The proposed capture plant is expected to source flue gas from the Milton R. Young Plant. Flue gas is created as a biproduct of electricity generation. Between 2021 and 2022, the MRY plant emitted flue gas with an average of 5,187,363 tons of CO_2. Electricity generation at MRY and the associated emissions processes are already in operation and would occur with or without construction and operation of the project. The proposed project would not capture and treat 100 percent of the CO_2 produced by the MRY coal plant, however, over the lifetime of the carbon capture facility it is projected to capture an annual average of 4.0 million tons of CO_2. Therefore, the project would result in a net reduction in CO_2 emissions (emissions that would otherwise be released to the atmosphere in the status quo scenario) every year over the anticipated operating life of the project. The project is designed to capture a minimum of 95 percent of unit-wide CO_2 emissions and store the captured CO_2 in secure subsurface geologic formations. Note that a 95 percent unit-wide capture indicates that a 95 percent capture efficiency is occurring at U1 or U2 at MRY.

A screening-level GHG assessment was conducted in accordance with the requirements outlined in Appendix J of DE-FOA-0002962 (DOE 2023b). The goal of the LCA was to begin quantifying environmental impacts from the implementation of the proposed project. The results of the Initial LCA are presented in the next section. Minnkota has performed additional analyses outside of DOE's EA, including a traditional analysis of grid CO_2 intensity (kg/MWh) of the MRY units for comparison with industry data reported to the EPA and the U.S. Energy Information Administration.

3.3.2.1 Life Cycle Analysis Results

The Initial LCA examined the CO_2, CH_4, N_2O, and sulfur hexafluoride (SF_6) emissions from upstream, the proposed project, and downstream processes. These emissions are ultimately represented by CO_2e calculated using 100-year GWP values established in the Appendix J guidance (DOE 2023b). Table 3-4 lists these GWP values.

Table 3-4: Global Warming Potentials Utilized in LCA

GWP Factors	
CO_2	1
CH_4	36
N_2O	298
SF_6	23,500

Source: Appendix J, Table J.1. GWP Characterization Factors (DOE 2023b).

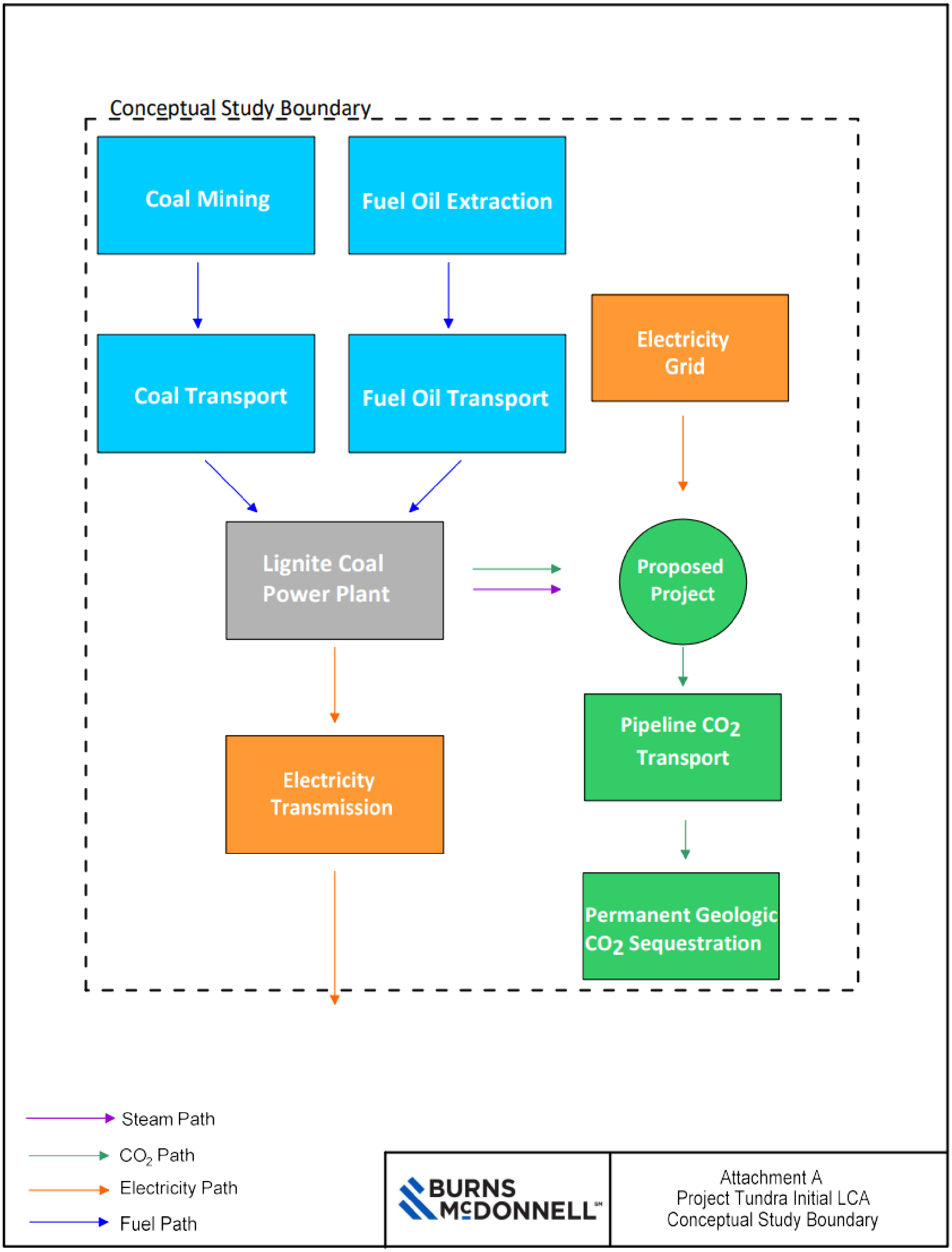
The Initial LCA established a system boundary that determines which unit processes, inputs, outputs, and impacts are considered in the analysis. An Initial LCA analysis as outlined in the DOE Appendix J guidance requires a screening level assessment of GHGs from cradle-to-delivered electricity only. Figure 3-1 provides a diagram of the Initial LCA system boundary. LCA results are presented in terms of a functional unit. This is defined as a reference unit for scaling the product system based on the function provided. The Initial LCA has been defined as kilograms (kg) of CO_2 stored and as megawatt-hours (MWh) delivered to the grid.

The Initial LCA utilized a combination of site-specific data when available and reasonable estimations when not available. The sections below provide an overview of the upstream, carbon capture plant, and downstream emission sources.

Upstream Emissions

The upstream analysis aimed to identify and quantify emissions that are a result of fuel (coal and fuel oil) extraction, production, processing, and transportation operations, as well as combustion occurring at MRY that would produce the CO_2 input stream (i.e., feedstock) for the proposed project. Upstream emissions were split into three categories: fuel extraction, fuel transportation, and MRY direct emissions. Fuel extraction and transportation were further divided to reflect the use of both lignite coal and No. 2 fuel oil at MRY. Fuel delivery was similarly split to reflect the transportation of both fuel types. Although the manufacturing of materials and construction of the proposed project would be considered upstream emissions, this level of analysis was determined to be outside the scope of a "screening-level" Initial LCA.

Figure 3-1: Conceptual Study Boundary



The maximum projected annual coal and fuel oil consumption for both boilers was used to calculate the upstream emissions from fuel extraction and transportation as well as the emissions from the operation of MRY. Calculations were completed based on projected fuel consumption data (for years 2025 to 2043) provided by Minnkota.

Table 3-5: Maximum Upstream Annual Data Inputs

Projected Year of Maximum Consumption	Projected MW Hours Net Produced	Maximum Coal Consumption (tpy)	Projected Maximum Fuel Oil Consumption (gallons per year)
2032	5,024,897	4,371,560	750,000

The GHG emissions calculations utilized the total annual amount of fuel consumed by MRY boilers 1 and 2. Based on this, the MRY plant is estimated to emit a maximum estimated 5.7 million tons of CO_2 annually. It should be noted that these upstream emissions processes are already in operation and they are not a result of the addition of the proposed project. Although the proposed project will not capture and treat 100 percent of the emitted CO_2 produced by the MRY coal plant, it is projected to capture an annualized average of 4.0 million tons of CO_2.

Proposed Capture Plant Direct Emissions

Plant Direct Emissions include the emissions from the operation of the proposed CO_2 separation and purification plant. CO_2 emissions from operation of the CO_2 compressor, including startups and discharges of this equipment, are included in this analysis. This is the only equipment that would have relevant GHG emissions. An estimated maximum of 34,800 metric tons (38,400 short tons) per year of CO_2 emissions are expected to occur annually as a result of plant operations. While CO_2 is expected to be released from the plant, these emissions are fugitive and, without the capture plant, would otherwise be released at the MRY stacks. The carbon capture plant would not be creating “new” sources of CO_2 in order to operate.

Energy Consumption at the proposed capture plant has been incorporated as a plant direct emission. The capture plant will require both electricity and steam to operate. Engineering estimates for the capture plant estimate an approximate requirement of 1,848 megawatts per day of electricity and 2,640 megawatts electric (MWe) per day of thermal (steam) energy. The project would be expected to source electricity and thermal energy from the Minnkota generating system. Emissions from energy consumption were calculated following methodology adapted from EPA's Greenhouse Gas Inventory Guidance: Indirect Emissions from Purchased Electricity (EPA 2023b).

Downstream Emissions

The downstream analysis included emissions from the transportation of CO_2 via flowline from the proposed carbon capture facility to the injection site of the permanent geologic storage site. For the CO_2

transport analysis, an approximate 370 metric tons of CO_2 are lost per year from maintenance activities and fugitive losses, utilizing engineering estimates for the 0.5-mile-long CO_2 flowline.

In accordance with the system boundary established by the DOE Appendix J guidance (DOE, 2023b), CO_2e emissions from the transmission of electricity from MRY were also included as a downstream emission. For this analysis, CO_2e emissions from the SF_6 in the transmission lines were determined utilizing the DOE Appendix J emission factor 7.87×10^5 kg of CO_2e per MWh. It is assumed that there are no measurable losses at the wellhead to the sequestration reservoir nor fugitive losses from the reservoir itself.

Results

Each GHG is represented in kilograms of emissions normalized to one kilogram of CO_2 sequestered. There is an expected 0.4 kg of CO_2e emitted per kg of CO_2 stored. This value is largely due to the upstream and downstream processes of the proposed project. This is further explained in the contribution analysis. Table 3-6 provides a breakdown of expected emissions by source.

Table 3-6: Initial Life Cycle Analysis Results (kg of emissions / kg CO_2 stored)

	CO_2	N_2O	CH_4	SF_6 [a]	CO_2e
Upstream					
Coal Mining	7.52×10^{-04}	5.94×10^{-06}	8.09×10^{-04}	-	3.16×10^{-02}
FO Extraction	8.87×10^{-05}	2.68×10^{-09}	4.76×10^{-07}	-	1.07×10^{-04}
Coal Transportation	9.35×10^{-04}	3.79×10^{-08}	7.59×10^{-09}	-	9.47×10^{-04}
FO Transportation	5.53×10^{-07}	1.42×10^{-11}	1.11×10^{-11}	-	5.58×10^{-07}
MRY Coal Plant	0.34	2.15×10^{-05}	1.47×10^{-05}	-	0.34
Proposed Project					
CO_2 Capture Plant [b]	0.01	-	-	-	0.01
Electricity Consumption	0.04	1.81×10^{-06}	1.24×10^{-06}	--	0.04
Downstream					
CO_2 transportation	8.58×10^{-05}	-	-	-	8.58×10^{-05}
CO_2 storage [c]	-		-	-	-
Electricity Transmission [d]	-	-	-	9.25×10^{-08}	2.17×10^{-03}
Total LCA	0.39	2.93×10^{-05}	8.26×10^{-04}	9.25×10^{-08}	0.43

[a] SF_6 is emitted in processes relating to the transmission and distribution of electricity.
[b] The MRY heat input does not change with the installation and operation of the CO_2 capture plant.
[c] Assuming no measurable losses at the wellhead to the reservoir and a reservoir leakage rate of zero.
[d] Does not account for electricity losses that occur as a result of transmission and distribution.

In addition to the original functional unit analysis, additional LCA outputs were generated in a standardized unit of kilograms of emissions normalized to 1.0 MWh. This analysis does not consider the electricity losses that occur during transmission and distribution once the electricity has left the MRY. Table 3-7 provides a breakdown of expected emissions by source.

Table 3-7: Proposed Action, Initial Life Cycle Analysis Results (kg of emissions / MWh)

	CO_2	**N_2O**	**CH_4**	**SF_6 [a]**	**CO_2e**
Upstream					
Coal Mining	0.79	0.01	0.85	-	33.27
FO Extraction	0.09	6.25×10^{-03}	5.00×10^{-04}	-	0.11
Coal Transportation	0.98	2.81×10^{-06}	7.98×10^{-06}	-	1.00
FO Transportation	5.81×10^{-04}	1.50×10^{-08}	1.16×10^{-08}	-	5.86×10^{-04}
MRY Coal Plant [b]	352.34	0.02	0.02	-	360
Proposed Project					
CO_2 Capture Plant	8.56	-	-	-	8.56
Electricity Consumption	49.90	1.92×10^{-03}	1.32×10^{-03}	--	50.52
downstream					
CO_2 transportation	0.09	-	-	-	0.09
CO_2 storage [c]	-	-	-	-	-
Electricity Transmission [d]	-	-	-	7.85×10^{-05}	1.84
Total LCA	412.76	0.03	0.87	7.85×10^{-05}	455

[a] SF_6 is emitted in processes relating to the transmission and distribution of electricity.
[b] The MRY heat input does not change with the installation and operation of the CO_2 capture plant.
[c] Assuming no measurable losses at the wellhead to the reservoir and a reservoir leakage rate of zero.
[d] Does not account for electricity losses that occur as a result of transmission and distribution.

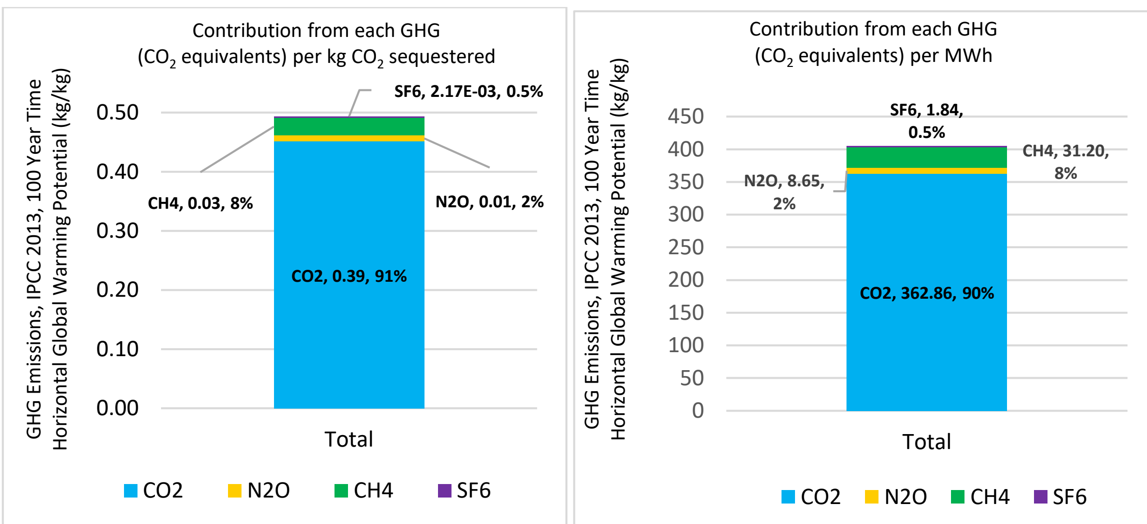
A contribution analysis was completed for fuel extraction and delivery, plant direct emissions, CO_2 transport, and storage categories as outlined in the DOE Appendix J guidance. Contribution of electricity transmission was not required by Appendix J for the initial analysis but was added for this document. Table 3-8 shows the results of the contribution analysis. The Upstream Emissions and the Electricity Transportation categories account for a large majority of emissions contributing to the carbon intensity regardless of functional unit. It should be noted that these two categories account for emission processes that are already in operation and are not dependent on the operation of the proposed project. CO_2 is the most abundant contributor to GHG emissions regardless of category except for electricity transportation. This is due to emissions from electricity transportation being wholly associated to SF_6. Figure 3-2 shows the contribution of each GHG in relation to the total emissions per functional unit. Note that regardless of functional unit, each GHG contributes the same relative percentage.

Table 3-8: Category Contribution Analysis

DOE Appendix J Category	CO_2e Total		Percent Contribution (rounded)
	kg CO_2e per kg CO_2 sequestered	Kg CO_2e per MWh	
Fuel Extraction and Delivery [a] (Upstream Emissions)	0.37	394	87%
Capture Plant Direct Emissions and Energy Use	0.05	59	12%
CO_2 Transport and Storage	8.58×10^{-05}	0.09	0%[b]
Electricity Transportation	2.17×10^{-03}	1.84	0.5%
Total	0.43	455	-

[a] Fuel Extraction and Delivery accounts for all processes identified under upstream emissions.
[b] Percent contribution associated with the proposed project is less than 0.5 percent and rounds to a 0 percent contribution.

Figure 3-2: Contribution Analysis from Each Greenhouse Gas (Carbon Dioxide Equivalents [CO_2e])



Further, a screening-level LCA was completed for a scenario where the proposed CO_2 capture plant does not move forward. The outputs were generated in a standardized unit of kilograms of emissions normalized to 1.0 MWh. In line with the Initial LCA, the analysis does not consider the electricity losses that occur during transmission and distribution once the electricity has left the MRY. Table 3-9 provides a breakdown of expected emissions by source.

Table 3-9: No Action, Initial Life Cycle Analysis Results (kg of emissions / MWh)

	CO_2	N_2O	CH_4	SF_6 [a]	CO_2e
Upstream					
Coal Mining	0.64	5.05×10^{-03}	0.69	-	26.86
FO Extraction	0.08	2.27×10^{-06}	4.04×10^{-04}	-	9.05×10^{-02}
Coal Transportation	0.79	3.22×10^{-05}	6.44×10^{-06}	-	0.80
FO Transportation	4.70×10^{-04}	1.21×10^{-08}	9.39×10^{-09}	-	4.73×10^{-04}
MRY Coal Plant	1,134	1.84×10^{-02}	1.26×10^{-02}	-	1,140
Downstream					
Electricity Transmission [b]	-	-	-	7.85×10^{-05}	1.84
Total LCA	1,136	2.34×10^{-02}	0.70	7.85×10^{-05}	1,170

[a] SF_6 is emitted in processes relating to the transmission and distribution of electricity.
[b] Does not account for electricity losses that occur as a result of transmission and distribution.

This screening-level LCA of MRY's current operations further explains the expected impact of the proposed carbon capture plant. The proposed plant is expected to cause an overall reduction to the carbon intensity associated with 1.0 MWh. Table 3-10 further breaks down the expected impact of the proposed project on each aspect of the Initial LCA analysis. The proposed project has a neutral impact on all processes upstream of MRY and on electricity transportation. A negative net change (a reduction in emissions) is seen at the MRY plant. In contrast, the proposed capture plant and the CO_2 pipeline used for transportation would be new emission sources and, therefore, would have a net positive change (an increase) in emissions when compared to current operations. Refer to Table 3-8 for the full contribution analysis.

Table 3-10: No-Action and Proposed Action Comparison, Initial LCA Results Normalized to 1.0 MWh

Emission Source	kg of CO_2e Emissions per MWh No Action	kg of CO_2e Emissions per MWh Proposed Action	Percent Change [a]
Upstream			
Coal Mining	26.89	33.27	24%[b]
FO Extraction	0.09	0.11	24%
Coal Transportation	0.80	1.00	24%
FO Transportation	$4.73x10^{-04}$	$5.86x10^{-04}$	24%
Coal Electricity Plant	1,140	360	-68%[c]
Proposed Project			
CO_2 Capture Plant	NA	8.56	NA
Electricity Consumption	NA	50.52	NA
Downstream			
CO_2 transportation	NA	0.09	NA
CO_2 storage	-	-	-
Electricity Transmission	1.84	1.84	0%
TOTAL LCA	**1,170**	**455**	**-61%**

Note: Equivalent to Table K-9 in Appendix K.
[a] Percent change, by definition, cannot be calculated for scenarios where the initial value is zero; such is the case in terms of the CO_2 capture plant, energy consumption, transportation, and storage.
[b] The MRY heat input does not change with the installation and operation of the CO_2 capture plant. The change in these numbers is instead reflective of a shift from producing only grid energy to grid energy and thermal heat for clients.
[c] The capture unit has a s 95 percent capture efficiency of flue gas that is treated by the system.

More details regarding the LCA methodology and calculations are provided in Appendix E.

3.4 Geology and Soils

3.4.1 Affected Environment

3.4.1.1 Soils

Major Land Resource Areas (MLRAs) represent landscape-level areas with distinct physiography, geology, climate, water, soils, biological resources, and land uses. The project area lies within MLRA 54, the Rolling Soft Shale Plain, characterized by Borolls with a frigid soil temperature regime and mixed mineralogy (NRCS 2022). These soils are generally moderately deep to very deep, well drained, and clayey or loamy (NRCS 2022).

Soil map units were assessed using the U.S. Department of Agriculture, Natural Resources Conservation Service (NRCS) Web Soil Survey (NRCS 2023a). The dominant soil map unit located within the project area consists of Amor-Werner-Farnuf loams (E2609C). These well-drained soils are derived from loamy residuum weathered from mudstone parent material and characterized by fine loamy surface textures. A majority of the soils within the proposed project area were previously disturbed from the construction of the MRY facility.

The carbon capture facilities would occupy 25.8 acres of land in the southwest portion of the MRY property (Figure 2-2). An additional 10 construction and laydown areas would serve various construction needs including parking, construction trailers, material storage and fabrication, and other activities to support the influx of workers and project construction activities (Figure 2-4). Approximately 97.0 acres of land would be required for the temporary construction and laydown areas within the Minnkota-owned property. Following construction, the construction and laydown areas would be restored to original conditions, with the exception of an approximately 7.0-acre area that would be retained for overflow parking for MRY and project operations.

3.4.1.2 Surficial Geology

The project would be located on the eastern flank of the Williston Basin. Figure 2-1 provides the topography of the general area near the MRY facility. Surface conditions and geology in the vicinity of the MRY facility are associated with the Sentinel Butte Formation, a relatively flat-lying sedimentary formation, up to 600 feet in thickness, overlying the Bullion Creek Formation. Both formations are part of the Williston Basin, which is a large intracratonic sedimentary basin extending from western South Dakota and North Dakota to eastern Montana and into southern Saskatchewan. The Sentinel Butte is composed of fluvial and lacustrine deposits, including lignite coal beds, from the Paleocene Epoch. Outcrops of poorly lithified portions of the Sentinel Butte are common and contain assemblages of non-marine plant and animal fossils (North Dakota Geological Survey 2021).

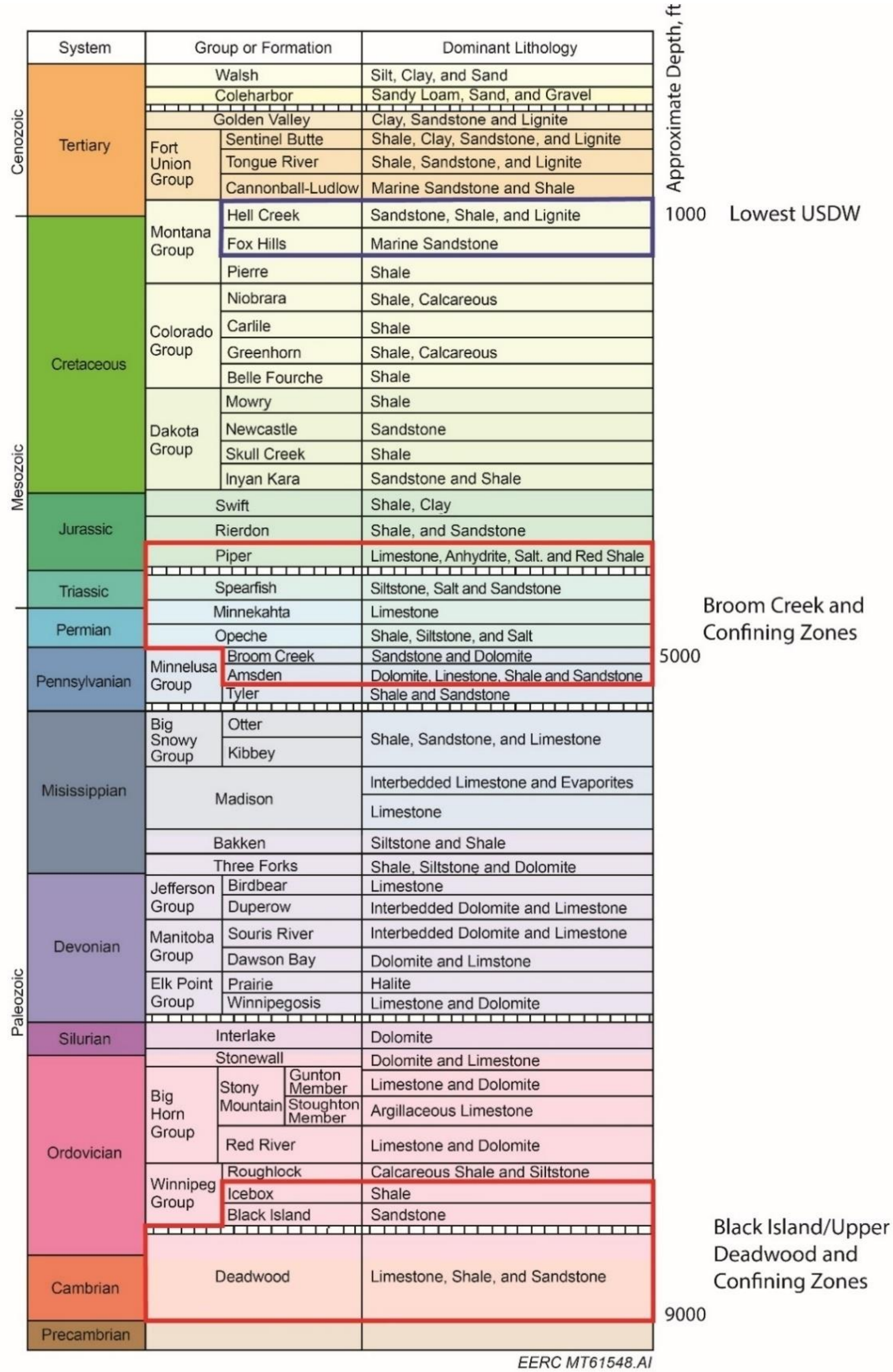
The ground surface at the MRY facility consists of various engineered materials such as granular fill and pavement. The shallow subsurface beneath the engineered materials consists of unconsolidated sediments composed of silts and sands, and to a lesser degree, clays that have been eroded from the Sentinel Butte and redeposited over the millennia by rivers, streams, and other naturally occurring forces. Numerous lakes, shallow ponds, and wetlands, often saline in nature, are present across the landscape in the vicinity of MRY.

3.4.1.3 Bedrock Stratigraphy

Unless otherwise cited, bedrock stratigraphy information in this section was derived from the CO_2 Storage Facility Permits issued by the North Dakota Department of Mineral Resources (DMR), Oil & Gas Division (Case Number 29029, Order Number 31583 for the Broom Creek Storage Facility [DMR 2022a]; Case Number 29032, Order Number 31586 for the Black Island-Deadwood Storage Facility [DMR 2022b]).

The proposed project site is in the eastern portion of the Williston Basin. Depth to bedrock in the vicinity of the MRY ranges from ground surface to approximately 350 feet below ground surface. The bedrock stratigraphy at the proposed project site is summarized on Figure 3-3 and in Section 3.5.1.2 (Figures 3-8 and 3-9). Overall, the stratigraphy of the Williston Basin has been well studied. 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 the basin's subtle structural character and tectonic stability (Peck 2014; Glazewski 2015).

Figure 3-3: North Dakota Stratigraphic Column of Proposed Project Area



Storage operations are planned in two geologic formations, the Broom Creek and Black Island-Deadwood Formations (Figure 3-3). Two wells are proposed for the injection of CO_2 into the Broom Creek Formation, and one well for injection of CO_2 into the Black Island-Deadwood Formation.

The project was designed using a stacked storage concept, where two storage reservoirs identified by varying vertical depths (i.e., the Broom Creek and Black Island-Deadwood Formations) could be accessed by a common well site. Detailed geologic, stratigraphic, and pore space information is provided in the Geologic Exhibits that were prepared for the project permit applications, which are available online (DMR 2022a, DMR 2022b).

The primary target CO_2 storage reservoir for the proposed project is the Broom Creek Formation (DMR 2022a). This formation is primarily composed of horizontally bedded sandstone which is approximately 4,915 feet below the MRY. Mudstones, siltstones, and interbedded evaporites of the undifferentiated Opeche and Spearfish Formations unconformably overlie the Broom Creek Formation. Mudstones and siltstones of the lower Piper Formation (Picard Member and lower) overlie the Opeche and Spearfish Formations. Together, the lower Piper and Opeche and Spearfish Formations (hereafter "Opeche–Picard interval") serve as the primary confining zone for the CO_2 storage reservoir, with an average thickness of 154 feet. The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone, with an average thickness of 270 feet. Together, the Opeche–Picard, Broom Creek, and Amsden Formations would comprise the CO_2 storage facility for the project.

Table 3-11 provides the average thickness and average depths for each formation. Tables 3-12 and 3-13, respectively, provide the geologic properties of the proposed storage facility and the geologic properties for the confining zones.

Table 3-11: Formations Comprising the Broom Creek CO_2 Storage Complex

	Formation	Purpose	Average Thickness, ft	Average Depth, ft	Lithology
Storage Facility	Opeche–Picard	Upper confining zone	154	4,712	Siltstone, mudstone evaporites
	Broom Creek	Storage reservoir (i.e., injection zone)	249	4,915	Sandstone, dolostone, dolomitic sandstone, anhydrite
	Amsden	Lower confining zone	270	5,175	Dolostone, limestone, anhydrite

Source: DMR 2022a

Table 3-12 provides the geologic properties of the proposed storage facility.

Table 3-12: Description of Broom Creek CO_2 Storage Reservoir (Primary Injection Zone)

Injection Zone Properties			
Property	**Description**		
Formation Name	Broom Creek		
Lithology	Sandstone, dolostone, dolomitic sandstone, anhydrite		
Formation Top Depth, ft	4,906		
Thickness, ft	Sandstone 168 Dolostone 103 Dolomitic Sandstone 26 Anhydrite 19		
Capillary Entry Pressure (CO_2/brine), psi	0.20		
Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Simulation Model Property Distribution**
Broom Creek (sandstone)	Porosity, %*	19.51 (2.46–27.38)	21.4 (1.0–36.0)
	Permeability, mD**	69.29 (0.06–2,690)	168.8 (0.0–8,601.1)
Broom Creek (dolostone)	Porosity, %	8.11 (5.48–8.97)	5.8 (0.0–18.0)
	Permeability, mD	0.03 (0.02–0.05)	0.13 (0.0–2,259.6)

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses. mD: millidarcy.
Source: DMR 2022a

Table 3-13 provides the geologic properties for the confining zones.

Table 3-13: Properties of Upper and Lower Confining Zones of the Broom Creek Geologic Storage Reservoir

Confining Zone Properties	**Upper Confining Zone**	**Lower Confining Zone**
Formation Name	Opeche–Picard	Amsden
Lithology	Siltstone	Dolostone
Formation Top Depth, ft	4,636	5,040
Thickness, ft	154	270
Porosity, % (core data)*	6.55	7.04
Permeability, mD (core data)**	0.112	0.017
Capillary Entry Pressure (CO_2/brine), psi	20.59	69.03
Depth Below Lowest Identified USDW, ft	3,409	3,813

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses.
Source: DMR 2022a

In addition to the Opeche–Picard interval, there is 820 feet (average thickness across the project area) of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation. An additional 2,545 feet (average over project area) of impermeable intervals separates the Inyan Kara Formation and the lowest USDW, the Fox Hills Formation, located approximately 2,545 feet below the MRY.[3]

The other proposed target CO_2 storage reservoir for the project is the sandstone horizons of the Black Island-Deadwood Formation, lying about 9,280 feet below MRY (Figure 3-3; DMR 2022b). Shales of the Icebox Formation conformably overly the Black Island Formation and serve as the primary upper confining zone with an average thickness of 118 ft (Table 3-14). The continuous shales of the Deadwood Formation B member serve as the lower confining zone with an average thickness of 34 feet.

Table 3-14: Formations Comprising the Black Island/Deadwood CO_2 Storage Complex

	Formation	Purpose	Average Thickness at Tundra Secure Geologic Storage Site, ft*	Average Depth Tundra Project Site, ft TVD	Lithology
Storage Facility	Icebox	Upper confining zone	118 (58 to 176)	9,308	Shale
	Black Island and Deadwood E member	Storage reservoir (i.e., injection zone)	118 (35 to 202)	9,427	Sandstone, shale, dolostone, limestone
	Deadwood C member sand	Storage reservoir (i.e., injection zone)	64 (40 to 88)	9,773	Sandstone
	Deadwood B member shale	Lower confining zone	34 (20 to 49)	9,791	Shale

*Thickness ranges were averaged from regional data in accordance with the Area of Review (model area) as depicted in Figure 2-4 of DMR 2022b. Actual thickness ranges across the Area of Review may differ from those identified in the Tundra Secure Geologic Storage Site (project area) per DMR 2022b.

In addition to the Icebox Formation, there are 570 feet of impermeable rock formations between the Black Island Formation and the next overlying porous zone, the Red River Formation. An additional 7,400 feet, including several thousands of feet of impermeable intervals separate the Black Island and the lowest USDW, the Fox Hills Formation.

[3] The Newcastle Sandstone USDW has a salinity level greater than 3,000 ppm; subsequently, under North Dakota Administrative Code 33-25-01-05 2(2), it is not reasonably expected to supply a public water system; therefore, Hell Creek is the lowest USDW.

The Black Island/Deadwood E Member and the Dead C Member (sand) comprise the proposed storage reservoirs (injection zone) for the project. The J-ROC1 test well[4] was drilled as a part of a separate, but related CarbonSAFE Phase III project in 2020 to a depth of 9,871 feet (results of J-ROC1 investigations detailed in Table 3-14). The upper proposed storage reservoir, the Black Island and Deadwood E Member, has an average thickness of 118 feet across the model area with an average depth of 9,427 feet at the Project Tundra site. The lower storage reservoir, the Deadwood C member (sand), averages 64 feet in thickness across the model area with an average depth of 9,773 feet at the Project Tundra site (DMR 29032). Based on offset well data and geologic model characteristics, the net reservoir thickness within the project area ranges from 63 to 287 feet, with an average of 165 feet.

The lower confining zone of the storage complex is the Deadwood B member shale. The Deadwood B member consists predominantly of shale. The shale within the Deadwood B member is 9,791 feet below the surface with a thickness of approximately 34 feet at the project site (Table 3-14). Table 3-15 provides the geologic properties of this geologic storage facility. Table 3-16 provides the geologic properties for the confining zones, including the average thickness and average depths for each formation.

Table 3-15: Description of Black Island/Deadwood CO_2 Storage Reservoir (Secondary Injection Zone)

Injection Zone Properties			
Property	**Description**		
Formation Name	Black Island, Deadwood E member, and Deadwood C-sand member		
Lithology	Sandstone, dolostone, limestone		
Formation Top Depth, ft	9782.2, 9820.9, and 10,077.4		
Thickness, ft	38.9, 92.3, and 60.9		
Capillary Entry Pressure (CO_2/Brine), psi	0.16		
Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Model Property Distribution**
Black Island (sandstone)	Porosity, %*	8.0 (3.4–10.3)	5.6 (1.1–14.8)
	Permeability, mD**	3.7 (0.0019–157)	0.805 (<0.0001–96.0)
Deadwood E Member (sandstone)	Porosity, %	10 (6.85–14.43)	7.0 (0–17.7)
	Permeability, mD	5.63 (0.0325–2,060)	3.88 (<0.0001–4549.2)
Deadwood C Sand Member	Porosity, %	7.6 (1.01–14.69)	7.6 (0.3–17.2)
	Permeability, mD	11 (0.0018–1140)	7.03 (<0.0001–830.3)

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses.
Source: DMR 2022b

[4] The J-ROC1 test well is at the same location as the planned Liberty 1 injection well.

Table 3-16: Properties of Upper and Lower Confining Zones of the Black Island-Deadwood Geologic Storage Reservoir

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Icebox	Deadwood B member shale
Lithology	Shale	Shale
Formation Top Depth, ft	9,308	9,791
Thickness, ft	118	34
Porosity, % (core data)[a]	3.6[c]	2.0
Permeability, mD (core data)[b]	0.00002[c]	0.0103
Capillary Entry Pressure (CO_2/brine), psi	845	176[d]
Depth Below Lowest Identified USDW, ft	8,097	8,580

[a] Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
[b] Permeability values are reported as the geometric mean followed by the range of values in parentheses.
[c] Porosity and permeability values derived from HPMI (high-pressure mercury injection) testing.
[d] No shale samples in the Deadwood were tested. Value is for a sample from a sandy–shale interval in the Deadwood D member.
Source: DMR 2022b

No known transmissible faults are within the confining systems in the project area. The formations between the Deadwood – Broom Creek – Inyan Kara and between the Inyan Kara 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).

3.4.1.4 Legacy Wells

Ten legacy wells are located within the project area, five that penetrate the cap rock of the Broom Creek Formation (Figure 3-4) and five that penetrate the cap rock of the Deadwood Formation (Figure 3-5).

Figure 3-4: Broom Creek Legacy Wells near the Project Area

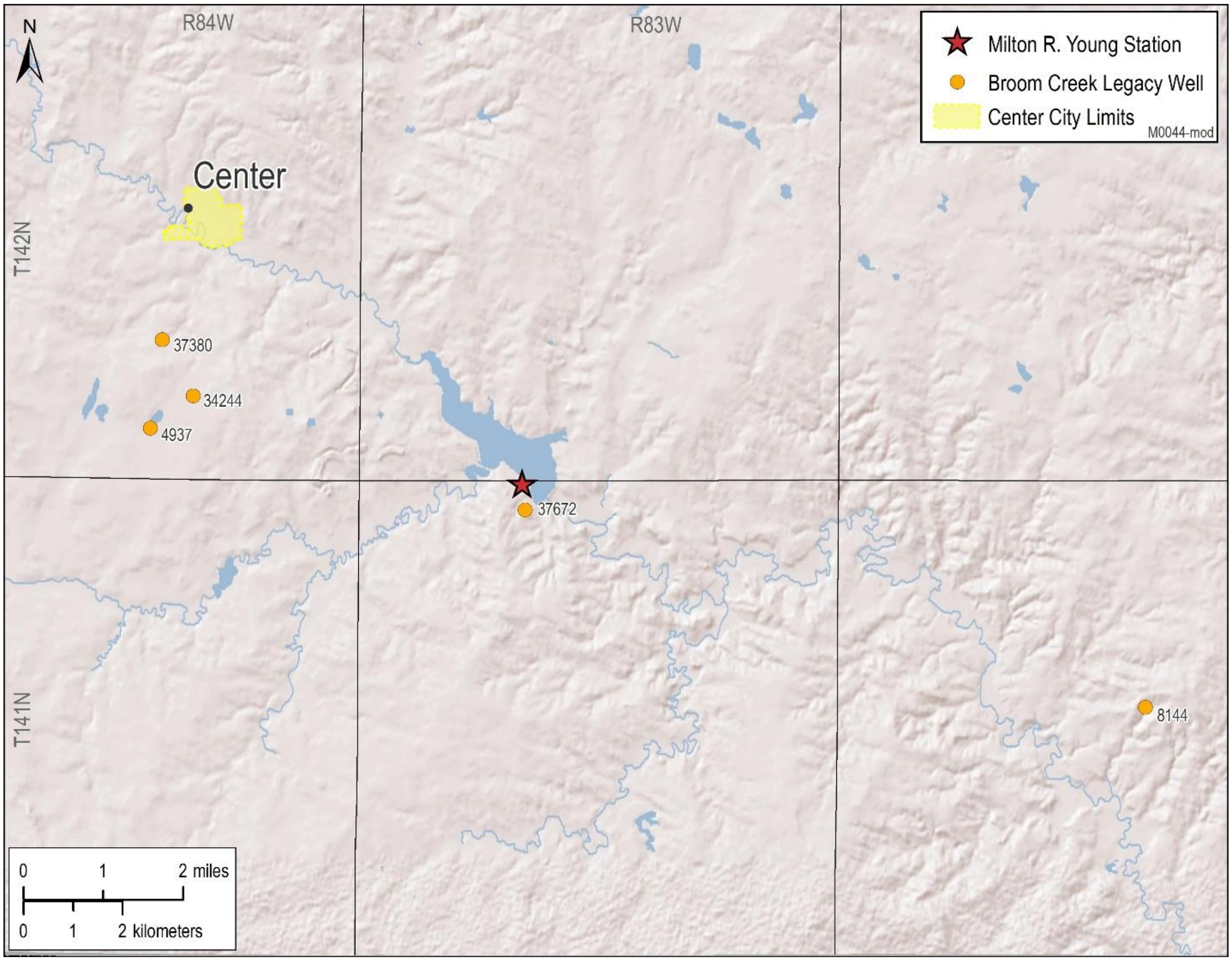
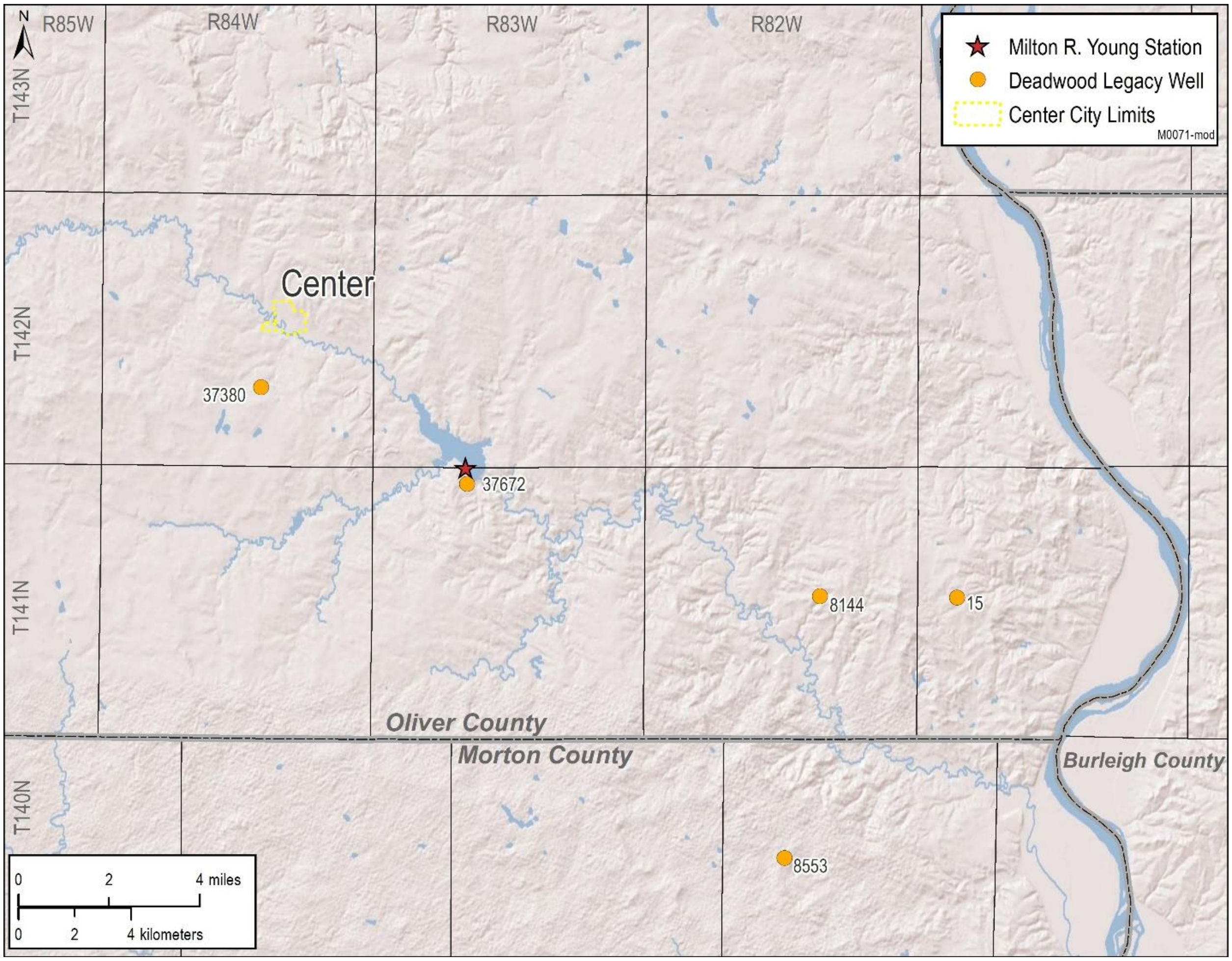


Figure 3-5: Deadwood Legacy Wells near the Project Area



3.4.2 Environmental Consequences

3.4.2.1 Soils

Construction activities would result in temporary and permanent disturbances to soils located in the project work areas. Construction of the project would result in the permanent disturbance of approximately 25.8 acres of soils within the MRY property to accommodate the project facilities. Additionally, approximately 97.0 acres of land would be required for temporary construction and laydown areas. Areas proposed for permanent impacts may require removal of vegetation, grading, and excavation to accommodate project components. Use of the construction and laydown areas would require removal of vegetation and addition of rock or gravel as needed to allow vehicle and equipment access. However, following construction, the construction and laydown areas would be restored to original conditions with the exception of an approximately 7.0-acre area that would be retained for overflow parking for MRY and project operations.

Permanent impacts to soils would occur within the project's permanent facility footprint and the area retained for overflow parking for MRY and project operations. However, these areas are primarily located in previously disturbed lands used for general MRY operations. Therefore, impacts to soils are anticipated to be minimal for the permanent facilities and temporary in nature for the construction and laydown areas that will be restored to original conditions following construction.

3.4.2.2 Surficial Geology

Construction activities would affect surface soils and near surface geology for site grading including vegetation removal, grubbing, topsoil segregation, and excavation as required for foundations. Excavation backfilling, gravel removal, and site restoration would be completed once installation of the project is complete.

The project would have minimal impact on geological resources beyond geologic formation targets for CO_2 injection and wastewater disposal. Following construction, the construction and laydown areas would be restored to original conditions with the exception of an approximately 7.0-acre area that would be retained for overflow parking for MRY and project operations. Further impacts from the project to surface soils and near surface geology within the proposed footprint of the MRY facility would be minimal.

CO_2 injection and its resulting pressure increases would be confined to the intended injection formations and there would be no expected impacts to any surface geology or soil conditions.

3.4.2.3 Bedrock Stratigraphy

The intention of the project is to conduct geologic storage operations of CO_2 by injecting it into the deep subsurface and naturally occurring geologic formations (Broom Creek Formation and Black Island-Deadwood Formation). These formations would be negligibly affected by a geochemical reaction with the injected CO_2 and temporarily impacted by the pressure buildup during CO_2 injection. Impacts to the deep subsurface geologic formations from drilling for injection well installation would be limited to the well boreholes. The size of the boreholes and injection facilities would not physically result in a material change to the underlying geologic formations.

For the project area, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation would be the cap rock, which would contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO_2 would be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), which would confine the CO_2 within the proposed storage reservoirs. After the injected CO_2 becomes dissolved in the formation brine, the brine density would increase. This higher-density brine would ultimately sink in the storage formation (convective mixing). Over a much longer period of time (greater than 100 years), mineralization of the injected CO_2 would result in long-term, permanent geologic confinement. A geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream into the injection zone. Figures 3-6 and 3-7 show the expected pressure difference and extent of CO_2 plume within the geologic storage facilities after 20 years of injection. The effects have been found to be minor and not threatening to the geologic integrity of the storage system. All injection and monitoring operations would be subject to NDIC Class VI regulations to ensure that there would be no impact on the area and surrounding communities.

Figure 3-6: Pressure Influence Associated with CO_2 Injection into the Deadwood Formation

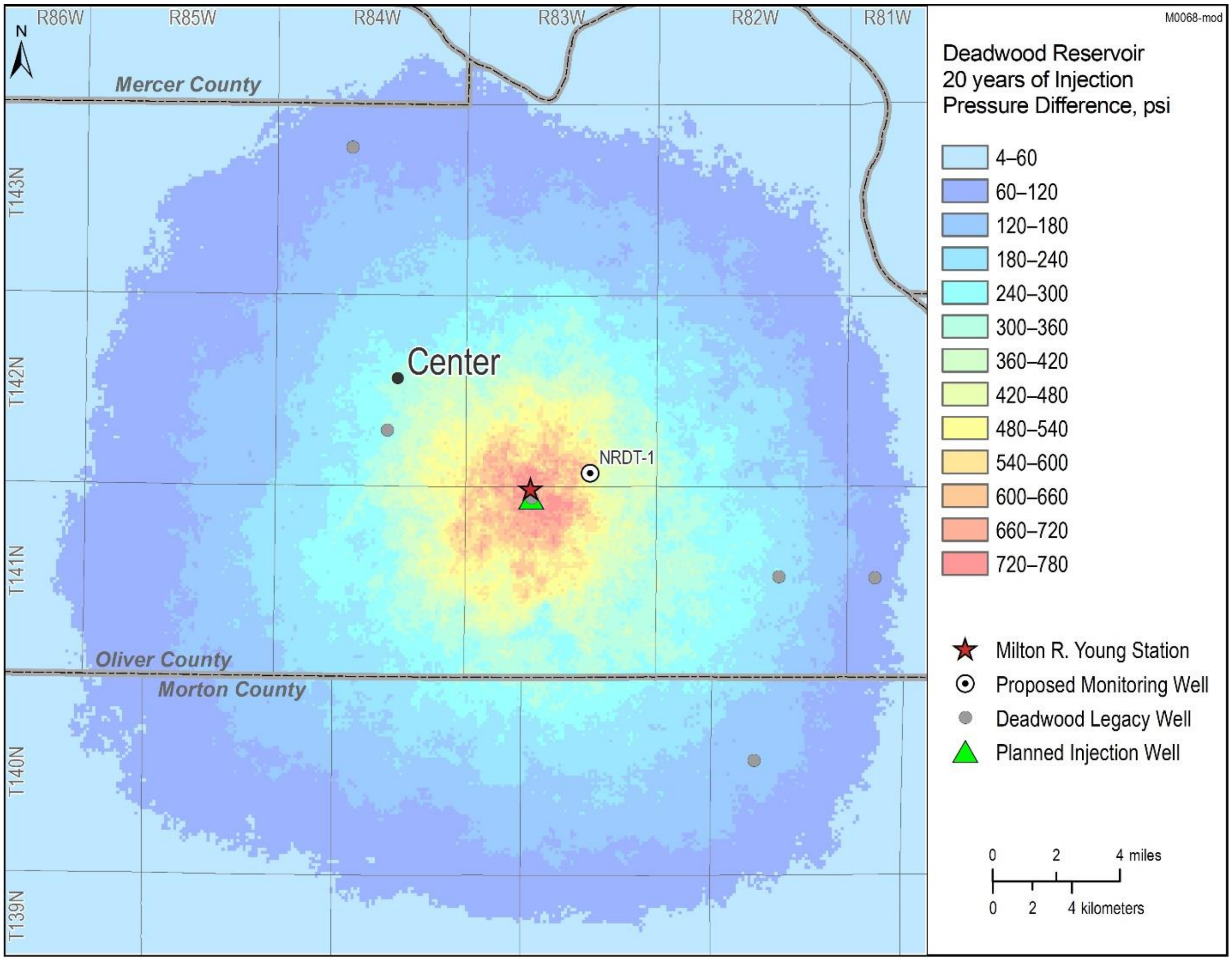
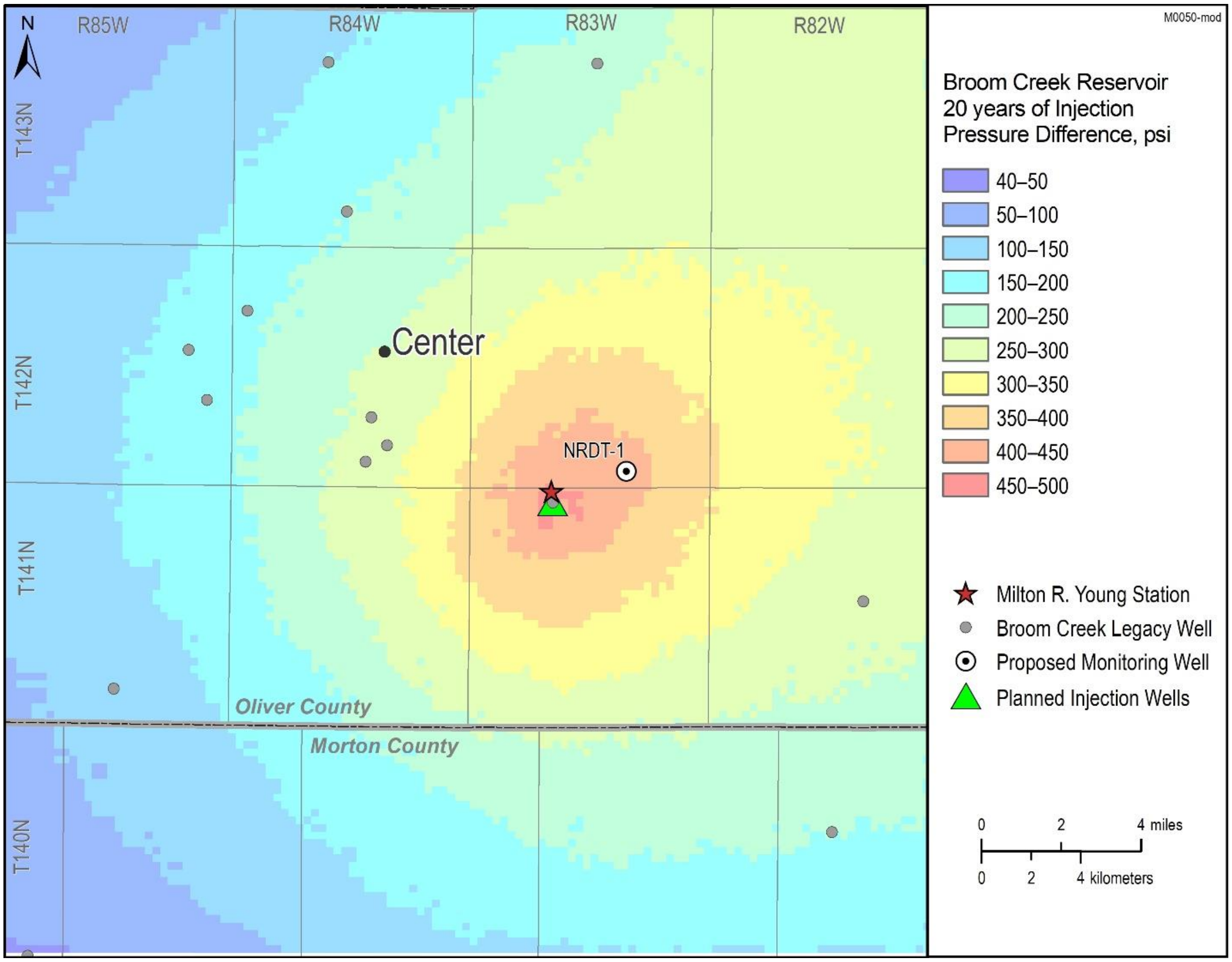


Figure 3-7: Pressure Influence Associated with CO_2 Injection into the Broom Creek Formation



Detailed information regarding Minnkota's strategy for monitoring for CO_2 leakage and establishing expected baselines to monitor against leakage is included in the Monitoring, Reporting, and Verification Plan (MRV Plan) for the project (Appendix F). Appendix F also includes additional information from the EERC regarding the equipment and methods used for seismic monitoring and mitigation measures to reduce potential impacts associated with seismic monitoring.

3.4.2.4 Legacy Wells

The low density of known legacy wellbores in the project area indicates that the CO_2 injection would occur in an area with few available leakage pathways. The legacy wells located in the project area were evaluated and all have the necessary casing and cement bonds needed to prevent leakage pathways and maintain integrity of the geologic storage facilities (Figures 3-4 and 3-5).

3.5 Water Resources

This section describes water resources (e.g., surface waters, water quality, floodplains, groundwater, hydrogeology, wetlands) in the project area and surrounding vicinity. Water resources typically are defined in terms and scale of watersheds, which are areas of land that drain all the streams and rainfall to a common outlet (e.g., river, lake, ocean); watersheds also include the underlying groundwater (U.S. Geological Survey [USGS] no date). Surface waters, wetlands, floodplains, and groundwater are distinct resources, but function as a single, integrated natural system in the watershed. As such, disruption of any part of these resources can have long-term and far-reaching consequences for the entire system (Federal Emergency Management Agency [FEMA] 2007).

The project falls within one sub-watershed, Nelson Lake-Square Butte Creek (Hydrologic Unit Code [HUC] 12: 101301010803), which is a part of the larger Headwater Square Butte Creek Watershed (HUC 10: 1013010108).

Federal regulatory requirements for water resources include, but are not limited to:

- EO 11990, *Protection of Wetlands,* requires federal agencies to "avoid to the extent possible the long- and short-term adverse impacts associated with the destruction or modification of wetlands and to avoid direct or indirect support of new construction in wetlands wherever there is practicable alternative." This EO does not apply to the issuance of federal agency permits, licenses, or allocations to private parties for activities involving wetlands on non-Federal property.
- EO 11988, Floodplain Management, requires federal agencies to "avoid to the extent possible the long- and short-term adverse impacts associated with the occupancy and modification of floodplains and to avoid direct or indirect support of floodplain development wherever there is a practicable alternative". This EO was designed to reduce the risk of flood loss, to minimize impact of floods on human safety, health, and welfare, and to restore and preserve the natural and beneficial values served by floodplains. This EO applies to management of federal lands and facilities; federally undertaken, financed, or assisted construction and improvements; and federal activities and programs affecting land use.
- The National Flood Insurance Act established the National Flood Insurance Program, which is a voluntary floodplain management program for communities administered by FEMA. Any action within a FEMA-mapped floodplain in participating communities must follow the community's FEMA-approved floodplain management regulations (FEMA 2005).
- The CWA enables the regulation of discharges into waters of the United States and establishment of surface water quality standards (see 40 CFR 230.3 and 33 CFR 328 for definition of waters of the United States). The sections of the CWA most applicable to the effects of ground disturbance activities include Section 303(d), Section 404, Section 401, and Section 402, which establishes the National Pollutant Discharge Elimination System (NPDES) permit program.

3.5.1 Affected Environment

3.5.1.1 Surface Waters, Surface Water Quality, and Floodplains

3.5.1.1.1 Surface Water

Surface waters include rivers, streams, creeks, lakes, ponds, reservoirs, oceans, or any other body of water found on the earth's surface. Surface water is a part of the larger hydrologic cycle (water cycle), maintained by precipitation and water runoff that can be lost through evaporation, seepage into the ground, or use by plants and animals. Typical beneficial surface water uses include drinking water, public supply, irrigation, agriculture, thermoelectric generation, mining, and other industrial uses.

The Headwater Square Butte Creek watershed is comprised of 190,069 acres and contains numerous sub-watersheds under HUC 12. The Nelson Lake-Square Butte sub-watershed encompasses over 31,078 acres. Drainage basins funnel all the streams, snowmelt, and rainfall to a common outlet such as the outflow of a reservoir, or mouth of a bay. Surface runoff from the project site would drain to the Square Butte Creek (Nelson Lake) via overland flow and continue southeast within the creek, eventually draining into the Missouri River south of Harmon, North Dakota.

In 1968, Square Butte Creek was dammed to provide water cooling supplies for the MRY Station. Nelson Lake makes up a large portion of the surface water present in the Nelson Lake-Square Butte sub-watershed, spanning 581 acres with 12.5 miles of shoreline (NDGF 2020). Nelson Lake is not a 303(d)-listed water. Assessment information from 2018, indicates that the waterbody is in good condition for all assessed uses (e.g., agricultural, fish and aquatic biota, fish consumption, industrial, and recreation) (EPA 2018a). Nelson Lake is maintained at a maximum of 1,926 feet above mean sea level, averages 14.4 feet in depth, and has a storage capacity of 8,322.8 acre-feet (NDGF 2020). Recreational and industrial activities associated with MRY power generation are the dominant land uses at and surrounding Nelson Lake.

The lake is owned and maintained by Minnkota, and primarily functions to provide cooling water for the power plant complex as well as provide a source of recreation and scenic beauty for the citizens of the area. Minnkota also maintains and operates Nelson Lake Dam.

Minnkota maintains a site-wide NPDES industrial wastewater permit for MRY operational discharges to Nelson Lake, issued by the NDDEQ (ND-000370). Additional outfalls are covered under the NPDES general stormwater discharge permit (NDR05-0012) associated with industrial activity.

Section 404 of the CWA requires approval from the U.S. Army Corps of Engineers before placing dredged or fill material into waters of the United States, including rivers, streams, ditches, coulees, lakes, ponds, or adjacent wetlands. Engineering evaluations are ongoing to determine all permit requirements for the project; however, it is anticipated that a Section 404 permit would not be required.

3.5.1.1.2 Water Quality

CWA Section 303(d) requires states, territories, and authorized tribes (as delegated by the EPA) to develop lists of impaired surface waters, which are those that do not meet water quality standards established by these jurisdictions. The CWA requires that these jurisdictions establish priority rankings for surface waters on the list and develop total maximum daily loads (TMDLs) of pollutants for these surface waters. A TMDL is a calculation of the maximum amount of pollutant that a surface water can receive and still meet established water quality standards. The NDDEQ has been delegated the authority by the EPA to assess water quality of North Dakota surface waters and develop the state’s Section 303(d) list of impaired surface waters.

Surface waters are assigned priority rankings of 1 through 5, with Category 5 considered impaired under Section 303(d) and requiring a TMDL. The 2018 list of Section 303(d) impaired surface waters is the most current published list (North Dakota Department of Health [DoH] 2019). Square Butte Creek, from Nelson Lake downstream to its confluence with Otter Creek is listed as a Category 5 impaired water for fish and other aquatic biota (DoH 2019). The impairments are caused by water quality standard exceedances for sedimentation/siltation. TMDLs have not yet been developed or approved for this segment and no existing plans for restoration were identified. This segment is listed as a low priority for TMDL development (DoH 2019). The project would not adversely impact downstream sedimentation or siltation impairment in accordance with applicable stormwater and wastewater permits.

3.5.1.1.3 Floodplains

Floodplains are defined as any land area susceptible to being inundated by waters from any source (44 CFR 59.1) and are often associated with surface waters and wetlands. Floodplains are valued for their natural flood and erosion control, enhancement of biological productivity, and socioeconomic benefits and functions. For human communities, floodplains can be considered a hazard area because buildings, structures, and properties located in a floodplain can be inundated and damaged during floods. FEMA develops Flood Insurance Rate Maps (FIRMs), the official maps on which FEMA delineates special flood hazard areas for regulatory purposes under the National Flood Insurance Program. Special flood hazard areas are also known as 100-year floodplains, or areas that have a 1 percent annual chance of flooding. FEMA also maps 500-year floodplains, or areas that have a 0.2 percent annual chance of flooding.

According to the FEMA National Flood Hazard Layer Viewer, digital data is unavailable for the unincorporated areas in Oliver County (FEMA 2023). Using the flood maps service center, FIRMs are unavailable for the proposed project area (FEMA 2023). A review of the North Dakota Risk Assessment Map Service through the North Dakota Water Commission was conducted. The project would not be located within any FEMA-mapped 100- or 500-year floodplains (North Dakota Water Commission 2023). Reviews of 1987 FIRMs confirmed the lack of floodplains present in the project area and surrounding region (FEMA 1987).

3.5.1.2 Groundwater and Hydrogeology

The hydrogeology of western North Dakota comprises several shallow freshwater-bearing formations of Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin. These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin. The Pierre Shale is a regionally extensive, dark gray to black marine shale between 1,000 and 1,500 feet thick which forms the lower boundary of the Fox Hills–Hell Creek formations (Thamke and others 2014).

Freshwater aquifers are present within the Cretaceous Fox Hills and Hell Creek Formations, overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group. The Tertiary Golden Valley Formation overlies the Tertiary Fort Union Group. Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the proposed project area (Figure 3-8; Croft, 1973).

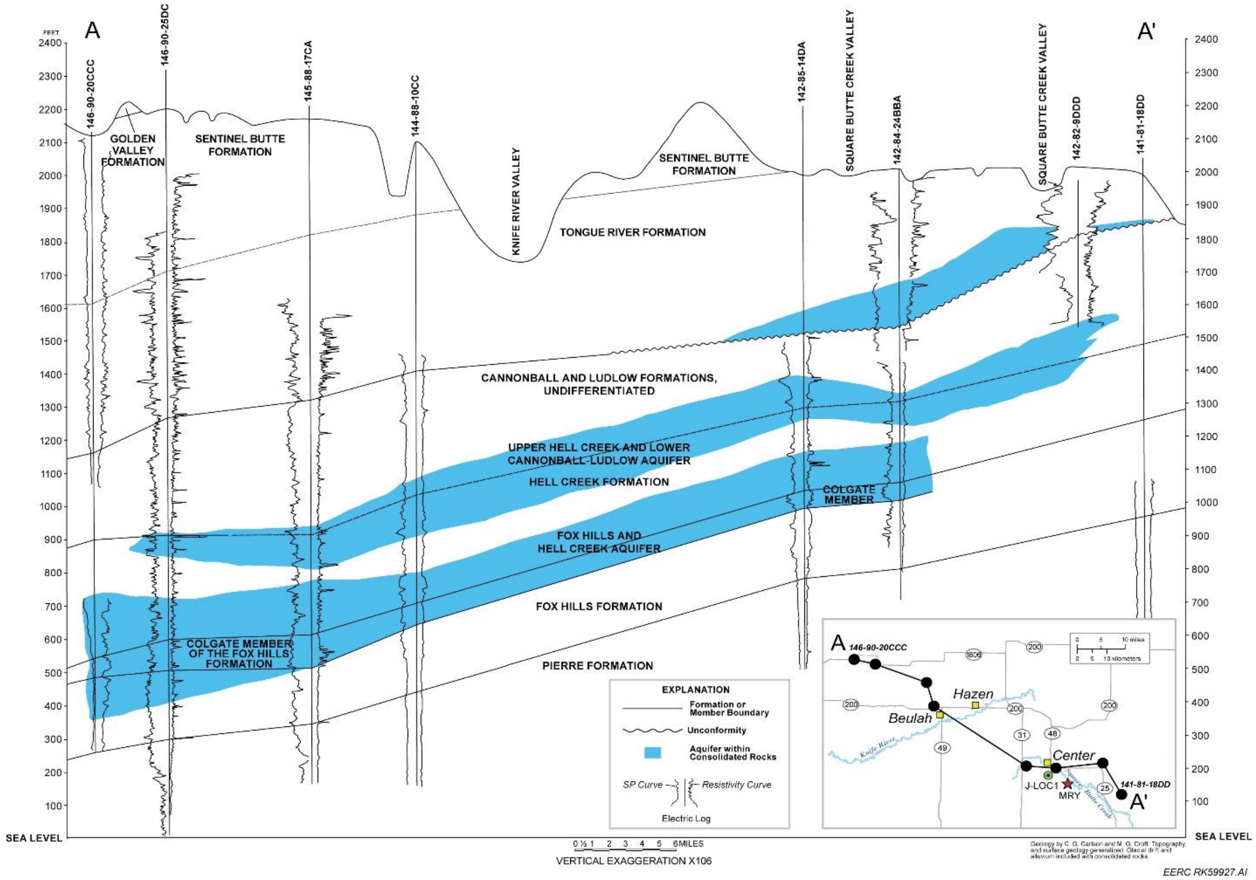
Figure 3-8: Upper Stratigraphy of Oliver County

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

Source: modified from Croft 1973

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system within the proposed project area (Figures 3-3, 3-8, and 3-9). These formations are often used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. The basal sandstone member of the Tongue River Formation is persistent and a reliable source of groundwater in the region. The thickness of this basal sand ranges from approximately 200 to 500 feet and directly underlies surficial glacial deposits in the project area. Tongue River groundwaters are generally a sodium bicarbonate type with a total dissolved solids (TDS) of approximately 1,000 parts per million (ppm) (Croft 1973).

Figure 3-9: Stratigraphy near the Project Area



Source: modified from Croft 1973
West-east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships. The black dots on the inset map represent the locations of the water wells illustrated on the cross section.

The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation in the extreme western portion of the project area. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the project area, the Sentinel Butte is not a source of groundwater within the project area. TDS in the Sentinel Butte Formation ranges from approximately 400 to 1,000 ppm (Croft 1973).

A sole source aquifer is one that supplies at least 50 percent of the drinking water for its service area, or aquifers where there are no reasonably available alternative drinking water sources should the aquifer become contaminated (EPA 2018b). No sole source aquifers are located in North Dakota (EPA 2018b).

3.5.1.3 Fox Hills and Hell Creek Formation

The deepest USDW in the project area is the Fox Hills Formation (Figure 3-9), 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 claystone with occasional carbonaceous beds, all fluvial in 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 project area is approximately 700 to 900 feet deep and 200 to 350 feet thick. 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 project area.

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, which isolates 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 the aquifer system discharges into overlying strata under central and eastern North Dakota (Fischer 2013).

The Fox Hills–Hell Creek aquifer system is not typically used as a primary source of drinking water due to high concentrations of TDS and fluoride among other constituents. However, the aquifer is occasionally used as a source for irrigation and livestock watering. The project conducted a baseline groundwater monitoring study (Appendix G; Burns & McDonnell 2022). Results from the analysis of water samples collected from wells in the Fox Hills-Hell Creek Formation in 2021 as part of the study indicate groundwater in this formation is a sodium bicarbonate type with a TDS content of approximately 1,520 to 1,760 milligrams per liter (mg/L). Fluoride concentrations ranged from 0.82 ppm to 3.54 mg/L. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Trapp and Croft 1975).

3.5.1.4 Wetlands

Wetlands are important landscape features that provide many beneficial services for people, fish, and wildlife. Some of these services, or functions, include protecting and improving water quality, providing fish and wildlife habitats, storing floodwaters, producing aesthetic value, ensuring biological productivity, filtering pollutant loads, and maintaining surface water flow during dry periods. Functions are the result of the inherent and unique natural characteristics of wetlands.

No wetlands would be directly affected by the proposed project. An excavated, human-made wetland is located approximately 350 feet south of the proposed CO_2 flowline (USFWS 2019)[5]. The nearest waterbody (Nelson Lake) is approximately 1,500 feet north and east of the project on the north side of MRY and is classified as a dike/impounded lacustrine wetland (USFWS 2019). The National Wetland Inventory also shows several adjacent reservoirs to Nelson Lake as dike/impounded lacustrine wetlands (USFWS 2019). Square Butte Creek is classified as a riverine, lower perennial wetland system (USFWS 2019).

[5] Note that this distance to the nearest delineated wetland and is not inclusive of human-made ponds.

3.5.2 Environmental Consequences

3.5.2.1 Surface Water, Surface Water Quality, and Floodplains

No surface waters or floodplains occur in the proposed project's construction footprint or temporary construction areas; therefore, no filling, excavating, or clearing would occur in these resources. The erosion and transport of sediment due to construction (e.g., clearing, excavating, filling) could result in localized water quality degradation of Nelson Lake due to its proximity to the project (about 1,500 feet away from carbon capture facility, and about 600 feet away from injection facility). Sediment deposition into surface waters can increase turbidity and adversely affect aquatic species and habitats by increasing water temperatures and decreasing dissolved oxygen levels (EPA 2023a). Sediment deposition into surface waters also can increase pollutant and nutrient levels which can adversely affect water quality conditions (EPA 2023a). For example, excess phosphorous may enhance algal growth in surface water, which can affect the availability of oxygen in water. The use of construction equipment also could result in accidental spills or leaks of petrochemicals (e.g., gasoline, hydraulic fluids) that could potentially reach surface waters if not contained and cleaned up. Any accidental spill that would reach Nelson Lake or associated tributaries and reservoirs could degrade surface water quality, which could adversely affect aquatic habitat or limit the beneficial use of the lake (e.g., recreation, fish consumption). Project construction would require the development of a Stormwater Pollution Prevention Plan (SWPPP), which would contain site-specific measures to avoid and minimize erosion and sediment transport to surface waters, as well as measures to contain and clean up accidental petrochemical spills. The potential impacts to Nelson Lake and Square Butte Creek would be mitigated using site-specific measures and best practices identified in the SWPPP and associated NPDES permit (CWA Section 402), designed for water quality protection and to ensure water quality standards of nearby surface waters are not exceeded.

The proposed project would operate under Minnkota's existing NPDES permit (ND-000370) to ensure any industrial discharge to Nelson Lake would not violate water quality standards. No significant modifications to the existing industrial NPDES permit would be required with the addition of the carbon capture facility, and any surface water runoff (e.g., rainfall) would be captured and discharged per MRY's existing site-wide NPDES permit. In addition, the facility design elements would help control runoff, including storm covers (over pumps, piping, etc.) to divert rainwater away from the project.

Spill prevention and containment measures would be considered during the engineering design to prevent pollutant discharges to the surface. Project designs require use of the following tanks (chemical storage and tank volumes are discussed in parenthesis, respectively): Solvent Tank (amine solvent; 399,688 gallons), Solvent Sump Tank (solvent, wash water, drain; 5,118 gallons), Caustic Soda Tank (caustic soda; 129,548 gallons), Reclaimed Waste Tank (reclaimed waste; 88,833 gallons), Wash Water Tank (amine contained water; 90,995 gallons), Dilute Wash Water Tank (diluted amine contained water; 87,121 gallons), Fresh Solvent Stank (fresh amine solvent; 61,499 gallons), Acid Wash Water Tank (diluted amine with sulfuric acid; 99,336 gallons), Sulfuric Acid Tank (sulfuric acid; 2,647 gallons), Acid Wash Waste Tank (acid wash waste; 20,629 gallons), Acid Wash Condensate Tank (acid wash water condensate; 326 gallons), Precoat Filter Wash Water Drum (precoat filter wash water; 8,269 gallons), and

TEG Tank (triethylene glycol; 381 gallons). Possible pollutant discharges will be mitigated through implementation of spill prevention and containment measures.

Minnkota would be required to maintain and implement a SWPPP which would outline BMPs, stormwater sampling guidelines, and control of potential pollutants. The purpose of the SWPPP would be to protect and maintain the quality of the receiving surface water in accordance with federal and state CWA regulations. All construction stormwater runoff which directly or indirectly impacts surface water would be controlled to minimize impacts by establishing a plan to manage the quality of stormwater runoff from the site. All attempts would be made to prevent contamination of water from construction activities, such as fuel spillage, lubricants, and chemicals, by following safe handling and storage procedures. Stormwater runoff would be managed to minimize sediment and silt movement, and other potential pollutants.

As described in Section 2.5.2.1, a new water appropriation of 15,000 acre-feet from the Missouri River has been approved by the North Dakota State Water Commission to supply the water needs for the project. DOE received comments on the Draft EA regarding potential effects of the project water appropriation from the Missouri River on downstream water users. Further analysis determined that the 15,000 acre-feet of water requested for the project is 0.10 percent of the mean annual discharge recorded at Garrison Dam and the requested withdrawal rate of 13,480 gallons per minute (gpm), or 30.0 cubic feet per second, is 0.14 percent of the mean daily discharge rate (see Section K.4.5 Appendix K for more information). This water appropriation does not represent a significant change to daily flow or annual discharge from the Missouri River. Therefore, the project would not preclude other water users from exercising their right to appropriate water, subject to North Dakota Water Commission permitting requirements and regulatory requirements at NDAC Title 89-03 and North Dakota Century Code 61-04.

3.5.2.2 Groundwater and Hydrogeology

The impermeable nature of the surface geology in the watershed and the disturbed and compacted nature of the project site would limit groundwater contamination during construction and operations. Subsurface activities may include the construction of pilings and injection wells for the project. Permitting requirements under the CWA protect surface and groundwater to prevent pollutant-laden discharges. The MRY facility maintains CWA permits and adheres to the requirements. New CWA or other applicable permits for the project would require implementation of BMPs as well as studies to ensure that the resource is protected. Therefore, impacts on groundwater or hydrogeologic resources would not be likely.

3.5.2.3 Wetlands

No filling, excavating, or clearing would occur in wetlands. The nearest wetland[6] is over 600 feet from the facility boundaries and approximately 30 feet from the closest temporary laydown and construction area. Due to the distance between the project facility and the nearest wetland, it is unlikely that facility operations would affect wetlands. BMPs (e.g., installation of silt fence and other erosion and sediment control devices) would be installed at the temporary construction and laydown areas as needed to avoid or minimize impacts to wetlands during construction.

3.6 Biological Resources

3.6.1 Affected Environment

Information regarding wildlife species and habitat within the project area was obtained from a review of existing published sources and site-specific wildlife and habitat information from Minnkota's Environmental Information Volume (EIV), the USFWS, and the NDGF file information.

3.6.1.1 Aquatic Resources

Nelson Lake is located adjacent to the project area (see Section 2.5.1) and supports various fish species, including largemouth bass (*Micropterus salmoides*), bluegill (*Lepomis macrochirus*), northern pike (*Esox lucius*), white crappie (*Pomoxis annularis*), black crappie (*Pomoxis nigromaculatus*), perch (Genus *Perca*), common carp (*Cyprinus carpio*), and walleye (*Sander vitreus*) (NDGF 2020). Per the NDGF, Nelson Lake is considered the best largemouth bass lake in North Dakota, with open water year-round allowing warmwater fish to grow better than in other lakes in North Dakota (NDGF 2022).

Aquatic mussels do not appear to have a regular presence in Nelson Lake or Square Butte Creek according to the historical and current ranges noted by NDGF (NDGF 2023b, NDGF 2015). No other publicly available evidence supporting freshwater mussel presence in waters near the project was identified.

3.6.1.2 Wildlife Resources

The proposed project site would be located within the existing MRY facility in an area historically used for coal pile storage that has since been reclaimed. While the area is undeveloped, it provides minimal, low-quality wildlife habitat due to the disturbed and industrial nature of the area. The areas surrounding the project area are generally low-quality wildlife habitat, including the adjacent landfill, coal mines, and industrial facilities. The project would not result in the loss of quality wildlife habitat. While wildlife may potentially use the area, the past and present disturbances for plant operations provide limited, minimally vegetated wildlife habitat. The carbon capture facilities would occupy 25.8 acres of land west and south of MRY that was previously used for stockpiling coal. Approximately 97.0 acres of land would be required for temporary construction and laydown areas within the Minnkota-owned property. However, following construction, the construction and laydown areas would be restored to original conditions with

[6] Note that these distances are to the nearest delineated wetland and are not inclusive of human-made ponds.

the exception of an approximately 7.0-acre area that would be retained for overflow parking for MRY and project operations. Potential habitat in the areas retained for the carbon capture facilities and overflow parking would be permanently removed and would result in displacement of wildlife species. However, impacts would be low due to the limited existing habitat at the project site, abundance of additional and higher quality habitat in the surrounding area, and the limited area of disturbance across the entire site.

Typical wildlife species likely to occur in the project vicinity could include squirrels, rabbits, fox, songbirds, shorebirds, grassland birds, raptors, coyotes (*Canis latrans*), skunks, raccoons (*Procyon lotor*), otters, white-tailed deer (*Odocoileus virginianus*), toads, turtles, snakes, and butterflies (NDGF 2023a). Given the active power generation facility, coal and industrial operations, landfill, and the roadways adjacent to the proposed project site, species likely to occur in the proposed project area would be those acclimated to more developed environments.

3.6.1.2.1 Federally Listed Species

The ESA of 1973, 16 United States Code (U.S.C.) 1531 et seq., establishes a national program for the conservation of threatened and endangered species of fish, wildlife, and plants, as well as the preservation of the supporting habitats and ecosystems. ESA Section 7 requires any federal agency authorizing, funding, or carrying out any action to confirm that the action is unlikely to jeopardize the long-term survival of any endangered or threatened species, or result in the destruction or adverse alteration of critical habitat of such species. Regulations implementing the ESA interagency consultation process are found in 50 CFR Part 402.

A review of the USFWS Information for Planning and Consultation (IPaC) system indicates five federally threatened or endangered species and one candidate species have the potential to occur within the project area based on known range and distribution. However, based on habitat requirements, the proposed project site does not support suitable habitat for any of these species. Table 3-17 summarizes these species, their habitat requirements, and their potential to occur in the project area (USFWS IPaC 2023a; NDGF 2015; Burns & McDonnell 2022). North Dakota does not have a state endangered or threatened species list; only those species listed under the ESA are considered threatened or endangered in North Dakota (NDGF 2021). Table 3-17 is not inclusive of all federally listed threatened or endangered species in North Dakota; only those with the potential to occur in the vicinity of the proposed project, per the IPaC system, are included.

Table 3-17: Federally Listed Species Potentially Occurring within the Project Area

Common Name	Scientific Name	Status	Potential to Occur within the Project Vicinity	Recommended Determination of Effect
Birds				
Piping plover	*Charadrius melodus*	T	Unlikely to occur; preferred habitat includes Alkali Lakes and Missouri River sandbars. The property site is an existing industrial site. Oliver County also contains critical habitat for the piping plover.	No Effect
Red knot	*Calidris cantus*	T	May occur; migrates through North Dakota in mid-May and mid-September to October in “extremely low numbers.” Breeding and nesting habitat is marine, while Red Knots have been observed during migration in the Missouri River system, sewage lagoons, and large permanent freshwater wetlands.	Not Likely to Adversely Affect
Whooping crane	*Grus americana*	E	May occur; migrates through North Dakota in April to mid-May and September to early November, found along wetlands and ponds.	Not Likely to Adversely Affect
Mammals				
Northern Long-eared bat (NLEB)	*Myotis septentrionalis*	E	Unlikely to occur; hibernates in caves and mine shafts during the winter months, and roosts in wooded areas during the summer months.	No Effect
Insects				
Dakota skipper	*Hesperia dacotae*	T	May occur; preferred habitat of mixed-grass prairies dominated by bluestem, purple coneflower, and needlegrasses may exist within project area, and species has been documented in Oliver County.	Not Likely to Adversely Affect
Monarch butterfly	*Danaus plexippus*	C[a]	May occur; preferred habitat of prairies, meadows, grasslands, and right-of-way ditches along roadsides. Eggs laid on milkweed host plant (primarily Asclepias spp.).	Not Likely to Jeopardize

Source: USFWS IPaC 2023a, NDGF 2015

BGEPA = Bald and Golden Eagle Protection Act; E = Endangered; T = Threatened; C = Candidate Species

[a] Federal candidate species are not currently listed and consultation under the ESA is not required.

3.6.1.2.2 Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act

The USFWS has statutory authority and responsibility for enforcing the MBTA (16 U.S.C. 703-712). Most native bird species (birds naturally occurring in the United States) are protected under the MBTA, and the list of protected species is identified in 50 CFR 10.13, which is reviewed and updated regularly. MBTA species having the potential to occur in the project area are listed in Table 3-18 (USFWS IPaC 2023a).

Table 3-18: Migratory Bird Species Potentially Occurring in the Project Area

Common Name	Scientific Name	Status	Habitat
Bald eagle	*Haliaeetus leucocephalus*	BGEPA, MBTA	Forested areas adjacent to large bodies of water, using select super-canopy roost trees that are open and accessible.
Bobolink	*Dolichonyz oryzivorus*	MBTA, Birds of Conservation Concern (BCC)	Grasslands, hayfields, and marshes with dense vegetation of grass, weeds, with low bushes.
Franklin's Gull	*Leucophaeus pipixcan*	MBTA, BCC	Prairie marshes with low vegetation density; prefers patchy areas with interspersed open water.
Golden Eagle	*Aquila chrysaetos*	BGEPA, MBTA	Open and semi-open prairies, woodlands, and barren areas; preference for hilly or mountainous regions.
Long-eared Owl	*Asio otus*	MBTA, BCC	Roosts in dense vegetation near open prairies and grasslands which are used for foraging.
Marbled Godwit	*Limosa fedoa*	MBTA, BCC	Species breeds in marshes and flooded plains, also found on mudflats and beaches during winter & migration.
Prairie Falcon	*Falco mexicanus*	MBTA, BCC	Prefers wide-open habitats, including prairies and agricultural fields. Also found in deserts and alpine meadows in the western United States.
Western grebe	*Aechmophorus occidentalis*	MBTA, BCC	Freshwater lakes and marshes with large open water areas surrounded by emergent vegetation. Nesting typically on floating vegetation well-hidden along shorelines.
Willet	*Tringa semipalmata*	MBTA, BCC	Nesting in grasslands and prairies near freshwater. Feeding on beaches, rocky coasts, mudflats, and marshes.

Source: USFWS IPaC 2023a, USFWS 2021

The bald eagle was officially removed from the federal threatened and endangered species list in 2007 but is still protected under the federal BGEPA as well as the MBTA. The BGEPA protects bald and golden eagles by prohibiting anyone without a permit issued by the Secretary of the Interior from "taking" a bald or golden eagle, including their parts, nests, or eggs (16 U.S.C. 668-668c).

The Fish and Wildlife Conservation Act, as amended in 1988, requires the USFWS to identify birds of conservation concern (BCC), which include species, subspecies, and populations of all migratory nongame birds that could become candidates for listing under the ESA if additional conservation actions are not taken (USFWS 2021). BCC species having the potential to occur in the project area are listed in Table 3-18.

There is a low occurrence potential for migratory bird species in the project area, given the current conditions and lack of vegetation communities and other habitat components at the site and the occurrences would be isolated to individuals briefly passing through the area.

3.6.1.2.3 Species of Conservation Priority

The state of North Dakota has developed a list of numerous avian, mammal, reptiles/amphibians, and fish Species of Conservation Priority (SCP) based on varying degrees of rarity, geographic range, breeding status, and other factors as part of its State Wildlife Action Plan (SWAP; NDGF 2015). Per the SWAP, the project would be located in the Missouri River System/Breaks Focus Area. While direct impacts to the aforementioned species groups would not be anticipated, indirect impacts associated with the proposed project could include increased construction-related noise, human presence, and the use of artificial lighting. These impacts already occur at the proposed project site in association with operation of the current MRY facility and would increase slightly under the Proposed Action. A discussion for SCP in the region surrounding MRY is provided below.

Birds

Bird species listed as key SCP in the Missouri River System/Breaks Focus Area are as follows: bald eagle, golden eagle, piping plover, red knot, least tern (*Sterna antillarum athalassos*), and red-headed woodpecker (*Melanerpes erythrocephalus*) (NDGF 2015). Many of the species have been previously discussed in Section 3.6.1.

The least tern was delisted in January 2021 (NDGF 2021). The species prefers sparsely vegetated sandbars or shoreline salt flats along the Missouri River System but was not noted to occur near Nelson Lake or Square Butte Creek (NDGF 2015). The Yellowstone River, Missouri River, Lake Sakakawea, and Lake Oahe are the only areas in the state where the species resides (NDGF 2015). Direct impacts to the least tern would not be expected as a result of project development.

The red-headed woodpecker is listed as a SCP species due to population decline and habitat destruction or degradation (NDGF 2015). The species has been found in deciduous woodlands, river bottoms, parks, shelterbelts, roadsides, agricultural areas, or in cities (NDGF 2015). Key areas for this species include the upper portion of the Little Missouri River, the lower Missouri River Valley, and the southern portion of the Red River Valley (NDGF 2015). Given the lack of key area presence in conjunction with the regularly occurring industrial activities, direct impacts to the red-headed woodpecker as a result of project development would not be expected.

Mammals

Mammal species listed as key SCP in the Missouri River System/Breaks Focus Area are as follows: river otter (*Lontra canadensis*), northern long-eared bat (*Myotis septentrionalis*), western small-footed bat (*Myotis ciliolabrum*), long-legged bat (*Macrophyllum macrophyllum*), long-eared bat (*Myotis evotis*), little brown bat (*Myotis lucifugus*), big brown bat (*Eptesicus fuscus*) (NDGF 2015). The northern long-eared bat is federally listed as endangered and is included in Table 3-17.

The river otter is listed as a SCP species due to historic occurrences throughout North Dakota; however, the species is currently considered uncommon in the state (NDGF 2015). River otters inhabit wetlands and woodland riparian habitat within approximately 300 yards of a river or stream (NDGF 2015). Notably, habitats that retain open water are critical for providing food sources for the species. Key areas for the species include the Red River of the North (and associated tributaries); reports of occurrence in the

Missouri River have been noted, but no population has been identified as of 2015 (NDGF 2015). Direct impacts to the species from the project would not be anticipated.

Direct impacts to the western small-footed bat, long-legged bat, long-eared bat, little brown bat, and big brown bat are not anticipated. The western small-footed bat, long-legged bat, and long-eared bat species are considered rare in North Dakota, while the little brown bat and big brown bat are considered common residents (NDGF 2015). Although little brown bats and big brown bats are considered common residents, no potential bat roosting or foraging habitat exists within the project site or would be disturbed during construction or operation of the proposed project. Additionally, no hibernacula are present within the project site. Bats are a highly mobile species; however, mortality due to collisions with project-related vehicles or construction equipment would not be likely. Given the lack of suitable roosting and foraging habitat within the proposed project site, in conjunction with the industrial operations presently occurring at the site, impacts to SCP bat species would be unlikely.

Reptiles/Amphibians

Reptile and amphibian species listed as key SCP in the Missouri River System/Breaks Focus Area are as follows: smooth softshell turtle (*Apalone mutica*), spiny softshell turtle (*Apalone spinifera*), and false map turtle (*Graptemys pseudogeographica*) (NDGF 2015).

The smooth softshell turtle is listed as a year-round resident with a rare abundance in the state (NDGF 2015). The species has only been verified in the extreme lower portion of the Missouri River system, where a large river with sandy beaches or sandbars is present (NDGF 2015). The habitat alteration of the Missouri River has adversely impacted the species habitat, leading to only a handful of documented occurrences (NDGF 2015).

The spiny softshell turtle is listed as a year-round resident with a rare abundance in the state (NDGF 2015). The species has only been documented in the tributaries of the Missouri River below Garrison Dam and the head waters of Lake Oahe (NDGF 2015). Like the smooth softshell, the species prefers large rivers with sandy beaches or sandbars (NDGF 2015). The habitat alteration of the Missouri River has adversely impacted the species habitat, leading to only a marginal number of documented occurrences (NDGF 2015).

The false map turtle is listed as a year-round resident with a rare abundance in the state (NDGF 2015). Similar to the spiny softshell turtle, this species has only been documented in the tributaries of the Missouri River below Garrison Dam (NDGF 2015). Much of the habitat alternation in and surrounding the Missouri River has led to the habitat and population decline of the false map turtle (NDGF 2015).

Due to a lack of suitable riverine habitat in the proposed project area, it is unlikely that activities associated with the Proposed Action would have any impact on SCP turtle species.

Fish

Fish species listed as key SCP in the Missouri River System/Breaks Focus Area are as follows: sturgeon chub (*Macrhybopsis gelida*), sicklefin chub (*Macrhybopsis meeki*), northern redbelly dace (*Chrosomus* *eos*), flathead chub (*Platygobio gracilis*), blue sucker (*Cycleptus elongatus*), paddlefish (*Polyodon spathula*), pallid sturgeon (*Scaphirhynchus albus*), and burbot (*Lota lota*) (NDGF 2015).

Direct impacts to the sturgeon chub, sicklefin chub, northern redbelly dace, flathead chub, blue sucker, paddlefish, pallid sturgeon, and burbot would not be expected as a result of the proposed project. All of the aforementioned species are considered to be rare, uncommon, or declining in North Dakota (NDGF 2015). While the proposed project is near Nelson Lake and Square Butte Creek, no in-water work is proposed as a part of the site designs; therefore, it is unlikely that the project would impact SCP fish species. See Section 3.5 for additional information regarding water resources.

3.6.1.3 Vegetation

The project would be located across two Level IV ecoregions, the Missouri Plateau (43a) and the River Breaks (43c), within the Level III Ecoregion of the Northwestern Great Plains (Bryce, Omernik et. al 1996). The Northwestern Great Plains is a semiarid rolling plain in which native grasslands persist in areas of steep or broken topography, which has been largely replaced by spring wheat and alfalfa fields. Agriculture is primarily dryland farming and cattle grazing due to precipitation patterns and limited irrigation potential in the region. On the Missouri Plateau, the landscape is open and consists of shortgrass prairie. Much of the original soil and complex stream drainage patterns have been retained. The River Breaks were formed by broken terraces and uplands descending to the Missouri River in soft, easily erodible strata. The dissected topography, wooded draws, and uncultivated areas provide habitat for wildlife, and steep slopes restrict land use to rangeland and grazing.

The proposed project site consists of previously disturbed land used for general storage of coal and materials. Currently, the project site has been reclaimed and is largely unused, except for some material storage and the existing well pad. Vegetation in the areas adjacent to the project site consists of grasses within graveled areas; open grassy areas, and small sparingly wooded riparian areas near the reservoirs surrounding Nelson Lake. The proposed construction and laydown areas would be predominantly located in previously disturbed lands used for general MRY operations but several of the laydown areas would be located in hayed fields. Construction areas and laydown areas that would be temporarily affected would be restored to original conditions, except for the proposed overflow parking area.

3.6.2 Environmental Consequences

3.6.2.1 Aquatic

Erosion and transport of sediment due to construction (e.g., clearing, excavating, filling) could result in localized water quality degradation of Nelson Lake, Square Butte Creek, and adjacent reservoirs and tributaries. Sediment deposition into surface waters can increase turbidity that can adversely affect aquatic species. For example, high turbidity levels can affect fish gill function, blood sugar levels, and behavior (e.g., altered response to predation risk; Bash *et al.* 2001). Sediment deposition into surface waters also can increase pollutant and nutrient levels, which can result in excess phosphorous loading that can enhance algal growth and the availability of oxygen for aquatic organisms. The use of construction equipment also could result in accidental spills or leaks of petrochemicals (e.g., gasoline, hydraulic fluids) that could reach surface waters if not contained and cleaned up. These petrochemicals can be toxic to aquatic organisms and can affect the health and survival of these organisms and their habitats. However, direct and indirect impacts to aquatic species and their habitats would not be expected during project construction or operation. While there would be a potential for accidental spills or sediment to reach Nelson Lake, the use of engineering controls and BMPs would limit the likelihood of such an accident. All surface runoff and wastewater generated during construction and operations would be controlled, contained, and treated prior to any discharge to Nelson Lake per the SWPPP and NPDES permits. These discharges to Nelson Lake would be compliant with water quality standards and would not affect aquatic habitat conditions. Refer to Section 3.5.2.1, Surface Water, Surface Water Quality, and Floodplains, for additional details regarding potential impacts to water resources. No direct or indirect impacts to aquatic species and their habitats are anticipated as a result of the project.

3.6.2.2 Wildlife

The project would be required to undergo Section 7 consultation with the USFWS to ensure that the action is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of critical habitat. While federally listed species are not anticipated to be present in the project area, Section 7 consultation would ensure that adverse impacts to listed species would not occur as a result of the project. Consultation with the USFWS for the proposed project is ongoing as of the issuance of this Draft EA.

As identified in Table 3-18, migratory bird species have the potential to occur in the vicinity of the project. However, due to the lack of suitable nesting and foraging habitat within the project area, no direct impacts to migratory birds would be expected to occur. Mortality due to vehicular collisions with project-related vehicles or construction equipment would not be likely, and all hazardous materials and wastes would be stored and disposed of in accordance with Minnkota’s standard operating health and safety procedures.

Indirect impacts could occur to migratory bird species residing in habitats adjacent to the project site due to increased noise, fugitive dust, and human presence associated with construction activities. This could result in habitat loss as a result of an avoidance response to an area greater than the project footprint; however, human presence and noise currently exist in the project area and would increase only slightly under the Proposed Action. Impacts to migratory birds would be short term and would not result in population-level impacts.

Based on a general lack of suitable habitat in the proposed project area, the project is unlikely to have direct or indirect long-term impacts on SCP. Indirect and temporary impacts, if any, would be similar to those described for migratory birds.

3.6.2.3 Vegetation

The proposed project area consists of reclaimed lands and is largely unused, except for minor amounts of material storage and the presence of the existing well pad. Laydown areas are primarily sited in reclaimed lands with the exception of two hayed fields. Vegetation in the areas adjacent to the proposed project and laydown areas do not contain any sensitive plant communities or sensitive habitats; therefore, impacts would not occur to vegetation communities or special status plant species from the Proposed Action.

3.7 Health and Safety

3.7.1 Affected Environment

The affected environment for health and safety includes the proposed project construction and operations personnel, Minnkota employees at MRY, as well as members of the public that could be potentially exposed to health and safety impacts of the proposed project. Construction personnel would be at higher risk than the general public during the construction period of the project; however, these increased human safety hazards are temporary.

Peak labor force is anticipated to be approximately 600 to 700 persons during project construction of various trades and assignments, plus project management and administrative personnel (see Section 3.13.2 for more information). Construction workers on site could be exposed to workplace hazards and health and safety impacts during proposed project construction and during project decommissioning after the end of proposed project operations.

Minnkota has indicated that there would be operations personnel on site 24 hours per day for operation of the project. Operations workers also would be involved in overseeing deliveries, materials management, and waste management activities, and could potentially be exposed to workplace hazards and health and safety impacts during project operations.

3.7.2 Environmental Consequences

Construction and operation of the proposed project would result in the potential for health and safety impacts to the personnel associated with construction, operations, and decommissioning; Minnkota employees; and members of the public. Potential health and safety impacts to project construction and operations personnel would include workplace (occupational) injuries during construction, operation, and decommissioning including those related to operation of mechanical and electrical equipment; fall hazards; vehicle accidents; and potential occupational exposure to hazardous materials from transport, storage, and use of process chemicals (including diesel fuel, gasoline, lubricating oils, hydraulic fluid, paints, solvents, or other corrosive, flammable, or toxic chemicals).

Human health and safety hazards would be mitigated by complying with applicable federal and state occupational safety and health standards, National Electric Safety Code regulations, and utility design and safety standards. Minnkota personnel and contractors would perform activities according to Minnkota’s standard operating health and safety procedures. Prior to beginning work each day, an Authorization to Work, Pre-Task Analysis form would be prepared and discussed. Heavy equipment would be up to Occupational Safety and Health Administration (OSHA) safety standards and personal safety equipment would be required for all workers on site. Any accidents or incidents would be reported to the designated safety officer.

The construction site would be managed to reduce risks to the general public, who would not be allowed to enter any construction areas within the project site. The highest risk to the general public would be from increased traffic volume on the roadways near or adjacent to the project as a result of commuting construction workers and transportation of equipment and materials. These impacts would be both temporary during construction and minimal during long-term daily operation of the project. No residences, businesses, or other structures are located in proximity to the project. Based on these measures, it is not anticipated that the project would create additional demands on human health services or the safety of the local community.

Minnkota maintains current safety and environmental programs which would be complied with during project design and construction. The project and all connected systems to MRY would utilize hazard and operability (HAZOP) studies to ensure that the system operational hazards have been mitigated. As part of the HAZOP, a flue gas transient analyses would be performed on the existing MRY Units 1 and 2, as integrated with the carbon capture facility, to account for any potential risk to system operation. All piping, vessels, tanks, and containments would be evaluated to ensure that the materials of construction are compatible.

Minnkota would conduct Process Safety Reviews of proposed project systems at five distinct stages to identify and mitigate potential hazards. The five stages are (1) project initiation and definition; (2) project award/start; (3) design; (4) construction; and (5) plant operations. Each Process Safety Review would review a series of checklists including safety and environment, technology/design, and plant controls and shut down. Minnkota relies on the Oliver County Fire Department to respond to all but minor fires at the facilities. It is anticipated that the proposed project would follow the same fire response plan as is in place for MRY.

Operation of the proposed project would involve use of hazardous and non-hazardous commercial chemical products. Operation of the proposed project would use amine solvent as a process fluid to capture the CO_2 from the power plant flue gas. Fresh (unused) amine solvent would be delivered to the site by truck prior to commencement of operation and stored in aboveground storage tanks. Any solvent wastes generated as a result of solvent reclamation would be safely stored for off-site disposal. Transport, storage, and handling of fresh and spent amine solvent would be conducted in accordance with solvent handling guidance developed by the solvent supplier.

All storage tanks associated with the project would be located within secondary containment systems, and piping systems would be designed to reduce the potential for a pollutant discharge. All chemicals used for the carbon capture process would be stored in storage tanks within the boundaries of the MRY facility. Operation of the project would involve the use of low-pressure steam and capture of CO_2; releases of which to the workplace environment could result in potential occupational health and safety hazards.

The capture process would be designed with appropriate industry standards to provide safe project operation. These design standards would reduce the potential for unplanned releases from process equipment and storage tanks. Safety relief values and/or overflow lines would be designed in accordance with applicable standards for storage vessels and equipment. Safety relief valves would only operate in the event of process vessel mechanical failure and would not open during routine operation of the carbon capture facility. Process instrumentation design would include safety-instrumented systems, flow restriction and safety interlocks, automatic safe-shutdown capability, and emergency power supply to maintain process safety and reduce the potential for unplanned incidents.

All project-related construction personnel and operations personnel would receive training in areas relevant to construction and operational safety and their job requirements including Hazard Communication/Right-to-Know, Hazardous Materials Management/Chemical Hygiene, Job Safety Assessment, and Hazardous and Solid Waste Management. Construction and operations personnel would use personal protective equipment appropriate for their work activities in accordance with Minnkota's project safety requirements. The project would be equipped with eye wash stations and emergency showers for response to chemical exposure from amine solvent and from handling of other hazardous materials.

3.8 Solid and Hazardous Waste

3.8.1 Affected Environment

The affected environment for solid and hazardous waste includes onsite areas within MRY in which solid and hazardous wastes would be generated and stored. Solid and hazardous wastes generated from project construction, operation, and decommissioning would be transported and disposed of appropriately in accordance with applicable regulations depending on the generated waste.

MRY generates non-hazardous solid wastes and is a very small quantity generator of hazardous wastes from its existing power plant operations. Wastes produced include coal combustion solids, spent solvents, waste oil, municipal solid waste, and non-hazardous and hazardous wastes. Minnkota maintains non-hazardous solid waste landfills adjacent to the MRY. Municipal solid waste from MRY is transported off-site to local municipal solid waste landfills for disposal. Other non-hazardous wastes are disposed of in on-site landfills.

3.8.2 Environmental Consequences

Adverse environmental impacts associated with construction and operation of the project would not be likely with the proper management of solid and hazardous wastes.

Construction of the proposed project would generate non-hazardous waste such as construction debris and scrap metal. Waste such as spent solvents and used oils resulting from construction activities may also be generated. All waste, both hazardous and non-hazardous, would be managed pursuant to federal and state environmental regulations. Stormwater generated from the construction site would be managed as specified in the project SWPPP.

New operational waste streams would be generated due to the carbon capture facility processes. All new waste streams would be profiled and either sent offsite to be disposed of by properly licensed disposal providers or disposed of in the MRY landfill in accordance with the landfill's permits. Hazardous waste would not be expected from any of the new waste streams, but if a waste was determined to be hazardous it would be disposed of in accordance with state and federal regulations.

The CO_2 capture process would use a proprietary amine solvent formulation to separate CO_2 from flue gas. The process includes both a solvent reclamation process and a filtering process that would produce waste streams. The waste streams are comprised of heat stable salts, nonvolatile solvent degradation products, unrecovered solvent, acid wash, reclaimed waste, precoat filter, water treatment waste, and cooling tower blowdown. The MHI process generates non-hazardous wastewater which would be injected into the Class I well(s).

3.9 Infrastructure and Utilities

3.9.1 Affected Environment

The affected environment for infrastructure and utilities includes the existing utility infrastructure at MRY and the existing production of electricity, water, and steam at the MRY Station. MRY includes two coal-fired steam turbine electric generators (with a total rating of 705 MWg). Minnkota produces electricity as a public utility and consumes electricity and water in operating its electric power generation equipment. MRY generates wastewater that is treated in a Minnkota wastewater treatment plant and subsequently discharged under a NPDES permit. MRY power plant flue gas desulfurization system effluent is indirectly discharged to a permitted pond immediately south of MRY and the proposed project.

3.9.2 Environmental Consequences

3.9.2.1 Water and Wastewater

The project would also include the construction and use of two Class I injection wells to dispose of excess process wastewater generated by the carbon capture facility. The first Class I well would be located at the injection site (Figure 2-2). The second Class I well would be installed approximately 300 feet northwest of the first well near the northwest corner of the existing injection site well pad (Figure 2-2). The Class I well(s) would enable the project to be a zero liquid discharge (ZLD) project during operation. Injectate water would be primarily a mixture of existing scrubber pond water and proposed combined wastewater from the carbon capture facility. The carbon capture process is not yet operational, so the exact chemistry of the injectate is unknown. The chemistry of the proposed combined wastewater from the carbon capture facility is based on modeling. However, chemical compositions of the proposed injectate waste streams indicate that the two primary wastewaters (scrubber pond water and combined wastewater from the carbon capture facility) and native waters in the proposed injection interval (formation water) are sodium sulfate ($NaSO_4$) dominant. Geochemical mixing model results are summarized in Table 3-19 (WSP, 2024). For modeling scenarios in which the estimated saturation indices are greater than 0.5, there is a potential risk of mineral scaling (precipitation) within the injection zone. This mineral scaling risk may be mitigated through proactive chemical additives to the injectate (e.g., pH adjustment, antiscalants) and/or through periodic well/reservoir maintenance activities. Additional information on injectate composition can be found in Appendix H, Class I (Non-hazardous) Injection Well Permit.[7] The injectate compatibility evaluation may be updated once the carbon capture facility is operational and representative wastewater can be sampled.

Table 3-19: Mixing Model Results for the Geomean of Formation Waters with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 4 Max TDS:Formation Water with added CO_2)										
Sample Name (Ratio of Injectate to Formation Water)		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celsius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-0.2	-0.3	-0.3	-0.3	-0.4	-0.5	-0.6	-0.7	-0.8	-1.1	-1.7
Gypsum	$CaSO_4{:}2H_2O$	-0.1	-0.2	-0.2	-0.3	-0.3	-0.4	-0.5	-0.6	-0.7	-1.0	-1.6
Barite	$BaSO_4$	**0.8**	**0.8**	**0.9**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.3**	**1.4**	**1.4**
Calcite	$CaCO_3$	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.5	-0.5	-0.4	-0.3	0.0
Magnesite	$MgCO_3$	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4	-1.3
Halite	NaCl	-3.4	-3.5	-3.6	-3.7	-3.7	-3.9	-4.0	-4.1	-4.3	-4.5	-4.8

Notes:
Saturation indices below -0.5 indicate undersaturation
Saturation indices between -0.5 and 0.5 indicate equilibrium and are identified by light grey shading
Saturation indices greater than 0.5 indicate oversaturation and are identified by bold type and dark grey shading

Low-pressure steam, cooling water, and other utilities would be provided to the project by MRY through direct connections to MRY electrical, steam, and process water, systems. The project would utilize the local rural water utility for potable water service. Various utilities, per the final project financial arrangements, would be directly metered by MRY.

Approximately 4,000 gpm of cooling water would be required for operating the project. Cooling water would be recycled through the project wastewater treatment system to the degree possible to minimize system makeup, and a portion would ultimately be disposed of in the Class 1 wells.

Potable water would be used for sanitary purposes, cooking, and eyewash stations at the proposed project. Potable water consumption would be less than 5 gpm (1.1 cubic meters per hour). Amine solvent would be supplied to the project already pre-mixed with water and therefore a large volume of fill water would not be needed for the amine solvent storage tank.

Low-pressure steam at a maximum operating pressure of 155 pounds per square inch gauge (psig) (770 °F) would be supplied by MRY for use in the capture process. Steam condensate would be returned from the project to MRY.

Demineralized water as required for the capture island equipment would be provided by MRY from the existing MRY water treatment system.

Wastewater streams resulting from operation of the project include both continuous and discontinuous flow. Continuous flow would result from condensate from the quencher flue gas treatment process which would be collected and re-used in the project cooling water system. Discontinuous flow results would be liquid waste from process water containing trace amine solvent concentrations; liquids from cleaning/flushing process equipment during maintenance activities; and stormwater runoff from the site.

[7] A revised Class I (Non-hazardous) Injection Well Permit will be included with the Final EA.

Once final quencher wastewater concentration values are determined, the proposed project would proceed with final wastewater design, co-disposing of it in permitted facilities with flue gas desulfurization waste streams from the MRY flue gas desulfurization scrubbers.

Liquids that would intermittently be generated from maintenance activities may not be acceptable for treatment in MRY's wastewater treatment plant. Any liquids generated would be monitored and liquids that are not acceptable for treatment in MRY's wastewater treatment plant would be either re-used, treated on site, or disposed of offsite in licensed treatment and disposal facilities. Stormwater from the project that is found to be contaminated also would be either treated on site or disposed of offsite in licensed facilities. Any water that contains amine solvent will be captured and re-used in the process. The project is ZLD, no process wastewater will be allowed to enter the MRY NPDES outfalls.

3.9.2.2 Stormwater

Captured and diverted uncontaminated stormwater from the project would be handled, treated, and discharged by Minnkota under its existing NPDES permit. No modification to the MRY Industrial NPDES permit (ND-000370, NDR05-0012) would be needed for management of uncontaminated stormwater from the project, except for potentially modifying the outfall descriptions to include project process areas.

A new construction stormwater permit (General Permit for Stormwater Discharges Associated with Construction Activities [NDR11-0000]) would be required for the project, as proposed ground-disturbing activities exceed 1.0 acre. Minnkota and or its contractors would comply with the federal NPDES and state stormwater regulations for construction activities, receiving coverage prior to initiating any ground-disturbing activities.

3.9.2.3 Electricity

Electricity needed to operate the project would be supplied by Minnkota through a direct connection to the MRY 230 kV transmission electrical system.

3.9.2.4 Natural Gas

Not applicable; the proposed project would not be supplied with or consume natural gas.

3.10 Land Use

3.10.1 Affected Environment

The project would source lands within the industrial footprint of the MRY under the ownership of Minnkota, including adjacent lands used as temporary construction and laydown areas. The carbon capture facilities would occupy 25.8 acres of land in the southwest portion of the MRY property (Figure 2-2). An additional 10 construction and laydown areas would serve various construction needs including parking, construction trailers, material storage and fabrication, and other activities to support the influx of workers and project construction activities. Approximately 97.0 acres of land would be required for temporary construction and laydown areas within the Minnkota-owned property. Following construction, the construction and laydown areas would be restored to original conditions, with the exception of an approximately 7.0-acre area that would be retained for overflow parking for MRY and project operations.

There are four existing 230 kV transmission lines that cross the MRY property. MRY is accessed via 24th Street SW. The MRY station is located on the southern end of Nelson Lake in central Oliver County, North Dakota. Oliver County does not provide publicly available mapping information on their zoning and land use designations. Land cover in Oliver County near the project is largely a mix of herbaceous areas and cultivated crops, with small areas of forest, hay/pasture, and open water (USGS 2019). Current land use in and around the area includes industrial activities associated with power generation and coal mining. Land uses in the temporary construction areas are predominantly reclaimed industrial lands with some areas under active hay production. Hay production would be temporarily ceased during construction; lands would eventually be reclaimed post-construction unless otherwise requested by the landowner. No isolated rural homes are near the proposed project. The highest concentration of homes in the area occurs in the city of Center, located approximately 4.5 miles northwest of the proposed project.

3.10.2 Environmental Consequences

Anticipated land use impacts from the project would be minor. With the exception of the deep subsurface monitoring well (classified as agricultural land, but on Minnkota-owned property), all aboveground infrastructure would be located within an existing industrial footprint that is large enough to accommodate the carbon capture facility. Construction of the project would result in the permanent disturbance of approximately 25.8 acres of land within the MRY property to accommodate the project facilities. Additionally, approximately 97.0 acres of land would be required for temporary construction and laydown areas. Following construction, the construction and laydown areas would be restored to original conditions, with the exception of an approximately 7.0-acre area that would be retained for overflow parking for MRY and project operations. The project would be consistent with current land uses and would not conflict with surrounding land uses. The project would require the relocation of two 230-kV transmission lines within the MRY property as well as a buried distribution line and a local overhead distribution line. After construction is complete, disturbed areas would be stabilized as appropriate in accordance with applicable construction and stormwater approvals. As a result, additional erosion during operation of the project would be minimal or avoided.

There is no publicly available Comprehensive Plan for Oliver County, and the County is not a part of a Metropolitan Planning Organization or Council of Governments. The new aboveground infrastructure would be located within the existing industrial footprint of the MRY on Minnkota-owned property in Oliver County. This would avoid potential impacts to farmland, scenic views, and environmental features. Following decommissioning of the project, lands affected by the project would be restored to the original condition.

3.11 Visual Resources

3.11.1 Affected Environment

The affected environment for visual resources would include the current view of the proposed project site, which is an existing power plant in a generally rural landscape in central North Dakota. The project would be an addition to the power plant site and therefore is in character with the existing viewshed. No tribally sensitive or other scenic vistas have been identified in the proposed project area (Burns & McDonnell 2022).

The Sakakawea Scenic Byway is located more than 18 miles north of the project area and is adjacent to the Missouri River. It follows Highway 200A from Washburn to Stanton. Approximately 72 miles south of the project areas is Standing Rock National Native America Scenic Byway, which is situated at the Cannonball River in Fort Yates following Highways 1806 and 24 to the South Dakota state line. On the western side of the project area is Old Red Old Ten Scenic Byway beginning at the Mandan Depot in Mandan, North Dakota, and generally extending west along Old Highway 10 to Dickinson, North Dakota.

The area surrounding the MRY is generally undeveloped grassland/herbaceous areas and cultivated crops. The existing MRY facility is a developed, industrial area that is visible from surrounding roads, including Highway 25 to the north. Existing security and safety lighting at the facilities create a visual contrast at night.

3.11.2 Environmental Consequences

Construction of the project would introduce additional permanent structures to the existing environment; however, the dominant visual features would still be the existing facilities associated with MRY, particularly the exhaust stacks. New equipment at the site would be below this height. The new facilities would be visible to landowners and community residents who live and travel near the project site. The project would not present a change to the visual landscape out of character with the existing and adjacent MRY. Lighting is currently in place at the MRY. The project would include additional lighting for maintenance, access, and egress in and around the new equipment as necessary. Some temporary lighting would also be installed to support construction activities. Other short- and long-term visual impacts associated with project construction and operation would include increased human activity and associated vehicles and equipment within the project area and the surrounding vicinity.

As noted previously, there are several designated Scenic Byways within North Dakota. Based on their distance from the project, it is anticipated that no scenic byways would be affected by the proposed project.

The preliminary design of the proposed cooling tower would be evaluated using the SACTI2 model to determine the potential impact of plume fogging and rime ice formation, as well as mineral deposition and elevated visible plumes. The purpose of the analysis is to determine what impacts the cooling tower would have on the surrounding area. Minnkota anticipates using five years of site-representative hourly meteorological data to determine plume impacts.

3.12 Cultural and Paleontological Resources

3.12.1 Affected Environment

The project area has been used by pre-tribal and tribal occupants for approximately 13,500 years. The earliest population of the area is the Clovis complex which is indicated by a distinct style of large, lanceolate spear points and other well-made stone tools of high-quality materials (Stanford 1999). Clovis artifacts are usually found in association with mammoth or other large megafaunal kill and butchering sites. These are usually found in grasslands and parklands adjacent to large natural lakes and major rivers. The Clovis complex is followed by the Folsom in which the emphasis on hunting changes from the megafauna, which was dying out, to bison (Bonnichesen and Turnmire 1999). The Folsom Culture spanned 1,700 years from 11,900 to 10,200 Before Present (BP). The artifact tool kit differed from Clovis by the use of smaller fluted or unfluted projectile points. Together with large kill sites of the large *Bison occidentalis*, these points are diagnostic of the Folsom Complex. The Folsom sites are usually found in riverine or lake environments.

The Paleoindian period is followed by the Plains Archaic Period, which breaks down into the Early Plains Archaic (7,500 to 5,000 BP), Middle Plains Archaic (5,000 to 3,000 BP), and Late Plains Archaic (3,000 to 2,500 BP) sub-periods. An extended episode of drought called the Altithermal took place during the Early Plains Archaic sub-period causing a reduction in biomass. Few sites from the Early Archaic sub-period have been dated because a decrease in game herds and other mammals triggered a depopulation of the area. During the Plains Middle Archaic sub-period, the drought ended and a cooling trend with rises in moisture levels produced an improvement in the climate. With the return of the vegetation, the bison herds grew, and the human populations rebounded as nomadic hunter/gathers that followed the bison herds. Sometime during this period, the atlatl came into use (Frison and Mainfort 1996). The Plains Late Archaic sub-period continued the hunting/gathering ways of life with the origins of regionalized projectile points styles, a decline of point knapping skills, and a reduction in the interaction between geographic areas and cultural groups (Frison 1991).

Plains Village Culture (2,000 to 220 BP) introduced horticulture within the Northern Great Plains. These inhabitants were semi-sedentary and lived in earth-lodge villages. These villages are usually found on low bluffs just above the riparian floodplains. At the same time, there were several nomadic cultures with a patterned subsistence that depended primarily upon hunting and procurement of the modern bison (*B. bison*). This is a period of increasing interaction between the tribes and Euro-Americans that were entering the area. Of all trade items, it was the introduction of the horse which had the greatest impact on native cultures (McNees and Lowe 1999; Ruebelmann 1983). The adoption of the horse caused a social upheaval and resulted in various degrees of consolidation, political realignment, and tension between the various Plains tribes. Horses also were a sign of wealth, used as pack animals for the transportation of shelters, were employed as cavalry, and they served, if necessary, as food (Ewers 1980). The horse offered an increased mobility that freed former hunter-gatherer groups from pedestrian transhumance required for the exploitation of various plant and animal resources located across the landscape. Larger winter villages in lowland areas were a direct result of this mobility (Ruebelmann 1983).

As part of the NEPA process, DOE is consulting with the North Dakota State Historical Society, State Historic Preservation Office (SHPO) and the following federally recognized tribes in the project area: Apache Tribe of Oklahoma; Fort Belknap Indian Community of the Fort Belknap Reservation of Montana; and Three Affiliated Tribes of the Fort Berthold Reservation, North Dakota.

3.12.2 Environmental Consequences

A small number of sites, primarily lithic scatters, have been recorded within the footprint of the MRY at Nelson Lake. No significant known cultural resources sites are present on the MRY in the area for the proposed project facilities. No National Register of Historic Places (NRHP) listed historic resources are located in the proposed project site or surrounding region (National Park Service [NPS] 2023). Even if previously present, the development of this area over the years has likely compromised the integrity of any cultural and/or paleontological sites and they are likely no longer viable for information.

In the event of an inadvertent discovery of cultural or human remains during construction and/or operations, work would halt in the immediate area, the resource would be secured and protected, and the appropriate Minnkota and agency personnel would be notified in accordance with the procedures outlined in the Unanticipated Discoveries Plan (UDP) in Appendix I. The work would be allowed to resume after appropriate investigations are completed and clearance to resume activities is received from Minnkota's environmental specialist and the appropriate agency personnel as described in the UDP.

The temporary construction and laydown areas were evaluated for architectural and cultural significance pursuant to Section 106 of the National Historic Preservation Act. A Class III Intensive Cultural Resource Inventory was completed of the laydown areas and additional workspaces in August 2023 in accordance with the *North Dakota SHPO Guidelines Manual for Cultural Resource Inventory Projects* (SHPO 2020). The cultural report will be provided to SHPO for review and concurrence. Any cultural resources identified in any of the proposed temporary construction and laydown areas will be avoided or mitigated in consultation with SHPO.

3.13 Socioeconomic Conditions

The project would be located within Oliver County in North Dakota. The project could contribute to socioeconomic activity in nearby Morton, Burleigh, and McLean Counties. Population and employment data for local, state, and national jurisdictions were pulled from publicly available sources.

3.13.1 Affected Environment

The proposed project site is in Oliver County, North Dakota, roughly 4.5 miles southeast of the city of Center. Table 3-20 below illustrates the demographic information in Center, Oliver County, North Dakota, and the United States (U.S. Census Bureau [USCB] 2022; USCB 2021).

Table 3-20: Demographic and Economic Information 2020

	City of Center	Oliver County	North Dakota	United States
Total Population	588	1,877	779,094	331,499,281
Percent of population under 18 years of age	34.5	24.6	23.6	22.1
Percent of population over 65 years of age	25.6	23.7	16.1	16.8
Percent of population identifying as Caucasian, non-Hispanic	98.5	93.6	83.2	59.3
Percent of population identifying as African American	0.3	0.5	3.5	13.6
Percent of population in civil labor force	45.0	57.8	68.5	63.1
Percent of population in poverty	21.5	11.1	11.1	11.6

As depicted in Table 3-20, the city of Center has similar demographic characteristics to Oliver County. Center has slightly higher non-participation in the civil labor force and people in poverty, as well as a larger percentage of people under the age of 18. Oliver County has minimal differences in these demographics to the state of North Dakota, with the exception of an older population with less participation in the civil labor force. North Dakota has a higher percent of population identifying as Caucasian, non-Hispanic and a lesser percent of the population identifying as African American in comparison to the overall United States (USCB 2021, USCB 2022).

The agricultural industry employs the largest percentage of people in Oliver County (14.4 percent), followed by construction (11.1 percent), healthcare (9.0 percent), and retail (8.1 percent) (Burns & McDonnell 2022). Oil & gas (6.3 percent), education (5.8 percent), and transportation & warehousing (4.4 percent) employ higher percentages of the working population than other services such as food services and manufacturing, which are less than 3 percent (Data USA, 2021). Other industries employ 36.3 percent of the Oliver County population.

3.13.2 Environmental Consequences

Construction and operation of the project would generate socioeconomic activity in Oliver County and potentially surrounding counties. Construction of the project would temporarily elevate the need for additional workers in construction trades such as electricians, welders, laborers, and carpenters. Length of employment would range from a few weeks to several months, depending on skill and or specialty with the given work needs. Most construction contractors and workers would temporarily relocate to the project area as construction of the project would require a specialized workforce. Peak labor force is anticipated to be approximately 600 to 700 persons during project construction of various trades and assignments, plus project management and administrative personnel. Construction contractors would use local labor to the extent practicable. A small number of local construction workers could be hired for more general activities such as clearing, grading, and earthwork. However, due to the specialized nature of services required and the limited workforce in the area, it is anticipated that much of the construction workforce would come from outside the region. Gas stations, convenience stores, restaurants, hotels, campgrounds, and retail shops in communities such as Center and the Bismarck area could experience temporary and minimal increases in business during the construction period in response to activity from construction workers. In addition to services directly related to workers, services related to the construction of the project would also benefit. Expenditures made for equipment, fuel, building supplies (concrete, lumber, general hardware), operating supplies, and other products and services obtained locally would benefit businesses in the counties and the state. Local material suppliers, mechanics, and business support services would benefit most from construction.

There would be short-term and minimal impacts on local housing. Many of the construction workers would seek temporary housing for varying time periods based on their individual roles in the project. Generally, housing options for construction crews would consist of area hotels, existing crew camps, or RV camps. Arrangement for longer-term housing could be established by the construction contractor, with crews rotating in and out as their assignments commence and complete. It is anticipated that there would be an adequate supply of temporary housing units available in the region for use by construction workers relocating on a temporary basis due to the relatively low number of workers necessary compared to the overall workforce in the counties and the continued development of housing capacity in the area. Temporary housing would be required during the approximately two years of construction and commissioning, after which demand from the project would end and lodging used would be available for other needs.

Local governments could also experience short- and long-term benefits from sales tax revenue collected during construction of the proposed project. Once the project is completed, only minimal property taxes would be collected, pursuant to State law. Property owners may benefit from payments for required right-of-way easements associated with use of pore space for the geologic storage of CO_2.

The project would require approximately 22 permanent employees for operation, maintenance, and supervision of the project. Additional local services would likely occur during project operations as part of maintenance and repair. A short-term temporary influx of workers could also occur during scheduled outages and maintenance, resulting in minor upticks in requirements for lodging and other local services. These staff levels would stimulate minimal economic growth in the area and provide minimal new permanent job opportunities within Oliver County and the surrounding counties. These employment opportunities would not result in a noticeable increase in new permanent residents. Therefore, impacts on the job market, permanent resident population, and overall socioeconomic status of the counties from the project would be minimal.

3.14 Noise

3.14.1 Affected Environment

The primary existing noise sources at this location are activities occurring at the existing MRY, and include various industrial facilities, equipment, and machines (e.g., cooling systems, transformers, engines, pumps, boilers, steam vents, public address systems, and construction and materials-handling equipment). Other sources of noise include neighboring industrial facilities, occasional traffic on nearby roadways, and agricultural activities in the surrounding areas. The MRY location is nearly 2 miles from the nearest noise sensitive receivers (residences). The closest business is the Square Butte Creek Golf Course, located approximately one mile northwest of MRY. Center, North Dakota is located approximately 4.5 miles northwest of MRY. Once operational, the project would not be likely to adversely alter the level of noise beyond the levels currently produced by existing activities at MRY.

Neither Oliver County nor North Dakota have established noise regulations. To prevent activity interference or annoyance, EPA guidelines recommend an average day-night level of 55 decibels or less (EPA 1974).

3.14.2 Environmental Consequences

The project would include noise sources similar to the existing MRY facility. The project's major noise sources would include the cooling tower, the electrical substation, the boiler, emissions control equipment, and compressors. The noise generated by this equipment would increase noise levels on the project site, particularly in areas near the new equipment and facilities. However, with the equipment being similar in nature and operation to the existing MRY facility noise-emitting equipment, sound levels offsite would be expected to remain similar to the existing environment. Sound levels generated by the project would attenuate significantly over the 2-mile distance to the nearest noise sensitive receptors, and at that distance the project noise contribution would be indistinguishable from the existing MRY facility noise. No distinguishing noise characteristics would increase during operation of the proposed project.

3.15 Environmental Justice

3.15.1 Affected Environment

Under EO 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," federal agencies are responsible for identifying and addressing the possibility of disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority and low-income populations in the United States and its territories and possessions, the District of Columbia, the Commonwealth of Puerto Rico, and the Commonwealth of the Mariana Islands. Minority populations refer to persons of any race self-designated as Asian, Black, Native American, or Hispanic. Low-income populations refer to households with incomes below the federal poverty thresholds.

Environmental justice concerns the environmental impacts that proposed actions may have on minority and low-income populations, and whether such impacts are disproportionate to those on the population as a whole in the potentially affected area. The threshold used for identifying minority populations surrounding specific sites was developed consistent with CEQ guidance (CEQ 1997, Section 1-1) for identifying minority populations using either the 50-percent threshold or another percentage deemed "meaningfully greater" than the percentage of minority individuals in the general population. CEQ guidance does not provide a numerical definition of the term "meaningfully greater." CEQ guidance was supplemented using the Community Guide to Environmental Justice and NEPA Methods (EJ IWG 2019) and provides guidance using "meaningfully greater" analysis. For this analysis, meaningfully greater is defined as 20 percentage points above the population percentage in the general population.

The significance thresholds for environmental justice concerns were established at the state level. The average minority population percentage in North Dakota is 15.3-percent (USCB 2022). Comparatively, a meaningfully greater minority or low-income population percentage relative to the general population of the state would exceed an 18.36-percent threshold. Therefore, the lower threshold of 18.36 percent is used to identify areas with meaningfully greater minority populations surrounding the project. Meaningfully greater low-income populations are identified using the same methodology described above for identification of minority populations. The average in-poverty population percentage in North Dakota is 11.1 percent (USCB 2022). Comparatively, a meaningfully greater low-income population percentage using this value would be 20 percentage points greater than the state low-income population (i.e., 13.32 percent).

Oliver County has a larger percentage of Caucasian, non-Hispanic peoples (93.6 percent) in comparison to North Dakota (83.2 percent; USCB 2022). Oliver County has the same percentage of people in poverty as North Dakota (11.1 percent; USCB 2022). The City of Center has a larger percentage of Caucasian, non-Hispanic peoples (98.5 percent) and a larger percentage of peoples living in poverty (21.5 percent; USCB 2022). Based on calculations for "significance" using CEQ guidance, the City of Center would exceed the significance threshold (13.32 percent) for in-poverty populations. However, additional data were referenced from the CEQ's Climate and Economic Justice Screening Tool (CJEST) and the EPA's EJScreen tool. These tools detail potential burdens within affected communities. To be considered a disadvantaged community, a census tract must rank in the 80th percentile of the cumulative sum of 36 burden indicators and have at least 30 percent of households classified as low-income. According to CJEST, the City of Center is not considered a community that is economically disadvantaged.

3.15.2 Environmental Consequences

Environmental impacts from most projects tend to be highly concentrated at the actual project site and are nearly non-existent as distance from the project site is increased. The geologic storage of CO_2 would lead to a wider spread of impacts to a larger number of people in Oliver County. During project construction and operation, it is anticipated that environmental, health, and occupational safety impacts would be minimal, temporary, and confined to the project area. Based on the impacts analysis for resource areas, no adverse effects would be expected from project construction or operation. It is expected that any impacts would affect all populations in the area equally. There would be no discernable adverse impacts to any populations, land uses, visual resources, noise, water, air quality, geology and soils, ecological resources, socioeconomic resources, or cultural resources that would cumulatively impact environmental justice. In the long term, as DOE modernizes carbon capture facilities in the United States, the expected releases of CO_2 into the environment would be reduced, thus further reducing potential impacts to the environment and any low-income and minority populations.

According to CJEST, Center is not considered a community that is economically disadvantaged or overburdened by pollution. It is not anticipated that Center would experience high adverse health or environmental effects from air emissions associated with the MRY facility or project. The project would be constructed and operated in a manner consistent with environmental justice considerations. Additionally, it would have positive socioeconomic effects on minority and economically disadvantaged populations, as well as the general population in the socioeconomic impact area because it would generate new temporary and permanent jobs and economic activity while reducing air pollutant emissions in the local community. See Section K.4.6 of Appendix K for more detailed information.

3.16 Resource Areas Dismissed from Further Review

All resources areas were included as a part of the DOE EA review and submittal.

3.17 Cumulative Impacts

As defined by CEQ, cumulative effects are those that "result from the incremental impact of the Proposed Action when added to other past, present, and reasonably foreseeable future actions, without regard to the agency (federal or non-federal) or individual who undertakes such other actions" (40 CFR 1508.7). Cumulative effects analysis captures the effects that result from the Proposed Action in combination with the effects of other actions taken during the duration of the Proposed Action at the same time and place. Cumulative effects may be accrued over time and/or in conjunction with other pre-existing effects from other activities in the area (40 CFR 1508.25); therefore, pre-existing impacts and multiple smaller impacts should also be considered. Overall, assessing cumulative effects involves defining the scope of the other actions and their interrelationship with the Proposed Action to determine if they overlap in space and time.

The NEPA and CEQ regulations require the analysis of cumulative environmental effects of a Proposed Action on resources that may often manifest only at the cumulative level. Cumulative effects can result from individually minor, but collectively significant actions taking place at the same time, over time. As noted above, cumulative effects are most likely to arise when a Proposed Action is related to other actions that could occur in the same location and at a similar time.

The social cost of greenhouse gas (SC-GHG) is a metric designed to quantify climate damages, representing the net economic cost of CO_2 emissions. Estimates of SC-GHG emissions provide an aggregated monetary measure (in U.S. dollars) of the net harm to society associated with an incremental metric ton of emissions in a given year. These estimates include, but are not limited to, climate change impacts associated with net agricultural productivity, human health effects, property damage from increased risk of natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. In this way, SC-GHG estimates can help the public and federal agencies understand or contextualize the potential impacts of GHG emissions and, along with information on other potential environmental impacts, can inform the comparison of alternatives.

The Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 13990 published February 2021 by the United States Interagency Working Group (IWG) on Social Cost of Greenhouse Gases (IWG Report) was referenced to prepare the analysis below. The analysis contains interim estimates of the SC-GHG split to reflect the cost of carbon, methane, and nitrous oxide emissions individually (SC-CO_2, SC-CH_4, SC-N_2O). These estimates are provided by the IWG to allow analysts to incorporate, when appropriate, net social benefits or costs of GHG emissions in benefit-cost analyses and in policy decision making processes.

In the 2021 IWG Report, the SC-GHG monetary values were calculated for discount rates 5 percent, 3 percent, and 2.5 percent. Discount rates are used to determine how much weight is placed on impacts that occur in the future. High discount rates reflect future effects of an action, in this case the emission of GHGs, as less significant than present effects. Low discount rates reflect that future and present impacts are closer to equally significant. Discount rates are used to convert the damages of future actions into present-day values. The social cost values are found in Appendix A-1 through A-3 of the IWG Report. A representation of these tables can be seen in Table 3-21 below. The IWG Report presents the SC-GHG in 2020 dollars per metric ton. For consistency, the results of this analysis are also presented in 2020 dollars.

For this analysis, the build scenario represents the operation of the proposed project. The no-build scenario represents the continued operation of the MRY facility without the construction of the project. The operation start date for the proposed plant is targeted for 2028 and the design life of the project is 20 years. Therefore, this analysis calculates the SC-GHG from 2028 to 2048 (analysis lifespan). Annual emission values in metric tons were estimated based upon fuel consumption projections at the MRY facility and the annual expected amount of CO_2 to be sequestrated. The MRY facility utilizes coal and fuel oil. The coal use projections were limited to the year 2043. The consumption data for the remaining five years of the analysis lifespan were estimated using the average of the last five years of available data. Both fuel oil consumption and the amount of CO_2 sequestered were assumed to be the same for every year of the analysis. Since both boilers may send flue gas to the carbon capture system, the emissions from both boilers were considered for the analysis together.

Table 3-21: IWG Tables A-1, A-2 and A-3, Annual [unrounded] Social Cost of Greenhouses Gases 2025-2050

Emission Year	SC-CO_2 (2020 dollars per metric ton of CO_2)			SC-CH_4 (2020 dollars per metric ton of CO_2)			SC-N_2O (2020 dollars per metric ton of CO_2)		
	5.0%	3.0%	2.5%	5.0%	3.0%	2.5%	5.0%	3.0%	2.5%
2025	17	56	83	802	1,720	2,230	6,789	20,591	29,914
2026	17	57	84	829	1,767	2,286	6,991	21,028	30,471
2027	18	59	86	856	1,814	2,341	7,193	21,465	31,028
2028	18	60	87	884	1,861	2,397	7,395	21,902	31,585
2029	19	61	88	911	1,908	2,452	7,597	22,339	32,141
2030	19	62	89	938	1,954	2,508	7,799	22,776	32,698
2031	20	63	91	972	2,010	2,572	8,047	23,268	33,309
2032	21	64	92	1,007	2,065	2,635	8,295	23,760	33,921
2033	21	65	94	1,041	2,121	2,699	8,542	24,252	34,532
2034	22	66	95	1,075	2,176	2,763	8,790	24,744	35,144
2035	22	67	96	1,110	2,231	2,827	9,038	25,236	35,755
2036	23	69	98	1,144	2,287	2,891	9,285	25,728	36,366
2037	23	70	99	1,179	2,342	2,955	9,533	26,219	36,978
2038	24	71	100	1,213	2,397	3,019	9,781	26,711	37,589
2039	25	72	102	1,247	2,453	3,083	10,029	27,203	38,201
2040	25	73	103	1,282	2,508	3,147	10,276	27,695	38,812
2041	26	74	104	1,319	2,564	3,210	10,567	28,225	39,456
2042	26	75	106	1,357	2,620	3,273	10,857	28,754	40,100
2043	27	77	107	1,394	2,676	3,336	11,147	29,283	40,745
2044	28	78	108	1,432	2,732	3,399	11,437	29,813	41,389
2045	28	79	110	1,469	2,788	3,462	11,727	30,342	42,033
2046	29	80	111	1,507	2,844	3,524	12,018	30,872	42,677
2047	30	81	112	1,544	2,900	3,587	12,308	31,401	43,321
2048	30	82	114	1,582	2,955	3,650	12,598	31,930	43,965
2049	31	84	115	1,619	3,011	3,713	12,888	32,460	44,610
2050	32	85	116	1,657	3,067	3,776	13,179	32,989	45,254

The build scenario incorporates the expected annual reduction of CO_2 emissions due to the proposed project. These calculated annual emission values are used in conjunction with the social cost estimates provided in the IWG Report to calculate the SC-CO_2, SC-CH_4, SC-N_2O for each scenario for the analysis lifespan as well as the difference between the two scenarios.

SC-GHG Results

Presenting GHG emissions as a monetary value allows for the ability to directly compare social costs to the economic benefits provided by the project. Annual SC-CO_2, SC-CH_4, SC-N_2O values were calculated for discount rates of 5 percent, 3 percent, and 2.5 percent for years 2028 to 2048. Additionally, an estimate is provided for the 95th percentile of an applied 3-percent discount rate for future economic effects. This is a low probability but high damage scenario that represents an upper bound of damages within the 3-percent discount rate model. These values were then summed to represent a lifespan total cost of GHGs emitted by the site in 2020 dollars. These values are presented in Table 3-22. Results are displayed by discount rate. Tables showing calculation results on an annual basis and by GHG (CO_2, CH_4, N_2O) are included in Table 3-21.

Table 3-22: Lifespan Total Cost of Greenhouse Gases Emitted in 2020 Dollars

Discount Rates	**5%**	**3%**	**2.5%**	**3%**
Statistic	Average	Average	Average	95th Percentile
No-Build Scenario SC-GHG	$1,717,000,000	$6,106,000,000	$9,071,000,000	$18,629,000,000
Build Scenario SC-GHG	$393,000,000	$1,391,000,000	$2,066,000,000	$4,231,000,000
Difference	**-$1,324,000,000**	**-$4,715,000,000**	**-$7,005,000,000**	**-$14,398,000,000**

The addition of the project to the MRY facility operations has been projected to reduce total GHG emissions compared to the no-build scenario. Note that this difference is due to the expected reduction of CO_2 emissions; the addition of the project to the site is not expected to affect N_2O or CH_4 emissions. For discount rates high to low over the analysis lifespan, the reduction in the SC-GHG was calculated to be approximately -$1.3, -$4.7, and -$7.0 billion in 2020 dollars if the proposed project is constructed and operational. For the 95th percentile of an applied 3-percent discount rate, the reduction in the SC-GHG that would be attributed to the proposed project is approximately -$14 billion.

3.17.1 Environmental Consequences

This section identifies reasonably foreseeable proposed projects that may have cumulative, incremental impacts in conjunction with the Proposed Action.

3.17.1.1 Future Planned Operation of the Facility

The project has a design life of 20 years. There currently is no plan for continued operation of the project past the useful life of the project. As proposed, when the useful life is reached, the project would be decommissioned and removed from Minnkota grounds. Another consideration to be made near the end of the project's useful life would be considerations for renovations or reconstruction to extend the useful life of the project. Decommissioning activities or reconstruction activities would result in temporary and minor adverse cumulative impacts to air quality, noise, materials and wastes, and health and safety.

3.17.1.2 Future Planned Projects at MRY

MRY completes infrastructure maintenance and upgrades to maintain the existing infrastructure and support potential future growth opportunities at MRY. These maintenance/upgrade activities may include:

- Expansion of cell 5 and construction of cell 6
- Dam gate replacement
- BNI permitting for additional coal in Section 9 south of MRY
- Water well replacement
- DCC West flowline (not associated with this project)
- Summit Carbon Solutions Project
- Rare earth elements study
- Potential wind farm projects in the area
- Transmission line installation

The infrastructure modifications would result in temporary minor adverse cumulative impacts to air quality, noise, materials and wastes, and health and safety.

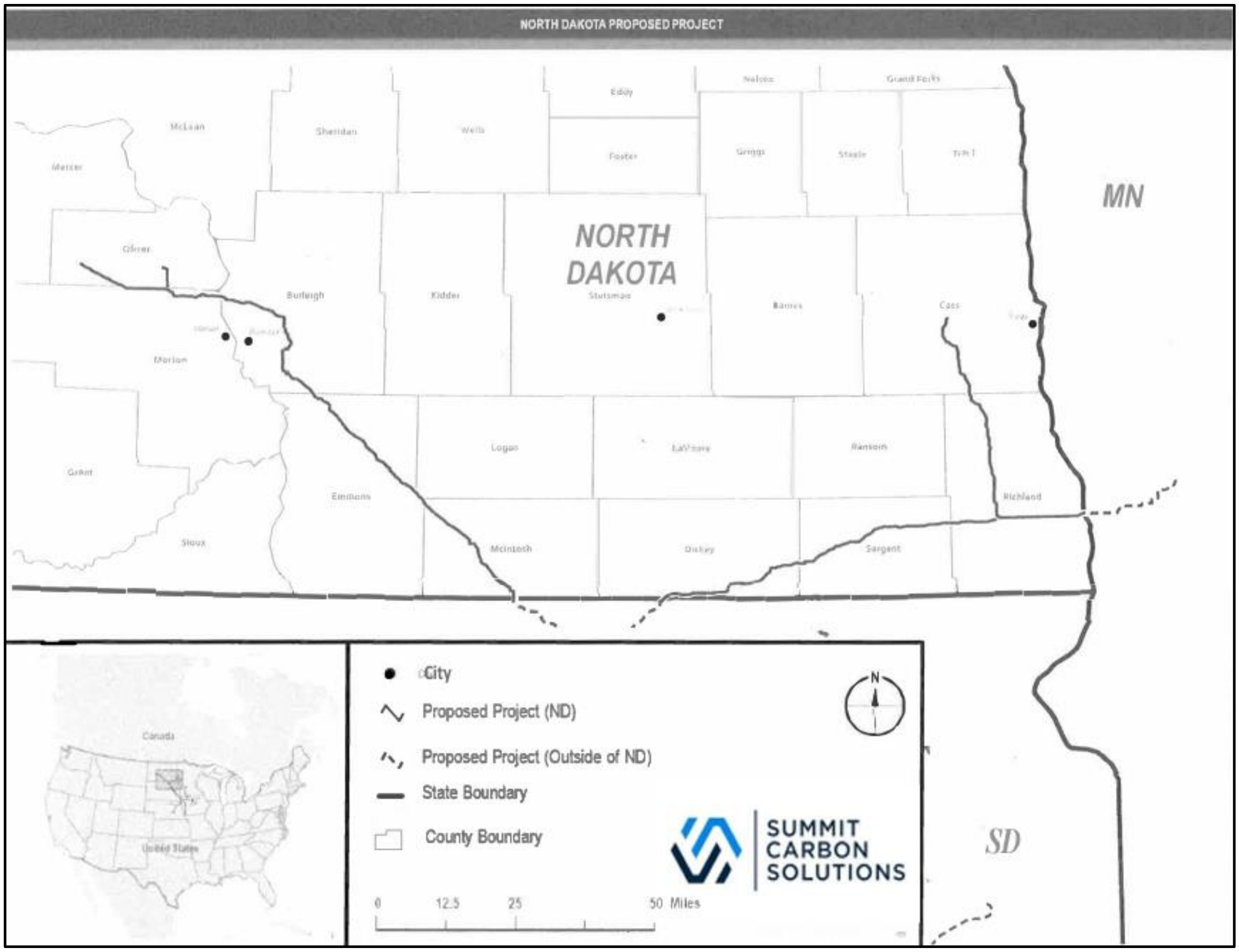
3.17.1.3 City of Center & Oliver County Projects

According to the city of Center and Oliver County websites, there are no additional projects currently proposed in the vicinity of the project.

There is a permitted storage facility approximately 7 miles to the west of the proposed Project Tundra sequestration site. The applicant is an affiliate of Minnkota and the storage facility will consist of incremental storage for Minnkota or third-party storage. There is no planned construction date for the development of this storage facility because the Class VI permit has not yet been issued. Should Minnkota continue to be affiliated with the entity, it is possible Minnkota could coordinate construction activities for efficiency.

Additionally, Summit Carbon Solutions has a pending application for a CO_2 transport pipeline in North Dakota, referred to as the Midwest Carbon Express CO_2 Pipeline Project (see Public Service Commission Case PU-22-39). The route for this pipeline crosses through Oliver County and there is a planned connection proximate to the Project Tundra sequestration site for potential use of the above-identified pending sequestration permit (see Figure 3-10). The construction timeline is not known for Summit Carbon Solutions pipeline project and is dependent on permits being issued in North Dakota, South Dakota, and Iowa.

Figure 3-10: Summit Carbon Solutions Published Route Map, PU-22-391.1, file 22



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CHAPTER 5. DISTRIBUTION LIST

Federal Agencies (via email)

Bureau of Indian Affairs

U.S. Fish and Wildlife Service

U.S. Forest Service

U.S. Department of the Interior

U.S. Environmental Protection Agency, Region 8

U.S. Army Corps of Engineers

State/Local Agencies (via email)

National Association of State Energy Officials

National Association of Tribal Historic Preservation Officers

North Dakota Industrial Commission

North Dakota Department of Environmental Quality

North Dakota Game and Fish Department

State and Tribal Government Working Group

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Libraries

Bismarck Veterans Memorial Public Library
515 North 5th Street
Bismarck, ND 58501

North Dakota State Library
604 East Boulevard Avenue
Bismarck, ND 58505

Non-governmental Organizations (via email)

Center for Biological Diversity

Ducks Unlimited, Inc.

Electric Power Research Institute

Environmental Defense Institute

Greenaction for Health and Environmental Justice

National Audubon Society

Sierra Club

Utilities Technology Council

Western Resource Advocates

Clean Water Action

Earthjustice

Environmental Defense Fund

Friends of the Earth

Institute for Energy and Environmental Research

The Nature Conservancy

Trout Unlimited

The Wilderness Society

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APPENDIX B – CATEGORICAL EXCLUSIONS

NETL F 451.1-1/1
Revised: 11/24/2014
Reviewed: 11/24/2014
(Previous Editions Obsolete)

U.S. DEPARTMENT OF ENERGY - NETL

CATEGORICAL EXCLUSION (CX) DESIGNATION FORM

Project No.: DE-FE0029488 Recipient Name: UND EERC Project Location: Grand Forks, ND

Sub-recipient(s) and Locations:

Schlumberger Carbon Services, Denver, CO; CETER, Gibsonia, PA and Green Bay, WI; Prairie Public Broadcasting, Fargo, ND; Basin Electric Power Cooperative, Bismarck, ND; field site in Mercer County, ND

NETL Sponsoring Org.: FE/TDIC/Coal/Carbon Storage Team NETL Contact: William O'Dowd

Brief Title of Proposed Action: North Dakota Integrated Carbon Storage Complex Feasibility Study

Brief Description of Activities:

The recipient will characterize one site in ND. The activities include drilling one strat well (with coring, logging, etc.), and collect additional 2-D seismic line. Other activities-outreach, etc.

THE PROPOSED ACTION FALLS WITHIN THE FOLLOWING CATEGORICAL EXCLUSION(S) FROM APPENDICES A AND B TO SUBPART D OF DOE NEPA IMPLEMENTING PROCEDURES (10 CFR 1021):

General Administration/Management
- ☒ A1 – Routine business actions
- ☒ A9 – Info gathering, analysis, documentation, dissemination, and training
- ☐ A11 – Technical advice and planning assistance

Facility Operations
- ☐ B1.3 – Routine maintenance and custodial services
- ☐ B1.7 – Communication system and data processing equipment acquisition, installation, operation, removal
- ☐ B1.15 – Support building or structure, non-waste storage, construction/ operation

Safety and Health
- ☐ B2.1 – Modifications to enhance workplace habitability
- ☐ B2.2 – Installation/improvement of building/equipment instrumentation
- ☐ B2.3 – Installation of equipment for personnel safety and health

General Research
- ☒ B3.1 – Site characterization/environmental monitoring
- ☒ B3.6 – R&D or pilot facility construction/operation/decommissioning
- ☒ B3.7 – New infill exploratory, experimental oil/gas/geothermal well construction and/or operation
- ☐ B3.9 – Certain CCT demonstration activities, emissions unchanged
- ☐ B3.11 – Outdoor tests, experiments on materials and equipment components

Electrical Power and Transmission
- ☐ B4.4 – Power management activities (storage, load shaping, and balancing)
- ☐ B4.6 – Transmission support addition/modifications at developed facility site
- ☐ B4.11 – Construction of power substations and interconnection facilities
- ☐ B4.13 – Upgrading and rebuilding existing power lines (< 20 miles)

Conservation, Fossil, and Renewable Energy Activities
- ☐ B5.1 – Actions to conserve energy, no indoor air quality degradation
- ☐ B5.3 – Modification/abandonment of wells
- ☐ B5.5 – Short crude oil/gas/steam/geothermal/carbon dioxide pipeline const/oper within an existing right-of-way (< 20 miles) between existing facilities
- ☒ B5.13 – Experimental wells for injection of small quantities of carbon dioxide (< 500,000 tons)
- ☒ B5.15 – Small scale renewable energy research/development/pilot projects
- ☐ B5.22 – Alternative fuel vehicle fueling stations
- ☐ B5.23 – Electric vehicle charging stations

Other
- ☒ Specify category: Drill one stratigraphic well-obtain core and logs and sampling
- ☐ Specify category:
- ☐ Specify category:

This action (1) would not present any extraordinary circumstances such that the action might have a significant impact upon the human environment; (2) is not connected to other actions with potentially significant impacts; (3) is not related to other actions with cumulatively significant impacts; and (4) is not inconsistent with 10 CFR 1021.211 - Interim Actions or 40 CFR 1506.1 - Limitations during the NEPA process.

SELECT ONE OF THE FOLLOWING:
- ☐ This Categorical Exclusion includes all tasks and phases in the Statement of Work or Statement of Project Objectives for this project.
- ☒ This Categorical Exclusion is only valid for the following tasks/phases and only one strat well . The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

SELECT ONE OF THE FOLLOWING:
- ☐ This Categorical Exclusion includes all locations and activities for this project.
- ☒ Additional sites, sub-recipients, or activities cannot be identified at this time. The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

NOTE: ANY CHANGE(S) TO THE PROJECT SCOPE OR LOCATIONS MAY REQUIRE A NEW NEPA DETERMINATION.

DOE Initiator Signature: William J. O'Dowd Date: 12 / 16 / 2016 (month day year)

NEPA Compliance Officer: Jesse Garcia Date: 12 / 28 / 2016 (month day year)

The following special condition is provided for the consideration of the Contracting Officer:

CX covers activities to include lab data analysis, computer modeling, planning and drilling one strat well(Mercer County)for data gathering. Appropriate required well permits must be obtained under this CX.

NETL F 451.1-1/1
Revised: 11/24/2014
Reviewed: 11/24/2014
(Previous Editions Obsolete)

U.S. DEPARTMENT OF ENERGY - NETL

CATEGORICAL EXCLUSION (CX) DESIGNATION FORM

Project No.: DE-FE0029488 Recipient Name: UND EERC Project Location: Grand Forks, ND

Sub-recipient(s) and Locations:

Field sites in Oliver and Mercer Counties, ND

NETL Sponsoring Org.: FE/TDIC/Coal/Carbon Storage Team NETL Contact: William O'Dowd

Brief Title of Proposed Action: North Dakota Integrated Carbon Storage Complex Feasibility Study

Brief Description of Activities:

The recipient will characterize two sites in ND. The activities include drilling two strat wells (with coring, logging,...),and collect 2-D seismic line data.

THE PROPOSED ACTION FALLS WITHIN THE FOLLOWING CATEGORICAL EXCLUSION(S) FROM APPENDICES A AND B TO SUBPART D OF DOE NEPA IMPLEMENTING PROCEDURES (10 CFR 1021):

General Administration/Management
- ☐ A1 – Routine business actions
- ☒ A9 – Info gathering, analysis, documentation, dissemination, and training
- ☐ A11 – Technical advice and planning assistance

Facility Operations
- ☐ B1.3 – Routine maintenance and custodial services
- ☐ B1.7 – Communication system and data processing equipment acquisition, installation, operation, removal
- ☐ B1.15 – Support building or structure, non-waste storage, construction/ operation

Safety and Health
- ☐ B2.1 – Modifications to enhance workplace habitability
- ☐ B2.2 – Installation/improvement of building/equipment instrumentation
- ☐ B2.3 – Installation of equipment for personnel safety and health

General Research
- ☒ B3.1 – Site characterization/environmental monitoring
- ☐ B3.6 – R&D or pilot facility construction/operation/decommissioning
- ☒ B3.7 – New infill exploratory, experimental oil/gas/geothermal well construction and/or operation
- ☐ B3.9 – Certain CCT demonstration activities, emissions unchanged
- ☐ B3.11 – Outdoor tests, experiments on materials and equipment components

Electrical Power and Transmission
- ☐ B4.4 – Power management activities (storage, load shaping, and balancing)
- ☐ B4.6 – Transmission support addition/modifications at developed facility site
- ☐ B4.11 – Construction of power substations and interconnection facilities
- ☐ B4.13 – Upgrading and rebuilding existing power lines (< 20 miles)

Conservation, Fossil, and Renewable Energy Activities
- ☐ B5.1 – Actions to conserve energy, no indoor air quality degradation
- ☐ B5.3 – Modification/abandonment of wells
- ☐ B5.5 – Short crude oil/gas/steam/geothermal/carbon dioxide pipeline const/oper within an existing right-of-way (< 20 miles) between existing facilities
- ☐ B5.13 – Experimental wells for injection of small quantities of carbon dioxide (< 500,000 tons)
- ☐ B5.15 – Small scale renewable energy research/development/pilot projects
- ☐ B5.22 – Alternative fuel vehicle fueling stations
- ☐ B5.23 – Electric vehicle charging stations

Other
- ☐ Specify category:
- ☐ Specify category:
- ☐ Specify category:

This action (1) would not present any extraordinary circumstances such that the action might have a significant impact upon the human environment; (2) is not connected to other actions with potentially significant impacts; (3) is not related to other actions with cumulatively significant impacts; and (4) is not inconsistent with 10 CFR 1021.211 - Interim Actions or 40 CFR 1506.1 - Limitations during the NEPA process.

SELECT ONE OF THE FOLLOWING:
- ☐ This Categorical Exclusion includes all tasks and phases in the Statement of Work or Statement of Project Objectives for this project.
- ☒ This Categorical Exclusion is only valid for the following tasks/phases Task 2.0 (2.1 and 2.4). The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

SELECT ONE OF THE FOLLOWING:
- ☒ This Categorical Exclusion includes all locations and activities for this project.
- ☐ Additional sites, sub-recipients, or activities cannot be identified at this time. The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

NOTE: ANY CHANGE(S) TO THE PROJECT SCOPE OR LOCATIONS MAY REQUIRE A NEW NEPA DETERMINATION.

DOE Initiator Signature: WILLIAM O'DOWD Digitally signed by WILLIAM O'DOWD Date: 2017.09.13 12:26:35 -04'00' Date: 09 / 13 / 2017 (month day year)

NEPA Compliance Officer: Jesse Garcia Digitally signed by Jesse Garcia Date: 2017.09.21 11:26:29 -07'00' Date: 09 / 21 / 2017 (month day year)

The following special condition is provided for the consideration of the Contracting Officer:

This supplemental CX is to cover activities at the Oliver and new Mercer County, ND well sites. Drill two stratigraphic wells-obtain core and logs and sampling. Acquire 2D seismic line data (Mercer Co. area)

NETL F 451.1-1/1
Revised: 11/24/2014
Reviewed: 11/24/2014
(Previous Editions Obsolete)

U.S. DEPARTMENT OF ENERGY - NETL

CATEGORICAL EXCLUSION (CX) DESIGNATION FORM

Project No.: DE-FE0029488 Recipient Name: UND EERC Project Location: Oliver County, ND

Sub-recipient(s) and Locations:

Minnkota Power Cooperative - Grand Forks, ND

NETL Sponsoring Org.: FE/TDIC/Coal/Carbon Storage Team NETL Contact: William O'Dowd

Brief Title of Proposed Action: North Dakota Integrated Carbon Storage Complex Feasibility Study

Brief Description of Activities:

Conduct a seismic source evaluation to determine if traditional vibration trucks or dynamite is required for successful surface reflection survey in the area (reclaimed mine land).

THE PROPOSED ACTION FALLS WITHIN THE FOLLOWING CATEGORICAL EXCLUSION(S) FROM APPENDICES A AND B TO SUBPART D OF DOE NEPA IMPLEMENTING PROCEDURES (10 CFR 1021):

General Administration/Management
- ☐ A1 – Routine business actions
- ☒ A9 – Info gathering, analysis, documentation, dissemination, and training
- ☐ A11 – Technical advice and planning assistance

Facility Operations
- ☐ B1.3 – Routine maintenance and custodial services
- ☐ B1.7 – Communication system and data processing equipment acquisition, installation, operation, removal
- ☐ B1.15 – Support building or structure, non-waste storage, construction/ operation

Safety and Health
- ☐ B2.1 – Modifications to enhance workplace habitability
- ☐ B2.2 – Installation/improvement of building/equipment instrumentation
- ☐ B2.3 – Installation of equipment for personnel safety and health

General Research
- ☒ B3.1 – Site characterization/environmental monitoring
- ☒ B3.6 – R&D or pilot facility construction/operation/decommissioning
- ☐ B3.7 – New infill exploratory, experimental oil/gas/geothermal well construction and/or operation
- ☐ B3.9 – Certain CCT demonstration activities, emissions unchanged
- ☐ B3.11 – Outdoor tests, experiments on materials and equipment components

Electrical Power and Transmission
- ☐ B4.4 – Power management activities (storage, load shaping, and balancing)
- ☐ B4.6 – Transmission support addition/modifications at developed facility site
- ☐ B4.11 – Construction of power substations and interconnection facilities
- ☐ B4.13 – Upgrading and rebuilding existing power lines (< 20 miles)

Conservation, Fossil, and Renewable Energy Activities
- ☐ B5.1 – Actions to conserve energy, no indoor air quality degradation
- ☐ B5.3 – Modification/abandonment of wells
- ☐ B5.5 – Short crude oil/gas/steam/geothermal/carbon dioxide pipeline const/oper within an existing right-of-way (< 20 miles) between existing facilities
- ☐ B5.13 – Experimental wells for injection of small quantities of carbon dioxide (< 500,000 tons)
- ☐ B5.15 – Small scale renewable energy research/development/pilot projects
- ☐ B5.22 – Alternative fuel vehicle fueling stations
- ☐ B5.23 – Electric vehicle charging stations

Other
- ☐ Specify category:
- ☐ Specify category:
- ☐ Specify category:

This action (1) would not present any extraordinary circumstances such that the action might have a significant impact upon the human environment; (2) is not connected to other actions with potentially significant impacts; (3) is not related to other actions with cumulatively significant impacts; and (4) is not inconsistent with 10 CFR 1021.211 - Interim Actions or 40 CFR 1506.1 - Limitations during the NEPA process.

SELECT ONE OF THE FOLLOWING:
- ☐ This Categorical Exclusion includes all tasks and phases in the Statement of Work or Statement of Project Objectives for this project.
- ☒ This Categorical Exclusion is only valid for the following tasks/phases supports Task 6.0 . The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

SELECT ONE OF THE FOLLOWING:
- ☒ This Categorical Exclusion includes all locations and activities for this project.
- ☐ Additional sites, sub-recipients, or activities cannot be identified at this time. The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

NOTE: ANY CHANGE(S) TO THE PROJECT SCOPE OR LOCATIONS MAY REQUIRE A NEW NEPA DETERMINATION.

DOE Initiator Signature: William O'Dowd Digitally signed by William O'Dowd Date: 2019.07.12 10:22:38 -04'00' Date: 7 / 12 / 2019 (month day year)

NEPA Compliance Officer: Jesse Garcia Digitally signed by Jesse Garcia Date: 2019.07.16 11:58:39 -07'00' Date: 07 / 16 / 2019 (month day year)

The following special condition is provided for the consideration of the Contracting Officer:

CX covers activities to be conducted in the field to gather seismic data near an existing coal fired plant, gather core samples and conduct down hole wellbore geophysical testing. Appropriate permitting obtained; state and federal regulations will be adhered to regarding all project activities.

NETL F 451.1-1/1
Revised: 11/24/2014
Reviewed: 11/24/2014
(Previous Editions Obsolete)

U.S. DEPARTMENT OF ENERGY - NETL

CATEGORICAL EXCLUSION (CX) DESIGNATION FORM

Project No.: DE-FE0031898 Recipient Name: EERC Project Location: Multiple

Sub-recipient(s) and Locations:

EERC has 4 offices (Grand Forks, ND; Oliver County, ND; Green Bay, WI; Pittsburgh, PA); and Minnkota Power Cooperative (Grand Forks, ND) is the industrial partner and will host the well sites and seismic survey.

NETL Sponsoring Org.: FE/TDIC/Coal/Carbon Storage Team NETL Contact: Joshua Hull

Brief Title of Proposed Action: Site Characterization Phase of Minnkota/Project Tundra CO2 Storage Complex

Brief Description of Activities:

EERC will assist Minnkota with site chracterization through the installation of a deep characterization well and two associated water monitoring wells.

THE PROPOSED ACTION FALLS WITHIN THE FOLLOWING CATEGORICAL EXCLUSION(S) FROM APPENDICES A AND B TO SUBPART D OF DOE NEPA IMPLEMENTING PROCEDURES (10 CFR 1021):

General Administration/Management
- ☐ A1 – Routine business actions
- ☒ A9 – Info gathering, analysis, documentation, dissemination, and training
- ☐ A11 – Technical advice and planning assistance

Facility Operations
- ☐ B1.3 – Routine maintenance and custodial services
- ☐ B1.7 – Communication system and data processing equipment acquisition, installation, operation, removal
- ☐ B1.15 – Support building or structure, non-waste storage, construction/ operation

Safety and Health
- ☐ B2.1 – Modifications to enhance workplace habitability
- ☐ B2.2 – Installation/improvement of building/equipment instrumentation
- ☐ B2.3 – Installation of equipment for personnel safety and health

General Research
- ☒ B3.1 – Site characterization/environmental monitoring
- ☒ B3.6 – R&D or pilot facility construction/operation/decommissioning
- ☐ B3.7 – New infill exploratory, experimental oil/gas/geothermal well construction and/or operation
- ☐ B3.9 – Certain CCT demonstration activities, emissions unchanged
- ☐ B3.11 – Outdoor tests, experiments on materials and equipment components

Electrical Power and Transmission
- ☐ B4.4 – Power management activities (storage, load shaping, and balancing)
- ☐ B4.6 – Transmission support addition/modifications at developed facility site
- ☐ B4.11 – Construction of power substations and interconnection facilities
- ☐ B4.13 – Upgrading and rebuilding existing power lines (< 20 miles)

Conservation, Fossil, and Renewable Energy Activities
- ☐ B5.1 – Actions to conserve energy, no indoor air quality degradation
- ☐ B5.3 – Modification/abandonment of wells
- ☐ B5.5 – Short crude oil/gas/steam/geothermal/carbon dioxide pipeline const/oper within an existing right-of-way (< 20 miles) between existing facilities
- ☐ B5.13 – Experimental wells for injection of small quantities of carbon dioxide (< 500,000 tons)
- ☐ B5.15 – Small scale renewable energy research/development/pilot projects
- ☐ B5.22 – Alternative fuel vehicle fueling stations
- ☐ B5.23 – Electric vehicle charging stations

Other
- ☐ Specify category:
- ☐ Specify category:
- ☐ Specify category:

This action (1) would not present any extraordinary circumstances such that the action might have a significant impact upon the human environment; (2) is not connected to other actions with potentially significant impacts; (3) is not related to other actions with cumulatively significant impacts; and (4) is not inconsistent with 10 CFR 1021.211 - Interim Actions or 40 CFR 1506.1 - Limitations during the NEPA process.

SELECT ONE OF THE FOLLOWING:
- ☐ This Categorical Exclusion includes all tasks and phases in the Statement of Work or Statement of Project Objectives for this project.
- ☒ This Categorical Exclusion is only valid for the following tasks/phases Tasks 1,2,4,5,6,8. The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

SELECT ONE OF THE FOLLOWING:
- ☐ This Categorical Exclusion includes all locations and activities for this project.
- ☒ Additional sites, sub-recipients, or activities cannot be identified at this time. The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

NOTE: ANY CHANGE(S) TO THE PROJECT SCOPE OR LOCATIONS MAY REQUIRE A NEW NEPA DETERMINATION.

DOE Initiator Signature: JOSHUA HULL Digitally signed by JOSHUA HULL Date: 2020.06.03 08:27:11 -04'00' Date: 6 / 3 / 2020 (month day year)

NEPA Compliance Officer: JESSE GARCIA Digitally signed by JESSE GARCIA Date: 2020.06.09 13:43:59 -07'00' Date: 06 / 09 / 2020 (month day year)

The following special condition is provided for the consideration of the Contracting Officer:

CX covers activities to be conducted within existing lab/office sites. Data compilation, analysis, computer modeling and simulation conducted under these tasks. Also,document preparation, and data dissemination and literature searches. Task 3 and Task 7 will require a separate NEPA review for the TBD sites.

NETL F 451.1-1/1
Revised: 11/24/2014
Reviewed: 11/24/2014
(Previous Editions Obsolete)

U.S. DEPARTMENT OF ENERGY - NETL

CATEGORICAL EXCLUSION (CX) DESIGNATION FORM

Project No.: DE-FE00031898 Recipient Name: EERC Project Location: Oliver County, ND

Sub-recipient(s) and Locations:

Minnkota, Center, ND

NETL Sponsoring Org.: Carbon Storage NETL Contact: Joshua Hull

Brief Title of Proposed Action: Drill Stratigraphic Test Well, associated water well, and 120k tonCO2 injection

Brief Description of Activities:

Drill Stratigraphic Test Well, associated water well, and 120k ton CO2 injection to test formation activity.

THE PROPOSED ACTION FALLS WITHIN THE FOLLOWING CATEGORICAL EXCLUSION(S) FROM APPENDICES A AND B TO SUBPART D OF DOE NEPA IMPLEMENTING PROCEDURES (10 CFR 1021):

General Administration/Management
- ☐ A1 – Routine business actions
- ☒ A9 – Info gathering, analysis, documentation, dissemination, and training
- ☐ A11 – Technical advice and planning assistance

Facility Operations
- ☐ B1.3 – Routine maintenance and custodial services
- ☐ B1.7 – Communication system and data processing equipment acquisition, installation, operation, removal
- ☐ B1.15 – Support building or structure, non-waste storage, construction/ operation

Safety and Health
- ☐ B2.1 – Modifications to enhance workplace habitability
- ☐ B2.2 – Installation/improvement of building/equipment instrumentation
- ☐ B2.3 – Installation of equipment for personnel safety and health

General Research
- ☒ B3.1 – Site characterization/environmental monitoring
- ☒ B3.6 – R&D or pilot facility construction/operation/decommissioning
- ☒ B3.7 – New infill exploratory, experimental oil/gas/geothermal well construction and/or operation
- ☐ B3.9 – Certain CCT demonstration activities, emissions unchanged
- ☐ B3.11 – Outdoor tests, experiments on materials and equipment components

Electrical Power and Transmission
- ☐ B4.4 – Power management activities (storage, load shaping, and balancing)
- ☐ B4.6 – Transmission support addition/modifications at developed facility site
- ☐ B4.11 – Construction of power substations and interconnection facilities
- ☐ B4.13 – Upgrading and rebuilding existing power lines (< 20 miles)

Conservation, Fossil, and Renewable Energy Activities
- ☐ B5.1 – Actions to conserve energy, no indoor air quality degradation
- ☐ B5.3 – Modification/abandonment of wells
- ☐ B5.5 – Short crude oil/gas/steam/geothermal/carbon dioxide pipeline const/oper within an existing right-of-way (< 20 miles) between existing facilities
- ☒ B5.13 – Experimental wells for injection of small quantities of carbon dioxide (< 500,000 tons)
- ☐ B5.15 – Small scale renewable energy research/development/pilot projects
- ☐ B5.22 – Alternative fuel vehicle fueling stations
- ☐ B5.23 – Electric vehicle charging stations

Other
- ☐ Specify category:
- ☐ Specify category:
- ☐ Specify category:

This action (1) would not present any extraordinary circumstances such that the action might have a significant impact upon the human environment; (2) is not connected to other actions with potentially significant impacts; (3) is not related to other actions with cumulatively significant impacts; and (4) is not inconsistent with 10 CFR 1021.211 - Interim Actions or 40 CFR 1506.1 - Limitations during the NEPA process.

SELECT ONE OF THE FOLLOWING:
- ☐ This Categorical Exclusion includes all tasks and phases in the Statement of Work or Statement of Project Objectives for this project.
- ☒ This Categorical Exclusion is only valid for the following tasks/phases Subtask 3.1. The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

SELECT ONE OF THE FOLLOWING:
- ☐ This Categorical Exclusion includes all locations and activities for this project.
- ☒ Additional sites, sub-recipients, or activities cannot be identified at this time. The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

NOTE: ANY CHANGE(S) TO THE PROJECT SCOPE OR LOCATIONS MAY REQUIRE A NEW NEPA DETERMINATION.

DOE Initiator Signature: Joshua K. Hull Digitally signed by Joshua K. Hull Date: 2020.06.23 16:10:14 -04'00' Date: 6 / 23 / 2020 (month day year)

NEPA Compliance Officer: JESSE GARCIA Digitally signed by JESSE GARCIA Date: 2020.06.24 10:55:06 -07'00' Date: 06 / 24 / 2020 (month day year)

The following special condition is provided for the consideration of the Contracting Officer:

CX covers activities to be conducted at existing industrial site; Drilling a stratigraphic test well, collecting core and fluid samples,running wireline logs,installing downhole gauges and sensors, injection testing and drilling a water well.

NETL F 451.1-1/1
Revised: 11/24/2014
Reviewed: 11/24/2014
(Previous Editions Obsolete)

U.S. DEPARTMENT OF ENERGY - NETL

CATEGORICAL EXCLUSION (CX) DESIGNATION FORM

Project No.: DE-FE00031889 Recipient Name: EERC Project Location: Oliver County, ND

Sub-recipient(s) and Locations:

Minnkota Power Cooperative - Center, ND

NETL Sponsoring Org.: FE/TDIC/Coal/Carbon Storage Team NETL Contact: Joshua Hull

Brief Title of Proposed Action: 2-D and 3-D Seismic, Controlled Source Electromagnetic Survey

Brief Description of Activities:

2-D and 3-D seismic surveys, controlled source electromagnetic survey, collect gravity and magnetic data.

THE PROPOSED ACTION FALLS WITHIN THE FOLLOWING CATEGORICAL EXCLUSION(S) FROM APPENDICES A AND B TO SUBPART D OF DOE NEPA IMPLEMENTING PROCEDURES (10 CFR 1021):

General Administration/Management
- ☐ A1 – Routine business actions
- ☐ A9 – Info gathering, analysis, documentation, dissemination, and training
- ☐ A11 – Technical advice and planning assistance

Facility Operations
- ☐ B1.3 – Routine maintenance and custodial services
- ☐ B1.7 – Communication system and data processing equipment acquisition, installation, operation, removal
- ☐ B1.15 – Support building or structure, non-waste storage, construction/ operation

Safety and Health
- ☐ B2.1 – Modifications to enhance workplace habitability
- ☐ B2.2 – Installation/improvement of building/equipment instrumentation
- ☐ B2.3 – Installation of equipment for personnel safety and health

General Research
- ☒ B3.1 – Site characterization/environmental monitoring
- ☐ B3.6 – R&D or pilot facility construction/operation/decommissioning
- ☐ B3.7 – New infill exploratory, experimental oil/gas/geothermal well construction and/or operation
- ☐ B3.9 – Certain CCT demonstration activities, emissions unchanged
- ☐ B3.11 – Outdoor tests, experiments on materials and equipment components

Electrical Power and Transmission
- ☐ B4.4 – Power management activities (storage, load shaping, and balancing)
- ☐ B4.6 – Transmission support addition/modifications at developed facility site
- ☐ B4.11 – Construction of power substations and interconnection facilities
- ☐ B4.13 – Upgrading and rebuilding existing power lines (< 20 miles)

Conservation, Fossil, and Renewable Energy Activities
- ☐ B5.1 – Actions to conserve energy, no indoor air quality degradation
- ☐ B5.3 – Modification/abandonment of wells
- ☐ B5.5 – Short crude oil/gas/steam/geothermal/carbon dioxide pipeline const/oper within an existing right-of-way (< 20 miles) between existing facilities
- ☐ B5.13 – Experimental wells for injection of small quantities of carbon dioxide (< 500,000 tons)
- ☐ B5.15 – Small scale renewable energy research/development/pilot projects
- ☐ B5.22 – Alternative fuel vehicle fueling stations
- ☐ B5.23 – Electric vehicle charging stations

Other
- ☐ Specify category:
- ☐ Specify category:
- ☐ Specify category:

This action (1) would not present any extraordinary circumstances such that the action might have a significant impact upon the human environment; (2) is not connected to other actions with potentially significant impacts; (3) is not related to other actions with cumulatively significant impacts; and (4) is not inconsistent with 10 CFR 1021.211 - Interim Actions or 40 CFR 1506.1 - Limitations during the NEPA process.

SELECT ONE OF THE FOLLOWING:
- ☐ This Categorical Exclusion includes all tasks and phases in the Statement of Work or Statement of Project Objectives for this project.
- ☒ This Categorical Exclusion is only valid for the following tasks/phases Subtask 3.2. The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

SELECT ONE OF THE FOLLOWING:
- ☐ This Categorical Exclusion includes all locations and activities for this project.
- ☒ Additional sites, sub-recipients, or activities cannot be identified at this time. The DOE initiator acknowledges the responsibility to obtain a NEPA determination prior to initiating any activities outside the scope of this Categorical Exclusion.

NOTE: ANY CHANGE(S) TO THE PROJECT SCOPE OR LOCATIONS MAY REQUIRE A NEW NEPA DETERMINATION.

DOE Initiator Signature: Joshua K. Hull Digitally signed by Joshua K. Hull Date: 2020.09.08 11:33:59 -04'00' Date: 9 / 08 / 2020 (month day year)

NEPA Compliance Officer: Mark Lusk Digitally signed by Mark Lusk Date: 2020.09.14 14:03:26 -04'00' Date: 9 / 14 / 2020 (month day year)

The following special condition is provided for the consideration of the Contracting Officer:

If any archaeological, historical or other cultural resources are discovered while conducting field work or ground disturbing activities, work should cease immediately and the NETL federal project manager should be contacted as soon as possible to obtain additional guidance.

APPENDIX C – AGENCY AND TRIBAL CORRESPONDENCE

July 21, 2023

U.S. Fish and Wildlife Service
NEPA Compliance Officer
North Dakota Field Office
3425 Miriam Avenue
Bismarck, ND 58501-7926

Re: Consultation Under Section 7 Endangered Species Act for the "North Dakota CarbonSAFE: Project Tundra" in Oliver County, North Dakota

Dear Sir or Ma'am:

The U.S. Department of Energy (DOE) is preparing an Environmental Assessment (EA) for DOE's proposed action of providing cost-sharing financial assistance to Minnkota Power Cooperative, Inc. (Minnkota) for the proposed North Dakota CarbonSAFE: Project Tundra. The EA is being prepared to fulfill DOE's obligation under the National Environmental Policy Act (NEPA), as amended, the Council on Environmental Quality's NEPA regulations, and DOE's NEPA implementing procedures. The EA will evaluate the potential effects of construction and subsequent operation of the project. The purpose of this letter is to initiate consultation with the U.S. Fish and Wildlife Service (USFWS) North Dakota Field Office and to request information on any federally listed threatened, endangered, or candidate species, or critical habitat within the vicinity of the Project.
The DOE's Proposed Action is to provide cost-shared financial assistance to Minnkota. DOE proposes to provide approximately $38.5 million of the Project's $77 million estimated total cost.
Minnkota's proposed project would include the design, construction, and operation of a carbon capture system at an existing lignite-fired coal power plant, the Milton R. Young (MRY) facility, in Oliver County, North Dakota. If built, Project Tundra would be the world's largest post-combustion carbon dioxide (CO_2) capture and geologic storage project, and would capture and permanently store CO_2 emissions from the existing MRY facility. The Project would be sized for capture and saline formation geologic storage of an average of 4.0 million metric tons per year (MMT/yr) of CO_2. The CO_2 would be compressed, piped via a new approximately 0.5-mile-long CO_2 pipeline to the storage complex, and injected into deep geologic reservoirs. Construction would begin in 2024 and would be complete by 2028.

The Project would be constructed as a stand-alone facility with a footprint that falls within an area of 25.8 acres, west and south of the MRY (see **Figure 1**). Currently the area comprises equipment and materials storage, access roadways, and barren lands. The proposed Project would be located within the larger MRY associated industrial area that is bound by Nelson Lake to the north and east, coal production and plant waste disposal areas to the south, and agricultural and natural areas to the west.

The proposed Project site would be located in an area historically used for coal pile storage that has since been reclaimed. The area is undeveloped and provides minimal, low-quality wildlife habitat due to the disturbed and industrial nature of the area. The areas surrounding the Project site are generally low-quality wildlife habitat, including the adjacent landfill, coal mines, and industrial facilities. Nelson Lake abuts the existing MRY facility, but not the proposed Project area.
Facility construction would include preparation of laydown and fabrication areas to be used for parking, construction trailers, material storage and fabrication, and other activities to support the influx of workers and project construction activities. **Figure 2** depicts 10 locations on Minnkota-

626 Cochran Mill Road, Pittsburgh, PA 15236
Pierina.Fayish@netl.doe.gov Phone (412) 386-5428 www.netl.doe.gov

owned property being considered for use as temporary construction and laydown areas. Approximately 97.0 acres of land within these designated areas would be required during construction. Following construction, these areas would be restored to their original conditions, with the exception of an approximately 7.0-acre area previously used for plant operations that would be retained for overflow parking for MRY and project operations.

DOE reviewed the USFWS Information for Planning and Consultation (IPaC) system for the proposed Project area in Oliver County, which indicated five federally threatened or endangered species and one candidate species with the potential occur within the Project area based on known range and distribution. Table 1 summarizes these species, their habitat requirements, and their potential to occur in the Project area.

Table 1: Federally Listed Species Potentially Occurring within the Project Area in Oliver County, North Dakota

Common Name	Scientific Name	Status	Habitat	Potential for Occurrence
Birds				
Piping plover	*Charadrius melodus*	Threatened	Preferred habitat includes Alkali Lakes and Missouri River sandbars.	None - The Project site is an existing industrial site and does not provide suitable habitat.
Red knot	*Calidris cantus*	Threatened	Species may migrate through North Dakota in mid-May and mid-September to October. Breeding and nesting habitat is marine; migratory habitat in North Dakota may include the Missouri River system, sewage lagoons, and large permanent freshwater wetlands.	None - The Project site is an existing industrial site and does not provide suitable habitat.
Whooping crane	*Grus americana*	Endangered	May occur; migrates through North Dakota in April to mid-May and September to early November, found along wetlands and ponds.	Low – the Project site is an existing industrial site and is unlikely to provide stopover habitat for migrating cranes.
Mammals				
Northern Long-eared bat (NLEB)	*Myotis septentrionalis*	Endangered	Unlikely to occur; hibernates in caves and mine shafts during the winter months, and roosts in wooded areas during the summer months.	None – there are no roost trees available within the Project site, and no known hibernaculum in proximity to the site.
Insects				
Dakota skipper	*Hesperia dacotae*	Threatened	May occur; preferred habitat of mixed-grass prairies dominated by bluestem, purple coneflower, and needlegrasses may exist within Project area, and species has been documented in Oliver County.	None - The Project site is an existing industrial site and does not provide suitable habitat.
Monarch butterfly	*Danaus plexippus*	Candidate species	May occur; preferred habitat of prairies, meadows, grasslands, and right-of-way ditches along roadsides. Eggs laid on milkweed host plant (primarily *Asclepias* spp.).	The Project site is an existing industrial site and does not provide suitable habitat.
Source: USFWS IPaC 2023; North Dakota Game and Fish Department (https://gf.nd.gov/wildlife/endangered)				

The DOE has determined that the proposed Project would have *no effect* on the piping plover, red knot, NLEB, or Dakota skipper. The Project *may affect, but is not likely to adversely affect* the whooping crane. The Project will not jeopardize the continued existence of the monarch butterfly. The DOE understands that North Dakota does not have a state endangered or threatened species list; only those species listed under the ESA are considered threatened or endangered in North Dakota. Subsequently, no additional listed species were considered in this review, and coordination with the North Dakota Game and Fish Department for listed species did not occur.

DOE does not anticipate any adverse effects on federally listed threatened or endangered species based on the proposed construction and operation of the proposed Project Tundra. As part of the NEPA process, we are seeking your input on any environmental issues or concerns your agency may have on the Proposed Action and the potentially affected areas as described above. We respectfully ask that you provide any information or comments within 30 days to enable us to complete this phase of the Project within the scheduled timeframe.

If you have any questions, please contact Ms. Pierina Fayish at:

National Energy Technology Laboratory M/S:922-W13
P.O. Box 10940
Pittsburgh, PA 15236-0940
Attention: Pierina Fayish
Pierina.Fayish@netl.doe.gov
(412) 386-5428

Thank you for your assistance in this matter.

Sincerely,

Pierina N. Fayish

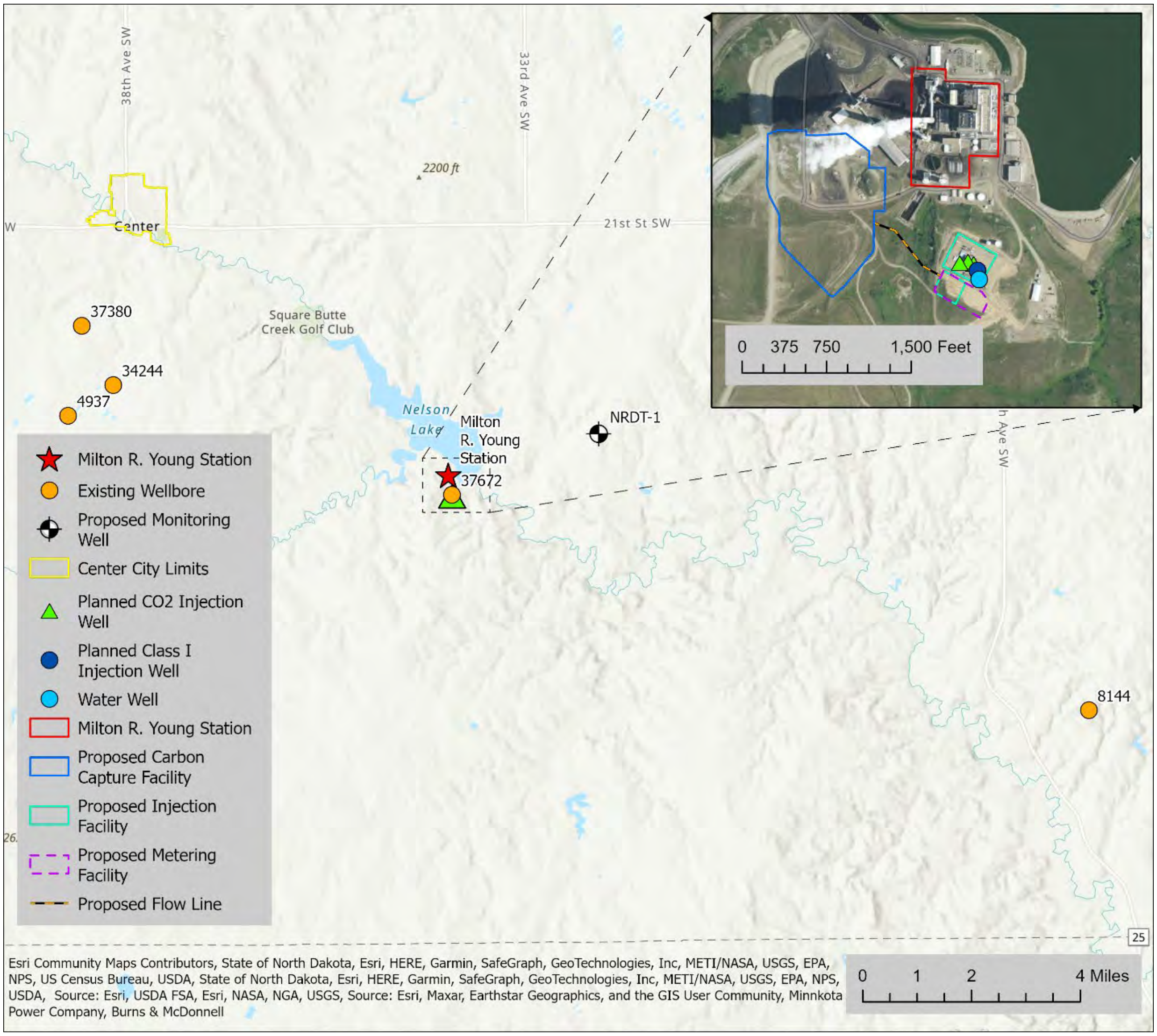

Figure 1 – Proposed Project Location – MRY Vicinity Map

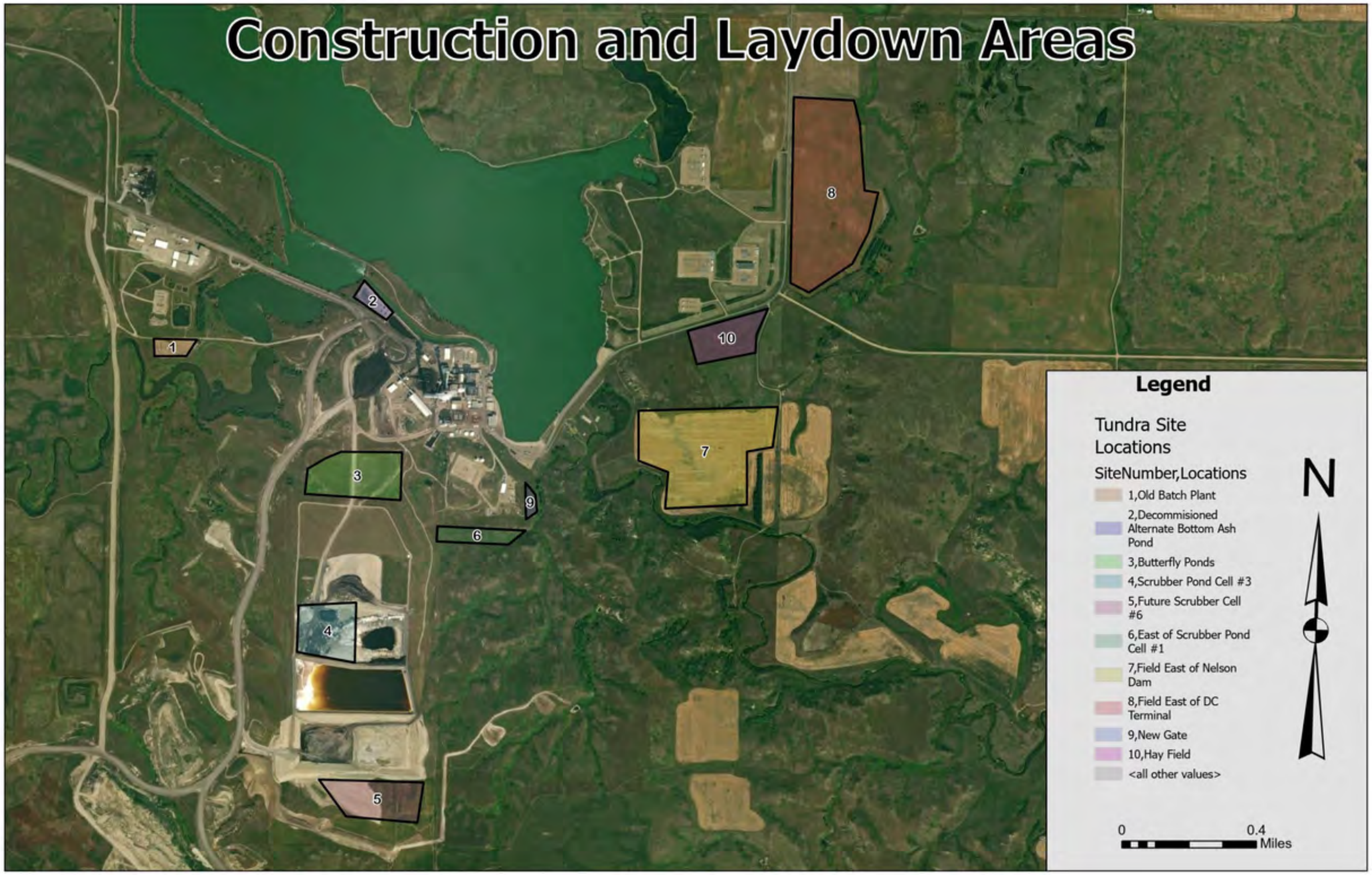

Figure 2 – Potential Construction and Laydown Areas

July 21, 2023

Archaeology and Historic Preservation Division
State Historical Society of North Dakota
612 East Boulevard Avenue
Bismarck, ND 58505-0830

Re: Consultation Under NHPA Section 106 for a Project in Oliver County, North Dakota

Dear Sir or Madam:

The U.S. Department of Energy (DOE) is preparing an Environmental Assessment (EA) for DOE's proposed action of providing cost-sharing financial assistance to Minnkota Power Cooperative, Inc. (Minnkota) for the proposed North Dakota CarbonSAFE: Project Tundra. The EA is being prepared to fulfill DOE's obligation under the National Environmental Policy Act (NEPA), as amended, the Council on Environmental Quality's NEPA regulations, and DOE's NEPA implementing procedures. The EA will evaluate the potential effects of construction and subsequent operation of the project.

This undertaking and its effects are also being considered under Section 106 of the National Historic Preservation Act (NHPA) of 1966, as amended, and implementing regulations at Title 36 of the Code of Federal Regulations (CFR) Part 800. As part of compliance with Section 106, DOE is writing to seek your comments on any issues or concerns for traditional cultural properties, sacred sites, or sites of traditional religious or cultural importance in the area that might be affected by the proposed Project. We would also like to know if you wish to receive a copy of the Draft EA. We respectfully ask that you provide any information or comments within 30 days to enable us to complete this phase of the Project within the scheduled timeframe.

The DOE's proposed action is to provide cost-shared financial assistance to Minnkota. DOE proposes to provide approximately $38.5 million of the Project's estimated $77 million total cost.

Minnkota's proposed project would include the design, construction, and operation of a carbon capture system at an existing lignite-fired coal power plant, the Milton R. Young (MRY) facility, in Oliver County, North Dakota. If built, Project Tundra would be the world's largest post-combustion carbon dioxide (CO_2) capture and geologic storage project, and would capture and permanently store CO_2 emissions from the existing MRY facility. The Project would be sized for capture and saline formation geologic storage of an average of 4.0 million metric tons per year (MMT/yr) of CO_2. The CO_2 would be compressed, piped via a new approximately 0.5-mile CO_2 pipeline to the storage complex, and injected into deep geologic reservoirs. Construction would begin in 2024 and would be complete by 2028.

The Project would be constructed as a stand-alone facility with a footprint that falls within an area of 25.8 acres, west and south of the MRY (see **Figure 1**). Currently the area comprises equipment and materials storage, access roadways, and barren lands. The proposed Project would be located within the larger MRY associated industrial area that is bound by Nelson Lake to the north and east, coal production and plant waste disposal areas to the south, and agricultural and natural areas to the west.

626 Cochrans Mill Road, P.O. Box 10940, Pittsburgh, PA 15236
Pierina.Fayish@netl.doe.gov • Voice (412) 386-5428 • Fax (412) 386-4775 • www.netl.doe.gov

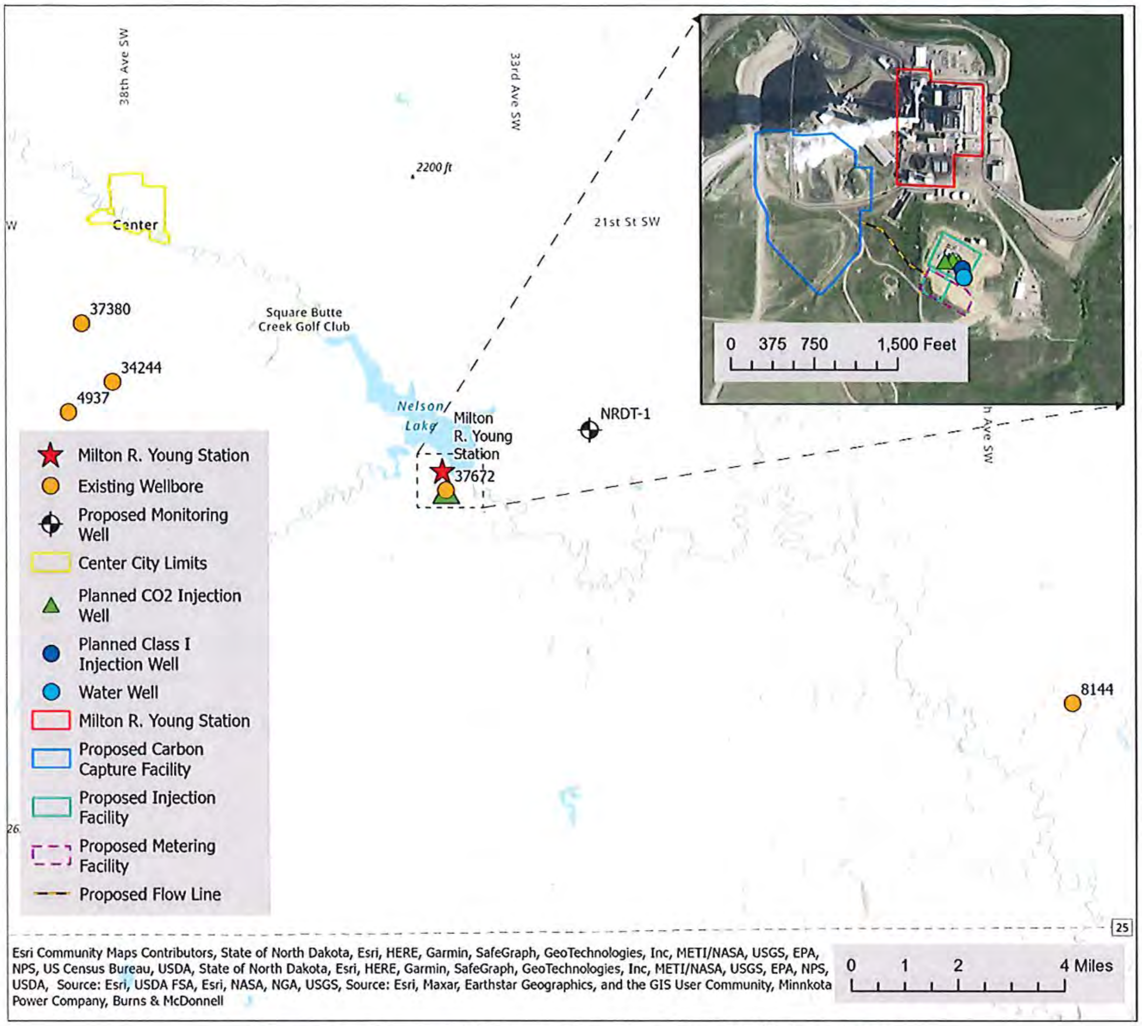

Figure 1 – Proposed Project Location – MRY Vicinity Map

The proposed Project site would be located in an area historically used for coal pile storage that has since been reclaimed. The area is undeveloped and provides minimal, low-quality wildlife habitat due to the disturbed and industrial nature of the area. The areas surrounding the Project site are generally low-quality wildlife habitat, including the adjacent landfill, coal mines, and industrial facilities. Nelson Lake abuts the existing MRY facility, but not the proposed Project area (see **Figures 2 and 3**).

Figure 2 – Proposed Project Site – Ground-level View of Carbon Capture Facility Location

The CO_2 flowline will transport the CO_2 from the facility to the injection site. The injection site includes up to three Class VI injection wells referred to as McCall 1, Liberty 1, and Unity 1. The injection site also includes a proposed Class I underground injection well (UIC) and an underground source of drinking water (USDW) monitoring well (see **Figure 3**).

Figure 3 – Proposed Project Site – Ground-level View of Proposed Injection Well Location

The Project would extract steam from the Unit 1 and Unit 2 steam turbines, a necessary component for use in the absorption process. The project would be designed to capture up to 13,000 short tons per day of CO_2. During operations, flue gas required to achieve this CO_2 capture rate would require all the flue gas from one unit and a portion of flue gas from the other unit for maximum operation. Various operating scenarios are available and planned to utilize various combinations of flue gas from both units (see **Figure 4**).

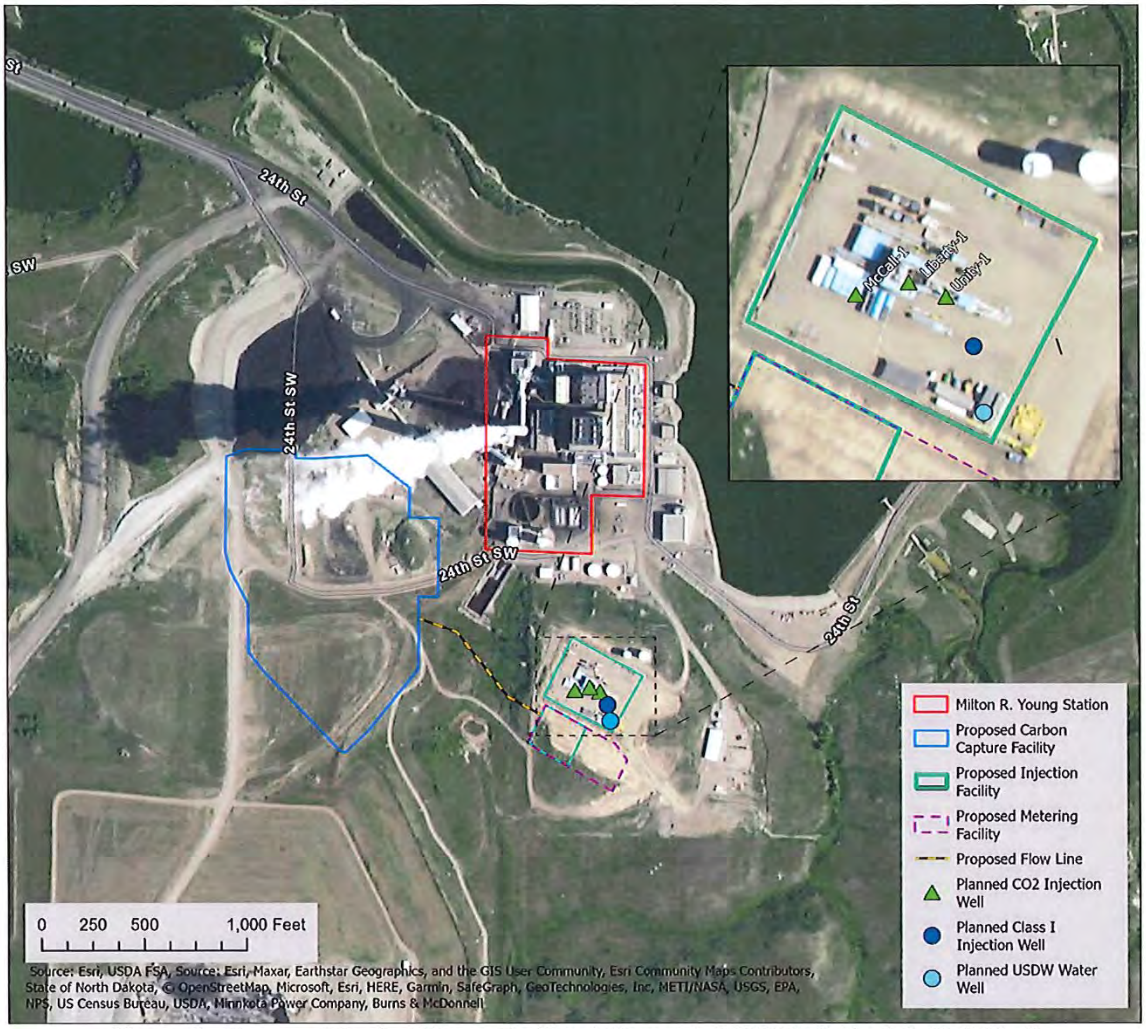

Figure 4 – Proposed Project Plan – Facility Adjacent to MRY Unit No. 1 & Unit No. 2

The Project would use Mitsubishi Heavy Industries' (MHI) Kansas Mitsubishi Carbon Dioxide Recovery (KM CDR) amine-based post-combustion carbon capture technology, which uses an amine-based solvent to capture CO_2. The steam produced from MRY's coal-fired boilers (Unit 1 and Unit 2) would be used to regenerate the amine. The flue gas would be processed by and vented through the facility. The stripped CO_2 vapor would then be compressed, purified (dried), and transported by the CO_2 flowline to the injection site for permanent geologic storage. **Figure 5** diagrams the carbon capture plant process.

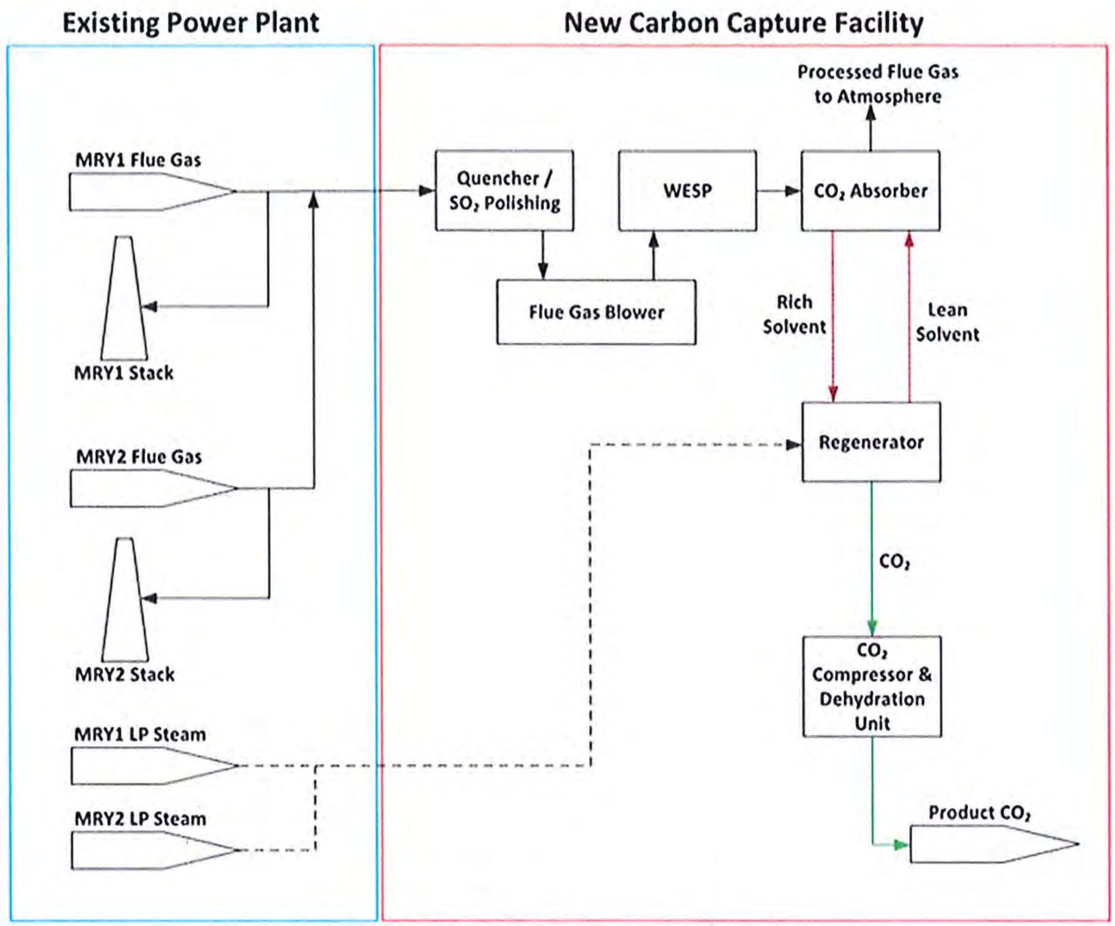

Figure 5 – Carbon Capture Plant Process

A small number of sites, primarily lithic scatters, have been recorded within the footprint of the MRY at Nelson Lake. No significant known cultural resources sites are present on the MRY in the area for the proposed project facilities. No National Register of Historic Places-listed historic resources are located in the proposed project site or surrounding region. Even if previously present, the development of this area over the years has likely compromised the integrity of any cultural and/or paleontological sites and they are probably no longer viable for information.

A Phase I survey was conducted in April 2022, which included the proposed Project location. This report was provided to the North Dakota State Historical Society, State Historic Preservation Office (SHPO) (SHPO Ref. 21-0571) and, on June 27, 2021, Minnkota received a letter of from SHPO providing concurrence with a determination of 'No Historical Properties Affected".

Facility construction would include preparation of laydown and fabrication areas. **Figure 6** depicts 10 locations on Minnkota-owned property being considered for use as temporary construction and laydown areas. These areas would serve various construction needs including parking, construction trailers, material storage and fabrication, and other activities to support the influx of workers and project construction activities.

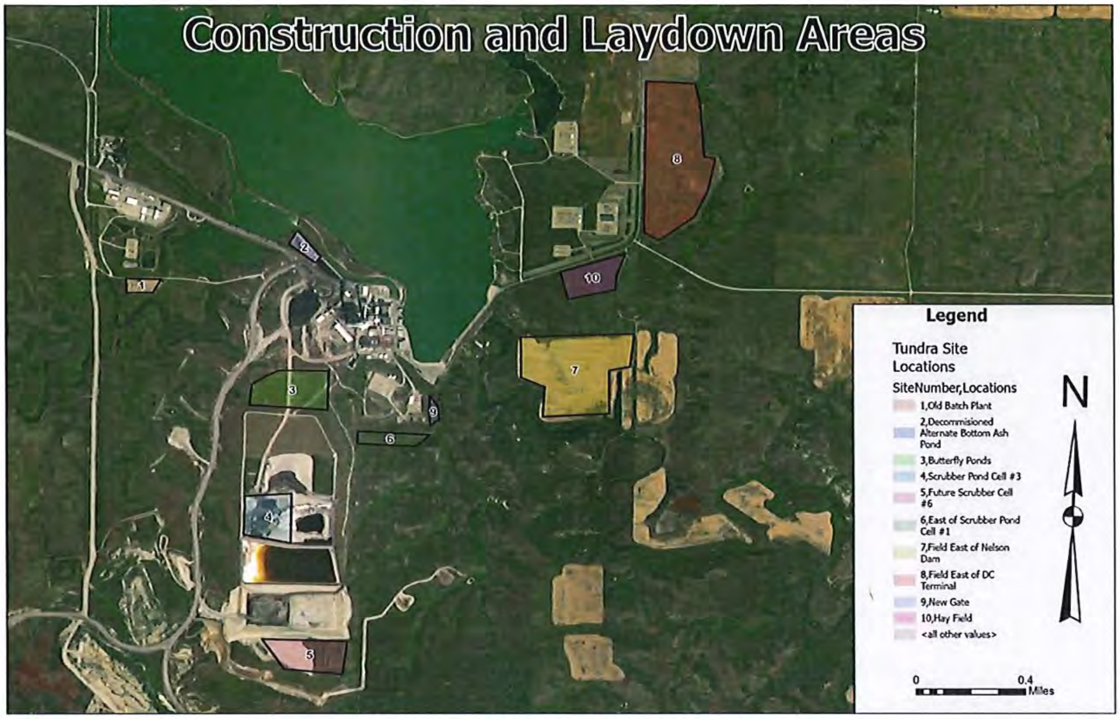

Figure 6 – Potential Construction and Laydown Areas

The temporary construction and laydown areas will be evaluated for architectural and cultural significance pursuant to Section 106 of the National Historic Preservation Act. Class I cultural resource surveys will be completed, and the cultural reports provided to SHPO for review and concurrence. Additional field surveys may also be required as a result of the Class I survey. All surveys will be completed in accordance with the North Dakota SHPO Guidelines Manual for Cultural Resource Inventory Projects. If cultural resources are identified in any of the proposed temporary construction and laydown areas, the sites will be avoided or mitigated in consultation with SHPO.

If you have any questions, please contact Ms. Pierina Fayish at:

National Energy Technology Laboratory M/S:922-W13
P.O. Box 10940
Pittsburgh, PA 15236-0940
Attention: Pierina Fayish
Pierina.Fayish@netl.doe.gov
(412) 386-5428

Thank you for your assistance in this matter.

Sincerely,

Pierina N. Fayish

July 21, 2023

Apache Tribe of Oklahoma
Durell Cooper, Chairman
P.O. Box 1330
Anadarko, OK 73005

Re: Consultation Under National Historic Preservation Act Section 106 for the North Dakota CarbonSAFE: Project Tundra in Oliver County, North Dakota

Dear Chairman Cooper:

The U.S. Department of Energy (DOE) is preparing an Environmental Assessment (EA) for DOE's proposed action of providing cost-sharing financial assistance to Minnkota Power Cooperative, Inc. (Minnkota) for the proposed North Dakota CarbonSAFE: Project Tundra. The EA is being prepared to fulfill DOE's obligation under the National Environmental Policy Act (NEPA), as amended, the Council on Environmental Quality's NEPA regulations, and DOE's NEPA implementing procedures. The EA will evaluate the potential effects of construction and subsequent operation of the facility.

This undertaking and its effects are also being considered under Section 106 of the National Historic Preservation Act (NHPA) of 1966, as amended, and the implementing regulations at Title 36 of the Code of Federal Regulations (CFR) Part 800. As part of compliance with Section 106, DOE is writing to seek your comments on any issues or concerns for traditional cultural properties, sacred sites, or sites of traditional religious or cultural importance in the area that might be affected by the proposed Project. We would also like to know if you wish to receive a copy of the Draft EA. We respectfully ask that you provide any information or comments within 30 days to enable us to complete this phase of the project within the scheduled timeframe.

The DOE's proposed action is to provide cost-shared financial assistance to Minnkota. DOE proposes to provide approximately $38.5 million of the Project's $77 million estimated total cost.

The Project would be constructed as a stand-alone facility with a footprint that falls within an area of 25.8 acres, west and south of the MRY (see **Figure 1**). Currently the area comprises equipment and materials storage, access roadways, and barren lands. The proposed Project would be located within the larger MRY associated industrial area that is bound by Nelson Lake to the north and east, coal production and plant waste disposal areas to the south, and agricultural and natural areas to the west.

The proposed Project site would be located in an area historically used for coal pile storage that has since been reclaimed. The area is undeveloped and provides minimal, low-quality wildlife habitat due to the disturbed and industrial nature of the area. The areas surrounding the Project site are generally low-quality wildlife habitat, including the adjacent landfill,

626 Cochran Mill Road, Pittsburgh, PA 15236
pierina.fayish@netl.doe.gov Phone (412) 386-5428 www.netl.doe.gov

coal mines, and industrial facilities. Nelson Lake abuts the existing MRY facility, but not the proposed Project area.

Facility construction would include preparation of laydown and fabrication areas to be used for parking, construction trailers, material storage and fabrication, and other activities to support the influx of workers and project construction activities. **Figure 2** depicts 10 locations on Minnkota-owned property being considered for use as temporary construction and laydown areas. Approximately 97.0 acres of land within these designated areas would be required during construction. Following construction, these areas would be restored to their original conditions, with the exception of an approximately 7.0-acre area previously used for plant operations that would be retained for overflow parking for MRY and project operations.

If you have any questions, please contact Ms. Pierina Fayish at:

National Energy Technology Laboratory M/S:922-W13
P.O. Box 10940
Pittsburgh, PA 15236-0940
Attention: Pierina Fayish
Pierina.Fayish@netl.doe.gov
(412) 386-5428

Thank you for your assistance in this matter.

Sincerely,

Pierina N. Fayish

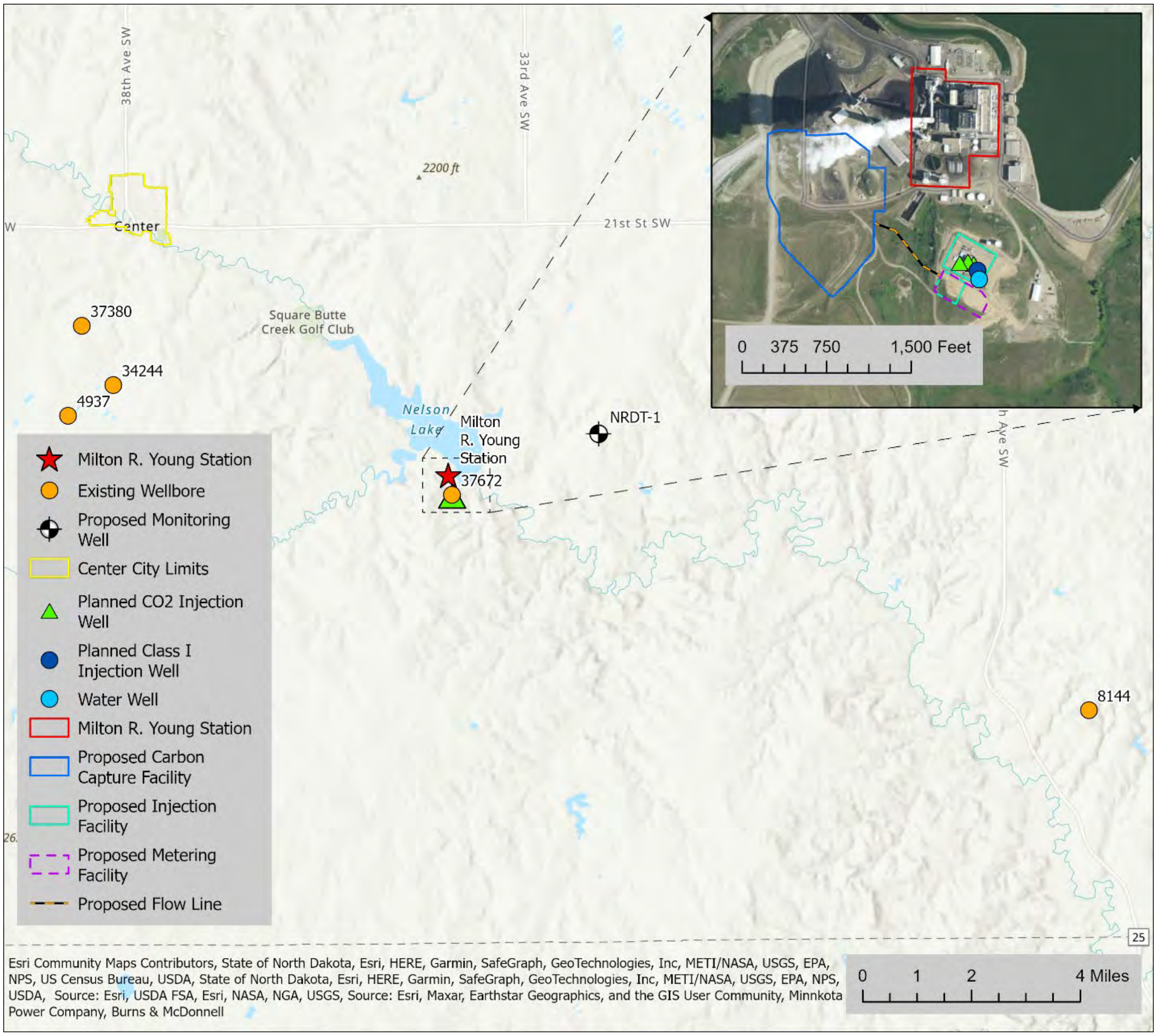

Figure 1 – Proposed Project Location – MRY Vicinity Map

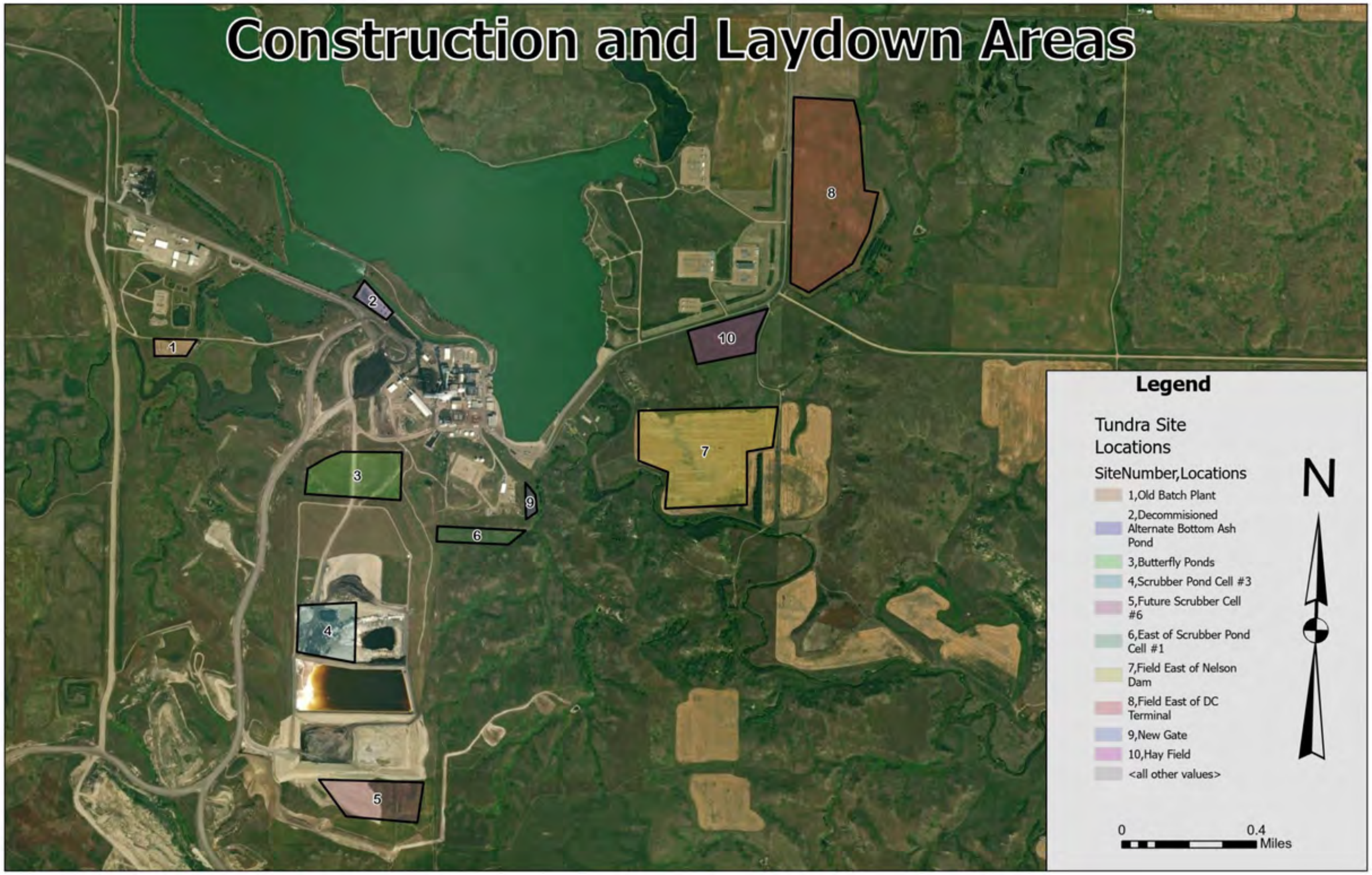

Figure 2 – Potential Construction and Laydown Areas

Distribution List for Tribal Consultation Letter

Tribes

Durell Cooper, Chairman
Apache Tribe of Oklahoma
P. O. Box 1330 Anadarko, OK 73005

Bobby Komardley, Chairman
Apache Tribe of Oklahoma
P. O. Box 1330 Anadarko, OK 73005

Jeffery Stiffarm, President
Fort Belknap Indian Community of the Fort Belknap Reservation of Montana
RR 1, Box 66
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Michael Blackwolf, THPO
Fort Belknap Indian Community of the Fort Belknap Reservation of Montana
RR 1, Box 66
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Allan Demaray, Director and THPO
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404 Frontage Road
New Town, ND 58763

Mark Fox, Chairperson
Three Affiliated Tribes of the Fort Berthold Reservation, North Dakota
404 Frontage Road
New Town, ND 58763

APPENDIX D – PROCESS HAZARD ANALYSIS

Minnkota Project Tundra

PHA / HAZOP Report

Report Issued February 12, 2020

By

Tom L. Hoglin, P.E.
Burns McDonnell Engineering / Hoglin Engineering

Minnkota Project Tundra

PHA / HAZOP Report

Table of Contents

1.0 Executive Summary

A Process Hazard Analysis (PHA) was conducted for the Minnekota Project Tundra. The meetings were held online by MS Teams February 11, 2021 with a team of representatives including engineering, design, management, and operations representing three (3) different operating companies. The project is still in a preliminary stage, operating procedures and some design details were not available at the time of study. Recommendations were made as appropriate.

The PHA study was performed as a structured session using a knowledge-based Hazard and Operability (HazOp) methodology. The team reviewed the project as three (3) nodes to evaluate the potential hazardous or undesirable consequences associated with the proposed equipment and piping. Each identified scenario was assigned a severity and likelihood ranking based on the possible safety, environmental, property damage and/or business interruption consequences identified by the team with the associated safeguards in place to prevent or mitigate the event.

The team developed thirty five (35) recommendations to further help mitigate risk inherent to the process. These recommendations are summarized in Section 6. The HazOp Worksheets that were developed during the review can be found in Appendix A.

2.0 Scope of Study

The following nodes of the site were reviewed during the HAZOP/LOPA study.

Nodes

Node	Type	Design Conditions/Parameters	Drawings / References	Equipment ID	Comment	Session
1. Main Meter Station	Piping	ANSI Class 900 Flanged Piping, 2160 psig @ 100 F MAWP Pig Trap: 1800 psig @ 200 F	MM0011 MM0012 MM0013	Orifice Meter, Flow Control Valve, Pig Launcher		1. 2/11/2021
2. Wellpad Meter Station #1	Piping	ANSI Class 900 Flanged Piping, 2160 psig @ 100 F MAWP Pig Trap: 1800 psig @ 200 F	MM0014 MM0015	Pig Receiver, Orifice Meter Skid		1. 2/11/2021
3. Wellpad Meter Station #2	Piping	ANSI Class 900 Flanged Piping, 2160 psig @ 100 F MAWP Pig Trap: 1800 psig @ 200 F	MM0014 MM0016	Pig Receiver, Orifice Meter Skid		1. 2/11/2021

3.0 Process Description / Design Intent

Dense phase CO2 comes from CCS through the Minnkota facilities and pipelines to the injection wells. The proposed design is detailed on the P&IDs and design drawings.

4.0 Methodology

The HAZOP study is performed using traditional HAZOP study methods.

Study methodology:

1. The facilitator will identify the nodes on the master drawing(s) before the first day of the HAZOP session

2. The design intent for that node/system is defined

3. Each node is reviewed using the process parameters (e.g. Pressure) and selected guidewords (e.g. More of) evaluates deviations (e.g. More Pressure)

4. The team then lists all credible causes and consequences

5. The team evaluates the event severity,and defines what undesirable Health & Safety; Environmental; and Operability consequences may occur. Severity is risk ranked per the 5x5 Risk Matrix in Appendix D.

6. The team then identifies existing safeguards (or independent protection layers) that reduce likelihood or severity, then the likelihood of the event with safeguards in place is risk ranked per the 5x5 Risk Matrix in Appendix D.

7. Recommendations are made if required to reduce the potential risk. If no recommendations are made, this means the PHA Team feels listed safeguards to be sufficient.

8. This process is repeated for different process parameters on the selected node. After exhausting all process parameters, the process is repeated for all other nodes

5.0 HAZOP Team, Roles, Attendance

Team Members

First Name	Last Name	Title	Company	Department	Expertise	Phone #	Extension	Fax #	E-Mail Address	Website Address	Comment
Tom	Hoglin	Facilitator / Engineer	Hoglin Engineering								
Denys	Stavnychi	Pipeline Section Manager	Burns & McDonnell								
Evan	Montz	Project Engineer	Burns & McDonnell								
Boualem	Boudid	Mechanical Lead	Burns & McDonnell								
Joe	Faber	E&I Lead	Burns & McDonnell								
Michael	Istre	Process/Piping Lead	Burns & McDonnell								
Stephanie	Villarreal		Burns & McDonnell								
Naresh	Murthy	Project Manager	Oxy								
Marion	Cole		Hies								
Dylan	Wolf		Minnkota								
Shannon	Mikula		Minnkota								
Kelly	Watson		Oxy								
Angie	Contreras		CCS								
			CCS								
			CCS								

6.0 HAZOP Recommendations

Recommendations

Recommendations	Place(s) Used	Responsibility	Maximum Risk		Rec Pri	Rec Cat	Status	% Complete	Estimated Dates		Actual Dates		Cost		Comments
			Before Action	After Action					Start Date	End Date	Start Date	End Date	Estimated	Actual	
1. Consider consequence number 2 (shutdown resulting in phase change, possible well issues) when developing operation procedures to prevent damage to well perforations.	Causes: 1.1.1														
2. Determine the maximum flow allowed for each wellpad, consider a high flow alarm at appropriate setpoint.	Causes: 1.2.1														
3. Determine what the maximum flow anticipated from the CCS facility is.	Causes: 1.2.1														
4. Assure the RTU building includes a high CO2 alarm with appropriate siren and/or beacon to alert personnel prior to building entry.	Causes: 1.2.2, 1.2.3		6												
5. Assure operating procedures are followed prior to building entry, assure portable CO2 monitors available.	Causes: 1.2.2, 1.2.3		6												
6. Consider adding an additional PCV for another pressure cut on the analyzer line.	Causes: 1.2.2		6												
7. Ensure coordination between operating companies to plan for a CCS unit shutdown which can reduce flow to 40%.	Causes: 1.1.6														
8. Review need for adding a check valve to the meter station with CCS and the well team.	Causes: 1.3.1														
9. Assure operating procedures call for plugs in all valves going to atmosphere, and to not open vents/drains with system in operation.	Causes: 1.4.1		4												
10. Assure operation procedures call for drains and vents closed when system down to prevent moisture entry and corrosion.	Causes: 1.4.2		5												
11. Ensure communication and control occurs between RTUs on CCS, pipeline,	Causes: 1.4.3														

Recommendations	Place(s) Used	Responsibility	Maximum Risk		Rec Pri	Rec Cat	Status	% Complete	Estimated Dates		Actual Dates		Cost		Comments
			Before Action	After Action					Start Date	End Date	Start Date	End Date	Estimated	Actual	
and well team facilities.															
12. Consider using pig trap closures with a physical locking mechanism that prevents opening the closure while under pressure.	Causes: 1.4.4		5												
13. Consider alternate measures of corrosion monitoring (instead of ILI pigs) on pipeline #2 due to the short distance of pipeline	Causes: 1.4.4		5												
14. Assure proper overpressure protection is in place for the system between CCS, pipeline, and wellpads, Assure overpressure protection is set at proper setpoints.	Causes: 1.5.1, 1.5.2		6												
15. Consider adding PAH and PAHH alarms on the station PITs, signal to RTU control.	Causes: 1.5.2		6												
16. Consider adding a PSLL pressure switch to close valve upstream of meter station.	Causes: 1.6.1, 2.6.1														
17. Consider several cases of pressure/temperature on the facility for piping stress analysis, consider potential high temperature from CCS due to cooler failure.	Causes: 1.7.1		6												
18. Consider adding a temperature transmitter with an alarm / shutdown at facility inlet to close on high and low temperatures.	Causes: 1.7.1, 1.8.1		6												
19. Assure proper protection for pipe stress due to high temperature is in place for all parties - CCS, pipeline, and wellpad.	Causes: 1.7.1		6												
20. Determine low temperature safe operating limit, and add a low temperature alarm and/or shutdown at CCS TI-0612, 0613.	Causes: 1.8.1														
21. Revisit the acceptable limits of potential contaminates from CCS for the Pipeline and Wells, assure proper analyzers in place with proper alarm and/or shutdown setpoints.	Causes: 1.11.1														

Recommendations	Place(s) Used	Responsibility	Maximum Risk		Rec Pri	Rec Cat	Status	% Complete	Estimated Dates		Actual Dates		Cost		Comments
			Before Action	After Action					Start Date	End Date	Start Date	End Date	Estimated	Actual	
22. Consider adding ballards and/or flags around aboveground piping to prevent 3rd party impact.	Causes: 1.13.1, 1.14.1, 2.13.1		7												
23. Assure inspection protocols and integrity management plan is in place to meet DOT pipeline requirements.	Causes: 1.13.1, 2.13.1		6												
24. Safeguards for snow removal need to be considered during final design, assure proper training for snow removal personnel.	Causes: 1.14.1		7												
25. Address any potential communication and cyber security breaches between CCS, Pipeline, Wells.	Causes: 1.14.2, 2.14.1		7												
26. Consider adding provisions for a temporary generator.	Causes: 1.16.1														
27. Review the potential for brine coming from the well formation back to the surface equipment causing excessive corrosion and loss of containment, assure proper safeguards are in place.	Causes: 2.3.1		5												
28. Determine what temperature is allowed for the wells and formation, assure proper safeguards are in place to protect wells.	Causes: 1.7.1		6												
29. Assure property owner is informed about the pipeline, potential exposure issues, and trained on how to respond in the event of a release.	Causes: 2.13.1		6												
30. Consider using fiber optic cable along the pipeline for leak detection.	Causes: 2.13.1		6												
31. Consider alternate routes for the pipeline ROW to add additional distance between the pipeline and 3rd party receptors.	Causes: 2.13.1		6												
32. Assure communications are in place with the mining operation and the pipeline group to prevent potential line strikes.	Causes: 2.13.2		6												

Recommendations	Place(s) Used	Responsibility	Maximum Risk		Rec Pri	Rec Cat	Status	% Complete	Estimated Dates		Actual Dates		Cost		Comments
			Before Action	After Action					Start Date	End Date	Start Date	End Date	Estimated	Actual	
33. Confirm MSHA requirements for road crossing during design phase. Review potential mining blasting operations impact on the pipeline.	Causes: 2.13.2		6												
34. Consider more physical security mitigations to prevent entry and/or tampering on remote site location (Wellpad #1).	Causes: 2.14.1		7												
35. Assure the proper failure modes are defined for all the automated valves on the system and identified on P&IDs.	Causes: 1.1.3														

7.0 Appendices

A. **HAZOP Worksheets**
B. **Node List and Definitions**
C. **P&IDs**
D. **Risk Ranking**

Appendix A: HAZOP Worksheets

PHA Worksheet

Node	Deviation	Cause	Consequence	Before Risk Reduction			Effective Safeguards	Recommendations	Responsibility	Status	After Risk Reduction		
				S	L	RR					S	L	RR
1. Main Meter Station	1. Less/No Flow	1. Shutdown of CCS facility.	1. Loss of flow to meter station and wellpads. Operability issues only. Potential for well shutdown, Operational issues in bringing wells back on.				1. MOV-1001 will close when loss of flow from CCS.	1. Consider consequence number 2 (shutdown resulting in phase change, possible well issues) when developing operation procedures to prevent damage to well perforations.					
			2. If extended shutdown, potential for dense phase CO2 to go more to liquid phase. Possible sand plugging of well tubing perforations downhole. Possible operational difficulties in restarting.				2. MOV-1004, 5 Shutdown valves upstream of wellpads will close on loss of flow.						
							3. Each well will have an automated shutdown valve.						
		2. MOV-1002, 3 malfunctions closed	1. Same scenario as above										
		3. FCV-1001,2 malfunctions closed	1. Same scenario as above					35. Assure the proper failure modes are defined for all the automated valves on the system and identified on P&IDs.					
		4. Any number of manual block valves closed.	1. Same scenario as above										
		5. Well workover or testing as part of permit requirements.	1. Shutdown of system. Same scenario as above										
		6. Intentional reduction of flow, one unit down for cleaning at CCS, when this occurs flow is reduced to 40% of total flow.	1. Operability issues, no hazards.					7. Ensure coordination between operating companies to plan for a CCS unit shutdown which can reduce flow to 40%.					
	2. More Flow	1. CCS system is not able to exceed the pipeline system design capacity.						2. Determine the maximum flow allowed for each wellpad, consider a high flow alarm at appropriate setpoint.					
								3. Determine what the maximum flow anticipated from the CCS facility is.					
		2. PCV-1001 malfunctions open.	1. Potential to overpressure the analyzer. Damage to analyzer, small release rate of CO2. Release is inside of the analyzer building. Possible low O2	A	2	6	1. PSV-1001, set at 80 psig, relieves to a safe location.	4. Assure the RTU building includes a high CO2 alarm with appropriate siren and/or beacon to alert personnel prior to building entry.					
								5. Assure operating procedures are followed prior to building entry, assure portable CO2					

Node	Deviation	Cause	Consequence	Before Risk Reduction			Effective Safeguards	Recommendations	Responsibility	Status	After Risk Reduction		
				S	L	RR					S	L	RR
			atmosphere and asphyxiation upon building entry.					monitors available.					
								6. Consider adding an additional PCV for another pressure cut on the analyzer line.					
		3. NC 1" vents inadvertently open inside RTU building, or small leaks in building.	1. Un contained release of CO2 from vent. Release is inside of the analyzer building. Possible low O2 atmosphere and asphyxiation upon building entry.	A	2	6	1. Valve is intended to be closed and plugged.	4. Assure the RTU building includes a high CO2 alarm with appropriate siren and/or beacon to alert personnel prior to building entry.					
								5. Assure operating procedures are followed prior to building entry, assure portable CO2 monitors available.					
	3. Reverse Flow	1. With system shutdown, potential reverse flow back to CCS	1. Potential for measurement errors from reverse flow. Minor operability issues.				1. Each compressor has a check valve on the discharge at CCS.	8. Review need for adding a check valve to the meter station with CCS and the well team.					
	4. Misdirected Flow	1. Drains and vents open to atmosphere, release of CO2	1. Un contained release of CO2 from vents and drains.	B	1	4	1. Plugs on all valves to atmosphere.	9. Assure operating procedures call for plugs in all valves going to atmosphere, and to not open vents/drains with system in operation.					
		2. Drains and vents open to atmosphere, entrance of air and moisture/water, etc. into piping.	1. Increased internal corrosion due to water presence.	A	1	5	1. Plugs on all valves to atmosphere. 2. CP may reduce corrosion rate for small amounts of moisture.	10. Assure operation procedures call for drains and vents closed when system down to prevent moisture entry and corrosion.					
		3. 16" manual bypass around FCV-1001 left open.	1. Loss of flow control, possible more flow to one of the well pads. Potential exceed permitted allowable's, formation damage not expected. Operability issues.				1. Flow control devices exist at the well pads. 2. Redundant metering at well pads.	11. Ensure communication and control occurs between RTUs on CCS, pipeline, and well team facilities.					
		4. Opening a pig trap door while under pressure.	1. Potential for injury while opening pig trap.	A	1	5	1. PI-1005 on barrel	12. Consider using pig trap closures with a physical locking mechanism that prevents opening the closure while under pressure.					
							2. Pressure safety indicator on the trap doors 3. Operating procedures. 4. Appropriate drains/vents on pig traps.	13. Consider alternate measures of corrosion monitoring (instead of ILI pigs) on pipeline #2 due to the short distance of pipeline					

Node	Deviation	Cause	Consequence	Before Risk Reduction			Effective Safeguards	Recommendations	Responsibility	Status	After Risk Reduction		
				S	L	RR					S	L	RR
	5. Higher Pressure	1. CCS compressor discharge overpressure protection failure (PSV, PSHH shutdowns, etc)	1. Possible overpressure of meter station piping and equipment, release and possible injury.	A	2	6	1. PS-1001 on inlet of facility closes MOV-1001 (ANSI 900) 2. PIT monitoring pressure in multiple areas, operator response.	14. Assure proper overpressure protection is in place for the system between CCS, pipeline, and wellpads, Assure overpressure protection is set at proper setpoints.					
		2. Pipeline outlet blockage or closure, continue to feed the pipeline from CCS.	1. Possible overpressure of meter station piping and equipment, release and possible injury.	A	2	6	1. PS-1001 on inlet of facility closes MOV-1001 (ANSI 900)	14. Assure proper overpressure protection is in place for the system between CCS, pipeline, and wellpads, Assure overpressure protection is set at proper setpoints.					
							2. PIT monitoring pressure in multiple areas, operator response.	15. Consider adding PAH and PAHH alarms on the station PITs, signal to RTU control.					
		3. Blocked in thermal expansion on pig trap.	1. Possible slight overpressure of barrel.				1. PSV-1002.						
	6. Lower Pressure	1. Upstream facility upset at CCS.	1. Potential for phase change of the CO2, possible injection issues and operability issues.				1. PIT monitoring pressure in multiple areas, operator response.	16. Consider adding a PSLL pressure switch to close valve upstream of meter station.					
	7. Higher Temperature	1. Cooler failure on downstream of compressors.	1. Potential for compressor discharge temperature CO2 (unknown temperature) coming to the pipeline facilities. Possible piping stress and release.	A	2	6	1. CCS has TSHH-0612, 0613 shutdown, set at 120 F.	17. Consider several cases of pressure/temperature on the facility for piping stress analysis, consider potential high temperature from CCS due to cooler failure.					
			2. Possible for coating damage to the pipeline (180 F limit), possible for increased corrosion and reduced design life.					18. Consider adding a temperature transmitter with an alarm / shutdown at facility inlet to close on high and low temperatures.					
			3. Potential high temp to the wells and formation.					19. Assure proper protection for pipe stress due to high temperature is in place for all parties - CCS, pipeline, and wellpad.					
								28. Determine what temperature is allowed for the wells and formation, assure proper safeguards are in place to protect wells.					

Node	Deviation	Cause	Consequence	Before Risk Reduction			Effective Safeguards	Recommendations	Responsibility	Status	After Risk Reduction		
				S	L	RR					S	L	RR
	8. Lower Temperature	1. Excessive cooling at CCS, cooling control valve malfunction open.	1. Potential for phase change of the CO2, possible injection issues and operability issues.				1. CCS has TSHH-0612, 0613 shutdown, set at 120 F.	18. Consider adding a temperature transmitter with an alarm / shutdown at facility inlet to close on high and low temperatures.					
								20. Determine low temperature safe operating limit, and add a low temperature alarm and/or shutdown at CCS TI-0612, 0613.					
		2. System shutdown for extended period of time due to ambient cooling.	1. Potential for phase change of the CO2, possible injection issues and operability issues.										
	9. Higher Level	1. Not applicable.											
	10. Lower Level	1. Not applicable.											
	11. Contamination	1. Failure of dehydration system and/or failure of other scrubbing systems resulting in contaminants to the inlet of the meter station.	1. Potential for corrosion and not meeting injection well specifications. Possible injection issues and reduced life of piping.				1. Moisture analyzers at CCS.	21. Revisit the acceptable limits of potential contaminates from CCS for the Pipeline and Wells, assure proper analyzers in place with proper alarm and/or shutdown setpoints.					
							2. Moisture analyzers at main meter station						
	12. Wrong Concentration	1. See contamination above.											
	13. Leak/Rupture	1. Corrosion, third party damage, overpressure, pipe stress, valves left open, etc.	1. Possible release and personnel exposure.	A			1. Metering between and wellpad mass balance will detect significant loss	22. Consider adding ballards and/or flags around aboveground piping to prevent 3rd party impact.					
							2. Corrosion coupon monitoring	23. Assure inspection protocols and integrity management plan is in place to meet DOT pipeline requirements.					
							3. Routing inline inspection						
							4. Steady quality of CO2						
							5. Cathodic protection						
							6. Pipeline markers						
							7. Line is buried additional 12" beyond requirements.						
	14. Human Factors	1. Snow accumulation on the site. Snow removal equipment on the site can result in damage to piping systems	1. Possible release and personnel exposure.	A	3	7	1. Site can be controlled and/or shut down remotely.	22. Consider adding ballards and/or flags around aboveground piping to prevent 3rd party impact.					
							2. Station is	24. Safeguards for snow removal					

Node	Deviation	Cause	Consequence	Before Risk Reduction			Effective Safeguards	Recommendations	Responsibility	Status	After Risk Reduction		
				S	L	RR					S	L	RR
							designed to be unmanned, routine access is not required.	need to be considered during final design, assure proper training for snow removal personnel.					
		2. Communications to outside entities, potential for hacking / sabotage.	1. Possible release and personnel exposure.	A	2	6		25. Address any potential communication and cyber security breachs between CCS, Pipeline, Wells.					
	15. Startup/Shutdown	1. No new concerns.											
	16. Loss of Utilities	1. Loss of power	1. Loss of communication and loss of flow control to the wells, possible permit violation.				1. For CCS: system has UPS and equipment goes to fail safe condition. 2. For Pipeline: each site has UPS and equipment goes to fail safe condition.	26. Consider adding provisions for a temporary generator.					
	17. Miscellaneous	1. No new concerns.											
2. Wellpad Meter Station #1	1. Less/No Flow	1. Same as node 1.											
	2. More Flow	1. Same as node 1.											
	3. Reverse Flow	1. System shutdown, potential reverse flow back to meter stations	1. Potential for measurement errors from reverse flow. Minor operability issues.				1. Each compressor has a check valve on the discharge at CCS.	27. Review the potential for brine coming from the well formation back to the surface equipment causing excessive corrosion and loss of containment, assure proper safeguards are in place.					
			2. Possible reverse flow from wells, possible brine from injection wells into surface equipment, possible increased corrosion.	A	1	5	2. Each wellpad has check valves						
	4. Misdirected Flow	1. Same as node 1.											
		2. One wellpad shutdown, same flow coming from CCS.	1. CCS plant would divert CO2 flow to the vent, compressors do have recycle ability for short term. Operability issues.				1. CCS can divert flow to the CO2 Vent 2. 2nd compressor can be shutdown 3. Compressor recycle systems						
	5. Higher Pressure	1. Same as node 1.											

Node	Deviation	Cause	Consequence	Before Risk Reduction			Effective Safeguards	Recommendations	Responsibility	Status	After Risk Reduction		
				S	L	RR					S	L	RR
	6. Lower Pressure	1. Upstream facility upset at CCS, or main meter station.	1. Potential for phase change of the CO2, possible injection issues and operability issues.				1. PIT monitoring pressure in multiple areas, operator response.	16. Consider adding a PSLL pressure switch to close valve upstream of meter station.					
							2. PSLL-1004 will close MOV-1004 stopping flow to well.						
		2. PSLL-1004 fails to close on a low pressure situation.	1. Potential for phase change of the CO2, possible injection issues and operability issues.				1. Wells have shutdown valves for high and low pressure.						
	7. Higher Temperature	1. Same as node 1.											
	8. Lower Temperature	1. Same as node 1.											
	9. Higher Level	1. Not applicable.											
	10. Lower Level	1. Not applicable.											
	11. Contamination	1. Same as node 1.											
	12. Wrong Concentration	1. Same as node 1.											
	13. Leak/Rupture	1. Corrosion, third party damage, overpressure, pipe stress, valves left open, etc.	1. Possible release and personnel exposure. Land owner property for a residence located near the pipeline ROW may experience high levels of CO2, possible fatalities. Note: Dispersion analysis has been completed indicating that high levels may reach 3rd party property line, but not to the 3rd party occupied residence.	A	2	6	1. Metering between and wellpad mass balance will detect significant loss.	22. Consider adding ballards and/or flags around aboveground piping to prevent 3rd party impact.					
							2. Corrosion coupon monitoring	23. Assure inspection protocols and integrity management plan is in place to meet DOT pipeline requirements.					
							3. Routing inline inspection	29. Assure property owner is informed about the pipeline, potential exposure issues, and trained on how to respond in the event of a release.					
							4. Steady quality of CO2	30. Consider using fiber optic cable along the pipeline for leak detection.					
							5. Cathodic protection	31. Consider alternate routes for the pipeline ROW to add additional distance between the pipeline and 3rd party receptors.					
							6. Pipeline markers						
							7. Line is buried additional 12" beyond requirements.						

Node	Deviation	Cause	Consequence	Before Risk Reduction			Effective Safeguards	Recommendations	Responsibility	Status	After Risk Reduction		
				S	L	RR					S	L	RR
		2. Third party damage in active mine property (line strike, use of explosives in mining activities, etc.)	1. Possible release and personnel exposure. Pipeline goes through an active mine potential increased chance for a line strike. Line goes under an MSHA road.	A	2	6	1. Same as above.	32. Assure communications are in place with the mining operation and the pipeline group to prevent potential line strikes. 33. Confirm MSHA requirements for road crossing during design phase. Review potential mining blasting operations impact on the pipeline.					
	14. Human Factors	1. Potential for hacking / sabotage on remote site.	1. Possible release and personnel exposure.	A	3	7		25. Address any potential communication and cyber security breaches between CCS, Pipeline, Wells. 34. Consider more physical security mitigations to prevent entry and/or tampering on remote site location (Wellpad #1).					
	15. Startup/Shutdown	1. Same as node 1.											
	16. Loss of Utilities	1. Same as node 1.											
	17. Miscellaneous	1. No new concerns.											
3. Wellpad Meter Station #2	1. Less/No Flow	1. Team discussed that node 3 is identical as node 2, without the public receptors specifically identified in node 2. Deviations cause/consequence/ safeguards are the same.											
	2. More Flow												
	3. Reverse Flow												
	4. Misdirected Flow												
	5. Higher Pressure												
	6. Lower Pressure												
	7. Higher Temperature												
	8. Lower Temperature												
	9. Higher Level												
	10. Lower Level												
	11. Contamination												
	12. Wrong Concentration												

Node	Deviation	Cause	Consequence	Before Risk Reduction			Effective Safeguards	Recommendations	Responsibility	Status	After Risk Reduction		
				S	L	RR					S	L	RR
	13. Leak/Rupture												
	14. Human Factors												
	15. Startup/Shutdown												
	16. Loss of Utilities												
	17. Miscellaneous												

Appendix B: Node List and Definitions

Nodes

Node	Type	Design Conditions/Parameters	Drawings / References	Equipment ID	Comment	Session	Revision #	Revision Date
1. Main Meter Station	Piping	ANSI Class 900 Flanged Piping, 2160 psig @ 100 F MAWP Pig Trap: 1800 psig @ 200 F	MM0011 MM0012 MM0013	Orifice Meter, Flow Control Valve, Pig Launcher		1. 2/11/2021		
2. Wellpad Meter Station #1	Piping	ANSI Class 900 Flanged Piping, 2160 psig @ 100 F MAWP Pig Trap: 1800 psig @ 200 F	MM0014 MM0015	Pig Receiver, Orifice Meter Skid		1. 2/11/2021		
3. Wellpad Meter Station #2	Piping	ANSI Class 900 Flanged Piping, 2160 psig @ 100 F MAWP Pig Trap: 1800 psig @ 200 F	MM0014 MM0016	Pig Receiver, Orifice Meter Skid		1. 2/11/2021		

Appendix C: P&IDs

NOTES:
1. LOCATION OF THE TIE–IN POINT WILL BE AT THE FENCE LIMIT. CO2 PLANT FACILITY CONTRACTOR TO BRING THE PIPING ABOVE GROUND TO THE FENCE LINE. THE PIPING WILL BE KEPT ABOVE GROUND TO THE METER STATION BUILDING.

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
A	01/12/21	MCH	BB	ISSUED FOR REVIEW

no.	date	by	ckd	description
				MM0010 P&ID SYMBOLS AND LEGEND
				MM0001 METER FLOW STATION PROCESS DIAGRAM
				MM0012 FLOW CONTROL VALVE SKIDS
				MM0017 RTUS & ANALYZER

BURNS McDONNELL
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816-333-9400
Burns & McDonnell Engineering Co, Inc.

designed: M. HOOVER
detailed: N. REISER

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MINNKOTA POWER COOPERATIVE
PIPING & INSTRUMENTATION DIAGRAM
ORIFICE METER SKID MS-1001
MAIN METER STATION

project: 128002
contract:
drawing: MM0011 –
rev.: A
sheet 1 of 1 sheets
file 128002MM0011.dwg

PRELIMINARY - NOT FOR CONSTRUCTION

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no.	date	by	ckd	description
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				MM0001 METER FLOW STATION PROCESS DIAGRAM
				MM0011 ORIFICE METER SKID MS-001
				MM0013 PIG LAUNCHER SKIDS

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FLOW CONTROL VALVE SKIDS
MAIN METER STATION

project 128002 | contract

drawing MM0012 – rev. A

sheet 1 of 1 sheets

file 128002MM0012.dwg

PRELIMINARY - NOT FOR CONSTRUCTION

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									MM0001 METER FLOW STATION PROCESS DIAGRAM, SHEET 1
									MM0012 FLOW CONTROL VALVE SKIDS
									MM0014 PIG RECEIVER SKIDS
A	01/12/21	MCH	BB	ISSUED FOR REVIEW					

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PIPING & INSTRUMENTATION DIAGRAM
PIG LAUNCHER SKIDS
MAIN METER STATION

project 128002 | contract

drawing MM0013 — rev. A

sheet 1 of 1 sheets

file 128002MM0013.dwg

no.	date	by	ckd	description
A	01/12/21	MCH	BB	ISSUED FOR REVIEW

no.	date	by	ckd	description
				MM0010 P&ID SYMBOLS AND LEGEND
				MM0002 METER FLOW STATION PROCESS DIAGRAM, SHEET 2
				MM0013 PIG LAUNCHER SKIDS
				MM0015 ORIFICE METER SKID MS-1002
				MM0016 ORIFICE METER SKID MS-1003

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detailed: N. REISER

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MINNKOTA POWER COOPERATIVE
PIPING & INSTRUMENTATION DIAGRAM
PIG RECEIVER SKIDS
WELL PAD #1 & WELL PAD #2

project: 128002
contract:
drawing: MM0014 –
rev. A
sheet 1 of 1 sheets
file 128002MM0014.dwg

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
A	01/12/21	MCH	BB	ISSUED FOR REVIEW

MM0010 P&ID SYMBOLS AND LEGEND
MM0002 METER FLOW STATION PROCESS DIAGRAM, SHEET 2
MM0014 PIG RECEIVER SKIDS

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MINNKOTA POWER COOPERATIVE
PIPING & INSTRUMENTATION DIAGRAM
ORIFICE METER SKID MS-1002
WELL PAD #1 & WELL PAD #2

project: 128002
contract:
drawing: MM0015 – rev. A
sheet 1 of 1 sheets
file 128002MM0015.dwg

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
A	01/12/21	MCH	BB	ISSUED FOR REVIEW

no.	date	by	ckd	description
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				MM0002 METER FLOW STATION PROCESS DIAGRAM, SHEET 2
				MM0014 PIG RECEIVER SKIDS

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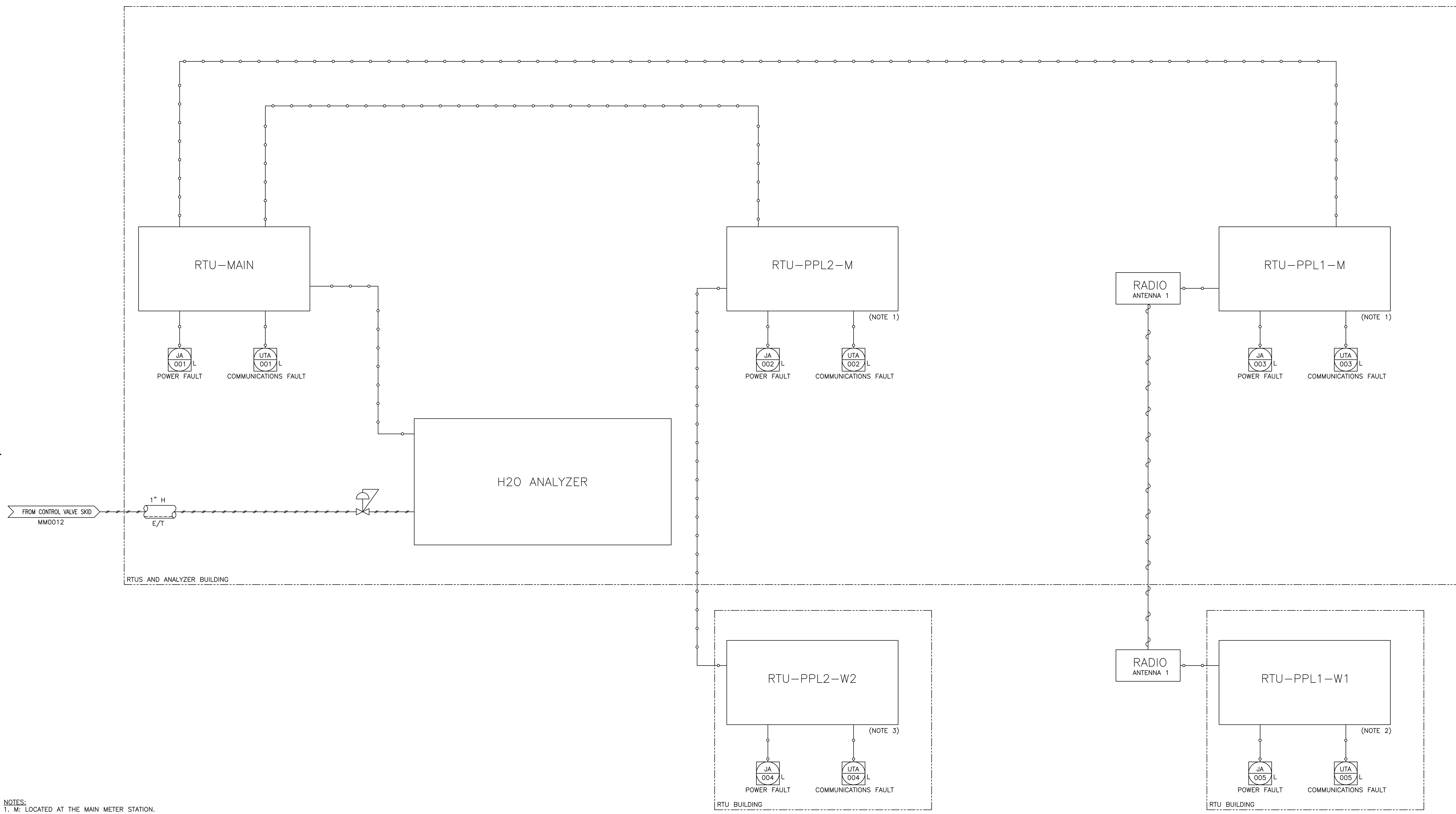
MINNKOTA POWER COOPERATIVE
PIPING & INSTRUMENTATION DIAGRAM
ORIFICE METER SKID MS-1003
WELL PAD #1 & WELL PAD #2

project: 128002
contract:
drawing: MM0016 –
rev. A
sheet 1 of 1 sheets
file 128002MM0016.dwg



NOTES:
1. M: LOCATED AT THE MAIN METER STATION.
2. W1: LOCATED AT WELL PAD #1.
3. W2: LOCATED AT WELL PAD #2.

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
A	01/12/21	MCH	BB	ISSUED FOR REVIEW

no.	date	by	ckd	description
				MM0010 P&ID SYMBOLS AND LEGEND
				MM0001 METER FLOW STATION PROCESS DIAGRAM, SHEET 1
				MM0002 METER FLOW STATION PROCESS DIAGRAM, SHEET 2
				MM0012 FLOW CONTROL VALVE SKIDS

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MINNKOTA POWER COOPERATIVE
PIPING & INSTRUMENTATION DIAGRAM
RTUS & ANALYZER
WELL PAD #1 & WELL PAD #2

project: 128002
contract:
drawing: MM0017 –
rev.: A
sheet 1 of 1 sheets
file 128002MM0017.dwg

no.	date	by	ckd	description
B	1/12/21	SAR	BB	ISSUED FOR REVIEW
A	12/09/20	SAR	BB	ISSUED FOR BID

no.	date	by	ckd	description

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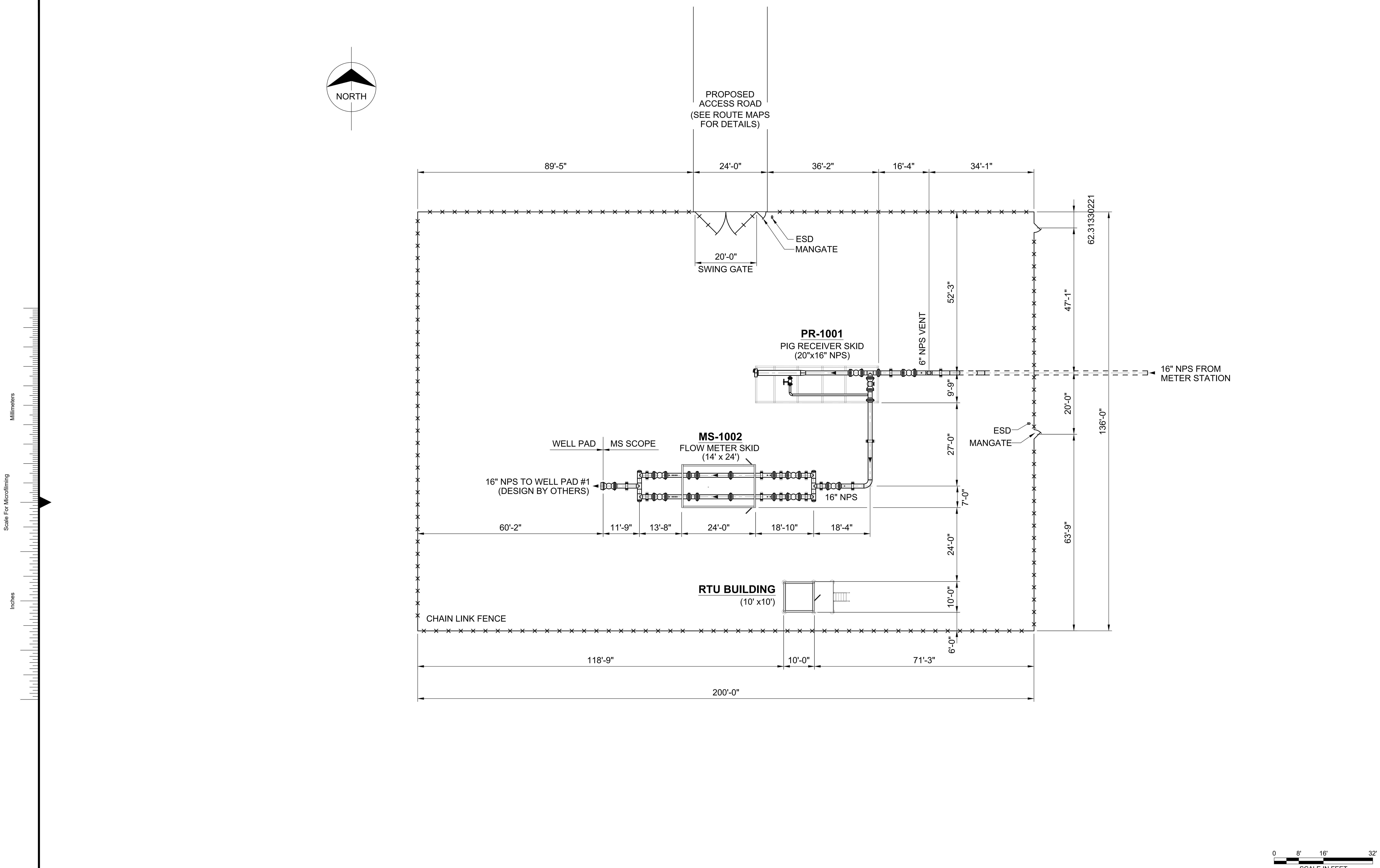
MINNKOTA POWER COOPERATIVE
PROJECT TUNDRA CO2 PIPELINE
MAIN METER STATION
GENERAL ARRANGEMENT

project: 128002
contract:
drawing: MS001 – rev. B
sheet 1 of 3 sheets
file 128002MS001



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B	1/12/21	SAR	BB	ISSUED FOR REVIEW
A	12/09/20	SAR	BB	ISSUED FOR BID

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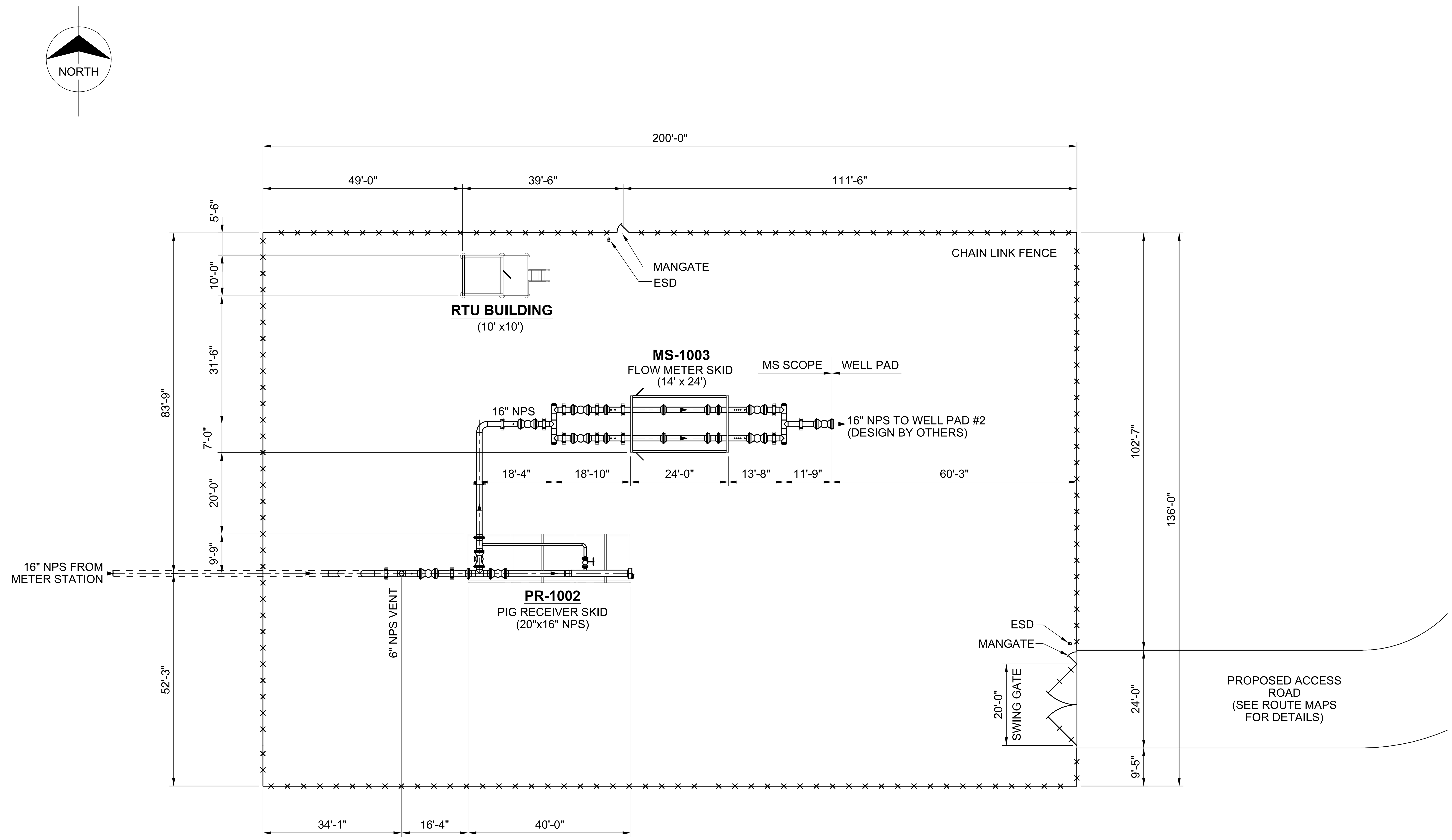
MINNKOTA POWER COOPERATIVE
PROJECT TUNDRA CO2 PIPELINE
WELL PAD 1
GENERAL ARRANGEMENT

project: 128002
contract:
drawing: MS002 – rev. B
sheet 2 of 3 sheets
file 128002MS002



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SCALE IN FEET

no.	date	by	ckd	description
B	01/12/21	SAR	BB	ISSUED FOR REVIEW
A	12/09/20	SAR	BB	ISSUED FOR BID

no.	date	by	ckd	description

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detailed: S. RUSSELL

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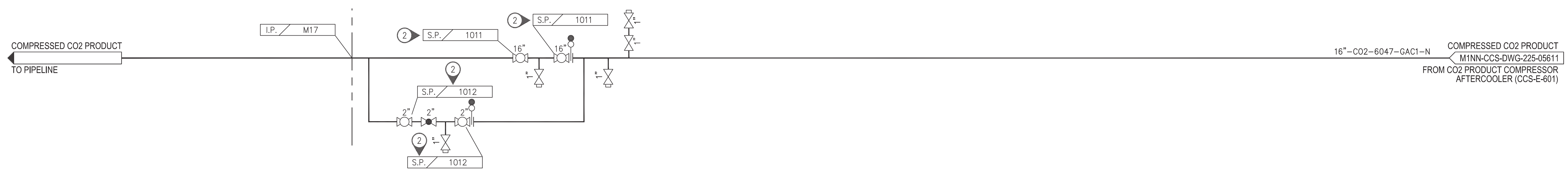
MINNKOTA POWER COOPERATIVE
PROJECT TUNDRA CO2 PIPELINE
WELL PAD 2
GENERAL ARRANGEMENT

project: 128002
contract:
drawing: MS003 – rev. B
sheet 3 of 3 sheets
file 128002MS003



NOTES:

2. CO2 PRODUCT BATTERY LIMIT ISOLATION VALVES ARE CLASS VI SHUT–OFF.

REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REFERENCE DWG NUMBER	REFERENCE DRAWINGS
A	N/A	INTERNAL ISSUE (NOT USED)	---	---	---								
B	21AUG20	ISSUED FOR CLIENT REVIEW	MKS	KA	SR								
C	02OCT20	ISSUED FOR PHA II	MKS	KA	SR								
0	11DEC20	ISSUED FOR DESIGN	MKS	KA	SR								

FLUOR®

CONTRACT M1NN

NOTICE: RESTRICTED, TRADE SECRET INFORMATION AND BACKGROUND INTELLECTUAL PROPERTY OF FLUOR, SUBJECT TO THE TERMS OF THE PARTIES' EXECUTED AGREEMENTS FOR MINNKOTA POWER COOPERATIVE, INC. PROJECT TUNDRA.

CONTRACT M1NN		
DESIGNED BY M. STILLMAN		
CHECKED BY K. AFSHAR		
PROCESS TECHNOLOGY S. REDDY	APP DATE	
LEAD ENGR/SPEC. K. AFSHAR	APP DATE	
FLUOR R. GRAEBE	APP DATE	
CLIENT D. WOLF	APP DATE	

MINNKOTA POWER COOPERATIVE

PROJECT TUNDRA

CARBON CAPTURE AND SEQUESTRATION

PIPING AND INSTRUMENTATION DIAGRAM

ECONAMINE FG PLUS℠ PROCESS

BATTERY LIMIT

SCALE	DRAWING NUMBER	REV
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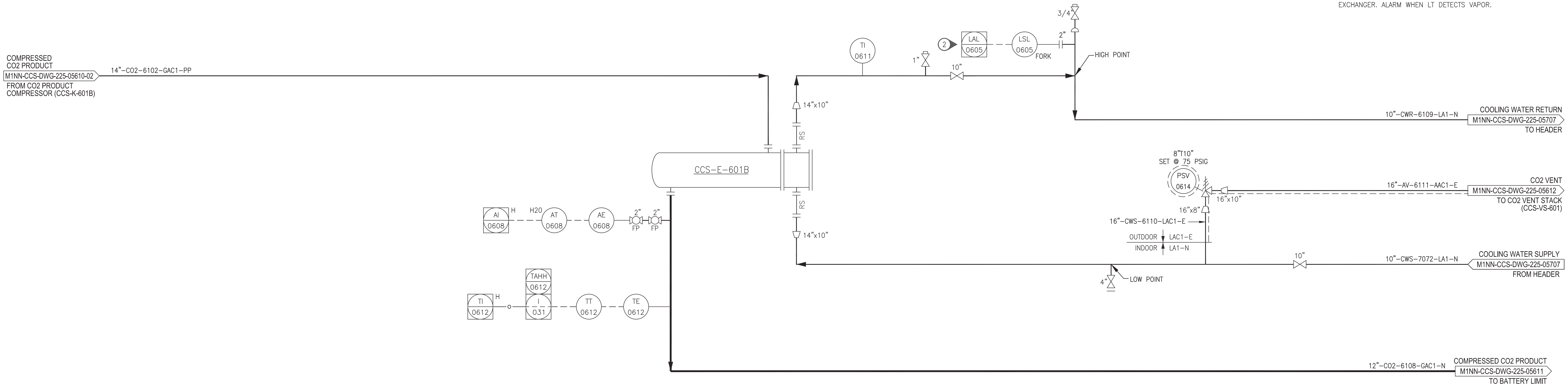
CCS-E-601B
CO2 PRODUCT COMPRESSOR
AFTERCOOLER

DESIGN DUTY:
SHELL DESIGN: 1770 PSIG @ 290°F
TUBE DESIGN: 1370 PSIG @ 250°F
INSULATION: PP
SHELL TRIM: CO2-6112-GAC1-PP
TUBE TRIM: CWS-6113-GAC1-N

NOTES:

2. HIGH POINT POCKET TO INDICATE TUBE LEAK IN UPSTREAM EXCHANGER. ALARM WHEN LT DETECTS VAPOR.



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A	N/A	INTERNAL ISSUE	---	---	---								
B	21AUG20	ISSUED FOR CLIENT REVIEW	MKS	KA	SR								
C	02OCT20	ISSUED FOR PHA II	MKS	KA	SR								
0	11DEC20	ISSUED FOR DESIGN	MKS	KA	SR								

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CLIENT	D. WOLF	APP DATE

MINNKOTA POWER COOPERATIVE
PROJECT TUNDRA
CARBON CAPTURE AND SEQUESTRATION

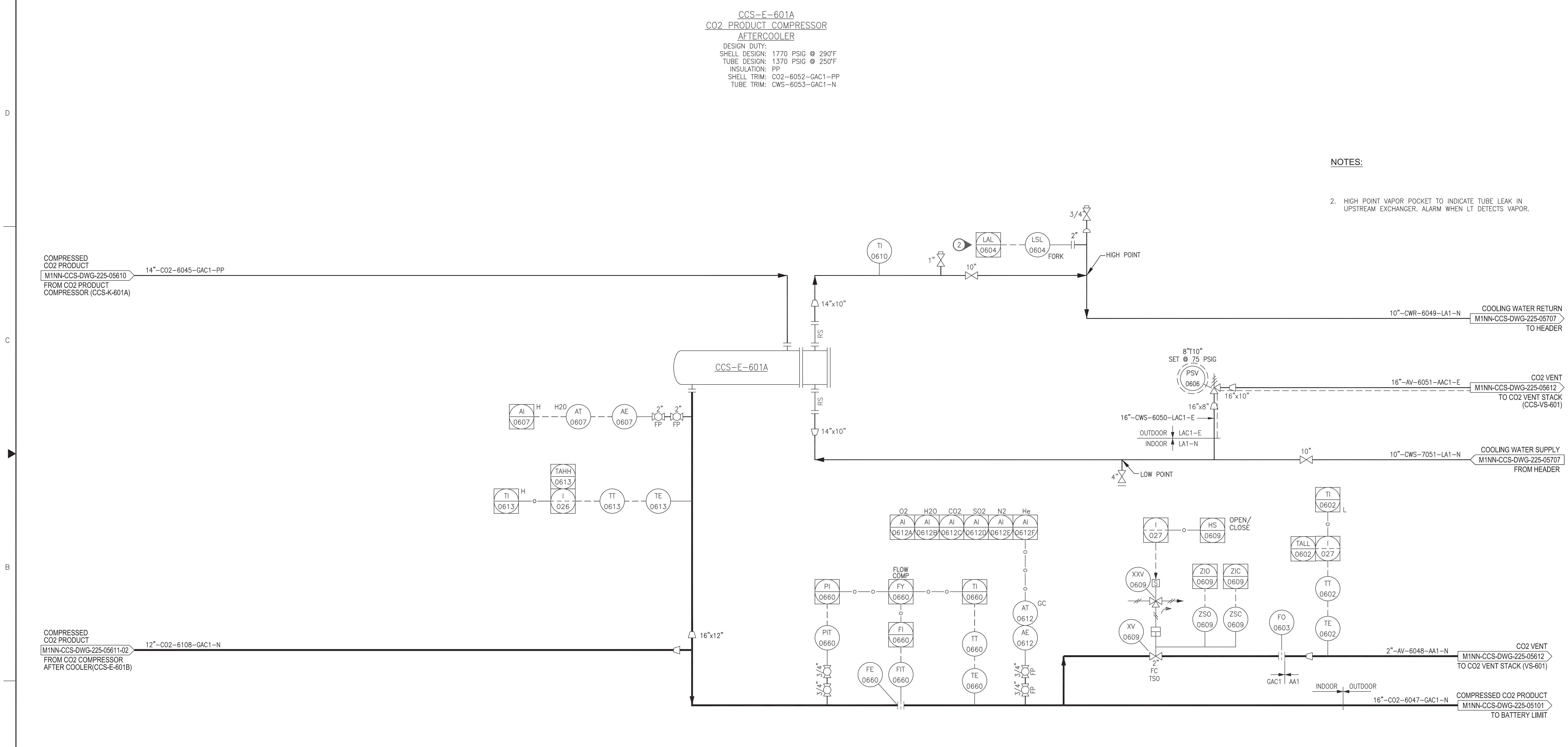
PIPING AND INSTRUMENTATION DIAGRAM
ECONAMINE FG PLUS℠ PROCESS
CO2 PRODUCT COMPRESSOR AFTERCOOLER

SCALE	DRAWING NUMBER	REV
NONE	M1NN-CCS-DWG-225-05611-02	0

CAD FILE NAME M1NN-CCS-DWG-225-05611-02.dwg

F-022.DWG 01JUL09

PLOT DATE: \\fdnet.com\ov_depts\WRK090\225\Proprietary Equipment\MPC Project Tundra_Process Graphics\PROCESS GRAPHICS Transfer_NATIVES Files - Tundra__PIDs\M1NN-CCS-DWG-225-05611-02.dwg 12-10-20 10:45 am Printed By: sco57212



NOTES:

2. HIGH POINT VAPOR POCKET TO INDICATE TUBE LEAK IN UPSTREAM EXCHANGER. ALARM WHEN LT DETECTS VAPOR.

REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REFERENCE DWG NUMBER	REFERENCE DRAWINGS
A	N/A	INTERNAL ISSUE	---	---	---								
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FLUOR R. GRAEBE — APP DATE
CLIENT D. WOLF — APP DATE

MINNKOTA POWER COOPERATIVE
PROJECT TUNDRA
CARBON CAPTURE AND SEQUESTRATION

PIPING AND INSTRUMENTATION DIAGRAM
ECONAMINE FG PLUS℠ PROCESS
CO2 PRODUCT COMPRESSOR AFTERCOOLER

SCALE NONE — DRAWING NUMBER M1NN-CCS-DWG-225-05611 — REV 0

CAD FILE NAME M1NN-CCS-DWG-225-05611.dwg

PLOT DATE: \\fdnet.com\av_depts\WRK090\225\Proprietary Equipment\MPC Project Tundra_Process Graphics\PROCESS GRAPHICS Transfer_NATIVES Files - Tundra__PIDs\M1NN-CCS-DWG-225-05611.dwg 12-10-20 10:43 am Printed By: sco57212

Appendix D: Risk Ranking

RISK MATRIX

		LIKELIHOOD				
		1	2	3	4	5
SEVERITY	A	5	6	7	8	9
	B	4	5	6	7	8
	C	3	4	5	6	7
	D	2	3	4	5	6
	E	1	2	3	4	5

SEVERITY RANKING

Severity	Description
A	One or More Fatalities, Catastrophic Burns / Serious Public Health and Environmental Impact / Major Property Damage
B	Serious Injury or Multiple Injured Personnel / Limited Public Health and Environmental Impact / Significant Property Damage
C	Medical Treatment for Personnel / No Public Health Impact / Moderate Property Damage and Environmental Impact
D	First Aid Injury / No Public Health Impact / Possible Incipient Fire, Minor Property Damage and Environmental Impact
E	No Injury or Health Impact / Minimal or No Property Damage or Environmental Impact

LIKELIHOOD

Frequency /Likelihood	Description	Frequency
5	Likely to occur several times in facility, possibly annually	>10^-1 to 1 / yr
4	Likely to occur once or twice within facility lifetime	>10^-2 to 10^-1
3	Likely to occur within the lifetime of 10 similar facilities	>10^-3 to 10^-2
2	Not likely, but similar Event has occurred in similar facilities	>10^-4 to 10^-3
1	Not likely, but similar Event has occurred in industry	>10^-5 to 10^-4

APPENDIX E – PROJECT TUNDRA INITIAL LIFE CYCLE ANALYSIS CALCULATIONS

Project Tundra LCA Data Inputs and Assumptions

Data	Source	Notes and Assumptions
Surface Mines CO2 Emission Factor	Equation 4.1.7A (New) Average Global Emission Factor IPCCC 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 2: Energy Retrieved April 25, 2023, From https://www.ipcc-nggip.iges.or.jp/public/2019rf/pdf/2_Volume2/19R_V2_4_Ch04_Fugitive_Emissions.pdf	
Post- Mining Activities CO2 Emission Factor	From IPCC Guidelines "While no default method is provided for estimating Post-mining emissions of CO2, countries may choose to provide their own country-specific emission estimate."	IPCC Guidelines do not provide an emission factor. The CO_2 emission factor for surface mines is between the NTEC provided emission factors for No. 6 and PRB Coal and is therefore a reasonable estimation. If an emission factor for post-mining activities is identified then calculations will be updated.
N2O Emission Factor	Table 5: Raw Material Acquisition Inventory PRB Coal DOE/NETL Upstream Dashboard Tool Documentation (Aug, 2016). Retrieved April 25, 2023, From https://netl.doe.gov/energy-analysis/details?id=a79a1cff-c7a6-43e0-ae57-16dcc806840d	N_2O Emission Factor specific to lignite coal or North Dakota unavailable. Emission Factor for PBR coal from the NETL provided database substituted. NETL Upstream Tool defines Raw Material Acquisition as "starts when material or energy has been drawn from the environment without previous human transformation and includes the extraction of raw feedstocks from the earth and any partial processing of the raw materials that may occur before transport to the energy conversion facility" so emission factor is inclusive of post-mining activities
Surface Mining CH4 Emission Factor	Equation 4.1.7 (New) Average Global Emission Factor IPCCC 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 2: Energy Retrieved April 25, 2023, From https://www.ipcc-nggip.iges.or.jp/public/2019rf/pdf/2_Volume2/19R_V2_4_Ch04_Fugitive_Emissions.pdf	
Post-Mining Activities CH4 Emission Factor	Equation 4.1.8 Average Global Emission Factor IPCCC 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 2: Energy Retrieved April 25, 2023, From https://www.ipcc-nggip.iges.or.jp/public/2019rf/pdf/2_Volume2/19R_V2_4_Ch04_Fugitive_Emissions.pdf	
Emission Factors (CO_2, N_2O, CH_4)	Table 5: Raw Material Acquisition Inventory Domestic Petroleum DOE/NETL Upstream Dashboard Tool Documentation (Aug, 2016).Retrieved April 25, 2023, From https://netl.doe.gov/energy-analysis/details?id=a79a1cff-c7a6-43e0-ae57-16dcc806840d	
FO Consumption	Annual FO consumption projection of MRY Boiler 1 and Boiler 2 provided by Minnkota	
Truck Type	https://insideenergy.org/2016/08/15/why-north-dakota-coal-is-the-last-man-standing/lignite-mine-haul-truck/	Haul Truck Type assumed from research into typically equipment at North Dakota Mining Facilities. Aligns with haul capacity provided by client.
Engine HP	Kress 200C III Coal Hauler Spec Sheet https://www.heavyequipments.org/blog/398-kress-200c-iii-mining-truck-coal-hauler-specifications	
Haul Capacity (short tons)	Kress 200C III Coal Hauler Spec Sheet : https://www.heavyequipments.org/blog/398-kress-200c-iii-mining-truck-coal-hauler-specifications Confirmed by Dylan Wolf (Minnkota) via email	
Average Speed	Kress 200C III Coal Hauler Spec Sheet https://www.heavyequipments.org/blog/398-kress-200c-iii-mining-truck-coal-hauler-specifications	Assumes that the trucks typically travels in Gears 1-4 with mph
Max Coal Consumption (short ton per year)	Coal Consumption Projections MRY Boiler 1 and Boiler 2 Years: 2032-2043 Provided by Minnkota	
Max Roundtrip Distance (miles)	Provided by Minnkota	
Max Trips per Year	Calculated: Maximum Coal Consumption divided by Haul Capacity	Assumes trucks are carrying full loads equivalent to haul capacity every trip
GHG Emission Factors	Greenhouse gas emissions from 40 CFR 98, Table C-1 and C-2	Conversion of 2544.43 Btu/hp-hr. is assumed
Load Factor	Conservative Estimate based on similar equipment	

Project Tundra LCA Data Inputs and Assumptions

Data	Source	Notes and Assumptions
Emission Factors (CO_2, N_2O, CH_4)	Table 5: Raw Material Acquisition Inventory Domestic Petroleum DOE/NETL Upstream Dashboard Tool Documentation (Aug, 2016).Retrieved April 25, 2023, From https://netl.doe.gov/energy-analysis/details?id=a79a1cff-c7a6-43e0-ae57-16dcc806840d	
FO Consumption	Annual FO consumption projections of MRY Boiler 1 and Boiler 2 provided by Minnkota	
CO2 Emission Factor	Based on past actuals submitted to the Acid Rain Program (ARP) years 2018-2021	Emission Factor reflects both Coal and FO combustion
N2O and CH4 Emission Factors	GHG Emission Data 40 CFR, Part 98, Subpart C (Emission Factors)	
Coal HHV	Based on Past Actuals reported to ARP for MRY Boiler 1 and Boiler 2	
Fuel Oil HHV	Based on Past Actuals reported to ARP for MRY Boiler 1 and Boiler 2	
FO Consumption	Annual FO consumption projection of MRY Boiler 1 and Boiler 2 provided by Minnkota	
Max Coal Consumption	Coal Consumption Projections MRY Boiler 1 and Boiler 2 Years: 2032-2043 Provided by Minnkota	
Maximum Heat Input	Calculated based on fuel consumption expectations and previous actual HHV values	
Annual Amount CO_2 Stored	Calculated : Annual amount of CO_2 processed minus processing emissions and transportation emissions.	
CO2 Emissions	Provided by Minnkota Based on preliminary engineering estimations	
Amount of CO_2 processed at the plant on an annual basis	Calculated from the Daily Amount of CO_2 processed by the Plant, Based on operating scenarios Provided by Minnkota	Assumes operation 365/days per year Minnkota's operation scenario is based on a 99% capture efficiency
Pipeline Loss	Provided by Minnkota CO_2 loss from pipeline calculated by Sargent and Lundy	CCS Island to JROC Pipeline (0.25 miles) + Operational Fugitive Losses Sargent and Lundy included a 10% safety factor
Amount of CO2 processed at the plant on an annual basis	Calculated from the Daily Amount of CO_2 processed by the Plant, Based on operating scenarios Provided by Minnkota	Assumes operation 365/days per year Minnkota's operation scenario is based on a 99% capture efficiency
Amount of CO_2 Transported Annually	Calculated: Annual amount of CO_2 processed minus processing emissions.	
SF6 Emission Factor	From DE-FOE-0002962 Appendix J	This emission factor is published in Appendix J with units "kg SF_6 / kg CO_2 stored" updated to "kg SF_6 / Mwh" based on consultation with NETL

Revised Initial LCA
Functional Unit: kg CO_2e per kg CO_2 Stored

Project Tundra LCA Data Inputs and Assumptions

Project Tundra Initial Life Cycle Analysis Results
REVISED

Table 1: Updated Initial LCA Results to incorporate CO_2 sequestered from Coal Plant Emissions

Emissions Source	kg of Emissions per CO2 Sequestered				
	CO_2	N_2O	CH_4	SF_6	CO_2e
Upstream					
Coal Mining	**7.52E-04**	**5.94E-06**	**8.09E-04**	-	**3.16E-02**
FO Extraction	**8.87E-05**	**2.68E-09**	**4.76E-07**	-	**1.07E-04**
Coal Transportation	**9.35E-04**	**3.79E-08**	**7.59E-09**	-	**9.47E-04**
FO Transportation	5.53E-07	1.42E-11	1.11E-11	-	5.58E-07
Coal Electricity Plant	**0.34**	2.15E-05	1.47E-05	-	**0.34**
Proposed Project					
CO2 Capture Plant	**8.15E-03**	-	-	-	**8.15E-03**
Electricity Consumption	**0.04**	**1.81E-06**	**1.24E-06**	--	**0.04**
Downstream					
CO2 transportation	8.58E-05	-	-	-	8.58E-05
CO2 storage*	-		-	-	-
Electricity Transmission	-	-	-	**9.25E-08**	**2.17E-03**
TOTAL LCA	**0.39**	**2.93E-05**	**8.26E-04**	**9.25E-08**	**0.43**

*Assuming there are no measurable losses at the wellhead to the reservoir

****Bold Numbers** indicate numbers that have been updated from previous iterations

Contribution Analysis - kg CO_2 Equivalents per kg CO_2 Sequestered

Appendix J Category	CO_2	N_2O	CH_4	SF6	Total	%
Fuel Extraction and Delivery	**0.34**	0.01	**0.03**	-	**0.37**	**97.30%**
Plant Direct Emissions	0.01	-	-	-	0.01	**2.11%**
CO2 Transport and Storage	8.58E-05	-	-	-	**8.58E-05**	**0.02%**
Electricity Transportation	-	-	-	**2.17E-03**	**2.17E-03**	**0.56%**
Total	**0.35**	0.01	**2.97E-02**	**2.17E-03**	**0.39**	

*Fuel is defined as the CO_2 utilized at the CO_2 Separation and Purification Plant

Project Tundra Initial Life Cycle Analysis
Upstream Emissions - Fuel Extraction: Coal Mining

Summary

GHG	kg emissions / metric tonne coal extracted	BUILD kg emissions / kg CO_2 stored
CO_2	0.81	7.52E-04
N_2O	6.40E-03	5.94E-06
CH_4	8.71E-01	8.09E-04
SF_6	-	-
CO_2e	34.07	3.16E-02

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors
IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change

	Emission Factor	Units
Surface Mines CO_2	0.44	m3 CO2 / metric tonne lignite Coal
	8.10E-01	kg CO2 / metric tonne lignite Coal
Post- Mining Activities CO_2		
	0.00	kg CO_2 / metric tonne Lignite Coal
N_2O	6.40E-06	kg N2O / kg PBR Coal
	6.40E-03	kg N2O / metric tonne PBR Coal
Mining CH_4	1.2	m3 CH4 / metric tonne lignite Coal
	8.04E-01	kg CH4 / metric tonne Lignite Coal
Post-Mining Activities CH_4	0.1	m3 CH4 / metric tonne Lignite Coal
	6.70E-02	kg CH4 / metric tonne Lignite Coal

Conversions		
CO_2 Density	1.84	kg/m^3
CH_4 Density	0.67	kg/m^3
1 tonne =	1000	kg
1 M^3 =	35.3147	ft^3
1 tonne =	1.10231	short ton

Project Tundra Initial Life Cycle Analysis
Upstream Emissions - Fuel Delivery: Coal Transportation

Summary		
GHG	kg emissions / metric tonnes coal transported	kg emissions / kg CO_2 stored
CO_2	1.01	9.35E-04
N_2O	4.08E-05	3.79E-08
CH_4	8.17E-06	7.59E-09
SF_6	-	-
CO2e	1.02	9.47E-04

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors

IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

						GHG Emission Factors (g/hp-hr)[a]			GHG Emissions kg per Year			
Equipment	Fuel	Engine Horsepower	Load Factor	Loaded Horsepower	Hours Operated per Year	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	CO2e
Semi-Truck	Diesel	2100	0.8	1680	15361	188.19	7.63E-03	1.53E-03	4,856,423.67	1.97E+02	3.94E+01	1,448,147,191.36

(a) Greenhouse gas emissions from 40 CFR 98, Table C-1 and C-2; conversion of 2544.43 Btu/hp-hr is assumed

Project Tundra Initial Life Cycle Analysis

Upstream Emissions - Fuel Delivery: Coal Transportation

Assumptions and Data

	YOUNG Boiler 1		YOUNG Boiler 2		Total facility
Year	Megawatt Hours Net	Tons Lignite	Megawatt Hours Net	Tons Lignite	Tons Lignite
2023	1,789,638	1,571,510	3,241,042	2,804,620	4,376,130
2024	1,627,779	1,429,480	3,217,477	2,784,300	4,213,780
2025	1,796,587	1,577,720	2,897,224	2,507,210	4,084,930
2026	1,794,703	1,576,090	3,188,853	2,759,520	4,335,610
2027	1,497,859	1,315,400	3,226,215	2,791,880	4,107,280
2028	1,822,299	1,600,320	2,988,707	2,586,360	4,186,680
2029	1,799,645	1,580,410	3,218,132	2,784,870	4,365,280
2030	1,617,994	1,420,870	3,213,750	2,781,100	4,201,970
2031	1,805,975	1,585,960	2,964,249	2,565,170	4,151,130
2032	1,811,105	1,590,460	3,213,792	2,781,100	4,371,560
2033	1,616,142	1,419,260	3,253,285	2,815,270	4,234,530
2034	1,811,105	1,590,460	2,851,496	2,467,600	4,058,060
2035	1,811,105	1,590,460	3,205,522	2,773,970	4,364,430
2036	1,616,141	1,419,250	3,218,950	2,785,570	4,204,820
2037	1,811,105	1,590,460	2,843,919	2,461,030	4,051,490
2038	1,811,104	1,590,460	3,213,704	2,781,040	4,371,500
2039	1,611,011	1,414,750	3,195,077	2,764,910	4,179,660
2040	1,811,105	1,590,460	2,879,342	2,491,680	4,082,140
2041	1,795,712	1,576,960	3,216,135	2,783,140	4,360,100
2042	1,616,141	1,419,260	3,218,400	2,785,090	4,204,350
2043	1,811,105	1,590,460	2,884,162	2,495,860	4,086,320

Transport Assumptions	
Truck Type	Kress 200C III Coal Hauler
Enginer HP	2,100
Haul Capacity (short tons)	240
Average Speed	15.55
Max Coal (short ton per year)	4,376,130
Max Coal (metric tonnes per	4,823,852
Max trips per year	18234
Max Roundtrip Distance (miles)	13.1
Max Distance Traveled per year (miles)	238,864
Hours per year	15361

Table 1: Maximum Travel Speed

Gear	mph
1	9.4
2	12.6
3	17.1
4	23.1
5	31.4
6	42.3

Conversions		
1 metric tonne =	1.10231	short ton

Haul Distances	
Year	Round Trip Haul Distance (miles)
2028	9.7
2029	10.4
2030	11
2031	11.6
2032	11.7
2033	11.8
2034	12.1
2035	12.4
2036	12.7
2037	12.8
2038	13.1
2039	12.9
2040	12.8

Project Tundra Initial Life Cycle Analysis
Upstream Emissions - Fuel Extraction: Fuel Oil #2

Summary		
GHG	**kg emissions / gallon FO extracted**	**kg emissions / kg CO_2 stored**
CO_2	5.051E-01	8.874E-05
N_2O	1.524E-05	2.677E-09
CH_4	2.707E-03	4.755E-07
SF_6	-	-
CO2e	0.61	1.067E-04

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors
IPCC. (2013). Climate Change 2013 The Physical Science Basis. New Yo

Assumptions and Data

Projected Annual FO Consumption

MRY Boiler 1	350,000	gal/year
MRY Boiler 2	400,000	gal/year

Project Tundra Initial Life Cycle Analysis
Upstream Emissions - Fuel Delivery: Fuel Oil Transportation

Summary		
GHG	**kg emissions / gallons FO transported**	**kg emissions / kg CO_2 stored**
CO_2	3.149E-03	5.531E-07
N_2O	8.097E-08	1.422E-11
CH_4	6.301E-08	1.107E-11
SF_6	-	-
CO2e	3.18E-03	5.578E-07

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors

IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

Assumptions and Data

Projected Annual FO Consumption

MRY Boiler 1	350,000	gal/year
MRY Boiler 2	400,000	gal/year

Project Tundra Initial Life Cycle Analysis

Upstream Emissions - Plant Direct Emissions: Coal Electricity Generation Plant

Includes Unit 1 and 2 (boilers) ONLY does not include auxillary equipment on site

Summary		
GHG	**kg emissions / year**	**kg emissions / kg CO_2 stored**
CO_2	1.43E+09	0.34
N_2O	9.16E+04	2.15E-05
CH_4	6.28E+04	1.47E-05
SF_6	-	-
CO2e	1.46E+09	0.34

Functional Unit: CO_2 Stored

Normalize Emissions to Functional Unit		
Operation Period	1.00	year
Annual Amount CO2 stored	4.27E+09	kg
Normalizing Factor	2.34E-10	time operation / kg CO_2 stored

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors

IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

Project Tundra Initial Life Cycle Analysis

Upstream Emissions - Plant Direct Emissions: Coal Electricity Generation Plant

Includes Unit 1 and 2 (boilers) ONLY does not include auxillary equipment on site

Assumptions and Data

Emission Calcs

Unit ID	CO2		NO2		CH4	
	lb/year	kg/year	lb/year	kg/year	lb/year	kg/year
Unit 1 Coal	4.54E+09	2.06E+09	72866.92	33051.92	49965.89	22,664
Unit 1 FO #2	[redacted]		169.075	76.691	115.937	53
Unit 2 Coal	8.02E+09	3.64E+09	128,778.84	58413.17	88305.49	40,055
Unit 2 FO #2	[redacted]		193.228	87.647	132.499	60
Total	1.26E+10	5.70E+09	202008.06	91629.42	138519.81	62,832

Operation Data Unit 1

Coal HHV	13.09	MMBtu/ short ton
Fuel Oil HHV	0.13802	MMBtu/gal
Usage	350,000	gal/year
Maximum Heat Input	20,867,428.40	MMBtu/yr

Operation Data Unit 2

Coal HHV	13.23	MMBtu/ short ton
Fuel Oil HHV	0.13802	MMBtu/gal
Usage	400,000	gal/year
Maximum Heat Input	36,849,161.00	MMBtu/yr

Emission Factors

Unit	Fuel	GHG	Emission Factor	Units	Source
U1 and U2	Coal	CO2	217.74	lb/MMBtu	ARP Data
		NO2	0.0035	lb/MMBtu	GHG Emission Data 40 CFR, Part 98,
		CH4	0.0024	lb/MMBtu	GHG Emission Data 40 CFR, Part 98,
	FO #2	NO2	0.0013	lb/MMBtu	GHG Emission Data 40 CFR, Part 98,
		CH4	0.0066	lb/MMBtu	GHG Emission Data 40 CFR, Part 98

Conversions

1 kg =	2.20462	lbs
1 short ton =	2000	lbs

	YOUNG Boiler 1		YOUNG Boiler 2		Total facility	
	Megawatt	Short Tons	Megawatt	Short Tons	Megawatt	Short Tons
Year	Hours Net	Lignite	Hours Net	Lignite	Hours Net	Lignite
2023	1,789,638	1,571,510	3,241,042	2,804,620	5,030,680	4,376,130
2024	1,627,779	1,429,480	3,217,477	2,784,300	4,845,256	4,213,780
2025	1,796,587	1,577,720	2,897,224	2,507,210	4,693,811	4,084,930
2026	1,794,703	1,576,090	3,188,853	2,759,520	4,983,556	4,335,610
2027	1,497,859	1,315,400	3,226,215	2,791,880	4,724,074	4,107,280
2028	1,822,299	1,600,320	2,988,707	2,586,360	4,811,006	4,186,680
2029	1,799,645	1,580,410	3,218,132	2,784,870	5,017,777	4,365,280
2030	1,617,994	1,420,870	3,213,750	2,781,100	4,831,744	4,201,970
2031	1,805,975	1,585,960	2,964,249	2,565,170	4,770,224	4,151,130
2032	1,811,105	1,590,460	3,213,792	2,781,100	5,024,897	4,371,560
2033	1,616,142	1,419,260	3,253,285	2,815,270	4,869,427	4,234,530
2034	1,811,105	1,590,460	2,851,496	2,467,600	4,662,601	4,058,060
2035	1,811,105	1,590,460	3,205,522	2,773,970	5,016,627	4,364,430
2036	1,616,141	1,419,250	3,218,950	2,785,570	4,835,091	4,204,820
2037	1,811,105	1,590,460	2,843,919	2,461,030	4,655,024	4,051,490
2038	1,811,104	1,590,460	3,213,704	2,781,040	5,024,808	4,371,500
2039	1,611,011	1,414,750	3,195,077	2,764,910	4,806,088	4,179,660
2040	1,811,105	1,590,460	2,879,342	2,491,680	4,690,447	4,082,140
2041	1,795,712	1,576,960	3,216,135	2,783,140	5,011,847	4,360,100
2042	1,616,141	1,419,260	3,218,400	2,785,090	4,834,541	4,204,350
2043	1,811,105	1,590,460	2,884,162	2,495,860	4,695,267	4,086,320

Project Tundra Initial Life Cycle Analysis

Proposed Project - CO_2 Separation and Purification Plant

Includes CO2 compressor ONLY based on old supplier values, excludes auxilary equipment on

Summary		
GHG	kg emissions / metric tonnes CO2 Processed	kg emissions / kg CO_2 stored
CO_2	8.08	0.01
N_2O	0	0
CH_4	0	0
SF_6	0	0
CO2e	8.08	0.01

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors

IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

Assumptions and Data

Emissions from CO2 compressor startups and discharge		
CO2	38,338	short tons per year
	34,779,690	kg / yr
Amount of CO2 Processed by the Plant		
Total CO2 Capture Target	13,000	short tons per day
	4,745,000	short tons per year
	4,304,597	metric tonnes per year

Conversions		
1 metric tonne =	1.10231	short ton
1 metric tonne =	1000	kg

Project Tundra Initial Life Cycle Analysis
CO_2 Separation and Purification Plant Power Consumption

Electricty Summary			
GHG	Electricity	Steam	Total
	kg emissions / kg CO_2 Stored		
CO_2	0.04	0.06	--
N_2O	1.81E-06	0.00	--
CH_4	1.24E-06	0.00	--
SF_6	--	--	--
CO2e	0.04	0.07	0.11

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors

IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

Functional Unit kg CO_2 Stored		
Normalize Emissions to Functional Unit		
Operation Period	1.00	year
Final Annual Amount CO_2 stored	4.27E+09	kg
Normalizing Factor	2.34E-10	time operation / MWh produced

Assumptions and Data

Electricity Consumption		Emission Factor		Source	Emissions
MW	MWh Annual	Pollutant	**kg** / MWh		**kgs** / Year
77	674,520	CO_2	265	Historical Actuals Three Year Average (2020-2022) of historic Minnkota System	178,832,691
		N_2O	1.15E-02		7,748
		CH_4	7.88E-03		5,313
		CO_2e	269		181,332,843

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Steam Consumption		Emission Factor		Source	Emissions
MW	MWh Annual	Pollutant	**kg** / MWh		**kgs**/ Year
110	963,600	CO_2	285	LCA previous calculated CI for MRY based on Future Projected Coal Usage	274,405,641
		N_2O	1.82E-02		17,571
		CH_4	1.25E-02		12,049
		CO_2e	291		280,075,658

Conversions		
1 lb =	0.453592	kg

Project Tundra Initial Life Cycle Analysis
Downstream - CO2 Transportation

Summary		
GHG	kg emissions / tonnes CO2 transported	kg emissions / kg CO_2 stored
CO_2	8.57E-02	8.58E-05
N_2O	0	0
CH_4	0	0
SF_6	0	0
CO2e	8.57E-02	8.58E-05

Functional Unit: CO_2 Stored

Normalize Emissions to Functional Unit		
Amount CO_2 Transported	4269817.02	metric tonnes
Final Annual Amount CO_2 stored	4.27E+09	kg
Normalizing Factor	1.00E-03	Metric tonnes CO2 Transported / kg CO_2 stored

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors

IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

Assumptions and Data

Pipeline Loss		
Total Released CO2	366.13	metric tonnes per year

Amount of CO2 Processed by the Plant		
Total CO2 Capture Target	13,000	short tons per day
	4,745,000	short tons per year
	4,304,597	metric tonnes per year
Tonnes CO2 Tranported	4269817.021	metric tonnes per year

Conversions		
1 metric tonne =	1.10231	short ton
1 metric tonne =	1000	kg

Project Tundra Initial Life Cycle Analysis
Downstream - Electricity Transmission

Summary	
GHG	**kg emissions / kg CO2 stored**
CO_2	0
N_2O	0
CH_4	0
SF_6	9.25E-08
CO2e	2.17E-03

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors

IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

Assumptions and Data

Electricity transmision emissions

GHG	Emission Factor	Unit
SF6	7.85E-05	kg / MWh

Given in FOA Appendix J

Initial LCA
Functional Unit: kg CO_2e per MWh

Project Tundra Initial Life Cycle Analysis Results
REVISED

Table 1-1: Build Scenario, Initial LCA Results Normalized to 1 MWh produced at MRY

Emissions Source	kg of Emissions per MWh produced at MRY				
	CO_2	N_2O	CH_4	SF_6	CO_2e
Upstream					
Coal Mining	0.79	6.25E-03	0.85	-	33.27
FO Extraction	0.09	2.81E-06	5.00E-04	-	0.11
Coal Transportation	0.98	3.99E-05	7.98E-06	-	1.00
FO Transportation	5.81E-04	1.50E-08	1.16E-08	-	5.86E-04
Coal Electricity Plant	352	0.02	0.02	-	360
Proposed Project					
CO_2 Capture Plant	8.56	-	-	-	8.56
Electricty	49.90	1.92E-03	1.32E-03	--	50.52
Downstream					
CO_2 Transportation	0.09	-	-	-	0.09
CO_2 Storage*	-	0.00E+00	-	-	-
Electricity Transmission	-	-	-	7.85E-05	1.84
TOTAL LCA	413	0.03	0.87	7.85E-05	455

*Assuming there are no measurable losses at the wellhead to the reservoir

**Does not account for electricity losses from T&D

Table 1-2: No-Build Scenario, Initial LCA Results Normalized to 1 MWh produced at MRY

Emissions Source	kg of Emissions per MWh produced at MRY				
	CO_2	N_2O	CH_4	SF_6	CO_2e
Upstream					
Coal Mining	0.64	5.05E-03	0.69	-	26.89
FO Extraction	0.08	2.27E-06	4.04E-04	-	0.09
Coal Transportation	0.79	3.22E-05	6.45E-06	-	0.80
FO Transportation	4.70E-04	1.21E-08	9.40E-09	-	4.74E-04
Coal Electricity Plant	1,134	0.02	0.01	-	1,140
Downstream					
Electricity Transmission	-	-	-	7.85E-05	1.84
TOTAL LCA	1,136	0.02	0.70	7.85E-05	1,170

*Assuming there are no measurable losses at the wellhead to the reservoir

**Does not account for electricity losses from T&D

Project Tundra Initial Life Cycle Analysis
Upstream Emissions - Fuel Extraction: Coal Mining

Summary

GHG	kg emissions / metric tonne coal extracted	BUILD kg emissions / MWh Produced at Mry	NO BUILD kg emissions / MWh Produced at Mry
CO_2	0.81	0.79	0.64
N_2O	0.01	0.01	0.01
CH_4	0.87	0.85	0.69
SF_6	-	-	-
CO_2e	34.07	33.27	26.89

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors
IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

	Emission Factor	Units
Surface Mines CO_2	0.44	m^3 CO_2 / metric tonne lignite Coal
	8.10E-01	kg CO_2 / metric tonne lignite Coal
Post- Mining Activities CO_2		
	0.00	kg CO_2 / metric tonne Lignite Coal
N_2O	6.40E-06	kg N_{2O} / kg PBR Coal
	6.40E-03	kg N_2O / metric tonne PBR Coal
Mining CH_4	1.2	m^3 CH_4 / metric tonne lignite Coal
	8.04E-01	kg CH_4 / metric tonne Lignite Coal
Post-Mining Activities CH_4	0.1	m^3 CH_4 / metric tonne Lignite Coal
	6.70E-02	kg CH_4 / metric tonne Lignite Coal

Conversions		
CO_2 Density	1.84	kg/m^3
CH_4 Density	0.67	kg/m^3
1 tonne =	1000	kg
1 M^3 =	35.3147	ft^3
1 tonne =	1.10231	short ton

Project Tundra Initial Life Cycle Analysis
Upstream Emissions - Fuel Delivery: Coal Transportation

Summary			
GHG	kg emissions / metric tonnes coal transported	BUILD kg emissions / MWh Produced at Mry	NO BUILD kg emissions / MWh Produced at Mry
CO_2	1.01	0.98	0.79
N_2O	4.08E-05	3.99E-05	3.22E-05
CH_4	8.17E-06	7.98E-06	6.45E-06
SF_6	-	-	-
CO_2e	1.02	1.00	0.80

Maximu

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors
IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

Equipment	Fuel	Engine Horsepower	Load Factor	Loaded Horsepower	Hours Operated per Year	GHG Emission Factors (g/hp-hr)[a]			GHG Emissions kg per Year			
						CO_2	CH_4	N_2O	CO_2	CH_4	N_2O	CO2e
Semi-Truck	Diesel	2100	0.8	1680	15345	188.19	7.63E-03	1.53E-03	4,851,352.10	1.97E+02	3.94E+01	1,446,634,888.78

(a) Greenhouse gas emissions from 40 CFR 98, Table C-1 and C-2; conversion of 2544.43 Btu/hp-hr is assumed

Project Tundra Initial Life Cycle Analysis

Upstream Emissions - Fuel Delivery: Coal Transportation

Assumptions and Data

	YOUNG Boiler 1		YOUNG Boiler 2		Total facility
	Megawatt	Tons	Megawatt	Tons	Tons
Year	Hours Net	Lignite	Hours Net	Lignite	Lignite
2023	1,789,638	1,571,510	3,241,042	2,804,620	4,376,130
2024	1,627,779	1,429,480	3,217,477	2,784,300	4,213,780
2025	1,796,587	1,577,720	2,897,224	2,507,210	4,084,930
2026	1,794,703	1,576,090	3,188,853	2,759,520	4,335,610
2027	1,497,859	1,315,400	3,226,215	2,791,880	4,107,280
2028	1,822,299	1,600,320	2,988,707	2,586,360	4,186,680
2029	1,799,645	1,580,410	3,218,132	2,784,870	4,365,280
2030	1,617,994	1,420,870	3,213,750	2,781,100	4,201,970
2031	1,805,975	1,585,960	2,964,249	2,565,170	4,151,130
2032	1,811,105	1,590,460	3,213,792	2,781,100	4,371,560
2033	1,616,142	1,419,260	3,253,285	2,815,270	4,234,530
2034	1,811,105	1,590,460	2,851,496	2,467,600	4,058,060
2035	1,811,105	1,590,460	3,205,522	2,773,970	4,364,430
2036	1,616,141	1,419,250	3,218,950	2,785,570	4,204,820
2037	1,811,105	1,590,460	2,843,919	2,461,030	4,051,490
2038	1,811,104	1,590,460	3,213,704	2,781,040	4,371,500
2039	1,611,011	1,414,750	3,195,077	2,764,910	4,179,660
2040	1,811,105	1,590,460	2,879,342	2,491,680	4,082,140
2041	1,795,712	1,576,960	3,216,135	2,783,140	4,360,100
2042	1,616,141	1,419,260	3,218,400	2,785,090	4,204,350
2043	1,811,105	1,590,460	2,884,162	2,495,860	4,086,320

Transport Assumptions	
Truck Type	Kress 200C III Coal Hauler
Enginer HP	2,100
Haul Capacity (short tons)	240
Average Speed	15.55
Max Coal (short ton per year)	4,371,560
Max Coal (metric tonnes per	4,818,814
Max trips per year	18,215
Max Roundtrip Distance (miles)	13
Max Distance Traveled per year (miles)	238,614
Hours per year	15,345

Coal Hauler: Maximum Travel Speed

Gear	mph
1	9.4
2	12.6
3	17.1
4	23.1
5	31.4
6	42.3

Haul Distances	
Year	Round Trip Haul Distance (miles)
2028	9.7
2029	10.4
2030	11
2031	11.6
2032	11.7
2033	11.8
2034	12.1
2035	12.4
2036	12.7
2037	12.8
2038	13.1
2039	12.9
2040	12.8

Conversions		
1 metric tonne =	1.10231	short ton

Project Tundra Initial Life Cycle Analysis
Upstream Emissions - Fuel Extraction: Fuel Oil #2

Summary			
GHG	kg emissions / gallon FO extracted	BUILD kg emissions / MWh produced at MRY	NO BUILD kg emissions / MWh produced at MRY
CO_2	5.051E-01	9.33E-02	7.54E-02
N_2O	1.524E-05	2.81E-06	2.27E-06
CH_4	2.707E-03	5.00E-04	4.04E-04
SF_6	-	-	-
CO2e	0.61	1.12E-01	9.06E-02

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors

IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York:

Assumptions and Data

Projected Annual FO Consumption

MRY Boiler 1	350,000	gal/year
MRY Boiler 2	400,000	gal/year

Project Tundra Initial Life Cycle Analysis
Upstream Emissions - Fuel Delivery: Fuel Oil Transportation

Summary

GHG	kg emissions / gallon FO extracted	BUILD kg emissions / MWh produced at MRY	NO BUILD kg emissions / MWh produced
CO_2	3.149E-03	5.81E-04	4.70E-04
N_2O	8.097E-08	1.50E-08	1.21E-08
CH_4	6.301E-08	1.16E-08	9.40E-09
SF_6	-	-	-
CO2e	3.18E-03	5.86E-04	4.74E-04

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors
IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

Assumptions and Data

Projected Annual FO Consumption

MRY Boiler 1	350,000	gal/year
MRY Boiler 2	400,000	gal/year

Project Tundra Initial Life Cycle Analysis

Upstream Emissions - Plant Direct Emissions: Coal Electricity Generation Plant

Includes Unit 1 and 2 (boilers) ONLY does not include auxillary equipment on site

Summary (Build Scenario)		
GHG	kg emissions / year	kg emissions / MWh produced at MRY
CO_2	1.43E+09	352.34
N_2O	9.23E+04	0.02
CH_4	6.33E+04	0.02
SF_6	-	-
CO_2e	1.46E+09	359.67

Summary (No-Build Scenario)		
GHG	kg emissions / year	kg emissions / MWh produced at MRY
CO_2	5.70E+09	1134.43
N_2O	9.23E+04	0.02
CH_4	6.33E+04	0.01
SF_6	-	-
CO_2e	5.73E+09	1140.36

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors

IPCC. (2013). Climate Change 2013 The Physical Science

Project Tundra Initial Life Cycle Analysis

Upstream Emissions - Plant Direct Emissions: Coal Electricity Generation Plant

Includes Unit 1 and 2 (boilers) ONLY does not include auxillary equipment on site

Assumptions and Data

Emission Calcs

Unit ID - Fuel	CO2		N2O		CH4	
	lb/year	kg/year	lb/year	kg/year	lb/year	kg/year
Unit 1 - Coal	4.54E+09	2.06E+09	72,867	33,052	49,966	22,664
Unit 1 - FO #2	[redacted]		169	77	116	53
Unit 2 - Coal	8.02E+09	3.64E+09	130,361	59,131	89,390	40,547
Unit 2 - FO #2	[redacted]		193	88	132	60
Total	1.26E+10	5.70E+09	203,590	92,347	139,605	63,324

Emission Factors

Unit	Fuel	GHG	Emission Factor	Units	Source
U1 and U2	Coal	CO2	217.74	lb/MMBtu	ARP Data: FO and Coal combined
		N2O	0.0035	lb/MMBtu	GHG Emission Data 40 CFR, Part 98, Subpart C (Emission Factors)
		CH4	0.0024	lb/MMBtu	GHG Emission Data 40 CFR, Part 98, Subpart C (Emission Factors)
	FO #2	N2O	0.0013	lb/MMBtu	GHG Emission Data 40 CFR, Part 98, Subpart C (Emission Factors)
		CH4	0.0066	lb/MMBtu	GHG Emission Data 40 CFR, Part 98, Subpart C (Emission Factors)

	YOUNG Boiler 1		YOUNG Boiler 2		Total facility	
	Megawatt	**Short Tons**	**Megawatt**	**Short Tons**	**Megawatt**	**Short Tons**
Year	**Hours Net**	**Lignite**	**Hours Net**	**Lignite**	**Hours Net**	**Lignite**
2023	1,789,638	1,571,510	3,241,042	2,804,620	5,030,680	4,376,130
2024	1,627,779	1,429,480	3,217,477	2,784,300	4,845,256	4,213,780
2025	1,796,587	1,577,720	2,897,224	2,507,210	4,693,811	4,084,930
2026	1,794,703	1,576,090	3,188,853	2,759,520	4,983,556	4,335,610
2027	1,497,859	1,315,400	3,226,215	2,791,880	4,724,074	4,107,280
2028	1,822,299	1,600,320	2,988,707	2,586,360	4,811,006	4,186,680
2029	1,799,645	1,580,410	3,218,132	2,784,870	5,017,777	4,365,280
2030	1,617,994	1,420,870	3,213,750	2,781,100	4,831,744	4,201,970
2031	1,805,975	1,585,960	2,964,249	2,565,170	4,770,224	4,151,130
2032	1,811,105	1,590,460	3,213,792	2,781,100	5,024,897	4,371,560
2033	1,616,142	1,419,260	3,253,285	2,815,270	4,869,427	4,234,530
2034	1,811,105	1,590,460	2,851,496	2,467,600	4,662,601	4,058,060
2035	1,811,105	1,590,460	3,205,522	2,773,970	5,016,627	4,364,430
2036	1,616,141	1,419,250	3,218,950	2,785,570	4,835,091	4,204,820
2037	1,811,105	1,590,460	2,843,919	2,461,030	4,655,024	4,051,490
2038	1,811,104	1,590,460	3,213,704	2,781,040	5,024,808	4,371,500
2039	1,611,011	1,414,750	3,195,077	2,764,910	4,806,088	4,179,660
2040	1,811,105	1,590,460	2,879,342	2,491,680	4,690,447	4,082,140
2041	1,795,712	1,576,960	3,216,135	2,783,140	5,011,847	4,360,100
2042	1,616,141	1,419,260	3,218,400	2,785,090	4,834,541	4,204,350
2043	1,811,105	1,590,460	2,884,162	2,495,860	4,695,267	4,086,320

Operation Data Unit 1

Coal HHV	13.09	MMBtu/ short ton
Fuel Oil HHV	0.13802	MMBtu/gal
Projected Annual Fuel Oil Usage	350,000	gal/year
Maximum Heat Input	20,867,428.40	MMBtu/yr

Operation Data Unit 2

Coal HHV	13.23	MMBtu/ short ton
Fuel Oil HHV	0.13802	MMBtu/gal
Projected Annual Fuel Oil Usage	400,000	gal/year
Maximum Heat Input	36,849,161.00	MMBtu/yr

CO_2 Storage

Annual Amount CO_2 stored	4.27E+09	kg

Conversions

1 kg =	2.20462	lbs
1 short ton =	2000	lbs

Project Tundra Initial Life Cycle Analysis
CO_2 Separation and Purification Plant

Summary

GHG	kg emissions / metric tonnes CO2 Processed	kg emissions / MWh produced at
CO_2	8.08	8.56
N_2O	0	0.00
CH_4	0	0.00
SF_6	0	0.00
CO2e	8.08	8.56

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors

IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

Assumptions and Data

Emissions from CO2 compressor startups and discharge		
CO2	38,338	short tons per year
	34,779,690	kg / yr
Amount of CO2 Processed by the Plant		
Total CO2 Capture Target	13,000	short tons per day
	4,745,000	short tons per year
	4,304,597	metric tonnes per year

Conversions		
1 metric tonne =	1.10231	short ton
1 metric tonne =	1000	kg

Project Tundra Initial Life Cycle Analysis
CO_2 Separation and Purification Plant Power Consumption

GHG	Electricity	Total
	Electricty Summary	
	kg emissions / MWh produced at MRY	
CO_2	49.90	49.90
N_2O	1.92E-03	1.92E-03
CH_4	1.32E-03	1.32E-03
SF_6	--	--
CO2e	50.52	50.52

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors
IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

Assumptions and Data 0.0000

Electricity Consumption		Emission Factor		Source	Emissions
MW	MWh Annual	Pollutant	**kg** / MWh		**kgs** / Year
77	674,520	CO_2	301	Historical Actuals Three Year Average (2020-2022) of historic Minnkota System	202,941,812
		N_2O	1.16E-02		7,801
		CH_4	7.93E-03		5,349
		CO_2e	305		205,459,021

Project Tundra Initial Life Cycle Analysis
Downstream - CO2 Transportation via pipeline

Summary		
GHG	**kg emissions / tonnes CO2 transported**	BUILD **kg emissions / MWh produced at MRY**
CO_2	8.57E-02	0.09
N_2O	0	0
CH_4	0	0
SF_6	0	0
CO2e	0.09	0.09

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors
IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from https://www.ipcc.ch/report/ar5/wg1/

Assumptions and Data

Pipeline Loss		
Total Released CO2	366.13	metric tonnes per year

Amount of CO2 Processed by the Plant		
Total CO2 Capture Target	13,000	short tons per day
	4,745,000	short tons per year
	4,304,597	metric tonnes per year
Tonnes CO2 Tranported	4,269,817.02	metric tonnes per year

Conversions		
1 metric tonne =	1.10231	short ton
1 metric tonne =	1000	kg

Project Tundra Initial Life Cycle Analysis
Downstream - Electricity Transmission

Summary	
GHG	**kg emissions / MWh produced at MRY**
CO_2	0
N_2O	0
CH_4	0
SF_6	7.85E-05
CO2e	1.84E+00

AR5 IPCC 2013 GWP Factors - 100 year	
CO_2	1
N_2O	298
CH_4	36
SF_6	23,500

Appendix J Table J.1. GWP Characterization Factors
IPCC. (2013). Climate Change 2013 The Physical Science Basis. New York: Cambridge University Press: Intergovernmental Panel on Climate Change Retrieved December 12, 2013, from

Assumptions and Data

Electricity transmision emissions

GHG	Emission Factor	Unit
SF6	7.85E-05	kg / MWh

Given in FOA Appendix J

APPENDIX F – MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

TUNDRA SGS
SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Wells

Facility(GHGRP) ID 579201

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT (SFP) DESIGNATIONS

Within the text of this monitoring, reporting, and verification plan, Tundra SGS SFPs and their individual sections for Broom Creek and Deadwood are designated as follows:

Attachment 1: Tundra SGS – Carbon Dioxide Geologic SFP (Broom Creek) Case No. 29029-29031

Section 1 – Pore Space Access
Section 2 – Geologic Exhibits
Section 3 – Area of Review
Section 4 – Supporting Permit Plans
Section 5 – Injection Well and Storage Operations
Appendix A – Data, Processing, Outcomes of CO_2 Storage Geomodeling and Simulations
Appendix B – Well and Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Near-Surface Monitoring Parameters and Baseline Data
Appendix D – Testing and Monitoring: Quality Control and Surveillance Plan
Appendix E – Risk Assessment Emergency Remedial and Response Plan
Appendix F – Corrosion Control Matrix
Appendix G – Financial Assurance Demonstration Plan
Appendix H – Storage Agreement Tundra Broom Creek: Secure Geologic Storage Oliver County, North Dakota
Appendix I – Storage Facility Permit Regulatory Compliance Table

Attachment 2: Tundra SGS – Carbon Dioxide Geologic SFP (Deadwood) Case No. 29032-29034

Section 1 – Pore Space Access
Section 2 – Geologic Exhibits
Section 3– Area of Review
Section 4 – Supporting Permit Plans
Section 5 – Injection Well and Storage Operations
Appendix A – Data, Processing, Outcomes of CO_2 Storage Geomodeling and Simulations
Appendix B – Well and Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Near-Surface Monitoring Parameters and Baseline Data
Appendix D – Testing and Monitoring: Quality Control and Surveillance Plan
Appendix E – Risk Assessment Emergency Remedial and Response Plan
Appendix F – Corrosion Control Matrix
Appendix G – Financial Assurance Demonstration Plan
Appendix H – Storage Agreement Tundra Broom Creek: Secure Geologic Storage Oliver County, North Dakota
Appendix I – Storage Facility Permit Regulatory Compliance Table

*Attachments within this MRV document will follow use the following referencing convention:

- A1 and A2 will refer to the Attachments, A1 being the Broom Creek SFP and A2 being the Deadwood SFP.
- Numbers or letters that appear after the colon will represent the numbered section or appendix of the appropriate Storage Facility Permit. For example:
  - A1:3.1.1 will direct the reader to refer to Section 3.1.1, (Area of Review Section, Written Description Subsection) within the Broom Creek SFP.
  - A2:A will direct the reader to refer to Appendix A (Data, Processing, Outcomes of CO_2 Storage Geomodeling and Simulations) within the Deadwood SFP

TUNDRA SGS
SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

1.0 PROJECT DESCRIPTION

Minnkota Power Cooperative, Inc. (Minnkota) is a regional generation and transmission cooperative headquartered in Grand Forks, North Dakota, providing wholesale power to 11 member–owner rural electric distribution cooperatives in eastern North Dakota and northwestern Minnesota. Minnkota also acts as the operating agent of the Northern Municipal Power Agency, which serves the electric needs of 12 municipalities in the same geographic region as the Minnkota member–owners.

Minnkota's primary generating resource is the two-unit Milton R. Young Station (MRYS), a mine-mouth lignite coal-fired power plant. The mine, which provides the lignite coal for MRYS, is owned and operated by BNI Coal, Inc. (BNI) and is located adjacent to the MRYS facility. Minnkota prepared this MRV plan in support of the operation, reporting, and accounting for the storage component of Project Tundra, a carbon capture retrofit to MRYS with saline formation geologic storage. Project Tundra proposes 20 years of operation and the secure geologic storage of an approximate cumulative total of 77.5 MMt of carbon dioxide (CO_2) over the course of the 20 years of injection into two saline aquifer reservoirs: the Broom Creek and Deadwood–Black Island. The Broom Creek is being primarily targeted for the total injection of 77.5 MMt however the Deadwood-Black Island has a projected capacity of 23.4MMt over 20 years, which provides the project with contingent capacity or expansion opportunities. However, Deadwood-Black Island formation is being primarily contemplated as a back-up or redundant storage facility. The geologic storage facility and operation are referred to as Tundra SGS. The Tundra SGS surface facilities, wellsite, and operating location comprise land mostly associated with the coal-mining operation of BNI, the area where MRYS is located, and the land is primarily industrial and agricultural. The nearest densely populated area is Center, North Dakota, which is approximately 3.4 miles northwest of the Tundra SGS site (Figure 1-1).

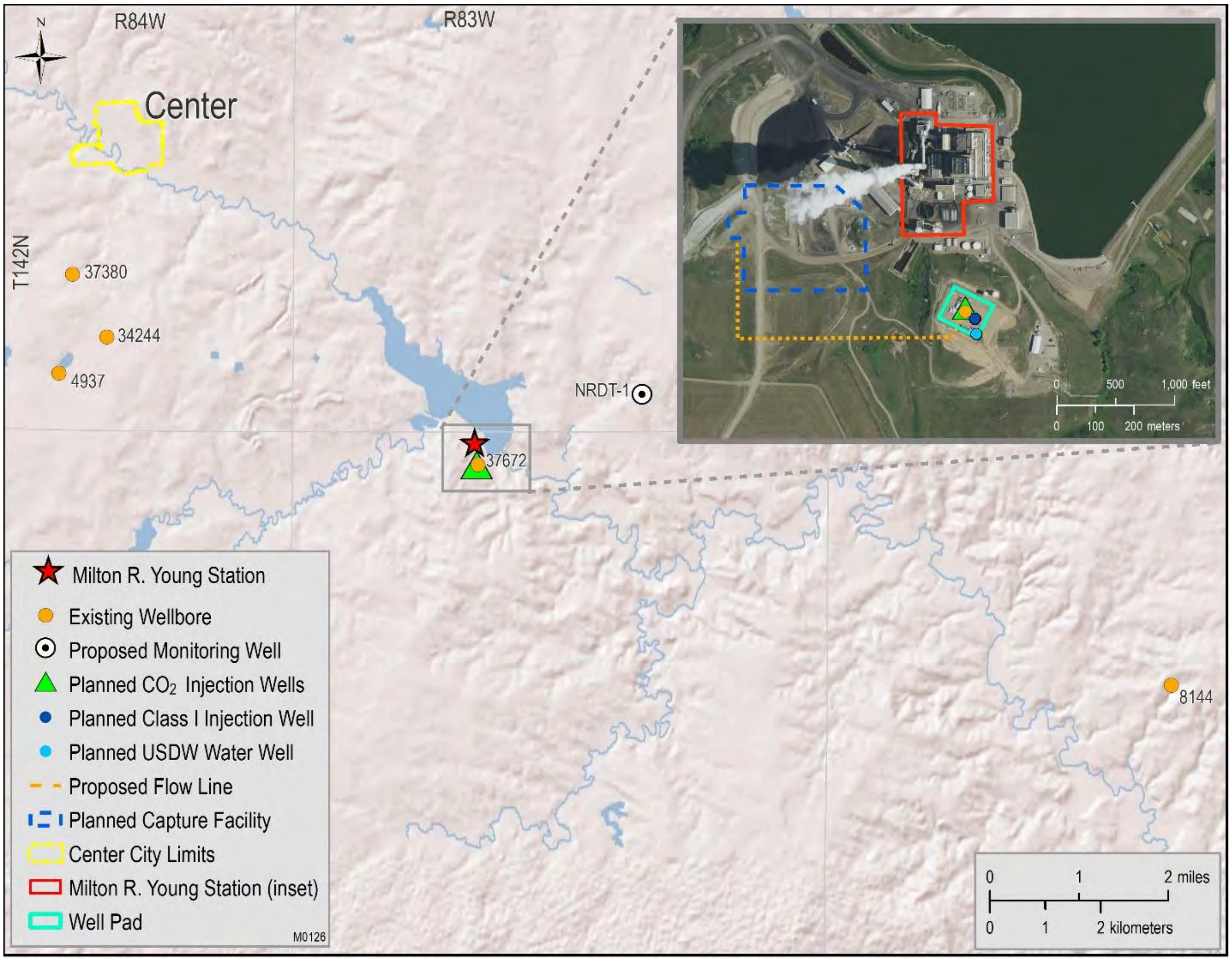


Figure 1-1. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the proposed CO_2 flowline and well pad layout. The red star denotes MRYS. The existing J-ROC1 wellbore (37672) is the wellbore planned for reentry and conversion to a Class VI injection well, which will be renamed Liberty 1. Offset wells (8144, 37380, 34244, and 4937) are included as they were evaluated in the area of review (AOR) of the Tundra SGS Carbon Dioxide Geologic Storage Facility Permit (SFP) for both Broom Creek and Deadwood storage reservoirs (A1 and A2).

1.1 Operation and Equipment

Tundra SGS plans to capture and store an average of 4 MMt/yr of CO_2 over the course of 20 years of injection, followed by 10 years of post-injection site care. MRYS Units 1 and 2 will be retrofitted with a capture facility system that utilizes amine absorption technology to generate a high-purity stream of CO_2 from the flue gas. The CO_2 captured will be dehydrated and compressed to a supercritical state, then transported via a 0.25-mile flowline to the storage site, where it will be securely and permanently stored in saline geologic formations. Figure 1-2 provides a simplified process flow diagram of the Tundra SGS project, which includes the CO_2 flowline from the metering station (M1) at the outlet of the capture facility compressor and the Phase 1 and Phase 2 injection and monitoring wells (Figure 1-2).

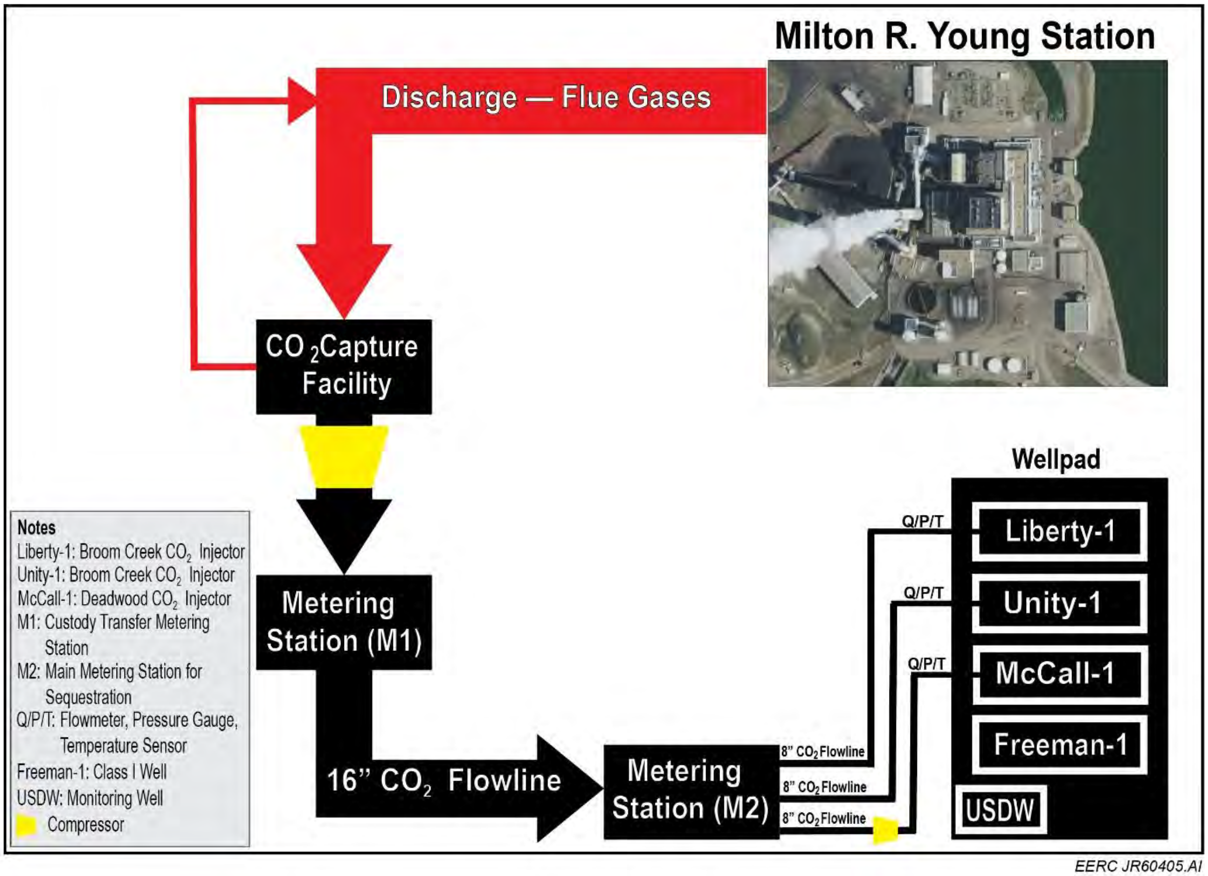


Figure 1-2. Flow diagram for Tundra SGS capture, transport, and storage facilities (USDW is underground source of drinking water).

Tundra SGS will receive captured and dehydrated CO_2 at the compressor outlet (M1), then it will be transported 0.25 miles via CO_2 flowline to the metering station (M2) for distribution to the injection wells for secure and permanent storage in the Broom Creek and Deadwood–Black Island geologic formations. These two storage formations as well as their confining seals have been extensively characterized by Minnkota through local and regional studies led by the Energy & Environmental Research Center (EERC). The focus of these studies includes North Dakota geology, results of three stratigraphic wells drilled on-site, special logs, coring, fluid sampling, seismic surveys, and an advanced numerical model, as described in A1:1 and A2:1.

The project proposes a phased development approach, with Phase 1 construction and operation of two injector wells in the Broom Creek reservoir (approximately 5,000 feet in depth), targeting 100% of the captured CO_2 volume. Following validation through operations in Phase 1, the owner and operator will assess the need to construct a third well, the McCall-1. This additional well would be completed in the Deadwood–Black Island reservoir (approximately 10,000 feet in depth) to store any excess CO_2 identified in Phase 1. The stacked storage concept and phased development approach allows the project to maximize the areal extent of the storage facilities, provides operational flexibility and redundancy, and generates further assurance to investors and stakeholders.

In addition to the three proposed injection wells, the injection pad, located within the MRYS fence line, will include one dedicated monitoring well for the lowest USDW as well as associated surface facility infrastructure that will accept CO_2 transported via a CO_2 flowline. Layout of the wells and surface facility infrastructure can be found at Figure 1-2. Minnkota proposes one deep subsurface monitoring well (NRDT-1) installed on Minnkota property located approximately 2 miles northeast of the injection site.

This procedure is applicable to Tundra SGS storage facility operations consisting of the following infrastructure:

SFP Case Number: **29029, 29030, 29031**
UIC Class VI, ADP Form No. 28643[Unity-1]
UIC Class VI, ADP Form No. 30200[Liberty-1]
UIC Class VI, ADP Form No. 29077 [NRDT-1]
SFP Case Number: **29032, 29033, 29034**
UIC Class VI, ADP Form No. 28977 [McCall-1]
UIC Class VI, ADP Form No. 29077 [NRDT-1]

The current mailing address for the Tundra SGS facility, as the storage facility operator, is the following:

Minnkota Power Cooperative, Inc.
c/o Tundra SGS
5301 32nd Avenue South
Grand Forks, ND 58201

1.2 Environmental Setting/Geology

The Williston Basin lies in the western half of North Dakota; this area has a long history of hydrocarbon exploration and utilization. This region has been identified as an excellent candidate for long-term CO_2 storage because of the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structural character and tectonic stability. The proposed location of Tundra SGS is approximately 3.4 miles southeast of the town of Center on the eastern flank of the Williston Basin. This proposed facility location serves as a suitable site for an injection operation, as it is located outside of the primary oil-producing fields, with little to no well development that would interfere with storage operations and containment. Further discussion of potential mineral zones is found at A1:2.6 and A2:2.6.

The target CO_2 storage reservoir for Tundra SGS Phase 1 is the Broom Creek Formation, a predominantly sandstone horizon lying 4,740 feet below the MRYS facility (Figure 1-3). The lower Piper and Opeche and Spearfish Formations (hereafter "Opeche/Spearfish Formation") serve as the primary confining zone overlying the Broom Creek Formation. This confining interval comprises 56 feet of mudstones, siltstones, and interbedded evaporites of the undifferentiated Opeche/Spearfish Formation overlain by 90 feet of mudstones and siltstones of the lower Piper Formation (Picard Member and lower). The Amsden Formation (dolostone, limestone, and anhydrite) underlies the Broom Creek Formation and serves as the lower confining zone. Together, the Opeche–Picard (upper confining), Broom Creek, and Amsden Formations (lower confining) make up the CO_2 storage complex for Tundra SGS Phase 1 operations.

The target CO_2 storage reservoirs for Tundra SGS Phase 2, if pursued, are the predominantly sandstone horizons of the Black Island and Deadwood Formations, lying approximately 9280 feet below MRYS (Figure 1-3). The shales of the Icebox Formation conformably overlie the Black Island and serve as the primary confining zone. The Icebox Formation provides a suitable confining layer, with an average thickness of 118 feet. The continuous shales of the Deadwood Formation B Member serve as the lower confining zone. One hundred and fifty-five feet below the lower injection horizon in the Deadwood Formation B is Precambrian metamorphosed granite. Together, the Icebox (upper confining), Black Island, and Deadwood Formations comprise this CO_2 storage complex for Tundra SGS Phase 2. For additional details regarding the site characteristics, refer to A1:2 and A2:2.

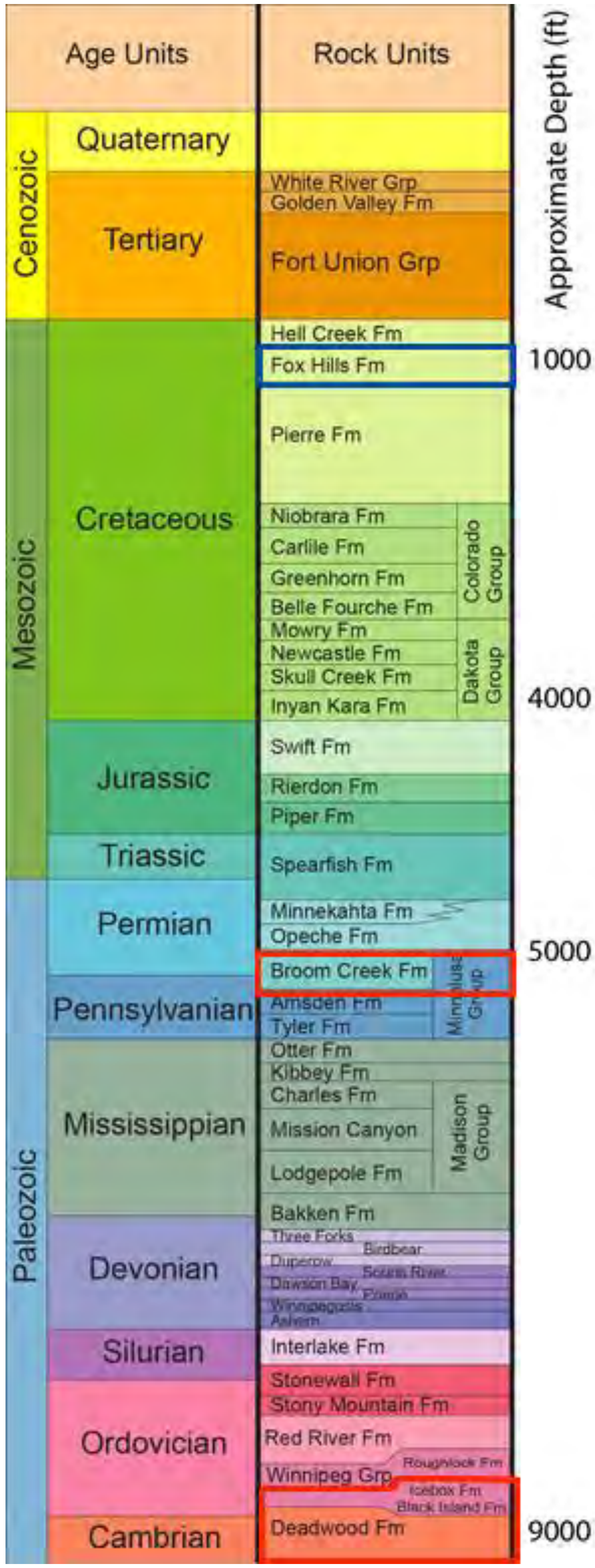


Figure 1-3. Stratigraphic column of North Dakota. Red boxes around the Broom Creek and Deadwood Formations delineate the targeted injection zones.

1.3 Reservoir Model

1.3.1 Broom Creek (Phase 1)

Phase 1 includes two wells: Liberty-1 (originally drilled as J-ROC 1, a stratigraphic well to be converted to a Class VI injector) and Unity-1 (Figure 1-2). Numerical simulation of CO_2 injection in the sandstones of the Broom Creek Formation predicted the wellhead injection pressure (WHP) of both wells would not exceed 1700 psi during injection. Bottomhole pressures (BHPs) reached 3,035.1 and 3,018.3 psi for Liberty-1 and Unity-1 wells, respectively. For the Broom Creek CO_2 plume boundary delineation, the CO_2 plume boundary was modeled using operating assumptions of 20 years at a rate of an annual 4 MMt/year for the first 15 years and 3.5 MMt/year for Years 16 through 20. The reservoir simulation model indicated target injection rates were consistently achievable over 20 years of injection. A total of 77.5 MMt of CO_2 would be injected into the Broom Creek Formation with two wells at the end of 20 years. Injected volumes were 41.1 and 36.4 MMt for the Unity-1 and Liberty-1 wells, respectively. A maximum formation pressure increase of 488 psi is estimated in the near-wellbore area during the injection period (A1:A).

1.3.2 Deadwood (Phase 2)

The Deadwood–Black Island reservoir model simulation for Phase 2 includes the McCall-1 well, drilled on the same pad as the Broom Creek wells (Figure 1-2). This model was constrained by WHP and bottomhole fracture gradient without any injection rate constraint. Within the sandstones of the Black Island and Deadwood Formations, numerical simulation of CO_2 injection predicted that injection BHP will not exceed 6,179 psi during injection operations, assuming a WHP limit of 2,800 psi is maintained. Cumulative CO_2 injection at the above-described pressure conditions was 23.4 MMt over the 20 years of injection. The resulting average injection rate of CO_2 into the Black Island and Deadwood Formations was 1.17 MMt/year. Near the wellbore area, a maximum increase of 1620 psi was estimated within the Black Island and Deadwood Formations.

Through numerical simulation efforts, long-term CO_2 migration potential was investigated in each of the Broom Creek and Deadwood models. The results did not indicate migration outside the storage facility area boundaries in either scenario. Storage facility area boundaries were established using a 20-year injection period, with the output boundary at Year 20 identified at a 5% CO_2 saturation rate and then rounded outward to the nearest 40-acre tract (A1:A).

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area

The active monitoring area (AMA) is defined as "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free-phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) The area projected to contain the free-phase CO_2 plume at the end of year t+5" (40 Code of

Federal Regulations [CFR] § 98.449). For purposes of this MRV plan, Minnkota proposes that the Broom Creek AOR, as delineated in Attachment 1, Section 3, serve as the AMA for both the Broom Creek and the Deadwood–Black Island storage facilities (Figure 2-1). Based on review of the data and information of record, and data and information collected in support of A1 and A2, there are no known or suspected lateral leakage pathways within the area projected to contain free-phase CO_2 and the default one-half mile buffer zone.

2.1.1 Tundra SGS AOR Delineation in Accordance with U.S. Environmental Protection Agency (EPA) and North Dakota Rules

Under North Dakota Century Code (NDCC) and North Dakota Administrative Code (NDAC) storage facility and Class VI requirements for an AOR, delineation was completed based on the Project Tundra SFP. The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (NDAC § 43-05-01-01). The NDAC requires the operator develop an AOR and corrective action plan utilizing the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, the NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (NDCC § 38-22-08). Minnkota elected to permit the storage facility area boundaries based on the 20-year reservoir model output discussed in Section 1.3 and then added an additional buffer rounding out to the nearest 40-acre tract.

The Broom Creek proposed AOR was delineated using a risk-based AOR approach (A1:3.1). The risk-based delineation examines the area encompassing the region overlying the injected free-phase CO_2 and the region overlying the extent of increased formation fluid pressure sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or conductive fractures) are present. The risk-based approach established that the CO_2 plume boundary is also the extent of the AOR boundary (A1:3.1). However, in compliance with the NDAC evaluation and monitoring requirements, Minnkota extended the permitted AOR boundary beyond the risk-based delineation to encompass the storage facility boundary plus an additional 1-mile buffer (A1:3.1). Utilizing the 20-year operating output, plus a 1-mile buffer for monitoring from the outset of operations, provides significant assurance that operations can be conducted safely and as contemplated within the permitted storage facility.

The proposed AOR for the Deadwood–Black Island storage facility used EPA Method 1 to establish the AOR (A2:3.1). The Deadwood–Black Island reservoir model simulation discussed in Section 1.1 yielded an annual average injection rate of approximately 1.17 MMt/year for 20 years. Applying EPA Method 1, the Deadwood–Black Island AOR has a larger areal extent, due to the estimated pressure front under EPA Method 1, than the Broom Creek AOR, which applied the risk-based AOR approach; however, the free-phase CO_2 plume for Deadwood is contained in the delineated AOR for Broom Creek. Because of the significant overlap between the two AORs and the phased development approach, the Tundra SGS technical evaluation and proposed monitoring plan were developed to account for monitoring both injection horizons in accordance with the requirements and to the maximum areal extent simulated.

2.1.2 *Tundra SGS AOR Encompasses Subpart RR AMA of both Broom Creek and Deadwood*

AMA minimum delineation requirements are found in 40 CFR § 98.449 and used in Figure 2-1. Using a period of t=20 years, the Broom Creek delineated AMA boundary and the Deadwood–Black Island AMA boundary fall within the Broom Creek AOR. Minnkota proposes that the Broom Creek AOR serve as the AMA for both the Broom Creek and the Deadwood–Black Island storage facilities (AOR outlined in black in Figure 2-1), delineation of the AOR is discussed further in A1:3 and A2:3. Aligning the calculated AMA under the more expansive Broom Creek AOR allows for consistent monitoring and recording throughout the proposed injection and post-injection periods and avoids unnecessary duplication and complication in reporting.

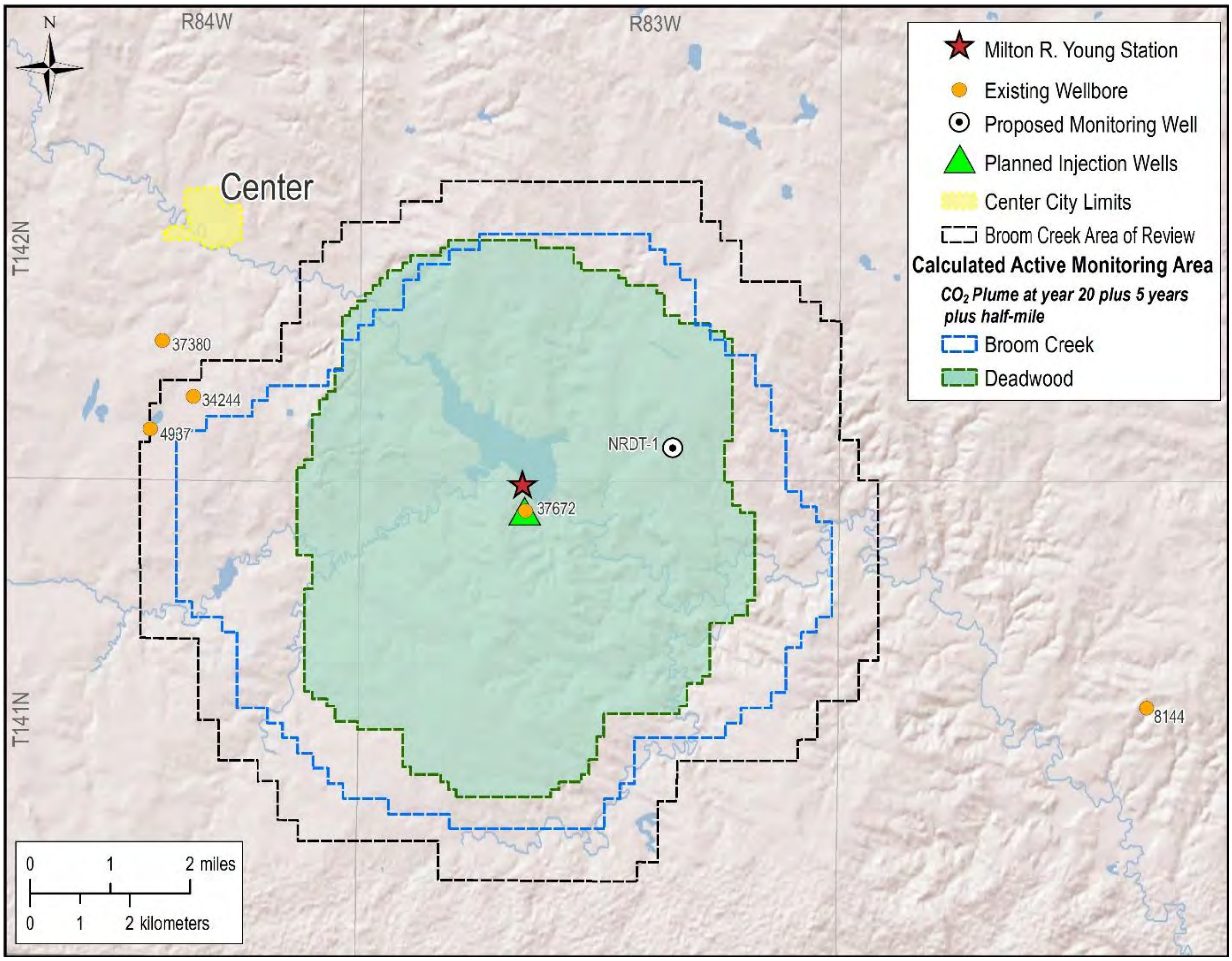


Figure 2-1. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the calculated AMA in comparison to the permitted AOR. AOR subsumes the calculated AMA for both formations and exceeds requirements for AMA; therefore, the AOR serves as the AMA for Project Tundra.

2.2 Maximum Monitoring Area

The maximum monitoring area (MMA) as defined in 40 CFR § 98.440–449 (Subpart RR) is the area defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The calculated MMA delineated in Figure 2-2 for the Broom Creek and Deadwood–Black Island storage facilities uses a period of t=20 years and represents the period t+10 and a half-mile buffer extending beyond that boundary. The permitted AOR for Broom Creek, as delineated in A1 and A2, exceeds the minimum areal extent required by the Subpart RR approach for delineating the MMA (Figure 2-2); therefore, Minnkota proposes that the Broom Creek AOR serve as the calculated MMA for both the Broom Creek and the Deadwood–Black Island storage facilities.

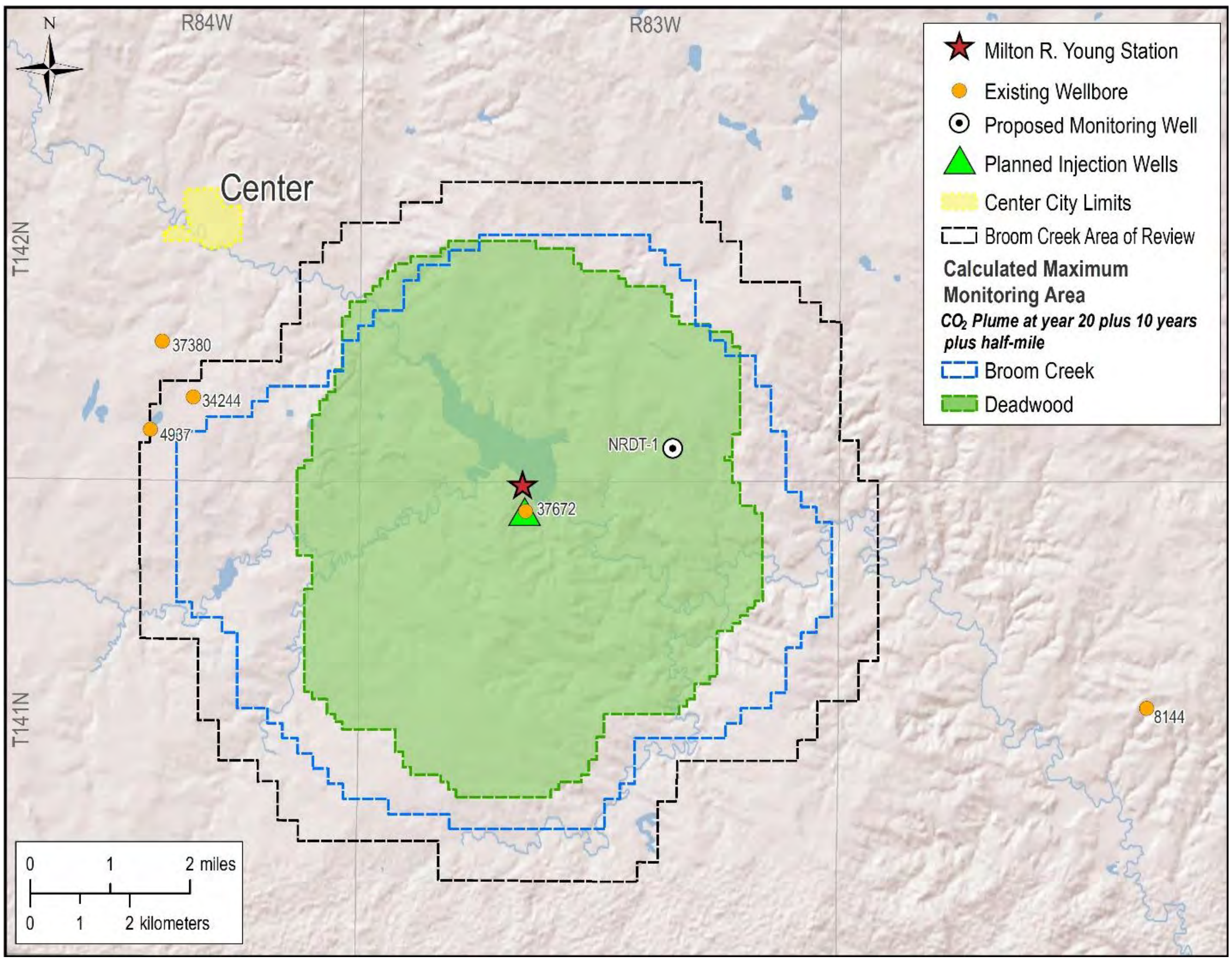


Figure 2-2. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the calculated MMA in comparison to the permitted AoR. AOR subsumes the MMA for both formations and exceeds requirements for the MMA; therefore, the AOR serves as both the AMA and MMA for Project Tundra.

Aligning the calculated AMA and MMA under the more expansive Broom Creek AOR allows for consistent monitoring and recording throughout the proposed injection and post-injection periods and avoids unnecessary duplication and complication in reporting.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2, as described in A1:4.1 and A2:4.1, comprises three distinct periods: 1) preoperational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. The time frame of these monitoring periods will encompass the entire life cycle of the injection. For purposes of this MRV plan, it is expected that reporting will be initiated during the operational period and continue through the post-injection period.

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

Preoperational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and inherent uncertainty associated with the measurement of each of the key storage system parameters. An understanding of the repeatability and variability of each measurement is key to successfully determining the amount of CO_2 that is contained in the formation at any given time. This information will be incorporated into the final Class VI permit. If results from this preoperational monitoring period necessitate changes to this MRV plan, an amendment will be submitted prior to the start of operations.

The operational injection period is focused on validating and updating numerical models of the storage system and ensuring that the geologic storage project is operating safely and is protecting USDWs. Lastly, the purpose of post-operational monitoring is to verify the stability of the CO_2 plume location and assess the integrity of all decommissioned wells. The duration of these three monitoring periods is a minimum of 1 year, 20 years, and a minimum of 10 years, respectively.

3.0 EVALUATION OF POTENTIAL PATHWAYS AND MECHANISMS FOR LEAKAGE TO THE SURFACE

An evaluation of potential pathways for CO_2 leakage to the surface during the implementation of the project was completed by representatives of Minnkota as well as third-party subject matter experts from Oxy Low Carbon Ventures and the EERC. During these meetings, potential leakage pathways were identified and evaluated for the following:

- Existing wellbores
- Faults and fractures
- Natural or induced seismicity
- Flowline and surface equipment
- Lateral migration of CO_2 beyond the AOR

- Vertical migration: injector and monitoring wells
- Vertical migration: diffuse leakage through seal

This leakage assessment determined that none of the pathways required corrective action and the probability of leakage is unlikely. However, a robust monitoring program, described in A1:4.1 and 2:4.1, and summarized in Table 5-2, forms the basis for this MRV plan.

3.1 Existing and Planned Wellbores

Five existing wellbores and one potential wellbore were evaluated as potential leakage pathways. There are no other known wellbores that could impact the project because there is no active or prior production of oil and gas in the vicinity of the Tundra SGS project. A detailed discussion of potential mineral zones is found at A1:2.6 and A2:2.6. Table 3-1 summarizes the existing wellbore names and status and future actions. Additional explanation is provided after the table.

Table 3-1. Wellbore Summary

	Well Name	Current Status	Future Status
a	J-ROC1 [NDIC[1] No. 37672]	Openhole plugged (surface casing installed)	Reenter and construct Class VI injection well
b	J-LOC1 [NDIC No. 37380]	Temporarily abandoned (cased hole)	TBD[2]
c	BNI-1 [NDIC No. 34244]	Openhole plugged	NA[3]
d	Herbert Dresser 1-34 [NDIC No. 4937]	Openhole plugged	NA
e	Little Boot 15-44 [NDIC No. 8144]	Openhole plugged	NA
f	Future Wells (Freeman-1)	NA	Class I injection well

[1] North Dakota Industrial Commission.
[2] To be determined.
[3] Not applicable.

3.1.1 J-ROC1 [NDIC No. 37672]

The J-ROC1 well was drilled by Minnkota and the EERC in 2020 as part of the CarbonSAFE North Dakota project, Phase III. An entire geologic column from surface to the Precambrian was drilled and core collected, and fluid samples as well as special logs were obtained. The well is currently in a plugged and abandoned status openhole in the injection section, which will be reentered and converted to a CO_2 injector well. Further discussion of reentry program provided in Supplement-1. Once the well conversion takes place, J-ROC1 will be renamed Liberty-1, on authorization of pending reentry drilling permit. This well will be monitored in real time during injection to detect any potential mechanical integrity issues associated with potential leakage, and once the injection period ceases, the well will be properly plugged and abandoned.

3.1.2 J-LOC1 [NDIC No. 37380]

The J-LOC1 well was drilled by Minnkota in 2020 as a stratigraphic well. The construction materials used were compatible with Class VI and CO_2 operating standards. The well was drilled through the entire geologic column from surface to the Precambrian. The drilling program included collecting core, obtaining fluid samples and special logs, and injectivity testing in the Broom Creek and Deadwood Formations. The well is currently in a temporarily abandoned status, plugged for future use. Abandonment procedure and well schematic details can be found in A2:3, Table 3-5 and Figure 3-8. In case the well has no future potential use, it will be permanently abandoned to ensure integrity. This well is located slightly outside the delineated AOR for the Broom Creek, but it is included in the pressure front delineated for Deadwood–Black Island Formation storage.

3.1.3 BNI-1 [NDIC No. 34244]

The BNI-1 well was drilled in 2018 as a stratigraphic well by the EERC under North Dakota CarbonSAFE Phase II. The well was drilled through the Broom Creek Formation and reached total depth in the Amsden Formation. The well was plugged and abandoned in 2018 in accordance with approved guidance and regulations of the state.

3.1.4 Herbert Dresser 1-34 [NDIC No. 4937]

The Herbert Dresser 1-34 well was drilled and plugged in 1970 after being classified as a dry hole. The well was replugged in 2001 by BNI. It was drilled through the Broom Creek Formation and reached total depth at the Charles Formation. Several cement plugs isolate any potential movement of fluids between the different flow units and USDW aquifers.

3.1.5 Little Boot 15-44 [NDIC No. 8144]

The Little Boot 15-44 well was drilled and abandoned as a dry hole in 1981. The well was drilled through the Broom Creek and reached the Black Island Formation. It was properly plugged and abandoned with cement plugs isolating the different flowing units before the Fox Hill Aquifer. This well is outside the delineated AOR for the Broom Creek Formation but is included in the pressure front delineated for the Deadwood–Black Island Formation.

3.1.6 Future Wells

Minnkota is planning to drill Freeman-1, a Class I well, on the same well pad of the injection site to dispose of the residual water from the capture process. The Inyan Kara is the proposed geologic formation for disposal and is stratigraphically located approximately 1,000 feet above the Broom Creek Formation. The water disposal zone is separated from the Phase 1 Broom Creek target by a series of impermeable rocks. Since the Class I well will not penetrate the primary or secondary confining seals of the Broom Creek storage facility, the risk of leakage is very unlikely.

There is no active or prior production of oil and gas in the vicinity of the Tundra SGS area. This fact, combined with the understanding that potential leakage pathways of injected CO_2 through existing wellbores are very unlikely, makes the Tundra SGS site an ideal location for the geologic storage of CO_2.

3.2 Faults and Fractures

No known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified in the Tundra SGS area through site-specific characterization activities, prior studies, or previous oil and gas exploration activities.

A 5-mile-long seismic source test and 6.5-mi^2 3D seismic survey were acquired in 2019, and a 12-mi^2 3D seismic survey and 21 miles of 2D seismic lines were acquired in 2020 (Figure 3-1). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The 2D seismic data provided a means to connect the two 3D seismic data sets and ensure consistent interpretation across the Tundra SGS area. The seismic data were used for assessment of the geologic structure, interpretation of interwell heterogeneity, and well placement (A1:2.5 and A2:2.5). No structural features, faults, or discontinuities that would cause 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 seismic data.

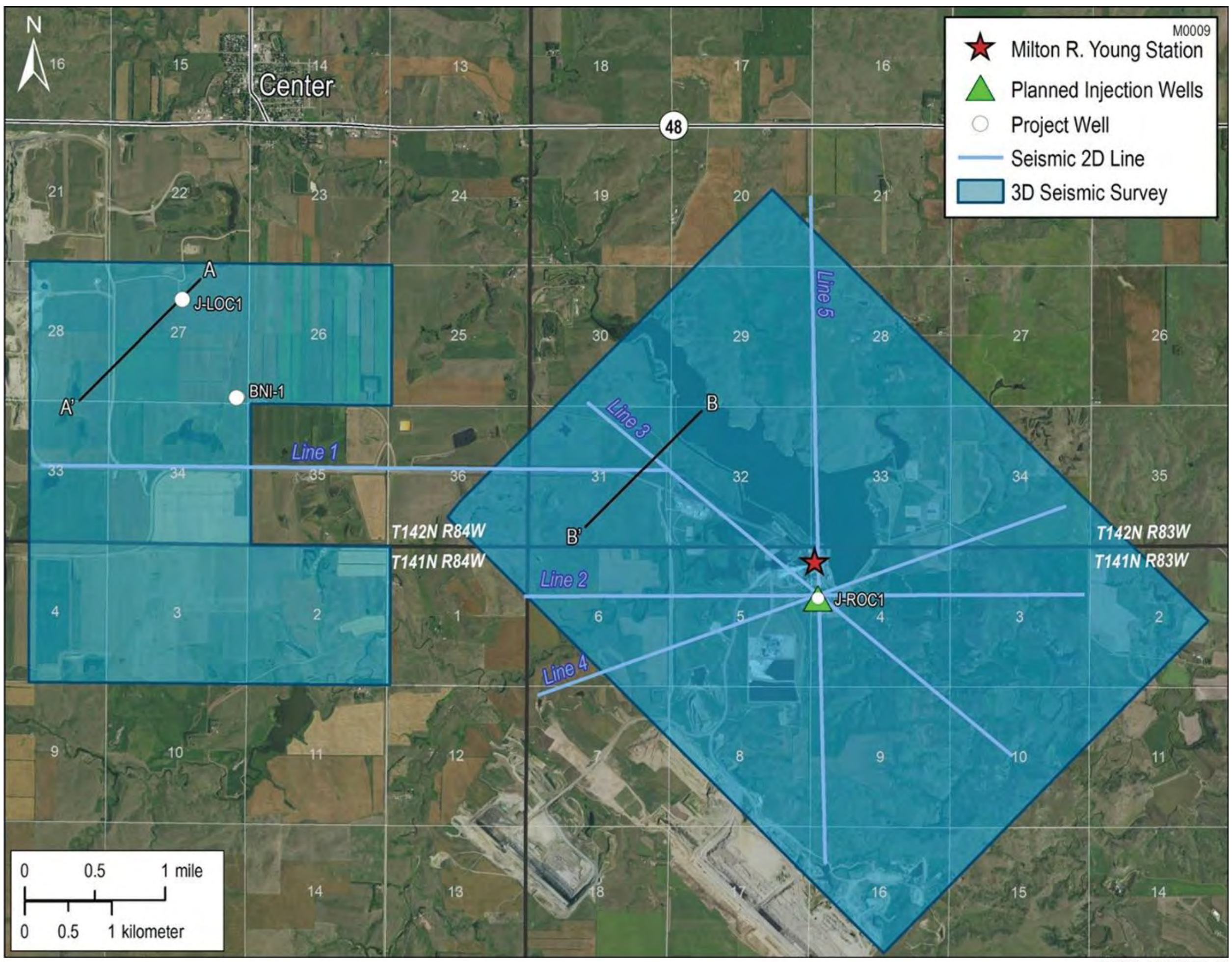


Figure 3-1. Map showing the 2D and 3D seismic surveys in the Tundra SGS area.

Leakage through faults and fractures was shown to be very unlikely to nearly impossible in the risk assessment carried out. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the emergency remedial and response plan (A1:E and A2:E). Estimating volumetric losses of CO_2 would require consideration of the leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based on the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed, and volumetric accounting would follow industry standards as applicable.

3.3 Natural or Induced Seismicity

Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Table 3-2) (Anderson, 2016). Of these 13 seismic events, only three have occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 3-2). The seismic event recorded closest to the Tundra SGS storage facility area occurred 39.6 miles from the J-ROC1 well in Huff, North Dakota (Table 3-2). This seismic event is estimated to have been a 4.4 magnitude from the reported modified Mercalli intensity (MMI) value. The results in Table 3-2 indicate stable geologic conditions in the region surrounding the potential injection site.

Table 3-2. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, mile	Longitude	Latitude	City or Vicinity of Seismic Event	Map Label	Distance to Tundra SGS J-ROC1 Well, mile
Sept 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	124.6
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	149.1
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	144.1
Aug 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	67.4
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	156.0
Nov 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	61.6
Nov 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	166.5
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	164.9
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	39.6
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	74.9
Oct 26, 1946	3.7**	U	−103.70	48.20	Williston	K	140.2
April 29, 1927	0.2**	U	−102.10	46.90	Hebron	L	43.4
Aug 8, 1915	3.7**	U	−103.60	48.20	Williston	M	136.4

* Estimated depth.

** Magnitude estimated from reported MMI value.

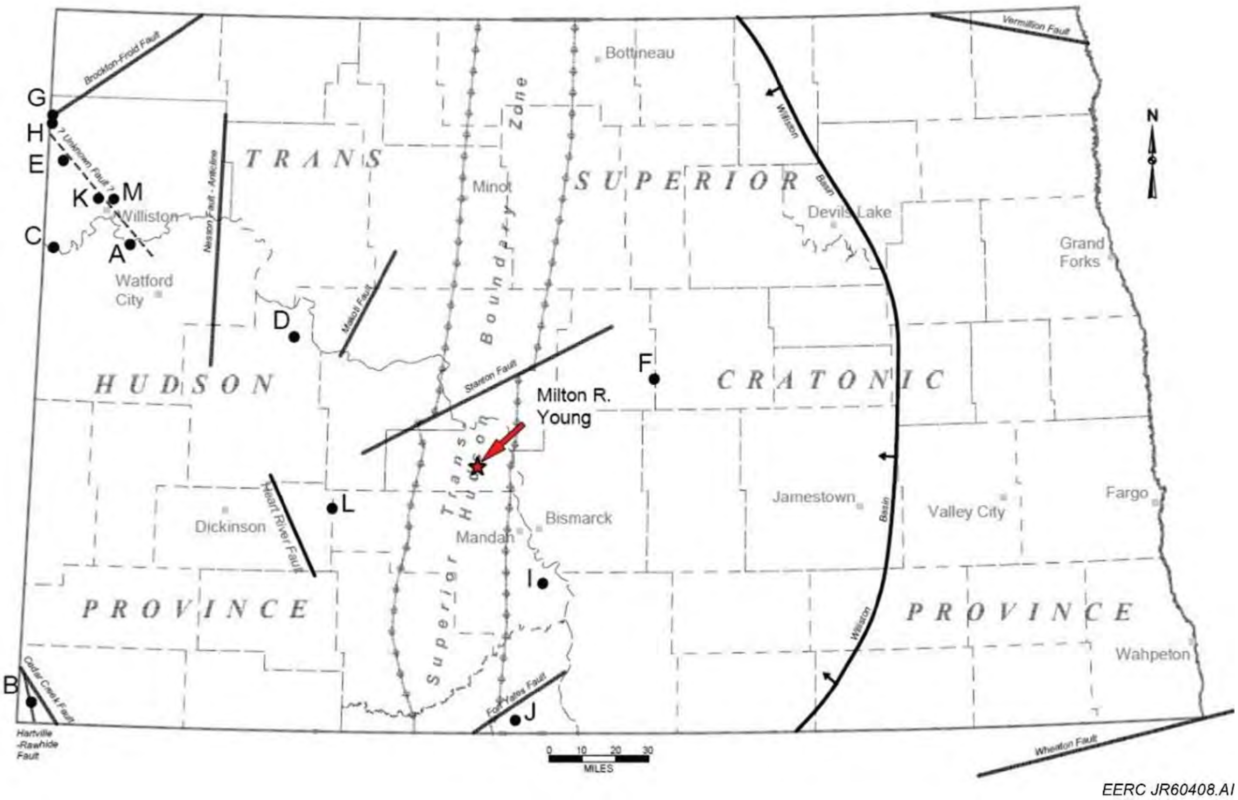


Figure 3-2. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016).

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment. Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging seismic events occurring in North Dakota, with less than two such events predicted to occur over a 10,000-year time period (Figure 3-3) (U.S. Geological Survey, 2019).

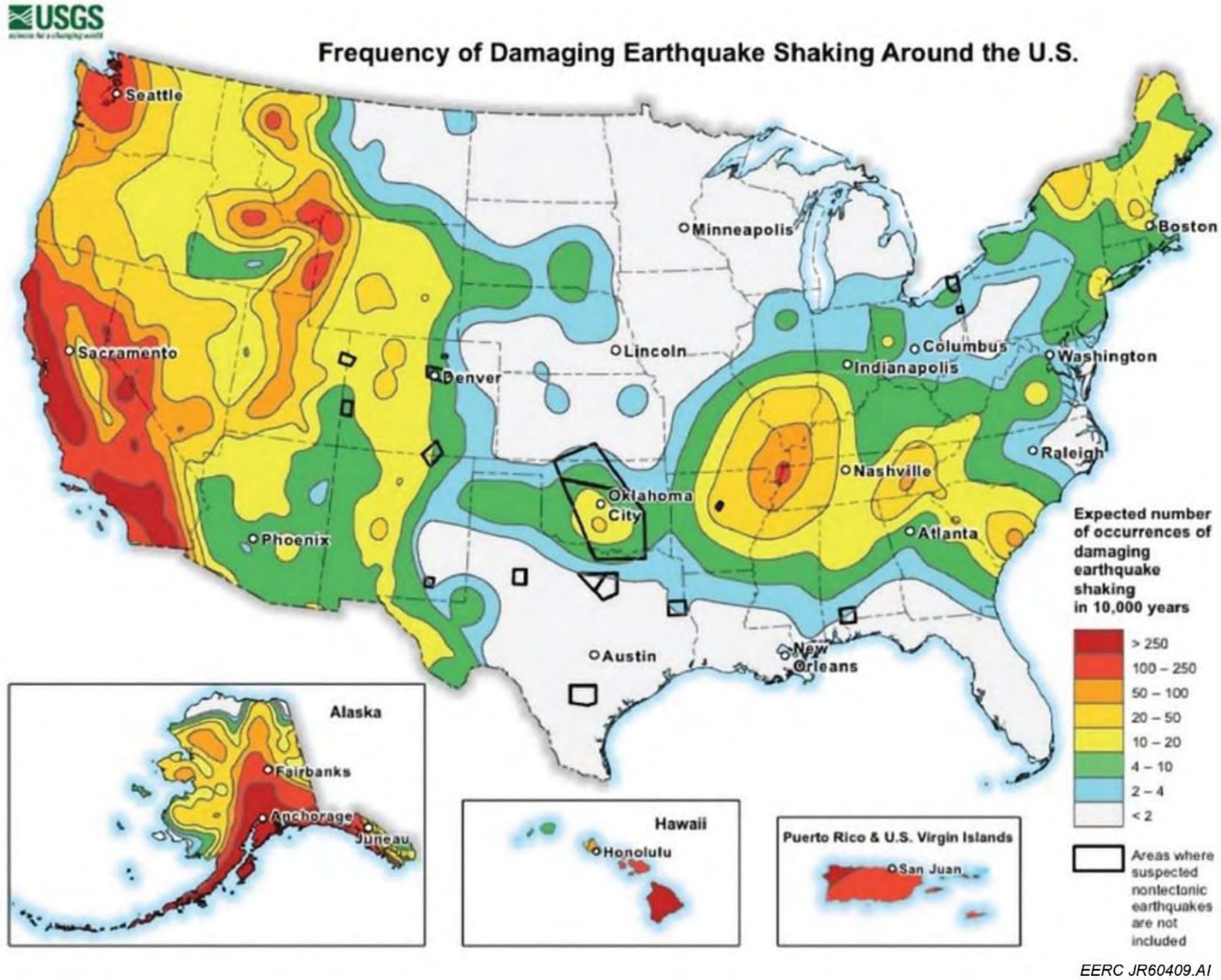


Figure 3-3. Probabilistic map showing how often scientists expect damaging seismic events to occur throughout the United States (U.S. Geological Survey, 2019). The map shows a low probability of damaging seismic events (less than two events per 10,000 years) occurring in North Dakota.

To understand potential induced seismicity, a detailed geomechanical study is described in A1:2.5 and A2:2.5, was carried out to understand the highest possible risk scenario. A scenario where the interpreted Precambrian fault extends into the Deadwood Formation was considered even though the seismic data suggest that it does not. The failure analysis indicated that a pressure increase of 3,600–4,800 psi would be required to induce shear failure.

The maximum expected pressure changes in the Deadwood Formation due to planned injection activities do not exceed 1,800 psi, which is well below the 3,600–4,800-psi pressure threshold for failure (Figure 3-4). Additionally, the injection interval is approximately 120 feet above the Precambrian–Deadwood boundary, and expected pressure change due to planned injection activities at the Precambrian–Deadwood boundary does not exceed 60 psi. Analysis of the geomechanics study results, as applied to the characteristics of the interpreted Precambrian fault and site-specific geomechanical data, suggests planned injection activities will not cause induced seismicity. Furthermore, no faults interpreted in the AOR would affect the Broom Creek Formation; therefore, the probability of induced seismicity is minimal.

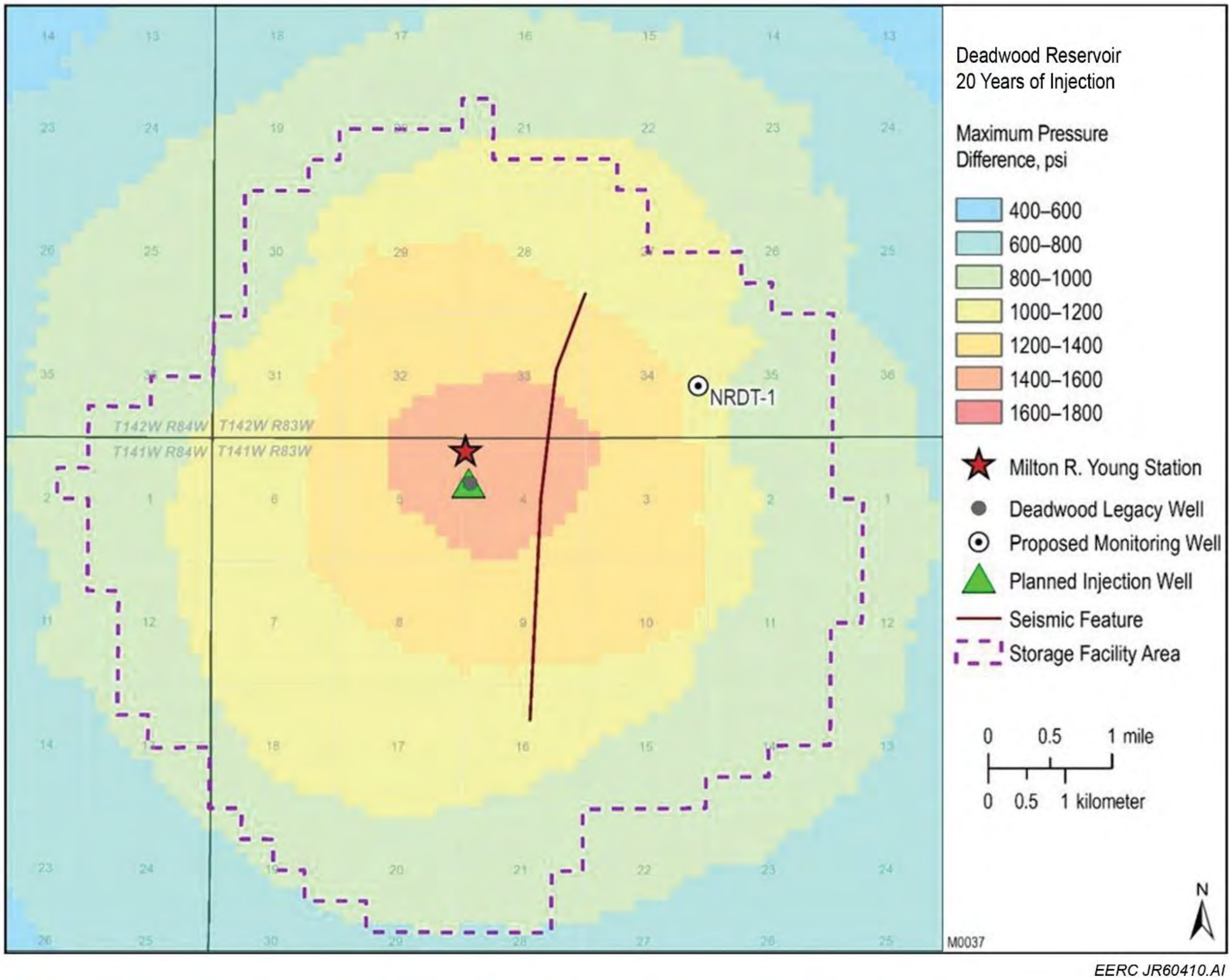


Figure 3-4. Map showing the maximum pressure change expected within the injection zone from the proposed injection activities. The location of the interpreted paleochannel and flexure is indicated by the red line.

Leakage through natural or induced seismicity was shown to be very unlikely to nearly impossible through the risk assessment. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:E and A2:E). Estimating volumetric losses of CO_2 would require consideration of the leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based upon the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

3.4 Flowline and Surface Equipment

Surface equipment is the likeliest leakage pathway on the Tundra SGS site during the injection period. Surface equipment is subject to deterioration due to normal aging throughout its functional life. Corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

The Tundra SGS system includes a 16-inch surface flowline buried 4 feet to transport CO_2 from the capture facility to the sequestration site (0.25 miles). The flowline will be connected to the metering station (M2), which is located contiguous with the south side of the well pad. Distributed temperature-sensing/distributed acoustic-sensing (DTS/DAS) fiber optics will be installed along the flowline as part of the leak detection program and mechanical integrity protocol. Flowmeters and temperature and pressure transducers will be installed at each metering station.

Each well will be connected independently to the metering station (M2) by 8-inch flowlines equipped with a dedicated flowmeter and pressure and temperature transducers to monitor well performance. Shutoff devices will be installed in the well flowlines to control any potential release and send alarms to the automated system. Pressure gauges will be installed on the wellhead to monitor annular pressure between tubing and casing.

Surface components of the injection system, including the CO_2 transport flowline and wellhead, will be monitored using CO_2 leak detection equipment. Routine visual inspections will be conducted and real-time operating parameters tracked through an automated system for alarm notification and process management. The Tundra SGS mechanical integrity and monitoring program strives to proactively identify potential surface leak events to ensure the integrity of the facility and minimize the amount of CO_2 released to the ambient air. Maintenance on surface equipment after the delivery point (M2) may require venting cumulated CO_2 volumes before isolating a section of the system; this amount would be quantified and reported.

The risk of leakage in surface equipment is mitigated through:

i. Adhering to regulatory requirements for construction and operation of the site.
ii. Implementing highest standards on material selection and construction processes for the flowline and wells.
iii. The implementation of best practices and a robust mechanical integrity program as well as operating procedures.
iv. Continuous monitoring through an automated system and integrated databases.

As a result, the risk of leakage through surface equipment (under normal operating conditions) is unlikely and the magnitude will vary according to the failure observed. A leakage event from instrumentation or valves could represent a few pounds of CO_2 released during several hours, while a puncture in the flowline could represent several tons of CO_2 until the shutoff device stops the injection automatically or the operator ceases the CO_2 supply.

The second risk identified was potential leakage at surface equipment through catastrophic damage to surface facilities because of an object striking the equipment or a natural event that causes disconnection and loss of containment during the injection period at or before the wellhead. To account for such a hypothetical event, the project team performed a leak model simulating a worst-case blowout scenario and a dispersion model to evaluate risks and potential mass of CO_2 released. The model is referenced in the risk assessment evaluation matrix and emergency response plan, with the results included in the financial assurance demonstration plan, referenced sections of the applications are found at A1:E, A2:E, and A1:4.3, A2:4.3. This leakage scenario could represent thousands of tons of CO_2 released during the pendency of the response period before the well is controlled and integrity is reestablished. Even though this event is considered high-impact, occurrence is very unlikely since most of the flowline will be buried; the wellhead, valves, and instrumentation will be protected by barriers; and will have a fence around the equipment location, located on private MRYS property. Further, containment of any leak is enhanced by the well pad design, including a 4-foot berm and double liner to avoid any brine spill to surface water bodies.

The risk of leakage through surface equipment or major damage is present during the injection phase of the project and reduces to almost zero during the post-injection site care period. At cessation of the injection period, the injector wells will be properly plugged and abandoned and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the monitoring well, NRDT-1, identified as a potential leakage pathway at the wellhead valves or in the instrumentation.

3.5 Lateral Migration of CO_2 Beyond the AOR

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), which confines the CO_2 within the storage facility area. Numerical simulations of CO_2 injection predict slow lateral migration of the plume throughout the injection and post-injection period (A1:A and A2:A). This is the result of the trapping mechanisms combined with the effects of buoyancy and the low dipping structurally characteristic of the storage complexes. 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 cap rock or lower-permeability layers present in the Broom Creek and Deadwood Formations and then outward. The free-phase CO_2 plume migrates outward, favoring relatively high permeabilities and low pressure bounded vertically by the low-permeability cap rock. This process results in a higher concentration of CO_2 at the center, which gradually spreads to the edge of the plume at Year t, where the CO_2 saturation is lower.

As the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 is gradually lost after year t+10. 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.

Early monitoring and operational data will be used to evaluate conformance of the operating storage system with the requirements of the SFP using both observations and history-matched simulation of CO_2 and pressure distribution. The early monitoring and operational data will be used for additional calibration of the geologic model and associated simulations. These calibrated simulations and model interpretations will be used to demonstrate the current and predicted future lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

Tundra SGS will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure front for comparison to the information provided in the storage reservoir permit. If the data predicts additional lateral movement of the plume, Tundra SGS would proactively meet with landowners to negotiate in good faith terms for leasing the pore space interests, good faith attempt to obtain consent is required under North Dakota Century Code, Chapter 38-22, and revise the monitoring area to appropriately establish equivalent monitoring protocols implemented in the original AMA. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and post-operational periods.

The risk assessment identifies lateral migration and impact for surface leakage as events with very low likelihood.

3.6 Vertical Migration: Injection and Monitoring Wells

Design and construction of the Class VI injector wells (Liberty-1, Unity-1, and McCall-1) as well as the in-zone monitoring well, NRDT-1, will follow the standards required for UIC Class VI wells to minimize any potential leak due to loss of integrity in the wellbores. Material selection complies with CO_2 operating standards, and the wells will be instrumented for continuous, real-time monitoring of well integrity. Well instrumentation will be integrated with an automated data management system to provide alerts and activate the shutoff device if the threshold for controlling parameters is exceeded. Additionally, the wells will follow a rigorous corrosion and mechanical integrity program, described in A1:4.1 and A2:4.1, to ensure proper maintenance of the facilities and timely response in case substandard conditions are detected.

Once the injection period ceases, the injector wells will be evaluated for mechanical condition with corrosion and casing inspection logs and will be properly abandoned with CO_2-resistant cement according to the detailed plugging procedure proposed in A1:4.6 and A2:4.6. The NRDT-1 monitoring well will continue to be operational until plume stabilization and the issuance of a certificate of site closure, then the same rigorous plug-and-abandonment protocol will be followed as proposed for the injector wells.

Based on the design and monitoring program proposed, the project defined the risk of leak through these pathways as unlikely. The amount and timing, if it were to occur, will be minimum since the program is designed to shut off injection or alert the operator to manually shut off injection until the alarm is clear or remediation is complete. The timing of the leak will be estimated based on the collected data from the monitoring tools until the event is cleared or remediation is completed.

3.7 Vertical Migration: Diffuse Leakage Through Seal

The primary mechanism for geologic confinement of the stored CO_2 in the Broom Creek and Deadwood–Black Island Formations will be containment of the initially buoyant CO_2 by the cap rock (Opeche–Picard, Icebox), under the effects of relative permeability and capillary pressure. Figure 3-5 shows a stratigraphic column with the well schematic for the injector and monitoring wells and highlights the additional secondary seals and buffer formation.

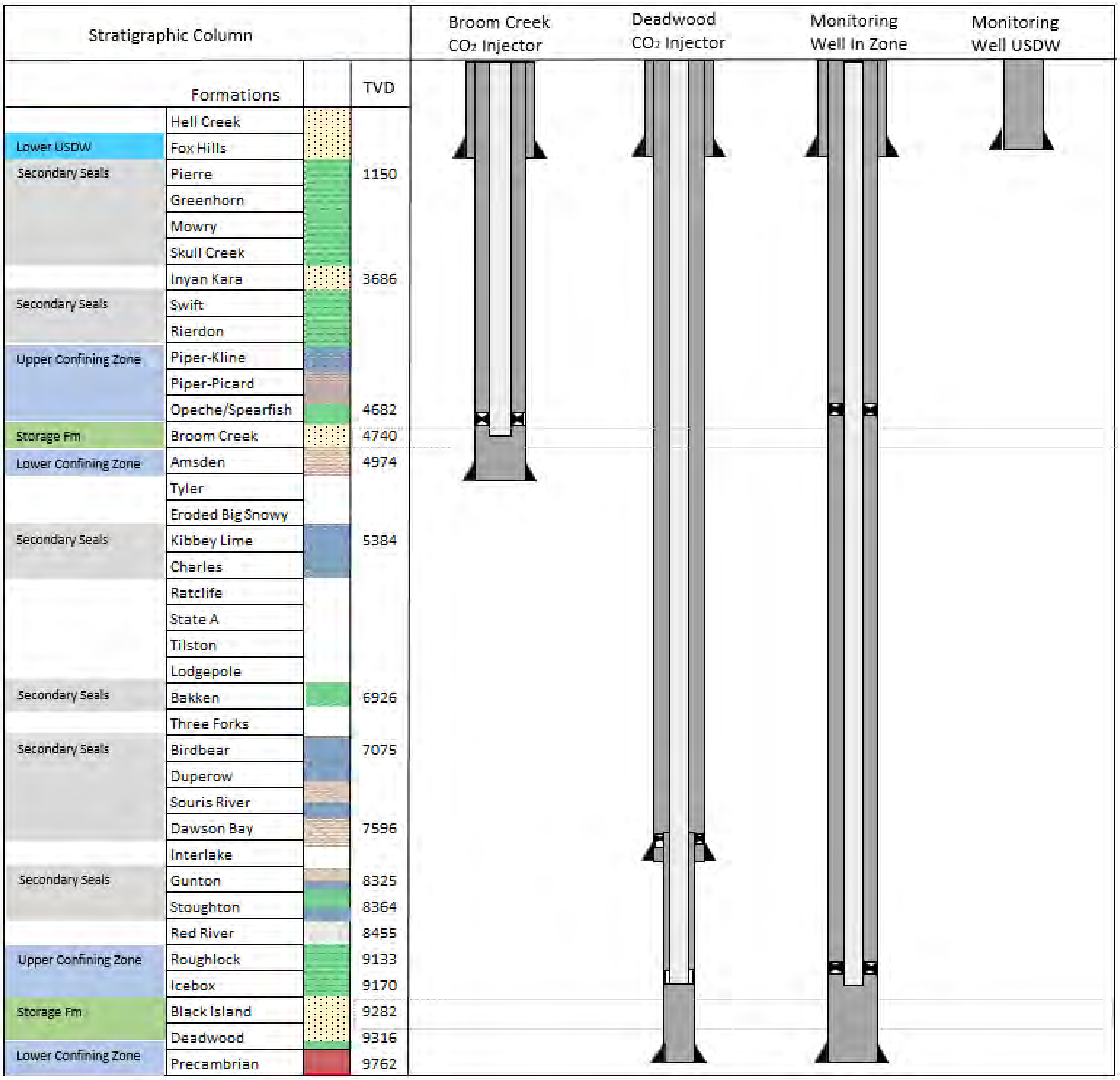


Figure 3-5. Stratigraphic column and well schematic for injector and monitoring wells.

The Picard Member of the Piper Formation within the study area consists of siltstone, while the Opeche/Spearfish Formation consists of tight, silty mudstone. Both intervals are free of transmissive faults and fractures. When considered as a single interval, the Opeche–Picard and other formations create an impermeable, laterally extensive cap rock to the Broom Creek Formation capable of containing injected CO_2. The Opeche–Picard interval is 4636 feet below the land surface at the storage site and 154 feet thick at the Tundra SGS site.

In addition to the Opeche–Picard interval, which serves as the cap rock for the Broom Creek Formation, 820 feet of impermeable rock formations separate the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. Surrounding the storage facility area, an average of 2,545 feet of impermeable intervals separates the Inyan Kara Formation and the lowest USDW, the Fox Hills Formation.

Within the Tundra SGS area, the Icebox Formation serves as the upper confining zone of the Black Island and Deadwood Formations. The Icebox Formation consists mostly of impermeable shale, is 9,308 feet below the land surface, and reaches a thickness of 118 feet within the storage facility area. The cap rock has sufficient areal extent and integrity and is free of transmissive faults and fractures to contain injected CO_2.

Impermeable rocks above the primary cap rock include the Roughlock Formation and Red River D Member, which make up the first significant group of secondary confining formations. Together with the Icebox Formation, these formations reach a thickness of 612 feet separating the next overlying permeable zone: the Red River A, B, and C Members. Above the Red River Formation, more than 1,000 feet of impermeable rock acts as an additional seal between the Red River and Broom Creek Formations. No known transmissible faults are within these confining systems in the project area.

As previously noted, at the same time, lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). As the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 is gradually lost after Year t+10. 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. Over a much longer period (>100 years), mineralization of the injected CO_2 will ensure its long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation; therefore, adsorption is not considered to be a viable trapping mechanism in this project (A1:A and A2:A).

The upper and lower confining zones for the proposed storage formations were largely characterized through core sampling and lab analysis as well as imaging and sonic tools to define the sealing capacity. The great thickness of impermeable rock above each of the storage formations provides a best-in-class secondary seal if the main confining zone were to fail, thereby further reducing the risk of diffusion through the leak to almost zero.

Leakage through vertical migration was shown to be very unlikely to nearly impossible in the risk assessment carried out. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:4.2, A1:E, A2:4.2, and A2:E). Estimating volumetric losses of CO_2 would require consideration of the leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based on the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

The risk assessment defined this risk as an unlikely event. Response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:4.2, A1:E, A2:4.2, and A2:E). Estimating volumetric losses would require consideration of the leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based on the presenting facts and circumstances, a modeling of the geophysical measurements to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

Tundra SGS proposes a robust monitoring program based on the detailed risk assessment performed during the application for the storage facility and UIC Class VI permit. The program covers direct and indirect monitoring of the CO_2 plume, a corrosion and mechanical integrity protocol, and monitoring of near-surface conditions as well as induced seismicity and continuous, real-time surveillance of injection performance. Tundra SGS also proposes a detailed emergency remedial and response plan that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting for each risk.

Figure 4-1 summarizes the monitoring techniques proposed based on the leakage pathway analyzed for this MRV plan to provide a vision for the surveillance and management of the site.

These methodologies target early detection of the abnormalities in operating parameters or deviations from the baseline and threshold established for the project. These methodologies will lead to a verification process to validate if a leak has occurred or if the system has lost mechanical integrity. The data collected during monitoring are also used to calibrate the numerical model and improve the prediction for the injectivity, CO_2 plume, and pressure front. Table 4-1 provides a full picture of the monitoring frequency in different periods of the project life, and Table 4-2 summarizes for each technique the leakage path that it is targeting to detect. For additional details regarding strategy for detecting and quantifying surface leakage of CO_2, refer to A1:4.1, E, F and A2:4.1, E, F.

Integrated Remote Automated System (SCADA) and Surveillance Protocol

Leak Detection through:

- Routine visual inspections conducted by field personnel.
- Facilities inspection with handheld and Optical Gas Imaging (OGI) cameras.
- Automated CO_2 sensors in the wellhead.
- Real time (RT) injection performance on surface and downhole (Pressure, Temperature, flow).
- Distribute temperature sensing (DTS) technology to track well integrity and vertical conformance downhole.
- DTS and Distributed acoustic sensing fiber (DAS) for CO_2 flow line monitoring.
- Mechanical Integrity Program.
- Corrosion Monitoring Program.
- Annular pressure test on injectors and monitoring wells.

Reservoir Monitoring through:

- Monitoring wells in reservoir .
- Pressure and temperature gauges downhole in injector.
- 4D seismic surveys.
- Interferometric synthetic aperture radar (INSAR).
- History Match Reservoir Simulation.
- Saturation Log in reservoir.
- Real time temperature profile (DTS) on injectors.
- Seismometers network (induced events)

Operational & Near Surface Monitoring through:

- Soil Gas Analysis
- CO_2 stream analysis.
- Water sampling USDW (baseline and during operation)

Figure 4-1. Tundra SGS monitoring strategy.

Table 4-1. Summary of Tundra SGS Monitoring Strategy

Method	Pre-injection (baseline 1 year)	Injection Period (20 years)	Post-injection (10 years)
CO_2 Stream Analysis – Gas Composition	Pre-injection	Quarterly	NA
Pressure Gauges and Temperature Sensors at Surface – Injection Wells and Flowline	NA[1]	Real time	NA
Pressure Gauges and Temperature Sensors at Surface – Monitoring Wells	NA	Real time	Quarterly
Flowmeters (mass/volume) – Injection Wells and Flowline	NA	Real time	NA
Visual Inspections	Start-up	Weekly	Quarterly
Automated Remote System (SCADA)[2]	Start-up	Real time	NA
OGI[3] Cameras	Start-up	Quarterly	If required
NDIA4 CO_2 Leak Sensors in Wellhead – Injectors	NA	Real time	NA
NDIR CO_2 Leak Sensors in Wellhead – Monitors	NA	Real time	Real time
Handheld CO_2 Monitor	NA	Weekly	Quarterly
Soil Gas Analysis	3–4 seasonal samples per year	Three to four seasonal samples per year	Three to four seasonal samples every 3 years
Water Sampling USDW	Three to four sample events per selected wells (baseline)	One sample in each selected well at the following frequency: • Year 1 to 3: once a year • At Year 5 • Every 5 years after that	• Three to four sample events at cessation of injection • Three to four sample events before site closure
Water Sampling Surface Water	Three to four sample events per selected wells (baseline)	One sample in each selected well at the following frequency: • Year 1 to 3: once a year • At Year 5 • Every 5 years after that	• Three to four sample events at cessation of injection • Three to four sample events before site closure
Cement Bond Logs	After cementing	If needed	Prior to P&A[5]

[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Optical gas imaging.
[4] Nondispersive infrared.
[5] Plugged and abandoned.
[6] Electromagnetic.
[7] Downhole.
[8] Reservoir saturation tool.

Continued . . .

Table 4-1 Summary of Tundra SGS Monitoring Strategy (continued)

Casing Inspection Tool (EM[6]/sonic) – Injection Wells	Baseline	• Every 5 years for Broom Creek • Annually for Deadwood─Black Island • During workover	Prior P&A
Casing Inspection Tool (EM/sonic) – Monitoring Wells	Baseline	Every 5 years	Prior to P&A
Temperature Log – Monitoring Wells	Baseline	Annually	Annually
Annular Pressure Test – Injection Wells	Prior injection	• Every 5 years for Broom Creek • Annually for Deadwood─Black Island • During workovers	Prior to P&A
Annular Pressure Test – Monitoring Wells	During completion	• Every 5 years	• Every 5 years • During workovers • Prior to P&A
Corrosion Coupons	NA	Quarterly	NA
DTS/DAS Fiber – Installed on the Casing – Injection Wells	NA	Real time	NA
DTS/DAS Fiber – Main Flowline	NA	Real time	NA
DH[7] Pressure Gauges and Temperature Sensors – Injection Wells	NA	Real time	NA
DH Pressure Gauges and Temperature Sensors – Monitoring Wells	NA	Real time	Bimonthly
RST[8] Log (pulse neutron) – Monitoring Wells	Baseline	Every 5 years	Every 5 years
RST Log (pulse neutron) – Injection Wells	Baseline	As needed	NA
Pressure Falloff Test – Injection Wells	Prior injection	Every 5 years	Prior to P&A
2D/3D Time-Lapsed Surface Seismic	Baseline	Every 5 years	Every 5 years
Interferometric Synthetic Aperture Radar	Baseline	Continuous monitoring	Continuous monitoring
Surface Seismometers	Baseline	Real time	NA

[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Optical gas imaging.
[4] Nondispersive infrared.
[5] Plugged and abandoned.
[6] Electromagnetic.
[7] Downhole.
[8] Reservoir saturation tool.

Table 4-2. Monitoring Strategies and Leakage Pathway Associated to Detect CO_2

Method	Existing Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration Injectors and Monitoring Wells	Lateral	Diffuse Leakage Through Seal
CO_2 Stream Analysis – Gas Composition		X		X	X		
Pressure Gauges and Temperature Sensors at Surface – Injection Wells and Flow Line				X	X		
Pressure Gauges and Temperature Sensors at Surface – Monitoring Wells				X	X	X	
Flowmeters (mass/volume) – Injection Wells and Flowline				X	X		
Visual Inspection	X			X	X		
Automated Remote System (SCADA)			X	X	X		
OGI Cameras				X	X		
NDIR CO_2 Leak Sensors in Wellhead – Injectors				X	X		
NDIR CO_2 Leak Sensors in Wellhead – Monitors				X	X		
Handheld CO_2 Monitor	X			X	X		X
Soil Gas Analysis		X			X		
Water Sampling USDW		X			X		X
Water Sampling Surface Water		X			X		X
Cement Bond Logs					X		
Casing Inspection Tool (EM/sonic) – Injection Wells					X		

Continued . . .

Table 4-2. Monitoring Strategies and Leakage Pathway Associated to Detect (continued)

Method	Existing Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration Injectors and Monitoring Wells	Lateral Migration	Diffuse Leakage Through Seal
Casing Inspection Tool (EM/sonic) – Monitoring Wells					X		
Temperature Log – Monitoring Wells					X		
Annular Pressure Test – Injection Wells				X	X		
Annular Pressure Test – Monitoring Wells				X	X		
Corrosion Coupons				X	X		
DTS/DAS Fiber Installed on the Casing – Injection Wells		X			X		
DTS/DAS Fiber – Main Flowline				X			
DH Pressure Gauges and Temperature Sensors – Injection Wells		X			X	X	
DH Pressure Gauges and Temperature Sensors – Monitoring Wells		X			X	X	
RST Log (pulse neutron) – Monitoring Wells		X			X	X	X
RST Log (pulse neutron) – Injection Wells		X			X	X	X
Pressure Falloff Test – Injection Wells		X			X	X	
2D/3D Time-Lapsed Surface Seismic	X	X			X	X	X
Interferometric Synthetic Aperture Radar	X	X			X	X	
Surface Seismometers		X	X				

4.1 Leak Verification

Tundra SGS will monitor injection wells through continuous, automated pressure and temperature monitoring in the injection zone, monitoring of the annular pressure in wellheads, DTS alongside the casing, and routine maintenance and inspection.

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

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

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

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

Discovery of an event triggers a response, as presented in the A1 and A2, Section 4.2, emergency remedial and response plan. Response plan actions and activities will depend upon the circumstances and severity of the event. The Tundra SGS operator will address an event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery.

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

4.2 Quantification of Leakage

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

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

Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database. For additional details regarding quantification of leakage, refer to A1: 4.3.1 and A2:4.3.1.

5.0 DETERMINATION OF BASELINES

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

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

Determinations of these baselines are a critical component of a Class VI SFP. A detailed description of these baselines for both the surface and subsurface for the Tundra SGS project area are provided in A1: 4.1.6, A, B and A2: 4.1.6, A, B.

5.1 Surface Baselines

Baseline sampling includes selected domestic wells in the Square Butte Creek, Tongue River, Upper Hell Creek–Lower Cannonball and Ludlow, and Upper Fox Hills–Lower Hell Creek Aquifers and one USGS Fox Hills observation well. Verification of the domestic well status, based on viability of the well (existence, depth, access, etc.) and landowner cooperation, has been completed and selected wells sampled August 11–13, 2021.

The locations of these candidate wells are shown in A1:C and A2:C, Figure 4-2. Characterization of selected domestic wells and one USGS Fox Hills observation well will include the water quality parameters; anions; dissolved and total carbon, major cations, and trace metals; and isotope analysis to establish the natural partitioning of the groundwater constituents listed in A1:C and A2:C.

5.2 Subsurface Baseline

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

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AOR. A 3D seismic survey was conducted to establish baseline conditions in the storage reservoir.

A feasibility study of surface deformation monitoring with InSAR (interferometric synthetic aperture radar) technology will be performed to determine application before injection and to establish a baseline for the future application of this technology.

For passive seismicity monitoring, the project will install seismometer stations sufficient to confidently measure baseline seismicity 5 km from the injection area a year prior to injection. For additional information regarding surface baseline, refer to A1: 4.1.8 and A2: 4.1.8.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

Tundra SGS is a CO_2 storage site in a saline aquifer with no production associated from the storage complex. The proposed main metering station for mass balance calculation is identified as M2 in the facility diagram (Figure 1-2).

CO2I is equal to annual CO2 mass injected (metric tons) through all injection wells) for Tundra SGS, because we are not producing rather Tundra SGS is a permanent geologic sequestration operation. To calculate the annual mass of CO_2 that is stored in the storage complex, the project will use Equation RR-12 from 40 CFR Part 98, Subpart RR:

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

Where:

CO_2 = Total annual CO_2 mass stored in subsurface geologic formations (metric tons) at the facility.
CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells.
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used

to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Part 98, Subpart W.

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

The Tundra SGS project will use a volumetric flowmeter (M2) (Figure 1-2) to measure the flow of the injected CO_2 stream and will calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5 from 40 CFR Part 98, Subpart RR:

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

Where:

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

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

The Tundra SGS project characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in A1:4 and A2:4, to detect any potential leak and defined a baseline for monitoring.

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

Tundra SGS project will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98, Subpart RR:

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

Where:

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

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

The calculation of CO_{2FI}, the annual mass of CO_2 emitted (in metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead, will comply with the calculation and quality assurance/quality control requirements in Part 98, Subpart W, and will be reconciled with the annual data collected through the monitoring and surveillance plan proposed in A1:4, D and A2:4, D.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

It is proposed that this MRV plan will be implemented within 90 days of the placed-in-service date of the capture and storage equipment, including the Class VI injection wells. The project will not be placed in service until successfully completing performance testing, an essential milestone in achieving substantial completion. At the placed-in-service date, the project will commence collecting data for calculating total amount sequestered according to equations outlined in Section 7.0. As discussed under Sections 2.1 and 3.1, this proposed MRV plan was developed to account for both Phase 1 and Phase 2, and thus no modification to the MRV is anticipated if Phase 2 is pursued. Other greenhouse gas (GHG) reports are filed by the end of the third month of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time.

As described in Section 3.3, Tundra SGS anticipates that the MRV program will be in effect during the operational and post-operational monitoring periods, during which time Tundra SGS will operate the storage facilities for the purpose of secure, long-term containment of a measurable quantity of CO_2 in subsurface geologic formations. Tundra SGS anticipates a measurable amount of CO_2 injected during the operational period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, Tundra SGS will prepare a demonstration supporting the long-term containment determination in accordance with North Dakota statutes and regulations and submit a request to discontinue reporting under this MRV plan consistent with the North Dakota and Subpart RR requirements (see 40 CFR § 98.441[b][2][ii]).

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for Tundra SGS monitoring techniques and data management is provided in the Quality Assurance and Surveillance Plan found in A1:D and A2:D.

Tundra SGS will ensure compliance with the quality assurance requirement in § 98.444.

<u>CO_2 received</u>:

- The quarterly flow rate of CO_2 received by pipeline is measured at a receiving meter on the injection well path.

- The CO_2 concentration is measured quarterly upstream or downstream of the receiving meter on the injection well path.

Flowmeter provision:

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

Concentration of CO_2:

- CO_2 concentration will be measured using the appropriate standard method. All measured volumes will be converted from CO_2 to standard cubic meters at a temperature of 60°F and an absolute pressure of 1 atmosphere.

8.1 Missing Data Procedures

In the event Tundra SGS is unable to collect data needed for the mass balance calculations, procedures for estimating missing data in § 98.445 will be used as follows.

8.1.1 Quarterly Flow Rate of CO_2 Received

- Tundra SGS may use the quarterly flow rate data from the sales contract from the capture facility or invoices associated with the commercial transaction.

- A quarterly flow rate value that is missing must be estimated using a representative flow rate value from the nearest previous time period.

8.1.2 Quarterly CO_2 Concentration of a CO_2 Stream Received

- Tundra SGS may use the CO_2 concentration data from the sales contract for that quarter if the sales contract was contingent on CO_2 concentration and the supplier of the CO_2 sampled the CO_2 stream in a quarter and measured its concentration in accordance with the sales contract terms.

- A quarterly concentration value that is missing must be estimated using a representative concentration value from the nearest previous time period.

8.1.3 Quarterly Quantity of CO_2 Injected

- The quarterly amount of CO_2 injected will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

8.1.4 *Values Associated with CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment at the Facility*

- Implementation will follow missing data estimation procedures specified in 40 CFR, Part 98, Subpart W.

Any missing data should be followed up with an investigation into issues, whether they are concerned with equipment failure or incorrect estimations.

9.0 MRV PLAN REVISIONS

In the event there is a material change to the monitoring and/or operational parameters of the Tundra SGS project that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in § 98.448(d). Minnkota is the project sponsor of Tundra SGS and will contribute a portion of the total equity for the proposed storage project; other equity participants for the project have not yet been identified. As such, the MRV plan names Minnkota as the sole storage facility owner, operator, and applicant. However, at a time prior to construction of the Tundra SGS site infrastructure, Minnkota plans to contribute all necessary permits to the Tundra SGS project entity, resulting in the transfer of owner and operatorship to the Tundra SGS project. This transfer of ownership will be treated as a minor modification, which will be accomplished through submission of a certificate of representation identifying the change in ownership in accordance with 40 CFR 98.4(h) and will accurately identify and align MRV plan owner/operator/representative designation. Minnkota does not anticipate any material modification to the MRV plan, and as discussed under Section 2.1, if Phase 2 development is pursued, this proposed MRV plan accounts for all monitoring and reporting obligations under Subpart RR.

Tundra SGS reserves the opportunity to submit supplemental revisions to this proposed plan, which take into considerations responses, inquiries, and final determinations from the regulatory agencies having jurisdiction in A1 and A2 and associated Class VI drilling permits.

10.0 RECORDS RECORDING AND RETENTION

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

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.
- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

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

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

11.0 REFERENCES

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

U.S. Geological Survey, 2016, Induced earthquakes raise chances of damaging shaking in 2016: https://www.usgs.gov/news/induced-earthquakes-raise-chances-damaging-shaking-2016 (accessed December 2019).

University of North Dakota Energy and Environmental Research Center
Responses to U.S. Department of Energy's Questions on Seismic Monitoring and the Monitoring, Reporting, and Verification (MRV) Plan

University of North Dakota Energy and Environmental Research Center
Responses to U.S. Department of Energy's Questions on Seismic Monitoring and the Monitoring, Reporting, and Verification (MRV) Plan

1. What is the area around the wells that you will be surveying—will it be included in the same areas you show on p. 14?

Repeat (monitor) seismic surveys to track the extent of the CO_2 plume in the storage reservoir will be conducted within the extent of the three-dimensional (3D) seismic survey displayed on page 14 of Minnkota's approved Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) Plan.

2. When you indicate the 2D/3D seismic, what type of equipment is planned—vibroseis trucks or something else?

For two-dimensional (2D) or 3D seismic surveys, vibroseis trucks are the intended source.

3. Will you be using existing roads/ previously disturbed areas?

Existing roads and any previously disturbed paths will be used, if possible, to acquire repeat (monitor) seismic surveys. This depends largely on the availability of roads within the project area and would be more challenging to achieve with a 3D seismic survey given the greater density of receivers and source points.

4. I saw a note about 4D seismic in the table on p. 25. Can you clarify?

The term four-dimensional (4D) seismic is synonymous with repeat, monitor, or time-lapse seismic. This method of surveying involves acquisition of a baseline, or initial, seismic survey prior to CO_2 injection. After injection begins, repeat seismic surveys are conducted periodically throughout the project duration. These repeat seismic surveys are compared against the baseline survey to detect (time-lapse or 4D) changes in storage reservoir properties after injection of CO_2. The change in reservoir properties due to CO_2 injection is detectable in seismic data and is a proven method for plume extent monitoring.

5. What procedures/BMPs would your seismic company use to minimize impacts to wetlands/surface waters, cultural resources, biological resources, agricultural/irrigation tiles (i.e., avoiding certain areas, consulting w SHPO for the proposed routes, precluding seismic activity during mating or migration seasons, etc.)?

To mitigate environmental and cultural impacts, seismic surveying contractors will need to obtain all necessary permits, including land access permissions and right-of-way. Prior to seismic acquisition, site surveying and cultural mapping (e.g., pipelines, fences, waterways, etc.) will be conducted for the purpose of designing the survey to minimize acquisition impact. In North Dakota, the winter season has proven to be the ideal time for seismic acquisition due to the lower ground temperatures improving the seismic signal. Additionally, the impact to the ground from the vibroseis trucks is minimized in winter, where in warmer months ruts can become an issue in softer soil. This is also outside of the growing season, mitigating the impact to agricultural activities and land. Monitoring seismic surveys can be planned for the winter season for these reasons. Also, North Dakota regulations require that all operational incidents be reported and resolved.

6. With respect to other surface equipment, such as soil gas monitors, or other fixed arrays for monitoring, can you give approximate locations and the size of the impact? I know we're projecting a lot and we may not have locations nailed down, so understanding the size of the disturbance, approximate number of each *particular monitor, and any BMPs is helpful. For example, I have a geothermal project where they were installing some monitors in something about the size of a 5-gal bucket at the bottom of a 60ft borehole with a solar panel at the surface. Tina's team needs enough info to describe the fixed monitors and be able to quantify the impacts and discuss the ways that EERC will avoid or mitigate those impacts --consulting with agencies to avoid wetlands/ cultural resources/biological resources, getting applicable permits, following BMPs, reclaiming the drill pad, etc.*

Induced seismicity monitoring (ISM) stations, as shown in Figure 1, require permanent installation of equipment at the surface for the duration of the project. This typically includes the seismometer, which is installed either at the surface or within a shallow hole, a digitizer, communication equipment, and a solar panel for power. The ISM station is enclosed within a fence to prevent damage to the station. For a project of this size, approximately 3–5 ISM stations are anticipated. The ISM survey can be designed to place seismometer stations in locations to minimize environmental and cultural impact.

Figure 1. Example of an ISM station from the Texas Seismological Network. Image source: https://news.utexas.edu/2021/03/08/texas-earthquake-system-strengthens-national-network/

As shown in Figure 2, other surface equipment associated with monitoring the storage facility will include three soil gas profile stations, one Fox Hills (lowest underground source of drinking water [USDW]) groundwater monitoring well, and a reservoir-monitoring well (NRDT-1). The soil gas profile stations are approximately 4" in diameter and are drilled to approximately 15-20 feet beneath the ground surface. The surface footprint of each soil gas profile station is about 0.5'x0.5'. The groundwater monitoring well is approximately 8" in diameter and drilled to a depth of approximately 1,200'. The surface footprint of the groundwater well is about 1'x1'.

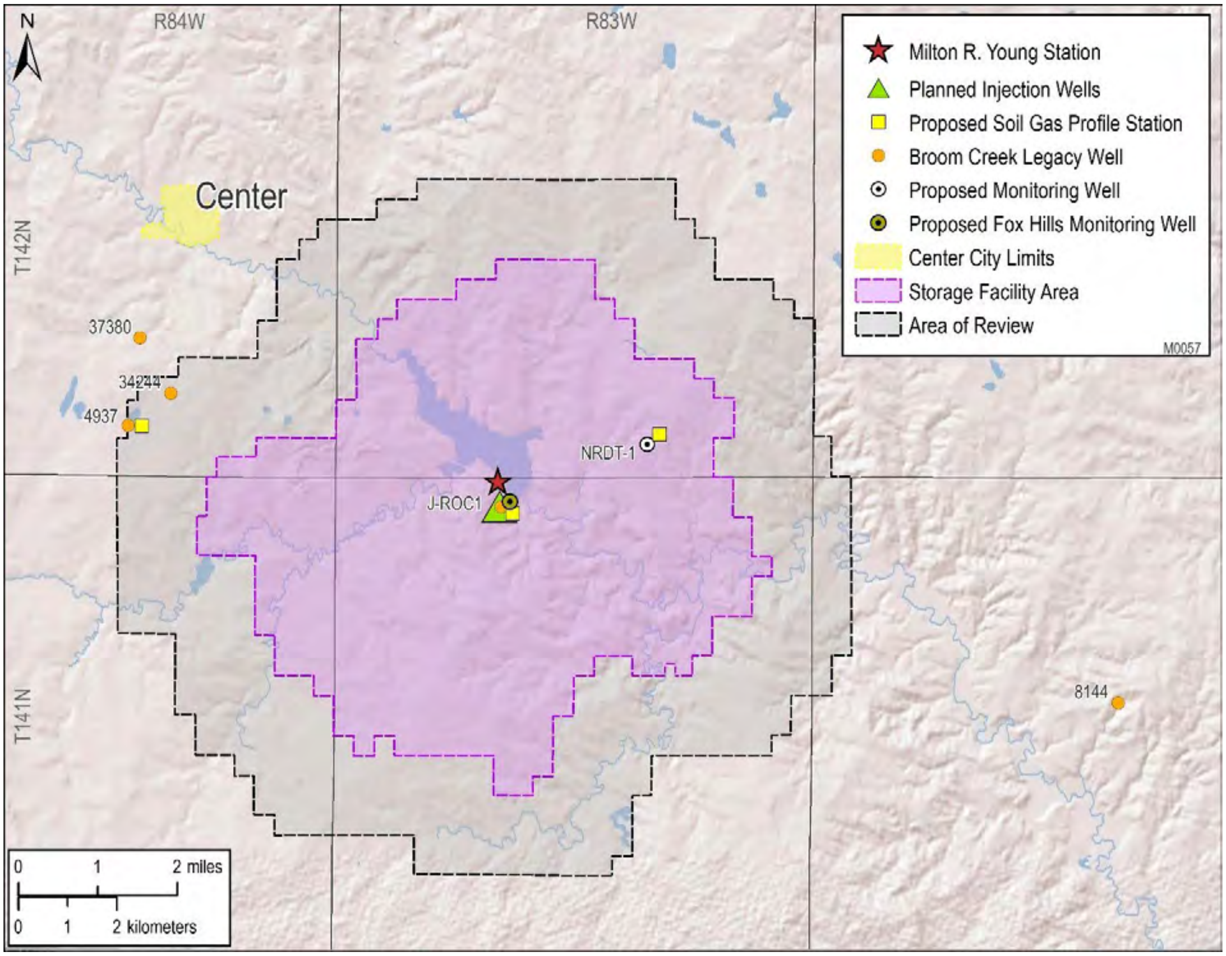
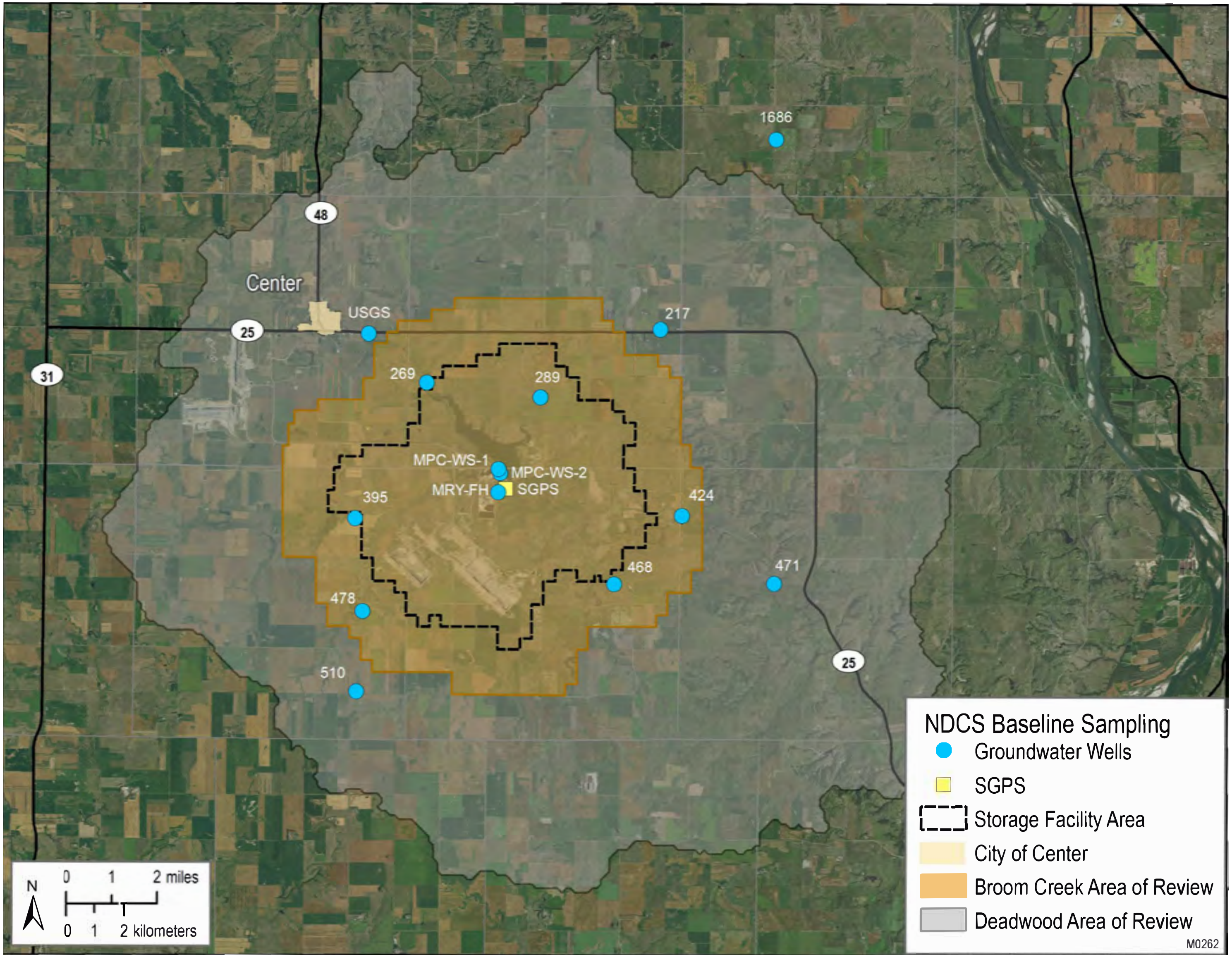


Figure 2. Map illustrating the locations of the soil gas profile stations, Fox Hills monitoring well, and the reservoir-monitoring well (NRDT-1) relative to the project storage facility area and area of review.

APPENDIX G – BASELINE GROUNDWATER MONITORING STUDY

Note, Information and data provided in Appendix G *is a derived from a baseline monitoring program throughout the area of study with respect to select hydrogeologic conditions. The monitoring program is ongoing as part of the approved SFP. A report summarizing the associated data will be prepared upon completion of baseline monitoring activities. For the purposes of the* EA*, data review is limited to the Fox Hills-Hell Creek Formations.*



NDCS Baseline Sampling
Groundwater Wells
SGPS
Storage Facility Area
City of Center
Broom Creek Area of Review
Deadwood Area of Review
M0262
N
0 1 2 miles
0 1 2 kilometers
Center
USGS
1686
217
269
289
MPC-WS-1
MPC-WS-2
MRY-FH
SGPS
395
424
468
471
478
510
48
25
31
25

MINNESOTA VALLEY TESTING LABORATORIES, INC.

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MEMBER ACIL

Amended 2Feb21 (TDS)

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	12 Jan 21	HT
pH - Field	8.42	units	NA	SM 4500 H+ B	12 Jan 21 12:45	JSM
Temperature - Field	11.8	Degrees C	NA	SM 2550B	12 Jan 21 12:45	JSM
Total Alkalinity	938	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Bicarbonate	912	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Carbonate	26	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Conductivity - Field	2641	umhos/cm	1	EPA 120.1	12 Jan 21 12:45	JSM
Tot Dis Solids(Summation)	1520	mg/l	12.5	SM1030-F	15 Jan 21 11:45	Calculated
Nitrate as N	< 0.2	mg/l	NA	EPA 353.2	14 Jan 21 9:17	Calculated
Bromide	2.83	mg/l	0.100	EPA 300.0	14 Jan 21 22:24	RMV
Total Organic Carbon	1.7	mg/l	0.5	SM5310C-11	22 Jan 21 17:28	NAS
Dissolved Organic Carbon	1.7	mg/l	0.5	SM5310C-96	22 Jan 21 17:28	NAS
Fluoride	3.54	mg/l	0.10	SM4500-F-C	12 Jan 21 17:00	HT
Sulfate	< 5	mg/l	10.0	ASTM D516-11	15 Jan 21 8:50	EV
Chloride	323	mg/l	2.0	SM4500-Cl-E-11	13 Jan 21 11:25	EV
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	14 Jan 21 9:17	EV
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	14 Jan 21 7:59	EV
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	15 Jan 21 8:17	EV
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	15 Jan 21 8:17	EV
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	13 Jan 21 11:16	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Jan 21 11:16	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

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MEMBER
ACIL

Amended 2Feb21 (TDS)

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Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	4.0	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Magnesium - Total	< 1	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Sodium - Total	630	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Potassium - Total	2.8	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Lithium - Total	0.186	mg/l	0.020	6010D	21 Jan 21 15:22	MDE
Aluminum - Total	< 0.1	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Iron - Total	0.40	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Silicon - Total	5.04	mg/l	0.10	6010D	26 Jan 21 9:37	MDE
Strontium - Total	0.16	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Zinc - Total	< 0.05	mg/l	0.05	6010D	20 Jan 21 10:36	MDE
Boron - Total	2.87	mg/l	0.10	6010D	26 Jan 21 10:46	MDE
Calcium - Dissolved	3.7	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Sodium - Dissolved	670	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Potassium - Dissolved	3.2	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Lithium - Dissolved	0.102	mg/l	0.020	6010D	21 Jan 21 15:22	MDE
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Iron - Dissolved	0.25	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Silicon - Dissolved	5.12	mg/l	0.10	6010D	26 Jan 21 9:37	MDE
Strontium - Dissolved	0.15	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	20 Jan 21 9:36	MDE
Boron - Dissolved	2.85	mg/l	0.10	6010D	26 Jan 21 10:46	MDE
Antimony - Total	< 0.001	mg/l	0.0010	6020B	14 Jan 21 19:47	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

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MEMBER
ACIL

Amended 2Feb21 (TDS)

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Barium - Total	0.0966	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Lead - Total	0.0006	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Manganese - Total	0.0088	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Molybdenum - Total	0.0058	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	14 Jan 21 19:47	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	15 Jan 21 14:56	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Barium - Dissolved	0.0954	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	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

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Amended 2Feb21 (TDS)

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Manganese - Dissolved	0.0081	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Molybdenum - Dissolved	0.0058	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	15 Jan 21 14:56	MDE
Silver - Dissolved	< 0.001 ^	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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CERTIFICATION: ND # ND-00016

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MEMBER
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Report Date: 23 Aug 21
Lab Number: 21-W2892
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 15:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-MPC-WS-1

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	12 Aug 21	RAA
pH	* 7.8	units	N/A	SM4500-H+-B-11	13 Aug 21 17:00	RAA
Conductivity (EC)	1320	umhos/cm	N/A	SM2510B-11	12 Aug 21 17:00	RAA
pH - Field	7.28	units	NA	SM 4500 H+ B	11 Aug 21 15:00	
Temperature - Field	17.6	Degrees C	NA	SM 2550B	11 Aug 21 15:00	
Total Alkalinity	464	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Bicarbonate	464	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Tot Dis Solids(Summation)	812	mg/l	12.5	SM1030-F	19 Aug 21 14:04	Calculated
Percent Sodium of Cations	54.8	%	NA	N/A	19 Aug 21 14:04	Calculated
Total Hardness as CaCO3	329	mg/l	NA	SM2340B-11	19 Aug 21 14:04	Calculated
Hardness in grains/gallon	19.3	gr/gal	NA	SM2340-B	19 Aug 21 14:04	Calculated
Cation Summation	14.8	meq/L	NA	SM1030-F	19 Aug 21 14:04	Calculated
Anion Summation	14.2	meq/L	NA	SM1030-F	16 Aug 21 12:01	Calculated
Percent Error	1.99	%	NA	SM1030-F	19 Aug 21 14:04	Calculated
Sodium Adsorption Ratio	4.46		NA	USDA 20b	19 Aug 21 14:04	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	18 Aug 21 12:10	RMV
Total Organic Carbon	4.8	mg/l	0.5	SM5310C-11	13 Aug 21 18:17	NAS
Dissolved Organic Carbon	4.5	mg/l	0.5	SM5310C-96	13 Aug 21 18:17	NAS
Fluoride	0.32	mg/l	0.10	SM4500-F-C	12 Aug 21 17:00	RAA
Sulfate	222	mg/l	5.00	ASTM D516-11	16 Aug 21 11:34	EV
Chloride	10.4	mg/l	2.0	SM4500-Cl-E-11	16 Aug 21 12:01	SD
Nitrate-Nitrite as N	0.30	mg/l	0.20	EPA 353.2	12 Aug 21 15:36	SD

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CERTIFICATION: ND # ND-00016

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Report Date: 23 Aug 21
Lab Number: 21-W2892
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 15:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-MPC-WS-1

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	12 Aug 21 10:40	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	13 Aug 21 13:53	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	13 Aug 21 13:53	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 11:43	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 12:58	MDE
Total Dissolved Solids	832	mg/l	10	USGS I1750-85	13 Aug 21 15:00	RAA
Calcium - Total	76.7	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Magnesium - Total	33.5	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Sodium - Total	186	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Potassium - Total	4.7	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Lithium - Total	0.048	mg/l	0.020	6010D	17 Aug 21 8:51	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Iron - Total	1.03	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Silicon - Total	11.5	mg/l	0.10	6010D	17 Aug 21 11:40	SZ
Strontium - Total	1.14	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Zinc - Total	0.05	mg/l	0.05	6010D	16 Aug 21 11:31	SZ
Boron - Total	0.36	mg/l	0.10	6010D	20 Aug 21 9:34	SZ
Calcium - Dissolved	75.9	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Magnesium - Dissolved	33.0	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Sodium - Dissolved	187	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Potassium - Dissolved	4.9	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Lithium - Dissolved	0.043	mg/l	0.020	6010D	17 Aug 21 9:51	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Aug 21 11:06	MDE
Iron - Dissolved	0.30	mg/l	0.10	6010D	19 Aug 21 11:06	MDE
Silicon - Dissolved	11.4	mg/l	0.10	6010D	17 Aug 21 12:40	SZ

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CERTIFICATION: ND # ND-00016

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Report Date: 23 Aug 21
Lab Number: 21-W2892
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 15:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-MPC-WS-1

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Strontium - Dissolved	1.14	mg/l	0.10	6010D	19 Aug 21 11:06	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	19 Aug 21 11:06	MDE
Boron - Dissolved	0.35	mg/l	0.10	6010D	20 Aug 21 11:34	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	20 Aug 21 11:16	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Barium - Total	0.0947	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Copper - Total	0.0235	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Manganese - Total	0.2512	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Nickel - Total	0.0053	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	20 Aug 21 11:16	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	20 Aug 21 12:22	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Barium - Dissolved	0.0903	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

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CERTIFICATION: ND # ND-00016

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MEMBER
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Report Date: 23 Aug 21
Lab Number: 21-W2892
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 15:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-MPC-WS-1

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Copper - Dissolved	0.0074	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Manganese - Dissolved	0.2518	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Nickel - Dissolved	0.0058	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Aug 21 12:22	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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Report Date: 23 Aug 21
Lab Number: 21-W2893
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 16:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-MPC-WS-1 Dup

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	12 Aug 21	RAA
pH	* 7.8	units	N/A	SM4500-H+-B-11	13 Aug 21 17:00	RAA
Conductivity (EC)	1298	umhos/cm	N/A	SM2510B-11	12 Aug 21 17:00	RAA
Total Alkalinity	468	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Bicarbonate	468	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Tot Dis Solids(Summation)	816	mg/l	12.5	SM1030-F	19 Aug 21 14:04	Calculated
Percent Sodium of Cations	52.8	%	NA	N/A	19 Aug 21 14:04	Calculated
Total Hardness as CaCO3	321	mg/l	NA	SM2340B-11	19 Aug 21 14:04	Calculated
Hardness in grains/gallon	18.8	gr/gal	NA	SM2340-B	19 Aug 21 14:04	Calculated
Cation Summation	14.9	meq/L	NA	SM1030-F	19 Aug 21 14:04	Calculated
Anion Summation	14.5	meq/L	NA	SM1030-F	16 Aug 21 12:01	Calculated
Percent Error	1.56	%	NA	SM1030-F	19 Aug 21 14:04	Calculated
Sodium Adsorption Ratio	4.40		NA	USDA 20b	19 Aug 21 14:04	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	18 Aug 21 12:31	RMV
Total Organic Carbon	4.6	mg/l	0.5	SM5310C-11	13 Aug 21 18:17	NAS
Dissolved Organic Carbon	4.5	mg/l	0.5	SM5310C-96	13 Aug 21 18:17	NAS
Fluoride	0.32	mg/l	0.10	SM4500-F-C	12 Aug 21 17:00	RAA
Sulfate	232	mg/l	5.00	ASTM D516-11	16 Aug 21 11:34	EV
Chloride	10.3	mg/l	2.0	SM4500-Cl-E-11	16 Aug 21 12:01	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	12 Aug 21 15:36	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	12 Aug 21 10:40	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	13 Aug 21 13:53	SD

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CERTIFICATION: ND # ND-00016

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL

Report Date: 23 Aug 21
Lab Number: 21-W2893
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 16:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-MPC-WS-1 Dup

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	13 Aug 21 13:53	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 11:43	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 12:58	MDE
Total Dissolved Solids	824	mg/l	10	USGS I1750-85	13 Aug 21 15:00	RAA
Calcium - Total	74.7	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Magnesium - Total	32.6	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Sodium - Total	181	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Potassium - Total	4.7	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Lithium - Total	0.046	mg/l	0.020	6010D	17 Aug 21 8:51	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Iron - Total	0.92	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Silicon - Total	11.5	mg/l	0.10	6010D	17 Aug 21 11:40	SZ
Strontium - Total	1.13	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Zinc - Total	< 0.05	mg/l	0.05	6010D	16 Aug 21 11:31	SZ
Boron - Total	0.36	mg/l	0.10	6010D	20 Aug 21 9:34	SZ
Calcium - Dissolved	75.6	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Magnesium - Dissolved	33.4	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Sodium - Dissolved	190	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Potassium - Dissolved	5.0	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Lithium - Dissolved	0.043	mg/l	0.020	6010D	17 Aug 21 9:51	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Aug 21 12:06	MDE
Iron - Dissolved	0.23	mg/l	0.10	6010D	19 Aug 21 12:06	MDE
Silicon - Dissolved	11.4	mg/l	0.10	6010D	17 Aug 21 12:40	SZ
Strontium - Dissolved	1.16	mg/l	0.10	6010D	19 Aug 21 12:06	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	19 Aug 21 12:06	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MINNESOTA VALLEY TESTING LABORATORIES, INC.

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MEMBER
ACIL

Report Date: 23 Aug 21
Lab Number: 21-W2893
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 16:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-MPC-WS-1 Dup

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Boron - Dissolved	0.35	mg/l	0.10	6010D	20 Aug 21 11:34	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	20 Aug 21 11:16	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Barium - Total	0.0954	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Copper - Total	0.0200	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Manganese - Total	0.2528	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Nickel - Total	0.0055	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	20 Aug 21 11:16	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	20 Aug 21 12:22	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Barium - Dissolved	0.0909	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Copper - Dissolved	0.0021	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

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CERTIFICATION: ND # ND-00016

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MEMBER
ACIL

Report Date: 23 Aug 21
Lab Number: 21-W2893
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 16:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-MPC-WS-1 Dup

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Manganese - Dissolved	0.2476	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Nickel - Dissolved	0.0053	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Aug 21 12:22	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	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:
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MEMBER
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Report Date: 23 Aug 21
Lab Number: 21-W2894
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 17:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-W289

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	12 Aug 21	RAA
pH	* 8.5	units	N/A	SM4500-H+-B-11	13 Aug 21 17:00	RAA
Conductivity (EC)	1846	umhos/cm	N/A	SM2510B-11	12 Aug 21 17:00	RAA
Total Alkalinity	883	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Bicarbonate	855	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Carbonate	28	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Tot Dis Solids(Summation)	1090	mg/l	12.5	SM1030-F	19 Aug 21 14:04	Calculated
Percent Sodium of Cations	96.4	%	NA	N/A	19 Aug 21 14:04	Calculated
Total Hardness as CaCO3	14.6	mg/l	NA	SM2340B-11	19 Aug 21 14:04	Calculated
Hardness in grains/gallon	0.85	gr/gal	NA	SM2340-B	19 Aug 21 14:04	Calculated
Cation Summation	20.3	meq/L	NA	SM1030-F	19 Aug 21 14:04	Calculated
Anion Summation	19.8	meq/L	NA	SM1030-F	16 Aug 21 12:01	Calculated
Percent Error	1.07	%	NA	SM1030-F	19 Aug 21 14:04	Calculated
Sodium Adsorption Ratio	51.2		NA	USDA 20b	19 Aug 21 14:04	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	18 Aug 21 12:52	RMV
Total Organic Carbon	6.3	mg/l	0.5	SM5310C-11	13 Aug 21 18:17	NAS
Dissolved Organic Carbon	7.1	mg/l	0.5	SM5310C-96	13 Aug 21 18:17	NAS
Fluoride	1.96	mg/l	0.10	SM4500-F-C	12 Aug 21 17:00	RAA
Sulfate	93.2	mg/l	5.00	ASTM D516-11	16 Aug 21 11:34	EV
Chloride	8.6	mg/l	2.0	SM4500-Cl-E-11	16 Aug 21 12:01	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	12 Aug 21 15:36	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	12 Aug 21 10:40	SD
Phosphorus as P - Total	0.31	mg/l	0.20	EPA 365.1	13 Aug 21 13:53	SD

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Report Date: 23 Aug 21
Lab Number: 21-W2894
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 17:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-W289

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Phosphorus as P-Dissolved	0.31	mg/l	0.20	EPA 365.1	13 Aug 21 13:53	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 11:43	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 12:58	MDE
Total Dissolved Solids	1180	mg/l	10	USGS I1750-85	13 Aug 21 15:00	RAA
Calcium - Total	3.2	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Magnesium - Total	1.6	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Sodium - Total	449	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Potassium - Total	2.4	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Lithium - Total	0.051	mg/l	0.020	6010D	17 Aug 21 8:51	SZ
Aluminum - Total	0.35	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Iron - Total	0.51	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Silicon - Total	4.05	mg/l	0.10	6010D	17 Aug 21 11:40	SZ
Strontium - Total	0.11	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Zinc - Total	< 0.05	mg/l	0.05	6010D	16 Aug 21 11:31	SZ
Boron - Total	0.46	mg/l	0.10	6010D	20 Aug 21 9:34	SZ
Calcium - Dissolved	2.4	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Magnesium - Dissolved	1.3	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Sodium - Dissolved	459	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Potassium - Dissolved	2.3	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Lithium - Dissolved	0.049	mg/l	0.020	6010D	17 Aug 21 9:51	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Aug 21 12:06	MDE
Iron - Dissolved	0.11	mg/l	0.10	6010D	19 Aug 21 12:06	MDE
Silicon - Dissolved	3.22	mg/l	0.10	6010D	17 Aug 21 12:40	SZ
Strontium - Dissolved	0.11	mg/l	0.10	6010D	19 Aug 21 12:06	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	19 Aug 21 12:06	MDE

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Report Date: 23 Aug 21
Lab Number: 21-W2894
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 17:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-W289

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Boron - Dissolved	0.45	mg/l	0.10	6010D	20 Aug 21 11:34	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	20 Aug 21 11:16	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Barium - Total	0.0786	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Copper - Total	0.0047	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Lead - Total	0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Manganese - Total	0.0194	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	20 Aug 21 11:16	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	20 Aug 21 12:22	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Barium - Dissolved	0.0750	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

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CERTIFICATION: ND # ND-00016

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Report Date: 23 Aug 21
Lab Number: 21-W2894
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 17:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-W289

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Manganese - Dissolved	0.0080	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Aug 21 12:22	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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MEMBER
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Report Date: 23 Aug 21
Lab Number: 21-W2895
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 19:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-W510

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	12 Aug 21	RAA
pH	* 8.4	units	N/A	SM4500-H+-B-11	16 Aug 21 13:30	RAA
Conductivity (EC)	2699	umhos/cm	N/A	SM2510B-11	12 Aug 21 17:00	RAA
Total Alkalinity	1350	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Phenolphthalein Alk	25	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Bicarbonate	1300	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Carbonate	50	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 17:00	RAA
Tot Dis Solids(Summation)	1580	mg/l	12.5	SM1030-F	19 Aug 21 14:04	Calculated
Percent Sodium of Cations	98.0	%	NA	N/A	19 Aug 21 14:04	Calculated
Total Hardness as CaCO3	17.8	mg/l	NA	SM2340B-11	19 Aug 21 14:04	Calculated
Hardness in grains/gallon	1.04	gr/gal	NA	SM2340-B	19 Aug 21 14:04	Calculated
Cation Summation	28.1	meq/L	NA	SM1030-F	19 Aug 21 14:04	Calculated
Anion Summation	30.6	meq/L	NA	SM1030-F	16 Aug 21 12:01	Calculated
Percent Error	-4.24	%	NA	SM1030-F	19 Aug 21 14:04	Calculated
Sodium Adsorption Ratio	65.2		NA	USDA 20b	19 Aug 21 14:04	Calculated
Bromide	0.740	mg/l	0.100	EPA 300.0	18 Aug 21 13:13	RMV
Total Organic Carbon	3.5	mg/l	0.5	SM5310C-11	13 Aug 21 18:17	NAS
Dissolved Organic Carbon	3.4	mg/l	0.5	SM5310C-96	13 Aug 21 18:17	NAS
Fluoride	0.88	mg/l	0.10	SM4500-F-C	12 Aug 21 17:00	RAA
Sulfate	13.4	mg/l	5.00	ASTM D516-11	16 Aug 21 11:34	EV
Chloride	116	mg/l	2.0	SM4500-Cl-E-11	16 Aug 21 12:01	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	12 Aug 21 15:36	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	12 Aug 21 10:40	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	13 Aug 21 13:53	SD

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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CERTIFICATION: ND # ND-00016

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
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Report Date: 23 Aug 21
Lab Number: 21-W2895
Work Order #:82-2103
Account #: 007033
Date Sampled: 11 Aug 21 19:00
Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-W510

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	13 Aug 21 13:53	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 11:43	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 12:58	MDE
Total Dissolved Solids	1690	mg/l	10	USGS I1750-85	13 Aug 21 15:00	RAA
Calcium - Total	3.5	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Magnesium - Total	2.2	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Sodium - Total	632	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Potassium - Total	2.7	mg/l	1.0	6010D	19 Aug 21 9:54	SZ
Lithium - Total	0.105	mg/l	0.020	6010D	17 Aug 21 8:51	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Iron - Total	0.43	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Silicon - Total	5.69	mg/l	0.10	6010D	17 Aug 21 11:40	SZ
Strontium - Total	0.18	mg/l	0.10	6010D	16 Aug 21 11:31	SZ
Zinc - Total	0.23	mg/l	0.05	6010D	16 Aug 21 11:31	SZ
Boron - Total	1.55	mg/l	0.10	6010D	20 Aug 21 9:34	SZ
Calcium - Dissolved	3.6	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Magnesium - Dissolved	2.2	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Sodium - Dissolved	635	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Potassium - Dissolved	2.8	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Lithium - Dissolved	0.100	mg/l	0.020	6010D	17 Aug 21 9:51	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Aug 21 12:06	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	19 Aug 21 12:06	MDE
Silicon - Dissolved	5.51	mg/l	0.10	6010D	17 Aug 21 12:40	SZ
Strontium - Dissolved	0.18	mg/l	0.10	6010D	19 Aug 21 12:06	MDE
Zinc - Dissolved	0.10	mg/l	0.05	6010D	19 Aug 21 12:06	MDE

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Report Date: 23 Aug 21
Lab Number: 21-W2895
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Account #: 007033
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Date Received: 12 Aug 21 8:00
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-W510

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Boron - Dissolved	1.50	mg/l	0.10	6010D	20 Aug 21 11:34	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	20 Aug 21 11:16	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Barium - Total	0.1028	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Copper - Total	0.0058	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Lead - Total	0.0020	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Manganese - Total	0.0242	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Nickel - Total	0.0023	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	20 Aug 21 11:16	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	20 Aug 21 12:22	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Barium - Dissolved	0.0964	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Copper - Dissolved	0.0029	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

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Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: ND Carbon Safe
Sample Description: NDCS-W510

Temp at Receipt: 4.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Manganese - Dissolved	0.0240	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Aug 21 12:22	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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Report Date: 7 Sep 21
Lab Number: 21-W2920
Work Order #: 82-2121
Account #: 007033
Date Sampled: 12 Aug 21 10:30
Date Received: 13 Aug 21 7:21
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W269

Temp at Receipt: 7.0C ROI

		As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion					EPA 200.2	13 Aug 21	RAA
pH	*	7.6	units	N/A	SM4500-H+-B-11	13 Aug 21 18:00	RAA
Conductivity (EC)		1968	umhos/cm	N/A	SM2510B-11	13 Aug 21 18:00	RAA
Total Alkalinity		396	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Phenolphthalein Alk		< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Bicarbonate		396	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Carbonate		< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Hydroxide		< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Tot Dis Solids(Summation)		1370	mg/l	12.5	SM1030-F	20 Aug 21 9:07	Calculated
Percent Sodium of Cations		41.6	%	NA	N/A	19 Aug 21 14:04	Calculated
Total Hardness as CaCO3		710	mg/l	NA	SM2340B-11	19 Aug 21 14:04	Calculated
Hardness in grains/gallon		41.5	gr/gal	NA	SM2340-B	19 Aug 21 14:04	Calculated
Cation Summation		24.2	meq/L	NA	SM1030-F	19 Aug 21 14:04	Calculated
Anion Summation		21.7	meq/L	NA	SM1030-F	20 Aug 21 9:07	Calculated
Percent Error		5.42	%	NA	SM1030-F	20 Aug 21 9:07	Calculated
Sodium Adsorption Ratio		3.74		NA	USDA 20b	19 Aug 21 14:04	Calculated
Bromide		< 0.5 @	mg/l	0.100	EPA 300.0	18 Aug 21 13:34	RMV
Total Organic Carbon		7.5	mg/l	0.5	SM5310C-11	13 Aug 21 21:34	NAS
Dissolved Organic Carbon		7.6	mg/l	0.5	SM5310C-96	13 Aug 21 21:34	NAS
Fluoride		0.23	mg/l	0.10	SM4500-F-C	13 Aug 21 18:00	RAA
Sulfate		649	mg/l	5.00	ASTM D516-11	16 Aug 21 12:13	EV
Chloride		9.4	mg/l	2.0	SM4500-Cl-E-11	16 Aug 21 12:36	SD
Nitrate-Nitrite as N		< 0.2	mg/l	0.20	EPA 353.2	20 Aug 21 9:07	EV
Nitrite as N		< 0.2	mg/l	0.20	EPA 353.2	13 Aug 21 14:52	SD
Phosphorus as P - Total		< 0.2	mg/l	0.20	EPA 365.1	20 Aug 21 9:25	EMS

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Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W269

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	20 Aug 21 10:00	EMS
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 11:43	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 12:58	MDE
Total Dissolved Solids	1540	mg/l	10	USGS I1750-85	13 Aug 21 15:00	RAA
Calcium - Total	170	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Magnesium - Total	69.3	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Sodium - Total	229	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Potassium - Total	5.0	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Lithium - Total	0.059	mg/l	0.020	6010D	17 Aug 21 8:51	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Iron - Total	7.05	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Silicon - Total	13.5	mg/l	0.10	6010D	17 Aug 21 11:40	SZ
Strontium - Total	2.05	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Zinc - Total	0.05	mg/l	0.05	6010D	16 Aug 21 12:31	SZ
Boron - Total	0.27	mg/l	0.10	6010D	20 Aug 21 9:34	SZ
Calcium - Dissolved	168	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Magnesium - Dissolved	69.5	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Sodium - Dissolved	223	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Potassium - Dissolved	5.2	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Lithium - Dissolved	0.056	mg/l	0.020	6010D	17 Aug 21 9:51	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Aug 21 13:06	MDE
Iron - Dissolved	6.54	mg/l	0.10	6010D	19 Aug 21 13:06	MDE
Silicon - Dissolved	13.5	mg/l	0.10	6010D	17 Aug 21 12:40	SZ
Strontium - Dissolved	2.06	mg/l	0.10	6010D	19 Aug 21 13:06	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	19 Aug 21 13:06	MDE

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Report Date: 7 Sep 21
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Date Sampled: 12 Aug 21 10:30
Date Received: 13 Aug 21 7:21
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W269

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Boron - Dissolved	0.27	mg/l	0.10	6010D	20 Aug 21 11:34	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	20 Aug 21 11:16	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Barium - Total	0.0563	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Manganese - Total	0.5066	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Molybdenum - Total	0.0025	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	20 Aug 21 11:16	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	20 Aug 21 12:22	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Barium - Dissolved	0.0522	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

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Report Date: 7 Sep 21
Lab Number: 21-W2920
Work Order #: 82-2121
Account #: 007033
Date Sampled: 12 Aug 21 10:30
Date Received: 13 Aug 21 7:21
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W269

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Manganese - Dissolved	0.5240	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Molybdenum - Dissolved	0.0025	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Aug 21 12:22	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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Report Date: 7 Sep 21
Lab Number: 21-W2921
Work Order #: 82-2121
Account #: 007033
Date Sampled: 12 Aug 21 14:30
Date Received: 13 Aug 21 7:21
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W217

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	13 Aug 21	RAA
pH	* 8.2	units	N/A	SM4500-H+-B-11	13 Aug 21 18:00	RAA
Conductivity (EC)	2780	umhos/cm	N/A	SM2510B-11	13 Aug 21 18:00	RAA
Total Alkalinity	1040	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Bicarbonate	1040	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Tot Dis Solids(Summation)	1660	mg/l	12.5	SM1030-F	20 Aug 21 9:07	Calculated
Percent Sodium of Cations	100	%	NA	N/A	19 Aug 21 14:04	Calculated
Total Hardness as CaCO3	13.6	mg/l	NA	SM2340B-11	19 Aug 21 14:04	Calculated
Hardness in grains/gallon	0.80	gr/gal	NA	SM2340-B	19 Aug 21 14:04	Calculated
Cation Summation	26.9	meq/L	NA	SM1030-F	19 Aug 21 14:04	Calculated
Anion Summation	32.3	meq/L	NA	SM1030-F	20 Aug 21 9:07	Calculated
Percent Error	-9.18	%	NA	SM1030-F	20 Aug 21 9:07	Calculated
Sodium Adsorption Ratio	73.0		NA	USDA 20b	19 Aug 21 14:04	Calculated
Free Carbon Dioxide	12.9	mg/L	NA			Calculated
Total Carbon Dioxide	921	mg/L	NA			Calculated
Bromide	2.90	mg/l	0.100	EPA 300.0	18 Aug 21 13:55	RMV
Total Organic Carbon	1.7	mg/l	0.5	SM5310C-11	13 Aug 21 21:34	NAS
Dissolved Organic Carbon	1.8	mg/l	0.5	SM5310C-96	13 Aug 21 21:34	NAS
Fluoride	3.11	mg/l	0.10	SM4500-F-C	13 Aug 21 18:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	16 Aug 21 12:13	EV
Chloride	408	mg/l	2.0	SM4500-Cl-E-11	16 Aug 21 12:36	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	20 Aug 21 9:07	EV

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CERTIFICATION: ND # ND-00016

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL

Report Date: 7 Sep 21
Lab Number: 21-W2921
Work Order #: 82-2121
Account #: 007033
Date Sampled: 12 Aug 21 14:30
Date Received: 13 Aug 21 7:21
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W217

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	13 Aug 21 14:52	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	20 Aug 21 9:25	EMS
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	20 Aug 21 10:00	EMS
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 11:43	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 12:58	MDE
Total Dissolved Solids	1540	mg/l	10	USGS I1750-85	13 Aug 21 15:00	RAA
Calcium - Total	3.8	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Magnesium - Total	1.0	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Sodium - Total	619	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Potassium - Total	2.3	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Lithium - Total	0.088	mg/l	0.020	6010D	17 Aug 21 8:51	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Iron - Total	0.17	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Silicon - Total	5.28	mg/l	0.10	6010D	17 Aug 21 11:40	SZ
Strontium - Total	0.15	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Zinc - Total	0.12	mg/l	0.05	6010D	16 Aug 21 12:31	SZ
Boron - Total	2.88	mg/l	0.10	6010D	20 Aug 21 9:34	SZ
Calcium - Dissolved	3.8	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Sodium - Dissolved	612	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Potassium - Dissolved	2.4	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Lithium - Dissolved	0.088	mg/l	0.020	6010D	17 Aug 21 9:51	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Aug 21 13:06	MDE
Iron - Dissolved	0.15	mg/l	0.10	6010D	19 Aug 21 13:06	MDE
Silicon - Dissolved	5.25	mg/l	0.10	6010D	17 Aug 21 12:40	SZ

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Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W217

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Strontium - Dissolved	0.16	mg/l	0.10	6010D	19 Aug 21 13:06	MDE
Zinc - Dissolved	0.12	mg/l	0.05	6010D	19 Aug 21 13:06	MDE
Boron - Dissolved	2.89	mg/l	0.10	6010D	20 Aug 21 11:34	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	20 Aug 21 11:16	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Barium - Total	0.1130	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Manganese - Total	< 0.005 ^	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Molybdenum - Total	0.0043	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	20 Aug 21 11:16	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	20 Aug 21 12:22	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Barium - Dissolved	0.1112	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

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Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W217

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Manganese - Dissolved	< 0.005 ^	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Molybdenum - Dissolved	0.0039	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Aug 21 12:22	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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Report Date: 7 Sep 21
Lab Number: 21-W2922
Work Order #: 82-2121
Account #: 007033
Date Sampled: 12 Aug 21 15:30
Date Received: 13 Aug 21 7:21
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W1686

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	13 Aug 21	RAA
pH	* 7.2	units	N/A	SM4500-H+-B-11	13 Aug 21 18:00	RAA
Conductivity (EC)	2894	umhos/cm	N/A	SM2510B-11	13 Aug 21 18:00	RAA
Total Alkalinity	530	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Bicarbonate	530	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Tot Dis Solids(Summation)	2420	mg/l	12.5	SM1030-F	20 Aug 21 9:28	Calculated
Percent Sodium of Cations	23.0	%	NA	N/A	19 Aug 21 14:04	Calculated
Total Hardness as CaCO3	1440	mg/l	NA	SM2340B-11	19 Aug 21 14:04	Calculated
Hardness in grains/gallon	84.5	gr/gal	NA	SM2340-B	19 Aug 21 14:04	Calculated
Cation Summation	39.2	meq/L	NA	SM1030-F	19 Aug 21 14:04	Calculated
Anion Summation	39.9	meq/L	NA	SM1030-F	20 Aug 21 9:28	Calculated
Percent Error	-0.86	%	NA	SM1030-F	20 Aug 21 9:28	Calculated
Sodium Adsorption Ratio	2.36		NA	USDA 20b	19 Aug 21 14:04	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	18 Aug 21 14:16	RMV
Total Organic Carbon	9.9	mg/l	0.5	SM5310C-11	13 Aug 21 21:34	NAS
Dissolved Organic Carbon	10.1	mg/l	0.5	SM5310C-96	13 Aug 21 21:34	NAS
Fluoride	0.14	mg/l	0.10	SM4500-F-C	13 Aug 21 18:00	RAA
Sulfate	1370	mg/l	5.00	ASTM D516-11	16 Aug 21 12:13	EV
Chloride	25.8	mg/l	2.0	SM4500-Cl-E-11	16 Aug 21 12:36	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	20 Aug 21 9:28	EV
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	13 Aug 21 14:52	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	20 Aug 21 9:25	EMS

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Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W1686

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	20 Aug 21 10:00	EMS
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 11:43	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 12:58	MDE
Total Dissolved Solids	2680	mg/l	10	USGS I1750-85	13 Aug 21 15:00	RAA
Calcium - Total	364	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Magnesium - Total	130	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Sodium - Total	206	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Potassium - Total	5.4	mg/l	1.0	6010D	19 Aug 21 11:04	SZ
Lithium - Total	0.076	mg/l	0.020	6010D	17 Aug 21 8:51	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Iron - Total	4.96	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Silicon - Total	5.11	mg/l	0.10	6010D	17 Aug 21 11:40	SZ
Strontium - Total	3.62	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Zinc - Total	< 0.05	mg/l	0.05	6010D	16 Aug 21 12:31	SZ
Boron - Total	0.13	mg/l	0.10	6010D	20 Aug 21 9:34	SZ
Calcium - Dissolved	374	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Magnesium - Dissolved	136	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Sodium - Dissolved	207	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Potassium - Dissolved	5.8	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Lithium - Dissolved	0.075	mg/l	0.020	6010D	17 Aug 21 9:51	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Aug 21 13:06	MDE
Iron - Dissolved	4.97	mg/l	0.10	6010D	19 Aug 21 13:06	MDE
Silicon - Dissolved	5.18	mg/l	0.10	6010D	17 Aug 21 12:40	SZ
Strontium - Dissolved	3.76	mg/l	0.10	6010D	19 Aug 21 13:06	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	19 Aug 21 13:06	MDE

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Date Received: 13 Aug 21 7:21
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W1686

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Boron - Dissolved	0.13	mg/l	0.10	6010D	20 Aug 21 11:34	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	20 Aug 21 11:16	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Barium - Total	0.0270	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Manganese - Total	0.5100	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	20 Aug 21 11:16	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	20 Aug 21 12:22	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Barium - Dissolved	0.0270	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

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Date Received: 13 Aug 21 7:21
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W1686

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Manganese - Dissolved	0.5124	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Aug 21 12:22	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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Report Date: 7 Sep 21
Lab Number: 21-W2923
Work Order #: 82-2121
Account #: 007033
Date Sampled: 12 Aug 21 17:00
Date Received: 13 Aug 21 7:21
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-471

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	13 Aug 21	RAA
pH	* 8.5	units	N/A	SM4500-H+-B-11	13 Aug 21 18:00	RAA
Conductivity (EC)	2561	umhos/cm	N/A	SM2510B-11	13 Aug 21 18:00	RAA
Total Alkalinity	1160	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Phenolphthalein Alk	22	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Bicarbonate	1117	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Carbonate	43	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Tot Dis Solids(Summation)	1510	mg/l	12.5	SM1030-F	20 Aug 21 9:28	Calculated
Percent Sodium of Cations	97.8	%	NA	N/A	19 Aug 21 14:04	Calculated
Total Hardness as CaCO3	13.8	mg/l	NA	SM2340B-11	19 Aug 21 14:04	Calculated
Hardness in grains/gallon	0.80	gr/gal	NA	SM2340-B	19 Aug 21 14:04	Calculated
Cation Summation	27.0	meq/L	NA	SM1030-F	19 Aug 21 14:06	Calculated
Anion Summation	28.9	meq/L	NA	SM1030-F	20 Aug 21 9:28	Calculated
Percent Error	-3.43	%	NA	SM1030-F	20 Aug 21 9:28	Calculated
Sodium Adsorption Ratio	71.1		NA	USDA 20b	19 Aug 21 14:04	Calculated
Bromide	1.28	mg/l	0.100	EPA 300.0	18 Aug 21 14:37	RMV
Total Organic Carbon	5.2	mg/l	0.5	SM5310C-11	13 Aug 21 21:34	NAS
Dissolved Organic Carbon	5.5	mg/l	0.5	SM5310C-96	13 Aug 21 21:34	NAS
Fluoride	1.12	mg/l	0.10	SM4500-F-C	13 Aug 21 18:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	16 Aug 21 12:13	EV
Chloride	201	mg/l	2.0	SM4500-Cl-E-11	16 Aug 21 12:36	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	20 Aug 21 9:28	EV
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	13 Aug 21 14:52	SD
Phosphorus as P - Total	0.22	mg/l	0.20	EPA 365.1	20 Aug 21 9:25	EMS

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CERTIFICATION: ND # ND-00016

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ACIL

Report Date: 7 Sep 21
Lab Number: 21-W2923
Work Order #: 82-2121
Account #: 007033
Date Sampled: 12 Aug 21 17:00
Date Received: 13 Aug 21 7:21
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-471

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Phosphorus as P-Dissolved	0.24	mg/l	0.20	EPA 365.1	20 Aug 21 10:00	EMS
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 11:43	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 12:58	MDE
Total Dissolved Solids	1600	mg/l	10	USGS I1750-85	13 Aug 21 15:00	RAA
Calcium - Total	3.2	mg/l	1.0	6010D	19 Aug 21 12:04	SZ
Magnesium - Total	1.4	mg/l	1.0	6010D	19 Aug 21 12:04	SZ
Sodium - Total	606	mg/l	1.0	6010D	19 Aug 21 12:04	SZ
Potassium - Total	2.3	mg/l	1.0	6010D	19 Aug 21 12:04	SZ
Lithium - Total	0.092	mg/l	0.020	6010D	17 Aug 21 8:51	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Iron - Total	< 0.1	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Silicon - Total	4.62	mg/l	0.10	6010D	17 Aug 21 11:40	SZ
Strontium - Total	0.15	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Zinc - Total	< 0.05	mg/l	0.05	6010D	16 Aug 21 12:31	SZ
Boron - Total	2.34	mg/l	0.10	6010D	20 Aug 21 10:34	SZ
Calcium - Dissolved	3.2	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Magnesium - Dissolved	1.4	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Sodium - Dissolved	612	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Potassium - Dissolved	2.3	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Lithium - Dissolved	0.089	mg/l	0.020	6010D	17 Aug 21 9:51	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Aug 21 14:06	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	19 Aug 21 14:06	MDE
Silicon - Dissolved	4.46	mg/l	0.10	6010D	17 Aug 21 12:40	SZ
Strontium - Dissolved	0.15	mg/l	0.10	6010D	19 Aug 21 14:06	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	19 Aug 21 14:06	MDE

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Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-471

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Boron - Dissolved	2.44	mg/l	0.10	6010D	20 Aug 21 11:34	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	20 Aug 21 11:16	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Barium - Total	0.1326	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Manganese - Total	0.0110	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	20 Aug 21 11:16	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	20 Aug 21 12:22	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Barium - Dissolved	0.1258	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

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UND-Energy & Environmental
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Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-471

Temp at Receipt: 7.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Manganese - Dissolved	0.0102	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Aug 21 12:22	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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Report Date: 23 Aug 21
Lab Number: 21-W2932
Work Order #: 82-2129
Account #: 007033
Date Sampled: 13 Aug 21 8:00
Date Received: 13 Aug 21 11:38
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-MPC-WS-2

Temp at Receipt: 9.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	13 Aug 21	RAA
pH	* 7.9	units	N/A	SM4500-H+-B-11	13 Aug 21 18:00	RAA
Conductivity (EC)	1296	umhos/cm	N/A	SM2510B-11	13 Aug 21 18:00	RAA
Total Alkalinity	492	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Bicarbonate	492	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	13 Aug 21 18:00	RAA
Tot Dis Solids(Summation)	792	mg/l	12.5	SM1030-F	20 Aug 21 9:28	Calculated
Percent Sodium of Cations	56.9	%	NA	N/A	19 Aug 21 14:04	Calculated
Total Hardness as CaCO3	293	mg/l	NA	SM2340B-11	19 Aug 21 14:04	Calculated
Hardness in grains/gallon	17.1	gr/gal	NA	SM2340-B	19 Aug 21 14:04	Calculated
Cation Summation	14.9	meq/L	NA	SM1030-F	19 Aug 21 14:06	Calculated
Anion Summation	14.1	meq/L	NA	SM1030-F	20 Aug 21 9:28	Calculated
Percent Error	2.77	%	NA	SM1030-F	20 Aug 21 9:28	Calculated
Sodium Adsorption Ratio	4.93		NA	USDA 20b	19 Aug 21 14:04	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	18 Aug 21 14:58	RMV
Total Organic Carbon	5.4	mg/l	0.5	SM5310C-11	13 Aug 21 21:34	NAS
Dissolved Organic Carbon	5.4	mg/l	0.5	SM5310C-96	13 Aug 21 21:34	NAS
Fluoride	0.29	mg/l	0.10	SM4500-F-C	13 Aug 21 18:00	RAA
Sulfate	191	mg/l	5.00	ASTM D516-11	16 Aug 21 13:53	EV
Chloride	8.8	mg/l	2.0	SM4500-Cl-E-11	16 Aug 21 14:24	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	20 Aug 21 9:28	EV
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	13 Aug 21 14:52	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	20 Aug 21 10:00	EMS

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Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-MPC-WS-2

Temp at Receipt: 9.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	20 Aug 21 10:00	EMS
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 11:43	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Aug 21 12:58	MDE
Total Dissolved Solids	838	mg/l	10	USGS I1750-85	13 Aug 21 15:00	RAA
Calcium - Total	68.8	mg/l	1.0	6010D	19 Aug 21 12:04	SZ
Magnesium - Total	29.4	mg/l	1.0	6010D	19 Aug 21 12:04	SZ
Sodium - Total	194	mg/l	1.0	6010D	19 Aug 21 12:04	SZ
Potassium - Total	4.6	mg/l	1.0	6010D	19 Aug 21 12:04	SZ
Lithium - Total	0.051	mg/l	0.020	6010D	17 Aug 21 8:51	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Iron - Total	0.98	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Silicon - Total	9.15	mg/l	0.10	6010D	17 Aug 21 11:40	SZ
Strontium - Total	1.15	mg/l	0.10	6010D	16 Aug 21 12:31	SZ
Zinc - Total	< 0.05	mg/l	0.05	6010D	16 Aug 21 12:31	SZ
Boron - Total	0.36	mg/l	0.10	6010D	20 Aug 21 10:34	SZ
Calcium - Dissolved	67.6	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Magnesium - Dissolved	28.9	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Sodium - Dissolved	206	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Potassium - Dissolved	4.8	mg/l	1.0	6010D	19 Aug 21 14:04	SZ
Lithium - Dissolved	0.050	mg/l	0.020	6010D	17 Aug 21 9:51	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Aug 21 14:06	MDE
Iron - Dissolved	0.94	mg/l	0.10	6010D	19 Aug 21 14:06	MDE
Silicon - Dissolved	9.12	mg/l	0.10	6010D	17 Aug 21 12:40	SZ
Strontium - Dissolved	1.17	mg/l	0.10	6010D	19 Aug 21 14:06	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	19 Aug 21 14:06	MDE

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Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-MPC-WS-2

Temp at Receipt: 9.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Boron - Dissolved	0.38	mg/l	0.10	6010D	20 Aug 21 11:34	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	20 Aug 21 11:16	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Barium - Total	0.0776	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Copper - Total	0.0029	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Manganese - Total	0.1527	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Nickel - Total	0.0026	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	20 Aug 21 11:16	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 11:16	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	20 Aug 21 11:16	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	20 Aug 21 12:22	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Barium - Dissolved	0.0719	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

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Barry Botnen
UND-Energy & Environmental
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Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-MPC-WS-2

Temp at Receipt: 9.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Manganese - Dissolved	0.1232	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Nickel - Dissolved	0.0023	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Aug 21 12:22	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 21 12:22	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 21 12:22	MDE

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MINNESOTA VALLEY TESTING LABORATORIES, INC.

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1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL

Report Date: 14 Sep 21
Lab Number: 21-W3137
Work Order #: 82-2307
Account #: 007033
Date Sampled: 30 Aug 21 10:45
Date Received: 30 Aug 21 13:10
Sampled By: MVTL Field Services

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 9.3C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	31 Aug 21	RAA
pH - Field	8.46	units	NA	SM 4500 H+ B	30 Aug 21 10:45	JSM
Temperature - Field	13.5	Degrees C	NA	SM 2550B	30 Aug 21 10:45	JSM
Total Alkalinity	948	mg/l CaCO3	20	SM2320B-11	31 Aug 21 17:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	31 Aug 21 17:00	RAA
Bicarbonate	909	mg/l CaCO3	20	SM2320B-11	31 Aug 21 17:00	RAA
Carbonate	39	mg/l CaCO3	20	SM2320B-11	31 Aug 21 17:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	31 Aug 21 17:00	RAA
Conductivity - Field	2623	umhos/cm	1	EPA 120.1	30 Aug 21 10:45	JSM
Tot Dis Solids(Summation)	1540	mg/l	12.5	SM1030-F	2 Sep 21 11:43	Calculated
Cation Summation	29.4	meq/L	NA	SM1030-F	2 Sep 21 11:20	Calculated
Anion Summation	27.0	meq/L	NA	SM1030-F	2 Sep 21 11:43	Calculated
Percent Error	4.18	%	NA	SM1030-F	2 Sep 21 11:43	Calculated
Bromide	2.51	mg/l	0.100	EPA 300.0	13 Sep 21 15:47	RMV
Total Organic Carbon	2.0	mg/l	0.5	SM5310C-11	3 Sep 21 13:29	NAS
Dissolved Organic Carbon	2.1	mg/l	0.5	SM5310C-96	3 Sep 21 13:29	NAS
Fluoride	3.70	mg/l	0.10	SM4500-F-C	31 Aug 21 17:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	1 Sep 21 10:57	SD
Chloride	286	mg/l	2.0	SM4500-Cl-E-11	1 Sep 21 14:43	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	2 Sep 21 11:43	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	31 Aug 21 13:11	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	3 Sep 21 8:56	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	3 Sep 21 8:56	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	1 Sep 21 12:57	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

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Temp at Receipt: 9.3C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: Center USGS Well

Sample Description: USGS Well

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	1 Sep 21 14:26	MDE
Total Dissolved Solids	1670	mg/l	10	USGS I1750-85	3 Sep 21 14:43	RAA
Calcium - Total	3.5	mg/l	1.0	6010D	2 Sep 21 11:20	MDE
Magnesium - Total	< 1	mg/l	1.0	6010D	2 Sep 21 11:20	MDE
Sodium - Total	675	mg/l	1.0	6010D	2 Sep 21 11:20	MDE
Potassium - Total	2.5	mg/l	1.0	6010D	2 Sep 21 11:20	MDE
Lithium - Total	0.083	mg/l	0.020	6010D	9 Sep 21 10:31	MDE
Aluminum - Total	< 0.1	mg/l	0.10	6010D	1 Sep 21 10:53	MDE
Iron - Total	0.29	mg/l	0.10	6010D	1 Sep 21 10:53	MDE
Silicon - Total	5.02	mg/l	0.10	6010D	9 Sep 21 14:18	MDE
Strontium - Total	0.15	mg/l	0.10	6010D	1 Sep 21 10:53	MDE
Zinc - Total	< 0.05	mg/l	0.05	6010D	1 Sep 21 10:53	MDE
Boron - Total	2.81	mg/l	0.10	6010D	2 Sep 21 16:20	MDE
Calcium - Dissolved	3.4	mg/l	1.0	6010D	2 Sep 21 11:20	MDE
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	2 Sep 21 11:20	MDE
Sodium - Dissolved	670	mg/l	1.0	6010D	2 Sep 21 11:20	MDE
Potassium - Dissolved	2.7	mg/l	1.0	6010D	2 Sep 21 11:20	MDE
Lithium - Dissolved	0.086	mg/l	0.020	6010D	9 Sep 21 11:31	MDE
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	1 Sep 21 10:53	MDE
Iron - Dissolved	0.20	mg/l	0.10	6010D	1 Sep 21 10:53	MDE
Silicon - Dissolved	4.93	mg/l	0.10	6010D	9 Sep 21 14:18	MDE
Strontium - Dissolved	0.15	mg/l	0.10	6010D	1 Sep 21 10:53	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	1 Sep 21 10:53	MDE
Boron - Dissolved	2.79	mg/l	0.10	6010D	2 Sep 21 15:20	MDE

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PO #: B. Botnen

Temp at Receipt: 9.3C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: Center USGS Well

Sample Description: USGS Well

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Antimony - Total	< 0.001	mg/l	0.0010	6020B	8 Sep 21 12:29	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	8 Sep 21 12:29	MDE
Barium - Total	0.0966	mg/l	0.0020	6020B	8 Sep 21 12:29	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	8 Sep 21 12:29	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	8 Sep 21 12:29	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	8 Sep 21 12:29	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	8 Sep 21 12:29	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	8 Sep 21 12:29	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	8 Sep 21 12:29	MDE
Manganese - Total	0.0063	mg/l	0.0020	6020B	8 Sep 21 12:29	MDE
Molybdenum - Total	0.0057	mg/l	0.0020	6020B	8 Sep 21 12:29	MDE
Nickel - Total	< 0.005 ^	mg/l	0.0020	6020B	8 Sep 21 12:29	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	8 Sep 21 12:29	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	8 Sep 21 12:29	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	8 Sep 21 12:29	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	8 Sep 21 12:29	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	8 Sep 21 10:01	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	8 Sep 21 10:01	MDE
Barium - Dissolved	0.0910	mg/l	0.0020	6020B	8 Sep 21 10:01	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	8 Sep 21 10:01	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	8 Sep 21 10:01	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	8 Sep 21 10:01	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	8 Sep 21 10:01	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	8 Sep 21 10:01	MDE

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PO #: B. Botnen

Temp at Receipt: 9.3C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: Center USGS Well

Sample Description: USGS Well

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	8 Sep 21 10:01	MDE
Manganese - Dissolved	0.0052	mg/l	0.0020	6020B	8 Sep 21 10:01	MDE
Molybdenum - Dissolved	0.0051	mg/l	0.0020	6020B	8 Sep 21 10:01	MDE
Nickel - Dissolved	< 0.005 ^	mg/l	0.0020	6020B	8 Sep 21 10:01	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	8 Sep 21 10:01	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	8 Sep 21 10:01	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	8 Sep 21 10:01	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	8 Sep 21 10:01	MDE

Bromide was analyzed at MVTL, New Ulm, MN.
ND Certification #:R-040

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER
ACIL

Report Date: 26 Nov 21
Lab Number: 21-W4368
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 8:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-MPC-WS1

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	11 Nov 21	RAA
pH	* 7.5	units	N/A	SM4500-H+-B-11	10 Nov 21 17:00	AC
Conductivity (EC)	1438	umhos/cm	N/A	SM2510B-11	10 Nov 21 17:00	AC
pH - Field	7.28	units	NA	SM 4500 H+ B	9 Nov 21 8:30	
Temperature - Field	15.3	Degrees C	NA	SM 2550B	9 Nov 21 8:30	
Total Alkalinity	475	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Bicarbonate	475	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Tot Dis Solids(Summation)	911	mg/l	12.5	SM1030-F	18 Nov 21 14:17	Calculated
Cation Summation	15.2	meq/L	NA	SM1030-F	16 Nov 21 10:36	Calculated
Anion Summation	15.9	meq/L	NA	SM1030-F	18 Nov 21 14:17	Calculated
Percent Error	-1.98	%	NA	SM1030-F	18 Nov 21 14:17	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	15 Nov 21 19:17	RMV
Total Organic Carbon	5.9	mg/l	0.5	SM5310C-11	16 Nov 21 18:16	NAS
Dissolved Organic Carbon	5.8	mg/l	0.5	SM5310C-96	16 Nov 21 18:16	NAS
Fluoride	0.29	mg/l	0.10	SM4500-F-C	10 Nov 21 17:00	AC
Sulfate	290	mg/l	5.00	ASTM D516-11	15 Nov 21 14:26	SD
Chloride	10.6	mg/l	2.0	SM4500-Cl-E-11	10 Nov 21 10:55	SD
Nitrate-Nitrite as N	0.28	mg/l	0.20	EPA 353.2	18 Nov 21 14:17	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	10 Nov 21 14:18	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 8:56	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD

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MEMBER
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Report Date: 26 Nov 21
Lab Number: 21-W4368
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 8:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-MPC-WS1

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Total Dissolved Solids	959	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA
Calcium - Total	85.0	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Magnesium - Total	35.0	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Sodium - Total	200	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Potassium - Total	5.0	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Lithium - Total	0.045	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Iron - Total	0.98	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Silicon - Total	11.3	mg/l	0.10	6010D	16 Nov 21 13:55	SZ
Strontium - Total	1.14	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Zinc - Total	0.09	mg/l	0.05	6010D	12 Nov 21 11:33	MDE
Boron - Total	0.37	mg/l	0.10	6010D	17 Nov 21 9:08	SZ
Calcium - Dissolved	80.0	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Magnesium - Dissolved	34.3	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Sodium - Dissolved	190	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Potassium - Dissolved	4.8	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Lithium - Dissolved	0.048	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 9:55	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 9:55	MDE
Silicon - Dissolved	11.5	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	1.23	mg/l	0.10	6010D	15 Nov 21 9:55	MDE
Zinc - Dissolved	0.05	mg/l	0.05	6010D	15 Nov 21 9:55	MDE

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Account #: 007033
Date Sampled: 9 Nov 21 8:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-MPC-WS1

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Boron - Dissolved	0.38	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 11:07	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Barium - Total	0.0902	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Copper - Total	0.0264	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Manganese - Total	0.2717	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Nickel - Total	0.0064	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 11:07	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.0851	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 16:48	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

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Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-MPC-WS1

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Copper - Dissolved	0.0133	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Manganese - Dissolved	0.2154	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	0.0055	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

Bromide was analyzed at MVTL, New Ulm, MN.
ND Certification #:R-040

* 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
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CERTIFICATION: ND # ND-00016

MINNESOTA VALLEY TESTING LABORATORIES, INC.

MVTL

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL

Report Date: 26 Nov 21
Lab Number: 21-W4369
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 9:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-MPC-WS1 Dup

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	10 Nov 21	AC
pH	* 7.3	units	N/A	SM4500-H+-B-11	10 Nov 21 17:00	AC
Conductivity (EC)	1432	umhos/cm	N/A	SM2510B-11	10 Nov 21 17:00	AC
pH - Field	7.28	units	NA	SM 4500 H+ B	9 Nov 21 9:30	
Temperature - Field	7.28	Degrees C	NA	SM 2550B	9 Nov 21 9:30	
Total Alkalinity	572	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Bicarbonate	572	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Tot Dis Solids(Summation)	999	mg/l	12.5	SM1030-F	18 Nov 21 14:34	Calculated
Cation Summation	16.9	meq/L	NA	SM1030-F	15 Nov 21 9:55	Calculated
Anion Summation	17.9	meq/L	NA	SM1030-F	18 Nov 21 14:34	Calculated
Percent Error	-2.83	%	NA	SM1030-F	18 Nov 21 14:34	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	15 Nov 21 19:38	RMV
Total Organic Carbon	5.9	mg/l	0.5	SM5310C-11	16 Nov 21 18:16	NAS
Dissolved Organic Carbon	5.8	mg/l	0.5	SM5310C-96	16 Nov 21 18:16	NAS
Fluoride	0.29	mg/l	0.10	SM4500-F-C	10 Nov 21 17:00	AC
Sulfate	294	mg/l	5.00	ASTM D516-11	15 Nov 21 14:26	SD
Chloride	10.8	mg/l	2.0	SM4500-Cl-E-11	10 Nov 21 10:55	SD
Nitrate-Nitrite as N	0.27	mg/l	0.20	EPA 353.2	18 Nov 21 14:34	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	10 Nov 21 14:18	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 8:56	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD

RL = Method Reporting Limit

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Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-MPC-WS1 Dup

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 13:07	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 14:29	MDE
Total Dissolved Solids	967	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA
Calcium - Total	90.7	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Magnesium - Total	39.8	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Sodium - Total	215	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Potassium - Total	5.4	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Lithium - Total	0.051	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Iron - Total	0.30	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Silicon - Total	11.7	mg/l	0.10	6010D	16 Nov 21 13:55	SZ
Strontium - Total	1.24	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Zinc - Total	0.06	mg/l	0.05	6010D	12 Nov 21 11:33	MDE
Boron - Total	0.42	mg/l	0.10	6010D	17 Nov 21 9:08	SZ
Calcium - Dissolved	90.7	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Magnesium - Dissolved	38.6	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Sodium - Dissolved	208	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Potassium - Dissolved	5.1	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Lithium - Dissolved	0.052	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 9:55	MDE
Iron - Dissolved	0.87	mg/l	0.10	6010D	15 Nov 21 9:55	MDE
Silicon - Dissolved	11.7	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	1.29	mg/l	0.10	6010D	15 Nov 21 9:55	MDE
Zinc - Dissolved	0.14	mg/l	0.05	6010D	15 Nov 21 9:55	MDE

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Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-MPC-WS1 Dup

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Boron - Dissolved	0.42	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 11:07	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Barium - Total	0.0956	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Copper - Total	< 0.01 @	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Manganese - Total	0.2548	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Nickel - Total	0.0051	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 11:07	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.0906	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 16:48	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

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CERTIFICATION: ND # ND-00016

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Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-MPC-WS1 Dup

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Copper - Dissolved	< 0.01 @	mg/l	0.0020	6020B	23 Nov 21 15:59	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Manganese - Dissolved	0.2392	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	0.0047	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

Bromide was analyzed at MVTL, New Ulm, MN.
ND Certification #:R-040

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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Report Date: 26 Nov 21
Lab Number: 21-W4370
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 10:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-MPC-WS2

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	10 Nov 21	AC
pH	* 7.2	units	N/A	SM4500-H+-B-11	10 Nov 21 17:00	AC
Conductivity (EC)	1247	umhos/cm	N/A	SM2510B-11	10 Nov 21 17:00	AC
pH - Field	7.30	units	NA	SM 4500 H+ B	9 Nov 21 10:30	
Temperature - Field	11.1	Degrees C	NA	SM 2550B	9 Nov 21 10:30	
Total Alkalinity	580	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Bicarbonate	580	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Tot Dis Solids(Summation)	833	mg/l	12.5	SM1030-F	18 Nov 21 14:34	Calculated
Cation Summation	14.6	meq/L	NA	SM1030-F	15 Nov 21 9:55	Calculated
Anion Summation	15.5	meq/L	NA	SM1030-F	18 Nov 21 14:34	Calculated
Percent Error	-3.02	%	NA	SM1030-F	18 Nov 21 14:34	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	15 Nov 21 19:59	RMV
Total Organic Carbon	3.9	mg/l	0.5	SM5310C-11	16 Nov 21 21:44	NAS
Dissolved Organic Carbon	4.0	mg/l	0.5	SM5310C-96	16 Nov 21 21:44	NAS
Fluoride	0.30	mg/l	0.10	SM4500-F-C	10 Nov 21 17:00	AC
Sulfate	176	mg/l	5.00	ASTM D516-11	15 Nov 21 14:26	SD
Chloride	6.9	mg/l	2.0	SM4500-Cl-E-11	10 Nov 21 10:55	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 14:34	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	10 Nov 21 14:18	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 8:56	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD

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Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-MPC-WS2

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 13:07	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 14:29	MDE
Total Dissolved Solids	829	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA
Calcium - Total	69.5	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Magnesium - Total	27.8	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Sodium - Total	200	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Potassium - Total	4.8	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Lithium - Total	0.052	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Iron - Total	0.97	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Silicon - Total	8.85	mg/l	0.10	6010D	16 Nov 21 13:55	SZ
Strontium - Total	1.11	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Zinc - Total	< 0.05	mg/l	0.05	6010D	12 Nov 21 11:33	MDE
Boron - Total	0.36	mg/l	0.10	6010D	17 Nov 21 9:08	SZ
Calcium - Dissolved	70.6	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Magnesium - Dissolved	28.0	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Sodium - Dissolved	197	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Potassium - Dissolved	4.8	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Lithium - Dissolved	0.055	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 9:55	MDE
Iron - Dissolved	0.99	mg/l	0.10	6010D	15 Nov 21 9:55	MDE
Silicon - Dissolved	9.18	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	1.16	mg/l	0.10	6010D	15 Nov 21 9:55	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	15 Nov 21 9:55	MDE

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Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-MPC-WS2

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Boron - Dissolved	0.38	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 11:07	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Barium - Total	0.0728	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Manganese - Total	0.1033	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Nickel - Total	0.0025	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 11:07	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.0686	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 16:48	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

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CERTIFICATION: ND # ND-00016

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Barry Botnen
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Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-MPC-WS2

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Manganese - Dissolved	0.0986	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	0.0023	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

Bromide was analyzed at MVTL, New Ulm, MN.
ND Certification #:R-040

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix   # = Due to concentration of other analytes
! = Due to sample quantity   + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MINNESOTA VALLEY TESTING LABORATORIES, INC.

MVTL

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
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Report Date: 26 Nov 21
Lab Number: 21-W4371
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 13:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-1686

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	10 Nov 21	AC
pH	* 6.9	units	N/A	SM4500-H+-B-11	10 Nov 21 17:00	AC
Conductivity (EC)	2906	umhos/cm	N/A	SM2510B-11	10 Nov 21 17:00	AC
Total Alkalinity	504	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Bicarbonate	504	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Tot Dis Solids(Summation)	2500	mg/l	12.5	SM1030-F	18 Nov 21 14:34	Calculated
Cation Summation	40.7	meq/L	NA	SM1030-F	15 Nov 21 10:55	Calculated
Anion Summation	40.1	meq/L	NA	SM1030-F	18 Nov 21 14:34	Calculated
Percent Error	0.77	%	NA	SM1030-F	18 Nov 21 14:34	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	15 Nov 21 20:20	RMV
Total Organic Carbon	10.7	mg/l	0.5	SM5310C-11	16 Nov 21 21:44	NAS
Dissolved Organic Carbon	10.3	mg/l	0.5	SM5310C-96	16 Nov 21 21:44	NAS
Fluoride	0.13	mg/l	0.10	SM4500-F-C	10 Nov 21 17:00	AC
Sulfate	1410	mg/l	5.00	ASTM D516-11	15 Nov 21 14:26	SD
Chloride	24.1	mg/l	2.0	SM4500-Cl-E-11	10 Nov 21 10:55	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 14:34	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	10 Nov 21 14:18	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 8:56	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 13:07	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 14:29	MDE

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Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-1686

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Total Dissolved Solids	2770	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA
Calcium - Total	410	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Magnesium - Total	147	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Sodium - Total	201	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Potassium - Total	5.8	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Lithium - Total	0.078	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Iron - Total	5.46	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Silicon - Total	5.24	mg/l	0.10	6010D	16 Nov 21 13:55	SZ
Strontium - Total	3.50	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Zinc - Total	< 0.05	mg/l	0.05	6010D	12 Nov 21 11:33	MDE
Boron - Total	0.13	mg/l	0.10	6010D	17 Nov 21 9:08	SZ
Calcium - Dissolved	401	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Magnesium - Dissolved	142	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Sodium - Dissolved	200	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Potassium - Dissolved	5.6	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Lithium - Dissolved	0.082	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Iron - Dissolved	5.68	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Silicon - Dissolved	5.44	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	3.82	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	15 Nov 21 10:55	MDE
Boron - Dissolved	0.13	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 11:07	MDE

RL = Method Reporting Limit

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CERTIFICATION: ND # ND-00016

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Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-1686

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Barium - Total	0.0279	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Manganese - Total	0.5380	mg/l	0.0020	6020B	17 Nov 21 14:23	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 11:07	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.0260	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 16:48	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE

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CERTIFICATION: ND # ND-00016

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Report Date: 26 Nov 21
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Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-1686

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Manganese - Dissolved	0.5230	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

Bromide was analyzed at MVTL, New Ulm, MN.
ND Certification #:R-040

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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Report Date: 26 Nov 21
Lab Number: 21-W4372
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 15:00
Date Received: 10 Nov 21 7:24
Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-W217

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	10 Nov 21	AC
pH	* 7.9	units	N/A	SM4500-H+-B-11	10 Nov 21 17:00	AC
Conductivity (EC)	2750	umhos/cm	N/A	SM2510B-11	10 Nov 21 17:00	AC
Total Alkalinity	1040	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Bicarbonate	1040	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Tot Dis Solids(Summation)	1630	mg/l	12.5	SM1030-F	18 Nov 21 14:34	Calculated
Cation Summation	27.2	meq/L	NA	SM1030-F	15 Nov 21 10:55	Calculated
Anion Summation	31.5	meq/L	NA	SM1030-F	18 Nov 21 14:34	Calculated
Percent Error	-7.29	%	NA	SM1030-F	18 Nov 21 14:34	Calculated
Bromide	2.90	mg/l	0.100	EPA 300.0	15 Nov 21 20:42	RMV
Total Organic Carbon	1.1	mg/l	0.5	SM5310C-11	16 Nov 21 21:44	NAS
Dissolved Organic Carbon	1.2	mg/l	0.5	SM5310C-96	16 Nov 21 21:44	NAS
Fluoride	3.27	mg/l	0.10	SM4500-F-C	10 Nov 21 17:00	AC
Sulfate	< 5	mg/l	5.00	ASTM D516-11	15 Nov 21 14:26	SD
Chloride	379	mg/l	2.0	SM4500-Cl-E-11	10 Nov 21 10:55	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 14:34	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	10 Nov 21 14:18	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 8:56	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 13:07	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 14:29	MDE

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Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-W217

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Total Dissolved Solids	1660	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA
Calcium - Total	4.3	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Magnesium - Total	1.1	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Sodium - Total	615	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Potassium - Total	2.7	mg/l	1.0	6010D	11 Nov 21 13:00	SZ
Lithium - Total	0.090	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Iron - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Silicon - Total	5.32	mg/l	0.10	6010D	16 Nov 21 13:55	SZ
Strontium - Total	0.17	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Zinc - Total	0.11	mg/l	0.05	6010D	12 Nov 21 11:33	MDE
Boron - Total	2.96	mg/l	0.10	6010D	17 Nov 21 9:08	SZ
Calcium - Dissolved	4.3	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Magnesium - Dissolved	1.1	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Sodium - Dissolved	617	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Potassium - Dissolved	3.0	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Lithium - Dissolved	0.102	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Silicon - Dissolved	5.52	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	0.19	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Zinc - Dissolved	0.11	mg/l	0.05	6010D	15 Nov 21 10:55	MDE
Boron - Dissolved	3.06	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 11:07	MDE

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CERTIFICATION: ND # ND-00016

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Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-W217

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Barium - Total	0.1333	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Copper - Total	0.0163	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Manganese - Total	0.0050	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Molybdenum - Total	0.0053	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 11:07	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.1295	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 16:48	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	0.0114	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE

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CERTIFICATION: ND # ND-00016

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Report Date: 26 Nov 21
Lab Number: 21-W4372
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 15:00
Date Received: 10 Nov 21 7:24
Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-W217

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Manganese - Dissolved	0.0043	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Molybdenum - Dissolved	0.0051	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

Bromide was analyzed at MVTL, New Ulm, MN.
ND Certification #:R-040

* 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
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CERTIFICATION: ND # ND-00016

MINNESOTA VALLEY TESTING LABORATORIES, INC.

MVTL

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
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MEMBER
ACIL

Report Date: 26 Nov 21
Lab Number: 21-W4373
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 16:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-W395

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	10 Nov 21	AC
pH	* 8.2	units	N/A	SM4500-H+-B-11	10 Nov 21 17:00	AC
Conductivity (EC)	2904	umhos/cm	N/A	SM2510B-11	10 Nov 21 17:00	AC
Total Alkalinity	1030	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Bicarbonate	1030	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Tot Dis Solids(Summation)	1740	mg/l	12.5	SM1030-F	18 Nov 21 14:34	Calculated
Cation Summation	28.7	meq/L	NA	SM1030-F	15 Nov 21 10:55	Calculated
Anion Summation	33.1	meq/L	NA	SM1030-F	18 Nov 21 14:34	Calculated
Percent Error	-7.12	%	NA	SM1030-F	18 Nov 21 14:34	Calculated
Bromide	3.20	mg/l	0.100	EPA 300.0	15 Nov 21 21:03	RMV
Total Organic Carbon	1.2	mg/l	0.5	SM5310C-11	16 Nov 21 21:44	NAS
Dissolved Organic Carbon	1.2	mg/l	0.5	SM5310C-96	16 Nov 21 21:44	NAS
Fluoride	2.31	mg/l	0.10	SM4500-F-C	10 Nov 21 17:00	AC
Sulfate	< 5	mg/l	5.00	ASTM D516-11	15 Nov 21 14:26	SD
Chloride	442	mg/l	2.0	SM4500-Cl-E-11	10 Nov 21 10:55	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 14:34	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	10 Nov 21 14:18	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 8:56	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 13:07	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 14:29	MDE

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MEMBER
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Lab Number: 21-W4373
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 16:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-W395

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Total Dissolved Solids	1760	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA
Calcium - Total	4.9	mg/l	1.0	6010D	11 Nov 21 14:00	SZ
Magnesium - Total	1.8	mg/l	1.0	6010D	11 Nov 21 14:00	SZ
Sodium - Total	668	mg/l	1.0	6010D	11 Nov 21 14:00	SZ
Potassium - Total	3.1	mg/l	1.0	6010D	11 Nov 21 14:00	SZ
Lithium - Total	0.099	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Iron - Total	1.86	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Silicon - Total	5.20	mg/l	0.10	6010D	16 Nov 21 14:55	SZ
Strontium - Total	0.23	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Zinc - Total	0.60	mg/l	0.05	6010D	12 Nov 21 11:33	MDE
Boron - Total	2.79	mg/l	0.10	6010D	17 Nov 21 9:08	SZ
Calcium - Dissolved	4.9	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Magnesium - Dissolved	1.7	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Sodium - Dissolved	647	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Potassium - Dissolved	3.4	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Lithium - Dissolved	0.106	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Iron - Dissolved	0.35	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Silicon - Dissolved	5.25	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	0.25	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Zinc - Dissolved	0.09	mg/l	0.05	6010D	15 Nov 21 10:55	MDE
Boron - Dissolved	2.87	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 11:07	MDE

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CERTIFICATION: ND # ND-00016

MVTL

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MEMBER
ACIL

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Lab Number: 21-W4373
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 16:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-W395

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Barium - Total	0.1742	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Copper - Total	0.0075	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Lead - Total	0.0049	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Manganese - Total	0.0167	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Molybdenum - Total	0.0045	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 11:07	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.1580	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 16:48	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE

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CERTIFICATION: ND # ND-00016

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MEMBER
ACIL

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Lab Number: 21-W4373
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 16:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-W395

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Manganese - Dissolved	0.0094	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Molybdenum - Dissolved	0.0043	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

Bromide was analyzed at MVTL, New Ulm, MN.
ND Certification #:R-040

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL

Report Date: 7 Dec 21
Lab Number: 21-W4440
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 9:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W269

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	11 Nov 21	RAA
pH	* 7.7	units	N/A	SM4500-H+-B-11	11 Nov 21 18:00	RAA
Conductivity (EC)	1376	umhos/cm	N/A	SM2510B-11	11 Nov 21 18:00	RAA
Total Alkalinity	379	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Bicarbonate	379	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Tot Dis Solids(Summation)	895	mg/l	12.5	SM1030-F	19 Nov 21 15:13	Calculated
Cation Summation	16.6	meq/L	NA	SM1030-F	16 Nov 21 12:36	Calculated
Anion Summation	15.0	meq/L	NA	SM1030-F	19 Nov 21 15:13	Calculated
Percent Error	5.06	%	NA	SM1030-F	19 Nov 21 15:13	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	15 Nov 21 23:51	RMV
Total Organic Carbon	5.3	mg/l	0.5	SM5310C-11	16 Nov 21 21:44	NAS
Dissolved Organic Carbon	5.2	mg/l	0.5	SM5310C-96	16 Nov 21 21:44	NAS
Fluoride	0.23	mg/l	0.10	SM4500-F-C	11 Nov 21 18:00	RAA
Sulfate	347	mg/l	5.00	ASTM D516-11	19 Nov 21 15:13	SD
Chloride	5.6	mg/l	2.0	SM4500-Cl-E-11	17 Nov 21 13:30	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 15:33	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	11 Nov 21 15:01	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 8:56	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Total Dissolved Solids	977	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA

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MEMBER ACIL

Report Date: 7 Dec 21
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Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 9:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W269

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	107	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Magnesium - Total	42.1	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Sodium - Total	162	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Potassium - Total	4.2	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Lithium - Total	0.040	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Iron - Total	4.55	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Silicon - Total	12.8	mg/l	0.10	6010D	16 Nov 21 14:55	SZ
Strontium - Total	1.27	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Zinc - Total	0.15	mg/l	0.05	6010D	12 Nov 21 15:33	MDE
Boron - Total	0.25	mg/l	0.10	6010D	17 Nov 21 11:08	SZ
Calcium - Dissolved	111	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Magnesium - Dissolved	43.9	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Sodium - Dissolved	164	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Potassium - Dissolved	4.8	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Lithium - Dissolved	0.043	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Iron - Dissolved	4.65	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Silicon - Dissolved	14.2	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	1.32	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Zinc - Dissolved	0.08	mg/l	0.05	6010D	15 Nov 21 12:55	MDE
Boron - Dissolved	0.26	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 13:21	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Barium - Total	0.0323	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE

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CERTIFICATION: ND # ND-00016

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Date Sampled: 10 Nov 21 9:00
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Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W269

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Manganese - Total	0.3174	mg/l	0.0020	6020B	17 Nov 21 14:23	MDE
Molybdenum - Total	0.0035	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 13:21	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.0388	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 16:48	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Manganese - Dissolved	0.3332	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE
Molybdenum - Dissolved	0.0033	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

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@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
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Report Date: 7 Dec 21
Lab Number: 21-W4440
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 9:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W269

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.001 @	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	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

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Report Date: 7 Dec 21
Lab Number: 21-W4441
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 11:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W478

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	11 Nov 21	RAA
pH	* 8.2	units	N/A	SM4500-H+-B-11	11 Nov 21 18:00	RAA
Conductivity (EC)	2167	umhos/cm	N/A	SM2510B-11	11 Nov 21 18:00	RAA
Total Alkalinity	1230	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Bicarbonate	1230	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Tot Dis Solids(Summation)	1370	mg/l	12.5	SM1030-F	19 Nov 21 15:13	Calculated
Cation Summation	25.1	meq/L	NA	SM1030-F	16 Nov 21 12:36	Calculated
Anion Summation	25.9	meq/L	NA	SM1030-F	19 Nov 21 15:13	Calculated
Percent Error	-1.66	%	NA	SM1030-F	19 Nov 21 15:13	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	16 Nov 21 0:11	RMV
Total Organic Carbon	7.1	mg/l	0.5	SM5310C-11	16 Nov 21 23:56	NAS
Dissolved Organic Carbon	7.2	mg/l	0.5	SM5310C-96	16 Nov 21 23:56	NAS
Fluoride	1.62	mg/l	0.10	SM4500-F-C	11 Nov 21 18:00	RAA
Sulfate	34.3	mg/l	5.00	ASTM D516-11	19 Nov 21 15:13	SD
Chloride	20.9	mg/l	2.0	SM4500-Cl-E-11	17 Nov 21 13:30	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 15:33	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	11 Nov 21 15:01	SD
Phosphorus as P - Total	0.23	mg/l	0.20	EPA 365.1	19 Nov 21 8:56	SD
Phosphorus as P-Dissolved	0.24	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Total Dissolved Solids	1420	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA

RL = Method Reporting Limit

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+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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Report Date: 7 Dec 21
Lab Number: 21-W4441
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 11:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W478

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	2.8	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Magnesium - Total	1.5	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Sodium - Total	572	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Potassium - Total	3.0	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Lithium - Total	0.076	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Iron - Total	0.43	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Silicon - Total	4.12	mg/l	0.10	6010D	16 Nov 21 14:55	SZ
Strontium - Total	0.14	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Zinc - Total	0.06	mg/l	0.05	6010D	12 Nov 21 15:33	MDE
Boron - Total	0.56	mg/l	0.10	6010D	17 Nov 21 12:08	SZ
Calcium - Dissolved	2.7	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Magnesium - Dissolved	1.5	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Sodium - Dissolved	568	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Potassium - Dissolved	3.5	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Lithium - Dissolved	0.076	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Iron - Dissolved	0.48	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Silicon - Dissolved	4.23	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	0.14	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Zinc - Dissolved	0.06	mg/l	0.05	6010D	15 Nov 21 12:55	MDE
Boron - Dissolved	0.58	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 13:21	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Barium - Total	0.0912	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE

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CERTIFICATION: ND # ND-00016

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Report Date: 7 Dec 21
Lab Number: 21-W4441
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 11:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W478

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Copper - Total	0.0053	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Manganese - Total	0.0048	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 13:21	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.0913	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 16:48	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	0.0044	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Manganese - Dissolved	0.0053	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

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Report Date: 7 Dec 21
Lab Number: 21-W4441
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 11:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W478

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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Report Date: 7 Dec 21
Lab Number: 21-W4442
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W468

Temp at Receipt: 1.2C ROI

		As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion					EPA 200.2	11 Nov 21	RAA
pH	*	8.3	units	N/A	SM4500-H+-B-11	11 Nov 21 18:00	RAA
Conductivity (EC)		1650	umhos/cm	N/A	SM2510B-11	11 Nov 21 18:00	RAA
Total Alkalinity		882	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Phenolphthalein Alk		< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Bicarbonate		881	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Carbonate		< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Hydroxide		< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Tot Dis Solids(Summation)		1100	mg/l	12.5	SM1030-F	19 Nov 21 15:13	Calculated
Cation Summation		19.1	meq/L	NA	SM1030-F	16 Nov 21 12:36	Calculated
Anion Summation		20.4	meq/L	NA	SM1030-F	19 Nov 21 15:13	Calculated
Percent Error		-3.29	%	NA	SM1030-F	19 Nov 21 15:13	Calculated
Bromide		< 0.5 @	mg/l	0.100	EPA 300.0	16 Nov 21 0:32	RMV
Total Organic Carbon		2.8	mg/l	0.5	SM5310C-11	16 Nov 21 23:56	NAS
Dissolved Organic Carbon		2.5	mg/l	0.5	SM5310C-96	16 Nov 21 23:56	NAS
Fluoride		1.71	mg/l	0.10	SM4500-F-C	11 Nov 21 18:00	RAA
Sulfate		129	mg/l	5.00	ASTM D516-11	19 Nov 21 15:13	SD
Chloride		3.6	mg/l	2.0	SM4500-Cl-E-11	17 Nov 21 13:30	SD
Nitrate-Nitrite as N		< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 15:33	SD
Nitrite as N		< 0.2	mg/l	0.20	EPA 353.2	11 Nov 21 15:01	SD
Phosphorus as P - Total		0.35	mg/l	0.20	EPA 365.1	19 Nov 21 8:56	SD
Phosphorus as P-Dissolved		0.34	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total		< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved		< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Total Dissolved Solids		1100	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA

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Report Date: 7 Dec 21
Lab Number: 21-W4442
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W468

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	2.4	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Magnesium - Total	1.2	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Sodium - Total	430	mg/l	1.0	6010D	7 Dec 21 9:07	SZ
Potassium - Total	2.4	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Lithium - Total	0.046	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Iron - Total	0.14	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Silicon - Total	3.18	mg/l	0.10	6010D	16 Nov 21 14:55	SZ
Strontium - Total	0.10	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Zinc - Total	< 0.25	mg/l	0.05	6010D	12 Nov 21 15:33	MDE
Boron - Total	0.46	mg/l	0.10	6010D	17 Nov 21 12:08	SZ
Calcium - Dissolved	2.4	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Magnesium - Dissolved	1.3	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Sodium - Dissolved	433	mg/l	1.0	6010D	7 Dec 21 10:07	SZ
Potassium - Dissolved	2.5	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Lithium - Dissolved	0.050	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Silicon - Dissolved	3.28	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	0.10	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	15 Nov 21 12:55	MDE
Boron - Dissolved	0.48	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 13:21	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Barium - Total	0.0276	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE

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CERTIFICATION: ND # ND-00016

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Report Date: 7 Dec 21
Lab Number: 21-W4442
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W468

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Chromium - Total	< 0.01 @	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Copper - Total	0.0041	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Lead - Total	0.0040	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Manganese - Total	0.0050	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Molybdenum - Total	0.0020	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Nickel - Total	< 0.01 @	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 13:21	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Vanadium - Total	0.0084	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.0298	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 16:48	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.01 @	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	0.0042	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Lead - Dissolved	0.0043	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Manganese - Dissolved	0.0044	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Molybdenum - Dissolved	0.0021	mg/l	0.0020	6020B	29 Nov 21 11:36	MDE
Nickel - Dissolved	< 0.01 @	mg/l	0.0020	6020B	29 Nov 21 11:36	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

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

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Report Date: 7 Dec 21
Lab Number: 21-W4442
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W468

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 Nov 21 11:36	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	0.0102	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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Report Date: 7 Dec 21
Lab Number: 21-W4443
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 14:30
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W424

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	11 Nov 21	RAA
pH	* 8.3	units	N/A	SM4500-H+-B-11	11 Nov 21 18:00	RAA
Conductivity (EC)	2422	umhos/cm	N/A	SM2510B-11	11 Nov 21 18:00	RAA
Total Alkalinity	1250	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Bicarbonate	1250	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Tot Dis Solids(Summation)	1500	mg/l	12.5	SM1030-F	19 Nov 21 15:13	Calculated
Cation Summation	26.8	meq/L	NA	SM1030-F	16 Nov 21 12:36	Calculated
Anion Summation	29.1	meq/L	NA	SM1030-F	19 Nov 21 15:13	Calculated
Percent Error	-4.10	%	NA	SM1030-F	19 Nov 21 15:13	Calculated
Bromide	1.03	mg/l	0.100	EPA 300.0	16 Nov 21 0:53	RMV
Total Organic Carbon	3.4	mg/l	0.5	SM5310C-11	16 Nov 21 23:56	NAS
Dissolved Organic Carbon	3.5	mg/l	0.5	SM5310C-96	16 Nov 21 23:56	NAS
Fluoride	0.83	mg/l	0.10	SM4500-F-C	11 Nov 21 18:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	19 Nov 21 15:13	SD
Chloride	144	mg/l	2.0	SM4500-Cl-E-11	17 Nov 21 13:30	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 15:33	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	11 Nov 21 15:01	SD
Phosphorus as P - Total	0.31	mg/l	0.20	EPA 365.1	19 Nov 21 9:35	SD
Phosphorus as P-Dissolved	0.20	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 14:00	MDE
Total Dissolved Solids	1560	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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CERTIFICATION: ND # ND-00016

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Report Date: 7 Dec 21
Lab Number: 21-W4443
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 14:30
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W424

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	3.3	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Magnesium - Total	1.6	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Sodium - Total	600	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Potassium - Total	2.7	mg/l	1.0	6010D	7 Dec 21 9:07	SZ
Lithium - Total	0.090	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Iron - Total	0.12	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Silicon - Total	4.44	mg/l	0.10	6010D	16 Nov 21 14:55	SZ
Strontium - Total	0.15	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Zinc - Total	< 0.05	mg/l	0.05	6010D	12 Nov 21 15:33	MDE
Boron - Total	1.75	mg/l	0.10	6010D	17 Nov 21 12:08	SZ
Calcium - Dissolved	3.3	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Magnesium - Dissolved	1.6	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Sodium - Dissolved	607	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Potassium - Dissolved	3.0	mg/l	1.0	6010D	7 Dec 21 10:07	SZ
Lithium - Dissolved	0.095	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 13:55	MDE
Iron - Dissolved	0.12	mg/l	0.10	6010D	15 Nov 21 13:55	MDE
Silicon - Dissolved	4.64	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	0.16	mg/l	0.10	6010D	15 Nov 21 13:55	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	15 Nov 21 13:55	MDE
Boron - Dissolved	1.80	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 13:21	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Barium - Total	0.1210	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE

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Report Date: 7 Dec 21
Lab Number: 21-W4443
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 14:30
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W424

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Copper - Total	0.0155	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Manganese - Total	0.0211	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 13:21	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.1230	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	0.0089	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Manganese - Dissolved	0.0212	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

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Report Date: 7 Dec 21
Lab Number: 21-W4443
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 14:30
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W424

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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Report Date: 7 Dec 21
Lab Number: 21-W4444
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 15:30
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W471

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	11 Nov 21	RAA
pH	* 8.2	units	N/A	SM4500-H+-B-11	11 Nov 21 18:00	RAA
Conductivity (EC)	2535	umhos/cm	N/A	SM2510B-11	11 Nov 21 18:00	RAA
Total Alkalinity	1260	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Bicarbonate	1260	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Tot Dis Solids(Summation)	1590	mg/l	12.5	SM1030-F	19 Nov 21 15:38	Calculated
Cation Summation	27.5	meq/L	NA	SM1030-F	2 Dec 21 16:56	Calculated
Anion Summation	30.4	meq/L	NA	SM1030-F	19 Nov 21 15:38	Calculated
Percent Error	-4.95	%	NA	SM1030-F	2 Dec 21 16:56	Calculated
Bromide	1.28	mg/l	0.100	EPA 300.0	16 Nov 21 1:14	RMV
Total Organic Carbon	3.2	mg/l	0.5	SM5310C-11	16 Nov 21 23:56	NAS
Dissolved Organic Carbon	3.1	mg/l	0.5	SM5310C-96	16 Nov 21 23:56	NAS
Fluoride	1.14	mg/l	0.10	SM4500-F-C	11 Nov 21 18:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	19 Nov 21 15:38	SD
Chloride	183	mg/l	2.0	SM4500-Cl-E-11	17 Nov 21 13:30	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 15:33	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	11 Nov 21 15:01	SD
Phosphorus as P - Total	0.24	mg/l	0.20	EPA 365.1	19 Nov 21 9:35	SD
Phosphorus as P-Dissolved	0.24	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 14:00	MDE
Total Dissolved Solids	1740	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA

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CERTIFICATION: ND # ND-00016

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Report Date: 7 Dec 21
Lab Number: 21-W4444
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 15:30
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W471

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	3.4	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Magnesium - Total	1.5	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Sodium - Total	643	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Potassium - Total	2.9	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Lithium - Total	0.100	mg/l	0.020	6010D	16 Nov 21 10:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Iron - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Silicon - Total	4.83	mg/l	0.10	6010D	16 Nov 21 14:55	SZ
Strontium - Total	0.16	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Zinc - Total	< 0.05	mg/l	0.05	6010D	12 Nov 21 15:33	MDE
Boron - Total	2.42	mg/l	0.10	6010D	17 Nov 21 12:08	SZ
Calcium - Dissolved	3.3	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Magnesium - Dissolved	1.4	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Sodium - Dissolved	624	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Potassium - Dissolved	3.4	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Lithium - Dissolved	0.101	mg/l	0.020	6010D	16 Nov 21 12:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 13:55	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	2 Dec 21 16:56	SZ
Silicon - Dissolved	4.69	mg/l	0.10	6010D	16 Nov 21 16:55	SZ
Strontium - Dissolved	0.16	mg/l	0.10	6010D	15 Nov 21 13:55	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	15 Nov 21 13:55	MDE
Boron - Dissolved	2.36	mg/l	0.10	6010D	17 Nov 21 15:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 13:21	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Barium - Total	0.1466	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE

RL = Method Reporting Limit

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CERTIFICATION: ND # ND-00016

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Report Date: 7 Dec 21
Lab Number: 21-W4444
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 15:30
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W471

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Copper - Total	0.0390	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Lead - Total	0.0014	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Manganese - Total	0.0112	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 13:21	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.1431	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	0.0244	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	0.0007	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Manganese - Dissolved	0.0105	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	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

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

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Report Date: 7 Dec 21
Lab Number: 21-W4444
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 15:30
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W471

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	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

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Report Date: 24 Nov 21
Lab Number: 21-W4445
Work Order #: 82-3151
Account #: 007033
Date Sampled: 11 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W510

Temp at Receipt: 1.0C ROI

		As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion					EPA 200.2	11 Nov 21	RAA
pH	*	8.3	units	N/A	SM4500-H+-B-11	11 Nov 21 18:00	RAA
Conductivity (EC)		2648	umhos/cm	N/A	SM2510B-11	11 Nov 21 18:00	RAA
Total Alkalinity		1430	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Phenolphthalein Alk		< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Bicarbonate		1430	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Carbonate		< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Hydroxide		< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Tot Dis Solids(Summation)		1640	mg/l	12.5	SM1030-F	19 Nov 21 15:38	Calculated
Cation Summation		29.0	meq/L	NA	SM1030-F	16 Nov 21 12:36	Calculated
Anion Summation		31.8	meq/L	NA	SM1030-F	19 Nov 21 15:38	Calculated
Percent Error		-4.72	%	NA	SM1030-F	19 Nov 21 15:38	Calculated
Bromide		0.770	mg/l	0.100	EPA 300.0	16 Nov 21 1:35	RMV
Total Organic Carbon		2.6	mg/l	0.5	SM5310C-11	19 Nov 21 13:57	NAS
Dissolved Organic Carbon		2.6	mg/l	0.5	SM5310C-96	19 Nov 21 13:57	NAS
Fluoride		0.82	mg/l	0.10	SM4500-F-C	11 Nov 21 18:00	RAA
Sulfate		13.7	mg/l	5.00	ASTM D516-11	19 Nov 21 15:38	SD
Chloride		104	mg/l	2.0	SM4500-Cl-E-11	17 Nov 21 13:30	SD
Nitrate-Nitrite as N		< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 15:33	SD
Nitrite as N		< 0.2	mg/l	0.20	EPA 353.2	11 Nov 21 15:01	SD
Phosphorus as P - Total		< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 9:35	SD
Phosphorus as P-Dissolved		< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total		< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved		< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 14:00	MDE
Total Dissolved Solids		1680	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA

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

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Report Date: 24 Nov 21
Lab Number: 21-W4445
Work Order #: 82-3151
Account #: 007033
Date Sampled: 11 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W510

Temp at Receipt: 1.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	3.6	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Magnesium - Total	1.8	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Sodium - Total	655	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Potassium - Total	3.3	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Lithium - Total	0.096	mg/l	0.020	6010D	16 Nov 21 10:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Iron - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Silicon - Total	5.87	mg/l	0.10	6010D	16 Nov 21 14:55	SZ
Strontium - Total	0.18	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Zinc - Total	0.33	mg/l	0.05	6010D	12 Nov 21 15:33	MDE
Boron - Total	1.54	mg/l	0.10	6010D	17 Nov 21 12:08	SZ
Calcium - Dissolved	3.7	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Magnesium - Dissolved	1.8	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Sodium - Dissolved	656	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Potassium - Dissolved	4.0	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Lithium - Dissolved	0.103	mg/l	0.020	6010D	16 Nov 21 12:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 13:55	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 13:55	MDE
Silicon - Dissolved	6.14	mg/l	0.10	6010D	16 Nov 21 16:55	SZ
Strontium - Dissolved	0.19	mg/l	0.10	6010D	15 Nov 21 13:55	MDE
Zinc - Dissolved	0.33	mg/l	0.05	6010D	15 Nov 21 13:55	MDE
Boron - Dissolved	1.54	mg/l	0.10	6010D	17 Nov 21 15:08	SZ
Antimony - Total	< 0.002 ^	mg/l	0.0010	6020B	17 Nov 21 14:23	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 14:23	MDE
Barium - Total	0.1072	mg/l	0.0020	6020B	17 Nov 21 14:23	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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CERTIFICATION: ND # ND-00016

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Report Date: 24 Nov 21
Lab Number: 21-W4445
Work Order #: 82-3151
Account #: 007033
Date Sampled: 11 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W510

Temp at Receipt: 1.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 14:23	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 14:23	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 14:23	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 14:23	MDE
Copper - Total	0.0460	mg/l	0.0020	6020B	17 Nov 21 14:23	MDE
Lead - Total	0.0032	mg/l	0.0005	6020B	17 Nov 21 14:23	MDE
Manganese - Total	0.0022	mg/l	0.0020	6020B	17 Nov 21 14:23	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 14:23	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 14:23	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	17 Nov 21 14:23	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 14:23	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 14:23	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 14:23	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.1052	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	0.0026	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Manganese - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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Report Date: 24 Nov 21
Lab Number: 21-W4445
Work Order #: 82-3151
Account #: 007033
Date Sampled: 11 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W510

Temp at Receipt: 1.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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Report Date: 24 Nov 21
Lab Number: 21-W4446
Work Order #: 82-3151
Account #: 007033
Date Sampled: 11 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W510 Dup

Temp at Receipt: 1.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	11 Nov 21	RAA
pH	* 8.4	units	N/A	SM4500-H+-B-11	11 Nov 21 18:00	RAA
Conductivity (EC)	2651	umhos/cm	N/A	SM2510B-11	11 Nov 21 18:00	RAA
Total Alkalinity	1430	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Bicarbonate	1419	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Tot Dis Solids(Summation)	1700	mg/l	12.5	SM1030-F	19 Nov 21 15:38	Calculated
Cation Summation	29.0	meq/L	NA	SM1030-F	16 Nov 21 12:36	Calculated
Anion Summation	31.8	meq/L	NA	SM1030-F	19 Nov 21 15:38	Calculated
Percent Error	-4.63	%	NA	SM1030-F	19 Nov 21 15:38	Calculated
Bromide	0.770	mg/l	0.100	EPA 300.0	16 Nov 21 1:56	RMV
Total Organic Carbon	2.6	mg/l	0.5	SM5310C-11	19 Nov 21 13:57	NAS
Dissolved Organic Carbon	2.6	mg/l	0.5	SM5310C-96	19 Nov 21 13:57	NAS
Fluoride	0.82	mg/l	0.10	SM4500-F-C	11 Nov 21 18:00	RAA
Sulfate	13.3	mg/l	5.00	ASTM D516-11	19 Nov 21 15:38	SD
Chloride	104	mg/l	2.0	SM4500-Cl-E-11	17 Nov 21 13:30	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 15:33	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	11 Nov 21 15:01	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 9:35	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 14:00	MDE
Total Dissolved Solids	1680	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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Report Date: 24 Nov 21
Lab Number: 21-W4446
Work Order #: 82-3151
Account #: 007033
Date Sampled: 11 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W510 Dup

Temp at Receipt: 1.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	3.7	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Magnesium - Total	1.8	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Sodium - Total	720	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Potassium - Total	3.5	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Lithium - Total	0.100	mg/l	0.020	6010D	16 Nov 21 10:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Iron - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Silicon - Total	6.07	mg/l	0.10	6010D	16 Nov 21 14:55	SZ
Strontium - Total	0.19	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Zinc - Total	0.34	mg/l	0.05	6010D	12 Nov 21 15:33	MDE
Boron - Total	1.58	mg/l	0.10	6010D	17 Nov 21 12:08	SZ
Calcium - Dissolved	3.6	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Magnesium - Dissolved	1.8	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Sodium - Dissolved	657	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Potassium - Dissolved	4.0	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Lithium - Dissolved	0.100	mg/l	0.020	6010D	16 Nov 21 12:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 13:55	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 13:55	MDE
Silicon - Dissolved	6.24	mg/l	0.10	6010D	16 Nov 21 16:55	SZ
Strontium - Dissolved	0.18	mg/l	0.10	6010D	15 Nov 21 13:55	MDE
Zinc - Dissolved	0.32	mg/l	0.05	6010D	15 Nov 21 13:55	MDE
Boron - Dissolved	1.56	mg/l	0.10	6010D	17 Nov 21 15:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 13:21	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Barium - Total	0.1086	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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Report Date: 24 Nov 21
Lab Number: 21-W4446
Work Order #: 82-3151
Account #: 007033
Date Sampled: 11 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W510 Dup

Temp at Receipt: 1.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Copper - Total	0.0031	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Manganese - Total	0.0028	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 13:21	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.1041	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	0.0025	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Manganese - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL

Report Date: 24 Nov 21
Lab Number: 21-W4446
Work Order #: 82-3151
Account #: 007033
Date Sampled: 11 Nov 21 10:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W510 Dup

Temp at Receipt: 1.0C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
# = Due to concentration of other analytes
! = Due to sample quantity
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL

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MEMBER
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Report Date: 5 Jan 22
Lab Number: 21-W4746
Work Order #: 82-3423
Account #: 007033
Date Sampled: 13 Dec 21 9:30
Date Received: 13 Dec 21 13:30
Sampled By: MVTL Field Service

Temp at Receipt: 10.1C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Sample Description: MRY

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	13 Dec 21	RAA
pH	* 8.4	units	N/A	SM4500-H+-B-11	14 Dec 21 17:00	RAA
Conductivity (EC)	2801	umhos/cm	N/A	SM2510B-11	13 Dec 21 17:00	RAA
pH - Field	8.15	units	NA	SM 4500 H+ B	13 Dec 21 9:30	JSM
Temperature - Field	10.8	Degrees C	NA	SM 2550B	13 Dec 21 9:30	JSM
Total Alkalinity	960	mg/l CaCO3	20	SM2320B-11	14 Dec 21 17:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	14 Dec 21 17:00	RAA
Bicarbonate	941	mg/l CaCO3	20	SM2320B-11	14 Dec 21 17:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	14 Dec 21 17:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	14 Dec 21 17:00	RAA
Conductivity - Field	2823	umhos/cm	1	EPA 120.1	13 Dec 21 9:30	JSM
Tot Dis Solids(Summation)	1570	mg/l	12.5	SM1030-F	16 Dec 21 14:31	Calculated
Cation Summation	30.3	meq/L	NA	SM1030-F	20 Dec 21 12:19	Calculated
Anion Summation	27.5	meq/L	NA	SM1030-F	16 Dec 21 14:31	Calculated
Percent Error	4.80	%	NA	SM1030-F	20 Dec 21 12:19	Calculated
Bromide	3.06	mg/l	0.100	EPA 300.0	17 Dec 21 21:11	RMV
Total Organic Carbon	1.0	mg/l	0.5	SM5310C-11	20 Dec 21 11:36	AC
Dissolved Organic Carbon	1.1	mg/l	0.5	SM5310C-96	20 Dec 21 11:36	AC
Fluoride	2.67	mg/l	0.10	SM4500-F-C	13 Dec 21 17:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	15 Dec 21 16:02	SD
Chloride	296	mg/l	2.0	SM4500-Cl-E-11	15 Dec 21 12:01	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	16 Dec 21 14:31	EV
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	14 Dec 21 10:38	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	17 Dec 21 9:24	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	23 Dec 21 14:06	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	23 Dec 21 14:24	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER
ACIL

Report Date: 5 Jan 22
Lab Number: 21-W4746
Work Order #: 82-3423
Account #: 007033
Date Sampled: 13 Dec 21 9:30
Date Received: 13 Dec 21 13:30
Sampled By: MVTL Field Service

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Sample Description: MRY

Temp at Receipt: 10.1C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	23 Dec 21 12:43	MDE
Total Dissolved Solids	1720	mg/l	10	USGS I1750-85	17 Dec 21 9:00	RAA
Calcium - Total	4.0	mg/l	1.0	6010D	14 Dec 21 12:22	MDE
Magnesium - Total	< 1	mg/l	1.0	6010D	14 Dec 21 12:22	MDE
Sodium - Total	690	mg/l	1.0	6010D	14 Dec 21 12:22	MDE
Potassium - Total	3.0	mg/l	1.0	6010D	14 Dec 21 12:22	MDE
Lithium - Total	0.099	mg/l	0.020	6010D	16 Dec 21 11:47	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	20 Dec 21 10:19	SZ
Iron - Total	< 0.1	mg/l	0.10	6010D	20 Dec 21 10:19	SZ
Silicon - Total	6.73	mg/l	0.10	6010D	16 Dec 21 15:44	SZ
Strontium - Total	0.15	mg/l	0.10	6010D	20 Dec 21 10:19	SZ
Zinc - Total	< 0.05	mg/l	0.05	6010D	20 Dec 21 10:19	SZ
Boron - Total	3.68	mg/l	0.10	6010D	28 Dec 21 14:28	SZ
Calcium - Dissolved	3.9	mg/l	1.0	6010D	14 Dec 21 11:22	MDE
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	14 Dec 21 11:22	MDE
Sodium - Dissolved	691	mg/l	1.0	6010D	14 Dec 21 11:22	MDE
Potassium - Dissolved	3.4	mg/l	1.0	6010D	14 Dec 21 11:22	MDE
Lithium - Dissolved	0.101	mg/l	0.020	6010D	16 Dec 21 11:47	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	20 Dec 21 12:19	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	20 Dec 21 12:19	SZ
Silicon - Dissolved	6.64	mg/l	0.10	6010D	16 Dec 21 15:44	SZ
Strontium - Dissolved	0.15	mg/l	0.10	6010D	20 Dec 21 12:19	SZ
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	20 Dec 21 12:19	SZ
Boron - Dissolved	3.43	mg/l	0.10	6010D	17 Dec 21 13:53	MDE
Antimony - Total	< 0.001	mg/l	0.0010	6020B	15 Dec 21 12:28	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	15 Dec 21 12:28	MDE

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! = Due to sample quantity + = Due to internal standard response

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MEMBER
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Report Date: 5 Jan 22
Lab Number: 21-W4746
Work Order #: 82-3423
Account #: 007033
Date Sampled: 13 Dec 21 9:30
Date Received: 13 Dec 21 13:30
Sampled By: MVTL Field Service

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Sample Description: MRY

Temp at Receipt: 10.1C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Barium - Total	0.1128	mg/l	0.0020	6020B	15 Dec 21 12:28	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	15 Dec 21 15:53	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	15 Dec 21 12:28	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	15 Dec 21 12:28	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	15 Dec 21 12:28	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	15 Dec 21 15:24	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	15 Dec 21 12:28	MDE
Manganese - Total	0.0038	mg/l	0.0020	6020B	15 Dec 21 15:24	MDE
Molybdenum - Total	0.0054	mg/l	0.0020	6020B	27 Dec 21 16:15	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	15 Dec 21 12:28	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	15 Dec 21 12:28	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	15 Dec 21 12:28	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	27 Dec 21 16:15	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	15 Dec 21 12:28	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	15 Dec 21 13:56	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Dec 21 13:56	MDE
Barium - Dissolved	0.1102	mg/l	0.0020	6020B	15 Dec 21 13:56	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Dec 21 15:24	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Dec 21 13:56	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Dec 21 13:56	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Dec 21 13:56	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Dec 21 15:24	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Dec 21 13:56	MDE
Manganese - Dissolved	0.0031	mg/l	0.0020	6020B	15 Dec 21 15:24	MDE
Molybdenum - Dissolved	0.0049	mg/l	0.0020	6020B	27 Dec 21 17:04	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Dec 21 13:56	MDE

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CERTIFICATION: ND # ND-00016

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MEMBER
ACIL

Report Date: 5 Jan 22
Lab Number: 21-W4746
Work Order #: 82-3423
Account #: 007033
Date Sampled: 13 Dec 21 9:30
Date Received: 13 Dec 21 13:30
Sampled By: MVTL Field Service

Temp at Receipt: 10.1C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Sample Description: MRY

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	15 Dec 21 13:56	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	28 Dec 21 12:06	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Dec 21 17:04	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Dec 21 13:56	MDE

Bromide was analyzed at MVTL, New Ulm, MN.
ND Certification #:R-040

* Holding time exceeded

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

June 4, 2021

EERC
Barry Botnen
15 North 23rd St
Grand Forks, ND 58202

RE: USGS Well near Center, ND

Dear Mr. Botnen,

On June 3, 2021, MVTL Laboratories' Field Services division collected a ground water sample from a USGS well near Center, ND. Well ID is 142-084-24 BBA. MVTL installed a non-dedicated 3" Grundfos pump to a depth of 300 ft to purge and sample the well. The sample collected was placed on ice and transported back to the MVTL lab in Bismarck, ND for analysis.

Thank you for your continued trust and support of our services. If you have any questions, please call me at (701) 391-4900.

Sincerely,

Jeremy Meyer
MVTL Field Services Manager

MVTL

2616 E. Broadway Ave, Bismarck, ND

Phone: (701) 258-9720

Field Datasheet

Groundwater Assessment

Company: EERC

Event:

Sample ID: USGS well

Sampling Personal: Jerry Mayer / Darren Neswazo

Weather Conditions: Temp: 75 °F Wind: N @ 5-10 Precip: ~~Sunny~~ / **Partly Cloudy** / **Cloudy**

WELL INFORMATION

Well Locked?	YES	NO	
Well Labeled?	YES	NO	
Casing Strait?	YES	NO	
Grout Seal Intact?	YES	NO	Not Visible
Repairs Necessary?			

Casing Diameter:	~~2"~~ 3"	
Water Level Before Purge:	210.36	ft
Total Depth of Well:	1000 t	ft
Well Volume:	~~1098.0~~	liters 1950.4
Depth to Top of Pump:	300.0	ft
Water Level After Sample:		ft
Measurement Method:	**Electric Water Level Indicator**	

SAMPLING INFORMATION

Purging Method:	Grundfoss 3"	
Sampling Method:	Grundfors 3"	
Dedicated Equipment?	YES	NO

Duplicate Sample?	YES	NO
Duplicate Sample ID:	—	

Control Settings:	
Purge: —	Sec.
Recover: —	Sec.
PSI: —	

Bottle List:

FIELD READINGS

Stabilization Parameters (3 Consecutive)		Temp. (°C)	Spec. Cond.	pH	DO (mg/L)	ORP (mV)	Turbidity (NTU)	Water Level (ft)	Pumping Rate L/Min	Liters Removed	Appearance or Comment Clarity, Color, Odor, Ect. clear, slightly turbid, turbid
Purge Date	**Time**										
3 June 21	0835	**Start of Well Purge** 60min									
	0935	13.78	2652	8.59	1.29	-5.1	1.62	253.96	35.0	2100.0	Clear
	1035	15.40	2621	8.45	1.44	-7.9	1.53	255.47	35.0	2100.0	Clear
	1135	15.67	2617	8.41	2.57	3.4	0.85	256.40	35.0	2100.0	Clear
	1235	15.01	2639	8.44	1.79	-3.6	2.50	257.02	35.0	2100.0	Clear

Well Stabilized? **YES** NO Total Volume Purged: 8400.0 Liters

Sample Date	Time	Temp. (°C)	Spec. Cond.	pH			Turbidity (NTU)				Appearance or Comment Clarity, Color, Odor, Ect.
3 June 21	1235	15.01	2639	8.44			2.50				Clear

Comments:	
	142-084-24 BBA well ID

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MEMBER ACIL

Report Date: 21 Jun 21
Lab Number: 21-W1550
Work Order #: 82-1301
Account #: 007033
Date Sampled: 3 Jun 21 12:35
Date Received: 3 Jun 21 13:54
Sampled By: MVTL Field Services

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: Center USGS Well

Sample Description: USGS Well

PO #: B. Botnen

Temp at Receipt: 14.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	3 Jun 21	RAA
pH - Field	8.44	units	NA	SM 4500 H+ B	3 Jun 21 12:35	JSM
Temperature - Field	15.0	Degrees C	NA	SM 2550B	3 Jun 21 12:35	JSM
Total Alkalinity	969	mg/l CaCO3	20	SM2320B-11	3 Jun 21 18:00	RAA
Phenolphthalein Alk	32	mg/l CaCO3	20	SM2320B-11	3 Jun 21 18:00	RAA
Bicarbonate	905	mg/l CaCO3	20	SM2320B-11	3 Jun 21 18:00	RAA
Carbonate	64	mg/l CaCO3	20	SM2320B-11	3 Jun 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	3 Jun 21 18:00	RAA
Conductivity - Field	2639	umhos/cm	1	EPA 120.1	3 Jun 21 12:35	JSM
Tot Dis Solids(Summation)	1590	mg/l	12.5	SM1030-F	10 Jun 21 14:29	Calculated
Cation Summation	26.6	meq/L	NA	SM1030-F	8 Jun 21 11:41	Calculated
Anion Summation	29.0	meq/L	NA	SM1030-F	10 Jun 21 14:29	Calculated
Percent Error	-4.43	%	NA	SM1030-F	10 Jun 21 14:29	Calculated
Bromide	2.71	mg/l	0.100	EPA 300.0	9 Jun 21 18:32	RMV
Total Organic Carbon	1.2	mg/l	0.5	SM5310C-11	4 Jun 21 23:58	NAS
Dissolved Organic Carbon	1.2	mg/l	0.5	SM5310C-96	4 Jun 21 23:58	NAS
Fluoride	3.69	mg/l	0.10	SM4500-F-C	3 Jun 21 18:00	RAA
Sulfate	< 5	mg/l	5.00	ASTM D516-11	7 Jun 21 11:16	SD
Chloride	342	mg/l	2.0	SM4500-Cl-E-11	7 Jun 21 14:59	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	10 Jun 21 14:29	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	4 Jun 21 12:20	EV
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	11 Jun 21 9:10	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	11 Jun 21 13:02	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	11 Jun 21 13:02	MDE
Total Dissolved Solids	1660	mg/l	10	USGS I1750-85	4 Jun 21 8:50	RAA
Calcium - Total	3.6	mg/l	1.0	6010D	8 Jun 21 11:41	MDE
Magnesium - Total	< 1	mg/l	1.0	6010D	8 Jun 21 11:41	MDE
Sodium - Total	660	mg/l	1.0	6010D	8 Jun 21 11:41	MDE
Potassium - Total	2.7	mg/l	1.0	6010D	8 Jun 21 11:41	MDE
Lithium - Total	0.100	mg/l	0.020	6010D	14 Jun 21 10:31	MDE
Aluminum - Total	< 0.1	mg/l	0.10	6010D	11 Jun 21 10:06	SZ
Iron - Total	0.34	mg/l	0.10	6010D	7 Jun 21 15:02	MDE
Silicon - Total	5.00	mg/l	0.10	6010D	8 Jun 21 8:50	SZ
Strontium - Total	0.14	mg/l	0.10	6010D	7 Jun 21 15:02	MDE
Zinc - Total	< 0.05	mg/l	0.05	6010D	7 Jun 21 15:02	MDE
Boron - Total	2.83	mg/l	0.10	6010D	8 Jun 21 14:13	MDE
Calcium - Dissolved	3.4	mg/l	1.0	6010D	4 Jun 21 16:32	SZ

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

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MEMBER ACIL

Report Date: 21 Jun 21
Lab Number: 21-W1550
Work Order #: 82-1301
Account #: 007033
Date Sampled: 3 Jun 21 12:35
Date Received: 3 Jun 21 13:54
Sampled By: MVTL Field Services

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

PO #: B. Botnen

Project Name: Center USGS Well

Sample Description: USGS Well

Temp at Receipt: 14.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	4 Jun 21 16:32	SZ
Sodium - Dissolved	605	mg/l	1.0	6010D	4 Jun 21 16:32	SZ
Potassium - Dissolved	2.9	mg/l	1.0	6010D	4 Jun 21 16:32	SZ
Lithium - Dissolved	0.101	mg/l	0.020	6010D	14 Jun 21 10:31	MDE
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	4 Jun 21 13:57	MDE
Iron - Dissolved	0.17	mg/l	0.10	6010D	4 Jun 21 13:57	MDE
Silicon - Dissolved	4.79	mg/l	0.10	6010D	8 Jun 21 8:50	SZ
Strontium - Dissolved	0.15	mg/l	0.10	6010D	4 Jun 21 13:57	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	4 Jun 21 13:57	MDE
Boron - Dissolved	3.10	mg/l	0.10	6010D	8 Jun 21 14:13	MDE
Antimony - Total	< 0.001	mg/l	0.0010	6020B	8 Jun 21 12:11	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	8 Jun 21 12:11	MDE
Barium - Total	0.0926	mg/l	0.0020	6020B	8 Jun 21 12:11	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	8 Jun 21 12:11	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	8 Jun 21 12:11	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	8 Jun 21 12:11	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	8 Jun 21 12:11	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	8 Jun 21 12:11	MDE
Lead - Total	0.0009	mg/l	0.0005	6020B	8 Jun 21 12:11	MDE
Manganese - Total	0.0066	mg/l	0.0020	6020B	17 Jun 21 14:51	MDE
Molybdenum - Total	0.0050	mg/l	0.0020	6020B	17 Jun 21 14:51	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	8 Jun 21 12:11	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	8 Jun 21 12:11	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	8 Jun 21 12:11	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	8 Jun 21 12:11	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	8 Jun 21 12:11	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	4 Jun 21 18:26	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	4 Jun 21 18:26	MDE
Barium - Dissolved	0.0863	mg/l	0.0020	6020B	4 Jun 21 18:26	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	4 Jun 21 18:26	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	4 Jun 21 18:26	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	4 Jun 21 18:26	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	4 Jun 21 18:26	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	4 Jun 21 18:26	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	4 Jun 21 18:26	MDE
Manganese - Dissolved	0.0044	mg/l	0.0020	6020B	17 Jun 21 15:48	MDE
Molybdenum - Dissolved	0.0048	mg/l	0.0020	6020B	17 Jun 21 15:48	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
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www.mvtl.com

MEMBER ACIL

Report Date: 21 Jun 21
Lab Number: 21-W1550
Work Order #: 82-1301
Account #: 007033
Date Sampled: 3 Jun 21 12:35
Date Received: 3 Jun 21 13:54
Sampled By: MVTL Field Services

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: Center USGS Well

Sample Description: USGS Well

PO #: B. Botnen

Temp at Receipt: 14.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	4 Jun 21 18:26	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	4 Jun 21 18:26	MDE
Silver - Dissolved	< 0.002 ^	mg/l	0.0005	6020B	4 Jun 21 18:26	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	4 Jun 21 18:26	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	4 Jun 21 18:26	MDE

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

CC

Approved by: Claudette K. Carroll 21 Jun 21

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to 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: Center USGS Well	Event:	Work Order Number: 88-1301
Report To: EERC Attn: Barry Botnen Address: 15 North 23rd St, Grand Forks, ND 58202 Phone: 701-777-5073 Email: bbotnen@undeerc.org	CC:	Collected By: [signature]

Lab Number	Sample ID	Date	Time	Sample Type	1 Liter Raw	500 mL Nitric	500 mL Nitric (filtered)	250 mL Sulfuric	125mL Raw	TOC (set of 3)	DOC (set of 3)	Temp (°C)	Spec. Cond.	pH	Analysis Required
W1550	USGS Well	3 Jun 21	1235	GW	4	2	2	2	4	2	X	15.01	2639	8.44	See Attachment + TDS & TDS Calc

Comments:

Relinquished By		Sample Condition		Received By	
Name	Date/Time	Location	Temp (°C)	Name	Date/Time
1 [signature]	3 Jun 21 1354	Log In Walk In #2	R01 14.5 TM562 / TM805	[signature]	3 Jun 21 1354
2					

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MEMBER ACIL

November 18, 2021

EERC
Barry Botnen
15 North 23rd St
Grand Forks, ND 58202

RE: USGS Well near Center, ND

Dear Mr. Botnen,

On November 15, 2021, MVTL Laboratories' Field Services division collected a ground water sample from a USGS well near Center, ND. Well ID is 142-084-24 BBA. MVTL installed a non-dedicated 3" Grundfos pump to a depth of 300 ft to purge and sample the well. The sample collected was placed on ice and transported back to the MVTL lab in Bismarck, ND for analysis.

Thank you for your continued trust and support of our services. If you have any questions, please call me at (701) 391-4900.

Sincerely,

Jeremy Meyer
MVTL Field Services Manager

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MEMBER ACIL

Report Date: 26 Nov 21
Lab Number: 21-W4464
Work Order #: 82-3166
Account #: 007033
Date Sampled: 15 Nov 21 13:00
Date Received: 15 Nov 21 14:25
Sampled By: MVTL Field Services

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 9.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	15 Nov 21	RAA
pH	* 8.4	units	N/A	SM4500-H+-B-11	16 Nov 21 17:00	AC
Conductivity (EC)	2645	umhos/cm	N/A	SM2510B-11	16 Nov 21 17:00	AC
pH - Field	8.35	units	NA	SM 4500 H+ B	15 Nov 21 13:00	JSM
Temperature - Field	13.8	Degrees C	NA	SM 2550B	15 Nov 21 13:00	JSM
Total Alkalinity	958	mg/l CaCO3	20	SM2320B-11	16 Nov 21 17:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	16 Nov 21 17:00	AC
Bicarbonate	933	mg/l CaCO3	20	SM2320B-11	16 Nov 21 17:00	AC
Carbonate	25	mg/l CaCO3	20	SM2320B-11	16 Nov 21 17:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	16 Nov 21 17:00	AC
Conductivity - Field	2586	umhos/cm	1	EPA 120.1	15 Nov 21 13:00	JSM
Tot Dis Solids(Summation)	1560	mg/l	12.5	SM1030-F	19 Nov 21 15:38	Calculated
Cation Summation	32.7	meq/L	NA	SM1030-F	19 Nov 21 12:52	Calculated
Anion Summation	27.5	meq/L	NA	SM1030-F	19 Nov 21 15:38	Calculated
Percent Error	8.62	%	NA	SM1030-F	19 Nov 21 15:38	Calculated
Bromide	2.62	mg/l	0.100	EPA 300.0	24 Nov 21 17:34	RMV
Total Organic Carbon	1.1	mg/l	0.5	SM5310C-11	19 Nov 21 16:46	NAS
Dissolved Organic Carbon	1.1	mg/l	0.5	SM5310C-96	19 Nov 21 16:46	NAS
Fluoride	3.78	mg/l	0.10	SM4500-F-C	16 Nov 21 17:00	AC
Sulfate	< 5	mg/l	5.00	ASTM D516-11	19 Nov 21 15:38	SD
Chloride	295	mg/l	2.0	SM4500-Cl-E-11	17 Nov 21 13:30	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 15:33	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	16 Nov 21 15:33	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 9:35	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 14:00	MDE
Total Dissolved Solids	1600	mg/l	10	USGS I1750-85	17 Nov 21 11:53	AC
Calcium - Total	3.5	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Magnesium - Total	1.0	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Sodium - Total	680	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Potassium - Total	3.2	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Lithium - Total	0.091	mg/l	0.020	6010D	16 Nov 21 10:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	19 Nov 21 10:52	SZ
Iron - Total	0.26	mg/l	0.10	6010D	19 Nov 21 10:52	SZ
Silicon - Total	5.14	mg/l	0.10	6010D	16 Nov 21 14:55	SZ
Strontium - Total	0.15	mg/l	0.10	6010D	19 Nov 21 10:52	SZ

RL = Method Reporting Limit

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+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 26 Nov 21
Lab Number: 21-W4464
Work Order #: 82-3166
Account #: 007033
Date Sampled: 15 Nov 21 13:00
Date Received: 15 Nov 21 14:25
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 9.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Zinc - Total	< 0.05	mg/l	0.05	6010D	19 Nov 21 10:52	SZ
Boron - Total	2.88	mg/l	0.10	6010D	17 Nov 21 12:08	SZ
Calcium - Dissolved	3.4	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Sodium - Dissolved	745	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Potassium - Dissolved	3.4	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Lithium - Dissolved	0.090	mg/l	0.020	6010D	16 Nov 21 12:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	19 Nov 21 12:52	SZ
Iron - Dissolved	0.20	mg/l	0.10	6010D	19 Nov 21 12:52	SZ
Silicon - Dissolved	5.23	mg/l	0.10	6010D	16 Nov 21 16:55	SZ
Strontium - Dissolved	0.15	mg/l	0.10	6010D	19 Nov 21 12:52	SZ
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	19 Nov 21 12:52	SZ
Boron - Dissolved	2.83	mg/l	0.10	6010D	17 Nov 21 15:08	SZ
Antimony - Total	< 0.002 ^	mg/l	0.0010	6020B	17 Nov 21 13:05	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 13:05	MDE
Barium - Total	0.0942	mg/l	0.0020	6020B	17 Nov 21 13:05	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 13:05	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 13:05	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 13:05	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 13:05	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 13:05	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 13:05	MDE
Manganese - Total	0.0053	mg/l	0.0020	6020B	17 Nov 21 13:05	MDE
Molybdenum - Total	0.0059	mg/l	0.0020	6020B	17 Nov 21 13:05	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 13:05	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	17 Nov 21 13:05	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 13:05	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 13:05	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	17 Nov 21 13:05	MDE
Antimony - Dissolved	< 0.002 ^	mg/l	0.0010	6020B	17 Nov 21 15:06	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE
Barium - Dissolved	0.0910	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Nov 21 15:06	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

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MEMBER ACIL

Report Date: 26 Nov 21
Lab Number: 21-W4464
Work Order #: 82-3166
Account #: 007033
Date Sampled: 15 Nov 21 13:00
Date Received: 15 Nov 21 14:25
Sampled By: MVTL Field Services

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 9.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Manganese - Dissolved	0.0051	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE
Molybdenum - Dissolved	0.0055	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	17 Nov 21 15:06	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Nov 21 15:06	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

CC

Approved by: Claudette K Carroll 29NOV21

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

Phone: (701) 258-9720

Field Datasheet

Groundwater Assessment

Company: EERC

Event: Cenderwell / USGS well

Sample ID: ~

Sampling Personal: [illegible]

Weather Conditions: Temp: 45 °F Wind: S @ 5~10 Precip: **Sunny / Partly Cloudy / Cloudy**

WELL INFORMATION

Well Locked?	**YES**	**NO**	
Well Labeled?	**YES**	**NO**	
Casing Strait?	**YES**	**NO**	
Grout Seal Intact?	**YES**	**NO**	**Not Visible**
Repairs Necessary?			
Casing Diameter:	**2"**		
Water Level Before Purge:	210.60	ft	
Total Depth of Well:	1000+	ft	
Well Volume:	1949.8	liters	
Depth to Top of Pump:	—	ft	
Water Level After Sample:	—	ft	
Measurement Method:	**Electric Water Level Indicator**		

SAMPLING INFORMATION

Purging Method:	**Bail**	**S. Pump**	**D. Pump**	**Peristaltic**	3" Grundfoss
Sampling Method:	**Bail**	**S. Pump**	**D. Pump**	**Peristaltic**	3" Grund foss
Dedicated Equipment?	**YES**	**NO**			

Duplicate Sample?	**YES**	**NO**
Duplicate Sample ID:	—	

Bottle List:

FIELD READINGS

Stabilization Parameters (3 Consecutive)		Temp. (°C)	Spec. Cond.	pH	DO	ORP	Turbidity (NTU)		Pumping Rate	Liters Removed	Appearance or Comment Clarity, Color, Odor, Ect.
Purge Date	**Time**	±0.5°	±5%	±0.1					mL/Min		clear, slightly turbid, turbid
15 Nov 21	1000	**Start of Well Purge**									
	1100	13.30	2555	8.35	1.94	6.1	1.06		35.0	2100.0	Clear
	1200	13.52	2629	8.37	2.19	8.6	1.08		35.0	2100.0	Clear
	1300	13.77	2586	8.35	3.08	32.9	0.52		35.0	2100.0	Clear

Well Stabilized? **YES** **NO** Total Volume Purged: 6300.0 Liters

Sample Date	**Time**	**Temp. (°C)**	**Spec. Cond.**	**pH**							**Appearance or Comment** Clarity, Color, Odor, Ect.
15 Nov 21	1300	13.77	2586	8.35							Clear

Comments:	

MVTL
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Chain of Custody Record

Project Name: Center USGS Well	Event:	Work Order Number: 82-3166
Report To: EERC Attn: Barry Botnen Address: 15 North 23rd St Grand Forks, ND 58202 Phone: 701-777-5073 Email: bbotnen@undeerc.org	CC:	Collected By: [signature]

Lab Number	Sample ID	Date	Time	Sample Type	1 Liter Raw	500 mL Nitric	500 mL Nitric (filtered)	250 mL Sulfuric	250 mL Sulfuric (filtered)	125mL Raw	TOC (set of 3)	DOC (set of 3)	Temp (°C)	Spec. Cond.	pH	Analysis Required
W4464	USGS Well	15Nov21	1300	GW	4	2	2	2	2	4	2	2	13.77	2586	8.35	Same analysis as work order 82-2307

Comments:

Relinquished By		Sample Condition		Received By	
Name	Date/Time	Location	Temp (°C)	Name	Date/Time
1 [signature]	15Nov21 1425	~~Log In~~ Walk In #2	R01 9.9 TM562 / ~~TM805~~	[signature]	15Nov21 1425
2					

ISOTECH
a Stratum Reservoir brand
www.isotechlabs.com

Lab #:	809443	Job #: 49367	IS-65777	Co. Job#:	
Sample Name:	NDCS-MPC-WS-1			Co. Lab#:	
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	1 Liter Plastic Bottle				
Field/Site Name:	North Dakota CarbonSafe (NDCS)				
Location:					
Formation/Depth:					
Sampling Point:					
Date Sampled:	11/09/2021 8:30	Date Received: 11/17/2021		Date Reported:	1/24/2022

δD of water	---------------	-118.2 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-14.48 ‰ relative to VSMOW
Tritium content of water	---------------	2.57 ± 0.17 TU
$\delta^{13}C$ of DIC	---------------	-11.5 ‰ relative to VPDB
^{14}C content of DIC	---------------	62.4 ± 0.2 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

Lab #:	809444	Job #:	49367	IS-65777	Co. Job#:		
Sample Name:	NDCS-MPC-WS-2				Co. Lab#:		
Company:	EERC - Energy & Environmental Research						
API/Well:							
Container:	1 Liter Plastic Bottle						
Field/Site Name:	North Dakota CarbonSafe (NDCS)						
Location:							
Formation/Depth:							
Sampling Point:							
Date Sampled:	11/09/2021 10:30	Date Received:	11/17/2021			Date Reported:	1/24/2022

δD of water	---------------	-123.1 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-15.42 ‰ relative to VSMOW
Tritium content of water	---------------	2.93 ± 0.26 TU
$\delta^{13}C$ of DIC	---------------	-10.0 ‰ relative to VPDB
^{14}C content of DIC	---------------	52.9 ± 0.2 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

ISOTECH
a Stratum Reservoir brand
www.isotechlabs.com

Lab #:	809445	Job #: 49367	IS-65777	Co. Job#:	
Sample Name:	NDCS-W1686			Co. Lab#:	
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	1 Liter Plastic Bottle				
Field/Site Name:	North Dakota CarbonSafe (NDCS)				
Location:					
Formation/Depth:					
Sampling Point:					
Date Sampled:	11/09/2021 13:30	Date Received: 11/17/2021		Date Reported:	1/24/2022

δD of water	---------------	-120.8 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-16.08 ‰ relative to VSMOW
Tritium content of water	---------------	3.74 ± 0.28 TU
$\delta^{13}C$ of DIC	---------------	-11.9 ‰ relative to VPDB
^{14}C content of DIC	---------------	53.3 ± 0.2 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

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Lab #:	809446	Job #:	49367	IS-65777	Co. Job#:
Sample Name:	NDCS-W217				Co. Lab#:
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	1 Liter Plastic Bottle				
Field/Site Name:	North Dakota CarbonSafe (NDCS)				
Location:					
Formation/Depth:					
Sampling Point:					
Date Sampled:	11/09/2021 15:00	Date Received:	11/17/2021	Date Reported:	1/24/2022

δD of water	---------------	-118.4 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-14.86 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.47 TU
$\delta^{13}C$ of DIC	---------------	-9.0 ‰ relative to VPDB
^{14}C content of DIC	---------------	1.5 ± 0.0 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

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Lab #:	809447	Job #:	49367	IS-65777	Co. Job#:	
Sample Name:	NDCS-MPC-WS-1 Dup				Co. Lab#:	
Company:	EERC - Energy & Environmental Research					
API/Well:						
Container:	1 Liter Plastic Bottle					
Field/Site Name:	North Dakota CarbonSafe (NDCS)					
Location:						
Formation/Depth:						
Sampling Point:						
Date Sampled:	11/09/2021 9:30	Date Received:	11/17/2021		Date Reported:	1/24/2022

δD of water	---------------	-118.4 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-14.45 ‰ relative to VSMOW
Tritium content of water	---------------	2.71 ± 0.24 TU
$\delta^{13}C$ of DIC	---------------	-11.5 ‰ relative to VPDB
^{14}C content of DIC	---------------	62.8 ± 0.2 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

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Lab #:	809448	Job #: 49367	IS-65777	Co. Job#:	
Sample Name:	NDCS-W395			Co. Lab#:	
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	1 Liter Plastic Bottle				
Field/Site Name:	North Dakota CarbonSafe (NDCS)				
Location:					
Formation/Depth:					
Sampling Point:					
Date Sampled:	11/09/2021 16:00	Date Received: 11/17/2021		Date Reported:	1/24/2022

δD of water	---------------	-119.7 ‰ relative to VSMOW
δ^{18}O of water	---------------	-15.04 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.43 TU
δ^{13}C of DIC	---------------	-11.1 ‰ relative to VPDB
^{14}C content of DIC	---------------	0.5 ± 0.0 percent modern carbon
δ^{15}N of nitrate	---------------	na
δ^{18}O of nitrate	---------------	na
δ^{34}S of sulfate	---------------	na
δ^{18}O of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

Lab #:	809449	Job #:	49367	IS-65777	Co. Job#:		
Sample Name:	NDCS-W269				Co. Lab#:		
Company:	EERC - Energy & Environmental Research						
API/Well:							
Container:	1 Liter Plastic Bottle						
Field/Site Name:	North Dakota CarbonSafe (NDCS)						
Location:							
Formation/Depth:							
Sampling Point:							
Date Sampled:	11/10/2021 9:00	Date Received:	11/17/2021		Date Reported:	1/24/2022	

δD of water	---------------	-128.1 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-16.63 ‰ relative to VSMOW
Tritium content of water	---------------	0.92 ± 0.21 TU
$\delta^{13}C$ of DIC	---------------	-10.9 ‰ relative to VPDB
^{14}C content of DIC	---------------	58.6 ± 0.2 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

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Lab #:	809450	Job #:	49367	IS-65777	Co. Job#:	
Sample Name:	NDCS-W478				Co. Lab#:	
Company:	EERC - Energy & Environmental Research					
API/Well:						
Container:	1 Liter Plastic Bottle					
Field/Site Name:	North Dakota CarbonSafe (NDCS)					
Location:						
Formation/Depth:						
Sampling Point:						
Date Sampled:	11/10/2021 11:00	Date Received:	11/17/2021		Date Reported:	1/24/2022

δD of water	---------------	-130.7 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-16.94 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.37 TU
$\delta^{13}C$ of DIC	---------------	-8.9 ‰ relative to VPDB
^{14}C content of DIC	---------------	< 0.4 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

Lab #:	809451	Job #:	49367	IS-65777	Co. Job#:
Sample Name:	NDCS-W468				Co. Lab#:
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	1 Liter Plastic Bottle				
Field/Site Name:	North Dakota CarbonSafe (NDCS)				
Location:					
Formation/Depth:					
Sampling Point:					
Date Sampled:	11/10/2021 10:00	Date Received:	11/17/2021	Date Reported:	1/24/2022

δD of water	---------------	-142.3 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-18.82 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.45 TU
$\delta^{13}C$ of DIC	---------------	-4.3 ‰ relative to VPDB
^{14}C content of DIC	---------------	9.7 ± 0.1 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

ISOTECH
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Lab #:	809452	Job #: 49367	IS-65777	Co. Job#:	
Sample Name:	NDCS-W424			Co. Lab#:	
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	1 Liter Plastic Bottle				
Field/Site Name:	North Dakota CarbonSafe (NDCS)				
Location:					
Formation/Depth:					
Sampling Point:					
Date Sampled:	11/10/2021 14:30	Date Received: 11/17/2021		Date Reported:	1/24/2022

δD of water	---------------	-122.0 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-15.48 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.45 TU
$\delta^{13}C$ of DIC	---------------	-15.1 ‰ relative to VPDB
^{14}C content of DIC	---------------	1.0 ± 0.0 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

ISOTECH
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Lab #:	809453	Job #: 49367	IS-65777	Co. Job#:
Sample Name:	NDCS-W471			Co. Lab#:
Company:	EERC - Energy & Environmental Research			
API/Well:				
Container:	1 Liter Plastic Bottle			
Field/Site Name:	North Dakota CarbonSafe (NDCS)			
Location:				
Formation/Depth:				
Sampling Point:				
Date Sampled:	11/10/2021 15:30	Date Received: 11/17/2021	Date Reported:	1/24/2022

δD of water	---------------	-121.3 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-15.34 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.50 TU
$\delta^{13}C$ of DIC	---------------	-12.0 ‰ relative to VPDB
^{14}C content of DIC	---------------	< 0.4 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

ISOTECH
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Lab #:	809454	Job #:	49367	IS-65777	Co. Job#:	
Sample Name:	NDCS-W510				Co. Lab#:	
Company:	EERC - Energy & Environmental Research					
API/Well:						
Container:	1 Liter Plastic Bottle					
Field/Site Name:	North Dakota CarbonSafe (NDCS)					
Location:						
Formation/Depth:						
Sampling Point:						
Date Sampled:	11/11/2021 9:00	Date Received:	11/17/2021		Date Reported:	1/24/2022

δD of water	---------------	-129.9 ‰ relative to VSMOW
δ^{18}O of water	---------------	-16.67 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.47 TU
δ^{13}C of DIC	---------------	-15.6 ‰ relative to VPDB
^{14}C content of DIC	---------------	< 0.4 percent modern carbon
δ^{15}N of nitrate	---------------	na
δ^{18}O of nitrate	---------------	na
δ^{34}S of sulfate	---------------	na
δ^{18}O of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

Lab #:	809455	Job #:	49367	IS-65777	Co. Job#:
Sample Name:	Center Well				Co. Lab#:
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	1 Liter Plastic Bottle				
Field/Site Name:	EERC				
Location:					
Formation/Depth:					
Sampling Point:					

Date Sampled: 11/15/2021 13:00 Date Received: 11/17/2021 Date Reported: 1/24/2022

δD of water	---------------	-120.2 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-15.10 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.47 TU
$\delta^{13}C$ of DIC	---------------	-8.1 ‰ relative to VPDB
^{14}C content of DIC	---------------	< 0.4 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	No

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

Lab #:	802165	Job #:	48607	IS-65777	Co. Job#:
Sample Name:	MPC-WS-1				Co. Lab#:
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	Plastic Bottle				
Field/Site Name:	NDCS				
Location:	Center, ND				
Formation/Depth:					
Sampling Point:					

Date Sampled: 8/11/2021 15:00 Date Received: 8/26/2021 Date Reported: 10/04/2021

δD of water	---------------	-116.3 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-14.53 ‰ relative to VSMOW
Tritium content of water	---------------	2.35 ± 0.23 TU
$\delta^{13}C$ of DIC	---------------	-11.3 ‰ relative to VPDB
^{14}C content of DIC	---------------	64.3 ± 0.2 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	Yes

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

ISOTECH
a Stratum Reservoir brand
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Lab #:	802166	Job #:	48607	IS-65777	Co. Job#:	
Sample Name:	MPC-WS-1 DUP				Co. Lab#:	
Company:	EERC - Energy & Environmental Research					
API/Well:						
Container:	Plastic Bottle					
Field/Site Name:	NDCS					
Location:	Center, ND					
Formation/Depth:						
Sampling Point:						
Date Sampled:	8/11/2021 15:00	Date Received:	8/26/2021		Date Reported:	10/04/2021

δD of water	---------------	-124.6 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-15.57 ‰ relative to VSMOW
Tritium content of water	---------------	2.38 ± 0.30 TU
$\delta^{13}C$ of DIC	---------------	-11.4 ‰ relative to VPDB
^{14}C content of DIC	---------------	64.2 ± 0.2 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	Yes

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

Lab #:	802167	Job #:	48607	IS-65777	Co. Job#:
Sample Name:	W289				Co. Lab#:
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	Plastic Bottle				
Field/Site Name:	NDCS				
Location:	Center, ND				
Formation/Depth:					
Sampling Point:					

Date Sampled: 8/11/2021 17:00 Date Received: 8/26/2021 Date Reported: 10/04/2021

δD of water	---------------	-123.5 ‰ relative to VSMOW
δ^{18}O of water	---------------	-16.19 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.73 TU
δ^{13}C of DIC	---------------	-8.6 ‰ relative to VPDB
^{14}C content of DIC	---------------	11.2 ± 0.1 percent modern carbon
δ^{15}N of nitrate	---------------	na
δ^{18}O of nitrate	---------------	na
δ^{34}S of sulfate	---------------	na
δ^{18}O of sulfate	---------------	na
Vacuum Distilled? *	---------------	Yes

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

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Lab #:	802168	Job #: 48607	IS-65777	Co. Job#:	
Sample Name:	W510			Co. Lab#:	
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	Plastic Bottle				
Field/Site Name:	NDCS				
Location:	Center, ND				
Formation/Depth:					
Sampling Point:					
Date Sampled:	8/11/2021 19:00	Date Received:	8/26/2021	Date Reported:	10/04/2021

δD of water	---------------	-127.9 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-16.53 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.45 TU
$\delta^{13}C$ of DIC	---------------	-16.0 ‰ relative to VPDB
^{14}C content of DIC	---------------	0.8 ± 0.0 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	Yes

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

Lab #:	802169	Job #: 48607	IS-65777	Co. Job#:	
Sample Name:	W269			Co. Lab#:	
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	Plastic Bottle				
Field/Site Name:	NDCS				
Location:	Center, ND				
Formation/Depth:					
Sampling Point:					
Date Sampled:	8/12/2021 10:30	Date Received:	8/26/2021	Date Reported:	10/04/2021

δD of water	---------------	-119.6 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-15.72 ‰ relative to VSMOW
Tritium content of water	---------------	1.80 ± 0.23 TU
$\delta^{13}C$ of DIC	---------------	-10.6 ‰ relative to VPDB
^{14}C content of DIC	---------------	65.5 ± 0.2 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	Yes

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

ISOTECH
a Stratum Reservoir brand
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Lab #:	802170	Job #: 48607	IS-65777	Co. Job#:	
Sample Name:	W217			Co. Lab#:	
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	Plastic Bottle				
Field/Site Name:	NDCS				
Location:	Center, ND				
Formation/Depth:					
Sampling Point:					
Date Sampled:	8/12/2021 14:30	Date Received:	8/26/2021	Date Reported:	10/04/2021

δD of water	---------------	-116.2 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-14.64 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.54 TU
$\delta^{13}C$ of DIC	---------------	-8.0 ‰ relative to VPDB
^{14}C content of DIC	---------------	< 0.4 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	Yes

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

ISOTECH
a Stratum Reservoir brand
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Lab #:	802171	Job #:	48607	IS-65777	Co. Job#:	
Sample Name:	W1686				Co. Lab#:	
Company:	EERC - Energy & Environmental Research					
API/Well:						
Container:	Plastic Bottle					
Field/Site Name:	NDCS					
Location:	Center, ND					
Formation/Depth:						
Sampling Point:						
Date Sampled:	8/12/2021 15:30	Date Received:	8/26/2021		Date Reported:	10/04/2021

δD of water	---------------	-120.5 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-15.99 ‰ relative to VSMOW
Tritium content of water	---------------	3.59 ± 0.28 TU
$\delta^{13}C$ of DIC	---------------	-11.5 ‰ relative to VPDB
^{14}C content of DIC	---------------	52.9 ± 0.2 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	Yes

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

ISOTECH
a Stratum Reservoir brand
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Lab #:	802172	Job #:	48607	IS-65777	Co. Job#:	
Sample Name:	W471				Co. Lab#:	
Company:	EERC - Energy & Environmental Research					
API/Well:						
Container:	Plastic Bottle					
Field/Site Name:	NDCS					
Location:	Center, ND					
Formation/Depth:						
Sampling Point:						
Date Sampled:	8/12/2021 17:00	Date Received:	8/26/2021		Date Reported:	10/04/2021

δD of water	---------------	-119.0 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-15.20 ‰ relative to VSMOW
Tritium content of water	---------------	< 0.71 TU
$\delta^{13}C$ of DIC	---------------	-11.6 ‰ relative to VPDB
^{14}C content of DIC	---------------	< 0.4 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	Yes

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

ISOTECH
a Stratum Reservoir brand
www.isotechlabs.com

Lab #:	802173	Job #:	48607	IS-65777	Co. Job#:
Sample Name:	MPC-WS-2				Co. Lab#:
Company:	EERC - Energy & Environmental Research				
API/Well:					
Container:	Plastic Bottle				
Field/Site Name:	NDCS				
Location:	Center, ND				
Formation/Depth:					
Sampling Point:					

Date Sampled: 8/13/2021 8:30 Date Received: 8/26/2021 Date Reported: 10/04/2021

δD of water	---------------	-119.4 ‰ relative to VSMOW
$\delta^{18}O$ of water	---------------	-15.01 ‰ relative to VSMOW
Tritium content of water	---------------	3.57 ± 0.39 TU
$\delta^{13}C$ of DIC	---------------	-10.1 ‰ relative to VPDB
^{14}C content of DIC	---------------	54.8 ± 0.2 percent modern carbon
$\delta^{15}N$ of nitrate	---------------	na
$\delta^{18}O$ of nitrate	---------------	na
$\delta^{34}S$ of sulfate	---------------	na
$\delta^{18}O$ of sulfate	---------------	na
Vacuum Distilled? *	---------------	Yes

Remarks:

nd = not detected. na = not analyzed.
*Indicates if vacuum distillation was utilized for hydrogen and oxygen isotopic analysis of water

WELL DRILLER'S REPORT

NORTH DAKOTA BOARD OF WATER WELL CONTRACTORS
STATE OF NORTH DAKOTA
SFN 60273 (8/2020)

ND Board of Water Well Contractors • 900 E. Boulevard Ave. - Dept. 770 • Bismarck, ND, 58505-0850
State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

WELL OWNER

Name: EERC / Minnkota Power

Address: Center ND

WELL LOCATION
Sketch map location must agree with written location.

County	GPS	
Oliver		
1/4	1/4 SW	1/4 NW
Township 141 N	Range 83 W	Section 4

PROPOSED USE
☐ Domestic ☐ Geothermal ☐ Municipal ☐ Industrial
☐ Stock ☐ Irrigation ☒ Monitoring ☐ Test Hole

METHOD DRILLED
☐ Cable ☐ Jetted ☒ Forward Rotary ☐ Reverse Rotary
☐ Bored ☐ Auger ☐ If Other, Specify

WATER QUALITY
Was a water sample collected for

Chemical Analysis? ☒ Yes ☐ No

Bacteriological Analysis? ☐ Yes ☐ No

If So, To What Laboratory Was It Sent? MVTL

WELL CONSTRUCTION

Diameter Of Hole In Inches: 9 7/8 | Depth In Feet: 1160

Casing:
☐ Steel ☒ Plastic ☐ Concrete ☐ Other
☐ Threaded ☐ Welded ☐ If Other, Specify: SPLINED

Pipe Weight	Diameter	From	To
lb/ft SCH 80	inches 5	feet 0	feet 920
lb/ft	inches	feet	feet
lb/ft	inches	feet	feet

Was A Well Screen Installed? ☒ Yes ☐ No

Was Perforated Pipe Used? ☐ Yes ☒ No

Screen Or Perforation Interval: From In Feet 920-980 + To In Feet 1080-1120

Was Casing Left Open End? ☐ Yes ☒ No

Material: | Diameter In Inches:

Slot Size	Set From In Feet	To In Feet
13	920	980
13	1080	1120

Was Packer Or Seal Used? ☐ Yes ☒ No

If So, What Material: | Depth In Feet:

Type Of Well: ☐ Straight Screen ☐ Gravel Packed SILICA 10-20

Depth Grouted	From	To
	920	0

Grouting Material	Cement	Other
		BENT GROUT

If Other, Explain: PUMPED THROUGH CASING BOTTOM UP TO TOP

Well Head Completion: Pitless Unit YES

12" Above Grade: YES | Other (Specify):

If Other, Specify:

Was Pump Installed? ☒ Yes ☐ No

Was Well Disinfected Upon Completion? ☒ Yes ☐ No

WATER LEVEL

Static Water Level (In Feet) Below Surface: 232

If Flowing, Closed-In Pressure In PSI:

GPM Flow | Through | Inch Pipe

Controlled By ☐ Valve ☐ Reducers ☐ Other
☐ If Other, Specify

WELL TEST DATA
☒ Pump ☐ Bailer ☐ Other

Pumping Level Below Land Surface

Feet After	Hrs. Pumping	GPM
302		10

WELL LOG

Formation	Depth (ft.) From	To
Fill	0	2
Yellow Sandy Clay	2	14
Coal	14	14.5
Gray Clay	14.5	15
Coal	15	16
Sandy Gray Clay	16	20
Gray Clay	20	40
Coal	40	43
Gray Clay	43	80
Coal	80	82
Gray Clay	82	99
Rock ledge	99	100
Gray Clay	100	115
Sandy Gray Clay	115	120
Gray Sand	120	145
Gray Clay	145	160
Gray Sand	160	165
Gray Clay	165	170
Coal	170	173
Gray Clay	173	180

Use Separate Sheet If Necessary

DATE COMPLETED 12-3-2021

WAS WELL PLUGGED OR ABANDONED? ☐ Yes ☒ No

If So, How

REMARKS

DRILLER'S CERTIFICATION
This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

Driller's Or Firm's Name: Earth Energy + Water | Certificate Number: 153

Address: New Salem, ND

Signed By: [signature] | Date: 12-3-21

COPY FOR BOARD | COPY FOR DRILLER | COPY FOR CUSTOMER

NAME: EERC/Minnkota		
Center, ND		
COUNTY: Oliver		
SECTION: 4		
TOWNSHIP: 141N		
RANGE: 83W		
FORMATION	**Depth (ft.) FROM**	**Depth (ft.) TO**
Gray Sand	180	220
Gray Clay Sandy	220	240
Sandy Gray Clay	240	246
Gray Sand	246	251
Gray Clay	251	265
Rock Ledge	265	267
Gray Clay	267	277
Gray Sand	277	290
Gray Clay	290	322
Rock Ledge	322	324
Gray Clay	324	333
Rock Ledge	333	336
Gray Sandy Clay	336	340
Coal	340	345
Gray Clay Sandy	345	360
Sandy Gray Clay	360	370
Gray Clay	370	383
Rock Ledge	383	389
Gray Clay	389	496
Rock Ledge	496	497
Sandy Gray Clay	497	545
Medium Blue Sand	545	570
Gray Clay	570	615
Rock Ledge	615	617
Fine Gray Sand	617	620
Gray Clay	620	725
Medium Gray Sand	725	750
Gray Clay	750	780
Gray Sand w/Clay	780	800
Rock Ledge	800	802
Gray Clay	802	822
Coal	822	825
Gray Clay	825	840
Gray Sand	840	850
Coal	850	851
Gray Clay	851	895
Sandstone Clay	895	900
Sandy Gray Clay	900	905
Fine Sand w/Clay Stringer	905	920
Medium to Fine Sand	920	980
Fine Sand Silty Mud	980	1000
Fine Sand Silty Muddy Clay Stringers	1000	1050
Sandstone	1050	1051
Medium to Fine Sand	1051	1105
Sandstone	1105	1106
Medium to Fine Sand	1106	1115
Sandstone	1115	1117
Fine Sand	1117	1120
Fine Sand w/silt	1120	1140
Fine Silty Sand	1140	1155
Rock Ledge	1155	1157
Shale	1157	1160

STATE OF NORTH DAKOTA

BOARD OF WATER WELL CONTRACTORS

900 E. BOULEVARD • BISMARCK, NORTH DAKOTA 58501

WELL DRILLER'S REPORT

State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

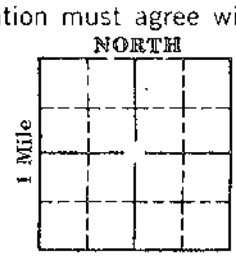
1. WELL OWNER

Name ____________________

Address ____________________

2. WELL LOCATION

Sketch map location must agree with written location.



Sec. (1 Mile) ______

County ____________________

____ ¼ ____ ¼ ____ ¼ Sec. ____ Twp. ____ N. Rg. ____ W.

3. PROPOSED USE

☐ Domestic ☐ Stock ☐ Geothermal ☐ Irrigation ☐ Municipal ☐ Monitoring ☐ Industrial ☐ Test Hole

4. METHOD DRILLED

☐ Cable ☐ Forward Rotary ☐ Reverse Rotary ☐ Jetted ☐ Bored ☐ Auger

If other, specify ____________________

5. WATER QUALITY

Was a water sample collected for chemical analysis?

☐ Yes ☐ No

If so, to what laboratory was it sent ____________________

6. WELL CONSTRUCTION

Diameter of hole ______ inches. Depth ______ feet.

Casing: ☐ Steel ☐ Plastic ☐ Concrete ☐ Threaded ☐ Welded ☐ Other

If other, specify ____________________

Pipe Weight:	Diameter:	From:	To:
______ lb/ft.	______ inches	______ feet	______ feet
______ lb/ft.	______ inches	______ feet	______ feet
______ lb/ft.	______ inches	______ feet	______ feet

Was perforated pipe used? ☐ Yes ☐ No

Perforated pipe set from ______ ft to ______ feet

Was casing left open end? ☐ Yes ☐ No

Was a well screened installed? ☐ Yes ☐ No

Material ______ Diameter ______ inches
(stainless steel, bronze, etc.)

Slot size ______ set from ______ feet to ______ feet

Slot size ______ set from ______ feet to ______ feet

Was a packer or seal used? ☐ Yes ☐ No

If so, what material ______ Depth ______ Ft.

Type of well: Straight screen ☐ Gravel packed ☐

Depth grouted: From ______ To ______

Grouting Material: Cement ______ Other ______

If other explain: ____________________

Well head completion: Pitless unit ______

12″ above grade ______ Other ______

If other, specify ____________________

Was pump installed: ☐ Yes ☐ No

Was well disinfected upon completion? ☐ Yes ☐ No

7. WATER LEVEL

Static water level ______ feet below land surface

If flowing: closed-in pressure ______ psi

GPM flow ______ through ______ inch pipe

Controlled by: ☐ Valve ☐ Reducers ☐ Other

If other, specify ____________________

8. WELL TEST DATA

☐ Pump ☐ Bailer ☐ Other

Pumping level below land surface:

______ ft. after ______ hrs. pumping ______ gpm

______ ft. after ______ hrs. pumping ______ gpm

______ ft. after ______ hrs. pumping ______ gpm

9. WELL LOG

Formation	Depth (ft.) From	To

(Use separate sheet if necessary.)

10. DATE COMPLETED ____________________

11. WAS WELL PLUGGED OR ABANDONED?

☐ Yes ☐ No

If so, how ____________________

12. REMARKS:

13. DRILLER'S CERTIFICATION

This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

Driller's or Firm's Name Certificate No.

Address

Signed by Date

WHITE—DRILLER'S COPY YELLOW—BOARD'S COPY PINK—CUSTOMER'S COPY

STATE OF NORTH DAKOTA

BOARD OF WATER WELL CONTRACTORS

900 E. BOULEVARD • BISMARCK, NORTH DAKOTA 58501

WELL DRILLER'S REPORT

State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

1. WELL OWNER

Name ____________

Address ____________

2. WELL LOCATION

Sketch map location must agree with written location.

NORTH

1 MILE

Sec. (1 mile) _____

County ____________

___¼___¼___¼ Sec.____ Twp. ____ N.Rg ____ W.

3. PROPOSED USE

☐ Domestic ☐ Stock ☐ Geothermal ☐ Irrigation ☐ Municipal ☐ Monitoring ☐ Industrial ☐ Test Hole

4. METHOD DRILLED

☐ Cable ☐ Forward Rotary ☐ Reverse Rotary ☐ Jetted ☐ Bored ☐ Auger

If other, specify ____________

5. WATER QUALITY

Was a water sample collected for:

Chemcial Analysis? ☐ Yes ☐ No

Bacteriological Analysis? ☐ Yes ☐ No

If so, to what laboratory was it sent? ____________

6. WELL CONSTRUCTION

Diameter of hole ________ inches. Depth ______ feet.

Casing: ☐ Steel ☐ Plastic ☐ Concrete ☐ Threaded ☐ Welded ☐ Other

If other, specify ____________

Pipe Weight:	Diameter:	From:	To:
____lb/ft	____inches	____feet	____feet
____lb/ft	____inches	____feet	____feet
____lb/ft	____inches	____feet	____feet

Was perforated pipe used? ☐ Yes ☐ No

Perforated pipe set from ________ ft to ________ feet

Was casing left open end? ☐ Yes ☐ No

Was a well screened installed? ☐ Yes ☐ No

Material ____________ Diameter ______ inches

Slot Size ________ set from ______ feet to ______ feet

Slot Size ________ set from ______ feet to ______ feet

Was packer or seal used? ☐ Yes ☐ No

If so, what material ____________ Depth ______ ft.

(stainless steel, bronze, etc.)

Type of well: Straight screen ☐ Gravel packed ☐

Depth grouted: From ________ To ________

Grouting Material: Cement ________ Other ________

If other explain: ____________

Well head completion: Pitless unit ____________

12" above grade ________ Other ________

If other, specify ____________

Was pump installed: ☐ Yes ☐ No

Was well disinfected upon completion? ☐ Yes ☐ No

7. WATER LEVEL

Static water level ____________ feet below surface

If flowing: closed-in pressure ________ psi

GPM flow ________ through ______ inch pipe

Controlled by: ☐ Valve ☐ Reducers ☐ Other

If other, specify ____________

8. WELL TEST DATA

☐ Pump ☐ Bailer ☐ Other

Pumping level below land surface:

______ ft. after ______ hrs. pumping ______ gpm

______ ft. after ______ hrs. pumping ______ gpm

______ ft. after ______ hrs. pumping ______ gpm

9. WELL LOG

Formation	Depth (ft.)	
	From	To

(Use separate sheet if necessary)

10. DATE COMPLETED 7-7-99

11. WAS WELL PLUGGED OR ABANDONED?

☐ Yes ☐ No

If so, how ____________

12. REMARKS:

13. DRILLER'S CERTIFICATION

This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

Driller's or Firm's Name Certificate No

Address

Signed by Date

WHITE-DRILLER'S COPY YELLOW-BOARD'S COPY PINK-CUSTOMER'S COPY

STATE OF NORTH DAKOTA

BOARD OF WATER WELL CONTRACTORS

900 E. BOULEVARD • BISMARCK, NORTH DAKOTA 58501

WELL DRILLER'S REPORT

State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

JUL 1983

1. WELL OWNER

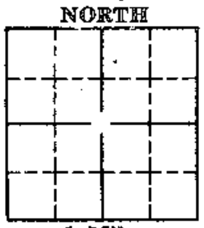
Name ______________________

Address ______________________

2. WELL LOCATION

Sketch map location must agree with written location.

NORTH



1 Mile

County ______________________

_____ ¼ _____ ¼ _____ ¼ Sec. _____ Twp. _____ N. Rg. _____ W.

3. PROPOSED USE

☐ Domestic ☐ Irrigation ☐ Industrial

☐ Stock ☐ Municipal ☐ Test Hole

4. METHOD DRILLED

☐ Cable ☐ Reverse Rotary ☐ Bored

☐ Forward Rotary ☐ Jetted ☐ Other

If other, specify ______________________

5. WATER QUALITY

Was a water sample collected for chemical analysis?

☐ Yes ☐ No

If so, to what laboratory was it sent ______________________

6. WELL CONSTRUCTION

Diameter of hole _______ inches. Depth _______ feet.

Casing: ☐ Steel ☐ Plastic ☐ Concrete

☐ Threaded ☐ Welded ☐ Other

If other, specify ______________________

Pipe Weight:	Diameter:	From:	To:
_____ lb/ft.	_____ inches	_____ feet	_____ feet
_____ lb/ft.	_____ inches	_____ feet	_____ feet
_____ lb/ft.	_____ inches	_____ feet	_____ feet
_____ lb/ft.	_____ inches	_____ feet	_____ feet

Was perforated pipe used? ☐ Yes ☐ No

Length of pipe perforated ______________ feet

Was casing left open end? ☐ Yes ☐ No

Was a well screened installed? ☐ Yes ☐ No

Material ______________ Diameter _______ inches
(stainless steel, bronze, etc.)

Slot size _______ set from _______ feet to _______ feet

Slot size _______ set from _______ feet to _______ feet

Slot size _______ set from _______ feet to _______ feet

Slot size _______ set from _______ feet to _______ feet

Was a packer or seal used? ☐ Yes ☐ No

If so, what material ______________________

Type of well: Straight screen ☐ Gravel packed ☐

Was the well grouted? Yes ☐ No ☐

To what depth? ______________ feet

Material used in grouting ______________________

Well head completion: Pitless adapter ______________________

12" above grade ______________ Other ______________

If other, specify ______________________

Was well disinfected upon completion? ☐ Yes ☐ No

7. WATER LEVEL

Static water level ______________ feet below land surface

If flowing: closed-in pressure ______________ psi

GPM flow ______________ through ______________ inch pipe

Controlled by: ☐ Valve ☐ Reducers ☐ Other

If other, specify ______________________

8. WELL TEST DATA

☐ Pump ☐ Bailer ☐ Other

Pumping level below land surface:

_______ ft. after _______ hrs. pumping _______ gpm

_______ ft. after _______ hrs. pumping _______ gpm

_______ ft. after _______ hrs. pumping _______ gpm

9. WELL LOG

Formation	Depth (ft.) From	Depth (ft.) To

(Use separate sheet if necessary.)

10. DATE COMPLETED ______________________

11. WAS WELL PLUGGED OR ABANDONED?

☐ Yes ☐ No

If so, how ______________________

12. REMARKS:

13. DRILLER'S CERTIFICATION

This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

Driller's or Firm's Name Certificate No.

Address

Signed by Date

WHITE—DRILLER'S COPY YELLOW—BOARD'S COPY PINK—CUSTOMER'S COPY

STATE OF NORTH DAKOTA

BOARD OF WATER WELL CONTRACTORS

900 E. BOULEVARD • BISMARCK, NORTH DAKOTA 58501

WELL DRILLER'S REPORT

State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

1. WELL OWNER

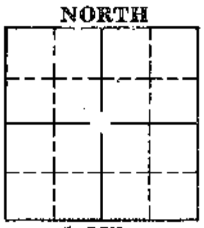
Name__________

Address__________

2. WELL LOCATION

Sketch map location must agree with written location.

NORTH



1 Mile

County__________

____¼____¼____¼ Sec.____ Twp.____ N. Rg.____W.

3. PROPOSED USE

☐ Domestic ☐ Irrigation ☐ Industrial

☐ Stock ☐ Municipal ☐ Test Hole

4. METHOD DRILLED

☐ Cable ☐ Reverse Rotary ☐ Bored

☐ Forward Rotary ☐ Jetted ☐ Other

If other, specify__________

5. WATER QUALITY

Was a water sample collected for chemical analysis?

☐ Yes ☐ No

If so, to what laboratory was it sent__________

6. WELL CONSTRUCTION

Diameter of hole_____inches. Depth_____feet.

Casing: ☐ Steel ☐ Plastic ☐ Concrete

☐ Threaded ☐ Welded ☐ Other

If other, specify__________

Pipe Weight:	Diameter:	From:	To:
____lb/ft.	____inches	____feet	____feet
____lb/ft.	____inches	____feet	____feet
____lb/ft.	____inches	____feet	____feet
____lb/ft.	____inches	____feet	____feet

Was perforated pipe used? ☐ Yes ☐ No

Length of pipe perforated __________feet

Was casing left open end? ☐ Yes ☐ No

Was a well screened installed? ☐ Yes ☐ No

Material__________ Diameter_____inches
(stainless steel, bronze, etc.)

Slot size_____ set from_____feet to_____feet

Slot size_____ set from_____feet to_____feet

Slot size_____ set from_____feet to_____feet

Slot size_____ set from_____feet to_____feet

Was a packer or seal used? ☐ Yes ☐ No

If so, what material__________

Type of well: Straight screen ☐ Gravel packed ☐

Was the well grouted? Yes ☐ No ☐

To what depth? __________feet

Material used in grouting__________

Well head completion: Pitless adapter__________

12″ above grade__________ Other__________

If other, specify__________

Was well disinfected upon completion? ☐ Yes ☐ No

7. WATER LEVEL

Static water level__________feet below land surface

If flowing: closed-in pressure_____psi

GPM flow________through________inch pipe

Controlled by: ☐ Valve ☐ Reducers ☐ Other

If other, specify__________

8. WELL TEST DATA

☐ Pump ☐ Bailer ☐ Other

Pumping level below land surface:

_____ft. after_____hrs. pumping_____gpm

_____ft. after_____hrs. pumping_____gpm

_____ft. after_____hrs. pumping_____gpm

9. WELL LOG

Formation	Depth (ft.) From	To

(Use separate sheet if necessary.)

10. DATE COMPLETED__________

11. WAS WELL PLUGGED OR ABANDONED?

☐ Yes ☐ No

If so, how__________

12. REMARKS:

13. DRILLER'S CERTIFICATION

This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

Driller's or Firm's Name __________ Certificate No. _____

Address __________

Signed by __________ Date _____

STATE OF NORTH DAKOTA
BOARD OF WATER WELL CONTRACTORS
900 E. BOULEVARD • BISMARCK, NORTH DAKOTA 58501

WELL DRILLER'S REPORT

State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

1. WELL OWNER

Name ____________

Address ____________

2. WELL LOCATION

Sketch map location must agree with written location.

NORTH

1 Mile

County ____________

____ ¼ ____ ¼ ____ ¼ Sec. ____ Twp. ____ N. Rg. ____ W.

3. PROPOSED USE

☐ Domestic ☐ Irrigation ☐ Industrial
☐ Stock ☐ Municipal ☐ Test Hole

4. METHOD DRILLED

☐ Cable ☐ Reverse Rotary ☐ Bored
☐ Forward Rotary ☐ Jetted ☐ Other

If other, specify ____________

5. WATER QUALITY

Was a water sample collected for chemical analysis?

☐ Yes ☐ No

If so, to what laboratory was it sent ____________

6. WELL CONSTRUCTION

Diameter of hole ______ inches. Depth ______ feet.

Casing: ☐ Steel ☐ Plastic ☐ Concrete
☐ Threaded ☐ Welded ☐ Other

If other, specify ____________

Pipe Weight:	Diameter:	From:	To:
____ lb/ft.	____ inches	____ feet	____ feet
____ lb/ft.	____ inches	____ feet	____ feet
____ lb/ft.	____ inches	____ feet	____ feet
____ lb/ft.	____ inches	____ feet	____ feet

Was perforated pipe used? ☐ Yes ☐ No

Length of pipe perforated ____________ feet

Was casing left open end? ☐ Yes ☐ No

Was a well screened installed? ☐ Yes ☐ No

Material ____________ Diameter ______ inches
(stainless steel, bronze, etc.)

Slot size ______ set from ______ feet to ______ feet
Slot size ______ set from ______ feet to ______ feet
Slot size ______ set from ______ feet to ______ feet
Slot size ______ set from ______ feet to ______ feet

Was a packer or seal used? ☐ Yes ☐ No

If so, what material ____________

Type of well: Straight screen ☐ Gravel packed ☐

Was the well grouted? Yes ☐ No ☐

To what depth? ____________ feet

Material used in grouting ____________

Well head completion: Pitless adapter ____________

12" above grade ____________ Other ____________

If other, specify ____________

Was well disinfected upon completion? ☐ Yes ☐ No

7. WATER LEVEL

Static water level ____________ feet below land surface

If flowing: closed-in pressure ______ psi

GPM flow ______ through ______ inch pipe

Controlled by: ☐ Valve ☐ Reducers ☐ Other

If other, specify ____________

8. WELL TEST DATA

☐ Pump ☐ Bailer ☐ Other

Pumping level below land surface:

______ ft. after ______ hrs. pumping ______ gpm
______ ft. after ______ hrs. pumping ______ gpm
______ ft. after ______ hrs. pumping ______ gpm

9. WELL LOG

Formation	Depth (ft.) From	To

(Use separate sheet if necessary.)

10. DATE COMPLETED ____________

11. WAS WELL PLUGGED OR ABANDONED?

☐ Yes ☐ No

If so, how ____________

12. REMARKS:

13. DRILLER'S CERTIFICATION

This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

Driller's or Firm's Name ____________ Certificate No.

Address ____________

Signed by ____________ Date

STATE OF NORTH DAKOTA
BOARD OF WATER WELL CONTRACTORS
900 E. BOULEVARD AVE., DEPT. 770 • BISMARCK, NORTH DAKOTA 58505-0850

WELL DRILLER'S REPORT

State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

1. WELL OWNER

Name Mike Keller

Address 2012 Divis[illegible]

Mandan 58[illegible]

2. WELL LOCATION

Sketch map location must agree with written location.

NORTH

1 MILE

Sec. (1 mile) 7

County Oliver

SE 1/4 NW 1/4 NW 1/4 Sec. 7 Twp. 141 N.Rg 82 W.

3. PROPOSED USE

☒ Domestic ☐ Stock ☐ Geothermal ☐ Irrigation ☐ Municipal ☐ Monitoring ☐ Industrial ☐ Test Hole

4. METHOD DRILLED

☐ Cable ☒ Forward Rotary ☐ Reverse Rotary ☐ Jetted ☐ Bored ☐ Auger

If other, specify

5. WATER QUALITY

Was a water sample collected for:

Chemical Analysis? ☐ Yes ☒ No

Bacteriological Analysis? ☐ Yes ☒ No

If so, to what laboratory was it sent? at owner discretion

6. WELL CONSTRUCTION

Diameter of hole 8 inches. Depth 470 feet.

Casing: ☐ Steel ☒ Plastic ☐ Concrete ☐ Threaded ☐ Welded ☐ Other

If other, specify

Pipe Weight:	Diameter:	From:	To:
200 lb/ft	4 inches	0 feet	470 feet
lb/ft	inches	feet	feet
lb/ft	inches	feet	feet

Was perforated pipe used? ☒ Yes ☐ No

Perforated pipe set from 430 ft. to 470 feet

Was casing left open end? ☐ Yes ☒ No

Was a well screen installed? ☒ Yes ☐ No

Material PVC Diameter 4 inches

Slot Size .016 set from 430 feet to 470 feet

Slot Size ____ set from ____ feet to ____ feet

Was packer or seal used? ☒ Yes ☐ No

If so, what material chips Depth 425-400 ft.

Type of well: Straight screen ☐ Gravel packed ☒

Depth grouted: From 7-142 and 140 To 165-400-425

Grouting Material: Cement — Other chips

If other, explain: hydrated chips

Well head completion: Pitless unit not yet

12" above grade 14" Other it will

If other, specify have a pitless unit

Was pump installed? ☐ Yes ☒ No

Was well disinfected upon completion? ☒ Yes ☐ No

7. WATER LEVEL

Static water level 145 feet below surface

If flowing: closed-in pressure — psi

GPM flow — through — inch pipe

Controlled by: ☐ Valve ☐ Reducers ☐ Other

If other, specify

8. WELL TEST DATA

☒ Pump ☐ Bailer ☐ Other

Pumping level below land surface:

270 ft. after 3 hrs. pumping 10 gpm

____ ft. after ____ hrs. pumping ____ gpm

____ ft. after ____ hrs. pumping ____ gpm

9. WELL LOG

Formation	Depth (ft.) From	To
gravel	0	20
gray clay	20	70
coal	70	72
gray clay	72	96
gray sandy clay seepage.	96	122
shale rock	122	123
gray sandy clay seepage	123	134
hard coal	134	137
gray clay	137	160
hard coal	160	160½
gray clay	160½	162
hard coal	162	165
gray sandy clay seepage 2 gpm	165	204
lime stone	204	205½
hard gray sandy clay	205½	243
gray clay	243	396
shale rock	396	396½
gray [illegible] clay	396½	415

(Use separate sheet if necessary)

next Page.

10. DATE COMPLETED 7-20-03

11. WAS WELL PLUGGED OR ABANDONED?

☐ Yes ☒ No

If so, how

12. REMARKS:

future house well 1 yr or so - well only at this time

13. DRILLER'S CERTIFICATION

This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

Schaff & Sons Repair Inc. — 14

Driller's or Firm's Name — Certificate No.

618 Rosie NE Mandan

Address

Bill Schaff — 3-14-04

Signed by — Date

WHITE-DRILLER'S COPY YELLOW-BOARD'S COPY PINK-CUSTOMER'S COPY

Mike Keller

	hard sandy clay (dry)	415- 425
	fine sandy clay seepage	425- 433
	hard rock	433- 437
	fine gray sandy clay	437- 442
	rock	442- 443
+Nuck	med blue sand	443- 456
St M	soft rock	456- 457
4	fine sand	457- 470
	gray clay	470- 480

STATE OF NORTH DAKOTA
BOARD OF WATER WELL CONTRACTORS
900 E. BOULEVARD AVE., DEPT. 770 • BISMARCK, NORTH DAKOTA 58505-0850

WELL DRILLER'S REPORT

State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

1. WELL OWNER
Name Dale Hilton
Address 3195 - 27th St.
Center ND 58530

2. WELL LOCATION
Sketch map location must agree with written location.

NORTH

1 MILE

X

Sec. (1 mile)

County Oliver
NW 1/4 NW 1/4 SE 1/4 Sec. 14 Twp. 141 N.Rg 83 W.

3. PROPOSED USE
☐ Domestic
☒ Stock
☐ Geothermal
☐ Irrigation
☐ Municipal
☐ Monitoring
☐ Industrial
☐ Test Hole

4. METHOD DRILLED
☐ Cable
☒ Forward Rotary
☐ Reverse Rotary
☐ Jetted
☐ Bored
☐ Auger

If other, specify

5. WATER QUALITY
Was a water sample collected for:
Chemical Analysis? ☐ Yes ☒ No
Bacteriological Analysis? ☐ Yes ☒ No
If so, to what laboratory was it sent?

6. WELL CONSTRUCTION
Diameter of hole 7 7/8 inches. Depth 320 feet.

Casing: ☐ Steel ☒ Plastic ☐ Concrete ☐ Threaded ☐ Welded ☐ Other

If other, specify

Pipe Weight:	Diameter:	From:	To:
SDR 21 lb/ft	4 inches	0 feet	~~320~~ feet
lb/ft	inches	feet	feet
lb/ft	inches	feet	feet

Was perforated pipe used? ☒ Yes ☐ No
Perforated pipe set from ~~[illegible]~~ 250 ft. to 320 feet
Was casing left open end? ☐ Yes ☒ No
Was a well screen installed? ☒ Yes ☐ No
Material PVC Diameter 4 inches
Slot Size 16 set from 250 feet to 320 feet
Slot Size set from feet to feet
Was packer or seal used? ☐ Yes ☒ No
If so, what material Depth ft.
Type of well: Straight screen ☐ Silica Gravel packed ☒
Depth grouted: From 240-230 To 20-0
Grouting Material: Cement Other Bent. Chips
If other, explain:
Well head completion: Pitless unit yes
12" above grade yes Other
If other, specify
Was pump installed? ☒ Yes ☐ No
Was well disinfected upon completion? ☒ Yes ☐ No

7. WATER LEVEL
Static water level 162 feet below surface
If flowing: closed-in pressure psi
GPM flow through inch pipe
Controlled by: ☐ Valve ☐ Reducers ☐ Other
If other, specify

8. WELL TEST DATA
☒ Pump ☐ Bailer ☐ Other
Pumping level below land surface:
225 ft. after 2 hrs. pumping 10 gpm
ft. after hrs. pumping gpm
ft. after hrs. pumping gpm

9. WELL LOG

Formation	Depth (ft.) From	To
Top	0	2
Gray Till	2	5
Gravels	5	8
Yellow Clay	8	20
Rock	20	20 1/2
Sandy - Yellow	20 1/2	37
Sand - Rock, hard	37	40
med. Brown Sand	40	48
Gray Sandstone	48	50
Br. Sand & Gray	50	75
Gray Sand	75	87
Gray Clay	87	90
Coal	90	92
Gray Clay	92	119
Coal	119	120
Clay - Gray	120	145
Coal	145	152
fine Clay Sandy	152	160

(Use separate sheet if necessary)

10. DATE COMPLETED 9-14-07

11. WAS WELL PLUGGED OR ABANDONED?
☐ Yes ☒ No
If so, how

12. REMARKS:

13. DRILLER'S CERTIFICATION
This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

Earth Energy & Water Systems, Inc #153
Driller's or Firm's Name Certificate No.
3890 Judson St, New Salem ND 58563
Address
[signature] Sept-14-2007
Signed by Date

WHITE-DRILLER'S COPY YELLOW-BOARD'S COPY PINK-CUSTOMER'S COPY

Earth Energy & Water Systems, Inc.
3890 Judson Street
New Salem ND 58563

Well Log for:
Dale Hilton
3195 – 27th St
Center ND 58530

Oliver County
NW1/4NW1/4SE1/4
Sec 14, Twn 141N, Rge 83W

Gray Clay	160 – 170
Coal & Clay	170 – 175
Gray Clay	175 – 240
Coal & Dark Clay	240 – 253
Med Sand	253 – 272
Sand with Clay	272 – 280
Sandy Clay	280 – 290
Med Fine Sand	290 – 310
Sandy Clay	310 – 320

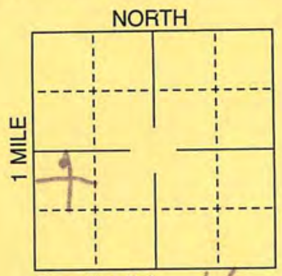
STATE OF NORTH DAKOTA
BOARD OF WATER WELL CONTRACTORS
900 E. BOULEVARD AVE., DEPT. 770 • BISMARCK, NORTH DAKOTA 58505-0850

WELL DRILLER'S REPORT

State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

1. WELL OWNER
Name Dan Haag
Address PO Box 1263
center ND 58530

2. WELL LOCATION
Sketch map location must agree with written location.



Sec. (1 mile) 16

County Olives

NW 1/4 NW 1/4 SW 1/4 Sec. 16 Twp. 141 N.Rg 82 W.

3. PROPOSED USE
☒ Domestic ☐ Stock ☐ Geothermal ☐ Irrigation ☐ Municipal ☐ Monitoring ☐ Industrial ☐ Test Hole

4. METHOD DRILLED
☐ Cable ☒ Forward Rotary ☐ Reverse Rotary ☐ Jetted ☐ Bored ☐ Auger

If other, specify

5. WATER QUALITY
Was a water sample collected for:
Chemical Analysis? ☐ Yes ☒ No
Bacteriological Analysis? ☐ Yes ☒ No
If so, to what laboratory was it sent? at owners discretion

6. WELL CONSTRUCTION
Diameter of hole 8½ inches. Depth 420 feet.

Casing: ☐ Steel ☒ Plastic ☐ Concrete ☐ Threaded ☐ Welded ☐ Other

If other, specify

Pipe Weight:	Diameter:	From:	To:
250 lb/ft	4.5 inches	0 feet	420 feet
lb/ft	inches	feet	feet
lb/ft	inches	feet	feet

Was perforated pipe used? ☒ Yes ☐ No
Perforated pipe set from 380 ft. to 420 feet
Was casing left open end? ☐ Yes ☒ No
Was a well screen installed? ☒ Yes ☐ No
Material PVC Diameter 4.5 inches
Slot Size .016 set from 380 feet to 420 feet
Slot Size set from feet to feet
Was packer or seal used? ☒ Yes ☐ No
If so, what material Cement + chips Depth 8'-375 ft.
Type of well: Straight screen ☐ Gravel packed ☒
Depth grouted: From 8' To 375
Grouting Material: Cement ✓ Other
If other, explain: Both cement + Hydrated chips
Well head completion: Pitless unit Monitor
12" above grade 14" Other
If other, specify
Was pump installed? ☒ Yes ☐ No
Was well disinfected upon completion? ☒ Yes ☐ No

7. WATER LEVEL
Static water level 160 feet below surface
If flowing: closed-in pressure — psi
GPM flow — through — inch pipe
Controlled by: ☐ Valve ☐ Reducers ☐ Other
If other, specify

8. WELL TEST DATA
☒ Pump ☐ Bailer ☐ Other

Pumping level below land surface:
180 ft. after ½ hrs. pumping 4 gpm
200 ft. after ½ hrs. pumping 9 gpm
240 ft. after 8 hrs. pumping 15 gpm

9. WELL LOG

Formation	Depth (ft.) From	To
Brown sandy clay	0	27
gray sandy clay	27	119
soft sandstone	119	120
gray clay	120	159
hard rock	159	164
gray clay	164	244
med hard rock	244	245
gray clay	245	274
fine silt + shale layers.	274	308
gray clay	308	312
fine gray sand	312	314
gray clay	314	377
soft shale + silt layers.	377	384
soft Brown Shale rock	384	385
fine gray silty sand	385	413
gray clay	413	420

(Use separate sheet if necessary)

10. DATE COMPLETED 5-15-2010

11. WAS WELL PLUGGED OR ABANDONED?
☐ Yes ☒ No
If so, how

12. REMARKS:
New house well N West of House

13. DRILLER'S CERTIFICATION
This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

Schaff + Son's Repair Inc — 14
Driller's or Firm's Name — Certificate No.

PO Box 339 Mandan N.D.
Address

Bill Schaff — 2-24-11
Signed by — Date

WHITE-DRILLER'S COPY YELLOW-BOARD'S COPY

STATE OF NORTH DAKOTA
BOARD OF WATER WELL CONTRACTORS
900 E. BOULEVARD • BISMARCK, NORTH DAKOTA 58501

WELL DRILLER'S REPORT

State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

1. WELL OWNER

Name__________

Address__________

2. WELL LOCATION

Sketch map location must agree with written location.

NORTH

1 Mile

County__________

____¼____¼____¼ Sec.____ Twp.____ N. Rg.____W.

3. PROPOSED USE

☐ Domestic ☐ Irrigation ☐ Industrial
☐ Stock ☐ Municipal ☐ Test Hole

4. METHOD DRILLED

☐ Cable ☐ Reverse Rotary ☐ Bored
☐ Forward Rotary ☐ Jetted ☐ Other
If other, specify __________

5. WATER QUALITY

Was a water sample collected for chemical analysis?
☐ Yes ☐ No
If so, to what laboratory was it sent__________

6. WELL CONSTRUCTION

Diameter of hole______inches. Depth______feet.
Casing: ☐ Steel ☐ Plastic ☐ Concrete
☐ Threaded ☐ Welded ☐ Other
If other, specify__________

Pipe Weight: Diameter: From: To:
____lb/ft. ____inches ____feet ____feet
____lb/ft. ____inches ____feet ____feet
____lb/ft. ____inches ____feet ____feet
____lb/ft. ____inches ____feet ____feet

Was perforated pipe used? ☐ Yes ☐ No
Length of pipe perforated __________ feet
Was casing left open end? ☐ Yes ☐ No
Was a well screened installed? ☐ Yes ☐ No
Material__________ Diameter______inches
(stainless steel, bronze, etc.)
Slot size______ set from______feet to______feet
Slot size______ set from______feet to______feet
Slot size______ set from______feet to______feet
Slot size______ set from______feet to______feet
Was a packer or seal used? ☐ Yes ☐ No
If so, what material__________
Type of well: Straight screen ☐ Gravel packed ☐
Was the well grouted? Yes ☐ No ☐
To what depth? __________feet
Material used in grouting__________
Well head completion: Pitless adapter__________
12" above grade______ Other______
If other, specify__________
Was well disinfected upon completion? ☐ Yes ☐ No

7. WATER LEVEL

Static water level__________feet below land surface
If flowing: closed-in pressure______psi
GPM flow______through______inch pipe
Controlled by: ☐ Valve ☐ Reducers ☐ Other
If other, specify__________

8. WELL TEST DATA

☐ Pump ☐ Bailer ☐ Other
Pumping level below land surface:
______ft. after______hrs. pumping______gpm
______ft. after______hrs. pumping______gpm
______ft. after______hrs. pumping______gpm

9. WELL LOG

Formation	Depth (ft.) From	To

(Use separate sheet if necessary.)

10. DATE COMPLETED__________

11. WAS WELL PLUGGED OR ABANDONED?

☐ Yes ☐ No
If so, how__________

12. REMARKS:

13. DRILLER'S CERTIFICATION

This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

ZACHMEIER WELL DRILLING, INC.
Driller's or Firm's Name Certificate No.
CENTER ROUTE
MANDAN, NO. DAK. 58554
Address

Signed by Date

DUPLICATE — BOARD'S COPY

STATE OF NORTH DAKOTA

BOARD OF WATER WELL CONTRACTORS

900 E. BOULEVARD • BISMARCK, NORTH DAKOTA 58501

WELL DRILLER'S REPORT

State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

1. WELL OWNER

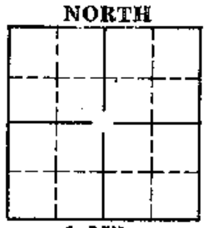
Name__________

Address__________

2. WELL LOCATION

Sketch map location must agree with written location.

NORTH



1 Mile

County__________

___¼___¼___¼ Sec.____ Twp.____ N. Rg.____W.

3. PROPOSED USE

☐ Domestic ☐ Irrigation ☐ Industrial

☐ Stock ☐ Municipal ☐ Test Hole

4. METHOD DRILLED

☐ Cable ☐ Reverse Rotary ☐ Bored

☐ Forward Rotary ☐ Jetted ☐ Other

If other, specify__________

5. WATER QUALITY

Was a water sample collected for chemical analysis?

☐ Yes ☐ No

If so, to what laboratory was it sent__________

6. WELL CONSTRUCTION

Diameter of hole______inches. Depth______feet.

Casing: ☐ Steel ☐ Plastic ☐ Concrete

☐ Threaded ☐ Welded ☐ Other

If other, specify__________

Pipe Weight:	Diameter:	From:	To:
____lb/ft.	____inches	____feet	____feet
____lb/ft.	____inches	____feet	____feet
____lb/ft.	____inches	____feet	____feet
____lb/ft.	____inches	____feet	____feet

Was perforated pipe used? ☐ Yes ☐ No

Length of pipe perforated __________feet

Was casing left open end? ☐ Yes ☐ No

Was a well screened installed? ☐ Yes ☐ No

Material__________ Diameter______inches
(stainless steel, bronze, etc.)

Slot size______ set from______feet to______feet

Slot size______ set from______feet to______feet

Slot size______ set from______feet to______feet

Slot size______ set from______feet to______feet

Was a packer or seal used? ☐ Yes ☐ No

If so, what material__________

Type of well: Straight screen ☐ Gravel packed ☐

Was the well grouted? Yes ☐ No ☐

To what depth? __________feet

Material used in grouting__________

Well head completion: Pitless adapter__________

12" above grade______ Other______

If other, specify__________

Was well disinfected upon completion? ☐ Yes ☐ No

7. WATER LEVEL

Static water level______feet below land surface

If flowing: closed-in pressure______psi

GPM flow______through______inch pipe

Controlled by: ☐ Valve ☐ Reducers ☐ Other

If other, specify__________

8. WELL TEST DATA

☐ Pump ☐ Bailer ☐ Other

Pumping level below land surface:

______ft. after______hrs. pumping______gpm

______ft. after______hrs. pumping______gpm

______ft. after______hrs. pumping______gpm

9. WELL LOG

Formation	Depth (ft.) From	Depth (ft.) To

(Use separate sheet if necessary.)

10. DATE COMPLETED__________

11. WAS WELL PLUGGED OR ABANDONED?

☐ Yes ☐ No

If so, how__________

12. REMARKS:

13. DRILLER'S CERTIFICATION

This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

Driller's or Firm's Name Certificate No.

Address

Signed by Date

DEAN A. CORRELL
2504 5th N.W.
Minot, N.D. 58701
PH. 701 839-6187

778 - 780 green sand
780 - 781 sand stone
781 - 810 green fine sand
810 - 812 lime stone
812 - 816 sandy clay.
816 - 820 lime stone
820 - 880 gry green sand
880 - 900 Clay.

STATE OF NORTH DAKOTA

BOARD OF WATER WELL CONTRACTORS

900 E. BOULEVARD AVE., DEPT. 770 • BISMARCK, NORTH DAKOTA 58505-0850

WELL DRILLER'S REPORT

State law requires that this report be filed with the State Board of Water Well Contractors within 30 days after completion or abandonment of the well.

1. WELL OWNER

Name: Wyman Schoetz

Address: 2546 16th St SW
Center ND 58530

2. WELL LOCATION

Sketch map location must agree with written location.

NORTH

1 MILE

Sec. (1 mile)

County: Oliver

___1/4 ___1/4 ___1/4 Sec 28 Twp 143 N. Rg 82 W.

3. PROPOSED USE

- [x] Domestic
- [x] Stock
- [ ] Geothermal
- [ ] Irrigation
- [ ] Municipal
- [ ] Monitoring
- [ ] Industrial
- [ ] Test Hole

4. METHOD DRILLED

- [ ] Cable
- [x] Forward Rotary
- [ ] Reverse Rotary
- [ ] Jetted
- [ ] Bored
- [ ] Auger

If other, specify ___

5. WATER QUALITY

Was a water sample collected for:

Chemical Analysis? [ ] Yes [ ] No

Bacteriological Analysis? [ ] Yes [ ] No

If so, to what laboratory was it sent? By owner

6. WELL CONSTRUCTION

Diameter of hole 8 3/4 inches. Depth 116' feet.

Casing: [ ] Steel [x] Plastic [ ] Concrete [ ] Threaded [ ] Welded [ ] Other

If other, specify ___

Pipe Weight:	Diameter:	From:	To:
___lb/ft	4 inches	42 feet	96 feet
___lb/ft	___inches	___feet	___feet
___lb/ft	___inches	___feet	___feet

Was perforated pipe used? [ ] Yes [x] No

Perforated pipe set from ___ ft. to ___ feet

Was casing left open end? [ ] Yes [x] No

Was a well screen installed? [x] Yes [ ] No

Material PVC Diameter 4 inches

Slot Size 20 set from 96 feet to 116 feet

Slot Size ___ set from ___ feet to ___ feet

Was packer or seal used? [ ] Yes [x] No

If so, what material ___ Depth ___ ft.

Type of well: Straight screen [ ] Gravel packed [x]

Depth grouted: From 92 To 10

Grouting Material: Cement ___ Other Benseal.

If other, explain: ___

Well head completion: Pitless unit ___

12" above grade X Other ___

If other, specify ___

Was pump installed? [ ] Yes [x] No

Was well disinfected upon completion? [x] Yes [ ] No

7. WATER LEVEL

Static water level 85 feet below surface

If flowing: closed-in pressure ___ psi

GPM flow ___ through ___ inch pipe

Controlled by: [ ] Valve [ ] Reducers [ ] Other

If other, specify ___

8. WELL TEST DATA

Rig Air Compressor

- [ ] Pump
- [ ] Bailer
- [x] Other

Pumping level below land surface:

96 ft. after 2 hrs. pumping 7. gpm

___ ft. after ___ hrs. pumping ___ gpm

___ ft. after ___ hrs. pumping ___ gpm

9. WELL LOG

Formation	Depth (ft.) From	Depth (ft.) To
Glacial Till	0	14
Sandstone	14	17
Brown Clay	17	28
Gray Clay	28	34
Coal	34	36
Gray Clay	36	52
Coal	52	56
Gray Clay	56	60
Very fine Sand	60	100
Fine Sand	100	108
Coal	108	110
Gray Silty Clay	110	116

(Use separate sheet if necessary)

10. DATE COMPLETED 04-20-2011

11. WAS WELL PLUGGED OR ABANDONED?

[ ] Yes [x] No

If so, how ___

12. REMARKS:

13. DRILLER'S CERTIFICATION

This well was drilled under my jurisdiction and this report is true to the best of my knowledge.

Mohl Drilling, Inc — 105

Driller's or Firm's Name — Certificate No.

1710 Arikara Dr. Beulah ND

Address

John Mohl — 4/25/11

Signed by — Date

Back

142-084-24 BBA

Data Source	ND State Water Commission	**Well Index**	9442
County	Oliver	**Date Drilled**	1967-11-29
Aquifer	Fox Hills	**Purpose**	Observation Well
Basin	Lake Oahe	**Casing Type**	Steel
MP Elevation (ft)	2009.23	**Diameter (in.)**	4.00
Surface Elev. (ft)	2005.81	**Screened Interval (ft)**	966 - 966
Elevation Source (Datum)	GPS (NAVD88)	**Coord (Long,Lat)**	-101.276007, 47.110619
Total Depth (ft)	1295.00	**USGS ID**	470642101162701
Bedrock Depth (ft)	0.00		

Lithologic Log

Interval (ft)	Unit	Description
0 - 484	SILTSTONE	Interbedded with claystone, at times lignitic, sandier 160-215, 340-418, 422-484 (Tongue River Formation). (An interpretation of the county study interpretation).
484 - 707	SILTSTONE	Sand between 517-520, 595-620, 696-707, fine grained (Cannonball-Ludlow Formations, undifferentiated)
707 - 945	SILTSTONE	Similar to above, maybe more argillaceous, sand zones 762-776, 895-930 (Hell Creek Formation)
945 - 1202	SANDSTONE	Fine to medium sand between 945-1000 feet, (Colgate Member), underlain by siltstone and claystone (Fox Hills Formation)
1202 - 1295	SHALE	Silty, olive gray (Pierre Formation)

[Hydrograph] [Water Levels] [Water Chemistry]

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

Amended 2Feb21 (TDS)

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	12 Jan 21	HT
pH - Field	8.42	units	NA	SM 4500 H+ B	12 Jan 21 12:45	JSM
Temperature - Field	11.8	Degrees C	NA	SM 2550B	12 Jan 21 12:45	JSM
Total Alkalinity	938	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Bicarbonate	912	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Carbonate	26	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Conductivity - Field	2641	umhos/cm	1	EPA 120.1	12 Jan 21 12:45	JSM
Tot Dis Solids(Summation)	1520	mg/l	12.5	SM1030-F	15 Jan 21 11:45	Calculated
Nitrate as N	< 0.2	mg/l	NA	EPA 353.2	14 Jan 21 9:17	Calculated
Bromide	2.83	mg/l	0.100	EPA 300.0	14 Jan 21 22:24	RMV
Total Organic Carbon	1.7	mg/l	0.5	SM5310C-11	22 Jan 21 17:28	NAS
Dissolved Organic Carbon	1.7	mg/l	0.5	SM5310C-96	22 Jan 21 17:28	NAS
Fluoride	3.54	mg/l	0.10	SM4500-F-C	12 Jan 21 17:00	HT
Sulfate	< 5	mg/l	10.0	ASTM D516-11	15 Jan 21 8:50	EV
Chloride	323	mg/l	2.0	SM4500-Cl-E-11	13 Jan 21 11:25	EV
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	14 Jan 21 9:17	EV
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	14 Jan 21 7:59	EV
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	15 Jan 21 8:17	EV
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	15 Jan 21 8:17	EV
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	13 Jan 21 11:16	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Jan 21 11:16	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix   # = Due to concentration of other analytes
! = Due to sample quantity   + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL

MINNESOTA VALLEY TESTING LABORATORIES, INC.

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL

Amended 2Feb21 (TDS)

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	4.0	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Magnesium - Total	< 1	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Sodium - Total	630	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Potassium - Total	2.8	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Lithium - Total	0.186	mg/l	0.020	6010D	21 Jan 21 15:22	MDE
Aluminum - Total	< 0.1	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Iron - Total	0.40	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Silicon - Total	5.04	mg/l	0.10	6010D	26 Jan 21 9:37	MDE
Strontium - Total	0.16	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Zinc - Total	< 0.05	mg/l	0.05	6010D	20 Jan 21 10:36	MDE
Boron - Total	2.87	mg/l	0.10	6010D	26 Jan 21 10:46	MDE
Calcium - Dissolved	3.7	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Sodium - Dissolved	670	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Potassium - Dissolved	3.2	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Lithium - Dissolved	0.102	mg/l	0.020	6010D	21 Jan 21 15:22	MDE
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Iron - Dissolved	0.25	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Silicon - Dissolved	5.12	mg/l	0.10	6010D	26 Jan 21 9:37	MDE
Strontium - Dissolved	0.15	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	20 Jan 21 9:36	MDE
Boron - Dissolved	2.85	mg/l	0.10	6010D	26 Jan 21 10:46	MDE
Antimony - Total	< 0.001	mg/l	0.0010	6020B	14 Jan 21 19:47	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MINNESOTA VALLEY TESTING LABORATORIES, INC.

MVTL

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER ACIL

Amended 2Feb21 (TDS)

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Barium - Total	0.0966	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Lead - Total	0.0006	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Manganese - Total	0.0088	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Molybdenum - Total	0.0058	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	14 Jan 21 19:47	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	15 Jan 21 14:56	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Barium - Dissolved	0.0954	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE

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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

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MVTL

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL

Amended 2Feb21 (TDS)

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: Center USGS Well

Sample Description: USGS Well

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

PO #: B. Botnen

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Manganese - Dissolved	0.0081	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Molybdenum - Dissolved	0.0058	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	15 Jan 21 14:56	MDE
Silver - Dissolved	< 0.001 ^	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:

@ = Due to sample matrix
\# = Due to concentration of other analytes
! = Due to sample quantity
\+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

APPENDIX H – CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

PERMIT APPLICATION

Class I (Non-hazardous) Injection Well Permit Application

Milton R. Young Station

Submitted to:

North Dakota Department of Environmental Quality

918 E. Divide Ave.
Bismarck, North Dakota 58501

Submitted by:

Golder Associates Inc.

7245 W Alaska Drive, Suite 200, Lakewood, Colorado, USA 80226

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19122669-31-R-0

June 7, 2021

Record of Issue

Company	Client Contact	Version	Date Issued	Method of Delivery
Minnkota Power Cooperative	Daniel Laudal	Revision 0	June 7, 2021	Electronic Copy

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TABLES

FIGURES

APPENDICES

1.0 INTRODUCTION

This permit application has been prepared by Golder Associates Inc. (Golder), a member of WSP, on behalf of Minnkota Power Cooperative (MPC) for two proposed Class I underground injection wells at Milton R. Young Station (MRY). Information presented in this application complies with applicable Underground Injection Control (UIC) Program permit application requirements of North Dakota Administrative Code (NDAC), Article 33.1-25 (North Dakota Legislative Council 1978); Title 40 of the Code of Federal Regulations (CFR) § 144 and 146 (USEPA n.d.); and the North Dakota Department of Environmental Quality (NDDEQ) UIC Program permit application form (Appendix A). A checklist of the requirements for a Class I (non-hazardous) injection well permit application in North Dakota, including the locations within this permit application where the requirements are addressed, is provided in Appendix A.

1.1 Background

MRY is a two-unit, lignite coal-based power plant with 705-megawatt generating capacity owned by both MPC (Unit 1) and Square Butte Electric Cooperative (Unit 2) and is operated by MPC. MRY is located adjacent to Nelson Lake, approximately six miles southeast of Center, North Dakota (Figure 1-1). Unit 1 began operations in 1970 and Unit 2 began generation in 1977. Both units have air emission controls, and plant process water is treated and tested prior to discharge to Nelson Lake through a permitted NPDES discharge (Permit No. ND-000370). The Standard Industrial Classification Code for MRY is 4911, Electric Services.

MRY is located in Sections 4 and 5 of Township 141N, Range 83W, in Oliver County. The facility address is:

Minnkota Power Cooperative
Milton R. Young Station
3401 24th St SW
Center, North Dakota 58530
Phone: (701) 794-8711

Correspondence regarding the Class I injection well(s) should be directed to:

Minnkota Power Cooperative
Attention: Daniel Laudal
5301 32nd Avenue South
Grand Forks, North Dakota 58201
Phone: (701) 330-3241

The approximate coordinates for the proposed Class I injection wells, which are positioned 0.5 miles apart, are as follows (NAD 83 State Plane Coordinate System North Dakota South, feet):

- Injection Well #1 – FREEMAN-1: N. 509,872 ft, E. 1,790,841 ft
- Injection Well #2 – RUBEN-1: N. 507,250 ft, E. 1,791,090 ft

The facility is not located on Indian lands, and MPC is unaware of historic or archaeological sites that may be impacted by the proposed Class I injection wells. Land ownership and structures in the vicinity of MRY are shown in Figures 1-2 and 1-3. A site map, including the proposed locations of the injection wells, and adjacent parcel boundaries and owner names are provided in Figure 1-3.

MPC is in the process of permitting and designing a new carbon capture and sequestration (CCS) system for MRY as part of Project Tundra, which would remove 90% of carbon dioxide emissions from Unit 2. The proposed Class I injection wells at MRY will be used to manage non-hazardous process water (primarily cooling water) from the carbon capture process. The proposed Class I injection wells (FREEMAN-1 and RUBEN-1) will be located on MPC property, south of the power block (Figure 1-3).

The proposed Class I injection wells will be operated by MPC staff. The proposed wells will be the first Class I wells that MPC has operated, and the only Class I injection wells located at the MRY site. MPC also plans to permit and construct Class VI injection wells near the plant for geologic sequestration of carbon dioxide as part of Project Tundra. All of the proposed Class VI wells will be completed in the Broom Creek Formation or the Deadwood Formation, which are both deeper than the target injection zone for the Class I injection wells (Inyan Kara Formation), as described further in Section 3.0.

1.2 Proposed Injection Overview

This permit application is for two Class I (non-hazardous) injection wells, proposed for emplacement of non-hazardous wastewater into the subsurface.

1.2.1 Proposed Injectate

MPC plans to discharge excess process water from the Project Tundra CCS system, which includes cooling tower blowdown, reverse osmosis reject, water treatment softening sludge, wet electrostatic precipitator discharge, and polishing scrubber blowdown to their existing flue gas desulfurization (FGD) scrubber blowdown vaults. FGD blowdown from the Unit 1 and Unit 2 scrubber absorber towers is delivered to the scrubber blowdown vaults and then sluiced to Scrubber Pond Cell 4, which is a composite-lined impoundment with a capacity of 307 million gallons below the permitted maximum operating elevation (2,093 feet above mean sea level [ft amsl]). Additional inflow to the FGD scrubber system includes makeup water from Nelson Lake, runoff, leachate from the closed scrubber pond cells (i.e., Cells 1, 2, and 3), and other site process waters. Free water in Scrubber Pond Cell 4 (Cells 5 and 6 will be used in the future) is siphoned back to the scrubbers for use in the scrubbing process and sluicing FGD solids. The proposed injectate will be sourced from the Unit 2 Pond Return Tank, which receives water siphoned from Scrubber Pond Cell 4. Given the known chemistry of water in the FGD scrubber system and the anticipated chemistry of the wastewaters from the CCS system, the proposed injectate is anticipated to be non-hazardous; however, because the CCS system is not operational at this time, the exact chemistry is unknown. A more detailed description of sources contributing flows to the Class I injection wells and potential water chemistry is provided in Section 6.2.

1.2.2 Permitting Strategy

This permit is for two Class I injection wells at MRY. MPC intends to construct the second injection well only if the operational flow capacity of the first well is insufficient to meet MPC's injection needs. Operation of these injection well(s) will be dependent upon whether one or two Class I injection wells are ultimately constructed.

Following approval by the NDDEQ, one injection well (FREEMAN-1) will be constructed on the existing well pad near the plant, adjacent to the proposed Class VI injection wells (Figure 1-3). Following construction and mechanical integrity testing, a step rate test, constant rate test, and falloff test will be conducted on FREEMAN-1 to determine the well's operational injection capacity. If FREEMAN-1 is determined to have sufficient capacity to meet MPC's injection needs, RUBEN-1 will not be constructed. If the capacity is determined to be insufficient, RUBEN-1 will be constructed approximately 0.5 miles south of FREEMAN-1.

The following two injection scenarios are considered as a part of this permit application:

- Scenario 1: One injection well operating at 950 gallons per minute (gpm) (1,368,000 gallons per day)
- Scenario 2: Two injection wells (spaced 0.5 miles apart) each capable of operating at 850 gpm (2,448,000 gallons per day)

1.2.3 Proposed Injection Flow

The proposed permitted injection flow rate is 950 gpm for one well operating or 850 gpm each for two wells operating, dependent upon whether one or two Class I injection wells are ultimately constructed (Section 1.2.2). In the case that two injection wells are constructed, it is unlikely that both wells will be operated at 850 gpm each continuously for 20 years because the disposal demand is not anticipated to be that high. The modeling completed to support this permit application with both injection wells operating continuously for 20 years at 850 gpm each is considered conservative and will allow for flexibility in how the wells are operated. The design life for each injection well is 20 years. The permitted injection flow rate(s) and lifespan were used for injection modeling (Section 4.0). Formation fracture pressure at MRY is estimated in Section 5.0. Upon drilling, testing, and completion of the new injection well(s), formation fracture pressure and formation hydraulic response to injection will be reevaluated. The actual maximum permitted injection flow rate at each well will be determined at the start of well operations based on injecting under pressures such that the sum of the formation hydrostatic pressure and wellhead pressure (measured at the surface) are less than the calculated formation fracture pressure, as specified in NDAC Article 33.1-25 (North Dakota Legislative Council 1978).

1.2.4 Proposed Injection Interval

The proposed injection interval for the Class I injection wells at MRY is composed of the sandstone intervals within the Inyan Kara Formation. To support characterization of the potential underground carbon dioxide storage reservoirs for Project Tundra, three separate stratigraphic test boreholes/wells were drilled to the base of the Inyan Kara Formation or deeper within five miles of MRY. Based on the logging and testing data from these nearby wells and information from other nearby drilling activities, the top of the shallowest sandstone interval of the Inyan Kara Formation at MRY is anticipated to be encountered approximately 3,667 feet below ground surface (ft bgs). Based on combinable magnetic resonance (CMR) logs from the stratigraphic test borehole constructed at MRY (J-ROC1), the Inyan Kara Formation at the Site is approximately 170 feet thick. Of that, the net thickness of permeable zones is approximately 90 feet (Section 4.3.1.1).

The Inyan Kara Formation is used extensively in North Dakota for injection of waters related to oil and gas activity (Class II injection wells). Available literature indicates that the Inyan Kara Formation will be an ideal injection interval for the proposed Class I injection wells at MRY. The injection zone is bounded by upper and lower confining units as summarized in Table 1.

Table 1: Proposed Injection Summary

Interval Name	Formations (listed from oldest to youngest)	Depth Interval (ft bgs)
Upper Confining Unit[a]	Cretaceous confining system: Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Shale	1,160 to 3,667
Injection Interval[b]	Inyan Kara Formation	3,667 to 3,838
Lower Confining Unit[a]	Jurassic confining system: Piper, Rierdon, Swift	3,838 to 4,705

a. Depth intervals for the upper and lower confining units are estimated at MRY using the lithostratigraphic unit top elevation figures (Figures 3-4 to 3-8), the geologic cross section figures (Figures 3-9 and 3-10), and formation top data obtained from the stratigraphic test wells constructed in support of Project Tundra (Section 2.0).

b. Depth interval for the injection interval is estimated at MRY using the CMR logs from the J-ROC1 stratigraphic test well (Section 4.3.1.1).

The concentration of total dissolved solids (TDS) in the Inyan Kara Formation at MRY is anticipated to be between 3,000 and 10,000 milligrams per liter (mg/L) based on measurements of TDS concentration for a formation water sample collected from the J-LOC1 stratigraphic test well (Section 4.3.1.6). Because the TDS concentration in the injection formation is anticipated to be below 10,000 mg/L, MPC is concurrently pursuing an Aquifer Exemption for injection into the Inyan Kara Formation. There is an existing area-based Class II aquifer exemption for the Inyan Kara Formation covering portions of west-central North Dakota, including the western two-thirds of Oliver County (Figure 1-4). The eastern edge of this exemption area covers the Oliver County townships within Range 84W. MPC's proposed Class I injection wells are located approximately two miles east of this boundary. Additionally, there are location exemptions for the Inyan Kara Formation for both Class I and Class II injection wells in neighboring counties (Figure 1-4).

1.3 Area of Review

1.3.1 Area of Review Definition

Per NDAC Article 33.1-25-01-14 (North Dakota Legislative Council 1978) and 40 CFR § 146.6 (USEPA n.d.) requirements, the area of review must be determined by either the zone of endangering influence or a fixed radius around the well not less than one quarter mile. For the purposes of this permit application, a fixed radius of 4.0 miles around each well has been proposed for the area of review. This radius is 16 times larger than the minimum required fixed radius and is a minimum of three times the distance of the radius of fluid displacement (discussed in Section 4.4.3) after 20 years of continuous injection under either injection scenario.

1.3.2 Injection Interval Penetrations

Improperly completed or abandoned wells within the area of review could potentially act as a conduit for injectate fluid or native formation fluid to flow from the injection interval into an underground source of drinking water (USDW). There is only one existing artificial penetration (J-ROC1, North Dakota Industrial Commission [NDIC] File No. 37672) into the proposed injection interval (Inyan Kara Formation) within the area of review (Figure 1-5). After drilling and testing J-ROC1, MPC plugged the borehole. Details for this one existing injection interval penetration within the area of review are provided in Table B-1 (Appendix B). As part of Project Tundra, MPC may convert J-ROC1 to a Class VI injection well and construct additional Class VI injection wells. The future wells will all be located within the area of review and will extend through the Inyan Kara Formation. They will be constructed in accordance with the standard of practice and will be tested for mechanical integrity to ensure they do not act as conduits between the Inyan Kara Formation and the lowermost USDW.

1.3.3 Shallow Groundwater Wells

A total of 158 shallow groundwater wells were identified within the area of review based on wells and driller's logs filed with the North Dakota State Water Commission (NDSWC) (Figure 1-6). An additional eight inactive United States Geological Survey (USGS) shallow wells were identified within the area of review based on groundwater monitoring sites filed in the USGS National Water Information System (USGS n.d.). Details for each of the shallow groundwater wells within the area of review identified from the NDSWC database and the USGS National Water Information System are provided in Table B-2A (Appendix B). MPC's well records contain 78 groundwater wells (73 monitoring wells) within the area of review (Figure 1-6), details of which are provided in Table B-2B (Appendix B). No attempt has been made to remove well records that may be duplicates between the NDSWC database and MPC's well network. There are no wells completed within the Fox Hills Sandstone (the lowermost USDW) within the area of review. MPC plans to construct one monitoring well in the Fox Hills Sandstone within 200 feet of FREEMAN-1 to serve as a monitoring well associated with the proposed Class VI injection wells for Project Tundra. In Oliver County, there are only two wells (one stock well and one observation well) completed in the Fox Hills Sandstone. There are 17 domestic wells located within one mile of MPC's property boundaries (Figure 1-2).

1.3.4 Corrective Action

If applicable, a corrective action plan is to be prepared and submitted to the NDDEQ for any improperly sealed, completed, or abandoned wells within the area of review. Within the 4-mile-radius area of review, there is one existing wellbore (J-ROC1) that penetrates the proposed injection interval. The J-ROC1 surface casing has been properly cemented and the borehole has been properly plugged. As such, no corrective action plan has been developed.

2.0 STRATIGRAPHIC TEST BOREHOLES/WELLS

In support of Project Tundra, three stratigraphic test boreholes/wells were drilled near MRY in Oliver County, North Dakota (Figure 1-5). Publicly available information for each of these test boreholes/wells can be obtained through the NDIC Oil and Gas Division:

- BNI-1 Borehole: NDIC Well File No. W34244 (BNI-1 Well File)
- J-LOC1 Well: NDIC Well File No. W37380 (J-LOC1 Well File)
- J-ROC1 Borehole: NDIC Well File No. W37672 (J-ROC1 Well File) (NDIC n.d.)

The three boreholes/wells were logged and tested to help characterize three geologic reservoirs for potential carbon sequestration and/or wastewater disposal (Inyan Kara Formation, Broom Creek Formation, and Deadwood Formation). The data collected from these test boreholes/wells are used to inform the local geology and hydrogeology (Section 3.0), flow and transport modeling in the Inyan Kara Formation for wastewater injection (Section 4.0), and estimation of formation fracture pressure (Section 5.0).

2.1 BNI-1 Borehole

The BNI-1 stratigraphic test borehole was drilled between January 17 and February 2, 2018. The borehole is located approximately two miles south of Center, North Dakota, in the SE quarter of the SE quarter of Section 27 T142N R84W. Ground elevation and Kelly Bushing (KB) elevation at BNI-1 are 2,067 ft amsl and 2,085 ft amsl, respectively (BNI-1 Well File). BNI-1 was drilled to a total depth of 5,316 ft below KB and terminated in the Amsden Formation (BNI-1 Well File). BNI-1 was drilled to perform geologic and petrophysical logging and conduct in situ testing. After sampling and testing was completed, BNI-1 was plugged and abandoned according to procedures established by the NDIC.

At BNI-1, the Inyan Kara Formation was encountered from a depth of approximately 3,874 to 4,043 ft below KB, for a total thickness of 178 feet (BNI-1 Well File). Formation static pressure and temperature were measured at two depths (3,996 and 4,030 ft below KB) within the Inyan Kara Formation via modular formation dynamics tester (MDT) pressure tests (see Sections 4.3.1.2 and 4.3.1.5, respectively). Additionally, a 6.7-square-mile three-dimensional seismic survey was acquired in the sections surrounding BNI-1. No hazards such as structural features, faults, or discontinuities were observed that would cause a concern about the integrity of the confining units overlying the Inyan Kara Formation.

2.2 J-LOC1 Well

MPC drilled the J-LOC1 stratigraphic test well in the SW quarter of the NW quarter of Section 27 T142 R84W in Oliver County, North Dakota, between May 14, 2020, through June 10, 2020. Ground elevation and KB elevation at J-LOC1 are 2,068 ft amsl and 2,093 ft amsl, respectively (J-LOC1 Well File). The J-LOC1 borehole was drilled to a total depth of 10,470 ft below KB and terminated within Precambrian amphibolite. This borehole was cased to a depth of 10,450 ft below KB to allow for brine injection testing into the coarse grained siliciclastics of the target formations (Inyan Kara Formation, Broom Creek Formation, and the Deadwood Formation) (J-LOC1 Well File). The primary objectives of completing the J-LOC1 well were to extract core samples, collect geologic and petrophysical log data, collect fluid samples, perform injection testing, and conduct in situ testing of the Inyan Kara, Broom Creek, and Deadwood Formations.

The Inyan Kara Formation was observed to be approximately 170 feet thick from 3,888 feet to 4,058 ft below KB. The Cretaceous confining system overlying the Inyan Kara Formation, which is composed of the formations listed in Table 1, was observed to be approximately 2,590 feet thick. The Jurassic confining system underlying the Inyan Kara Formation, which is composed of the formations listed in Table 1, was observed to be approximately 850 feet thick (J-LOC1 Well File).

Formation static pressure and temperature were measured at three depths (3,891, 4,018, and 4,019 ft below KB) within the Inyan Kara Formation via MDT pressure tests (see Sections 4.3.1.2 and 4.3.1.5, respectively). One fluid sample from the Inyan Kara Formation was collected (see Section 4.3.1.6 and Table E-1 in Appendix E). The well casing was perforated across a 10-foot interval within the Inyan Kara Formation (4,015 to 4,025 ft below KB) and the following tests were performed: 1) step rate injection test, 2) constant rate injection test, and 3) falloff test. Results of the step rate injection test were used to estimate formation fracture pressure (discussed in Section 5.0). Results of the falloff test were used to estimate formation permeability (discussed in Section 4.3.1.4). Core samples from the Inyan Kara Formation were tested in the laboratory for porosity, permeability (Section 4.3.1.4), and pore volume compressibility (Section 4.3.1.9).

2.3 J-ROC1 Borehole

MPC drilled the J-ROC1 borehole on the well pad south of the power block at MRY in the SW quarter of the NW quarter of Section 4 T141N R83W in Oliver County, North Dakota. J-ROC1 is approximately 100 feet northwest of the proposed FREEMAN-1. Ground elevation and KB elevation at J-ROC1 are 2,004 ft amsl and 2,029 ft amsl, respectively (J-ROC1 Well File). The J-ROC1 borehole was drilled to a total depth of 9,871 ft below KB and terminated within Precambrian basement rock (J-ROC1 Well File). J-ROC1 was drilled to collect additional geologic and petrophysical log data directly underlying MRY.

The Inyan Kara Formation was observed to be approximately 170 feet thick from 3,694 to 3,865 ft below KB. The Cretaceous confining system overlying the Inyan Kara Formation was observed to be approximately 2,520 feet thick. The Jurassic confining system underlying the Inyan Kara Formation was observed to be approximately 870 feet thick (J-ROC1 Well File).

Results of the CMR logs at J-ROC1 indicate the net thickness of permeable and porous sandstone within the Inyan Kara Formation to be approximately 90 feet at MRY (Section 4.3.1.1). The CMR logs at J-ROC1 were also used to estimate effective porosity (Section 4.3.1.3) and permeability (Section 4.3.1.4) of the permeable intervals of the Inyan Kara Formation. Additionally, a 12-square-mile three-dimensional seismic survey was acquired around J-ROC1. No hazards such as structural features, faults, or discontinuities were observed that would cause a concern about the integrity of the confining units overlying the Inyan Kara Formation.

3.0 GEOLOGY AND HYDROGEOLOGY

This section, describing the geology and hydrogeology near MRY, was developed primarily using local and regional literature sources from the North Dakota Geological Survey (NDGS) and the USGS, and supplemented with local information collected from the three recently drilled stratigraphic test boreholes/wells described in Section 2.0.

3.1 Regional Geology

MRY is located in central North Dakota within the southeastern part of the Williston Basin. A geologic map of North Dakota is provided in Figure 3-1. The North Dakota Stratigraphic Column is provided in Figure 3-2. For purposes of this permit application, the term "regional geology" refers to geologic features of the Williston Basin as a whole.

3.1.1 Geologic History

MRY is located in central Oliver County, North Dakota, approximately six miles southeast of Center, North Dakota. The Williston Basin covers approximately 300,000 square miles over parts of North Dakota, South Dakota, Montana, and parts of the adjacent Canadian provinces of Saskatchewan and Manitoba. The basin's deepest point is believed to be near Williston, North Dakota (NDGS 2020), and Oliver County is approximately 135 miles southeast of Williston. Oliver County is located within the southeastern portion of the structural basin (Carlson 1973).

Western North Dakota experienced a major orogeny approximately 1.9 to 1.6 billion years ago resulting in igneous and metamorphism in western North Dakota (Bluemle 2000). One well located in Oliver County penetrated Precambrian amphibolite at 8,850 feet (Carlson 1973). Two of the three stratigraphic test boreholes/wells (J-LOC1 and J-ROC1) drilled in support of Project Tundra encountered the Precambrian amphibolite between 9,725 and 10,280 ft bgs (J-LOC1 Well File and J-ROC1 Well File). The Williston Basin likely initially began to develop during the Late Precambrian or Early Cambrian during crustal uplift of the dense Precambrian rocks. Subsidence then began in the Early Paleozoic, possibly as a result of buoyant adjustment of the dense, uplifted crustal block. Sediments that have accumulated in the Williston Basin since the end of the Precambrian reach a maximum thickness greater than 16,000 feet (Bluemle 2000).

North Dakota subsided relative to the Canadian Shield during the Early Paleozoic, resulting in the development of an interior seaway (Bluemle 2000). Interior seaways developed in the northwest North Dakota portion of the Williston Basin at least four times during the Paleozoic, resulting in deposition of carbonates, sandstones, shales, and evaporites. The area was emergent during the Early to Middle Ordovician, Middle Silurian to Middle Devonian, Late Mississippian to Early Pennsylvanian, and during the Triassic. During these periods of significant erosion, unconformities developed between sedimentary units (Bluemle 1971).

Marine deposition dominated during the Mesozoic from Middle to Late Jurassic until a transition to non-marine deposition that continued until the Early Cretaceous. The Early Cretaceous marked a return to marine deposition as thick sequences of fine-grained clastics accumulated. The Late Cretaceous into the Paleocene was characterized by non-marine deposition with a period of marine deposition in the Paleocene followed by a return to non-marine deposition (Bluemle 1971).

Since the mid-Pliocene and continuing through the Pleistocene, North Dakota experienced a continental climate with a succession of ice sheets advancing south from Canada (Bluemle 2000).

3.1.2 Regional Physiography

The landscape of North Dakota can be split into two physiographic provinces: 1) the Great Plains, which covers much of southwestern North Dakota, and 2) the Central Lowlands, covering the north and eastern parts of the state. The effect of glacial activity on the modern landscape is the primary difference between the two provinces. The Central Lowlands have been shaped completely by glacial deposition, but little evidence of glacial activity is visible in the Great Plains, which extend westward to the Rocky Mountains (Bluemle 2000). The Central Lowlands are characterized by an intricate but low relief hill and valley topography. Drainage in the glaciated Central Lowlands ranges from non-existent to well-developed. Local relief (i.e., maximum difference in elevation within a township-sized area) in the Central Lowlands ranges from less than 100 feet to 300 feet, except in the hummocky Turtle Mountains and Prairie Coteau. The Great Plains were shaped primarily by bedrock erosion via fluvial and eolian processes, resulting in irregular surface structure that ranges from gently sloping to rugged hills. Local relief of the Great Plains province generally ranges from 300 feet to 500 feet, except for the Little Missouri Badlands, where local relief regularly exceeds 500 feet (Bluemle 2000).

The Williston Basin, which extends through all of western and approximately half of eastern North Dakota, is overlain by both the Central Lowlands and Great Plains provinces in North Dakota. The proposed injection site is in the southeastern portion of the Williston Basin and falls within the Central Lowlands province of North Dakota. Both the Great Plains and the Central Lowlands provinces can be subdivided into several distinct sub-physiographic regions (Bluemle 2000); those present in Oliver County are described in Section 3.2.1.

3.1.3 Structural Geology

The Williston Basin is generally characterized as a sag or depression and as tectonically benign; its configuration was most likely formed by structural deformation and down-to-the-basin block faulting in Precambrian-rooted structures. Additionally, deformation related to the Trans-Hudson orogenic belt played a role in the development of the basin (Anna et al. 2013). The Trans-Hudson orogenic belt sutured the Archean Superior craton to the Archean Wyoming craton and the resulting collision created a north–south trending strike-slip fault and shear belt. The basin center was created and impacted by later folding of the Trans-Hudson belt and possible rifting. Multiple Precambrian fault zones within the Williston Basin were reactivated during the Neoproterozoic to create new north–south and northwest–southeast-oriented structures. These reactivated fault zones acted as precursors to structures and zones of weakness that formed the Nesson, Cedar Creek, Little Knife, and Billings anticlines; the

Bismarck-Williston lineament; and Goose Lake trend along with many small-scale structures that are pervasive throughout the Williston Basin (Figure 3-3) (Anna et al. 2013).

Lithofacies distribution and thickness patterns reflect the influence of paleostructure on sedimentation in the Williston Basin. Recurrent movement of basement grabens, half-grabens, and horsts is expressed by patterns of faults, fractures, and folds. Drape folds were commonly created in overlying sedimentary rocks. Wrench or strike-slip faults occur as simple shears and are typically associated with folds, thrust faults, and reverse faults, while scissor-type faults are also common. Folds, thrust faults, and reverse faults are associated with Laramide features. Basement faults have less effect on sedimentation distribution as the rock section thickens, and the observed distribution and thickness of sediments stems from recurrent movement of Precambrian blocks, eustatic changes in sea level, and from quantity and quality of available sediments (Anna et al. 2013).

The present structural configuration of the basin was shaped in the Late Cretaceous (Bluemle 2000), and the regional dip of Cenozoic deposits is to the north and west (Carlson 1973).

3.1.4 Regional Stratigraphy

The Williston Basin represents a portion of the North American craton where the sedimentation history can be generally characterized as carbonate deposition during the Paleozoic and clastic deposition during the Mesozoic and Cenozoic, and where thickness of Phanerozoic strata is more than 16,000 feet in the basin center (Anna et al. 2013). Six major depositional sequences, each bound by major unconformities, are distinguished within Phanerozoic rocks of North America. As presented in the North Dakota Stratigraphic Column (Figure 3-2), from oldest to youngest, these sequences are the Sauk, Tippecanoe, Kaskaskia, Absaroka, Zuni, and Tejas (Anna et al. 2013). Within these major depositional sequences are allocyclic successions that are caused by variations external to the basin such as climate change and tectonic movements. First order cycles are likely caused by major eustatic cycles driven by the formation and breakup of supercontinents with durations of approximately 200 to 400 million years (m.y.). Second order cycles are caused by eustatic cycles induced by volume changes in global midocean spreading ridge systems with a duration of approximately 10 to 100 m.y. Third order cycles are possibly produced by spreading ridge changes and continental ice growth and decay that last for approximately 1 to 10 m.y. Fourth and fifth order cycles each are attributed to Milankovitch glacioeustatic cycles, while the duration of fourth order cycles is approximately 0.2 to 0.5 m.y. and the duration of fifth order cycles is approximately 0.01 to 0.2 m.y. (Boggs 2012).The major sequences that consist of first order and second order cycles within the Williston Basin are likely the result of eustatic sea level change, while third and fourth order cycles are possibly the result of tectonic activity or a combination of tectonic activity and eustacy. Substantial depositional environment and sedimentation changes were possible in response to changes in water depth because water depths during the Phanerozoic were relatively shallow (Anna et al. 2013). Paleozoic rocks range in thickness from 4,500 feet in southeastern Oliver County to approximately 7,500 feet in northwestern Mercer County. The Paleozoic stratigraphy is represented by the Sauk, Tippecanoe, Kaskaskia, and Absaroka Sequences. The Absaroka Sequence extends into the Triassic rocks of the Mesozoic. Mesozoic rocks range in thickness from approximately 3,900 feet in southeastern Oliver County to approximately 4,600 feet in northwestern Mercer County. The Mesozoic rocks fall within the Zuni Sequence. The Cenozoic rocks are represented by the Zuni and Tejas Sequences, and range in thickness from approximately 250 feet in southeastern Oliver County to approximately 1,350 feet in northwestern Mercer County (Carlson 1973).

3.1.4.1 Basement Rock

The Precambrian rocks, which are the deepest rock layers in the earth's crust, are metamorphic, having transformed over geologic time from sediments that settled in a marine environment. As a result of intense heat and pressure, these sediments were transformed into gneiss and marble alongside intrusive granite (Anna et al. 2013). The geology of the Precambrian rocks underlying the Williston Basin is complex, consisting of many juxtaposed, fault-bounded lithostructural domains (Peterman and Goldich 1982). Little is known with certainty about the Precambrian basement rock due to the depth and very few wells drilled into this sequence. The Precambrian basement rock is encountered at approximately 9,725 ft bgs at MRY, based on logging of drill cuttings and electric logs collected from J-ROC1 (J-ROC1 Well File).

3.1.4.2 Sauk Sequence

The Deadwood Formation represents the Sauk Sequence in Oliver County, and consists of approximately 295 feet of limestone, shale, and sandstone. The formation thickens to approximately 500 feet to the west in Mercer County (Carlson 1973). The Deadwood Formation represents the first order transgression over a low-relief Precambrian surface, while some major structural features impacted thickness patterns, such as the Nesson anticline. Weathered Precambrian rocks served as the sediment source for the Deadwood Formation, and the sediment was eroded from highlands to the east or from the Transcontinental arch to the southeast (Anna et al. 2013). Sandstones and shales are the dominant lithologies in North Dakota, resulting from siliciclastic sedimentation (NDGS 2000). The Sauk Sequence is anticipated to be encountered at approximately 9,285 ft bgs (top of Deadwood Formation) at MRY, based on logging of drill cuttings and electric logs collected from J-ROC1 (J-ROC1 Well File).

3.1.4.3 Tippecanoe Sequence

The thickness of Tippecanoe Sequence rocks ranges from approximately 1,360 feet in eastern Oliver County to approximately 1,820 feet in Mercer County (Carlson 1973). The early Tippecanoe Sequence is represented by the Winnipeg Group, and this package consists of the Black Island, Icebox, and Roughlock Formations (NDGS 2020). The Bighorn Group conformably overlies the Winnipeg Group. The Red River Formation is the basal unit of the Bighorn Group, and the Red River Formation is overlain by the Stony Mountain and Stonewall Formations. The Winnipeg Group unconformably overlies the Deadwood Formation except in the eastern portion of the basin where it overlies Precambrian basement. The latest deposition of the Tippecanoe Sequence resulted in the Interlake Formation, which conformably overlies the Stonewall Formation (NDGS 2020). The Red River, Stony Mountain, and Interlake Formations represent conformable sedimentation, but Tippecanoe deposition ended at the end of the Silurian by a major regression leading to significant erosion. Especially around the basin margin, parts of the Interlake Group, Stony Mountain, Stonewall, and Red River Formations were removed via erosion (Anna et al. 2013). The Tippecanoe Sequence is situated approximately 7,885 ft bgs (top of Interlake Formation) at MRY, using logging of drill cuttings and electric logs collected from J-ROC1 (J-ROC1 Well File).

3.1.4.4 Kaskaskia Sequence

The Kaskaskia Sequence rocks are approximately 2,250 feet thick in eastern Oliver County and approximately 3,400 feet thick to the west in Mercer County (Carlson 1973). The sequence began with a transgressive event in the Early Devonian and concluded with a major regression at the end of the Mississippian, and uplift of the Transcontinental arch resulted in the basin configuration shifting from circular in northwestern North Dakota to a northwest–southeast-trending elongated shelf basin. The Williston Basin became the southeastern corner of the newly formed Devonian Elk Point Basin (Anna et al. 2013). Within the greater Elk Point Basin, numerous cycles of sea level change resulted in diverse lithologies being deposited as part of the Elk Point Group, and the first transgression deposited the Ashern and Winnipegosis Formations followed by the regression-related Prairie Formation. The next transgression deposited the Manitoba Group consisting of the Dawson Bay Formation and overlying Souris River Formation (Anna et al. 2013; NDGS 2020). The Jefferson Group conformably overlies the

Souris River Formation, and is composed of the Duperow, Birdbear, and Three Forks Formations that were deposited as sea level regressed. A third major transgression in the Late Devonian resulted in the deposition of the Bakken Formation, which conformably overlies the Three Forks Formation in the basin center and unconformably overlies it elsewhere (Anna et al. 2013; NDGS 2020). During the Early Mississippian there was a shift from the northwest–southeast elongated Elk Point Basin back to a circular basin configuration, and the depocenter was reestablished in northwestern North Dakota. Following this structural change, the Madison Group was deposited within a renewed cycle of transgressions and regressions (Anna et al. 2013). Regressing sea levels led to the deposition of the Madison Group, which consists of the Lodgepole, Mission Canyon, and Charles Formations. The Madison Group formations are conformable in the basin center but exhibit complex intertonguing relationships along the basin margins (NDGS 2020). The Big Snowy Group, recorded by the Kibbey and Otter Formations, overlies the Madison Group and records influences of the Ancestral Rocky Mountain orogeny. The top of the Big Snowy Group represents a major regression (Anna et al. 2013; NDGS 2020). Based on logging of drill cuttings and electric logs collected from J-ROC1, the Kaskaskia Sequence is approximately 5,315 ft bgs (top of the Big Snowy Group) at MRY (J-ROC1 Well File).

3.1.4.5 Absaroka Sequence

The Absaroka Sequence rocks are approximately 550 feet thick in eastern Oliver County and approximately 1,130 feet thick in Mercer County (Carlson 1973). The sequence represents the upper part of a first order regression and includes several secondary transgressive and regressive cycles within a relatively shallow sea. The initial second order transgression was brought on by uplift of areas to the east, west, and south that became major sources of clastic sediment deposited into the Williston Basin. This transgressive sequence includes interbedded sandstone, siltstone, shale, and limestone of the Pennsylvanian Tyler Formation and equivalents (Anna et al. 2013). The Minnelusa Formation overlies the Tyler Formation and records sedimentation from the Ancestral Rocky Mountains and Transcontinental arch. Regression continued and major unconformities occur near the end of the Pennsylvanian, and the end of the Permian and Triassic. The Minnekahta Formation overlies the Minnelusa Formation (Anna et al. 2013). The Spearfish Formation overlies the Minnekahta Formation and unconformably overlies the Madison Group across much of eastern North Dakota (NDGS 2020). The Absaroka Sequence is located approximately 4,660 ft bgs (top of Spearfish Formation) at MRY, based on logging of drill cuttings and electric logs collected from J-ROC1 (J-ROC1 Well File).

3.1.4.6 Zuni Sequence

The Zuni Sequence rocks range in thickness from approximately 3,270 feet in eastern Oliver County to approximately 4,300 feet in Mercer County (Carlson 1973). The lithologic package contains three major chronostratigraphic units bounded by unconformities: Middle and Upper Jurassic, Lower Cretaceous, and Upper Cretaceous and Tertiary through Paleocene (Anna et al. 2013). Cretaceous rocks include well-developed sandstones in the Fall River-Lakota, also called the Inyan Kara interval, and poorly developed sandstone in the Newcastle Formation. The Cretaceous rocks below the Fox Hills Formation consist of gray and calcareous shales with thin bentonites; they include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations. The Fox Hills Formation conformably overlies the Pierre Formation (Bluemle 1973).

3.1.4.7 Tejas Sequence

The Tejas Sequence consists of silt, clay, sand, sandy loam, and gravel in Oliver County (Carlson 1973). The Tejas Sequence represents the final first order regression in the sedimentary record of the Williston Basin, and the system is composed of three regional transgression–regression cycles with strata ranging in age from mid-Paleocene through the Quaternary (Anna et al. 2013).

3.2 Local Geology

Within Section 3.2.1, the term "local" refers to Oliver County. The definition of "local" changes after Section 3.2.1 to describe the area within an approximately 40-mile radius of the proposed injection site.

3.2.1 Local Physiography

Oliver County is located within the Missouri Slope District of the Glaciated Missouri Plateau Section of the Central Lowland Province. Pleistocene and Recent deposits are found north of Square Butte Creek in Oliver County. South of this area, glacial deposits are patchy or absent on the uplands but are relatively thick in the Knife River valley. Since the glaciers retreated, Late Pleistocene to Recent slopewash from the valley walls has accumulated in lowland areas (Croft 1973).

3.2.2 Structural Geology

The structural geology within a 40-mile radius of the proposed injection site is generally shaped by the structure of the Williston Basin. Formation top data from the NDIC Oil and Gas Division were used to develop lithostratigraphic unit top elevation figures for the formations of interest, which includes the tops of the Pierre Shale (Figure 3-4), Mowry Formation (Figure 3-5), Inyan Kara Formation (Figure 3-6), Swift Formation (Figure 3-7), and Rierdon Formation (Figure 3-8). For simplicity, lithostratigraphic unit top elevation figures were not created for the shale formations of the Colorado Group (Niobrara, Carlile, Greenhorn, and Belle Fourche) or the Newcastle and Skull Creek Formations. Using the formation top data, these contours were developed by averaging the results of the inverse distances weighted interpolation and the Kriging method (linear semivariogram method).

Two geologic cross sections were created using the lithostratigraphic unit top elevation figures (Figures 3-4 to 3-8) to evaluate the general stratigraphic framework in the vicinity of MRY. Cross section A-A' has a northwest–southeast alignment (Figure 3-9) and cross section B-B' has a southwest–northeast alignment (Figure 3-10). The Inyan Kara Formation is approximately 170 to 200 feet thick in the vicinity of MRY. The structural tops depicted in these figures generally parallel each other, maintaining relatively consistent thicknesses within the 40-mile radius.

Cross section A-A' (Figure 3-9) depicts an irregular ground surface with small local variations in elevations (less than 500 feet) that generally slopes gently to the east and a relatively flat Missouri River valley. The tops of the Pierre Shale, Mowry Formation, Inyan Kara Formation, Swift Formation, and Rierdon Formation generally dip to the northwest, with deeper strata dipping the most steeply, most notably for the Swift and Rierdon Formations.

Cross section B-B' (Figure 3-10) depicts the Missouri River valley north of MRY and more irregular ground surface with relief of up to approximately 300 feet south of the Missouri River valley. North of MRY, ground topography is less variable with gentle slopes toward the Missouri River. The structural dips at MRY are generally sub-horizontal with a low-degree southern dip emerging below the top of the Mowry Formation approximately 10 miles north of MRY.

3.2.3 Injection Interval Stratigraphy

The following sections describe the proposed injection interval and surrounding units as present in Oliver County. Emphasis is placed on the bounding confining units.

3.2.3.1 Injection Interval – Inyan Kara Formation of the Lower Dakota Group

Within the Cretaceous System, the Dakota Group consists of, in ascending order, the Inyan Kara (also called the Fall River-Lakota), Skull Creek, Newcastle, and Mowry Formations (Butler 1984). Another definition of the Inyan Kara Group includes the locally recognized Fuson Shale Formation between the older Lakota Sandstone and the younger Fall River Sandstone (Buursink et al. 2014). The Inyan Kara Formation is primarily sandstone in the south-central, southeast, north-central, and northeast portions of North Dakota. In North Dakota, the water-bearing sandstones of the Inyan Kara Group, including other sandstones of the Dakota Group, form the Dakota aquifer. The Dakota aquifer is the shallowest aquifer with state-wide extent (Wartman 1984). The J-ROC1 well drilled at MRY encountered the Inyan Kara Formation at approximately 3,669 ft bgs. The transition from the overlying Skull Creek Formation to the Inyan Kara Formation at J-ROC1, J-LOC1, and BNI-1 were similar, with mud-dominated flaser bedding giving way to sand-dominated lenticular bedding with very fine grained, quartzose sandstone interbeds (J-ROC1, J-LOC1, and BNI-1 Well Files). The main sandstone interval of the Inyan Kara Formation is described as exhibiting large intervals of apparently moderate to good permeability, fine grained, well rounded, quartzose sandstone. The lower portions of the Inyan Kara Formation show increasing interbedding of sand-rich dark gray shale with increasingly significant portions of pyrite and organic rich clasts. Intervals of light to medium gray-green siltstones and very fine-grained sandstones with large zones of oxidation and reduction with chlorite cement constitute the lowermost Inyan Kara Formation (J-ROC1, J-LOC1, and BNI-1 Well Files).

The Inyan Kara Formation is the target interval for injection of non-hazardous wastewater at MRY. Northwest–southeast and northeast–southwest cross sections through MRY show the Inyan Kara is approximately 170 to 200 feet thick beneath MRY (Figures 3-9 and 3-10).

The Inyan Kara Formation is a favorable injection interval for the following reasons:

- The sandstone lenses in the Inyan Kara Formation have high permeability and porosity and do not typically require stimulation prior to injection.
- The Inyan Kara Formation is confined by thick and impermeable shales above by the Cretaceous confining units and below by the Jurassic confining units.

Because of these excellent properties, the Inyan Kara Formation is commonly used for wastewater injection in North Dakota. As described in Section 1.2.4, the proposed injection interval in the Inyan Kara Formation at MRY is anticipated between 3,667 and 3,838 ft bgs and is subject to change based on observed conditions during drilling of the Class I injection well(s).

3.2.3.2 Underlying and Overlying Confining Units

Underlying the target injection interval (Inyan Kara Group) in order of oldest to youngest, are the Piper, Rierdon, and Swift Formations. The Piper Formation is characterized by limestone, anhydrite, salt, and red shale. The Rierdon and Swift Formations are dominated by shale and sandstone (Carlson 1973). The upper units of the Dakota Group overlie the Inyan Kara Group, and in order of oldest to youngest are the Skull Creek, Newcastle, and Mowry Formations. The Skull Creek and Mowry Formations are dominated by shale, while the Newcastle Formation consists of sandstone. Overlying the Mowry Formation are thick shale units of the Colorado and Montana Groups, including the Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Carlson 1973). The Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations are considered the upper seal on the Inyan Kara Formation, isolating the proposed injection interval from the lowest USDW, the Fox Hills Sandstone. The Rierdon and Swift Formations serve as the lower seal, isolating the proposed injection interval from the underlying Pennsylvanian aquifer (Minnelusa Group) (Buursink et al. 2014). These units underlying and overlying the Inyan Kara Group serve as confining layers that can vertically contain injected fluids within the Inyan Kara Formation (Nesheim et al. 2016).

3.2.3.2.1 Underlying Confining Unit

The Jurassic confining unit, which underlies the Inyan Kara Formation, is composed of the Swift Formation and the Rierdon Formation. In North Dakota, the Swift Formation consists of varicolored shales; geophysical logs indicate that the Swift Formation is more shale-prone than in other regions. Near MRY, the Swift Formation is composed of approximately 400 to 500 feet (Figure 3-9 and 3-10) of shale with few sandstone interbeds. The Rierdon Formation consists of shale, anhydrite, limestone, salt, and sandstone. The Jurassic confining unit serves as an effective lower seal for the proposed injection interval (Buursink et al. 2014).

3.2.3.2.2 Overlying Confining Unit

The Cretaceous confining units, composed of a thick, impermeable group of shales, overlies the Inyan Kara Formation and effectively isolates it from the lowermost USDW, the Fox Hills Sandstone. The Cretaceous confining unit is composed of the Pierre Shale, Niobrara Formation, Carlile Formation, Greenhorn Formation, Belle Fourche Formation, and Mowry Formation (listed in descending order).

The Pierre Shale is a regionally extensive, thick unit of late-Cretaceous-aged marine shales that can exceed 3,000 feet of thickness in some areas of the northern Great Plains. Shale units underlying the Pierre Shale Formation also act as effective confining units, particularly as part of the larger group of formations composing the Cretaceous confining unit (Downey and Dinwiddie 1988). Underlying the Pierre Shale are the Niobrara (gray marine, calcareous shale), Carlile (gray marine shale with interbeds of thin sandstone), Greenhorn, Belle Fourche, and Mowry Formations. The Greenhorn Formation is a sandstone sequence with interbedded chalky shale, grey to black marine shale, and numerous bentonite beds. The Mowry Formation consists of a medium to dark gray shale with traces of bluish gray bentonitic claystone. Previous aquifer studies, most notably the USGS Regional Aquifer Systems Analysis (RASA) and the USGS Hydrologic Investigations Atlas, have grouped these units together as the uppermost bedrock confining unit in the Williston Basin region (Downey and Dinwiddie 1988; Whitehead 1996). The Cretaceous confining unit has an estimated thickness of 2,500 feet at MRY (Figures 3-9 and 3-10, J-ROC1 Well File) and serves as an effective upper seal for the proposed injection interval.

3.3 Groundwater

3.3.1 Regional Groundwater

North Dakota's groundwater resources are supplied by the Northern Great Plains regional aquifer system and various shallower local aquifers. The five bedrock aquifers present in North Dakota are described in the following sections. A conceptual depiction of the lateral and vertical extents of the bedrock aquifers in North Dakota is shown in Figure 3-11. A cross section depicting regional groundwater flow in North Dakota is provided in Figure 3-12.

3.3.1.1 Lower Tertiary Aquifer

Most of the water in the Lower Tertiary aquifer is stored in and transported through semi-consolidated to consolidated sandstone beds of the Fort Union Group. The thickness of the Fort Union Group is highly variable, ranging from 300 feet in northeastern Montana and northwestern North Dakota to 3,600 feet in the Powder River Basin. However, the thickness of the permeable layers within the Fort Union Group is much less than the total thickness of the unit. On a regional scale, groundwater in the Lower Tertiary aquifer generally flows northeastward from recharge areas at higher altitudes in eastern Montana, northeastern Wyoming, and southwestern North Dakota through the Williston Basin. The potentiometric surface of this aquifer generally parallels the surface topography due to its regionally unconfined condition. Large rivers in the region are discharge areas for the Lower Tertiary aquifer, resulting in potentiometric low points that follow the course of the rivers (Whitehead 1996). The potentiometric surface of the Lower Tertiary aquifer is shown in Figure 3-13.

3.3.1.2 Upper Cretaceous Aquifer

In the Williston Basin, the most significant water-yielding layers of the Upper Cretaceous aquifer are the sandstone beds of the Hell Creek Formation and the Fox Hills Sandstone Formation. Composed of interbedded sandstone, siltstone, claystone, and thin, localized beds of lignite, the Hell Creek Formation varies from 350 to 3,400 feet in thickness within the basin. The Fox Hills Sandstone is one of the most continuous water yielding formations within the aquifer system and is 300 to 450 feet thick. Regional groundwater flow patterns in the Upper Cretaceous aquifer closely resemble that of the overlying Lower Tertiary aquifer, with flow northeastward from high altitude recharge areas in eastern Montana and northeastern Wyoming and discharging into major rivers of the region (Figure 3-14). The Upper Cretaceous aquifer is confined in Wyoming and central Montana and unconfined in most of the Williston Basin (western North Dakota and northwestern South Dakota). Because of their connection with surface water resources, the Lower Tertiary and Upper Cretaceous aquifers are characterized by local flow systems with short flow paths. The Upper Cretaceous aquifer generally contains water with TDS concentrations less than 3,000 mg/L, with areas of less than 1,000 mg/L near the Black Hills Uplift and at the boundaries of the aquifer. Small, localized areas in North Dakota and South Dakota have dissolved solids concentrations as high as 10,000 mg/L. The dominant ions dissolved in water of the Upper Cretaceous aquifer are sodium, sulfate, and bicarbonate, and generally high sodium concentrations make the water unsuitable for irrigation. The Upper Cretaceous aquifer is a domestic and livestock watering supply for much of the region (Whitehead 1996).

3.3.1.3 Lower Cretaceous Aquifer

Several thick shale layers overlying the Lower Cretaceous aquifer separate it from the Upper Cretaceous aquifer and act as a confining unit. The Lower Cretaceous aquifer is composed of the following principal water-yielding units within the Williston Basin: The Fall River Sandstone and the Lakota Formation, collectively referred to as the Inyan Kara Formation, in addition to the Newcastle Sandstone. While the Newcastle Sandstone is more than 400 feet thick in southeastern South Dakota, it is mostly absent throughout North Dakota. The Inyan Kara Group is 700 feet thick in central Montana but thins eastward into the Dakotas. On a regional scale, groundwater flows northeastward from high altitude and structural uplift recharge areas in central Montana and northeast Wyoming to discharge areas in eastern North Dakota and South Dakota (Figure 3-15). Most of the aquifer is overlain by a thick confining unit that tends to isolate the aquifer from other systems, except in localized zones of recharge (central Montana and northeast Wyoming) and discharge (eastern North Dakota and South Dakota). In the Lower Cretaceous aquifer, freshwater (TDS concentrations less than 1,000 mg/L) is only present near the Bighorn Mountains and the Black Hills Uplift recharge areas. Throughout most of the remainder of the aquifer, the TDS concentrations are greater than 3,000 mg/L; much of the slightly saline water is hypothesized to result from upward leakage of highly mineralized water from underlying Paleozoic aquifers. The Lower Cretaceous aquifer is the primary source for livestock watering and domestic supply in eastern North Dakota because it is the shallowest bedrock aquifer in that area. In the deep parts of the Williston Basin, the water in this aquifer is classified as very saline or brine (Whitehead 1996).

Wells completed in the Inyan Kara Formation could be considered possible receptors of injectate from the proposed injection site. Based on the NDSWC database, the nearest downgradient water supply well extracting water from the Dakota Group (Inyan Kara Formation) is located approximately 75 miles northeast of MRY in the northwest corner of Wells County (NDSWC Well Index 11697). This well is classified as a domestic water well. Additional downgradient water supply wells completed in the Dakota Group are more than 100 miles from MRY.

3.3.1.4 Pennsylvanian Aquifer

Underlying the Lower Cretaceous aquifer are confining units composed of shales, limestones, and siltstones of Jurassic, Triassic, and Permian ages. Below that, the interbedded shale, sandstone, and carbonate of Pennsylvanian age makes up the Pennsylvanian aquifer. Water-bearing sandstone units are found in the Tensleep Formation in central to north-central Wyoming and in south-central Montana. In western North Dakota and along the eastern edge of the Williston Basin, analogous units are found in the middle of the Minnelusa Formation. Additionally, interbedded sandstone layers are prevalent in the upper part of the Minnelusa Formation in the Powder River Basin, the Williston Basin, and in western North Dakota. Regionally, groundwater flows northeastward from recharge zones in Wyoming, Montana, and South Dakota, before flowing southeastward in western North Dakota, and finally discharging by upward leakage to the Lower Cretaceous aquifers in central North and South Dakota (Figure 3-16). Freshwater is found in the Pennsylvanian aquifer only near the Bighorn Mountains, Little Belt Mountains, and Black Hills Uplift recharge areas. Downgradient of recharge zones, water progresses from brackish to briny, with TDS concentrations upward of 100,000 mg/L in parts of the Williston Basin and the Powder River Basin (Downey 1986). The Minnelusa Formation is not used as a water supply source in North Dakota due to its water quality and depth. Although the Pennsylvanian system falls within the Paleozoic era, and should therefore be considered an Upper Paleozoic aquifer, it is classified as a confining unit in the Groundwater Atlas (Whitehead 1996). The 1986 RASA study considered the Pennsylvanian aquifer an important source of water in the Northern Great Plains; therefore, in this permit application, it is considered as a regional aquifer. However, as Whitehead (1996) does not include the Pennsylvanian aquifer in his Upper Paleozoic aquifer system, it is considered distinct from the Upper Paleozoic aquifer.

3.3.1.5 Upper Paleozoic Aquifer

The next principal aquifer is the Upper Paleozoic aquifer, which is isolated from the Pennsylvanian aquifer by the interbedded shales, sandstones, and limestones of the Big Snowy Group. The Upper Paleozoic aquifer, as defined by Whitehead (1996), consists primarily of the Madison Group. From youngest to oldest, the Madison Group is composed of the Charles Formation, the Mission Canyon Limestone, and the Lodgepole Limestone. The Charles Formation, consisting mostly of evaporite deposits, is a confining unit, while the Mission Canyon and Lodgepole consist of limestone and dolomite beds. The Madison Group ranges in thickness from greater than 2,800 feet in western North Dakota to almost non-existent at its eastern limits. Karst topography has been observed in areas where the Madison Group outcrops. Karst topography occurs where circulating groundwater has dissolved minerals from the carbonate rocks, potentially producing large openings in the rock that can become interconnected to form cave systems. As with the other principal aquifers in the region, water in the Upper Paleozoic aquifer moves regionally northeastward from areas of recharge near the western and southern extents of the aquifer system (Figure 3-17). Water discharges from the aquifer by upward leakage to the Pennsylvanian and Lower Cretaceous aquifers in eastern North Dakota and central South Dakota. Freshwater is present in the Upper Paleozoic aquifer only in areas of recharge near the Bighorn Mountains and Black Hills outcrops. Downgradient of the recharge areas, the water quickly becomes saline and then briny, with TDS concentrations greater than 300,000 mg/L in the deep parts of the Williston Basin in western North Dakota (Whitehead 1996).

3.3.2 Local Groundwater

Important aquifers within Oliver County occur in the Fox Hills, Hell Creek, and Tongue River Formations. Wells that access these aquifers typically yield less than 150 gpm, and the water is likely not suitable for irrigation due to high sodium content. The largest yield and best quality water are obtained from the relatively undeveloped glacial drift and alluvial aquifers. The glacial drift and alluvial aquifers are generally one to five miles wide with maximum thicknesses of approximately 250 feet (Croft 1973).

3.3.2.1 Quaternary Glacial Drift and Alluvial Aquifers

Glacial drift and alluvial aquifers in Oliver County include the Missouri River aquifer and Square Butte Creek aquifer. The Missouri River aquifer underlies the terraces and floodplains of the Missouri River valley across eastern Oliver County, and it consists of coarse glaciofluvial and alluvial deposits. The majority of permitted wells screened in the Missouri River aquifer within Oliver County are intended for irrigation, while one permitted well is intended for stock. Water quality samples collected from observation wells screened in the Missouri River aquifer show TDS concentrations ranging from approximately 610 to 1,520 mg/L, conductivity ranging from approximately 980 microsiemens per centimeter (µS/cm) to 2,410 µS/cm, and pH measurements between 7.3 and 8.2 standard units (s.u.). The Square Butte Creek aquifer extends from Mercer County to the southeast corner of Oliver County. This aquifer is as much as 130 feet thick and consists of glaciofluvial and alluvial deposits (Croft 1973). There are no permitted water wells within the Square Butte Creek aquifer according to the North Dakota State Water Commission Ground/Surface Water Database.

3.3.2.2 Undifferentiated Lignite Aquifers in the Tongue River and Sentinel Butte Formations

Livestock and domestic wells in rural areas often screen fractures and joints in the undifferentiated beds of lignite for water supplies. The water quality of these aquifers is highly variable and typically contain 1,050 to 1,810 mg/L TDS based on water samples collected (Croft 1973).

3.3.2.3 Lower Tongue River Aquifer

The lower Tongue River aquifer is found in the lower part of the Tongue River Formation that underlies most of Oliver County. The lower Tongue River Formation is a fine- to medium-grained sandstone, and the aquifer is less than 150 feet thick. Siltstone and claystone separate the lower Tongue River aquifer from the upper Hell Creek and lower Cannonball-Ludlow aquifer. The sandstone of the lower Tongue River aquifer has a low hydraulic conductivity and is interbedded with siltstone and claystone (Croft 1973). Groundwater flows to the north-northeast with a hydraulic gradient of about 10 feet per mile. Differences in head indicate that groundwater is flowing vertically downward from the lower Tongue River aquifer into the upper Hell Creek and lower Cannonball-Ludlow aquifer. The groundwater is a sodium bicarbonate type with 1,440 to 1,700 mg/L TDS beneath Oliver County. The groundwater is suitable for livestock and domestic use but would not be suitable for irrigation due to a high sodium adsorption ratio (Croft 1973).

3.3.2.4 Upper Hell Creek and Lower Cannonball-Ludlow Aquifer

The upper Hell Creek and lower Cannonball-Ludlow aquifer is approximately 70 to 150 feet thick and underlies all of Oliver County. This aquifer is composed of fine- to medium-grained sandstone in the upper part of the Hell Creek Formation with fine-grained sandstone at the base of the Cannonball and Ludlow Formations, and contains some interbedded siltstone and claystone. Siltstone and claystone beds separate the aquifer from the Fox Hills and basal Hell Creek aquifer. Transmissivity ranges from 180 to 4,200 gallons per day per foot. Wells that screen this aquifer typically yield flows of approximately 5 to 100 gpm (Croft 1973). Groundwater generally flows from west to east, and head differences indicate that water is moving vertically upward from the Fox Hills and basal Hell Creek aquifer to the upper Hell Creek and lower Cannonball-Ludlow aquifer. The groundwater is a sodium bicarbonate type and contains approximately 1,510 to 1,890 mg/L TDS. The groundwater is suitable for livestock and domestic purposes, but likely not suitable for irrigation because it has a high sodium adsorption ratio (Croft 1973).

3.3.2.5 Fox Hills and Basal Hell Creek Aquifer

Extensive sandstone beds in the upper part of the Fox Hills and the lower part of the Hell Creek Formations form a major aquifer that underlies all of Oliver County. The sandstone is fine- to medium-grained with interbedded siltstone and has a low hydraulic conductivity. The aquifer is approximately 150 to 370 feet thick. Hundreds of wells in North Dakota are drilled as deep as 1,515 feet in this aquifer and supply municipal, domestic, and livestock water needs. Within Oliver County, one stock well and one observation well are completed in the Fox Hills (NDSWC n.d.). Groundwater within this aquifer generally flows from west to east, and the hydraulic gradient is approximately 3.5 feet per mile (Croft 1973). The groundwater is a sodium bicarbonate type and generally contains 1,230 to 1,990 mg/L TDS. The water is suited for livestock and most domestic needs but is not suitable for irrigation due to a high sodium adsorption ratio (Croft 1973). The Fox Hills and Basal Hell Creek aquifer represents the deepest source of drinking water in Oliver County.

3.3.3 Lowermost Underground Source of Drinking Water

As outlined in the Code of Federal Regulations 40 CFR § 144.3 (USEPA n.d.), a USDW is defined as an aquifer or its portion that supplies a public water system or contains a sufficient quantity of groundwater to supply a public water system and currently supplies drinking water for human consumption or contains fewer than 10,000 mg/L of TDS.

As described previously, the Fox Hills Formation, within the Upper Cretaceous Aquifer, contains the lowest potential USDW in Williams County, based on its estimated water quality and relatively shallow depth. The base of the Fox Hills Formation is estimated to be approximately 1,160 ft bgs at MRY based on geologic logs from J-ROC1, while the top is estimated to be approximately 900 ft bgs. The bottom of the Fox Hills Formation and the top of the Inyan Kara Formation are separated by approximately 2,500 feet of strata consisting of significant shale-dominated formations. North Dakota State Water Commission Well Index 9442 records a TDS concentration of 1,670 mg/L, conductivity of approximately 2,800 µS/cm, and a pH of 8.6 s.u. The TDS concentrations of water within the deeper aquifers in the area are too high to be considered USDWs.

4.0 FLOW AND TRANSPORT MODELING

4.1 Overview

Injection of wastewater into the Inyan Kara Formation requires forcing fluids through the wellbore at a pressure that exceeds the injection interval pore pressure to allow fluids to flow radially away from the wellbore without propagating fractures in the injection interval or confining formations. The expected changes in pressure within the formation as a result of injection is evaluated to understand the necessary wellbore pressure required to force injected wastewater radially away from the wellbore at the desired flow rate. The pressure increase within the formation decreases in magnitude with radial distance from the wellbore. If not properly evaluated and controlled, pressure increases within the injection interval can result in failure of nearby plugged and abandoned wells, fracture of the injection interval or adjacent confining units, or vertical migration of injected fluids through adjacent confining units, all of which can put the lowest USDW at risk. Analytical calculations and groundwater flow models are useful tools for estimating the pressure effects of injection into aquifers with specific hydrological properties.

The direction and movement of injected fluid within a confined aquifer must be understood in order to predict the potential impact to downgradient receptors. To assess the extent of potential impacts, it is important to understand how far and how quickly constituents will travel within the aquifer. A conservative estimate assumes that potential constituents of concern will travel at the same velocity as water particles; this allows particle tracking to serve as an effective tool to assess injection fluid movement. Transient particle tracking codes consider the formation porosity and the head distribution at a given time step to calculate water particle velocity and, therefore, particle travel distance during that time step and for the duration of the simulation.

At the proposed injection site at MRY, the total thickness of the sandstone intervals of the Inyan Kara Formation is approximately 90 feet (Section 4.3.1.1). The upper portion of the Inyan Kara Formation is composed of large intervals of moderate to good permeability, light gray, quartzose, fine-grained to coarse-grained sandstone interbedded with gray, silty, and lumpy shale. The lower portion is characterized by increased interbedding of sand-rich dark gray shale with intervals of light to medium gray-green siltstones and very fine-grained sandstones (J-LOC1 Well File).

4.2 Modeling Approaches

The formation pressure response to wastewater injection with respect to time and radial distance from the wellbore was calculated using the line source solution of the diffusivity equation for the flow of a single-phase fluid in a porous medium (Matthews and Russel 1967). The results of this evaluation were then compared to results from a subsequent evaluation using the software AquiferWin32 (by Environmental Simulations Inc.) to confirm agreement between the two modeling approaches in representing the impacts of injection into the Inyan Kara Formation.

As discussed in Section 1.2, two injection scenarios are evaluated: 1) one injection well operating at 950 gpm, and 2) two injection wells spaced 0.5 miles apart, each operating at 850 gpm. Both scenarios are evaluated assuming a 20-year lifespan with continuous injection.

4.2.1 Line Source Solution of Diffusivity Equation (Primary Modeling)

The line source solution of the diffusivity equation for the flow of a single-phase fluid in a porous medium is presented in Equation 1 (Matthews and Russel 1967).

$$P_{wf} = P_o - \frac{162.6\, q\mu B}{\kappa h}\left(\log\frac{\kappa t}{\phi_e \mu c_t r_w{}^2} - 3.23 + 0.869s\right) \qquad \text{(Eq.1)}$$

Where:

P_o = initial static pressure at top of injection interval (psi)
P_{wf} = pressure while flowing at top of injection interval (psi)
q = flow rate (bbl/day), positive when withdrawing, negative when injecting
μ = viscosity (cP)
B = formation volume factor (bbl/bbl)
κ = formation permeability (mD)
h = net sandstone thickness (ft)
t = injection duration (hours)
ϕ_e = effective porosity (-)
c_t = total compressibility (1/psi)
r_w = radial distance from well center (ft)
s = skin factor (-)

4.2.2 AquiferWin32 (Confirmatory Modeling)

AquiferWin32 is an interactive, analytic element modeling tool that simulates two-dimensional (in the horizontal plane) steady-state and transient groundwater flow using analytical functions developed for different types of aquifers (unconfined, confined, and leaky confined).The principle of superposition is used to evaluate the effects of multiple closed-form analytical functions, each representing a hydrological feature (e.g., point sinks for wells, line sinks for rivers, and area elements for zones of effective recharge), in a uniform regional flow field. The model depicts the flow field using streamlines, particle traces, and contours of hydraulic head. Streamlines are computed semi-analytically to illustrate groundwater flow directions, while particle-tracking techniques are implemented numerically to compute travel times and flow directions.

To understand the effects of injection into the Inyan Kara Formation, the transient solution for leaky aquifers (Hantush and Jacob 1955) was implemented within the AquiferWin32 framework. AquiferWin32 requires inputs such as aquifer properties, confining unit properties, and well sizing and capacity. Assumptions for the Hantush and Jacob transient solution for leaky aquifers are as follows:

- The aquifer and aquitard have infinite areal extents and are homogenous, isotropic, and of uniform thickness over the area of influence.
- Injection into the aquifer occurs at a constant rate.
- Flow in the aquitard is vertical, and drawdown in the aquitard is negligible.
- Water removed from storage in the aquifer and water supplied by leakage from the aquitard is discharged instantaneously with decline of head.
- The diameter of the well is small (i.e., well storage can be neglected).
- The aquitard is incompressible (i.e., changes in aquitard storage are negligible).

The simulated drawdown due to injection is used to understand the pressure increase effects on the formation and nearby abandoned well penetrations. The simulated particle traces help determine the extent to which the injectate will migrate through the formation in a given time period. Results of the AquiferWin32 modeling are compared to modeling results using the diffusivity equation (Equation 1).

4.3 Modeling Inputs

The following subsections describe the input variables estimated or developed for use in the groundwater flow and transport modeling and fracture pressure estimation. Input variables for use in the diffusivity equation are tabulated in Table C-1 (Appendix C). Input variables for use in the AquiferWin32 confirmatory modeling are tabulated in Table C-2 (Appendix C). Results of MDT pressure tests performed at BNI-1, J-LOC1, and J-ROC1 are summarized in Table C-3 (Appendix C).

Generally, modeling inputs were estimated from information gathered at the J-ROC1 well, which is nearest to the locations of the proposed Class I injection well(s). Occasionally, testing at J-LOC1 provided more direct measurements of certain modeling inputs compared to testing at J-ROC1. For those inputs, measurements from J-LOC1 were used.

4.3.1 Formation and Formation Fluid Properties

4.3.1.1 Net Sandstone Thickness

The net sandstone thickness (h) represents the total thickness of porous and permeable sandstone material within the injection interval that is anticipated to receive injected fluids. The top and bottom elevations of the sandstone beds in the Inyan Kara Formation are identified by evaluating the CMR log obtained during drilling of J-ROC1 (Figure 4-1) and the formation tops identified in the J-ROC1 Well File. At J-ROC1, the top and bottom of the sandstone intervals in the Inyan Kara Formation are located at 1,663 ft below msl and 1,834 ft below msl, respectively. It is assumed that the top and bottom elevations of the sandstone beds of the Inyan Kara Formation at the proposed locations for the Class I injection well(s) will be the same as at J-ROC1. This means that the depth to the top and bottom of the injection interval are approximately 3,667 ft bgs and 3,838 ft bgs, respectively, based on the ground surface elevation of 2,004 ft amsl at J-ROC1 (J-ROC1 Well File). Because the Inyan Kara Formation is composed of sandstones interbedded with shales and siltstones, the CMR log from J-ROC1 was used to estimate the net sandstone thickness by identifying zones within the formation where the CMR log-derived permeability values are generally greater than 10 millidarcies (mD). The net sandstone thickness was estimated to be approximately 90 feet (Figure 4-1).

Based on the Inyan Kara Sandstone Isopach Map in the area of MRY (Hazen 100K Sheet, North Dakota), the net sandstone thickness at MRY may be greater than 100 feet (Stolldorf 2021).

4.3.1.2 Formation Static Pore Pressure

Pore pressure (P_o) is the pressure of groundwater within the pore spaces of a rock or soil matrix at a known elevation and represents the static formation pressure that must be overcome by an injection well to induce radial flow of fluid away from the well in the injection interval. During drilling of BNI-1, J-LOC1, and J-ROC1, the MDT tool was deployed to perform pressure tests for obtaining estimates of pore pressure in the Inyan Kara Formation. The estimated pore pressure gradient for the Inyan Kara Formation at MRY was approximately 0.4198 pounds per square inch per foot (psi/ft), based on pressure tests at four depths within the formation at J-ROC1 (Table C-3, Appendix C). This pressure gradient was comparable to results from multiple pressure tests completed in the Inyan Kara Formation at BNI-1 and J-LOC1. At the top of the injection interval (3,667 ft bgs), the estimated pore pressure is 1,539 psi, which is used in groundwater flow and transport modeling and estimating formation fracture pressure.

Using the formation fluid specific gravity calculated in Section 4.3.1.8 and the estimated pore pressure at the top of the injection interval, the static potentiometric surface of the Inyan Kara Formation at the locations of the proposed Class I injection well(s) is estimated to be approximately 1,899 ft amsl using Equation 2.

$$H_{static} = \frac{144P_{otop}}{\rho_{form}} + z_{perf\ top} \qquad \text{(Eq.2)}$$

Where:

P_{otop} = static formation pressure at top of injection interval (1,539 psi)

H_{static} = static potentiometric surface elevation (ft amsl)

ρ_{form} = formation fluid density (lb/ft^3) (Section 4.3.1.8)

$z_{perf\ top}$ = elevation of top of perforated interval (1,663 ft below msl)

For use in the AquiferWin32 model simulations, the magnitude and direction of the regional hydraulic gradient was estimated using Figure 3-15. Within a five-mile radius of the proposed injection site at MRY, the average hydraulic gradient is approximately 2.7E^{-4} feet per foot (ft/ft) (1.43 ft/mile). The general flow direction in the Lower Cretaceous aquifer system near MRY is to the northeast; for modeling purposes, the direction was estimated to be 54 degrees north of east.

4.3.1.3 Formation Effective Porosity

Formation porosity (ϕ) is the ratio of the volume of voids (pores) to the total volume of material. In the Inyan Kara Formation, which is a confined unit, the void space is assumed to be 100% saturated with water. Effective porosity (ϕ_e) is the ratio of the volume of interconnected void spaces to the total volume of material.

Interconnected void space allows groundwater to flow into and out of porous material. Formation effective porosity has a small impact on the formation pressure response to injection; however, lower formation effective porosity values cause fluid particle velocities within the formation to increase, which in turn results in greater particle travel distances (the opposite is also true).

Estimates of effective porosity within the interpreted sandstone intervals of the Inyan Kara Formation were obtained from the CMR logs at J-ROC1 (Figure 4-2). The average effective sandstone interval porosity of 0.151 calculated from the CMR free fluid (CMFF) log at J-ROC1 is used for groundwater flow and transport modeling. The data presented in the CMFF curve is considered appropriate for modeling because it represents fluid that is free, rather than fluid that is bound to the formation grains by capillary and other forces (effective porosity).

4.3.1.4 Formation Permeability

Permeability, reported in units of millidarcies, is the ability of a rock to transmit fluid through its pore spaces and is a measure of the interconnectedness of those pore spaces. Permeability is not dependent upon the properties of the flowing fluid, only the formation properties.

Inyan Kara Formation permeability (k) was estimated using data from the CMR logs collected at the J-ROC1 test borehole. The CMR logs presented results from two models for estimating permeability: 1) the Schlumberger-Doll Research (SDR) model, and 2) the Timur-Coates model (Figure 4-1).

The CMR logs from J-ROC1 provide estimated formation permeability values at 0.5-foot-depth intervals using the SDR and Timur-Coates models. For each model, bulk formation permeability was estimated as the depth-weighted average of permeability values over the approximate 90-foot-thick permeable zone described in Section 4.3.1.1. In general, the SDR model tended to produce permeability estimates that were lower than permeability estimates using the Timur-Coates model. The average of these two bulk formation permeability values over the 90-foot-thick permeable zone, 950 mD, is used in this permit application.

The selected formation permeability value of 950 mD is conservative compared to other permeability estimates from the Inyan Kara Formation near MRY. The average of the bulk formation permeability estimates using the SDR and Timur-Coates models from CMR logs collected at J-LOC1 over the permeable zones is approximately 2,700 mD (Figure 4-3). Aquifer falloff testing conducted in the Inyan Kara Formation at the J-LOC1 test well indicated a permeability of approximately 1,566 mD (Figure 4-3). Additionally, laboratory permeability tests were performed on core samples collected from the Inyan Kara Formation at J-LOC1; the results of the lab testing compared well with the CMR log (Figure 4-3).

4.3.1.5 Formation Fluid Temperature

Formation temperature (T_{form}) is used to help estimate the properties of fluids (viscosity and specific gravity) within the injection interval. Higher formation fluid temperature results in lower viscosity and lower density of the formation fluid. Temperature probes were deployed during drilling of BNI-1, J-LOC1, and J-ROC1. Temperatures obtained by the MDT tool (collocated with the pore pressure measurements described in Section 4.3.1.2) ranged between 107 and 126°F, with temperatures generally increasing with depth (Table C-3, Appendix C). The formation fluid temperature is assumed to be 120°F for flow and transport modeling.

4.3.1.6 Formation Fluid Total Dissolved Solids Concentration

Formation TDS concentration (TDS_{form}) is used to help estimate the properties of fluids (viscosity and specific gravity) within the injection interval. Higher TDS concentration results in higher viscosity and higher density. During drilling of J-LOC1, a fluid sample from the Inyan Kara Formation was collected and analyzed for water chemistry. The TDS concentration of the unfiltered fluid sample from the Inyan Kara Formation at J-LOC1 was 3,450 mg/L (Table E-1, Appendix E), which is consistent with regional contour maps of TDS concentrations (Downey 1986), and has been used for estimating formation fluid properties for this permit application.

4.3.1.7 Formation Fluid Viscosity

The absolute viscosity (referred to as viscosity in this report) of a fluid is a measure of that fluid's internal friction, or resistance to flow, when acted upon by an external force, such as a pressure differential. Within a porous media, such as the sandstone intervals of the Inyan Kara Formation, the greater the viscosity of the fluid flowing through the media, the greater the resistance to flow and the greater the pressure differential required to produce the same flow rate. Formation fluid viscosity (μ_{form}) is strongly dependent upon the fluid temperature, moderately dependent on TDS concentration, and minimally dependent on pressure. Viscosity as a function of fluid temperature, TDS concentration, and pressure is calculated as 0.546 centipoise (cP) using Equation 3. TDS concentration is converted to a percentage by dividing the concentration in mg/L by 1.0E^{6}.

$$\mu_{form} = \left(-4.518E^{-2} + 9.312E^{-2}TDS_{form} - 3.93E^{-4}TDS_{form}^2 + \frac{70.365 + 9.576E^{-2}TDS_{form}^2}{T_{form}}\right)\left(1 + 3.5E^{-12}(P_i + 14.696)^2(T_{form} - 40)\right) \quad \text{(Eq.3)}$$

Where:

μ_{form} = viscosity of formation fluid (cP)
TDS_{form} = TDS concentration of formation fluid, expressed as a percent (0.35%)
T_{form} = temperature of formation fluid (120°F)
P_i = assumed formation pressure during injection (2,714 psi)

4.3.1.8 Formation Fluid Specific Gravity

The specific gravity of a liquid is the ratio of the density of the liquid to the density of water at 4°C and allows for the conversion between formation pore pressure and potentiometric elevation (total hydraulic head). Formation fluid specific gravity (γ_{form}) as a function of fluid temperature, TDS concentration, and pressure is calculated as 0.997, equivalent to a density of 62.226 pounds per cubic foot (lb/ft^3), using Equation 4.

$$\gamma_{form} = (7.572E^{-3}TDS_{form} + 0.998238)\left(1.002866exp^{\left[3.0997E^{-6}P_i - 2.2139E^{-4}(T_{form}-59) - 5.0123E^{-7}(T_{form}-59)^2\right]}\right) \quad \text{(Eq.4)}$$

Where:

γ_{form} = specific gravity of formation fluid (-)
TDS_{form} = TDS concentration of formation fluid, expressed as a percent (0.35%)
T_{form} = temperature of formation fluid (120°F)
P_i = assumed formation pressure during injection (2,714 psi)

4.3.1.9 Total Compressibility

Compressibility is the ratio of the percent change in volume to the change in pressure applied to a fluid or rock. Total compressibility (c_t) is the sum of compressibility of the fluid phases present (water, oil, and gas) and the pore volume compressibility (c_f). Because the injection interval is assumed to be 100% saturated with water (Section 4.3.1.3), the oil and gas saturation fractions are assumed to be zero and therefore oil and gas do not contribute to total compressibility. Total compressibility is calculated using Equation 5.

$$c_t = c_f + c_w \tag{Eq.5}$$

Where:

c_t = total compressibility (1/psi)
c_f = pore volume compressibility (1/psi)
c_w = water compressibility (1/psi)

Pore volume compressibility (also referred to as formation compressibility) is calculated as a function of effective porosity using a regression of the formation compressibility versus effective porosity data presented by Hall (1953) using Equation 6 presented by Lei et al. (2019). Using the estimated effective porosity of 0.151 (see Section 4.3.1.3), the calculated pore volume compressibility is 4.07E^{-6} 1/psi. These effective porosity and pore volume compressibility values compare well to the database of pore volume compressibility versus effective porosity measurements for cemented sandstones at initial reservoir stress conditions (Crawford et al. 2011).

$$c_f = \frac{1.7836E^{-6}}{\phi^{0.4358}} \tag{Eq.6}$$

Additionally, laboratory pore volume compressibility testing was performed on one core sample retrieved from 4,041 ft below KB at J-LOC1. Analysis of the pore volume versus confining pressure data using the exponential relationship described by de Oliveira (2013) yielded estimates of pore volume compressibility ranging from 4.9E^{-6} 1/psi to 2.5E^{-5} 1/psi. The calculated pore volume compressibility of 4.07E^{-6} 1/psi falls within this range.

Bulk volume compressibility (aquifer skeleton compressibility) is calculated as 6.14E^{-7} 1/psi using Equation 7 (Crawford et al. 2011).

$$c_m = \phi c_f \tag{Eq.7}$$

Water compressibility is calculated as 3.33E^{-6} 1/psi using Equation 8 and assuming a bulk modulus of elasticity of water of 3.00E^{5} psi (Lohman 1972).

$$c_w = \frac{1}{E_w} \tag{Eq.8}$$

As a result, the total compressibility assuming the formation is 100% saturated with water is 7.40E^{-6} 1/psi (calculated using Equation 5).

4.3.1.10 Formation Storage Coefficient

The storage coefficient of a formation is a unitless measure of the volume of water, per unit surface area of the formation, released from (or taken into) storage per unit fall (or rise) in head. A greater storage coefficient results in a smaller pressure increase because the formation can absorb more water into storage per unit increase in head. Storage coefficient (S) is calculated using Equation 9.

$$S = hS_s \tag{Eq.9}$$

Where:

S = storage coefficient (-)
h = net sandstone thickness (90 ft) (Section 4.3.1.1)
S_s = specific storage (1/ft)

Specific storage is the amount of water per unit volume of a saturated formation that is stored or expelled from storage due to the compressibility of the aquifer skeleton and the pore water per unit increase (or decrease) in head. Specific storage is calculated as $4.83E^{-7}$ 1/ft using Equation 10 (Fetter 2001).

$$S_s = \frac{\rho_{form}}{144}(c_m + \phi c_w) \qquad \text{(Eq.10)}$$

The resulting storage coefficient is calculated as $4.34E^{-5}$ using Equation 9.

4.3.1.11 Formation Volume Factor

The formation volume factor (B) is the ratio of the volume of water at the reservoir conditions (pressure and temperature) to the volume of water at standard conditions. The formation volume factor is assumed equal to 1.0.

4.3.1.12 Formation Hydraulic Conductivity (Formation Fluid)

Formation saturated hydraulic conductivity (K) is a measure of the ability of a porous medium to transmit fluid with particular properties; therefore, it is a function of both the permeability of the formation and the density and viscosity of the flowing fluid. For the same porous medium, a low-viscosity fluid (lower internal resistance to flow) results in a higher hydraulic conductivity (greater ability to transmit that fluid). The formation hydraulic conductivity, assuming native formation fluid, is calculated using Equation 11. The constant of 3574 in the denominator of Equation 11 is the result of dimensional analysis for unit conversions.

$$K = \frac{\kappa \rho_{form} g}{3574 \mu_{form}}$$

Where:

K = hydraulic conductivity (ft/day) (Eq.11)
κ = formation permeability (950 mD)
ρ_{form} = density of formation fluid (0.997 g/cm^3)
g = acceleration due to gravity (9.81 m/s^2)
μ_{form} = viscosity of formation fluid (0.546 cP)

A hydraulic conductivity value of 4.86 ft/day was calculated using Equation 11.

4.3.1.13 Formation Transmissivity (Formation Fluid)

Formation transmissivity (T) is a measure of the rate at which water is transmitted through a unit width of the formation under a unit hydraulic gradient applied across the vertical thickness of the formation. For a confined system, such as the Inyan Kara Formation, transmissivity is equal to the product of the net sandstone thickness (determined in Section 4.3.1.1) and hydraulic conductivity (determined in Section 4.3.1.12). Assuming all other formation properties are held constant, injection into a formation with higher transmissivity results in a lower pressure increase and a greater particle travel distance, while injection into a formation with lower transmissivity results in a higher pressure increase and a shorter particle travel distance. A formation transmissivity value of 437.8 square feet per day (ft^2/day) is calculated for the hydraulic conductivity value developed in Section 4.3.1.12.

4.3.1.14 Skin Factor

Skin factor is a numerical value used to represent the damage to the injection interval around the wellbore, which can either decrease (positive skin factor) or increase (negative skin factor) the permeability of the injection interval near the wellbore. This numerical value is used to analytically model the difference between the head loss predicted by Darcy's law and the actual head loss, which is influenced by the damage near the wellbore.

Formation damage is the impairment to the injection interval caused by wellbore fluids used during drilling and completion of the well and subsequent injection operations. Skin factor can typically range between negative six (-6), where the injection interval is highly stimulated, and positive 100, where the injection interval has been severely damaged. For this permit application, a skin factor of zero was assumed (no wellbore damage). While a larger skin factor is possible in practice, a well-designed drilling program, proper well development, and periodic maintenance of the well and near wellbore via surging, jetting, blasting, acidizing, or other methods can limit the development of large head losses due to skin effects.

4.3.2 Injectate Fluid Properties

4.3.2.1 Injectate Fluid Temperature

Injectate fluid temperature (T_{inj}) is used to help estimate the properties of injectate fluids (viscosity and specific gravity). MPC measures temperature of the MRY scrubber pond on a daily basis. Between 2014 and March 2021, these temperatures have ranged between 36°F and 89°F. Process waters from the proposed CCS (described in Section 1.2.1) are anticipated to be relatively warm because the majority of the water will be cooling tower blowdown. As a result, the temperatures in the scrubber pond are not anticipated to change significantly. The temperature of the injectate fluid is assumed to reflect fluctuations in environmental temperatures and is conservatively set at 55°F for modeling purposes.

4.3.2.2 Injectate Fluid Total Dissolved Solids Concentration

Injectate fluid TDS concentration (TDS_{inj}) is used to help estimate the properties of injectate fluids (viscosity and specific gravity). MPC measures TDS concentration in the MRY scrubber pond approximately once per week. Between 2014 and August 2020, these TDS concentrations ranged between approximately 15,000 and 130,000 mg/L, with an average of approximately 76,000 mg/L. As described in Section 1.2, wastewaters from the proposed carbon capture and sequestration system are planned to be routed to the MRY scrubber system. Because the combined wastewater from the carbon capture system is anticipated to have a relatively low TDS concentration (approximately 10,000 mg/L) and a relatively high flow rate (up to 1,100 gpm), the average TDS concentration of combined water is anticipated to be less than 76,000 mg/L. A TDS concentration of 40,000 mg/L is used in this permit application.

4.3.2.3 Injectate Fluid Viscosity and Specific Gravity

The injectate fluid viscosity, assuming a fluid temperature of 55°F (Section 4.3.2.1), a TDS concentration of 40,000 mg/L (Section 4.3.2.2), and a pressure of 2,714 psi, is calculated as 1.294 cP using Equation 3. Using the same input assumptions, the injectate fluid specific gravity is calculated as 1.041 using Equation 4 (equivalent to a density of 64.994 lb/ft^3).

4.3.2.4 Formation Storage Coefficient (Injectate Fluid)

Specific storage of the formation assuming injectate fluid properties is calculated as 5.04E^{-7} 1/ft using Equation 12 (Fetter 2001).

$$S_s = \frac{\rho_{inj}}{144}(c_m + \phi c_w) \qquad \text{(Eq.12)}$$

Where:

ρ_{inj} = injectate fluid density (64.994 lb/ft3) (Section 4.3.2.3)

The resulting storage coefficient is calculated as 4.54E^{-5} using Equation 9.

4.3.2.5 Formation Hydraulic Conductivity and Transmissivity (Injectate Fluid)

Using the formation permeability value of 950 mD estimated in Section 4.3.1.4 and the injectate fluid properties estimated in Section 4.3.2, a hydraulic conductivity value of 2.14 ft/day was calculated using Equation 11. For this hydraulic conductivity value, the corresponding formation transmissivity is 192.9 ft^2/day.

4.3.3 Confining Unit Properties

4.3.3.1 Vertical Hydraulic Conductivity

The vertical hydraulic conductivity of the confining unit (K') controls the rate at which water migrates vertically through the confining unit. The proposed injection interval (Inyan Kara Formation) is isolated from the lowermost USDW (Fox Hills Sandstone) by calcareous shales within the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations, which make up the Cretaceous Confining Unit. The vertical hydraulic conductivity of the Cretaceous Confining Unit was estimated to be $2.84E^{-7}$ ft/day, based on literature values (Milly 1978; Neuzil 1980) reported for the Pierre Shale in South Dakota.

4.3.3.2 Thickness

Based on formation descriptions in the North Dakota Stratigraphic Column (Figure 3-2) the formations separating the Inyan Kara Formation from the Fox Hills Sandstone are assumed to be composed primarily of low-permeability shales. Consequently, the thickness of the confining unit (b') is based on the total thickness between the base of the Fox Hills Sandstone and the top of the Inyan Kara Formation. Based on the geologic cross sections provided in Figures 3-9 and 3-10 and the J-ROC1 Well File, the confining unit thickness in the vicinity of MRY is approximately 2,500 feet.

4.3.3.3 Leakage Factor

When injecting into a leaky injection interval, the piezometric level of the injection interval increases and spreads radially outward, creating a difference in hydraulic head between the injection interval and the confining unit. Consequently, groundwater in the injection interval will move vertically upward into the confining unit. The pressure increase as a result of injection into the leaky injection interval is described by Hantush and Jacob (1955). Leakage through the confining unit is a function of the injection interval transmissivity and the confining unit thickness and vertical hydraulic conductivity. The leakage factor is calculated using Equation 13.

$$^1/_B = \left(\frac{K'}{Tb'}\right)^{1/2} \qquad \text{(Eq.13)}$$

Where:

$^1/_B$ = leakage factor (1/ft)

T = formation transmissivity (ft^2/day)

b' = confining unit thickness (2,500 ft)

K' = confining unit vertical hydraulic conductivity ($2.84E^{-7}$ ft/day)

Larger leakage factors are indicative of leakier formations, and can be the result of lower formation transmissivity, lower confining unit thickness, or higher confining unit vertical hydraulic conductivity. The leakage factors calculated using the transmissivity values developed in Sections 4.3.1.13 and 4.3.2.5 are presented in Table C-2 (Appendix C).

4.3.3.4 *Lowermost Underground Source of Drinking Water Properties*

The static potentiometric surface elevation of the Fox Hills Sandstone at MRY is approximately 1,800 ft amsl, based on water level elevations measured in monitoring well NDSWC Well Index 9442 (142-084-24 BBA), which is completed in the Fox Hills Sandstone and is located approximately 4.5 miles northwest of MRY (NDSWC n.d.). The elevation of the bottom of the USDW is approximately 840 ft amsl, which is the approximate elevation of the top of the Pierre Shale formation (J-ROC1 Well File).

4.3.4 Well Construction Properties

The well design assumes an injection tubing diameter of 7 inches. A perforated casing completion with 0.52-inch entrance diameter and 24-inch penetrations at a rate of 4 to 12 perforations per foot within the identified sandstone layers will be used (perforation rate to be determined after borehole drilling). The tubular sizes and hole diameters are provided in Table 2.

Table 2: Preliminary Well Tubular and Hole Sizing

Component	7-Inch Injection Tubing	
	Tubular	Hole Diameter
Injection tubing	7-inch OD Long thread coupling	-
Production casing	9.625-inch OD Long thread coupling	12.25-inch hole (1.3125-inch annulus)
Surface casing	13.375-inch OD Buttress thread coupling	17.5-inch hole (2.0625-inch annulus)
Conductor casing	20-inch OD Buttress thread coupling or welded	26-inch hole (3-inch annulus)

OD = outside diameter

4.4 Model Results

The following modeling results were calculated using the methods described in Section 4.2 and the model inputs described in Section 4.3 for both injection scenarios described in Section 1.2 (one well at 950 gpm or two wells at 850 gpm each).

4.4.1 Formation Pressure Response

The required formation pressure at the radius of the wellbore and at the top of the injection interval following 20 years of continuous injection was evaluated using Equation 1 and using AquiferWin32. Because the maximum formation pressure occurs at the wellbore (formation face), injectate fluid properties (Section 4.3.2) were used in the calculation, rather than formation fluid properties. The calculated formation pressure (evaluated at the top of the injection interval) versus time is provided in Figure 4-4 for the two injection scenarios described in Section 1.2. The maximum formation pressure following 20 years of continuous injection for one well operating at 950 gpm is estimated to be 2,454 psi. The maximum formation pressure for two injection wells operating concurrently, each at 850 gpm and spaced 0.5 miles apart, is estimated to be 2,490 psi. The formation fracture pressure of 2,714 psi, also shown in Figure 4-4, is estimated in Section 5.0. The expected maximum formation pressure for either injection scenario is less than the formation fracture pressure.

The formation pressure response at the wellbore after 20 years of continuous injection was evaluated for flow rates ranging from 200 to 1,400 gpm for the two injection scenarios described in Section 1.2. The calculated required formation pressures (evaluated at the top of the injection interval) versus injection flow rate are provided in Figure 4-5. Based on the estimated formation pressure response to injection, a maximum flow rate of greater than 950 gpm is expected to be feasible without fracturing the formation.

Formation pressure response results from the confirmatory modeling using AquiferWin32 compare well to the modeling results using the diffusivity equation, as shown in Figures 4-4 and 4-5.

4.4.2 Formation Pressure Response with Radial Distance

Using Equation 1 and the formation fluid properties estimated in Section 4.3.1, the formation pressure response (evaluated at the top of the injection interval) versus radial distance from FREEMAN-1 was calculated after 20 years of continuous injection for both injection scenarios. The formation pressure increase versus radial distance from FREEMAN-1 for both injection scenarios is provided in Figure 4-6. This figure provides an understanding of the pressure impacts in the injection interval radially out into the formation. Formation pressure response results from the confirmatory modeling using AquiferWin32 compare well to the modeling results using the diffusivity equation, as shown in Figures 4-6.

4.4.3 Radius of Fluid Displacement

The radius of fluid displacement due to injection and the regional hydraulic gradient was calculated using AquiferWin32, using the modeling inputs described in Section 4.3. The radius of fluid displacement versus time, assuming constant injection at the maximum permitted flow rate(s) and displacement due to the regional hydraulic gradient, is provided in Figure 4-7.

After 20 years of continuous injection with one injection well at 950 gpm, the radius of fluid displacement is expected to be less than 1.1 miles. With two injection wells operating continuously for 20 years at 850 gpm each (wells spaced 0.5 miles apart), the radius of fluid displacement from either well is expected to be less than 1.3 miles.

These scenarios are considered conservative (continuous operation at maximum flow rates) because the injection well(s) are likely to be operated at lower flow rates and on a more intermittent basis due to changes in water demand and maintenance needs. The predicted radius of fluid displacement will be updated annually during operation to evaluate the potential for fluid displacement beyond MPC's property boundaries. Based on these conservative analyses, the injected fluid would be expected to remain within MPC's property boundaries until after approximately 13 years of continuous injection for the one-well scenario and approximately 5 years of continuous injection for the two-well scenario. It is anticipated that the initial permit to inject from the NDDEQ will have a five-year renewal period, allowing for fluid displacement modeling and operating conditions to be updated prior to the current minimum estimated time for fluid displacement beyond MPC's property boundaries. MPC will work with adjacent landowners with respect to pore space rights if actual well operations and hydrogeologic conditions indicate that injected fluid will impact adjacent landowners.

4.5 Modeling Conclusions

Using the estimated properties of the injection interval, formation fluid, and injectate fluid, the maximum formation pressure at the wellbore face is estimated to be approximately 2,454 psi for the scenario in which one injection well is operating; this is approximately 260 psi less than the estimated fracture pressure (Section 5.0). For the scenario in which two injection wells are operating, the maximum formation pressure at either wellbore face is estimated to be approximately 2,490 psi, which is approximately 224 psi less than the estimated fracture pressure. The injectate is not expected to travel more than 1.3 miles laterally from the injection site in the injection interval for either injection scenario.

5.0 FRACTURE PRESSURE

The following section includes a discussion of fracture propagation pressure for the proposed injection interval at MRY. The United States Environmental Protection Agency (USEPA) regulatory standard for maximum injection pressures for Class I non-hazardous injection wells is established in 40 CFR § 146.13(a), as follows:

> Except during stimulation, injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water. (USEPA n.d.)

Fractures are formed when the pressure at the formation face exceeds the local stress and the tensile strength of the formation. Fractures are propagated when the pressures in the fracture exceed the minimum in situ stress. The local stress at the formation face is a function of the minimum in situ stress, the pore pressure at the location, and the stress concentration due to the presence of the well. In the absence of tectonic stresses, the minimum in situ stress is normally horizontal, and any fractures formed tend to be vertical planes normal to this minimum horizontal stress.

5.1 Inyan Kara Fracture Pressure

Measured formation fracture pressure, which is used in this permit application, is based on step rate testing conducted on the Inyan Kara Formation at the J-LOC1 well. A fracture pressure gradient is determined from this testing, which is then used to estimate fracture pressure at the top of the proposed injection interval (3,667 ft bgs) at MRY. For comparison, the fracture pressure is also estimated using methods described in the literature (Eaton 1969; Ward et al. 1995); the results of these approaches are provided in Table D-1 (Appendix D).

In the fall of 2020, a step rate test was conducted on a 10-foot-thick interval of the Inyan Kara Formation (4,015 to 4,025 ft below KB) at J-LOC1. Injection volume, flow rate, and downhole pressure were measured during the test. Pressure within the test interval was measured downhole using a main quartz gauge and an auxiliary strain gauge. Natural leak off and pressure falloff was observed after the first fracture propagation cycle and rebound and flowback tests were conducted after injection to verify the creation of a fracture. A fracture pressure gradient of 0.740 psi/ft was estimated using fracture pressures developed from the step rate test. This equates to a fracture pressure of 2,714 psi at the top of the injection interval at MRY (3,667 ft bgs).

To corroborate the fracture pressure measurement obtained from step rate testing at J-LOC1, fracture pressure was estimated with two analytical equations (Eaton 1969; Ward et al. 1995) using overburden stress gradient estimates from the J-ROC1 open hole bulk density logs. Ward et al. (1995) estimates the fracture propagation pressure (which is less than the fracture initiation pressure) using Equation 14.

$$P_{fp} = (1 - \phi)(\sigma_v - P_o) + P_o \quad \text{(Eq.14)}$$

Where:

P_{fp} = fracture pressure (psi)
ϕ = porosity (-) (effective porosity used)
σ_v = overburden stress (psi)
P_o = static pore pressure (psi)

Eaton's method (1969), presented in Equation 15, also estimates the formation fracture propagation pressure.

$$P_{fp} = \frac{\mu}{1-\mu}(\sigma_v - P_o) + P_o \quad \text{(Eq.15)}$$

Where:

μ = Poisson's ratio (-)

Poisson's ratio is an elastic constant that is a measure of the compressibility of material perpendicular to applied stress (ratio of latitudinal to longitudinal strain). Poisson's ratio is calculated using Equation 16 (Desroches and Bratton n.d.).

$$\mu = \frac{0.5\left(\frac{VP_c}{VS_c}\right)^2 - 1}{\left(\frac{VP_c}{VS_c}\right)^2 - 1} \quad \text{(Eq.16)}$$

Where:

VP_c = compression wave velocity (km/s)
VS_c = shear wave velocity (km/s)

Compression wave velocity and shear wave velocity are calculated using Equations 17 and 18, respectively (Castagna et al. 1985).

$$VP_c = 6.5 - 7.0\phi - 1.5V_c \quad \text{(Eq.17)}$$

$$VS_c = 3.52 - 6.0\phi - 1.8V_c \quad \text{(Eq.18)}$$

Where:

ϕ = porosity (0.151, effective porosity used)
V_c = clay volume (-)

A lower injection interval clay volume results in a lower Poisson's ratio, which is conservative when used to estimate the fracture pressure of the injection interval. As such, a clay volume of zero was conservatively selected to calculate the compression wave velocity (5.44 kilometers per second [km/s]) and the shear wave velocity (2.61 km/s). Using these velocities, Poisson's ratio is estimated to be approximately 0.35, which is the value used to estimate formation fracture pressure and maximum allowable injection pressure.

The overburden stress at the top of the injection interval is calculated as 3,581 psi by integrating with depth the bulk density log from the J-ROC1 well. The static pore pressure at the top of the injection interval is 1,539 psi (Section 4.3.1.2). Porosity is approximately 0.151 (Section 4.3.1.3). Formation fracture propagation pressures and fracture pressure gradients measured in J-LOC1 and calculated using Equations 14 and 15 are presented in Table 3.

Table 3: Estimated Fracture Pressure and Gradient at the Top of the Inyan Kara Formation

Estimation Method	Fracture Pressure (psi)	Fracture Pressure Gradient (psi/ft)
J-LOC1 Step-Rate Test	2,714	0.740
Ward et al. (1995) (Equation 14)	3,273	0.893
Eaton (1969) (Equation 15)	2,639	0.720

The fracture pressure of 2,714 psi measured from the J-LOC1 step rate test is within the range of fracture pressures estimated at J-ROC1 (2,639 to 3,273 psi) using methods found in the literature.

5.2 Confining Unit Fracture Pressure

The fracture pressure of the overlying confining unit was estimated at the top of the injection interval (3,667 ft bgs) as 2,958 psi using Equation 15 (Eaton 1969), with an overburden stress of 3,581 psi, pore pressure of 1,539 psi, and a Poisson's ratio of approximately 0.41 (estimated from the sonic scanner log at J-ROC1). This corresponds to a fracture pressure gradient of 0.807 psi/ft, which is consistent with the NDIC's prescriptive value for shale confining units of 0.8 psi/ft, used for permitting Class II injection wells in North Dakota.

5.3 Maximum Allowable Injection Pressure

To prevent propagation of existing fractures within the injection interval, the maximum allowable injection pressure at ground surface is calculated as the difference between the formation fracture pressure (2,714 psi, based on step rate test at J-LOC1) and the formation hydrostatic pressure, using Equation 19.

$$MAIP = P_{fp} - P_{hydtop}$$

Where:

MAIP = maximum allowable injection pressure (psi) (Eq.19)

P_{fp} = fracture pressure (2,714 psi)

P_{hydtop} = hydrostatic pressure at top of injection interval (psi)

Hydrostatic pressure at the top of the injection interval is defined herein as the pressure exerted at the top of the injection interval by a hypothetical column filled with injectate fluid to ground surface and is calculated using Equation 20.

$$P_{hydtop} = \frac{D_{screen\ top}\rho_{inj}}{144} \quad \text{(Eq.20)}$$

Where:

$D_{perf\ top}$ = depth from ground surface to top of injection interval (3,667 ft bgs, see Section 4.3.1.1)

ρ_{inj} = density of injectate (64.994 lb/ft^3, see Section 4.3.2.3)

The hydrostatic pressure at the top of the injection interval is presented in Table 4. The maximum pressure that can be applied at the surface (by a pump) to achieve the desired injection flow rate without fracturing the injection interval is estimated as the pressure difference between the calculated fracture pressure and this hypothetical column of injectate fluid (see Table 4). Due to injection tubing friction head losses and near-well losses, the pressure exerted on the injection interval under the calculated maximum allowable injection pressure (MAIP) will be less than the formation fracture pressure. Because these downhole well losses are neglected in the calculation of MAIP, no reduction has been applied to the MAIP value.

Table 4: Hydrostatic Pressure at Top of Injection Interval and MAIP

Hydrostatic Pressure at Top of Injection Interval (psi)	Fracture Pressure (psi)	MAIP (psi)
1,655	2,714 (J-LOC1 step rate test)	1,059

6.0 GEOCHEMISTRY

6.1 Overview

Geochemical modeling was conducted to assess the compatibility between the proposed injectate (cooling tower blowdown and scrubber pond water) and formation solids and liquids comprising the proposed injection interval. Meaningful geochemical compatibility models require that three parameters be well understood:

1) formation water chemistry (as well as dissolved gas concentrations or gas cap pressures) and temperature;
2) chemistry and temperature of the solution to be injected; and
3) mineralogical and chemical composition of the receiving formation solids.

The purpose of the geochemical modeling effort is to identify potentially detrimental geochemical effects associated with underground injection, such as formation souring, mineral scaling, and changes in the permeability or porosity of the receiving formation.

6.2 Formation and Injectate Water Chemistry

6.2.1 Data Sources

The chemistry data used to represent the composition of the formation water was collected from J-LOC1 (Section 2.2) on June 13, 2020 (Table E-1, Appendix E). The two samples (Minnesota Valley Testing Laboratories, Inc. [MVTL] and Energy and Environmental Research Center [EERC]-Unfiltered) were collected using the Schlumberger MDT tool. The decrease in pressure that occurs when the water sample is brought to the surface (approximately 1,670 psi within the formation at J-LOC1 versus approximately 15 psi at the surface) can cause rapid degassing of dissolved carbon dioxide (CO_2) and increase the pH. Formation gas cap and dissolved gas were not measured during sampling. Additionally, regional water chemistry for the proposed injection interval was not readily available from public sources.

MPC plans to discharge excess process water from the Project Tundra CCS system, which includes cooling tower blowdown, reverse osmosis reject, water treatment softening sludge, wet electrostatic precipitator discharge, and polishing scrubber blowdown to their existing FGD scrubber blowdown vaults. FGD blowdown from the Unit 1 and Unit 2 scrubber absorber towers is delivered to the scrubber blowdown vaults and then sluiced to Scrubber Pond Cell 4, which is a composite-lined impoundment with a capacity of 307 million gallons below the permitted maximum operating elevation (2,093 ft amsl). Additional inflow to the FGD scrubber system includes makeup water from Nelson Lake, runoff, leachate from the closed scrubber pond cells (i.e., Cells 1, 2, and 3), and other site process waters. Free water in Scrubber Pond Cell 4 (Cells 5 and 6 will be used in the future) is siphoned back to the scrubbers for use in the scrubbing process and sluicing FGD solids. The proposed injectate will be sourced from the Unit 2 Pond Return Tank, which receives water siphoned from Scrubber Pond Cell 4.

Injectate water is expected to be primarily a mixture of cooling tower blowdown and scrubber pond water. The carbon capture process is not operational at this time, so the exact chemistry of the injectate is unknown. The mixing proportions of blowdown with scrubber pond water to be injected is currently not known, so high and low concentration estimates of these two injectate water sources were selected to bound the range of potential injectate water qualities:

- MPC provided estimated cooling tower blowdown (from the proposed carbon capture system) water chemistry (Table E-2, Appendix E). Water chemistry estimates for the Winter Minimum scenario (low TDS) and Summer Peak Full Softening scenario (high TDS) were selected as cooling tower blowdown water in the geochemical model.
- MVTL collected six pond return water samples from Scrubber Pond Cell 3 and Scrubber Pond Cell 4 between July 2014 and July 2019, and the measured water qualities are presented in Table E-3 (Appendix E). Water chemistry for the samples collected from Cell 3 on July 30, 2014 (Cell 3 low TDS); Cell 3 on June 9, 2016 (Cell 3 high TDS); and Cell 4 on July 4, 2019 (Cell 4) were selected to represent scrubber pond water quality in the geochemical model.

6.2.2 Chemistry

A Piper diagram showing the distribution of predominant dissolved constituents in the injection formation, cooling tower blowdown, and scrubber pond is provided as Figure 6-1. Chemical compositions indicate that the three water sources (formation, cooling tower blowdown, and scrubber pond) are sodium sulfate ($Na\text{-}SO_4$) dominant. TDS concentrations for the injection formation, cooling tower blowdown, and scrubber pond samples are summarized in Table 5.

Table 5: TDS Concentrations in Injection Formation, Cooling Tower Blowdown, and Scrubber Pond Waters

Sample Name	TDS Concentration (mg/L)
Formation water	3,450
Cooling tower blowdown Winter Minimum	5,720
Cooling tower blowdown Summer Peak Full Softening	9,586
Scrubber Pond Cell 3 – minimum TDS (July 30, 2014)	49,700
Scrubber Pond Cell 3 – maximum TDS (June 9, 2016)	108,000
Scrubber Pond Cell 4 (July 24, 2019)	10,400

6.2.3 Formation Mineralogy

Water quality compatibility models require that the mineralogy of the receiving formation at the injection site is understood. Mineralogy by X-ray diffraction (XRD) was analyzed at regular intervals (4 to 5 feet; 33 samples) of borehole core along 160 feet of the Inyan Kara Formation at J-LOC1. XRD results are presented in Table E-4 (Appendix E) and a summary is presented in Table 6.

Table 6: Summary of Formation Mineralogy

Mineral Name	Average % Abundance	Maximum % Abundance	Minimum % Abundance
Quartz	70.6%	94.8%	29.0%
Illite/muscovite	9.7%	36.5%	0.0%
Kaolinite	5.4%	14.9%	0.0%
Clintonite	2.6%	14.3%	0.0%
Microcline	2.4%	9.2%	0.0%
Siderite	2.1%	22.9%	0.0%
Orthoclase	1.3%	10.4%	0.0%
Chlorite	1.1%	9.7%	0.0%
Albite	1.0%	9.1%	0.0%
Smectite, goethite, glauconite, anhydrite, pyrite, anatase, calcite, rutile, calcite magnesian, jarosite, dolomite	<1.0%	11.2%	0.0%

6.3 Geochemical Modeling

6.3.1 Modeling Strategy

The geochemical computer code PHREEQC (Parkhurst and Appelo 2013), developed by the USGS, was used for these simulations. PHREEQC version 3.4 is a general purpose geochemical modeling code used to simulate reactions in water and between water and solid mineral phases (e.g., rocks and sediments). Reactions simulated by the model include mixing, aqueous equilibria, mineral dissolution and precipitation, ion exchange, surface complexation, solid solutions, gas–water equilibrium, and kinetic biogeochemical reactions. The Pitzer thermodynamic database (Appelo et al. 2014) was used as a basis for the thermodynamic constants required for modeling. The Pitzer database is specialized for use with high-salinity waters that are beyond the range of the Debye Huckel activity model and can be applied to systems with elevated temperatures and pressures, as are expected in the injection formation. The Pitzer database only contains the most common scaling minerals.

Results reported as less than the detection limit were modeled at the detection limit. Charge imbalances were corrected by allowing the model to balance on sodium.

The potential for mineral precipitation was assessed in PHREEQC using a saturation index (SI) calculated according to Equation 21.

$$SI = log\left(\frac{IAP}{K_{sp}}\right) \quad \text{(Eq.21)}$$

Where:

IAP = ion activity product
K_{sp}= mineral solubility constant

An SI value greater than zero indicates that the water is supersaturated with respect to a particular mineral phase, and therefore precipitation of the mineral may occur. An evaluation of precipitation kinetics is then required to determine whether the supersaturated mineral will indeed form. An SI value less than zero indicates the water is undersaturated with respect to a particular mineral phase. An SI value close to zero indicates equilibrium conditions exist between the mineral and the solution. SI values between -0.5 and 0.5 are considered to represent equilibrium in this report to account for the uncertainties inherent in the analytical methods and geochemical modeling.

6.3.2 Saturation Evaluation

As discussed in Section 6.2.1, injection formation water chemistry from J-LOC1 and the injectate sources (cooling tower blowdown and scrubber pond), were selected for modeling and are presented in Tables E-1, E-2, and E-3 (Appendix E). Prior to evaluating the scaling potential of water mixtures, the saturation indices of the source waters (formation waters, cooling tower blowdown, and scrubber pond waters) were assessed at their pre-injection temperatures and pressures:

- formation waters at formation conditions prior to injection: 50°C and 1,670 psi
- cooling tower blowdown and scrubber pond waters at surface conditions: 5°C and 14.7 psi

The reported composition of the formation water indicated supersaturation with respect to calcite and barite at formation temperatures and pressure (Table E-5, Appendix E). Calcite precipitation kinetics are fast, and the formation water has a very long residence time; therefore, calcite supersaturation within formation waters is considered highly unlikely. Calcite would be expected to be either in equilibrium in formation water, or undersaturated if the formation does not contain any calcite. The apparent oversaturation with respect to calcite is likely an artifact of the elevated pH value measured at surface after degassing of CO_2 (pH = 8.63). Because the pH of formation water was likely increased by degassing of CO_2 during sample collection, modeling was conducted using two chemistries for the formation water: 1) the concentrations reported by the laboratory, and 2) a simulated injection formation water where dissolved CO_2 was added until the modeled water was in equilibrium with respect to calcite at the formation temperature and pressure (pH = 7.66). The chemistry of the simulated sample is presented in Table E-1 (Appendix E).

The simulated formation water with added CO_2 was in equilibrium with respect to calcite and oversaturated for barite. Formation waters (both as measured and with added CO_2) were undersaturated for magnesite and calcium sulfate minerals associated with scaling (gypsum and anhydrite).

The saturation evaluation indicated that cooling tower blowdown waters (Winter Minimum and Peak Summer Full Softening scenarios) are oversaturated with respect to barite, calcite, and magnesite at surface temperature and pressure. The cooling tower blowdown water quality was in equilibrium with respect to gypsum and undersaturated for anhydrite.

Scrubber pond waters (Cell 3 minimum TDS, Cell 3 maximum TDS, and Cell 4) are oversaturated with respect to barite at surface temperature and pressure. All three scrubber pond water qualities were in equilibrium with respect to gypsum and undersaturated with respect to anhydrite. Only the Cell 4 Scrubber Pond water was in equilibrium with respect to calcite. The Cell 3 minimum TDS and Cell 4 water qualities were both in equilibrium with respect to magnesite.

All solutions modeled were undersaturated with respect to halite.

6.3.3 Compatibility Evaluation

The compatibility of the injected water with the receiving formation water and solids can be evaluated by simple mixing simulations at different temperatures and pressures. After a period of injection, solutions near the wellbore will have a composition and temperature reflecting the injected water. With increasing distance from the wellbore, mixing between the injected water and formation water takes place and compositions and temperature begin to reflect those of the pre-injection formation water. To account for this gradual mixing process, the general modeling procedure is a three-step process:

1) Evaluate aqueous speciation models for the injectate (cooling tower blowdown or scrubber pond water) and receiving formation water.
2) Create a model simulating the mixing of the two solutions over a range of mixing ratios.
3) Evaluate saturation indices of the resulting mixed solutions for the minerals of interest to assess whether or not they are likely to dissolve or precipitate.

Given that aqueous dissociation constants and mineral solubility products are temperature and pressure dependent, downhole reservoir temperatures and pressures should be constrained as closely as possible. Based on the measured temperatures within the formation, a temperature of 50°C is used for modeling of the downhole reservoir temperature (Section 4.3.1.5), which is consistent with the estimated geothermal gradient in the region. The injection pressure is expected to be approximately 2,400 psi (Section 4.4.1).

6.3.4 Mixing Models

Saturation indices as a result of mixing the cooling tower blowdown or scrubber pond water injectate with formation waters (as measured or simulated with the addition of CO_2) are shown as a function of mixing fraction in Tables E-6 through E-9. A mixing ratio of 100:0 represents the formation water and is therefore reflective of conditions distant from the wellbore where the composition is equivalent to that of the initial groundwater. Conversely, a mixing ratio of 0:100 represents the injectate, and therefore reflects conditions at the wellbore where compositions mimic those of the injectate.

Assuming available pH values for the formation water bracket the range of actual downhole conditions, the chemistry of groundwater from the formation is unable to dilute cooling tower and scrubber pond water qualities to bring calcite, magnesite, and barite below saturation. Solutions near the wellbore appear to have a propensity for scaling carbonates (calcite and magnesite) and barite, which may cause issues with well fouling and formation plugging. Mixtures of formation waters (measured and simulated) with scrubber pond waters (Cell 3 maximum TDS and Cell 4) were in equilibrium with respect to gypsum. The geochemical model does not predict gypsum will precipitate, but it is a possibility if actual concentrations or temperatures are slightly different than the scenarios modeled.

Uncertainly in the modeling results exists because of the uncertainty in two variables:

1) pH: It is not known to what extent formation CO_2 concentrations will lower the pH. The approach presented herein does bracket the likely range of possibilities for the formation waters, but the risk of scaling persists over that range. In general, pH lowering significantly increases calcite solubility, making it less likely to precipitate.
2) Temperature: The modeling assumes isothermal mixing at temperatures representative of formation conditions. More likely, however, is that a lower temperature aureole exists around the wellbore after

injection. A decreased temperature would decrease saturation levels and the scaling propensity for calcite. Careful thermal modeling would be required to accurately assess thermal effects on mineral solubility near the injection area.

Conservatively assuming the injection rate of 950 gpm (Scenario #1 from Section 1.2.2) and equilibrium precipitation, the range of calculated volumes of precipitated minerals are presented in Tables E-6 through E-9 (Appendix E). A summary of calculated volumes of precipitated barite, calcite, and magnesite are presented in Table 6-3. The values clearly suggest that carbonates (calcite and magnesite) present a far greater scaling risk than barite in terms of the anticipated scaling mass. Management strategies to decrease the risk of scaling during injection include the addition of amendments (i.e., antiscalants) to the injectate that prevent mineral precipitation and/or the addition of an acid to decrease pH.

Other processes that could potentially occur in the formation, but were not modeled due to lack of available data, include:

- Acidification: Oxygen-rich injection waters could potentially oxidize pyrite and other sulfides potentially present (Section 6.2.3), which could result in a decrease in pH. Corrosion and increased dissolution of formation minerals are potential associated deleterious effects.
- Reservoir souring: Microbes and reducing formation waters (e.g., due to the presence of organic matter) can reduce sulfate present in the injection waters to form hydrogen sulfide and CO_2. Corrosion, bio-plugging, and toxicity are potential associated deleterious effects.
- Retardation: Clays, organic material, and hydrous amorphous phases present in the formation solids have the ability to adsorb components from the injected solution, changing its solubility characteristics.

Table 7: Predicted Volumes per Day of Mineral Precipitates Formed During Injection

Sample Name	Predicted Barite Precipitation Volume (m^3/day)		Predicted Calcite Precipitation Volume (m^3/day)		Predicted Magnesite Precipitation Volume (m^3/day)	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Mixed with Formation Water as Sampled						
Blowdown Winter Minimum	0.00016	0.00087	0.017	0.33	0	0
Blowdown Summer Peak Full Softening	0.00016	0.00087	0.017	0.14	0	0
Scrubber Pond Cell 3 – minimum TDS	0.00031	0.00087	0	0.060	0	0.19
Scrubber Pond Cell 3 – maximum TDS	0.00053	0.00087	0	0.060	0	0.14
Scrubber Pond Cell 4	0.00018	0.00087	0	0.19	0	0.076

Sample Name	Predicted Barite Precipitation Volume (m^3/day)		Predicted Calcite Precipitation Volume (m^3/day)		Predicted Magnesite Precipitation Volume (m^3/day)	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Mixed with Simulated Formation Water with Added CO_2						
Blowdown Winter Minimum	0.00016	0.00087	0	0.33	0	0
Blowdown Summer Peak Full Softening	0.00016	0.00087	0	0.10	0	0
Scrubber Pond Cell 3 – minimum TDS	0.00035	0.00087	0	0	0	0.083
Scrubber Pond Cell 3 – maximum TDS	0.00035	0.00087	0	0	0	0.083
Scrubber Pond Cell 4	0.00018	0.00087	0	0.12	0	0.057

m^3/day: cubic meters of precipitated mineral per day

7.0 INJECTION WELL DE3SIGN AND CONSTRUCTION

This section describes procedures for the design and construction of the injection well(s) and includes details on the casing and cementing program, logging procedures, drilling and testing program, and proposed annulus fluid. Well design and construction procedures follow the requirements of 40 CFR § 146.12 (USEPA n.d.) and NDAC Article 33.1-25 (North Dakota Legislative Council 1978) for Class I non-hazardous injection wells. The proposed well construction diagram, which is applicable for both injection wells, is shown in Figure 7-1.

The proposed injection interval for the Class I injection wells is between 3,667 and 3,838 ft bgs and will encompass the sandstone intervals of the Inyan Kara Formation. The drilling program provided in this section contains specifications and information on drilling procedures, casing lengths, and materials. General procedures to be required of the drilling contractor and site personnel are included throughout the program. Some of the drilling and completion details that are not relevant to overall permitting requirements may be modified in the field, as necessary. The logging program includes both open-hole and cased-hole logs that will be used to locate the lowest USDW, target the injection interval, and evaluate the mechanical integrity of the wells.

7.1 Well Drilling and Completion Program

Target depths and elevations for the drilling program are summarized in Table 8.

Table 8: Proposed Injection Well Data

Well Property	FREEMAN-1	RUBEN-1	Comments
Location (approximate)	N: 509,872 ft E: 1,790,841 ft	N: 507,250 ft E: 1,791,090 ft	
Ground surface elevation (approximate)	2,004 ft amsl	2,004 ft amsl	Ground surface elevation at completion of well
Top of proposed injection interval	3,667 ft bgs	3,667 ft bgs	Approximate
Base of proposed injection interval	3,838 ft bgs	3,838 ft bgs	Approximate

Depths are approximate and will be modified in the field based on injection well location-specific data.

7.1.1 Construction Procedures

The general procedures for the construction of each Class I injection well are as follows:

1) Install a 20-inch-diameter conductor casing cemented at an estimated depth of 80 feet in nominal 26-inch-diameter hole.
2) Drill 17.5-inch-diameter hole to approximately 1,260 ft bgs (100 feet below the bottom of the USDW). Run deviation surveys every 250 feet.
3) Conduct open-hole testing (wireline geophysical logs).
4) Run 13.375-inch-diameter surface casing to approximately 1,260 ft bgs (100 feet below the bottom of the USDW).
5) Grout surface casing annulus to ground surface using approximately 12 to 15 pounds (lbs) of Haliburton VariCem cement (or equivalent) per gallon of fresh water to ensure adequate sealing of the annular space.
6) Run cement bond log.
7) Drill 12.25-inch-diameter hole to approximately 3,940 ft bgs (approximately 50 feet below injection zone). Run deviation surveys every 1,000 feet.
8) Conduct open-hole testing (wireline geophysical logs and DST).
9) Run 9.625-inch-diameter production casing to approximately 3,888 ft bgs (approximately 50 feet below bottom of injection interval). Grout annulus to ground surface using approximately 12 to 15 lbs of Haliburton ElastiCem (or equivalent) cement per gallon of fresh water to ensure adequate sealing of the annular space.
10) Run cement bond log.
11) Perform pressure test on well casing.
12) Perforate production casing in the injection interval (approximately 3,667 to 3,838 ft bgs) with 0.52-inch entrance diameter and 24-inch penetrations at a rate of 4 to 12 shots per foot within the identified sandstone layers (perforation rate to be determined after borehole drilling).
13) Perform physical/chemical development of the well.
14) Install 7-inch-diameter injection tubing and packer to approximately 3,617 ft bgs (approximately 50 feet above injection zone). PermaPak single-bore packer (or equivalent) constructed to match production casing and injection tubing.
15) Place annular fluid.
16) Complete well surface features.

A summary of casing and injection tubing specifications (diameters, weight, grade, thread type, strengths, lining, and seat depth), and the cement program design are provided in Table F-1 (Appendix F). These construction specifications may change based on material availability and conditions encountered during drilling.

7.2 Logging Program

Cuttings from the drilling will be logged by a geologist at approximately 20-foot intervals from the ground surface to the top of the proposed injection interval, and at approximately 10-foot intervals from the top of the proposed injection interval to total depth.

The site lithology and stratigraphy information established by logging of the drill cuttings will be supplemented by open-hole wireline geophysical logging of the entire length of the borehole prior to installation of the surface casing string and production casing string. The wireline geophysical logging will occur in two stages:

- Stage 1: Log surface casing borehole (ground surface to minimum 1,260 ft bgs).
- Stage 2: Log production casing borehole (bottom of surface casing to total depth).

The geophysical logging for the surface casing borehole will, at a minimum, include caliper, dual induction (resistivity), and spontaneous potential. The geophysical logging for the production casing borehole will, at a minimum, include caliper, natural gamma ray, dual induction (resistivity), spontaneous potential, compensated density, and compensated neutron logs. The geophysical logs will be reviewed by the geologist responsible for logging the boring, and the cuttings observations and laboratory analyses will be compared with the geophysical testing results to validate the site lithology and stratigraphy.

7.3 Formation Testing Program

The proposed formation testing program is designed to obtain data on static fluid pressure, temperature, and permeability of the injection interval. The program is also designed to collect data to characterize the physical, chemical, and radiological characteristics of the formation fluid.

7.3.1 Characteristics of the Injection Interval

Testing will be performed to measure static fluid pressure, temperature, and permeability of the injection interval, and may include completion of drill stem tests (DSTs) within targeted zones of the injection interval and step rate injection, constant rate injection, and falloff testing of the entire injection interval.

7.3.2 Formation Water Sampling

Samples of formation water from the injection interval will be analyzed to determine the physical, chemical, and radiological characteristics of the water. Representative samples of formation water may be collected upon completion of drilling and prior to performing injection testing.

The aqueous analytical suite includes all major cations and anions, as well as the primary general fluid parameters, for purposes of simple QA/QC, charge balance analysis, and geochemical modeling. Additionally, both total and dissolved species will be measured to give an indication of fine suspended particles. Finally, a full suite of trace metals will be analyzed for water quality evaluation and geochemical modeling. The full analytical suite is summarized in Table 9.

Table 9: Full Analytical Suite for Formation Water Samples

Parameter Type	Parameters to be Analyzed
Field parameters	pH, specific conductance, temperature, dissolved oxygen, oxidation reduction potential
Redox couples	Iron speciation: Fe(II), Fe(III) Arsenic speciation: As(III), As(V)
General chemistry	pH, specific conductance, total dissolved solids (TDS), total suspended solids (TSS), turbidity, total hardness (as $CaCO_3$),
Major cations and anions	Alkalinity as $CaCO_3$, bicarbonate alkalinity of $CaCO_3$, carbonate alkalinity as $CaCO_3$, hydroxide alkalinity as $CaCO_3$, fluoride, sulfate, sulfite, chloride, calcium (total and dissolved), magnesium (total and dissolved), sodium (total and dissolved), potassium (total and dissolved), lithium (total and dissolved), ammonia nitrogen (as N), phosphorus (as P)
Other	Nitrate (as N), nitrite (as N), total kjeldahl nitrogen, total organic carbon (TOC), nitrogen (total), silicates (as SiO_2, dissolved)
Trace elements	Aluminum, antimony, arsenic, barium, beryllium, boron, cadmium, chromium, cobalt, copper, iron, lead, manganese, mercury, molybdenum, nickel, selenium, silver, strontium, thallium, tin, vanadium, zinc

All trace elements are analyzed as total and dissolved species.

7.4 Stimulation Program

While the perforated zone will likely be cleaned using a hydrochloric acid solution during well completion, the cleaning will not involve stimulation of the injection interval. No stimulation is expected to be necessary for the target injection interval. However, should it be required, stimulation would be performed using acidation techniques. Acid types, concentrations, quantities, and additives would be determined once the well has been completed. A stimulation plan would be submitted for NDDEQ approval prior to beginning an acidation program.

7.5 Mechanical Integrity Testing

The absence of significant leaks in the casing, tubing, or packer will be demonstrated through a pressure test on the annular space between the tubing and production casing. The test shall be conducted for a minimum of 60 minutes at a pressure equal to the maximum allowable injection pressure estimated in Section 5.3. A cement bond log will be used to demonstrate that there can be no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore.

7.6 Construction Contingency Plan

Drilling operations will be performed according to the current standard of practice. Should unforeseen problems occur with the potential to impact a USDW, drilling will be stopped and the NDDEQ will be contacted. A detailed solution would be developed for review and approval by the NDDEQ prior to resuming operations.

7.7 Surface Infrastructure

The proposed injection well locations and the locations and alignment of injection well supply piping and associated structures are shown in Figure 7-2. Surface infrastructure will include the following:

- A connection pipeline from the existing Unit 2 Pond Return Water Tank to the injection piping, within the Lime Prep Building near the south end of the power block. Also housed within the Lime Prep Building will be a supply pump, potential pre-injection water treatment system, and an injection well screen filter for removal of suspended solids.
- One high-pressure injection well pump (with variable frequency drive) and flow meter will be housed in a separate building near each Class I injection wellhead.
- FREEMAN-1 will be housed in a building on the well pad that will accommodate the injection wellhead, the injection well annulus pressurization equipment, and instrumentation and controls to ensure that the well is operated within the permit limitations for injection pressure and annulus pressure related to FREEMAN-1.
- If required, RUBEN-1 will be housed in a separate building approximately 0.5 miles south of FREEMAN-1 that will also accommodate an injection wellhead, injection well annulus pressurization equipment, and instrumentation and controls to ensure that the well is operated within the permit limitations for injection pressure and annulus pressure related to RUBEN-1.

8.0 INJECTION WELL OPERATIONS

This section describes injection well operating requirements, parameters, and procedures; monitoring and reporting; and recordkeeping.

8.1 Regulatory Requirements

The injection well operating requirements according to 40 CFR § 146.13(a) at a minimum, specify that:

1) Except during stimulation, injection pressure at the wellhead shall not exceed a maximum that shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into a USDW.
2) Injection between the outermost casing protecting underground sources of drinking water and the well bore is prohibited.
3) Unless an alternative to a packer has been approved under §146.12(c), the annulus between the tubing and the long string of casings shall be filled with a fluid approved by the director and a pressure, also approved by the director, shall be maintained on the annulus (USEPA n.d.).

8.2 Injection Parameters

8.2.1 Injection Rate

Non-hazardous wastewater from both the scrubber pond system and carbon capture system will be injected at or below the permitted flow rate of either 950 gpm for one injection well, or 850 gpm each for two injection wells. The maximum injection rate for each scenario will be established based on the maximum flow rate that can be sustained while maintaining the surface injection pressure below the maximum allowable injection pressure to prevent the propagation of existing fractures or initiation of new fractures within the injection interval. Increases to the injection rates will be discussed with the NDDEQ prior to implementation.

8.2.2 Injection Pressure

The injection well(s) will be operated so as not to initiate or propagate fractures in the injection interval and to prevent the movement of injectate or formation fluids into a USDW. Injection will occur through tubing as described in Section 7.0 and as shown in Figure 7-1. The maximum allowable surface injection pressure for both Class I injection wells has been estimated to be 1,059 psi based on the difference between the calculated fracture pressure and the estimated hydrostatic pressure (pressure caused by a column of injectate fluid from the top of the injection interval to ground surface) at the top of the injection zone (Section 5.0). Fracture pressure and maximum allowable surface injection pressure may be reevaluated using data collected during drilling for the specific injection well location. The estimated fracture pressure and maximum allowable surface injection pressure are listed in Table 10. Injection pressure will be controlled so that the downhole pressure remains below the fracture pressure.

Table 10: Estimated Fracture and Maximum Allowable Surface Injection Pressures

Item	Pressure (psi)	Source
Downhole fracture pressure	2,714	Estimated fracture pressure reported in Section 5.0
Maximum allowable surface injection pressure	1,059	Downhole injection pressure minus hydrostatic pressure from column of injectate fluid to ground surface

8.2.3 Annulus Pressure

Injection will not occur between the outermost casing intended to protect underground sources of drinking water and the well bore. MPC plans to fill the annulus between the injection tubing and the production casing with 9 to 10 pounds per gallon inhibited brine (or another fluid approved by the NDDEQ) and maintain a minimum differential pressure between the annulus pressure and the injection pressure of 100 psi.

8.3 Well Operations

8.3.1 Schedule

Following the required public comment period and if the NDDEQ deems the application acceptable, the NDDEQ will provide MPC with authorization to drill. After receiving such authorization, MPC will begin well construction and will submit notification to the NDDEQ after construction is complete. The NDDEQ will issue the final injection permit after all requested data have been collected and analyzed. Upon the NDDEQ's issuance of the permit to inject, MPC may begin to inject fluids as authorized by the UIC permit and applicable federal and state regulations.

8.3.2 Procedures

Injectate will be pumped from the existing Unit 2 Pond Return Water Tank in the Lime Prep Building to the wellheads via the piping alignments shown in Figure 7-2.

Pretreatment of the injectate fluid may include the addition of an antiscalant upstream of the injection pumps to reduce the risk of downhole scaling from calcium sulfate and calcium carbonate (Section 6.3.4). Dosing rates will depend on actual injectate fluid chemistry and injection flow rate.

The piping upstream of the wellheads will be equipped with an operable tap to allow for injectate fluid sampling prior to conveyance through the injection tubing string. Monitoring instrumentation will be installed to continuously measure and record surface injection pressure, casing–tubing annulus pressure, flow rate, and injection volumes (see Section 8.4) The maximum allowable surface pressure for injection will be finalized at each well after each well is completed (updated elevations and fluid density), and the wells will be operated so as not to exceed the established injection pressure.

8.3.3 Facilities

Pumps, pipelines, valves, instrumentation and controls, and related appurtenances will be installed and made operational prior to initiating injection well operations. Equipment will be sized appropriately for the design injection rate and pressure. The injection well and related appurtenances will be properly operated and maintained according to manufacturer's recommendations, MPC's internal procedures, and the current standard of practice.

Upon completion of the well, a building will be constructed around the well to protect the wellhead, instrumentation and controls, and related appurtenances and materials from the elements, and to provide a safe working environment for MPC's well operators.

8.3.4 Training

MPC will be responsible for operating the Class I injection well(s). Personnel responsible for the operation and maintenance of the Class I injection wells will have appropriate training and qualifications to ensure the safe, proper operation of the system. MPC is very familiar with operating mechanical and hydraulic systems, maintaining monitoring instrumentation, and ensuring regulatory compliance in their activities. Training will be conducted in areas including, but not limited to:

- site health and safety procedures
- well equipment operations
- regulatory requirements

The appropriate personnel will receive training prior to work, with regular refresher training as necessary to remain familiar with best management practices.

8.3.5 Operational Contingency Plan

Systems will be installed to continuously monitor the well performance (e.g., injection flow rate, surface injection pressure, casing–tubing annulus pressure) and periodically sample for injectate water quality (e.g., chemistry). Controls will be used to prevent the well from operating outside of permitted limits defined by the NDDEQ. In the event that the control system shuts down the injection operations, MPC will evaluate the reasons for the shutdown and consult with the NDDEQ if permit limits are jeopardized or there is a risk to a USDW prior to resuming operation.

In the event of a well shutdown (planned or unplanned), injectate will remain in the existing scrubber pond. Each scrubber pond is operated to maintain a minimum of two feet of freeboard, as required by the North Dakota Solid Waste Management Rules. By design, each pond is engineered for an additional three feet of freeboard while maintaining an acceptable factor of safety. If conditions would arise that necessitate operation of the scrubber pond above the minimum freeboard level, the NDDEQ Division of Waste Management would be consulted. If approved, the additional three feet of airspace (approximately 25 million gallons) would be available for storage of injectate. Assuming all other systems remain operational, there is approximately 18 days of available storage under these conditions at 950 gpm.

If one of the proposed injection wells fail mechanical integrity testing, or if monitoring suggests wellbore failure, MPC will immediately cease injection operations of that Class I injection well. Additional testing will be performed on the wellbore to determine the cause of failure. A plan will be developed for approval by the NDDEQ and implemented to remediate the well.

8.4 Monitoring and Reporting

8.4.1 Injectate Sampling

Except during time periods in which the Class I injection well is not operated, MPC will collect samples of injectate once per month for water chemistry analysis for List C parameters for an abbreviated waste characterization (Table G-3, Appendix G). Based on the results of these analyses, MPC may seek permission from the NDDEQ to reduce the frequency of sampling (monthly to quarterly). Additionally, MPC will collect injectate samples annually for analysis of parameters included in List A (Table G-1, Hazardous Waste Classification) and List B (Table G-2, General Waste Characterization) (Appendix G). Results of the water quality analyses will be provided with MPC's quarterly injection monitoring reports submitted to the NDDEQ.

8.4.2 Injection Monitoring

The primary methods to monitor well operations include continuous recording of the injection pressure and the casing–tubing annulus pressure at the wellhead, and continuous monitoring of the injection flow rate and volume. Before MPC begins injection operations, the following monitoring equipment will be installed and made operational:

- Injection pressure gauge: The surface injection pressure will be monitored using a digital, continuous reading pressure monitoring device installed on the injection piping immediately upstream of each wellhead.
- Wellhead annulus pressure monitoring device: The pressure of the casing–tubing annular space will be monitored using a digital, continuous reading pressure monitoring device installed on the casing–tubing annulus connection on each wellhead.
- Flow meter: Digital totalizer flow meter and digital continuous recording device will be installed in the injection piping upstream of each wellhead to record flow rates and total volumes of injectate delivered to the injection interval via each well.

Monitoring equipment will be calibrated and maintained on a regular basis in accordance with the manufacturer's recommendations to ensure proper working order of the equipment and collection of accurate monitoring data.

8.4.3 Mechanical Integrity Testing

The injection well must demonstrate mechanical integrity to comply with UIC permit requirements, as described in NDAC 33.1-25-01-13. The mechanical integrity demonstration must show that the casing, injection tubing, and injection packer do not contain leaks and that there is not significant fluid movement into a USDW adjacent to the well casing. The mechanical integrity demonstration must follow methods listed under 40 CFR § 146.8(b) (USEPA n.d.):

- Evaluate the absence of significant leaks in the casing, injection tubing, and injection packer by one of these methods:
  - Monitoring of casing–tubing annulus pressure, or
  - Pressure test with liquid or gas.

- Determine the absence of significant fluid movement into underground sources of drinking water through the cemented annular space between the production casing and the production casing borehole by evaluating results of temperature logs, noise logs, or radioactive tracer survey.
- Apply methods and standards generally accepted in the industry. A description of the tests and test methods conducted will be included in mechanical integrity test reports.

Mechanical integrity testing will be performed at least once every five years, and following any testing, rehabilitation, or workover of the well, during the life of the well.

8.4.4 Quarterly Reporting Requirements

As required by 40 CFR § 146.13(c) (USEPA n.d.), MPC will submit quarterly reports to the NDDEQ within 30 days after the last day of March, June, September, and December of each year. Quarterly reports will include:

- results of injectate fluid analyses
- monthly average, maximum, and minimum values for injection pressure, injection flow rate, injection volume, and casing-tubing annular pressure

When applicable, the first quarterly report after completion of the following activities will also contain results of these activities:

- periodic mechanical integrity tests
- annual pressure falloff testing results and analysis
- well rehabilitation or workover activities

8.4.5 Annual Reporting Requirements

Per 40 CFR § 146.13(d) (USEPA n.d.), MPC will monitor the pressure buildup in the injection zone on an annual basis. At a minimum, this will include a shutdown of the well for a time sufficient to conduct a valid observation of the pressure falloff curve (typically 24 to 48 hours). In addition, a standard annulus pressure test will be performed on the annular space between the 9.625-inch-diameter production casing and the 7-inch-diameter injection tubing. The annular space will be pressure tested and monitored with a pressure recorder at the surface to detect any leaks in the tubing, packer, or casing. Chemical analysis of the injectate fluids for hazardous waste classification and general waste characterization (Appendix G) will be conducted annually following the first year of operation. The results of the testing and analysis described in this section will be included in the subsequent quarterly report to the NDDEQ.

8.4.6 Immediate Reporting Requirements

MPC will verbally report the following information to NDDEQ within 24 hours from the time MPC becomes aware of the circumstances:

- any monitoring or other information that indicates that any contaminant may cause an endangerment to a USDW, and
- any noncompliance with a permit condition or malfunction of the injection system that may cause fluid migration into or between underground sources of drinking water.

Written submission to the NDDEQ will be provided within five days of the time MPC becomes aware of the circumstances.

8.5 Recordkeeping

MPC will maintain the following records and retention times:

- data used for this permit application for at least three years (from date of sample, measurement, report, or application)
- records concerning the nature and composition of injected fluids until three years after completion of well plugging and abandonment
- monitoring records, including items such as calibration and maintenance records, continuous monitoring readings including flow and pressure records, and reports for three years after the injection well has been properly plugged and abandoned

Records may be discarded after this retention time only with written approval from the NDDEQ.

9.0 WELL CLOSURE, PLUGGING AND ABANDONMENT PLAN

9.1 Regulatory Requirements

At least 60 days prior to well closure, MPC will notify the NDDEQ director in writing of the intent to plug and abandon the injection wells. The plugging will be conducted in a manner to ensure that movement of fluids into or between underground sources of drinking water does not occur. The notification will include the following information as required by 40 CFR § 146.14(c) (USEPS n.d.):

- type, number, and placement (including elevation of the top and bottom) of plugs to be used
- type, grade, and quantity of cement to be used, including any additives to be used
- method used to place plugs, including the method used to place the well in a state of static equilibrium prior to placement of the plugs
- procedures used to meet the requirements of 40 CFR § 146.10
- any information on newly constructed or discovered wells, or additional well data, within the Area of Review

Within 60 days of closure, MPC will submit a closure report to the NDDEQ. The report will include either a statement that the well was closed in accordance with this permit application or, if actual closure differed from the plan previously submitted, a written statement that specifies the differences between the previous plan and actual closure. MPC will retain records concerning the nature and composition of injected fluids until three years after completion of plugging and abandonment of the well.

9.2 Plugging and Abandonment Program

MPC plans to abandon the well by removing the wellhead building, wellhead, injection tubing, and injection packer, and placing cement grout plugs as follows:

- a 300-foot plug isolating the injection zone (cement perforated zone and 100 feet into production casing)
- a 200-foot plug at the base of the lowermost USDW (100 feet above and below the base of the Fox Hills Sandstone)
- a 100-foot plug at the surface of the wellbore

The well will be plugged and abandoned following procedures required by the NDDEQ. After removing the wellhead building, wellhead, injection tubing, and injection packer, the 9.625-inch-diameter production casing will remain from the ground surface to total depth. For each Class I injection well, approximately 300 cubic feet of grout will be required to install the plugs described above and as shown in Figure 9-1. The grout plan will be finalized prior to plugging and will likely consist of 15.4 pounds per gallon density cement grout using Class G cement, placed in lifts by either the balance method, dump bailer method, or alternative method approved by the NDDEQ. The well will be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method approved by the NDDEQ prior to placement of the cement plugs. The wellhead will be removed, casing will be cut five feet below the surface, and a steel plate will be welded to the top of the casing stub.

MPC will notify the NDDEQ no less than 60 days before conversion, workover, or abandonment. The injection well will be properly plugged (in accordance with the plugging and abandonment program) after injection operations have ceased for two years, unless MPC demonstrates that the well will be used in the future or that the well will not endanger underground sources of drinking water while temporarily out of use.

MPC will submit a survey plat to the local zoning authority upon completion of the plugging and abandonment. The survey plat will also be included with the final plugging and abandonment report, which will be submitted to the NDDEQ and NDIC.

9.3 Plugging and Abandonment Costs

Total costs for plugging and abandoning the two Class I injection wells have been estimated at approximately $380,000 (2021 dollars). The cost estimate summary provided in Table 11 was developed assuming that the injection intervals will be isolated by the squeeze cementing method through a cement retainer; the remainder of each of the wells was assumed to be cemented using the balance method.

Table 11: Plugging and Abandonment Costs (2021 Dollars)

Item	Estimated Cost FREEMAN-1	Estimated Cost RUBEN-1
Surface structure removal ▪ Remove wellhead building ▪ Remove wellhead ▪ Remove above grade components	$35,000	$35,000
Plug wellbore ▪ Pull tubing and packer ▪ Install plugs	$120,000	$120,000
Site restoration ▪ Regrading ▪ Topsoil, seed, and mulch	$20,000	$20,000
Oversight and documentation	$15,000	$15,000
Total Plugging and Abandonment Costs	**$190,000**	**$190,000**

To estimate the costs for plugging and abandoning FREEMAN-1 and RUBEN-1 over the five-year permit period (2021 through 2026), the 2021 cost estimate was escalated annually based on forecasted contractor costs. Based on experience and professional judgement, a conservative annual escalation rate of 4% is used to forecast plugging and abandonment costs through the permit period. As a reference point, the annual inflation rate (based on consumer price index) for the United States over the last five years (2016 to 2020) has ranged between 1.4% and 2.3%, with an average five-year inflation rate of 2.0% (annual inflation rate information from United States Bureau of Labor Statistics [BLS 2021]). The forecasted plugging and abandonment costs for FREEMAN-1 and RUBEN-1 are provided in Table 12.

Table 12: Forecasted Plugging and Abandonment Costs

Year	Estimated Cost FREEMAN-1	Estimated Cost RUBEN-1
2021	$190,000	$190,000
2022	$198,000	$198,000
2023	$206,000	$206,000
2024	$214,000	$214,000
2025	$223,000	$223,000
2026	$232,000	$232,000

9.4 Financial Assurance

Per the NDDEQ permit application requirements, and in accordance with 40 CFR § 144.63(f) (USEPA n.d.), MPC has provided a letter from their chief financial officer demonstrating that MPC passes a financial test for $462,000 to plug and abandon the proposed Class I injection wells. This letter demonstrates that MPC has the appropriate resources to close, plug, and abandon the injection wells through the permit period (see Appendix H).

10.0 FACILITY PERMITS

This section addresses compliance with applicable portions of NDAC Article 33.1-25 and 40 CFR § 144 and 146 (USEPA n.d.). MPC holds multiple environmental permits for the MRY facility. The following sections address environmental regulations listed in 40 CFR § 144.31(e) and their applicability to proposed underground injection well activities.

10.1 Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act (RCRA) regulates hazardous waste and provides the framework for regulation of non-hazardous solid wastes. The existing RCRA registration for MRY (Generator ID NDD076514298) will not be affected by injection well activities.

10.2 Safe Drinking Water Act

Under the Safe Drinking Water Act (SDWA), the USEPA sets drinking water quality standards and oversees states, local agencies, and water suppliers who implement the standards. Requirements and provisions for UIC are established under Part C of the SDWA. MPC maintains a permitted existing potable water system (Milton R.

Young Station Well – MPC, ND3310177). With this permit application, MPC complies with SDWA requirements related to underground injection permitting.

10.3 Clean Water Act

The Clean Water Act (CWA) enables the regulation of discharges into waters of the United States and establishment of surface water quality standards. The relevant aspects of the CWA pertaining to this permit application are addressed in the following sections.

10.3.1 NPDES Program

The CWA requires National Pollutant Discharge Elimination System (NPDES) permits for discharges of pollutants from point sources into waters of the United States. MPC maintains a site-wide NPDES industrial wastewater permit issued by the NDDEQ (ND-000370). Additional outfalls are covered under the NPDES general stormwater discharge permit associated with industrial activity; the coverage number for the MRY facility is NDR05-0012. The construction of the Class I injection well(s) should reduce the frequency at which MRY discharges process water under this NPDES permit.

10.3.2 Dredge and Fill Permits

Section 404 of the CWA requires approval from the United States Army Corps of Engineers before placing dredged or fill material into waters of the United States, including rivers, streams, ditches, coulees, lakes, ponds, or adjacent wetlands. MPC does not have a dredge and fill permit for the MRY site, nor need one for construction or operation of the Class I underground injection well(s).

10.4 Clean Air Act

The Clean Air Act (CAA) defines USEPA responsibility for protecting and improving air quality and the ozone layer. Under the CAA, the USEPA has implemented federal regulations and permitting programs and has established National Ambient Air Quality Standards (NAAQS). Prior to construction or modification of large air emission sources, sources must determine Prevention of Significant Deterioration (PSD) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) applicability. Injection well activities that could affect the Title V permit for MRY (T5-F76009) would be addressed separately with NDDEQ's Division of Air Quality.

10.4.1 Marine Protection, Research and Sanctuaries Act

Under the Marine Protection, Research and Sanctuaries Act (MPRSA), Congress requires regulation of the dumping of all types of materials into ocean water of any material which would adversely affect human health, welfare, marine environmental, ecological system, or economics. This regulation is not applicable for the proposed Class I underground injection well(s).

10.5 Other Permits

MPC maintains several other permits for MRY, including the following:

- Solid Waste Management Permit, 30-Year Pond: Permit No. SP-159
- Solid Waste Management Permit, Horseshoe Pit (closed): Permit No. SP-040
- Solid Waste Management Permit, Section 3 (closed): Permit No. IT-205
- Solid Waste Management Permit (closed): Permit No. IT-197

- Solid Waste Management Permit (closed): Permit No. IT-068
- Solid Waste Management Permit, Butterfly Ponds (closed): Permit No. SP-030
- NDSWC Annual Water Use Reports: SWC #1324, #1963, #1964, #7097
- Underground Storage Tanks Permit No. ND UST #46 (removed as of May 18, 2021)
- Petroleum Tank Insurance Fund #447
- Radiation Program License #33-81171-01

11.0 REFERENCES

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Signature Page

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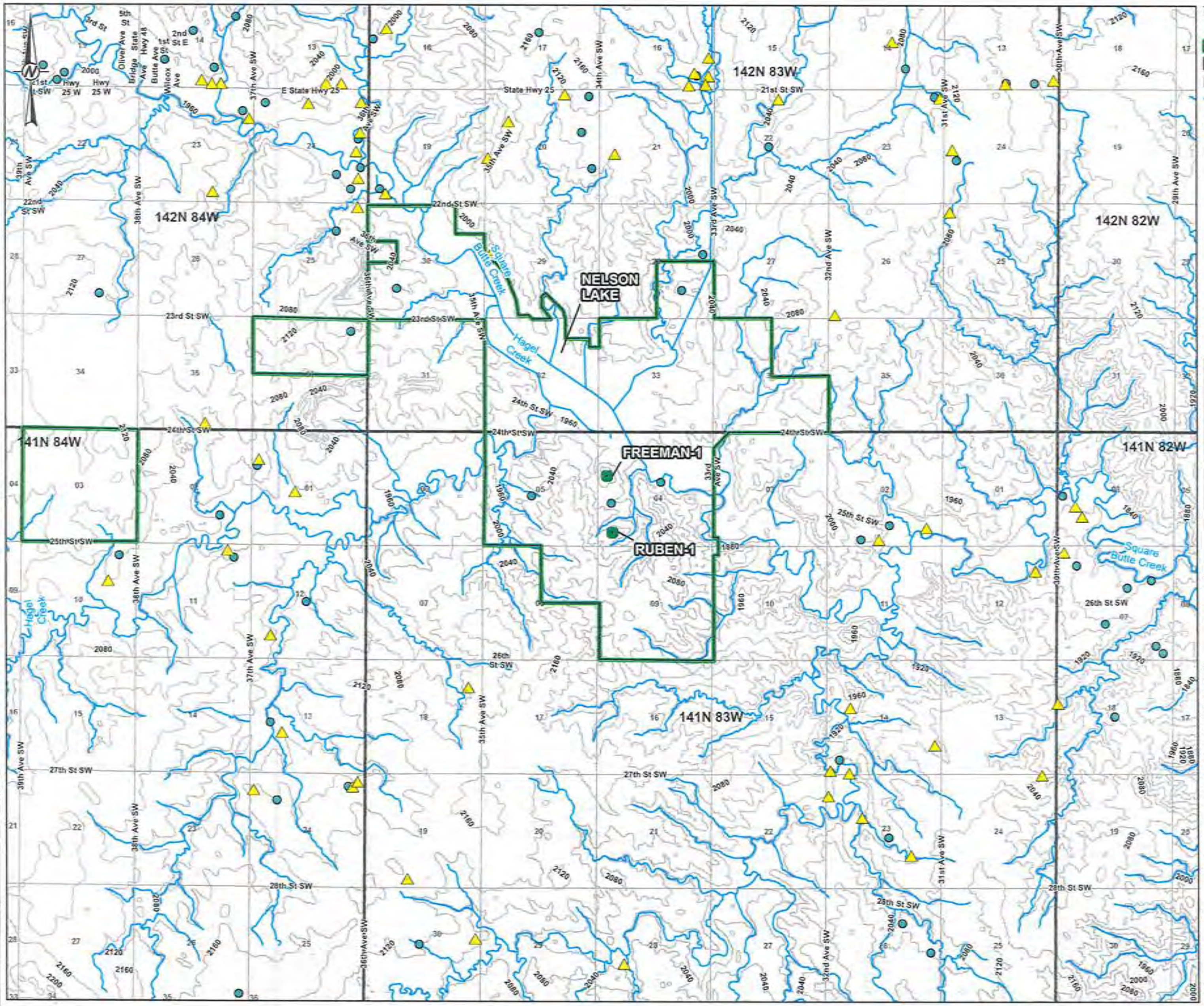
Todd Stong, PE (CO, ND)
Associate and Senior Consultant

AS/TS/af

https://golderassociates.sharepoint.com/sites/108764/project files/6 deliverables/reports/31-r-injection_permit_app/31-r-0/19122669-31-r-0-class_i_injection_well_permit_application_07jun21.docx

Figures



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MPC PROPERTY BOUNDARY
- TOWNSHIP
- SECTION
- LINEAR SURFACE WATER FEATURES
- DOMESTIC WATER WELL
- RESIDENCES
- USGS CONTOUR - 40 FOOT INTERVAL

KEY MAP

0 2,250 4,500 9,000 Feet

REFERENCES

1. TOPOGRAPHIC CONTOURS: U.S. GEOLOGICAL SURVEY, 2013, USGS 1/3 ARC-SECOND N47W102 & N48W102 1 X 1 DEGREE: U.S. GEOLOGICAL SURVEY.
2. STREAMS DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.
3. ROAD DATA: U.S. CENSUS BUREAU, TIGER ROAD DATA 2019.
4. WELL DATA: NORTH DAKOTA WATER COMMISSION AND STATE ENGINEER WELL DRILLERS LOGS, DOWNLOADED 4/14/2021.
5. RESIDENCES: BASED ON AERIAL IMAGERY.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

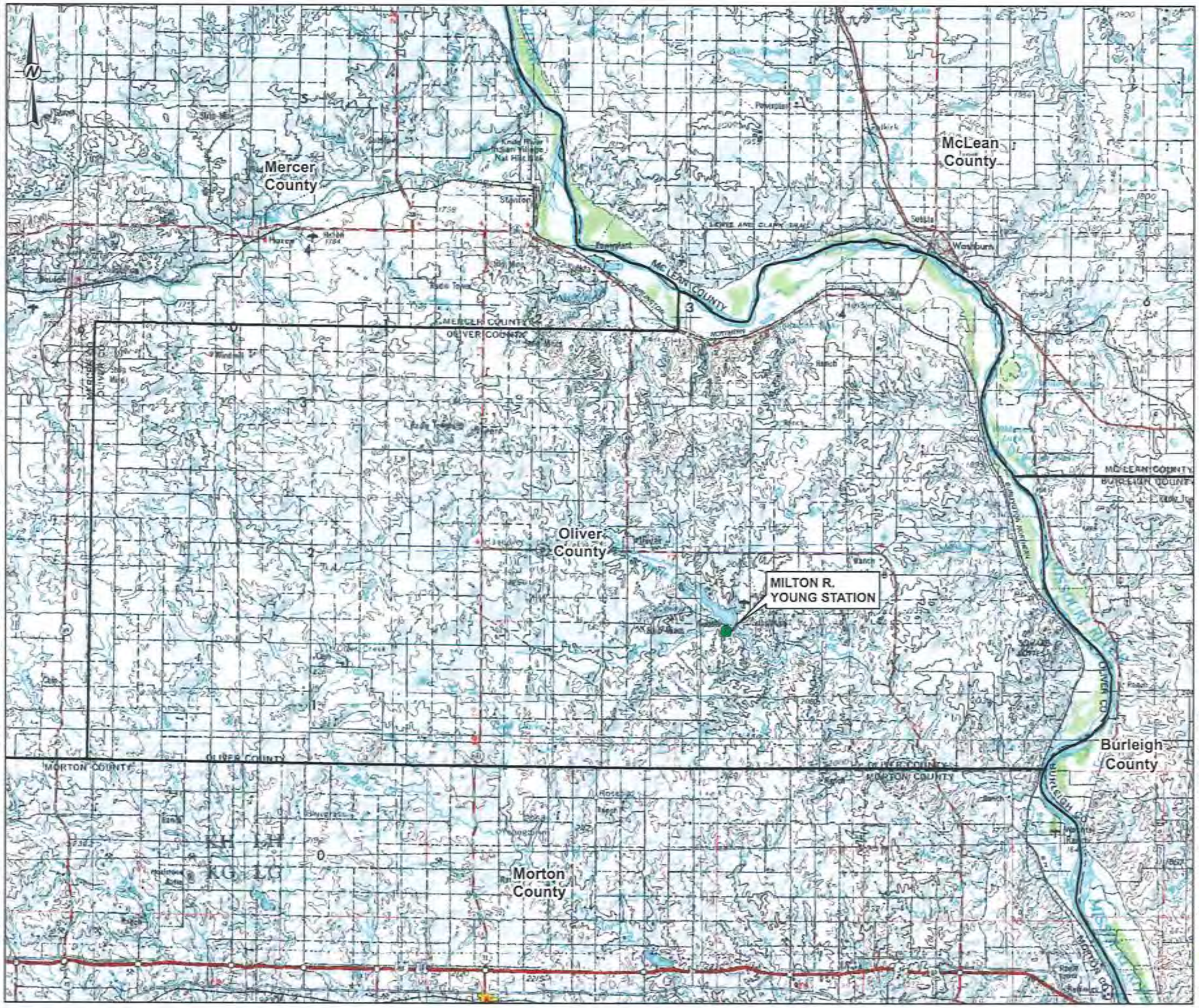
TITLE
SITE VICINITY MAP

CONSULTANT

GOLDER MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	BJP
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 1-2



LEGEND

MILTON R. YOUNG STATION

COUNTY BOUNDARY

KEY MAP

0 2 4 8 Miles

REFERENCES

1. TOPOGRAPHIC BACKGROUND: ESRI BASEMAP SERVICES, USGS.

CLIENT

MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT

CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE

SITE LOCATION MAP

CONSULTANT

GOLDER
MEMBER OF WSP

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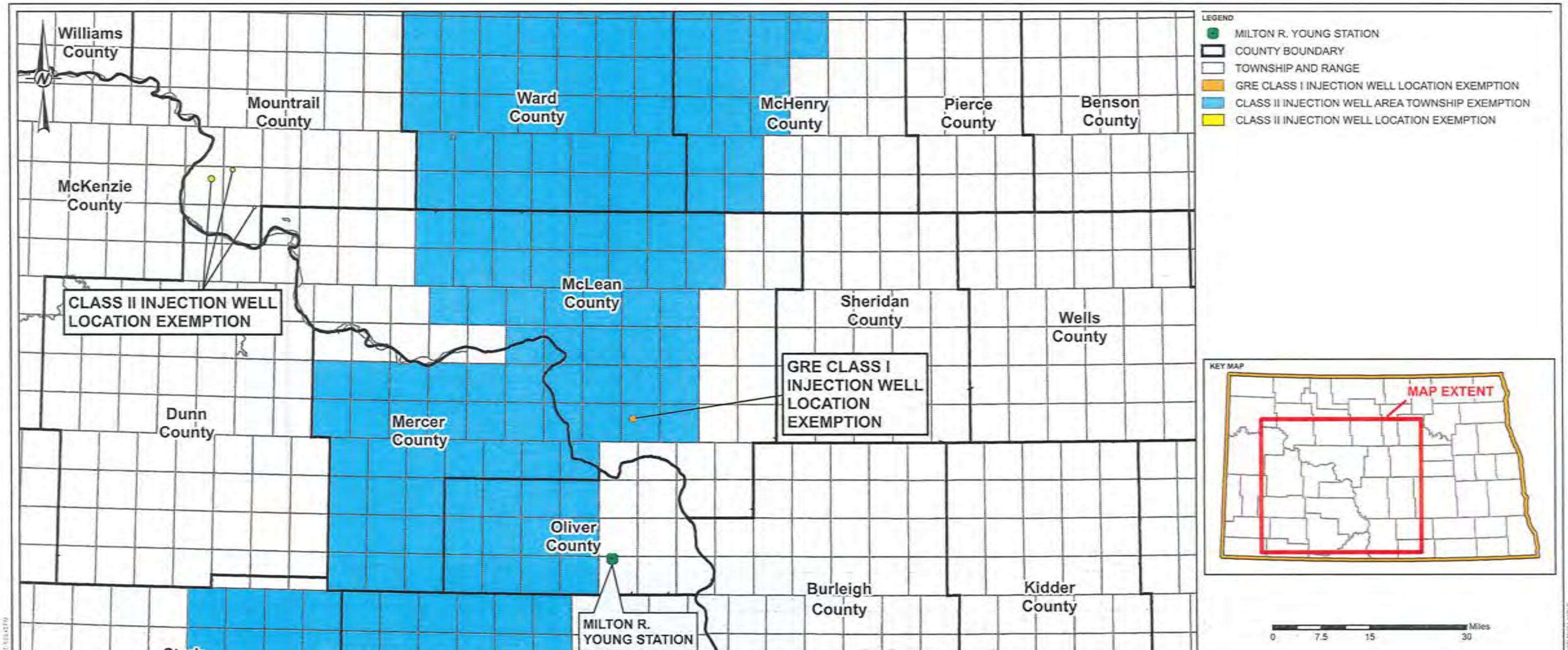
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 1-1



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CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
REGIONAL INYAN KARA AQUIFER EXEMPTIONS

CONSULTANT
GOLDER
MEMBER OF WSP

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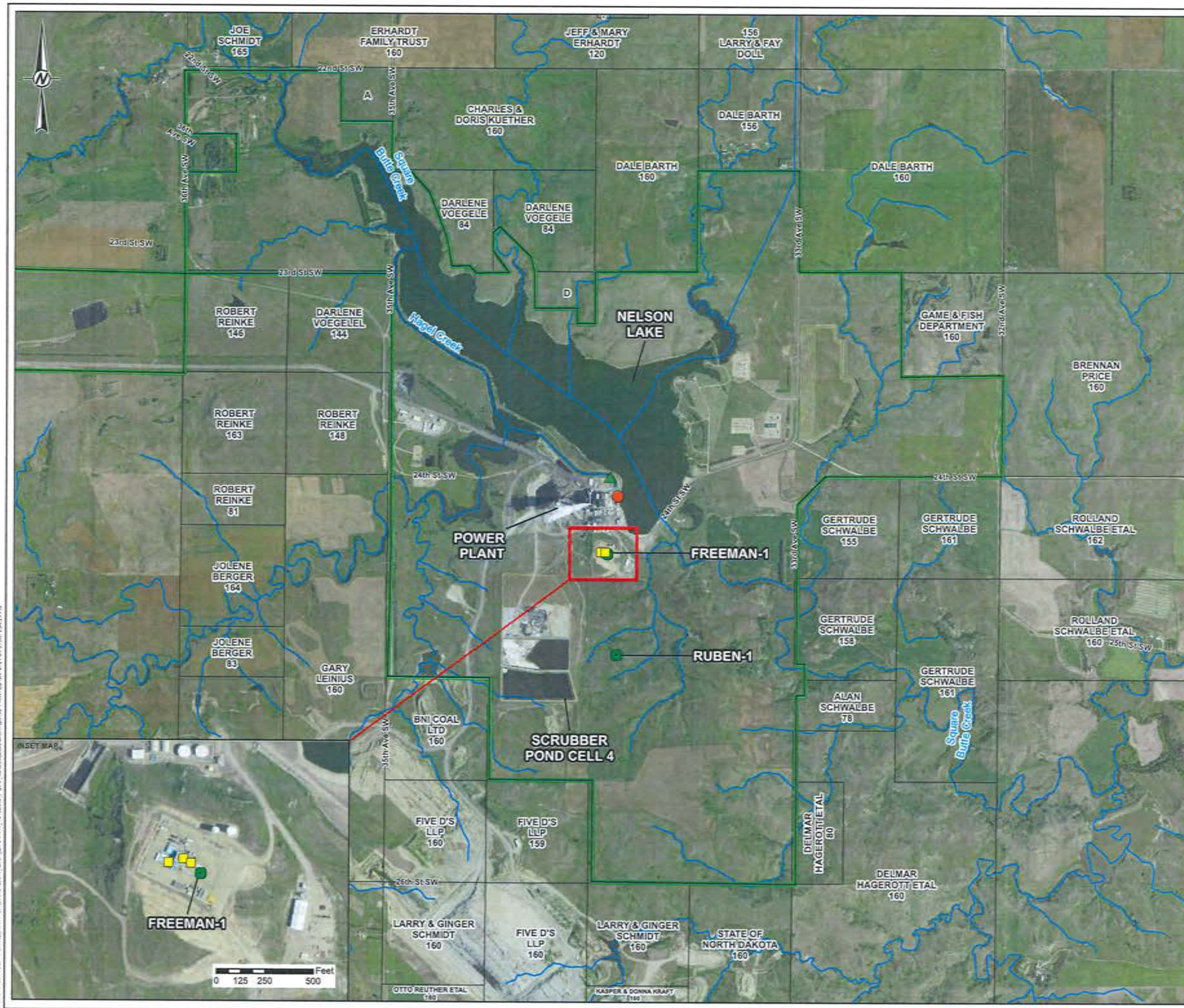
PROJECT NO.	REV.	FIGURE
19122669	0	1-4



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MPC PROPERTY BOUNDARY
- APPROXIMATE PARCEL BOUNDARIES
- LINEAR SURFACE WATER FEATURES
- INTAKE STRUCTURE
- DISCHARGE STRUCTURE
- PROPOSED CLASS VI INJECTION WELLS

KEY MAP

0 1,250 2,500 5,000 Feet

REFERENCES
1. AERIAL IMAGERY: NATIONAL AGRICULTURE IMAGERY PROGRAM (NAIP), USDA. IMAGE FLOWN 8/10/2020.
2. STREAMS DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.
3. ROAD DATA: U.S. CENSUS BUREAU, TIGER ROAD DATA 2019.
4. PARCEL BOUNDARIES: OLIVER COUNTY PLAT BOOK.

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MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

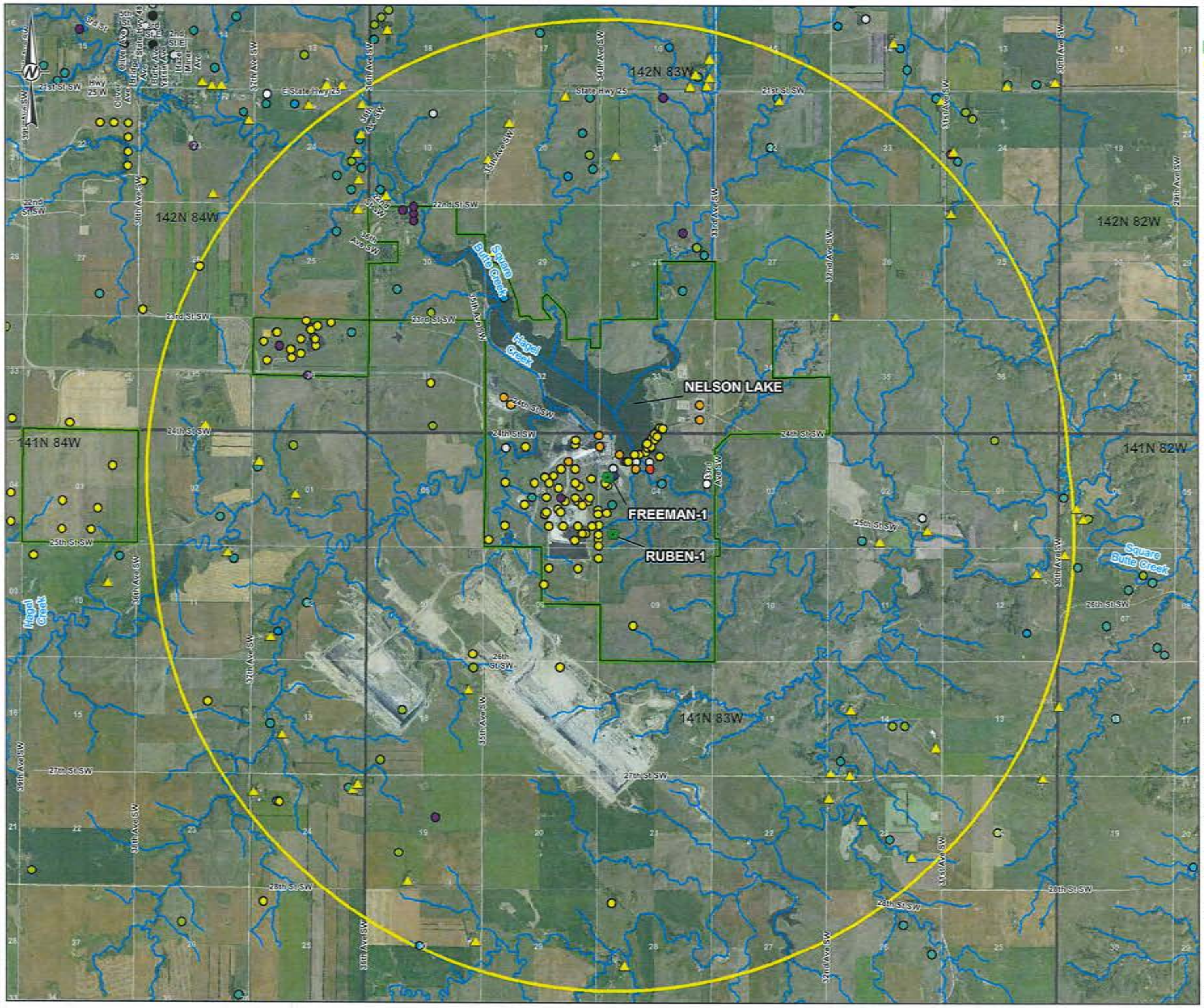
TITLE
SITE MAP

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	BJP
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 1-3



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MPC PROPERTY BOUNDARY
- AREA OF REVIEW (4 MILE RADIUS AROUND EACH WELL)
- TOWNSHIP
- SECTION
- LINEAR SURFACE WATER FEATURES
- RESIDENCES

WATER WELLS

- DOMESTIC
- DOMESTIC/STOCK
- INDUSTRIAL
- MONITORING
- STOCK
- TEST HOLE
- USGS INACTIVE
- MUNICIPAL
- OBSERVATION WELL
- UNKNOWN

KEY MAP

0 2,250 4,500 9,000 Feet

REFERENCES
1. AERIAL IMAGERY: NATIONAL AGRICULTURE IMAGERY PROGRAM (NAIP), USDA. IMAGE FLOWN 8/10/2020.
2. WELL DATA: NORTH DAKOTA WATER COMMISSION AND STATE ENGINEER WELL DRILLERS LOGS. DOWNLOADED 4/14/2021. (LOCATIONS ARE APPROXIMATE)
3. WELL DATA: MINNKOTA POWER COOPERATIVE MILTON R. YOUNG STATION MONITORING WELLS, PROVIDED BY MINNKOTA 4/8/2020.(LOCATIONS ARE APPROXIMATE)
4. WELL DATA: USGS NATIONAL WATER INFORMATION SYSTEM GROUNDWATER SITES DOWNLOAD 4/14/2021. (LOCATIONS ARE APPROXIMATE)
5. STREAMS DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.
6. ROAD DATA: U.S. CENSUS BUREAU, TIGER ROAD DATA 2019.
7. RESIDENCES: BASED ON AERIAL IMAGERY.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
AREA OF REVIEW - SHALLOW WELLS

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
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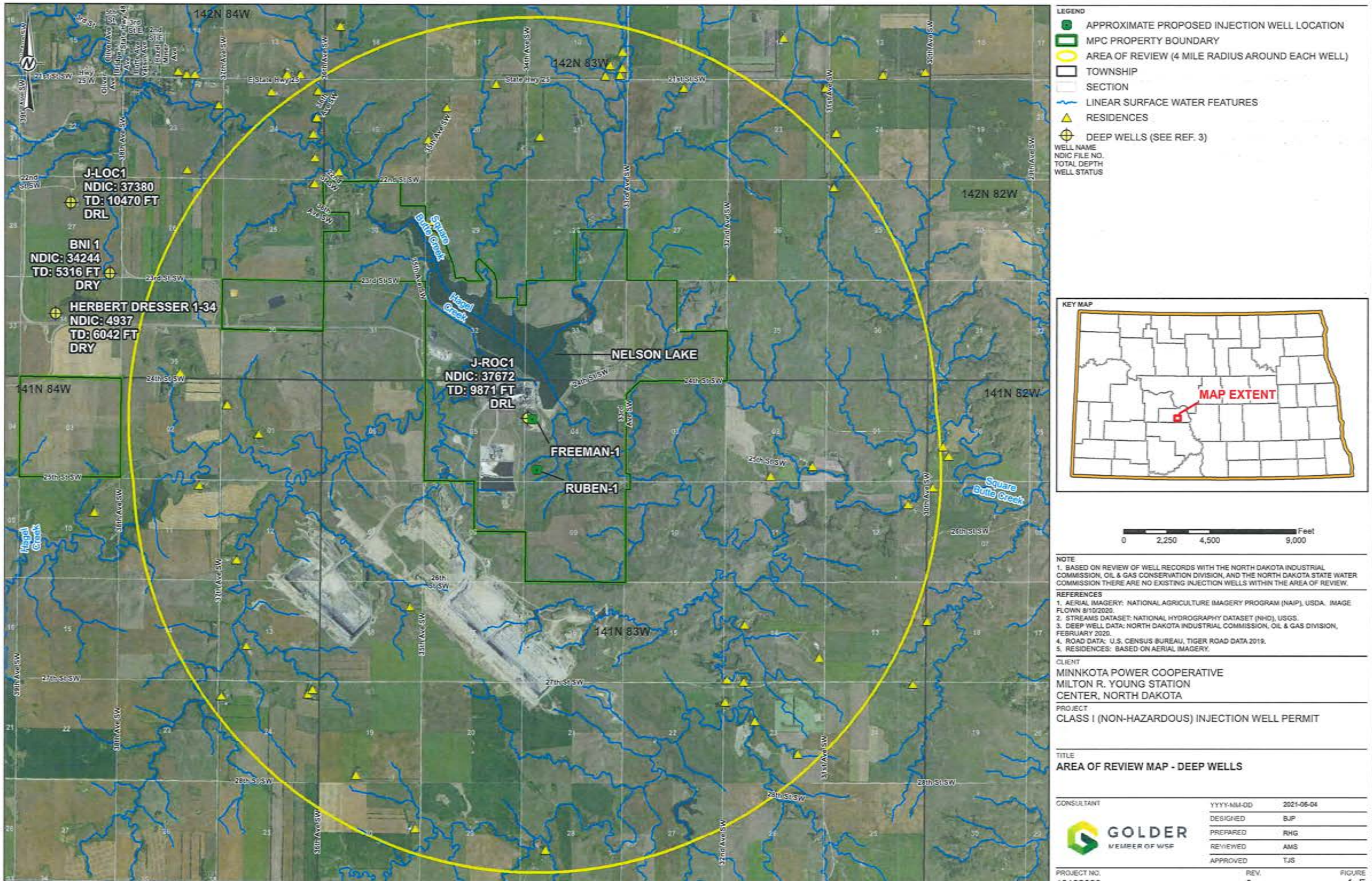
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 1-6



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MPC PROPERTY BOUNDARY
- AREA OF REVIEW (4 MILE RADIUS AROUND EACH WELL)
- TOWNSHIP
- SECTION
- LINEAR SURFACE WATER FEATURES
- RESIDENCES
- DEEP WELLS (SEE REF. 3)

WELL NAME
NDIC FILE NO.
TOTAL DEPTH
WELL STATUS

0 2,250 4,500 9,000 Feet

NOTE
1. BASED ON REVIEW OF WELL RECORDS WITH THE NORTH DAKOTA INDUSTRIAL COMMISSION, OIL & GAS CONSERVATION DIVISION, AND THE NORTH DAKOTA STATE WATER COMMISSION THERE ARE NO EXISTING INJECTION WELLS WITHIN THE AREA OF REVIEW.

REFERENCES
1. AERIAL IMAGERY: NATIONAL AGRICULTURE IMAGERY PROGRAM (NAIP), USDA. IMAGE FLOWN 8/10/2020.
2. STREAMS DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.
3. DEEP WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL & GAS DIVISION, FEBRUARY 2020.
4. ROAD DATA: U.S. CENSUS BUREAU, TIGER ROAD DATA 2019.
5. RESIDENCES: BASED ON AERIAL IMAGERY.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

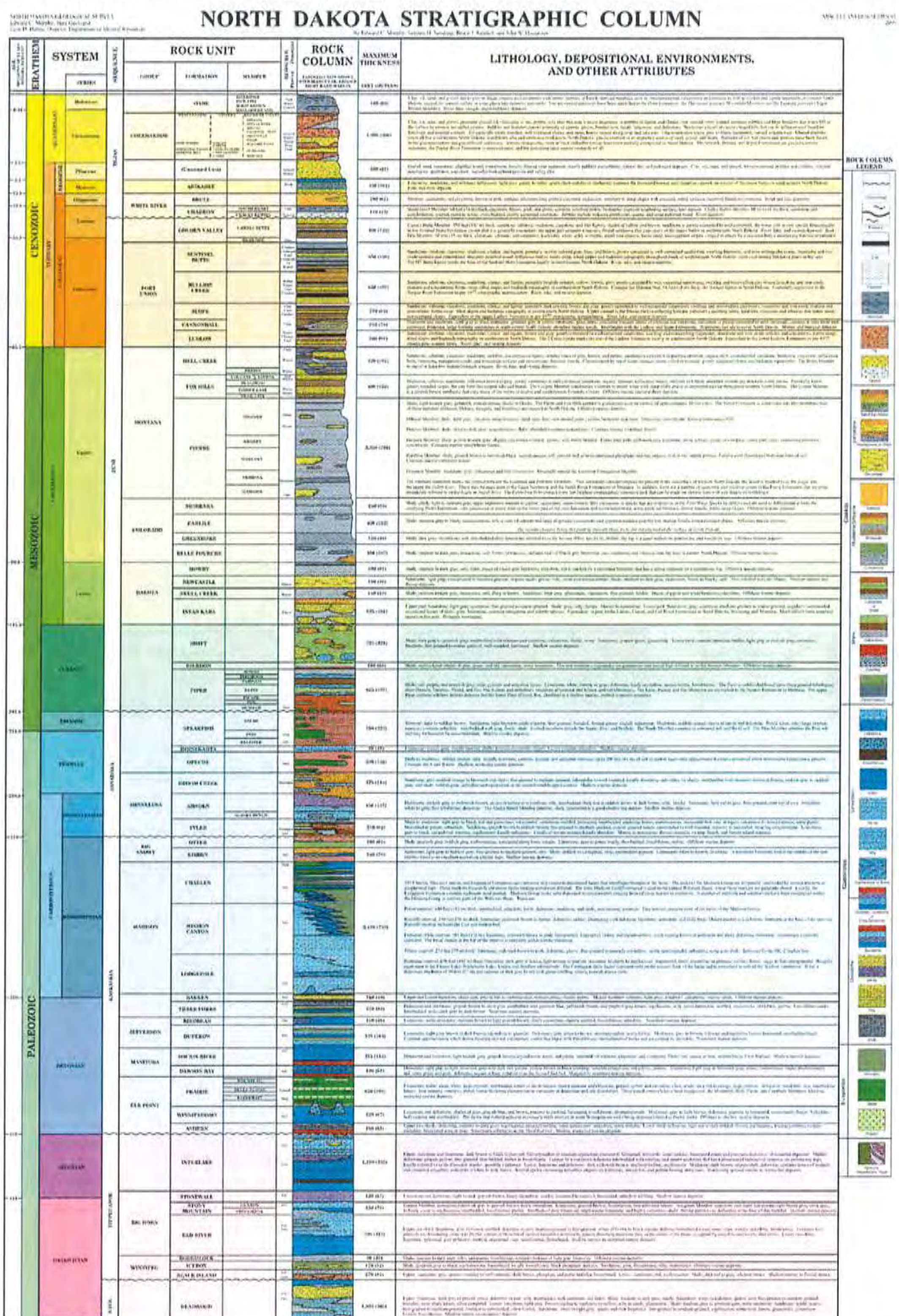
PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
AREA OF REVIEW MAP - DEEP WELLS

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	BJP
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	1-5



REFERENCE(S)
1. NORTH DAKOTA STRATIGRAPHIC COLUMN OBTAINED FROM NORTH DAKOTA GEOLOGICAL SURVEY WEBSITE (HTTPS://WWW.DMR.ND.GOV/NDGS/DOCUMENTS/PUBLICATION_LIST/PDF/STRAT-COLUMN-NDGS-(2009).PDF) ON JUNE 2, 2020.

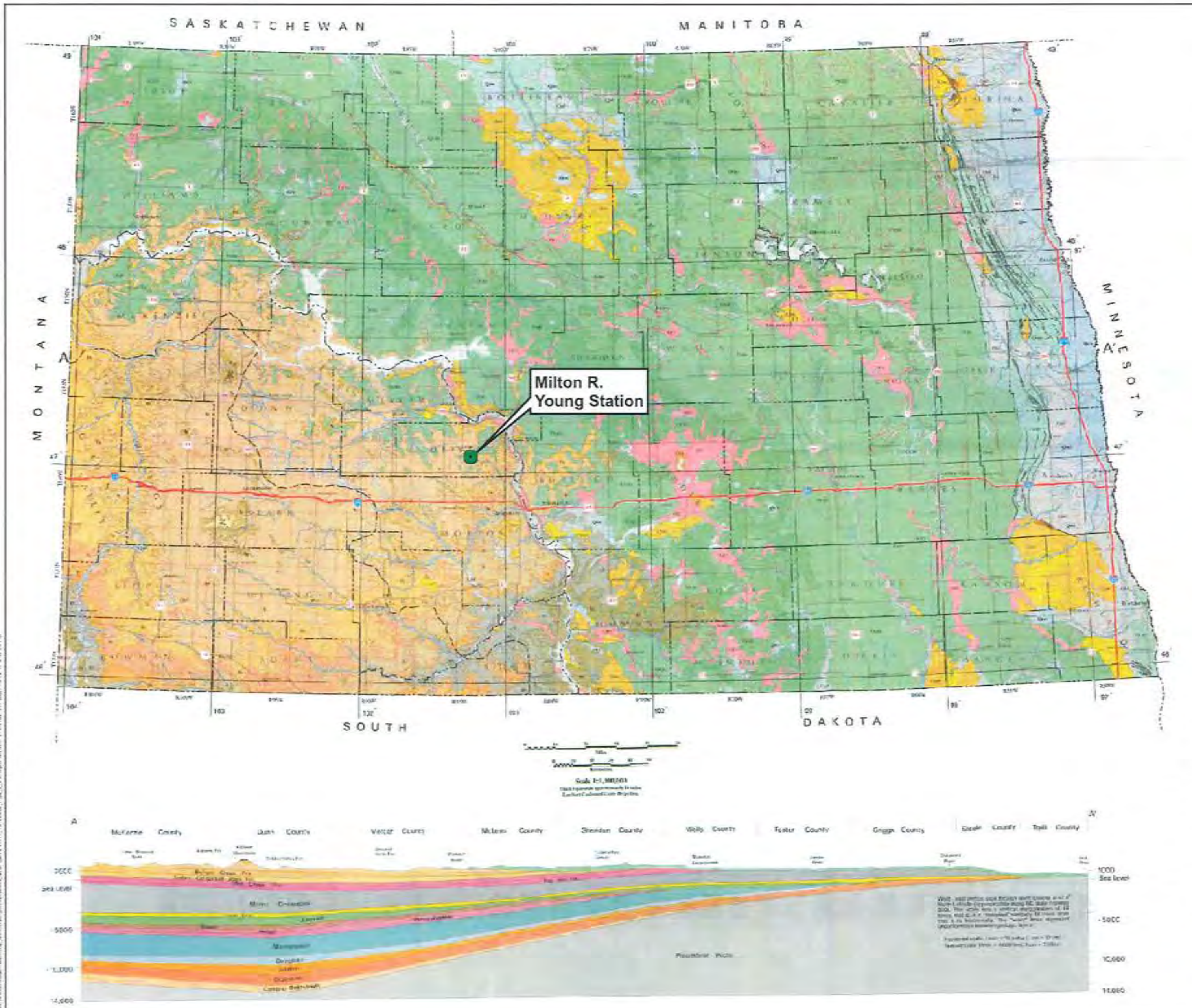
CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
NORTH DAKOTA STRATIGRAPHIC COLUMN

CONSULTANT		
GOLDER MEMBER OF WSP	YYYY-MM-DD	2021-06-04
	DESIGNED	TH
	PREPARED	RHG
	REVIEWED	AMS
	APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-2



REFERENCES
1. MAP OBTAINED FROM BLUEMLE, J.P. 2000. THE FACE OF NORTH DAKOTA, 3RD ED. 210 P.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

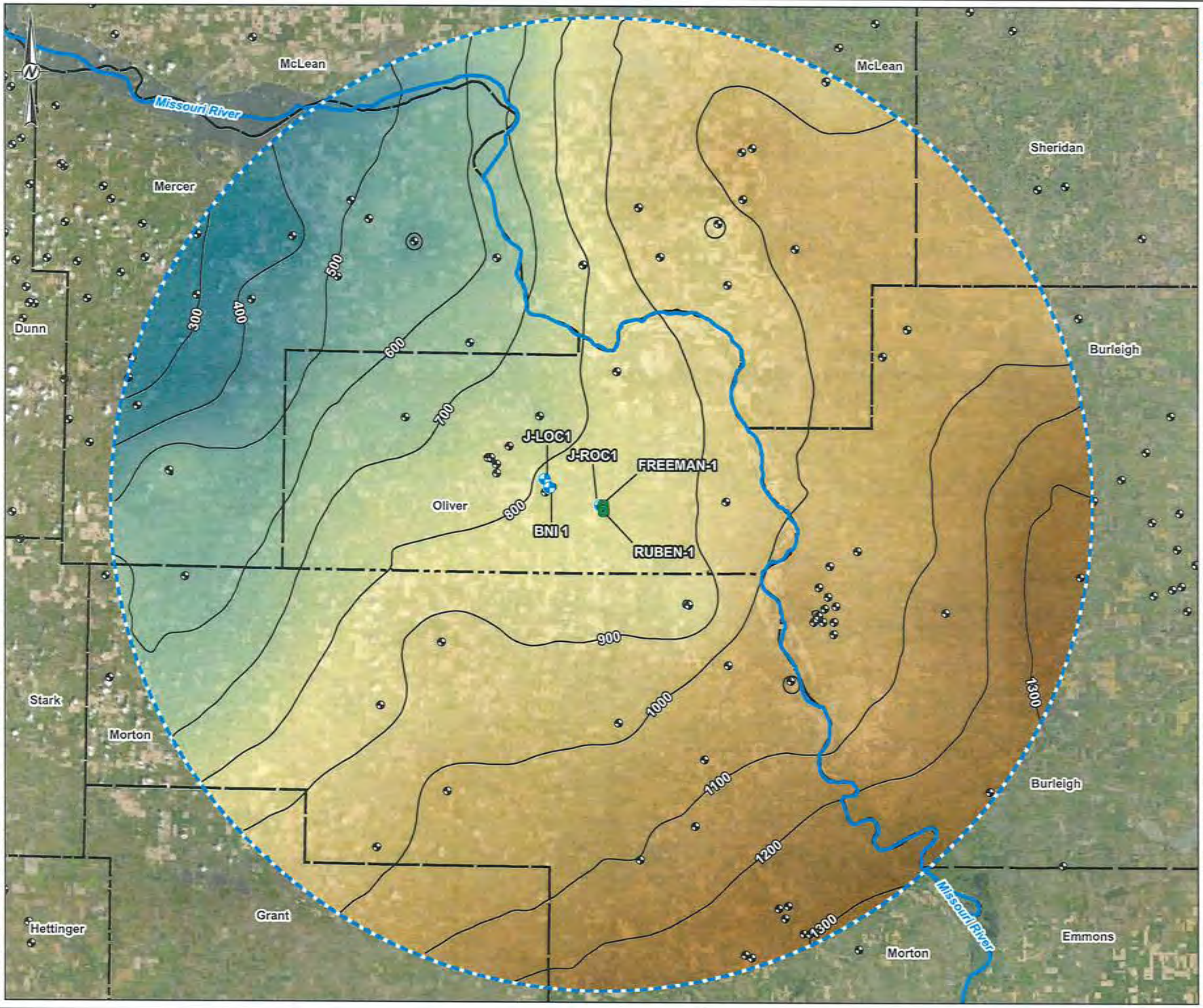
TITLE
GEOLOGIC PLAN AND PROFILE
OF NORTH DAKOTA

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-1



LEGEND
- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- 40-MILE RADIUS
- COUNTY BOUNDARY
- MISSOURI RIVER
- WELL USED FOR MODELLING FORMATION TOPS
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- FORMATION TOP ELEVATION CONTOUR (FT AMSL, 100-FT INTERVAL)

0 4 8 16 Miles

REFERENCES
1. AERIAL IMAGERY: ESRI, DIGITAL GLOBE, VIVID - USA. IMAGERY CAPTURED JULY 2016.
2. WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. RIVER DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUTS) INJECTION WELL PERMIT

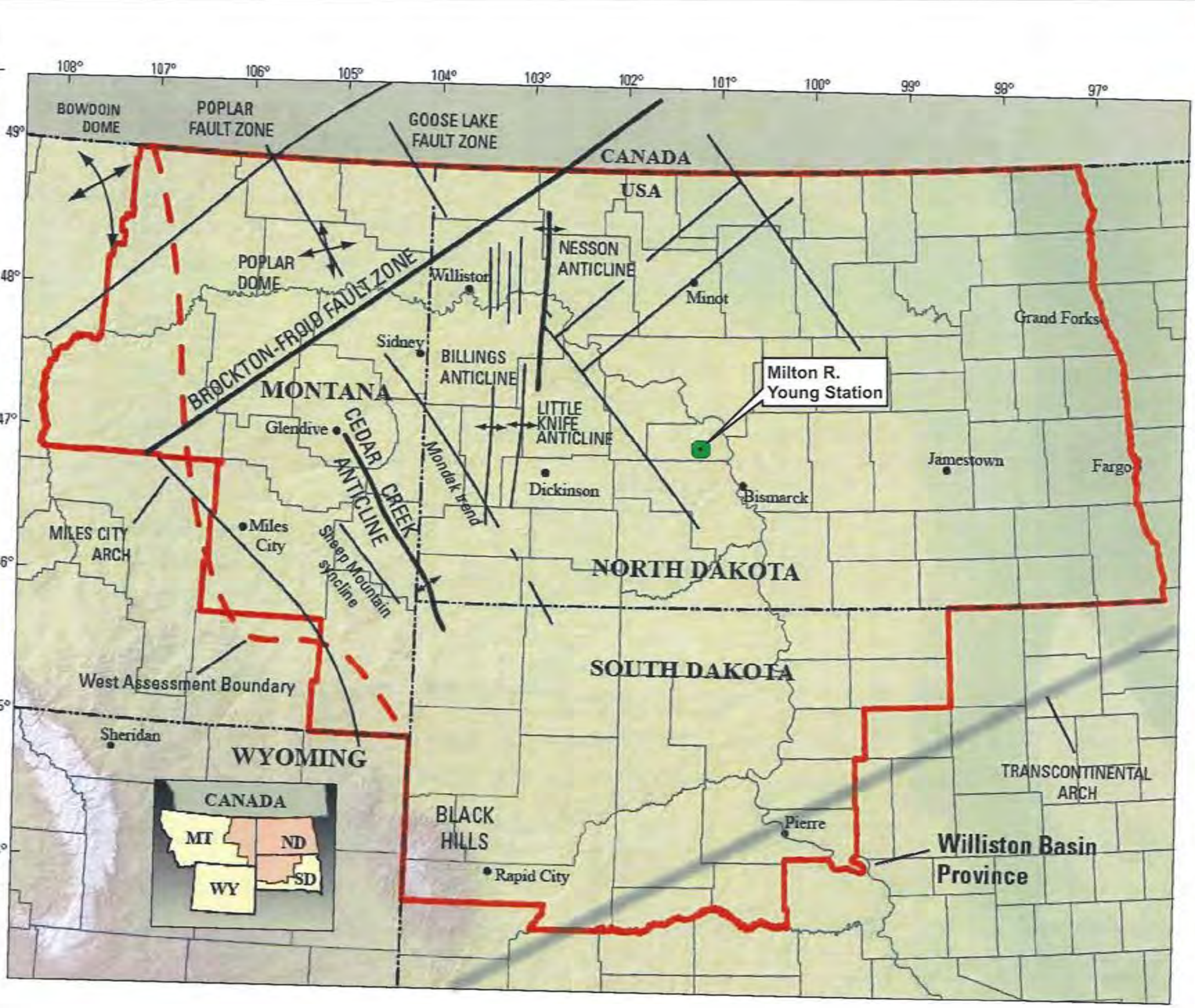
TITLE
FORMATION TOP ELEVATIONS - PIERRE SHALE FORMATION

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-4



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MAJOR LINEAMENTS OR FAULTS (UNLABELED)
- PROVINCE BOUNDARY
- WESTERN BOUNDARY FOR ASSESSMENT UNITS

NOTE
1. LOCATION AND PHYSIOGRAPHIC FEATURES OF THE WILLISTON BASIN PROVINCE. BLACK LINES NOT LABELED ARE MAJOR LINEAMENTS OR FAULTS. SOLID RED LINE IS PROVINCE BOUNDARY; DASHED RED LINE REPRESENTS THE WESTERN BOUNDARY FOR ASSESSMENT UNITS. LINEAMENTS AND STRUCTURE LOCATIONS ARE FROM GERHARD AND OTHERS (1982) AND ANNA (1986).

REFERENCES
1. MAP OBTAINED FROM ANNA, L. O., POLLASTRO, R. & GASWIRTH, S.B., 2013. WILLISTON BASIN PROVINCE - STRATIGRAPHIC AND STRUCTURAL FRAMEWORK TO A GEOLOGICAL ASSESSMENT OF UNDISCOVERED OIL AND GAS RESOURCES, RESTON, VIRGINIA: U.S. GEOLOGICAL SURVEY.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

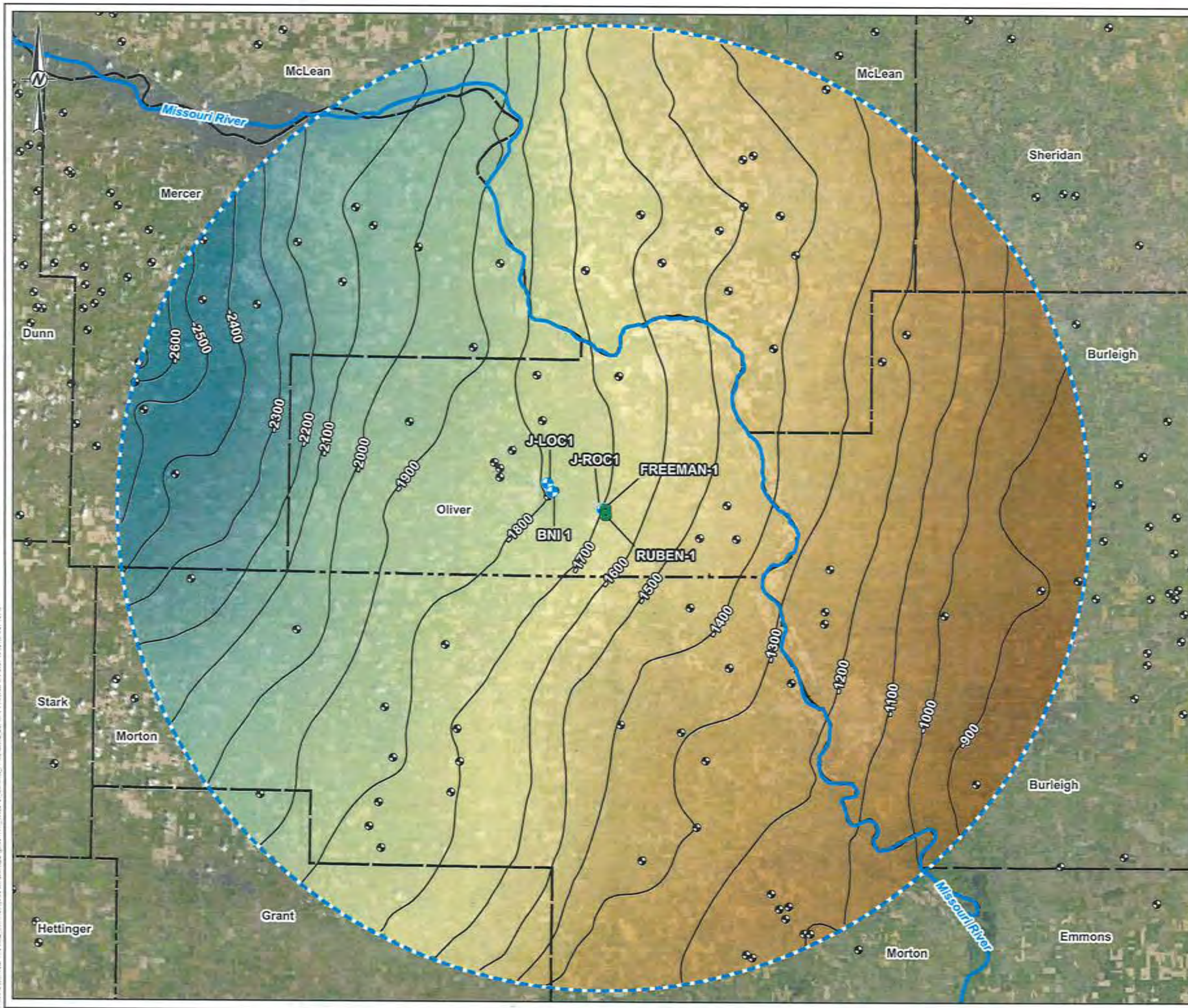
TITLE
STRUCTURAL FEATURES OF THE WILLISTON BASIN PROVINCE

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-3



LEGEND
- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- 40-MILE RADIUS
- COUNTY BOUNDARY
- MISSOURI RIVER
- WELL USED FOR MODELLING FORMATION TOPS
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- FORMATION TOP ELEVATION CONTOUR (FT AMSL, 100-FT INTERVAL)

REFERENCES
1. AERIAL IMAGERY: ESRI, DIGITAL GLOBE, VIVID - USA, IMAGERY CAPTURED JULY 2016.
2. WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. RIVER DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

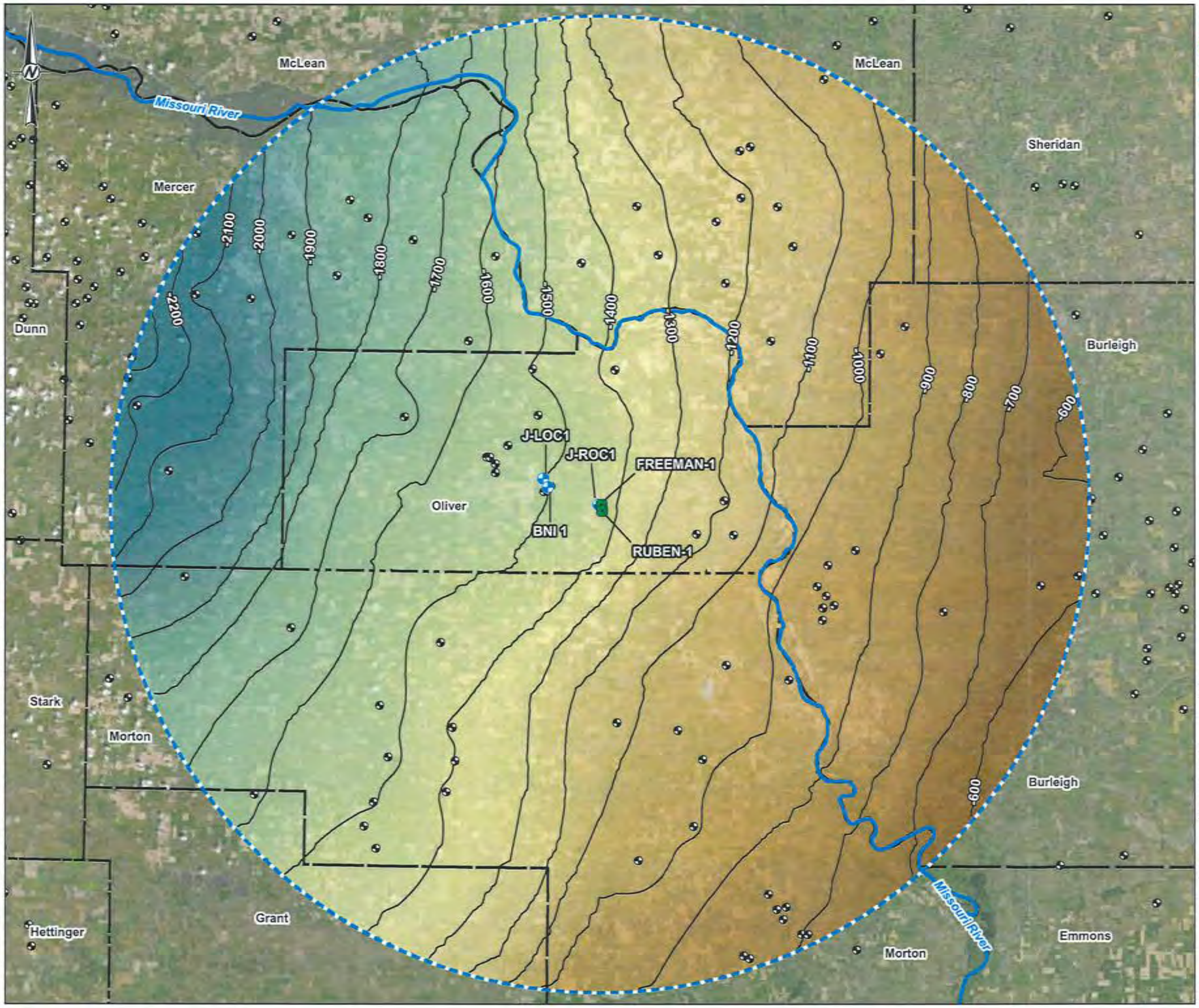
PROJECT
CLASS I (NON-HAZARDOUTS) INJECTION WELL PERMIT

TITLE
FORMATION TOP ELEVATIONS - INYAN KARA FORMATION

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-6



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- 40-MILE RADIUS
- COUNTY BOUNDARY
- MISSOURI RIVER
- WELL USED FOR MODELLING FORMATION TOPS
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- FORMATION TOP ELEVATION CONTOUR (FT AMSL, 100-FT INTERVAL)

REFERENCES
1. AERIAL IMAGERY: ESRI, DIGITAL GLOBE, VIVID - USA, IMAGERY CAPTURED JULY 2016.
2. WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. RIVER DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.

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MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

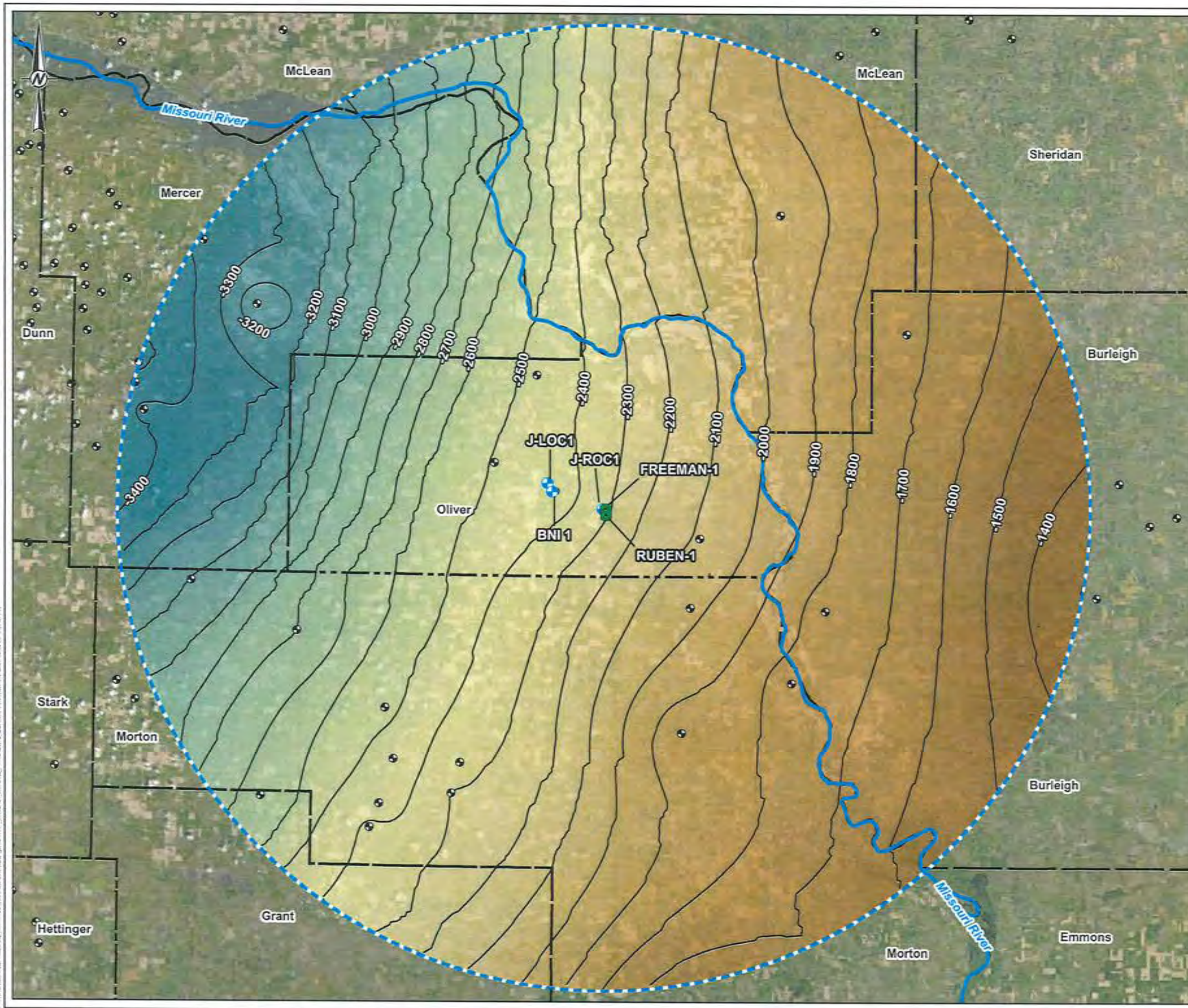
PROJECT
CLASS I (NON-HAZARDOUTS) INJECTION WELL PERMIT

TITLE
FORMATION TOP ELEVATIONS - MOWRY FORMATION

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-5



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- 40-MILE RADIUS
- COUNTY BOUNDARY
- MISSOURI RIVER
- WELL USED FOR MODELLING FORMATION TOPS
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- FORMATION TOP ELEVATION CONTOUR (FT AMSL, 100-FT INTERVAL)

0 4 8 16 Miles

REFERENCES
1. AERIAL IMAGERY: ESRI, DIGITAL GLOBE, VIVID - USA, IMAGERY CAPTURED JULY 2016.
2. WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. RIVER DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

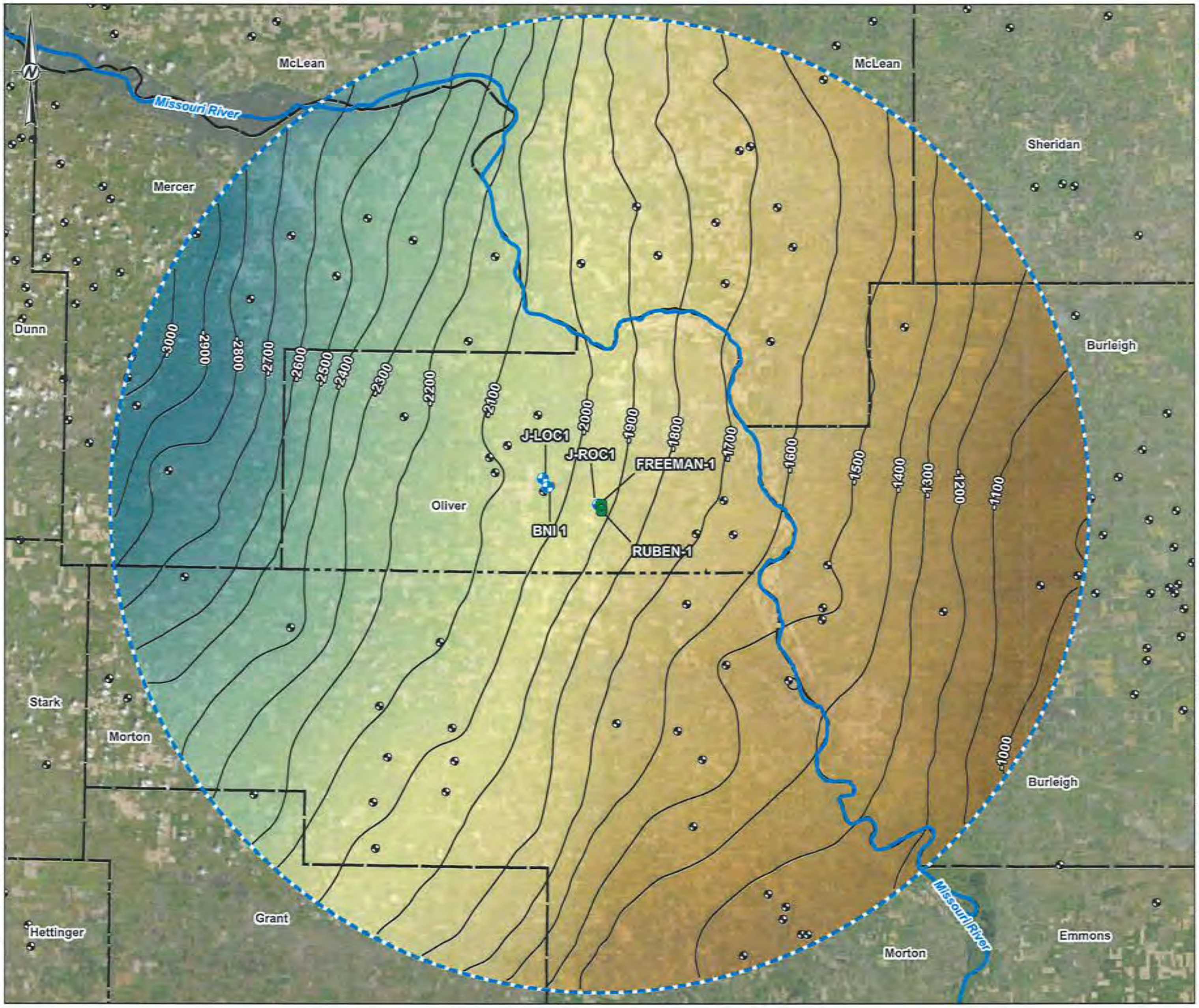
PROJECT
CLASS I (NON-HAZARDOUTS) INJECTION WELL PERMIT

TITLE
FORMATION TOP ELEVATIONS - RIERDON FORMATION

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-8



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- 40-MILE RADIUS
- COUNTY BOUNDARY
- MISSOURI RIVER
- WELL USED FOR MODELLING FORMATION TOPS
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- FORMATION TOP ELEVATION CONTOUR (FT AMSL, 100-FT INTERVAL)

0 4 8 16 Miles

REFERENCES

1. AERIAL IMAGERY: ESRI, DIGITAL GLOBE, VIVID - USA, IMAGERY CAPTURED JULY 2016.
2. WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. RIVER DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUTS) INJECTION WELL PERMIT

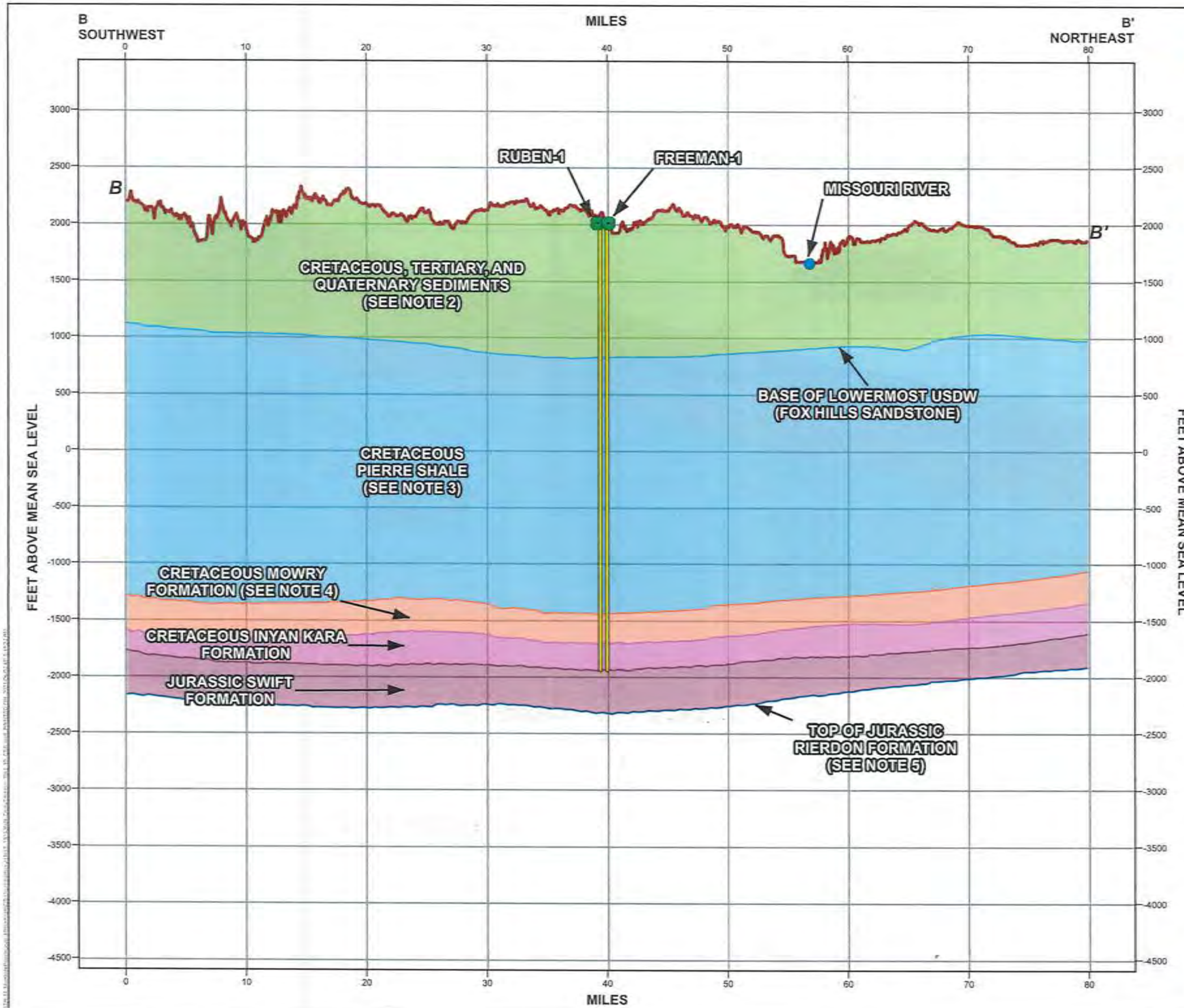
TITLE
FORMATION TOP ELEVATIONS - SWIFT FORMATION

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV	FIGURE
19122669	0	3-7



CROSS SECTION LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MISSOURI RIVER
- GROUND SURFACE (REF. 3)

NOTE

1. CROSS SECTIONS SET TO 50X VERTICAL EXAGGERATION.
2. FORMATION CONTACTS ABOVE THE TOP OF THE CRETACEOUS PIERRE SHALE HAVE NOT BEEN DELINEATED.
3. FORMATION CONTACTS BETWEEN THE TOP OF THE CRETACEOUS PIERRE SHALE AND THE TOP OF THE CRETACEOUS MOWRY FORMATION, INCLUDING THE NIOBRARA, CARLILE, GREENHORN, AND BELLE FOURCHE FORMATIONS, HAVE NOT BEEN DELINEATED.
4. FORMATION CONTACTS BETWEEN THE TOP OF THE CRETACEOUS MOWRY FORMATION AND THE TOP OF THE CRETACEOUS INYAN KARA FORMATION, INCLUDING THE NEWCASTLE AND SKULL CREEK FORMATIONS, HAVE NOT BEEN DELINEATED.
5. FORMATION CONTACTS BELOW THE TOP OF THE JURASSIC RIERDON FORMATION HAVE NOT BEEN DELINEATED.

REFERENCES

1. REFERENCE BASEMAP: ESRI PROVIDED BASEMAP SERVICES, NATIONAL GEOGRAPHIC BASEMAP.
2. NORTH DAKOTA WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. GROUND SURFACE ELEVATION: USGS NED 1/3 ARC-SECOND RESOLUTION DIGITAL ELEVATION MODEL. PUBLISHED 3/15/2017.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

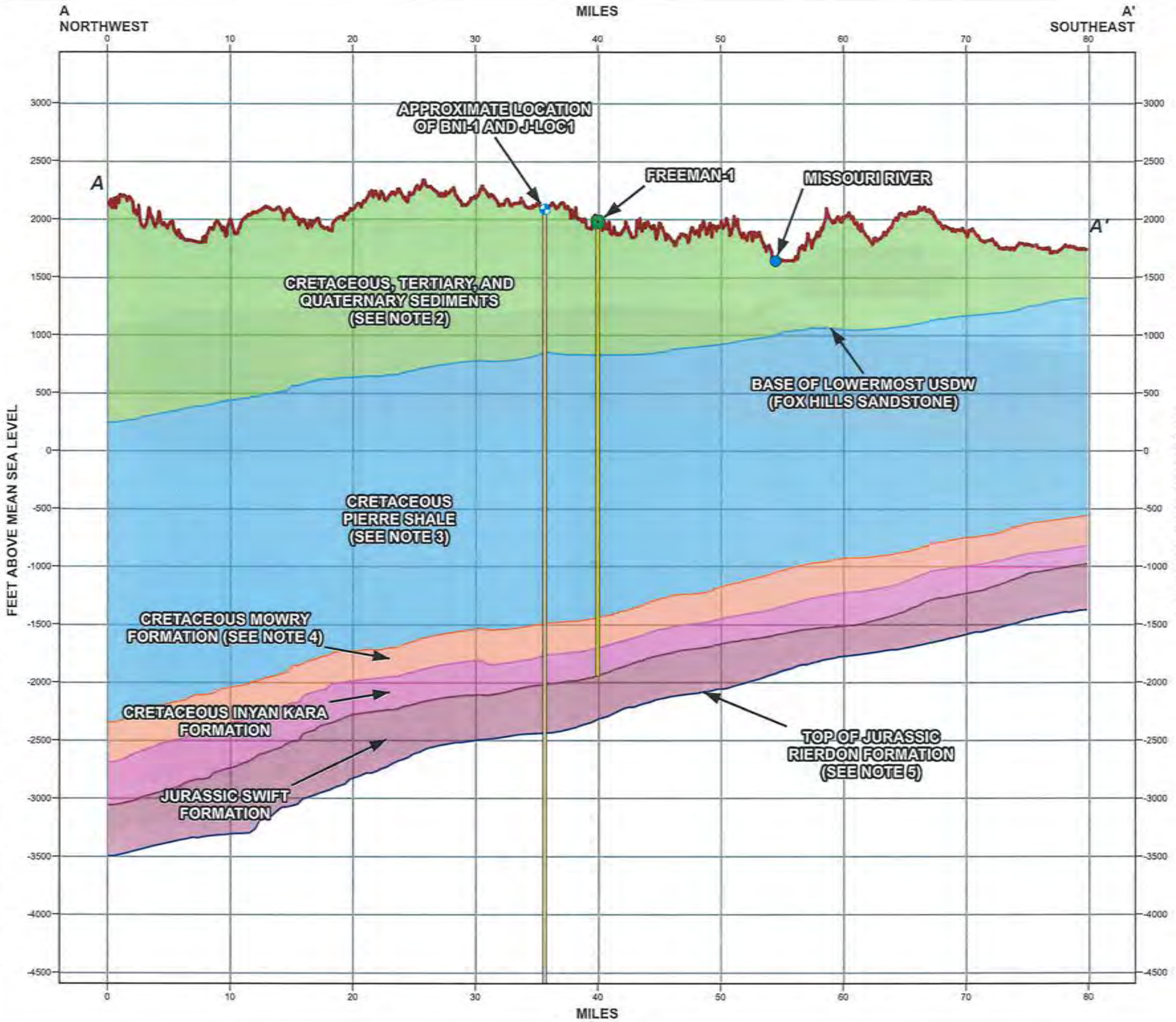
TITLE
GEOLOGIC CROSS SECTION B-B'

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-10



CROSS SECTION LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MISSOURI RIVER
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- GROUND SURFACE (REF. 3)

NOTE

1. CROSS SECTIONS SET TO 50X VERTICAL EXAGGERATION.
2. FORMATION CONTACTS ABOVE THE TOP OF THE CRETACEOUS PIERRE SHALE HAVE NOT BEEN DELINEATED.
3. FORMATION CONTACTS BETWEEN THE TOP OF THE CRETACEOUS PIERRE SHALE AND THE TOP OF THE CRETACEOUS MOWRY FORMATION, INCLUDING THE NIOBRARA, CARLILE, GREENHORN, AND BELLE FOURCHE FORMATIONS, HAVE NOT BEEN DELINEATED.
4. FORMATION CONTACTS BETWEEN THE TOP OF THE CRETACEOUS MOWRY FORMATION AND THE TOP OF THE CRETACEOUS INYAN KARA FORMATION, INCLUDING THE NEWCASTLE AND SKULL CREEK FORMATIONS, HAVE NOT BEEN DELINEATED.
5. FORMATION CONTACTS BELOW THE TOP OF THE JURASSIC RIERDON FORMATION HAVE NOT BEEN DELINEATED.

REFERENCES

1. REFERENCE BASEMAP: ESRI PROVIDED BASEMAP SERVICES, NATIONAL GEOGRAPHIC BASEMAP.
2. NORTH DAKOTA WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. GROUND SURFACE ELEVATION: USGS NED 1/3 ARC-SECOND RESOLUTION DIGITAL ELEVATION MODEL. PUBLISHED 3/15/2017.

CLIENT
MINNKOTA POWER COOPERATIVE
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CENTER, NORTH DAKOTA

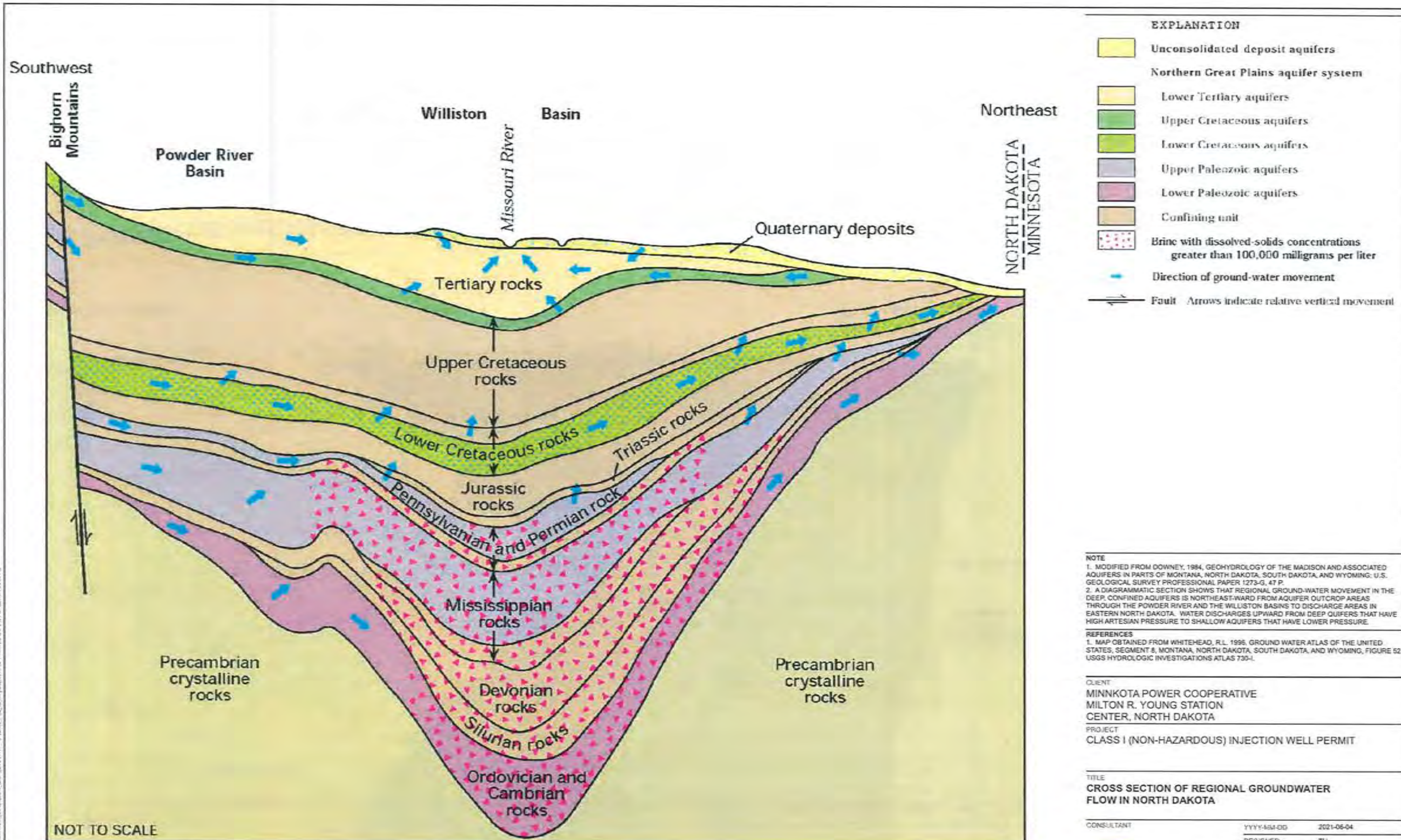
PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
GEOLOGIC CROSS SECTION A-A'

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-9



NOTE

1. MODIFIED FROM DOWNEY, 1984, GEOHYDROLOGY OF THE MADISON AND ASSOCIATED AQUIFERS IN PARTS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING: U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1273-G, 47 P.
2. A DIAGRAMMATIC SECTION SHOWS THAT REGIONAL GROUND-WATER MOVEMENT IN THE DEEP, CONFINED AQUIFERS IS NORTHEAST-WARD FROM AQUIFER OUTCROP AREAS THROUGH THE POWDER RIVER AND THE WILLISTON BASINS TO DISCHARGE AREAS IN EASTERN NORTH DAKOTA. WATER DISCHARGES UPWARD FROM DEEP QUIFERS THAT HAVE HIGH ARTESIAN PRESSURE TO SHALLOW AQUIFERS THAT HAVE LOWER PRESSURE.

REFERENCES

1. MAP OBTAINED FROM WHITEHEAD, R.L. 1996, GROUND WATER ATLAS OF THE UNITED STATES, SEGMENT 8, MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 52. USGS HYDROLOGIC INVESTIGATIONS ATLAS 730-I.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

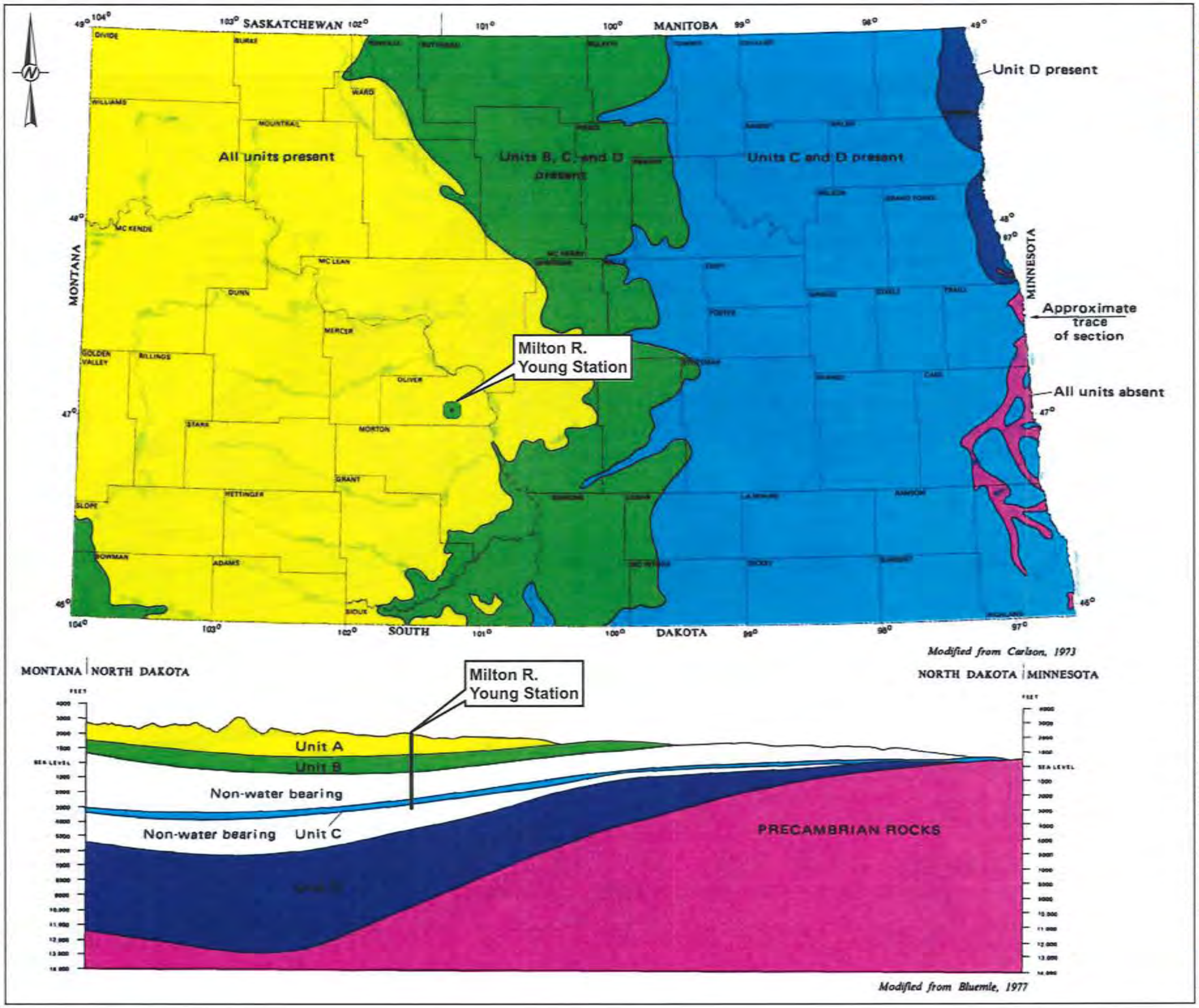
TITLE
CROSS SECTION OF REGIONAL GROUNDWATER FLOW IN NORTH DAKOTA

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-12



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- UNIT A: FORT UNION FORMATION
- UNIT B: LOWER PART OF HELL CREEK FORMATION AND FOX HILLS SANDSTONE
- UNIT C: DAKOTA SANDSTONE
- UNIT D: PALEOZOIC ROCKS (INCLUDING MINNELUSA AND MADISON GROUPS)
- ALL UNITS ABSENT

NOTE

1. LOCATION AND DEPTHS OF BEDROCK AQUIFER UNITS A, B, C AND D. MORE BEDROCK AQUIFERS ARE AVAILABLE IN WESTERN NORTH DAKOTA THAN IN THE EASTERN PART. HOWEVER, DEPTH TO AQUIFERS INCREASES TOWARDS THE WEST. COLOR ON MAP REPRESENTS UPPERMOST UNIT.

REFERENCES

1. MAP OBTAINED FROM PAULSON, Q. F. 1983. GUIDE TO NORTH DAKOTA'S GROUND-WATER RESOURCES, FIGURE 8. U.S. GEOLOGICAL SURVEY WATER-SUPPLY PAPER 2236.

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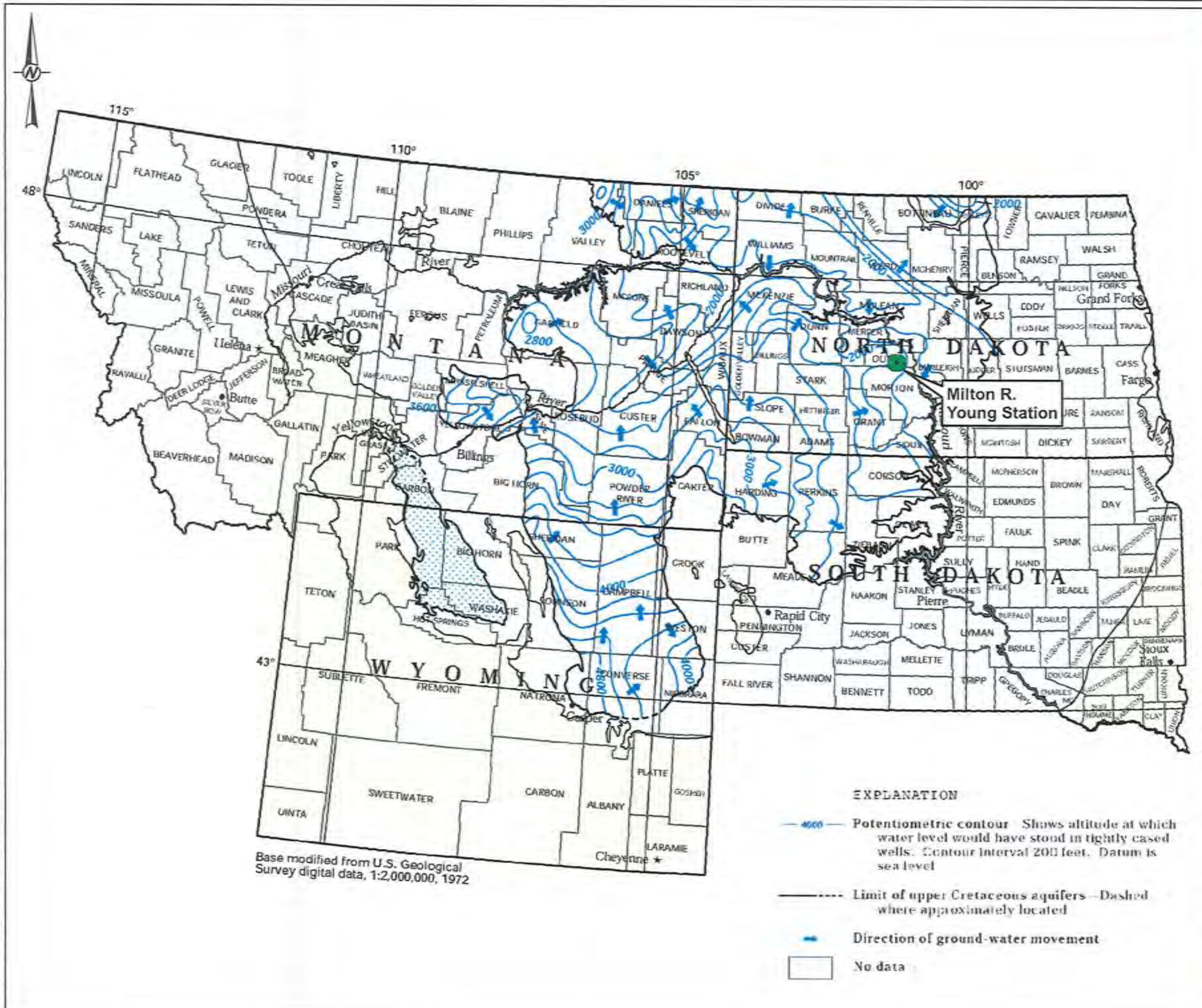
PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
CONCEPTUAL DEPICTION OF AQUIFER EXTENTS

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV	FIGURE
19122669	0	3-11



LEGEND

APPROXIMATE PROPOSED INJECTION WELL LOCATION

0 40 80 160 Miles

NOTE

1. MODIFIED FROM LOBMEYER, D.H., 1985, FRESHWATER HEADS AND GROUND-WATER TEMPERATURES IN AQUIFERS OF THE NORTHERN GREAT PLAINS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING: U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1402-D, 11 P.
2. WATER IN THE UPPER CRETACEOUS AQUIFERS GENERALLY MOVES NORTHWARD IN WYOMING AND NORTHEASTWARD ELSEWHERE. REGIONAL MOVEMENT IS FROM AQUIFER RECHARGE AREAS AT HIGHER ALTITUDES TOWARD LOW-LYING MAJOR STREAMS.

REFERENCES

1. MAP OBTAINED FROM WHITEHEAD, R.L. 1996, GROUND WATER ATLAS OF THE UNITED STATES, SEGMENT 8, MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 56. USGS HYDROLOGIC INVESTIGATIONS ATLAS 730-I.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

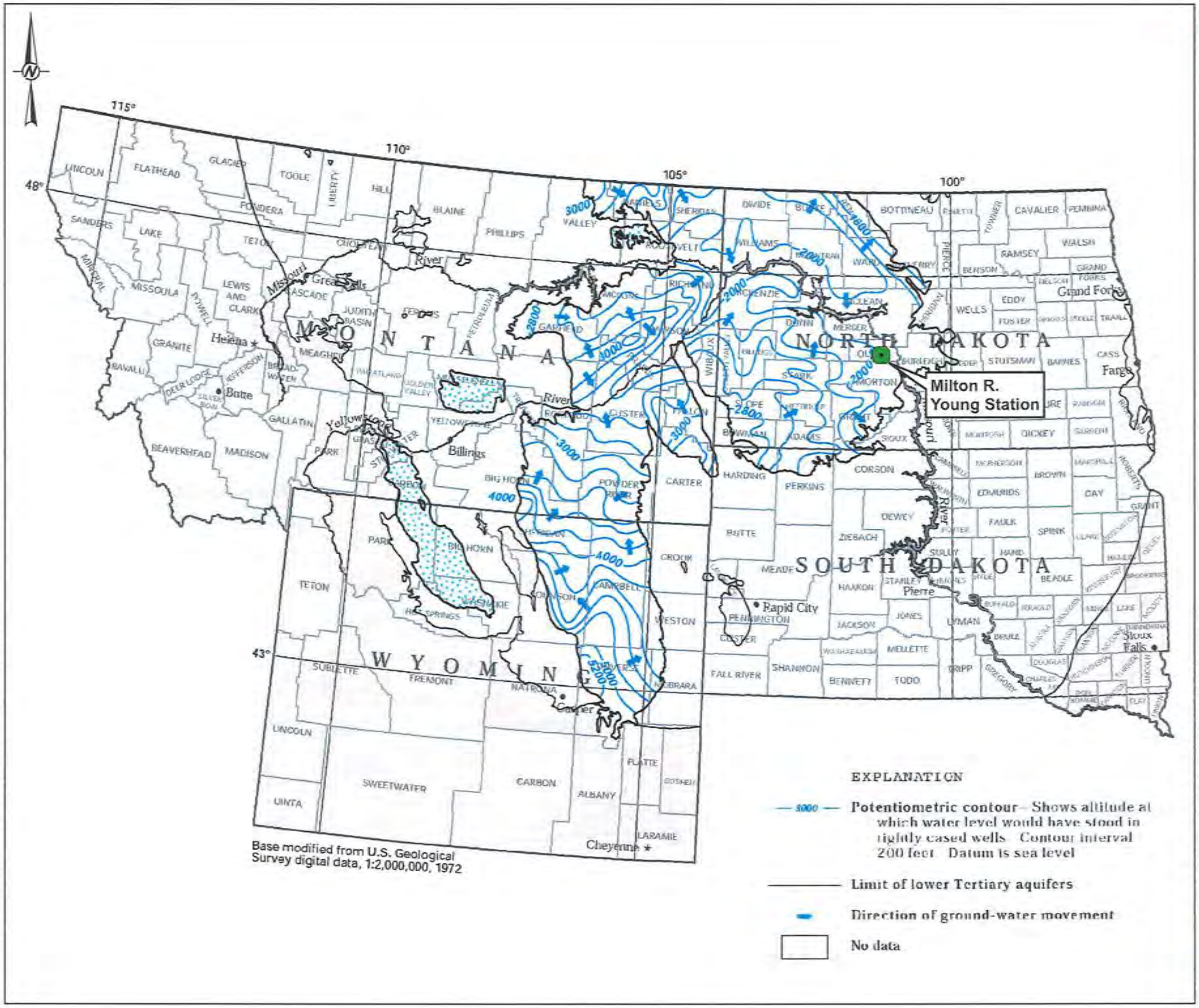
TITLE
POTENTIOMETRIC SURFACE OF THE UPPER CRETACEOUS AQUIFER SYSTEM

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-14



LEGEND

APPROXIMATE PROPOSED INJECTION WELL LOCATION

NOTE

1. MODIFIED FROM LOBMEYER, D.H., 1985, FRESHWATER HEADS AND GROUND-WATER TEMPERATURES IN AQUIFERS OF THE NORTHERN GREAT PLAINS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING: U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1402-D, 11 P.

2. WATER IN THE LOWER TERTIARY AQUIFERS GENERALLY MOVES NORTHWARD AND NORTHEASTWARD FROM RECHARGE AREAS AT HIGHER ALTITUDES. THE REGIONAL TREND OF MOVEMENT CHANGES LOCALLY WHERE THE AQUIFER DISCHARGES WATER TO LARGE STREAMS.

REFERENCES

1. MAP OBTAINED FROM WHITEHEAD, R.L. 1996, GROUND WATER ATLAS OF THE UNITED STATES, SEGMENT 8, MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 55. USGS HYDROLOGIC INVESTIGATIONS ATLAS 730-I.

CLIENT
MINNKOTA POWER COOPERATIVE
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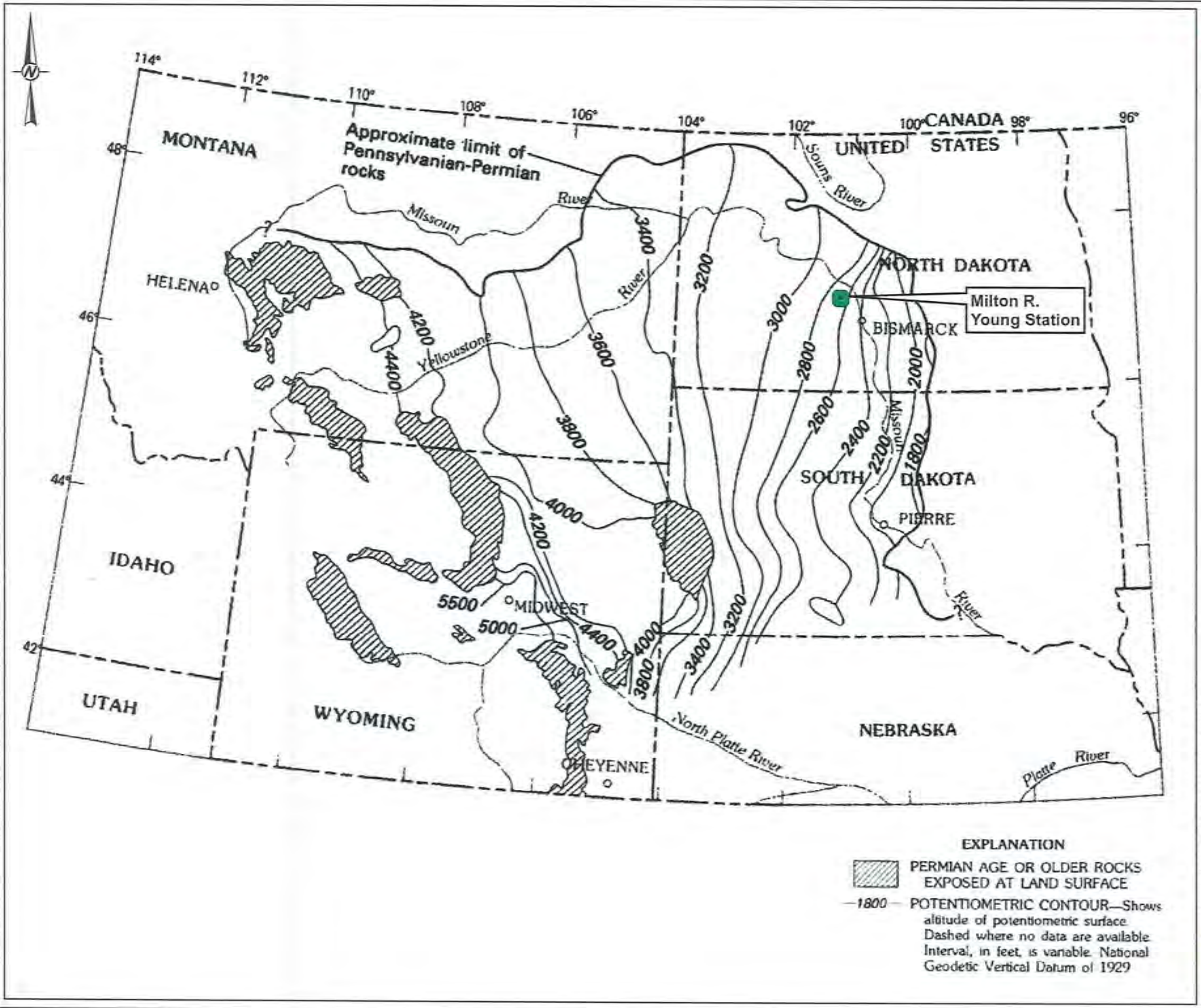
PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
POTENTIOMETRIC SURFACE OF THE LOWER TERTIARY AQUIFER SYSTEM

CONSULTANT		
GOLDER MEMBER OF WSP	YYYY-MM-DD	2021-06-04
	DESIGNED	TH
	PREPARED	RHG
	REVIEWED	AMS
	APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-13



LEGEND

APPROXIMATE PROPOSED INJECTION WELL LOCATION

REFERENCES

1. MAP OBTAINED FROM DOWNEY, J.A. 1986. GEOHYDROLOGY OF BEDROCK AQUIFERS IN THE NORTHERN GREAT PLAINS IN PARTS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 44. U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1402-E.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

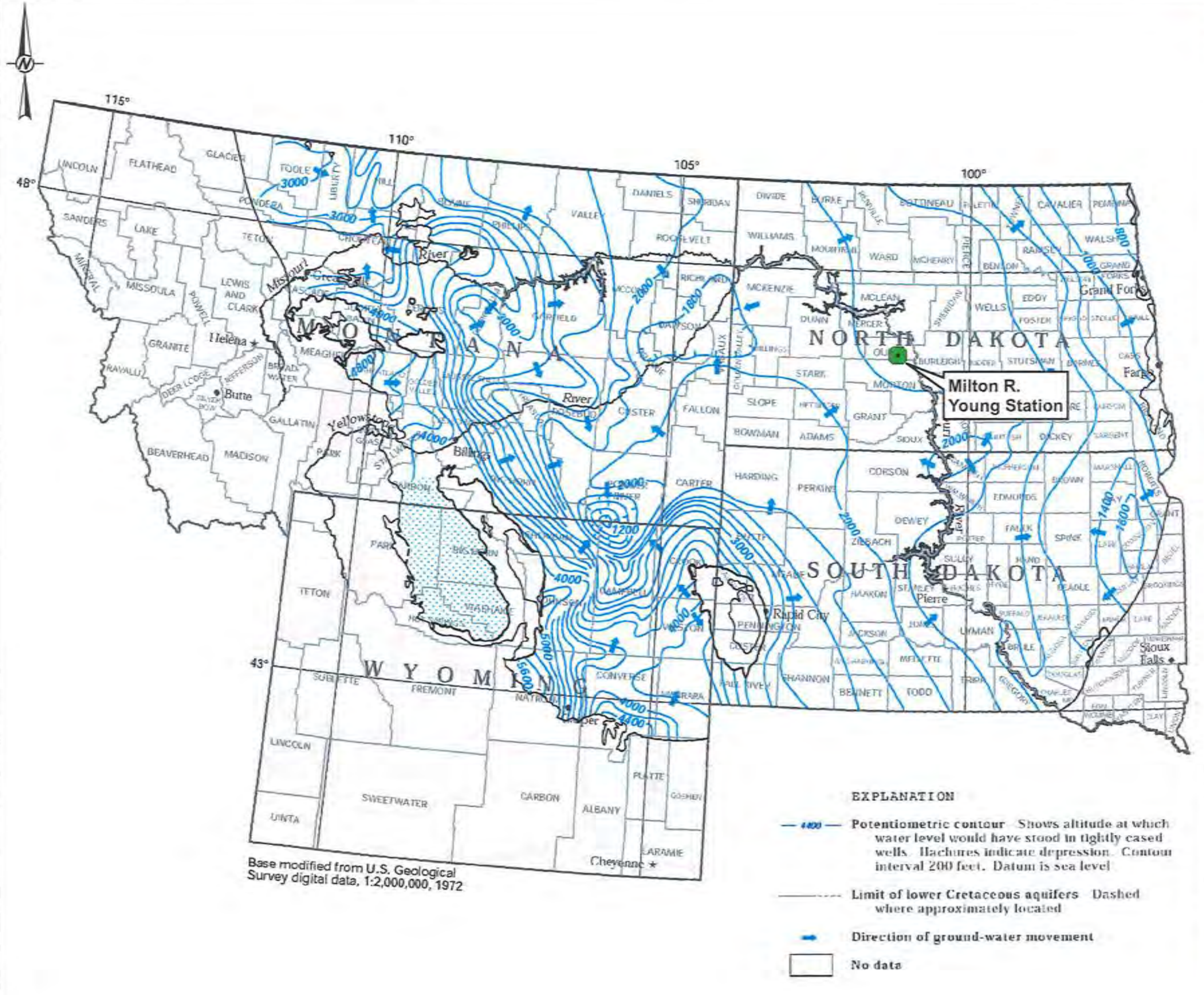
TITLE
POTENTIOMETRIC SURFACE OF THE PENNSYLVANIAN AQUIFER SYSTEM

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-16



LEGEND

APPROXIMATE PROPOSED INJECTION WELL LOCATION

0 40 80 160 Miles

NOTE

1. MODIFIED FROM LOBMEYER, D.H., 1985, FRESHWATER HEADS AND GROUND-WATER TEMPERATURES IN AQUIFERS OF THE NORTHERN GREAT PLAINS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING: U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1402-D, 11 P.
2. WATER MOVES REGIONALLY NORTHEASTWARD THROUGH THE DEEPLY BURIED LOWER CRETACEOUS AQUIFERS. SOME OF THE WATER MOVES HUNDREDS OF MILES FROM AQUIFER RECHARGE AREAS AROUND STRUCTURAL UPLIFTS ON THE WEST TO DISCHARGE AREAS IN EASTERN NORTH DAKOTA AND SOUTH DAKOTA.

REFERENCES

1. MAP OBTAINED FROM WHITEHEAD, R.L. 1996. GROUND WATER ATLAS OF THE UNITED STATES, SEGMENT 8, MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 58. USGS HYDROLOGIC INVESTIGATIONS ATLAS 730-I.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

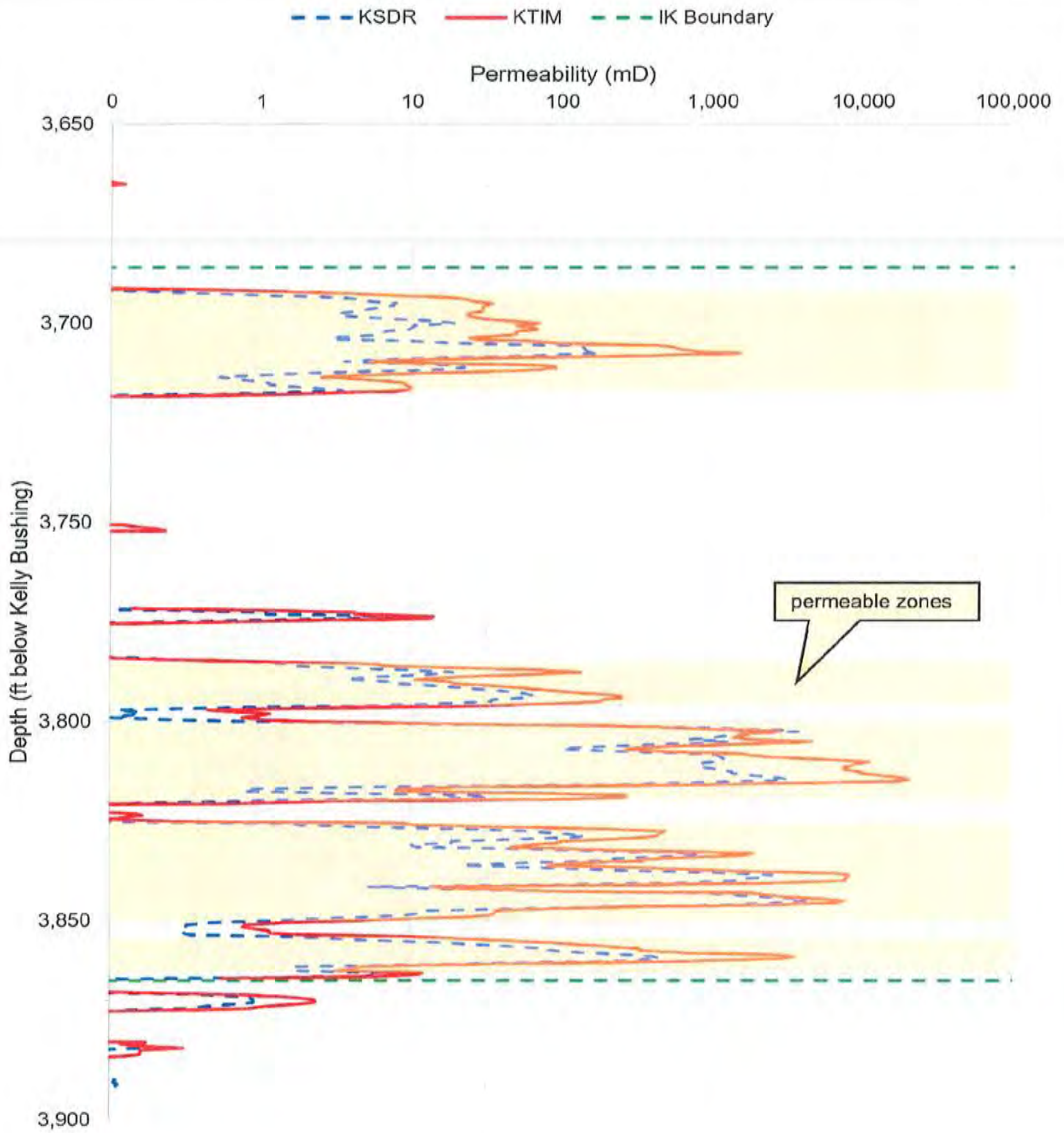
PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
POTENTIOMETRIC SURFACE OF THE LOWER CRETACEOUS AQUIFER SYSTEM

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

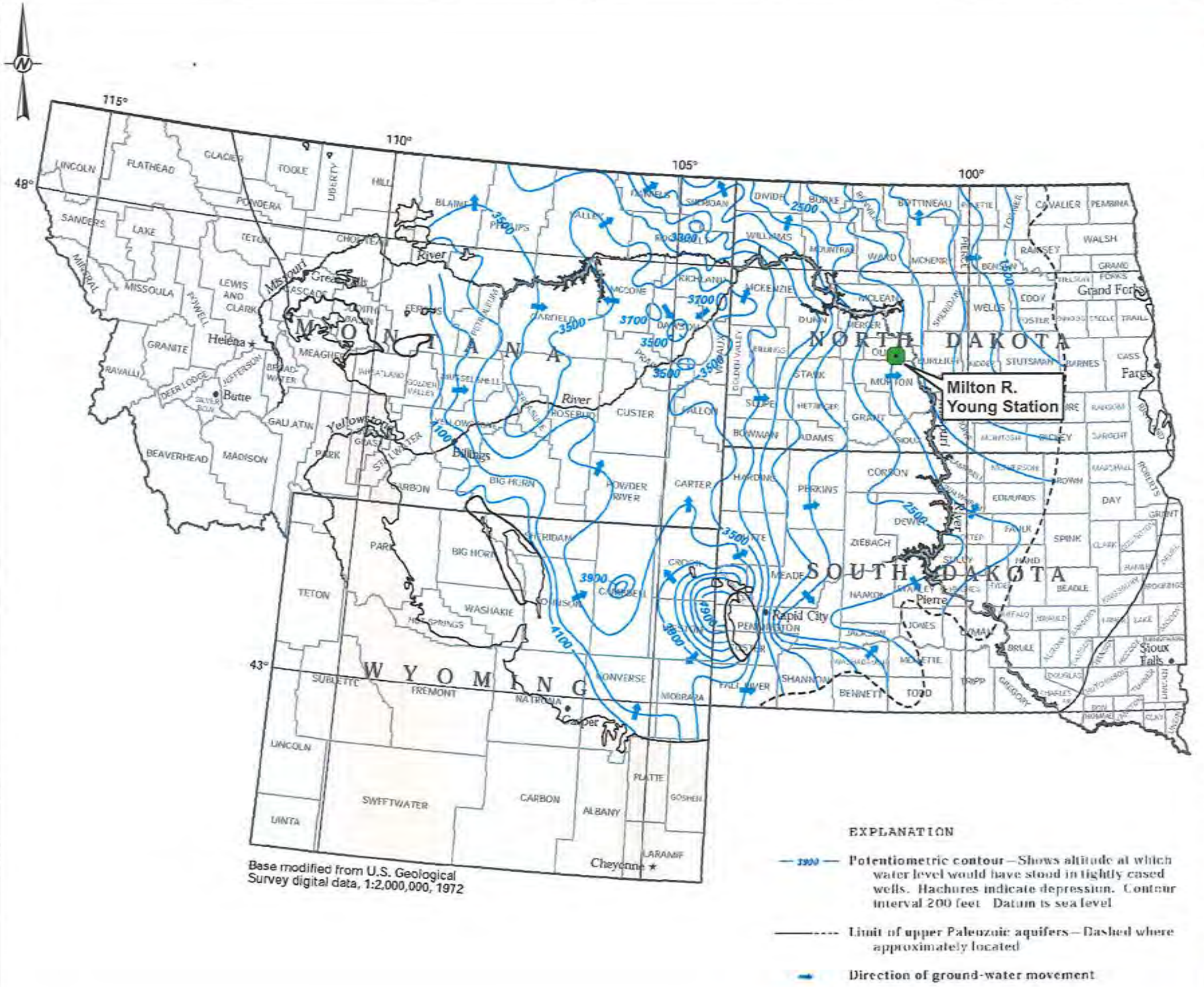
PROJECT NO. 19122669 REV. 0 FIGURE 3-15



Notes:

1. KSDR = Schlumberger-Doll Research permeability
2. KTIM = Timur-Coates permeability
3. IK = Inyan Kara Formation

GOLDER	CMR Log at J-ROC 1 - Permeability					
Client **Minnkota Power Cooperative**	Project No.	19122669	By	BJP	6/4/2021	Figure 4-1
	Title	Minnkota Injection Well	Check	AMS	6/4/2021	
	Revision	**0**	Review	TJS	6/4/2021	



LEGEND

APPROXIMATE PROPOSED INJECTION WELL LOCATION

NOTE

1. MODIFIED FROM DOWNEY, J.S., AND DINWIDDIE, G.A., 1988, THE REGIONAL AQUIFER SYSTEM UNDERLYING THE NORTHERN GREAT PLAINS IN PARTS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING - SUMMARY: U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1402-A, 64 P.
2. WATER IN THE UPPER PALEOZOIC AQUIFERS MOVES REGIONALLY NORTHEASTWARD FROM AQUIFER RECHARGE AREAS THAT ARE ON THE FLANKS OF STRUCTURAL UPLIFTS. LOCALLY, THE WATER MOVES RADIALLY AWAY FROM THE BLACK HILLS UPLIFT OR TOWARD DEPRESSIONS.

REFERENCES

1. MAP OBTAINED FROM WHITEHEAD, R.L. 1996. GROUND WATER ATLAS OF THE UNITED STATES, SEGMENT 8, MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 60. USGS HYDROLOGIC INVESTIGATIONS ATLAS 730-I.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

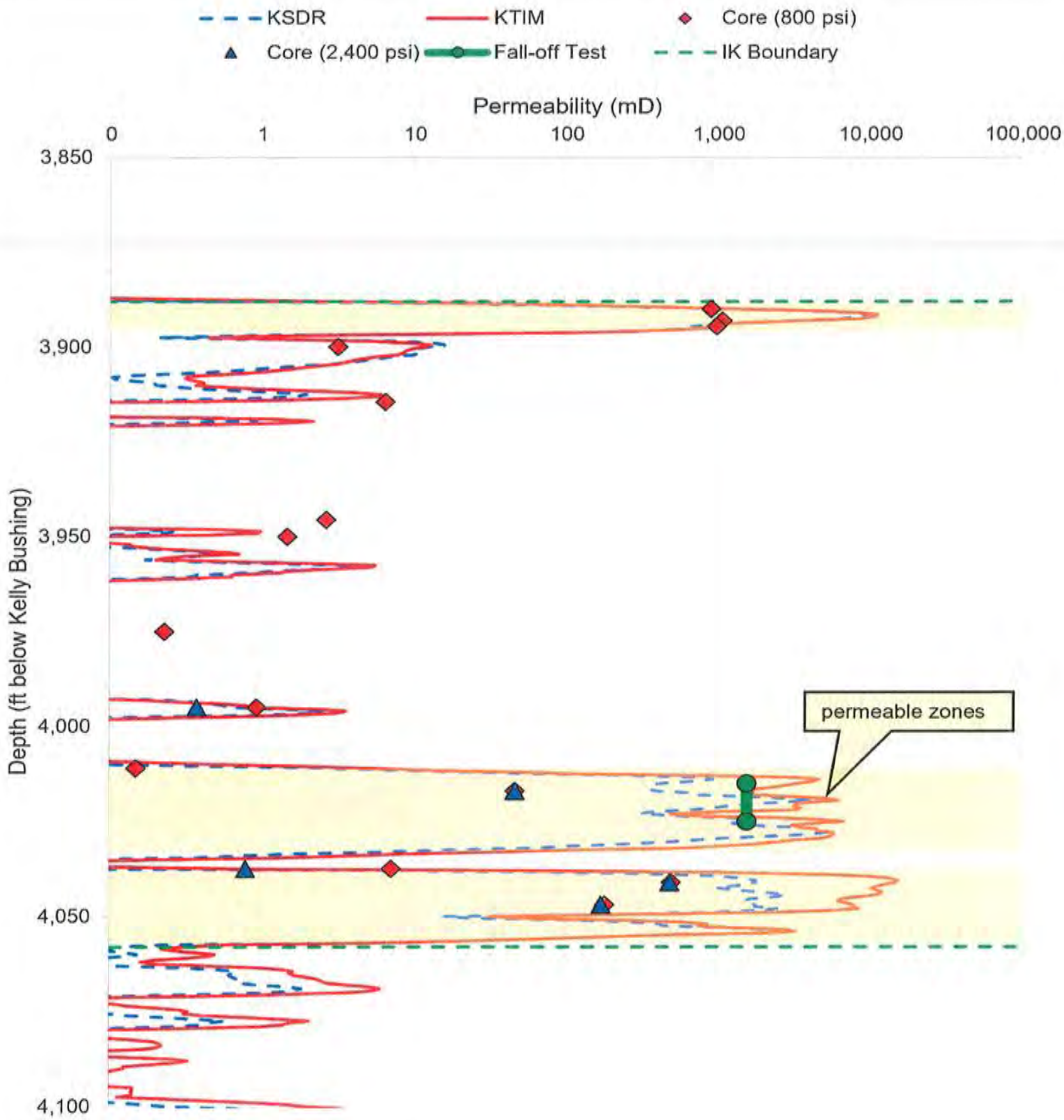
PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
POTENTIOMETRIC SURFACE OF THE UPPER PALEOZOIC AQUIFER SYSTEM

CONSULTANT: GOLDER MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-17

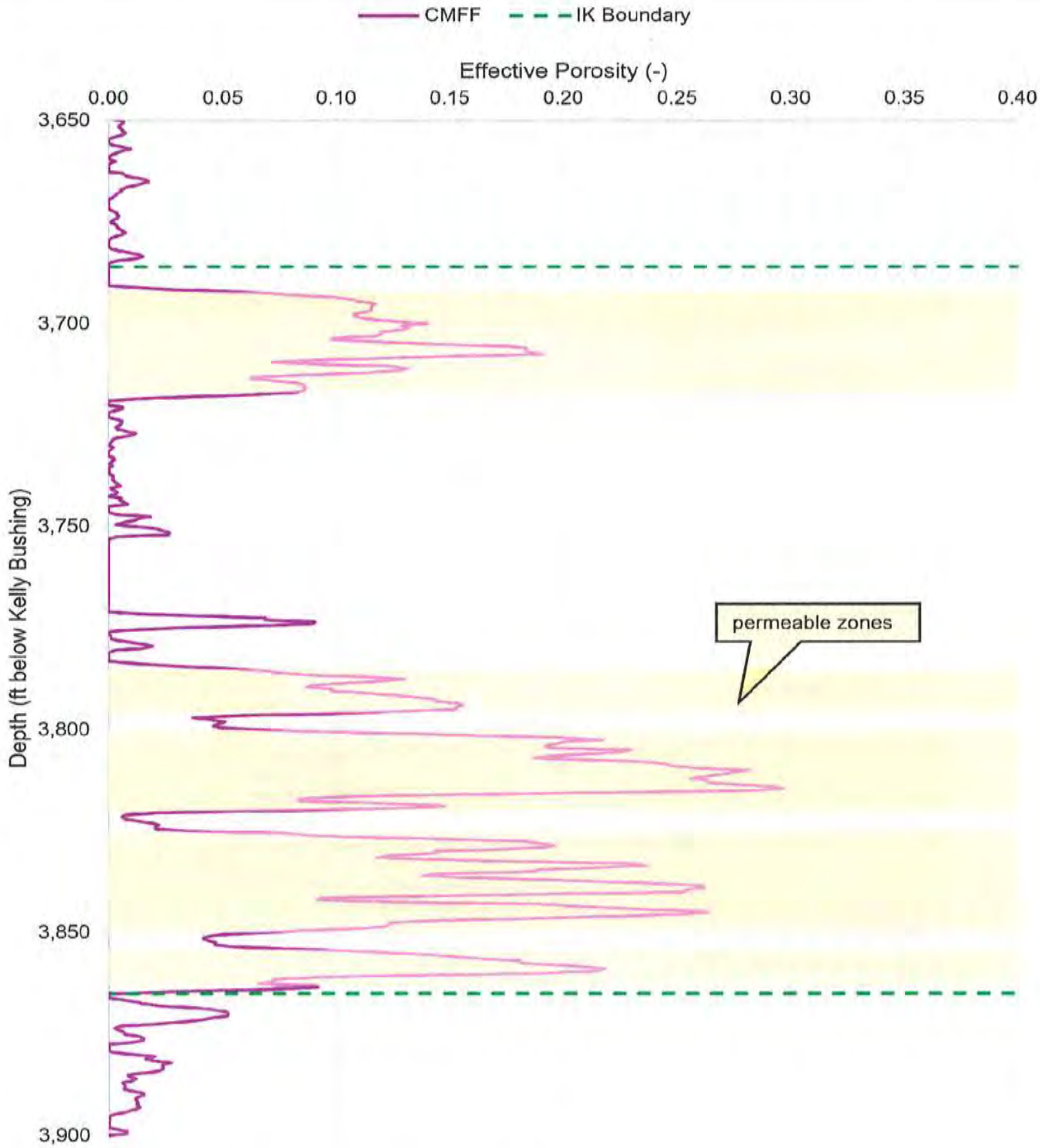


Notes:

1. KSDR = Schlumberger-Doll Research permeability
2. KTIM = Timur-Coates permeability
3. Core sample permeability tested at two confining pressures (800 psi and 2,400 psi).
4. IK = Inyan Kara Formation

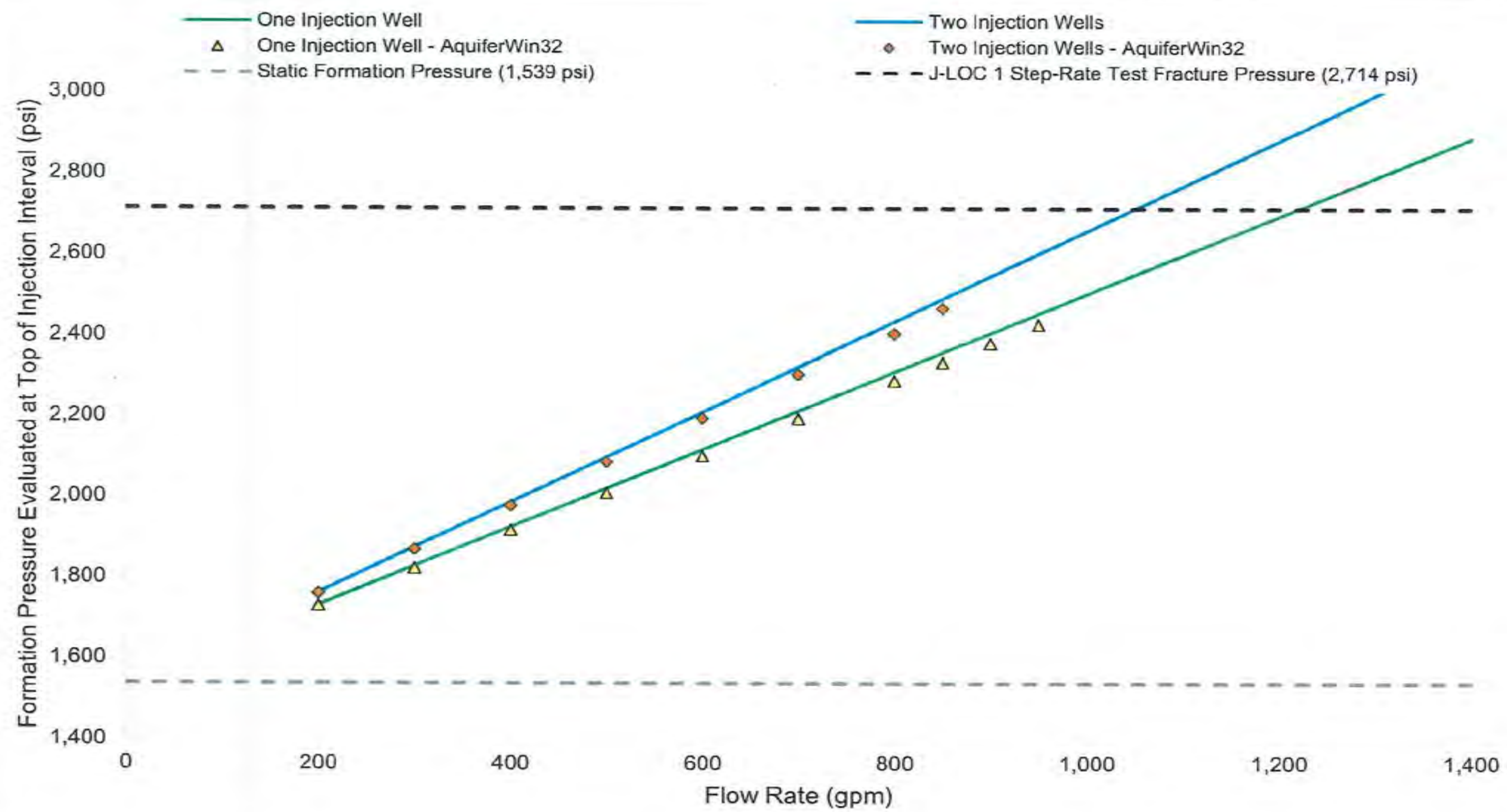
GOLDER	CMR Log at J-LOC 1 - Permeability				
Client	Project No.	19122669	By	BJP	6/4/2021
Minnkota Power Cooperative	Title	Minnkota Injection Well	Check	AMS	6/4/2021
	Revision	**0**	Review	TJS	6/4/2021

Figure 4-3



Notes:
1. CMFF = Combinable Magnetic Resonance Free Fluid Porosity
2. IK = Inyan Kara Formation

GOLDER	CMR Log at J-ROC 1 - Effective Porosity					
Client	Project No.	19122669	By	BJP	6/4/2021	Figure 4-2
Minnkota Power Cooperative	Title	Minnkota Injection Well	Check	AMS	6/4/2021	
	Revision	0	Review	TJS	6/4/2021	



Notes:

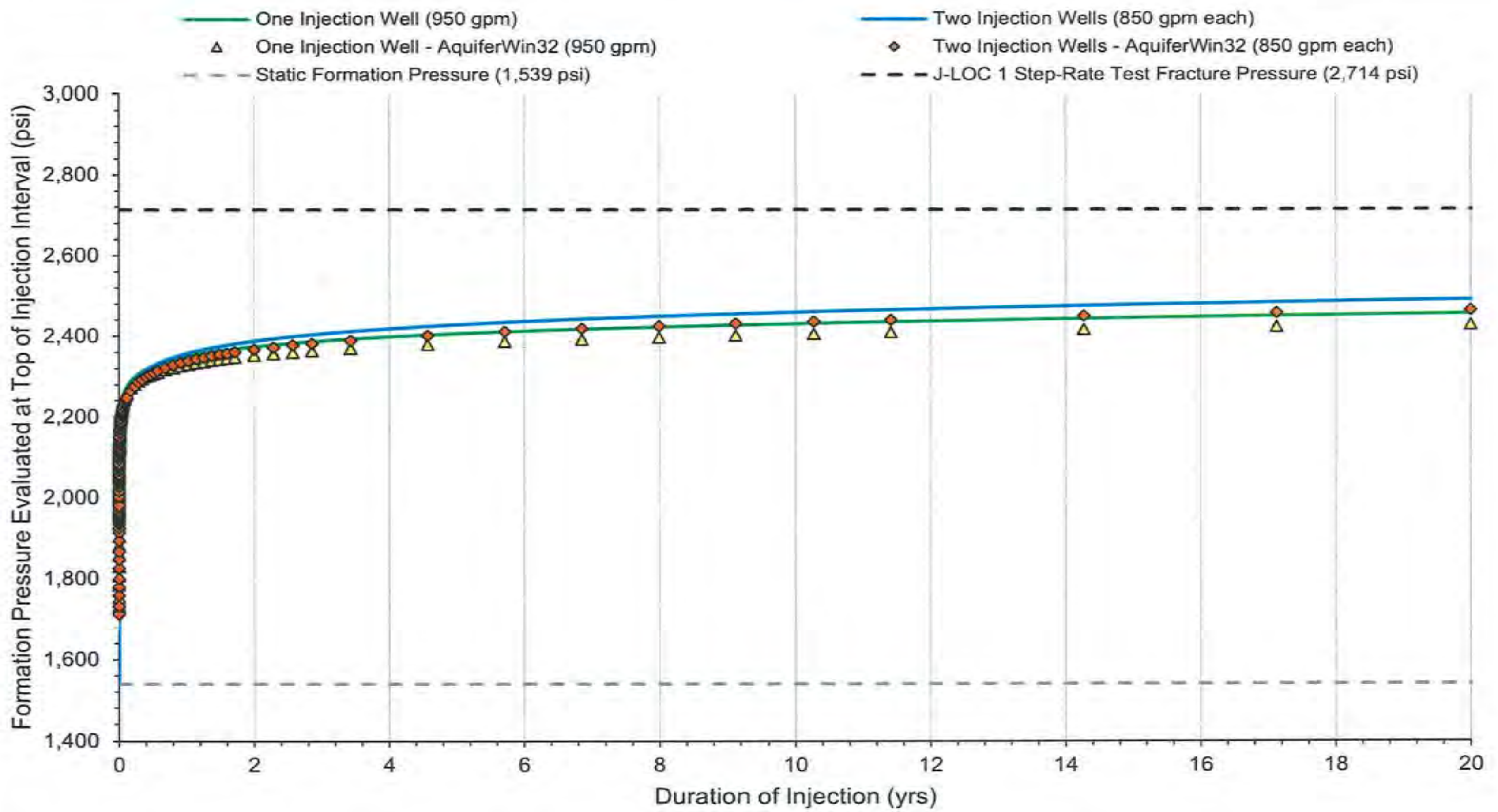
1. Injectate fluid properties (viscosity) used for Diffusivity Equation inputs and to calculate transmissivity for AquiferWin32 confirmatory modeling.
2. Permeability = 950 mD, Skin factor = 0

GOLDER

DENVER, COLORADO USA

Formation Pressure After 20 Years of Continuous Injection vs. Injection Flow Rate

Client **Minnkota Power Cooperative**	Project No.	19122669	By	BJP	6/4/2021	Figure 4-5
	Title	Minnkota Injection Well	Check	AMS	6/4/2021	
	Revision	0	Review	TJS	6/4/2021	



Notes:

1. Injectate fluid properties (viscosity) used for Diffusivity Equation inputs and to calculate transmissivity for AquiferWin32 confirmatory modeling.

2. Permeability = 950 mD, Skin factor = 0

GOLDER

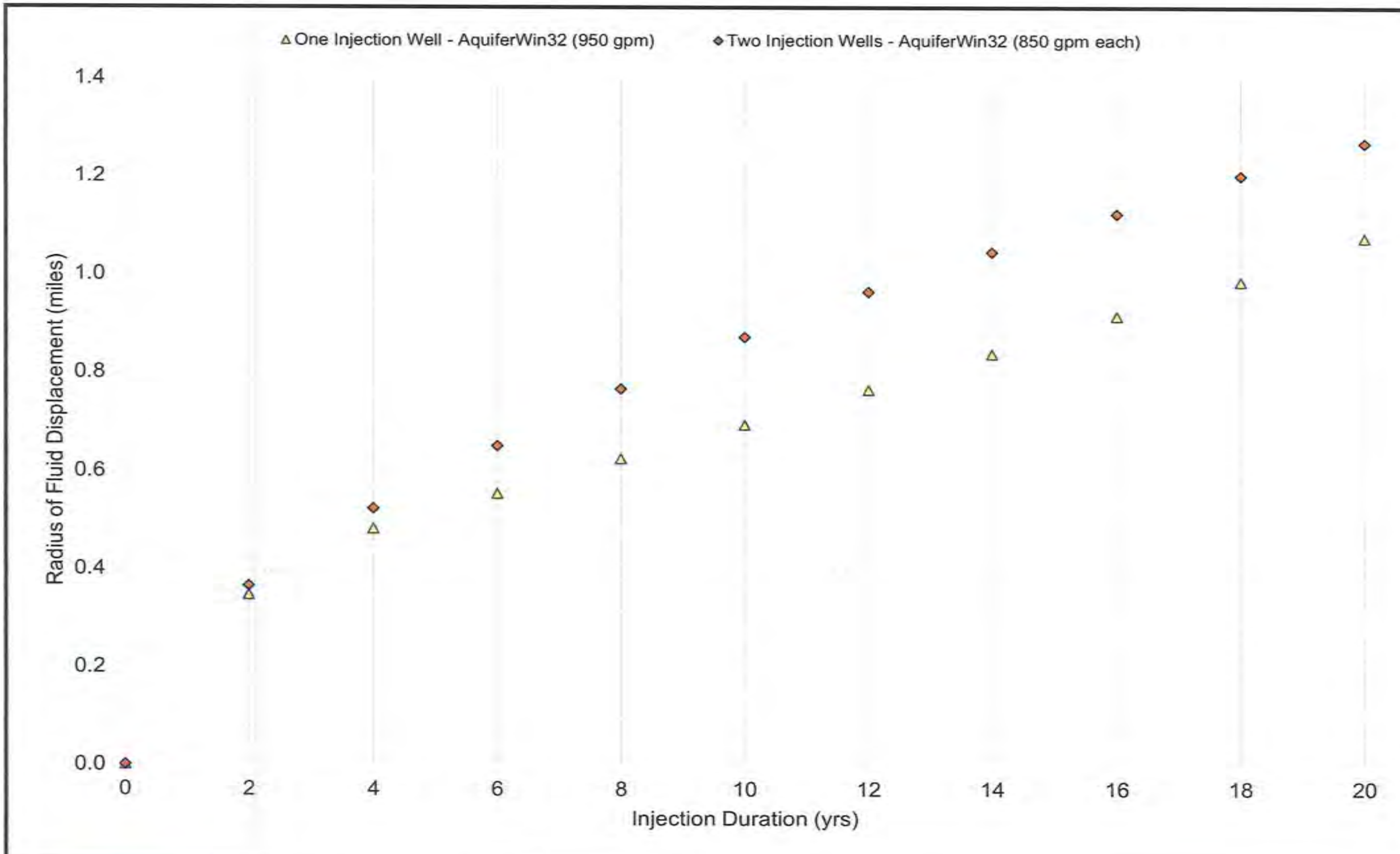
DENVER, COLORADO USA

Formation Pressure Response with Time at the Wellbore

Client

Minnkota Power Cooperative

Project No.	19122669	By	BJP	6/4/2021	Figure 4-4
Title	Minnkota Injection Well	Check	AMS	6/4/2021	
Revision	0	Review	TJS	6/4/2021	

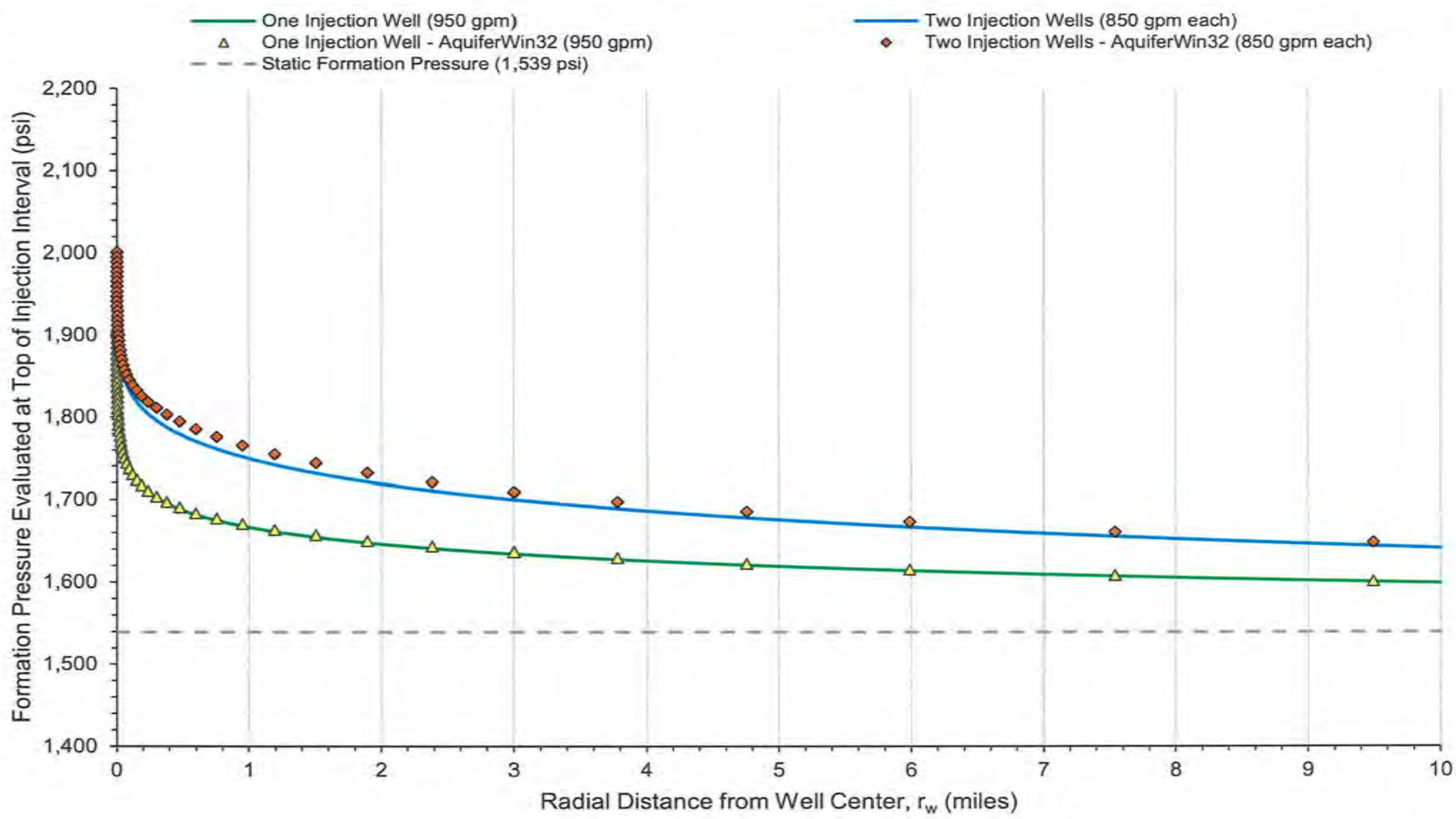


GOLDER
DENVER, COLORADO USA

Radius of Fluid Displacement

Client
Minnkota Power Cooperative

Project No.	19122669	By	BJP	6/4/2021	Figure 4-7
Title	Minnkota Injection Well	Check	AMS	6/4/2021	
Revision	0	Review	TJS	6/4/2021	



Notes:

1. Formation fluid properties (viscosity) used for Diffusivity Equation inputs and to calculate transmissivity for AquiferWin32 confirmatory modeling.

GOLDER

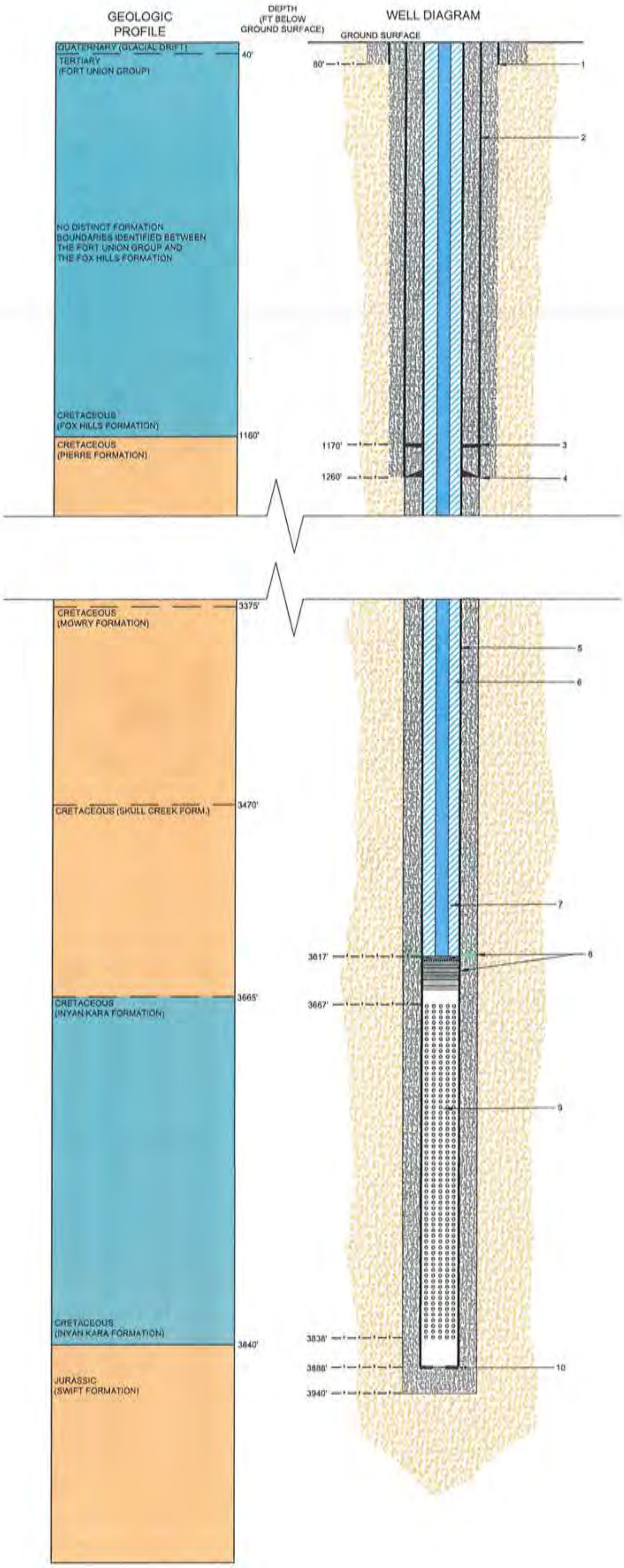
DENVER, COLORADO USA

Formation Pressure Response with Radial Distance from Wellbore After 20 Years of Continuous Injection

Client

Minnkota Power Cooperative

Project No.	19122669	By	BJP	6/4/2021	Figure 4-6
Title	Minnkota Injection Well	Check	AMS	6/4/2021	
Revision	**0**	Review	TJS	6/4/2021	



LEGEND

- CASING CEMENT
- EXISTING SUBSURFACE MATERIAL
- ANNULAR FLUID
- AQUIFER
- CONFINING UNIT
- FLOATS (SEE NOTE 3)
- DIFFERENTIAL VALVE TOOL (SEE NOTE 8)

NOTES

ALL DEPTHS ARE APPROXIMATE.

1. 20" CONDUCTOR CASING SET TO 80' BGS IN 26" HOLE; CEMENTED TO SURFACE.
2. 13-3/8" SURFACE CASING IN 17-1/2" HOLE, SET TO 1260' BGS (APPROXIMATELY 100' BELOW BASE OF FOX HILLS FORMATION). CEMENTED TO SURFACE.
3. FLOAT COLLAR ABOVE THE LOWEST JOINT OF THE SURFACE CASING AT AN APPROXIMATE DEPTH OF 1,170' BGS (TWO CASING JOINTS ABOVE THE FLOAT SHOE).
4. FLOAT SHOE AT THE BOTTOM OF THE LOWEST JOINT OF SURFACE CASING AT AN APPROXIMATE DEPTH OF 1,260' BGS.
5. 9-5/8" PRODUCTION CASING IN 12-1/4" HOLE SET TO 3,888' BGS (APPROXIMATELY 50' BELOW INJECTION ZONE). CEMENT TO SURFACE ABOVE INJECTION PACKER.
6. ANNULAR FLUID.
7. 7" INTERNALLY LINED INJECTION TUBING SET IN 9-5/8" CASING TO 3,617' BGS (APPROXIMATELY 50' ABOVE INJECTION ZONE).
8. INJECTION PACKER TOP SET AT 3,617' BGS (APPROXIMATELY). COMPRISED OF INTERNAL SEAL SHOE AND EXTERNAL CHROME PACKER. DIFFERENTIAL VALVE TOOL LOCATED DIRECTLY ABOVE THE PACKER AT 3,615' BGS.
9. PERFORATIONS PLANNED AT AT RATE OF 4 TO 12 SHOTS PER FOOT, 0.52" ENTRANCE WITH 24" PENETRATION. PENETRATIONS WILL BE PLACED WITHIN THE SANDSTONE INTERVALS OF THE INYAN KARA FORMATION (APPROXIMATELY 3,667' TO 3,838' BGS).
10. FLOAT COLLAR AND FLOAT SHOE AT BOTTOM OF PRODUCTION CASING.

NOT TO SCALE

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

CONSULTANT

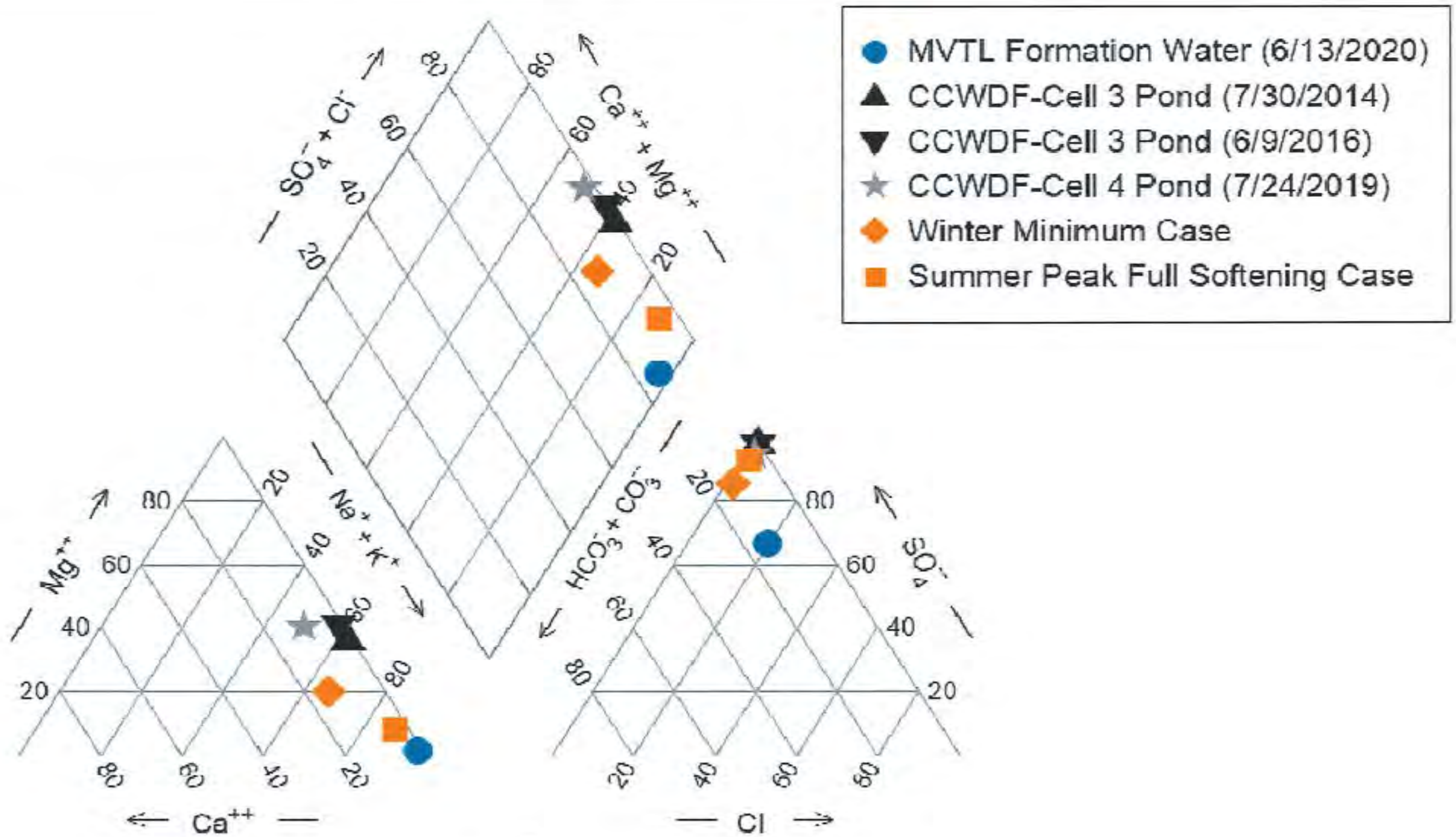
GOLDER MEMBER OF WSP

YYYY-MM-DD	2021-06-04
PREPARED	BJP
DESIGN	BJP
REVIEW	AMS
APPROVED	TJS

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
GEOLOGICAL PROFILE AND PROPOSED INJECTION WELL CONSTRUCTION DIAGRAM

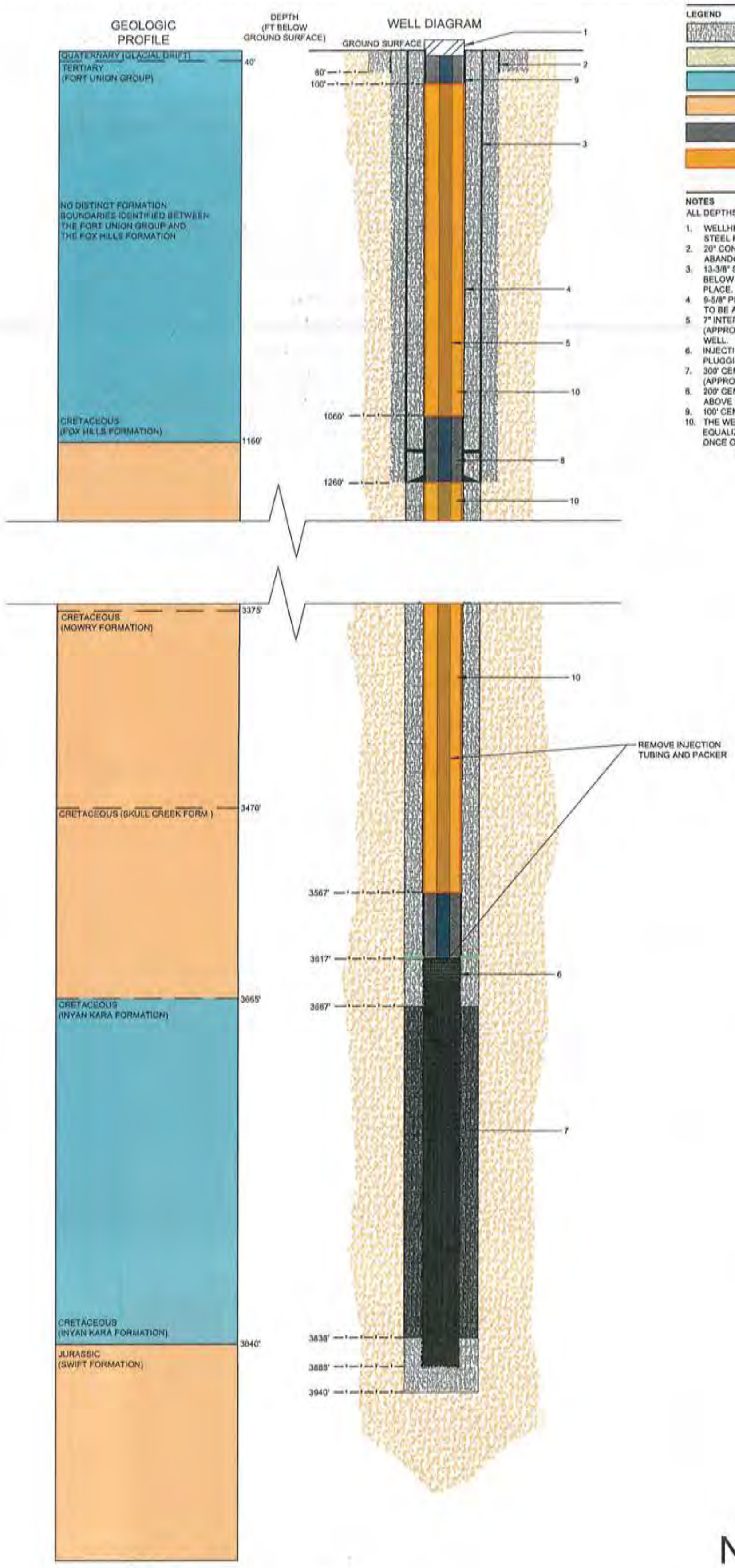
PROJECT No.	Rev.	FIGURE
19122669	0	7-1



Notes:

meq/L: milliequivalents per liter

GOLDER	Piper Diagram of Formation Water, Cooling Tower Blowdown, and Scrubber Pond Water					
Client	Project No.	19122669	By	GOL	6/4/2021	Figure 6-1
Minnkota Power Cooperative	Title	Minnkota Injection Well	Check	SH	6/4/2021	
	Revision	0	Review	TR	6/4/2021	



LEGEND

- CASING CEMENT
- EXISTING SUBSURFACE MATERIAL
- AQUIFER
- CONFINING UNIT
- CLASS G CEMENT GROUT PLUG
- STATICALLY EQUALIZED MUD FILL

NOTES

ALL DEPTHS ARE APPROXIMATE.

1. WELLHEAD TO BE REMOVED AND CASING STUB TO BE CUT 5' BELOW GROUND SURFACE. STEEL PLATE TO BE WELDED TO CASING STUB.
2. 20" CONDUCTOR CASING SET TO 80' BGS IN 26" HOLE; CEMENTED TO SURFACE. TO BE ABANDONED IN PLACE.
3. 13-3/8" SURFACE CASING IN 17-1/2" HOLE, SET TO 1,260' BGS (APPROXIMATELY 100' BELOW BASE OF FOX HILLS FORMATION). CEMENTED TO SURFACE. TO BE ABANDONED IN PLACE.
4. 9-5/8" PRODUCTION CASING IN 12-1/4" HOLE SET TO 3,888' BGS. CEMENTED TO SURFACE. TO BE ABANDONED IN PLACE.
5. 7" INTERNALLY LINED INJECTION TUBING SET IN 9-5/8" PRODUCTION CASING TO 3,617' BGS (APPROXIMATELY 50' ABOVE INJECTION ZONE). TO BE REMOVED PRIOR TO PLUGGING OF WELL.
6. INJECTION PACKER SET AT 3,617' BGS (APPROXIMATELY). TO BE REMOVED PRIOR TO PLUGGING OF WELL.
7. 300' CEMENT PLUG TO BE INSTALLED BETWEEN BOTTOM OF WELL AND 3,567 BGS (APPROXIMATELY 100' ABOVE INJECTION ZONE). PERFORATED ZONE TO BE SQUEEZED.
8. 200' CEMENT PLUG TO BE INSTALLED AT THE BASE OF THE FOX HILLS FORMATION (100' ABOVE AND 100' BELOW THE BASE OF THE FOX HILLS FORMATION).
9. 100' CEMENT PLUG TO BE INSTALLED AT THE SURFACE OF THE WELLBORE.
10. THE WELL WILL BE IN A STATE OF STATIC EQUILIBRIUM WITH THE MUD WEIGHT EQUALIZED TOP TO BOTTOM, EITHER BY CIRCULATING THE MUD IN THE WELL AT LEAST ONCE OR BY COMPARABLE METHOD.

NOT TO SCALE

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

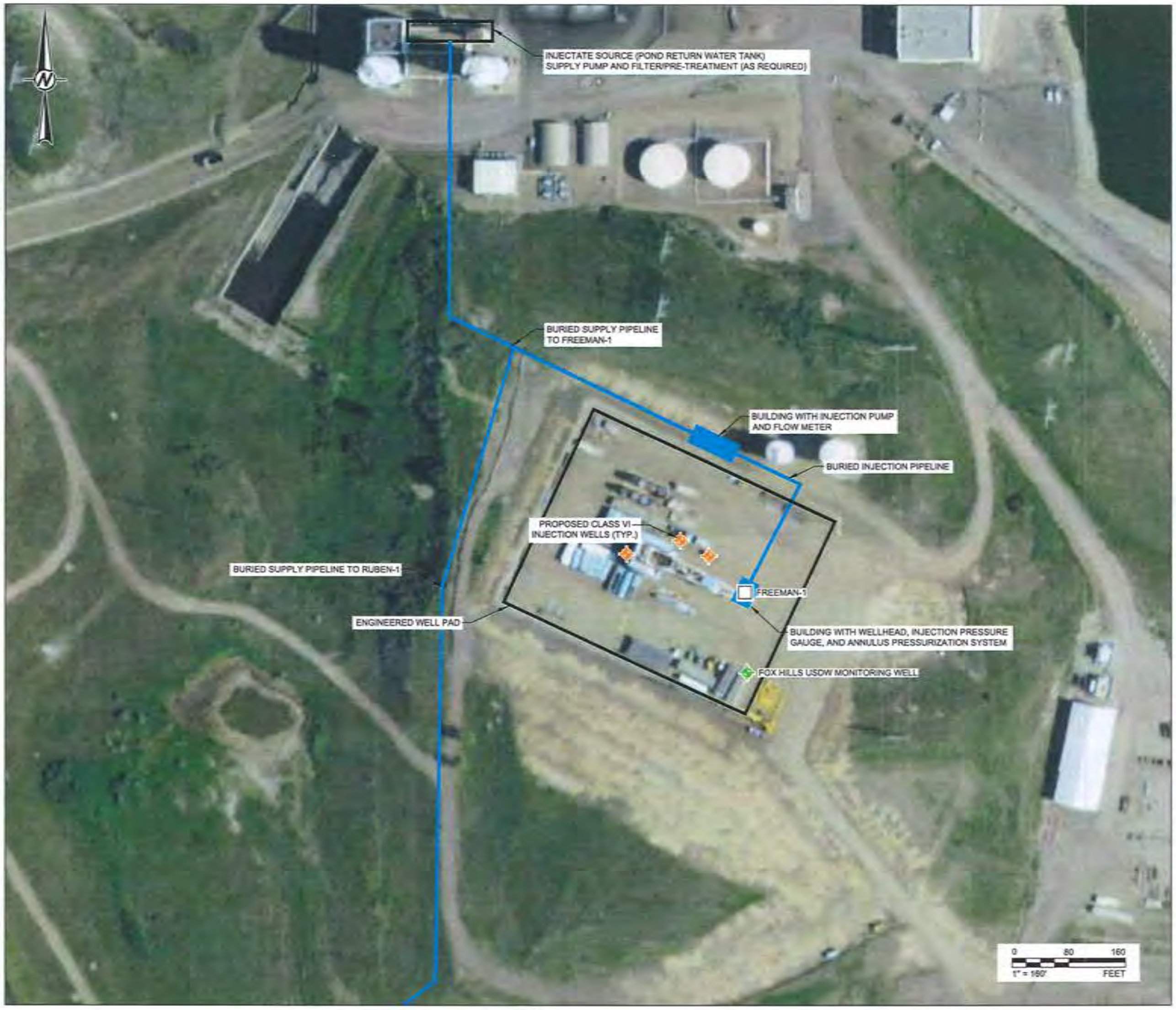
CONSULTANT
GOLDER MEMBER OF WSP

YYYY-MM-DD	2021-06-04
PREPARED	BJP
DESIGN	BJP
REVIEW	AMS
APPROVED	TJS

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
PLUGGING AND ABANDONMENT PLAN

PROJECT No.	Rev.	FIGURE
19122669	0	9-1



SCALE 1" = 160' 1 7-2 FREEMAN-1 PLAN VIEW

LEGEND

☐	PROPOSED CLASS I INJECTION WELL
◆	PROPOSED CLASS VI INJECTION WELL
◆	FOX HILLS USDW MONITORING WELL
—	BURIED INJECTION PIPES

KEY MAP

SCALE 1" = 160' 2 7-2 RUBEN-1 PLAN VIEW

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	BJP
PREPARED	AGD
REVIEWED	AMS
APPROVED	TJS

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
SURFACE INFRASTRUCTURE PLAN

PROJECT NO.	REV.	FIGURE
19122669	0	7-2

IF THIS MEASUREMENT DOES NOT MATCH WHAT IS SHOWN, THE SHEET SIZE HAS BEEN MODIFIED FROM: ANSI B

CLASS I UIC PERMIT APPLICATION

NORTH DAKOTA DEPARTMENT OF ENVIRONMENTAL QUALITY
WATER QUALITY DIVISION
SFN 8294 (April 2019)

Return completed form to:
North Dakota Department of Environmental Quality
Division of Water Quality
918 E. Divide Ave., 4th Floor
Bismarck, ND 58501-1947
Telephone Number: 701.328.5210
E-mail Address: juhlman@nd.gov

Name of Facility Milton R. Young Station		Application Date 06/07/2021	
Name of Facility Contact Daniel Laudal	Title Environmental Manager		
Mailing Address 5301 32nd Avenue South	City Grand Forks	State ND	Zip Code 58201
Facility Location: Address, Legal Description (Twp, Rng, Sec, Qtrs) 3401 24th Street SW		Latitude 47.0661056	Longitude -101.2138806
County Oliver	City Center	State ND	Zip Code 58530

SIC Codes: List in descending order of significance the four 4-digit Standard Industrial Classification (SIC) Codes found in the "Standard Industrial Classification Manul" which best describe your facility in terms of the principal products or services you produce or provide. Also, specify each classification in words.		SIC No.	Name
	1st Div. E	4911	Electric Services
	2nd		
	3rd		
	4th		

Name of Operator Minnkota Power Cooperative		Telephone Number 701-795-4216	
STATUS: ☐ F=Federal ☐ S=State ☑ P=Private ☐ M=Public (Other than Federal or State) ☐ O=Other (Specify)			
Mailing Address 5301 32nd Avenue South	City Grand Forks	State ND	Zip Code 58201
TRIBAL LANDS: Is this facility located on Tribal Land? ☑ No ☐ Yes			

EXISTING ENVIRONMENTAL PERMITS		
	UIC-Underground Injection Fluids	Permit No.: NA
	NPDES-Discharge to Surface Water	Permit No.: ND-000370
	RCRA-Hazardous Wastes	Permit No.: NDD076514298
	PSD-Air Emissions from Proposed Sources	Permit No.: T5-F76009
	Other (Specify) see below	Permit No.: see below

Brief Description of Nature of Business

Coal-fired power generation - Permits: Solid Waste Management Permits: SP-159, SP-040, IT-205, IT-197, IT-068, SP-030; NDSWC Annual Water Use Reports: SWC #1324, #1963, #1964, #7097; Underground Storage Tanks: ND UST #46; Petroleum Tank Insurance Fund #447

Certification: I certify, under penalty of the law, that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe the information is true, accurate, and complete. I am aware there are significant penalties for submitting false information, including the possiblity of imprisonment.

SEE BACK OF FORM FOR DETAILS ON MAP AND ENGINEERING REPORT THAT MUST BE SUBMITTED WITH THIS APPLICATION.	NAME (Typed) Craig Bleth
	TITLE (Typed) Senior Manager of Power Production
	Signature Craig J. Bleth

APPENDIX A

NDDEQ Permit Application Form and Checklist

APPENDIX B

Wells Within the Area of Review

Table A-1: Permit Application Checklist (SFN 8294, April 2019)

Item	Reference	Permit Application Location
Mapping		
Attach to this application, a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the following: 1. Outline of the facility; 2. Location of each of its existing and proposed intake and discharge structures; 3. Each hazardous waste treatment, storage, or disposal facility; 4. Each well where fluids will be or are injected underground; and 5. All springs, rivers, and other surface waterbodies in map area.	40 CFR 144.31(e)(7)	Section 1.1 Figures 1-2 and 1-3
Engineering Report		
1. **Maps** showing the injection wells for which a permit is sought, and the applicable area of review. The map must show the number or name and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines, quarries, water wells and other pertinent surface features, including residences and roads.	40 CFR 146.14(a)(2)	Section 1.3 Figures 1-5 and 1-6
2. A **tabulation** of data on all wells within the area of review which penetrate into the proposed injection zone.	40 CFR 146.14(a)(3)	Section 1.3 and Appendix B
3. **Maps and cross-sections** indicating the general vertical and lateral limits of all underground sources of drinking water within the area of review, their position relative to the injection formation and the direction of water movement, where known, in each USDW which may be affected by the proposed injection.	40 CFR 146.14(a)(4)	Section 3.3 Figures 3-1 to 3-17
4. **Maps and cross-sections** detailing the geologic structure of the local area.	40 CFR 146.14(a)(5)	Section 3.2 Figures 3-3 to 3-10
5. **Generalized maps and cross-sections** illustrating the regional geologic setting.	40 CFR 146.14(a)(6)	Section 3.1 Figures 3-1 and 3-2
6. **Proposed operating data** which should include average and maximum daily rate and volume of fluid to be injected, average and maximum injection pressure, and source and analysis of chemical, physical, radiological and biological characteristics of injection fluids.	40 CFR 146.14(a)(7)(i) 40 CFR 146.14(a)(7)(ii) 40 CFR 146.14(a)(7)(iii)	Section 1.2 Section 6.2
7. **Proposed formation testing program** to obtain analysis of chemical, physical and radiological characteristics and other information on the receiving formation, including estimated formation fracture pressure.	40 CFR 146.14(a)(8)	Section 7.3
8. **Proposed stimulation program**	40 CFR 146.14(a)(9)	Section 7.4
9. **Proposed injection procedure**	40 CFR 146.14(a)(10)	Section 8.3
10. **Engineering drawings** of the surface and subsurface construction details of the system.	40 CFR 146.14(a)(11)	Section 7.0 Figures 7-1 and 7-2
11. **Contingency plans** to cope with all shut-ins or well failures so as to prevent migration of fluids into any underground source of drinking water.	40 CFR 146.14(a)(12)	Section 8.3.5
12. **Corrective action** proposed to be taken for wells within the area of review which penetrate the injection zone and are not properly completed or plugged.	40 CFR 146.14(a)(14)	Section 1.3.4
13. **Construction procedures** including the cementing and casing program, logging procedures, deviation checks and a drilling testing and coring program.	40 CFR 146.14(a)(15)	Section 7.0
14. Information on **expected changes** in pressure, native fluid displacement and direction of movement of injection fluid.		Section 4.0 Figures 4-4 to 4-7
15. **Discussion** of the qualifications and training of injection operations supervisory personnel.		Section 8.3.4
16. A **certificate** that the applicant has assured, through a performance bond or other appropriate means, the resources necessary to close, plug or abandon the well.	40 CFR 146.14(a)(16)	Section 9.4 Appendix H
17. **Any other information** the staff requires to properly evaluate the application, such as proposed observation wells, etc. (permitting strategy, geochemistry, estimated formation fracture pressures)		See below
Estimated formation fracture pressure		Section 5.0 Appendix D
Signed and completed application	NDAC 33-25-01-06(1)(a)	Appendix A
Activities conducted that require permits under RCRA, UIC, NPDES, Clean Air Act	40 CFR 144.31(e)(1)	Section 1.1 Section 10.0
Name, mailing address, and location of facility	40 CFR 144.31(e)(2)	Section 1.1
SIC codes which best reflect principal products or services	40 CFR 144.31(e)(3)	Section 1.1
Operators name and contact information	40 CFR 144.31(e)(4)	Section 1.1
Facility landownership	40 CFR 144.31(e)(5)	Section 1.1 Figure 1-3
Other permits	40 CFR 144.31(e)(6)	Section 10.5
Description of business	40 CFR 144.31(e)(8)	Section 1.1
Names and addresses of landowners within one-quarter mile	40 CFR 144.31(e)(9)	Figure 1-3
Plugging and abandonment plan	40 CFR 144.31(e)(10)	Section 9.0 Figure 9-1

Table B-2A: Shallow Wells Within the Area of Review (North Dakota State Water Commission Database)

NDSWC File No.	Location	Well Type	Latitude	Longitude	Date Drilled
45677	14208330BAAC	Commercial	47.09560623120	-101.24885670400	6/21/1991
45676	14208330BAB	Commercial	47.09606761670	-101.25084664100	7/7/1999
45396	14108206CBB	Domestic	47.06055884580	-101.12891594200	9/8/1997
45414	14108302CDC	Domestic	47.05474270490	-101.16599525600	8/28/1986
45415	14108302DCB	Domestic	47.05658273520	-101.16073805300	5/15/1977
45419	14108304ACC	Domestic	47.06178361930	-101.20290605400	6/17/1975
45421	14108304CB	Domestic	47.05906513890	-101.21201067300	5/25/1975
45422	14108305CAA	Domestic	47.05989192760	-101.22667512000	6/27/1984
45448	14108314CC	Domestic	47.02679973910	-101.16970285400	4/17/1998
46273	14108323DBB	Domestic	47.01694051410	-101.16054717500	7/19/1999
45464	14108330	Domestic	47.00286671730	-101.24677469300	10/30/1980
45468	14108401BCB	Domestic	47.06333985880	-101.27720190500	7/31/1984
45470	14108402D	Domestic	47.05701188750	-101.28398731700	8/14/1987
45492	14108411AA	Domestic	47.05165014420	-101.28133741300	12/3/1973
45496	14108412	Domestic	47.04616310460	-101.26795959400	11/1/1972
45497	14108413CBA	Domestic	47.03083559140	-101.27445769700	8/28/1985
45503	14108424AA	Domestic	47.02278268180	-101.26003496800	5/20/1993
45505	14108424AA	Domestic	47.02278268180	-101.26003496800	11/4/1993
45502	14108424B	Domestic	47.02095393610	-101.27315646700	8/16/1978
45644	14208316DD	Domestic	47.11333666090	-101.19675383900	5/14/1996
45646	14208316DD	Domestic	47.11333666090	-101.19675383900	10/11/1978
46292	14208316DD	Domestic	47.11333666090	-101.19675383900	4/4/2002
45647	14208317	Domestic	47.11864602190	-101.22586864700	8/1/1973
45652	14208319CC	Domestic	47.09857667410	-101.25500955600	11/7/1990
45656	14208320AAA	Domestic	47.11062078970	-101.21661903900	5/30/1975
45655	14208320AD	Domestic	47.10603360640	-101.21792717000	9/27/1984
71649	14208320DAD	Domestic	47.10145864060	-101.21595452700	8/11/2014
45658	14208322	Domestic	47.10445610800	-101.18340649800	6/1/1979
45671	14208328ADD	Domestic	47.09074561340	-101.19544069100	7/15/1983
45670	14208328D	Domestic	47.08619509890	-101.19932787400	5/6/1974
74842	14208330C	Domestic	47.08600960180	-101.25176569100	9/13/2017
28591	14208424ADD	Domestic	47.10486211140	-101.25904158800	6/14/1977
45733	14208424D	Domestic	47.10033366110	-101.26299702000	9/17/1974
69798	14208424DAD	Domestic	47.10125690180	-101.25855688800	10/17/2012
45736	14208424DD	Domestic	47.09852225670	-101.26035725200	9/3/1976
45738	14208425A	Domestic	47.09319925830	-101.26297183200	10/1/1979
45765	14208436AA	Domestic	47.08048421820	-101.26015784200	11/6/1985
46270	14108312D	Domestic/Stock	47.04325606030	-101.13559645600	7/30/2004
45465	14108330	Domestic/Stock	47.00286671730	-101.24677469300	11/14/1980
45495	14108412C	Domestic/Stock	47.04252236110	-101.27318222700	6/20/1975
45645	14208316DB	Domestic/Stock	47.11698150430	-101.20203096400	7/19/1983
45653	14208320D	Domestic/Stock	47.10052791410	-101.22053984300	7/14/1980
46500	14208322ABB	Domestic/Stock	47.11082789900	-101.18209405900	6/7/2002
45674	14208329CCA	Domestic/Stock	47.08511096240	-101.23210285500	9/18/1980
45420	14108304B	Industrial	47.06450481880	-101.20941031100	7/1/1974
46264	14108304BBD	Industrial	47.06541260330	-101.21071043800	8/19/2002
46266	14108304BBD	Industrial	47.06541260330	-101.21071043800	8/21/2002
46268	14108304BBD	Industrial	47.06541260330	-101.21071043800	8/19/2002
62855	14108304BDB	Industrial	47.06359657560	-101.20773703900	8/24/2007
45423	14108305A	Industrial	47.06444396780	-101.22007952000	2/25/1975
45683	14208332C	Industrial	47.07157165140	-101.23073422500	7/19/1983
45684	14208332CBD	Industrial	47.07248736720	-101.23204302200	7/15/1984
62723	14208333DD	Industrial	47.06994730160	-101.19600191900	6/20/2007
58496	14108304B	Monitoring	47.06450481880	-101.20941031100	8/24/1993
58499	14108304B	Monitoring	47.06450481880	-101.20941031100	8/25/1993
58503	14108304B	Monitoring	47.06450481880	-101.20941031100	8/26/1993
58506	14108304B	Monitoring	47.06450481880	-101.20941031100	8/26/1993
45417	14108304BCC	Monitoring	47.06178533360	-101.21331072200	9/8/1992
58519	14108304BCC	Monitoring	47.06178533360	-101.21331072200	8/1/1995
77595	14108304BDB	Monitoring	47.06449072010	-101.20902890900	8/13/2020
45416	14108304CB	Monitoring	47.05906513890	-101.21201067300	6/9/1975
45426	14108305AAB	Monitoring	47.06717497090	-101.21876377900	9/3/1992
45438	14108305AAB	Monitoring	47.06717497090	-101.21876377900	6/24/1992
45439	14108305AC	Monitoring	47.06262318760	-101.22271949900	6/24/1992
58520	14108305ACA	Monitoring	47.06353358540	-101.22139953200	8/2/1995
73844	14108305ACC	Monitoring	47.06169917890	-101.22358581600	10/6/2016
58510	14108305ADB	Monitoring	47.06353364760	-101.21876317200	7/17/2000
58523	14108305ADC	Monitoring	47.06171298480	-101.21876286800	8/2/1995
58524	14108305ADC	Monitoring	47.06171298480	-101.21876286800	8/22/1995
45434	14108305BA	Monitoring	47.06626411980	-101.22799737700	9/4/1992
70411	14108305BCD	Monitoring	47.06169240830	-101.23158683300	9/26/2013
70410	14108305BDD	Monitoring	47.06169060340	-101.22625006000	9/26/2013
70412	14108305BDD	Monitoring	47.06169060340	-101.22625006000	9/30/2013
58511	14108305CA	Monitoring	47.05898146850	-101.22799490900	7/14/2000
58517	14108305CA	Monitoring	47.05898146850	-101.22799490900	12/6/1997
64007	14108305CCA	Monitoring	47.05628804250	-101.23157737800	9/16/2008
45440	14108305CCC	Monitoring	47.05442894260	-101.23459317900	6/22/1992
58518	14108305DA	Monitoring	47.05897926820	-101.21744230100	12/6/1997
58522	14108305DAA	Monitoring	47.05988960620	-101.21612233400	7/27/1995
45437	14108305DAB	Monitoring	47.05989232110	-101.21876256400	9/2/1992
45431	14108305DBA	Monitoring	47.05989225890	-101.22139874500	11/21/1991
58521	14108305DBA	Monitoring	47.05989225890	-101.22139874500	7/27/1995
58515	14108305DBB	Monitoring	47.05989211090	-101.22403893900	12/18/2001
68204	14108305DBB	Monitoring	47.05989214820	-101.22359756900	9/2/2010
68205	14108305DBB	Monitoring	47.05989214820	-101.22359756900	9/2/2010

Table B-1: Deep Wells Within the Area of Review

NDIC File No.	Well Operator	Well Type	Well Status	Latitude	Longitude	Spud Date	Total Depth (ft bgs)	Surface Casing Depth (ft bgs)	Depth to Pierre Formation (ft bgs)	Surface Casing Depth Below USDW (ft)	Plug Depths Between USDW and Inyan Kara Fm.	Plugs Types Between USDW and Inyan Kara Fm.	Top of Inyan Kara Formation (ft bgs)	Cement Depth Above Inyan Kara Formation (ft)	Surface Casing Cement Bond Log
37672 (J-ROC1)	Minnkota Power Cooperative, Inc.	ST	DRL	47.0627540	-101.2132330	9/8/2020	9,871	1,997	1,185	812	•Inyan Kara Plug: 3,400-3,715 ft bgs •Base of Surface Casing Plug: 1,800-2,050 ft bgs •Surface Plug: 30-90 ft bgs	•Inyan Kara Plug: 145 sacks EverCRETE •Base of Surface Casing Plug: 125/220 sacks Class G •Surface Plug: 45 sacks Class G	3,694	294	Yes Good bond from 1,800 to 1,935 ft bgs

Notes:
ST = stratigraphic test
DRL = drilled
bgs = below ground surface
USDW = underground source of drinking water

Table B-2A: Shallow Wells Within the Area of Review (North Dakota State Water Commission Database)

NDSWC File No.	Location	Well Type	Latitude	Longitude	Date Drilled
45435	14108305DBC	Monitoring	47.05807144640	-101.22403845600	8/31/1992
58509	14108305DBD	Monitoring	47.05806885270	-101.22139831500	12/18/2001
62224	14108305DCA	Monitoring	47.05629497510	-101.22093313700	5/31/2006
62223	14108305DCB	Monitoring	47.05629468630	-101.22359722500	6/1/2006
45428	14108305DD	Monitoring	47.05533793760	-101.21744178300	8/31/1992
62226	14108305DDA	Monitoring	47.05629544240	-101.21559292600	6/1/2006
64006	14108305DDA	Monitoring	47.05629544240	-101.21559292600	9/16/2008
62225	14108305DDB	Monitoring	47.05629796890	-101.21826507400	5/31/2006
45424	14108305DDC	Monitoring	47.05442758350	-101.21876161600	11/22/1991
45430	14108305DDC	Monitoring	47.05442758350	-101.21876161600	11/22/1991
45433	14108305DDC	Monitoring	47.05442758350	-101.21876161600	11/21/1991
45442	14108307DDD	Monitoring	47.03987361290	-101.23730201600	6/22/1992
45444	14108307DDD	Monitoring	47.03987361290	-101.23730201600	6/23/1992
75424	14108308AAC	Monitoring	47.05089676300	-101.21818880300	4/10/2018
75425	14108308ABC	Monitoring	47.05089632660	-101.22350440900	4/4/2018
45445	14108309CAC	Monitoring	47.04374031500	-101.20800881800	6/24/1992
45446	14108309CAC	Monitoring	47.04374031500	-101.20800881800	6/24/1992
45450	14108317ABA	Monitoring	47.03831048430	-101.22134947500	6/23/1992
45454	14108317ABA	Monitoring	47.03831048430	-101.22134947500	6/23/1992
70195	14108328BB	Monitoring	47.00850829930	-101.21159727700	8/16/2013
70196	14108328BB	Monitoring	47.00850829930	-101.21159727700	8/16/2013
75609	14108414AC	Monitoring	47.03354034840	-101.28599885700	7/9/2018
75610	14108414AC	Monitoring	47.03354034840	-101.28599885700	7/9/2018
71993	14108424B	Monitoring	47.02090999740	-101.27275888800	4/13/2015
71994	14108424B	Monitoring	47.02090999740	-101.27275888800	4/14/2015
74661	14108424B	Monitoring	47.02090999740	-101.27275888800	4/13/2015
74662	14108424B	Monitoring	47.02090999740	-101.27275888800	4/14/2015
45682	14208331DBB	Monitoring	47.07421357470	-101.24546374500	11/2/1994
45742	14208426DBB	Monitoring	47.08859870920	-101.28811425400	6/25/1992
45766	14208436ABC	Monitoring	47.07957126200	-101.26674785100	6/25/1992
68211	14208436ABC	Monitoring	47.07956557860	-101.26636644400	9/1/2010
68213	14208436ABC	Monitoring	47.07956557860	-101.26636644400	9/1/2010
58551	14208436B	Monitoring	47.07865795490	-101.27333362100	7/14/2000
58552	14208436B	Monitoring	47.07865795490	-101.27333362100	7/11/2000
58553	14208436B	Monitoring	47.07865795490	-101.27333362100	7/13/2000
58554	14208436B	Monitoring	47.07865795490	-101.27333362100	7/13/2000
45763	14208436BAD	Monitoring	47.07957286780	-101.26938102400	4/24/1996
45764	14208436BAD	Monitoring	47.07957286780	-101.26938102400	4/24/1996
46298	14208436BAD	Monitoring	47.07957286780	-101.26938102400	6/26/2003
76702	14208436BC	Monitoring	47.07684094790	-101.27563942400	9/24/2019
46297	14208436BDA	Monitoring	47.07774670240	-101.26938293700	6/27/2003
62936	14108301BAA	Stock	47.06769659220	-101.14172881700	9/18/2007
46271	14108314DBA	Stock	47.03134264290	-101.15793313800	7/30/2002
62952	14108314DBB	Stock	47.03137121000	-101.16012311000	9/14/2007
45457	14108318AAA	Stock	47.03819346360	-101.23719472000	11/9/1973
66247	14108318BDC	Stock	47.03272363460	-101.25025782700	6/27/2009
74664	14108318CC	Stock	47.02636107210	-101.25419897000	7/28/2017
45458	14108319CAC	Stock	47.01456594600	-101.25070183900	7/13/1972
45467	14108401BA	Stock	47.06606821900	-101.27067222700	7/3/1973
45494	14108412C	Stock	47.04252236110	-101.27318222700	10/24/1989
45654	14208320DAA	Stock	47.10328061860	-101.21662135900	8/12/1983
45668	14208328A	Stock	47.09347770090	-101.19932645100	11/30/1997
45672	14208328AD	Stock	47.09165631590	-101.19673723900	11/25/1992
46293	14208330DCC	Stock	47.08314362950	-101.24554365800	4/15/2002
62368	14208331DCC	Stock	47.06880096510	-101.24503541000	1/11/2007
45737	14208424DA	Stock	47.10214709710	-101.26036045000	10/8/1987
58508	14108304B	Test Hole	47.06450481880	-101.20941031100	8/26/1993
45425	14108305ADC	Test Hole	47.06171298480	-101.21876286800	4/22/1996
45432	14108305DBA	Test Hole	47.05989225890	-101.22139874500	4/22/1996
58513	14108305DBB	Test Hole	47.05989211090	-101.22403893900	12/18/2001
45459	14108319AC	Test Hole	47.01915004050	-101.24404209400	9/29/1994
45460	14108319AC	Test Hole	47.01915004050	-101.24404209400	9/1/1994
45657	14208321ABB	Test Hole	47.11070119990	-101.20314157600	5/27/1975
45666	14208328A	Test Hole	47.09347770090	-101.19932645100	11/30/1997
45678	14208330BAAB	Test Hole	47.09653026350	-101.24885755800	10/26/1990
45679	14208330BAAC	Test Hole	47.09560623120	-101.24885670400	10/28/1990
45675	14208330BAB	Test Hole	47.09606761670	-101.25084664100	7/8/1999
45680	14208330BADB	Test Hole	47.09468494050	-101.24885588800	10/28/1990
45770	14208436	Test Hole	47.07500532680	-101.26806329300	4/22/1996
45768	14208436B	Test Hole	47.07865795490	-101.27333362100	4/22/1996
45769	14208436B	Test Hole	47.07865795490	-101.27333362100	4/22/1996
45771	14208436B	Test Hole	47.07865795490	-101.27333362100	4/22/1996
45469	14108402B	Unknown	47.06423385790	-101.29443382100	7/25/1983
470630101144201	14208319ACB	USGS Groundwater	47.10832816000	-101.24542600000	8/1/1967
470358101135201	14108305BBD	USGS Groundwater	47.06610565000	-101.23153490000	5/1/1967
470349101124101	14108304BC	USGS Groundwater	47.06360540000	-101.21181200000	5/1/1967
470352101122601	14108304BDB	USGS Groundwater	47.06443869000	-101.20764520000	8/1/1967
470359101121701	14108304BAD	USGS Groundwater	47.06638310000	-101.20514520000	8/1/1967
470352101121701	14108304BDA	USGS Groundwater	47.06443866000	-101.20514510000	8/1/1967
470346101113901	14108304ADD	USGS Groundwater	47.06277186000	-101.19458920000	8/1/1967
470328101091601	14108302DDB1	USGS Groundwater	47.05777138000	-101.15486560000	5/1/1967

Notes:

1. No attempt was made to remove well records that may be duplicates between the records presented in this table and the records presented in Table B-2B.
2. NDSWC File Numbers for USGS Groundwater wells are USGS file numbers.
3. Locations of wells are approximate.

Table B-2B: Shallow Wells Within the Area of Review (MPC Facility Wells)

Name	Facility	Well Type	Latitude	Longitude	Total Depth (ft bgs)
2001-01	30 Year Pond Wells	Monitoring	47.06109923940	-101.22182160300	NA
2006-08-1r	30 Year Pond Wells	Monitoring	47.05843018790	-101.22188337200	NA
2006-08-4r	30 Year Pond Wells	Monitoring	47.05837890790	-101.21454709300	NA
2013-1	30 Year Pond Wells	Monitoring	47.05512100000	-101.22353900000	NA
2013-2	30 Year Pond Wells	Monitoring	46.82604023470	-107.77324319700	NA
2013-3	30 Year Pond Wells	Monitoring	47.05458645700	-101.21447415000	NA
2015-1	30 Year Pond Wells	Monitoring	47.05770507840	-101.22430536100	204
2015-2	30 Year Pond Wells	Monitoring	47.05772696180	-101.22431368100	150
2015-3	30 Year Pond Wells	Monitoring	47.05787335050	-101.21454999300	132
2015-4	30 Year Pond Wells	Monitoring	47.05520430730	-101.21446110900	136
2015-5	30 Year Pond Wells	Monitoring	47.05378223690	-101.21442934600	170
2016-1	30 Year Pond Wells	Monitoring	47.05643365440	-101.21439843200	155
2018-1	30 Year Pond Wells	Monitoring	47.05220225040	-101.21443800900	206
2018-2	30 Year Pond Wells	Monitoring	47.04880745550	-101.22441479200	216
92-1	30 Year Pond Wells	Monitoring	47.05530868560	-101.21674821100	NA
92-2A	30 Year Pond Wells	Monitoring	47.05801110030	-101.21292179200	166
92-2B	30 Year Pond Wells	Monitoring	47.05803316970	-101.21292236600	56
92-3	30 Year Pond Wells	Monitoring	47.06258203830	-101.21307198000	155
92-4	30 Year Pond Wells	Monitoring	47.06660313430	-101.21883755500	211
92-5A	30 Year Pond Wells	Monitoring	47.06248737940	-101.22441330600	187
92-5B	30 Year Pond Wells	Monitoring	47.06243000090	-101.22440282200	75
92-6A	30 Year Pond Wells	Monitoring	47.05787709860	-101.22425504200	NA
92-6B	30 Year Pond Wells	Monitoring	47.05785889830	-101.22430623300	55
92-7	30 Year Pond Wells	Monitoring	47.05942908830	-101.21825559900	272
95-1	30 Year Pond Wells	Monitoring	47.05942022160	-101.22063598000	NA
95-2	30 Year Pond Wells	Monitoring	47.05946441480	-101.21637349800	NA
95-3	30 Year Pond Wells	Monitoring	47.06127616980	-101.21793524400	NA
95-4	30 Year Pond Wells	Monitoring	47.06153601830	-101.21279057400	NA
97-1	30 Year Pond Wells	Monitoring	47.06231069420	-101.21581129100	NA
#8-1	Horseshoe Pit Wells	Monitoring	47.07716741950	-101.27113180500	145
5-1r	Horseshoe Pit Wells	Monitoring	47.07820936450	-101.27119470200	103
5-2r	Horseshoe Pit Wells	Monitoring	47.07821079310	-101.27125970500	NA
2003-6-2r	Horseshoe Pit Wells	Monitoring	47.07873169350	-101.26669968100	95
#6-1	Horseshoe Pit Wells	Monitoring	47.07880836980	-101.26673513500	NA
#4-1	Horseshoe Pit Wells	Monitoring	47.07919381390	-101.27630955600	NA
#10-1r	Horseshoe Pit Wells	Monitoring	47.07975125550	-101.26702307400	103
#3-1	Horseshoe Pit Wells	Monitoring	47.08035096190	-101.27392566700	134
#3-2	Horseshoe Pit Wells	Monitoring	47.08035379810	-101.27389130900	96
#3-3	Horseshoe Pit Wells	Monitoring	47.08035872570	-101.27383952000	171
2003-1	Horseshoe Pit Wells	Monitoring	47.08071794210	-101.26762304400	99
96-2	Horseshoe Pit Wells	Monitoring	47.08097218970	-101.26762965200	NA
96-1	Horseshoe Pit Wells	Monitoring	47.08098003210	-101.26760495800	NA
#12-1	Horseshoe Pit Wells	Monitoring	47.08125035600	-101.26637706200	114
#1-2r	Horseshoe Pit Wells	Monitoring	47.08167998120	-101.26394413700	86
#1-1	Horseshoe Pit Wells	Monitoring	47.08168017530	-101.26391905300	126
#9-1	Horseshoe Pit Wells	Monitoring	47.08186697320	-101.26843144500	147
14108304BBD	Miscellaneous Plant Wells	Industrial	47.06454604040	-101.33672835800	280
14208333DD	Miscellaneous Plant Wells	Industrial	47.06912285030	-101.32236476900	160
MPC-WS-2	Miscellaneous Plant Wells	Industrial	47.06780000000	101.21450000000	107
MPC-WS-1	Miscellaneous Plant Wells	Industrial	47.06640000000	101.21430000000	186
MP-WS-1	Miscellaneous Plant Wells	Industrial	47.07180000000	101.19610000000	NA
3	Nelson Lake Dam Wells	Monitoring	47.06521365040	-101.20328465900	12
9	Nelson Lake Dam Wells	Monitoring	47.06543380510	-101.20710607200	43
10	Nelson Lake Dam Wells	Monitoring	47.06544918470	-101.20793964200	44
7	Nelson Lake Dam Wells	Monitoring	47.06573354620	-101.20588103000	37
SB-3A	Nelson Lake Dam Wells	Monitoring	47.06630617280	-101.20560533700	15
SB-3	Nelson Lake Dam Wells	Monitoring	47.06632603650	-101.20558553400	35
8	Nelson Lake Dam Wells	Monitoring	47.06633597320	-101.20493570900	20
6	Nelson Lake Dam Wells	Monitoring	47.06643840410	-101.20476281800	19
98-4	Nelson Lake Dam Wells	Monitoring	47.06646286610	-101.20479801000	19
SB-2	Nelson Lake Dam Wells	Monitoring	47.06647686460	-101.20585035600	60
98-3	Nelson Lake Dam Wells	Monitoring	47.06660561560	-101.20505698700	24
SB-1	Nelson Lake Dam Wells	Monitoring	47.06662340570	-101.20533944300	37
2	Nelson Lake Dam Wells	Monitoring	47.06672723220	-101.20499722800	28
P1-20W-02-US1	Nelson Lake Dam Wells	Monitoring	47.06683040170	-101.20565596800	62
1	Nelson Lake Dam Wells	Monitoring	47.06696788760	-101.20548566400	60
98-2	Nelson Lake Dam Wells	Monitoring	47.06702061510	-101.20465421000	14
11	Nelson Lake Dam Wells	Monitoring	47.06709314850	-101.20517607200	53
P1-14-02-DS1	Nelson Lake Dam Wells	Monitoring	47.06728642710	-101.20421933200	13
P1-14-02-US1	Nelson Lake Dam Wells	Monitoring	47.06754987780	-101.20467544400	56
12	Nelson Lake Dam Wells	Monitoring	47.06772448420	-101.20448347100	54
P1-16-02-DS1	Nelson Lake Dam Wells	Monitoring	47.06776080160	-101.20381423200	15
P1-16-02-US1	Nelson Lake Dam Wells	Monitoring	47.06802453180	-101.20431449200	56
13	Nelson Lake Dam Wells	Monitoring	47.06840729590	-101.20373045100	54
98-1	Nelson Lake Dam Wells	Monitoring	47.06871201980	-101.20294473000	21
98-5	Nelson Lake Dam Wells	Monitoring	47.06873113710	-101.20293033300	22
P1-20-02-DS1	Nelson Lake Dam Wells	Monitoring	47.06874962460	-101.20281712800	24
P1-20-02-US1	Nelson Lake Dam Wells	Monitoring	47.06883964570	-101.20325171100	56

Notes:

1. No attempt was made to remove well records that may be duplicates between the records presented in this table and the records presented in Table B-2A.
2. Locations of wells are approximate.

APPENDIX C

Modeling Inputs Tables

Table C-1: Inputs for Diffusivity Equation Modeling

Variable	Sym.	Units	Value	Notes
Injection Duration	t	years	20	20 years of continuous injection
		days	7,300	
		hours	175,200	
Kelly Bushing Elevation	z_{KB}	ft amsl	2,029	Approximate Kelly Bushing elevation at J-ROC1
Ground Surface Elevation	z_{GS}	ft amsl	2,004	Approximate ground surface elevation at J-ROC1
Borehole Radius	r_w	ft	0.510	Radius of 12.25-inch borehole in injection interval
Injection Interval Properties				
Net Sandstone Thickness				
Depth to Top of Perforated Interval	$D_{perf\ top}$	ft bgs	3,667	Calculated
Depth to Bottom of Perforated Interval	$D_{perf\ bottom}$	ft bgs	3,838	Calculated
Elevation of Top of Perforated Interval	$z_{perf\ top}$	ft amsl	-1,663	Approximate elevation based on CMR log at J-ROC1 (Figure 4-1)
Elevation of Bottom of Perforated Interval	$z_{perf\ bottom}$	ft amsl	-1,834	Approximate elevation based on CMR log at J-ROC1 (Figure 4-1)
Injection Interval Net Sands Thickness	h	ft	90	Total thickness of permeable zones in Inyan Kara Formation based on CMR log at J-ROC1 (Figure 4-1)
Formation Static Pore Pressure				
Static Potentiometric Surface Elevation of Injection Interval	H_{static}	ft amsl	1,899	Approximate static potentiometric surface at MRY based on measured pressure gradient with depth at J-ROC1 (0.420 psi/ft)
Initial Static Pore Pressure Gradient		psi/ft	0.4198	Measured static pore pressure gradient at J-ROC1
Initial Static Pressure of Injection Interval	P_{otop}	psi	1,539	Static pressure evaluated at the top of the injection interval
Hydrostatic Pressure of Injection Interval	P_{hydtop}	psi	1,655	Hydrostatic pressure evaluated at the top of the injection interval assuming injectate fluid density
Formation Porosity				
Effective Porosity	ϕ	-	0.151	Average CMR free fluid porosity (CMFF) in permeable zones at J-ROC1 (Figure 4-2)
Formation Permeability				
Intrinsic Permeability	κ	mD	950	Average permeability from CMR log in permeable zones at J-ROC1 using SDR and Timur-Coates (Figure 4-1)

Table C-1: Inputs for Diffusivity Equation Modeling

Variable	Sym.	Units	Value	Notes
Formation Fluid Properties				
Formation Fluid Properties				
Temperature	T_{form}	°F	120	Approximate Inyan Kara Formation water temperature at MRY, measured using MDT tool
Total Dissolved Solids Concentration	TDS_{form}	mg/L	3,450	Measured TDS concentration from Inyan Kara Formation fluid sample collected at J-LOC1 using MDT tool (June 2020)
		%	0.35	Conversion to volumetric percent
Formation Pressure During Injection	P_i	psi	2,714	Assumed pressure of injection interval during injection for estimating fluid properties (conservatively equal to fracture pressure)
Viscosity	μ_{form}	cP	0.546	Calculated based on formation fluid temperature, TDS concentration, and formation pressure during injection
Specific Gravity	γ_{form}	-	0.997	Calculated based on formation fluid temperature, TDS concentration, and formation pressure during injection
Fluid Density	ρ_{form}	g/cm^3	0.997	Equal to specific gravity
		kg/m^3	996.8	Conversion
		lb/ft^3	62.226	Conversion
Total Compressibility				
Pore Volume Compressibility	c_f	1/psi	4.07E-06	Regression of data from Hall (1953) and presented in Lei et al. (2019): $c_f = \frac{1.7836E^{-6}}{\phi^{0.4358}}$
Bulk Volume Compressibility (Aquifer Skeleton Compressibility)	c_m (α)	1/psi	6.14E-07	Calculated as (Crawford et al. 2011): $c_m = \phi c_f$
Bulk Modulus of Elasticity of Water	E_w	psi	3.00E+05	Lohman (1972)
Water Compressibility	c_w (β)	1/psi	3.33E-06	Calculated as (Lohman 1972): $c_w = \frac{1}{E_w}$
Total Compressibility	c_t	1/psi	7.40E-06	Calculated assuming 100% water saturated with no presence of oil or gas $c_t = c_f + c_w$
Formation Storage Coefficient				
Specific Storage	Ss	1/ft	4.83E-07	Calculated as (Fetter 2001): $S_s = \frac{\rho_{form}}{144}(c_m + \phi c_w)$
Storage Coefficient	S	-	4.34E-05	Calculated as (Fetter 2001): $S = hS_s$
Formation Volume Factor				
Formation Volume Factor	B	bbl/bbl	1.0	Assumption

Table C-1: Inputs for Diffusivity Equation Modeling

Variable	Sym.	Units	Value	Notes
Hydraulic Conductivity				
Hydraulic Conductivity	K	ft/day	4.86	Calculated using formation fluid properties $K = \frac{\kappa \rho g}{3500\mu}$
Formation Transmissivity				
Transmissivity	T	ft^2/day	437.8	Calculated using formation fluid properties $T = Kh$
Injectate Fluid Properties				
Injectate Fluid Properties				
Temperature	T	°F	55	Assumption
Total Dissolved Solids	TDS	mg/L	40,000	Assumption
		%	4.00	Conversion to volumetric percent
Formation Pressure During Injection	P_I	psi	2,714	Assumed pressure of injection interval during injection for estimating fluid properties (conservatively equal to fracture pressure)
Viscosity	μ	cP	1.294	Calculated based on injectate fluid temperature, TDS concentration, and formation pressure during injection
Specific Gravity	γ	-	1.041	Calculated based on injectate fluid temperature, TDS concentration, and formation pressure during injection
Fluid Density	ρ	g/cm^3	1.041	Equal to specific gravity
		kg/m^3	1,041.1	Conversion
		lb/ft^3	64.994	Conversion
Formation Storage Coefficient				
Specific Storage	Ss	1/ft	5.04E-07	Calculated as (Fetter 2001): $S_s = \frac{\rho_{inj}}{144}(c_m + \phi c_w)$
Storage Coefficient	S	-	4.54E-05	Calculated as (Fetter 2001): $S = hS_s$
Hydraulic Conductivity				
Hydraulic Conductivity	K	ft/day	2.14	Calculated using injectate fluid properties $K = \frac{\kappa \rho g}{3500\mu}$
Formation Transmissivity				
Transmissivity	T	ft^2/day	192.9	Calculated using injectate fluid properties $T = Kh$

Table C-1: Inputs for Diffusivity Equation Modeling

Variable	Sym.	Units	Value	Notes
Lowest Underground Source of Drinking Water Formation Properties				
Elevation of USDW Bottom		ft amsl	840	Approximate top of Pierre Shale - J-ROC1 formation tops ~200 feet shallower than BNI-1 formation tops (top of Pierre Shale at BNI-1 1,282 feet below ground surface
Static Potentiometric Surface Elevation of USDW		ft amsl	1,800	Water level elevation from 142-084-24 BBA, completed in the Fox Hills Formation

Abbreviations:

ft: feet
ft bgs: feet below ground surface
ft amsl: feet above mean sea level
ft/day: feet per day
ft^2/day: square feet per day
cP: centipoise
mD: millidarcies
°F: degrees Fahrenheit
psi: pounds per square inch
bbl/bbl: barrel per barrel
mg/L: milligrams per liter
g/cm^3: grams per cubic centimeter
kg/m^3: kilograms per cubic meter
lb/ft^3: pounds per cubic foot
USDW: underground source of drinking water
TDS: total dissolved solids

Table C-2: Inputs for AquiferWin32 Confirmatory Modeling

Variable	Sym.	Units	Value	Notes
Proposed Injection Site				
FREEMAN-1 Easting	X	ft	1,790,841	Approximate location of FREEMAN-1 in NAD83 State Plane Coordinate System North Dakota South
FREEMAN-1 Northing	Y	ft	509,872	
Ground Surface Elevation	z	ft amsl	2,004	Table C-1
RUBEN-1 Easting	X	ft	1,791,090	Approximate location of RUBEN-1 in NAD83 State Plane Coordinate System North Dakota South
RUBEN-1 Northing	Y	ft	507,250	
Ground Surface Elevation	z	ft amsl	2,004	Table C-1
Injection Duration	t	yrs	20	Table C-1
Injection Interval Properties				
Regional Hydraulic Gradient	I	ft/ft	2.7E-04	Approximate regional hydraulic gradient estimated from Figure 3-15
Direction of Regional Hydraulic Gradient	θ	degrees	54° N of E	Approximate direction of regional hydraulic gradient estimated from Figure 3-15
Injection Interval Net Sands Thickness	h	ft	90	Table C-1
Effective Porosity	ϕ	-	0.151	Table C-1
Intrinsic Permeability	κ	mD	950	Table C-1
Injection Interval Static Head				
Static Potentiometric Surface Elevation of Injection Interval	H_{static}	ft amsl	1,899	Table C-1
Reference Head	H_{ref}	ft amsl	2,034.58	Reference head set to result in static potentiometric surface elevation at FREEMAN-1
Reference Head Easting	X_{ref}	ft	1,363,680	Reference head location in NAD83 State Plane Coordinate System North Dakota South
Reference Head Northing	Y_{ref}	ft	199,521	
Reference Head Distance from Well	Δ_{ref}	miles	100	Reference head situated sufficiently far from the well to not influence simulation results
Hydraulic Properties Estimated Using Native Formation Fluid Properties				
Hydraulic Conductivity	K	ft/day	4.86	Table C-1
Transmissivity	T	ft^2/day	437.8	Table C-1
Storage Coefficient	S	-	4.34E-05	Table C-1
Leakage Factor	1/B	1/ft	5.09E-07	Calculated $1/_B = \left[\frac{K'}{Tb'}\right]^{1/2}$

Table C-2: Inputs for AquiferWin32 Confirmatory Modeling

Variable	Sym.	Units	Value	Notes
Hydraulic Properties Estimated Using Injectate Fluid Properties				
Hydraulic Conductivity	K	ft/day	2.14	Table C-1
Transmissivity	T	ft^2/day	192.9	Table C-1
Storage Coefficient	S	-	4.54E-05	Table C-1
Leakage Factor	1/B	1/ft	7.67E-07	Calculated $^{1}/_{B} = \left[\frac{K'}{Tb'}\right]^{1/2}$
Confining Unit Properties				
Vertical Hydraulic Conductivity	K'	ft/day	2.84E-07	Mid-range of literature values reported for the Pierre Shale in South Dakota, 2.84E-6 to 2.84E-8 ft/day (Milly, 1978; Neuzil, 1980)
Thickness	b'	ft	2,500	Approximate thickness of Cretaceous Confining Unit (top of Pierre Shale to top of Inyan Kara Formation)
Simulated Well Properties				
Casing Inner Diameter	D_c	ft	0.730	Inside diameter of 9.625-inch OD 43.5# N-80 steel casing (ID = 8.755 inches)
Borehole Diameter	D_b	ft	1.021	Diameter of 12.25-inch borehole through injection interval
Screen Length	L_s	ft	90	Equal to the net sandstone thickness
Screen Top Depth	d_{ST}	ft	0	Distance from the top of the injection interval to the top of the well screen (fully penetrating well)

Abbreviations:

ft/day: feet per day

ft: feet

ft amsl: feet above mean sea level

mD: millidarcies

OD: outside diameter

ID: inside diameter

Table C-3: Modular Formation Dynamics Testing Results at Test Boreholes/Wells

Borehole / Well	Kelly Bushing Elevation	Ground Surface Elevation	Measurement Depth		Measurement Elevation	Measured Pore Pressure	Pore Pressure Gradient	Temperature
	(ft amsl)		(ft below KB)	(ft bgs)	(ft amsl)	(psi)	(psi/ft)	(°F)
BNI-1	2,085	2,067	3,996	3,978	-1,911	1,652	0.4153	123.73
			4,030	4,012	-1,945	1,666	0.4153	124.90
J-LOC1	2,093	2,068	3,892	3,867	-1,799	1,610	0.4163	123.75
			4,019	3,994	-1,926	1,664	0.4166	124.19
			4,040	4,015	-1,947	1,673	0.4167	124.75
			4,019	3,994	-1,926	1,663	0.4165	125.95
J-ROC1	2,029	2,004	3,794	3,769	-1,765	-	-	107.20
			3,796	3,771	-1,767	1,583	0.4197	108.14
			3,810	3,785	-1,781	1,588	0.4197	108.86
			3,846	3,821	-1,817	1,604	0.4198	109.56
			3,845	3,820	-1,816	1,605	0.4201	113.91

Notes:

1. ft = feet
2. ft amsl = feet above mean sea level
3. ft bgs = feet below ground surface
4. KB = Kelly Bushing
5. psi = pounds per square inch
6. °F = degrees Fahrenheit
7. Information provided by Energy & Environmental Research Center (not currently publicly available).

APPENDIX D

Fracture Pressure Calculation

Table D-1: Fracture Pressure Calculation

Variable	Sym.	Units	Value	Notes
Inyan Kara Formation Properties				
Ground Surface Elevation	z_{GS}	ft amsl	2,004	Table C-1
Depth to Top of Screened Interval	$D_{screen\ top}$	ft bgs	3,667	Table C-1
Static Potentiometric Surface Elevation of Injection Interval	H_{static}	ft amsl	1,899	Table C-1
Overburden Stress Gradient		psi/ft	0.977	Evaluated using J-ROC1 bulk density logs at top of screened int.
Overburden Stress	σ_v	psi	3,581	Calculated based on depth to top of screened interval
Pore Pressure at Top of Injection Interval	P_o	psi	1,539	Table C-1
Pore Pressure Gradient		psi/ft	0.420	Pore pressure divided by depth to top of screened interval
Vertical Effective Pressure	σ_e	psi	2,042	Calculated as: $\sigma_e = \sigma_v - P_o$
Porosity	ϕ	-	0.151	Table C-1, effective porosity used
Clay Volume	V_c	-	0.00	Assumption
Compression Wave Velocity	VP_c	km/s	5.443	Calculated as (Castagna, et al. 1985): $VP_c = 6.5 - 7.0\phi - 1.5V_c$
Shear Wave Velocity	VS_c	km/s	2.614	Calculated as (Castagna, et al. 1985): $VS_c = 3.52 - 6.0\phi - 1.8V_c$
Poisson's Ratio	μ	-	0.350	Calculated as (Desroches & Bratton n.d.): $\mu = \frac{0.5\left(\frac{VP_c}{VS_c}\right)^2 - 1}{\left(\frac{VP_c}{VS_c}\right)^2 - 1}$
Fracture Propagation Pressure Calculation				
Ward et al (1995)				
Fracture Pressure, P_{fp}		psi	3,273	$P_{fp} = (1-\phi)(\sigma_v - P_o) + P_o$
Fracture Pressure Gradient		psi/ft	0.893	Calculated with reference to top of injection interval
Eaton (1969)				
Fracture Pressure, P_{fp}		psi	2,639	$P_{fp} = \frac{\mu}{1-\mu}(\sigma_v - P_o) + P_o$
Fracture Pressure Gradient		psi/ft	0.720	Calculated with reference to top of injection interval
J-LOC 1 Step-Rate Test				
Fracture Pressure, P_{fp}		psi	2,714	Calculated as fracture pressure gradient multiplied by depth to top of injection interval
Fracture Pressure Gradient		psi/ft	0.740	Propagation pressure gradient calculated from Step-Rate test at J-LOC1 well

APPENDIX E

Geochemical Modeling

Table E-1: Formation Water Quality Results

Constituent	Units	MVTL 6/13/2020	EERC - Unfiltered 6/13/2020	Geomean of Formation Water Samples	Simulated Formation Water with Added CO_2
pH	SU	8.63		8.63	7.66
Temperature	Deg C	21		21	21
Conductivity (EC)	µmhos/cm	4,774		4,774	4,774
Total Dissolved Solids	mg/L	3,450		3,450	3,450
Alkalinity as $CaCO_3$	mg/L $CaCO_3$	544		544	544
Bicarbonate Alkalinity as $CaCO_3$	mg/L $CaCO_3$	501		501	
Carbonate Alkalinity as $CaCO_3$	mg/L $CaCO_3$	43		43	
Hydroxide Alkalinity as $CaCO_3$	mg/L $CaCO_3$	<20		<20	
Phenolphthalein Alkalinity as $CaCO_3$	mg/L $CaCO_3$	22		22	
Sulfate	mg/L	2,450		2,450	2,450
Chloride	mg/L	554		554	554
Calcium, Total	mg/L	17	14	16	16
Magnesium, Total	mg/L	<5	<1	<3	3.0
Sodium, Total	mg/L	1,120	1,270	1,193	1,193
Potassium, Total	mg/L	5.7	5.1	5.4	5.4
Ammonia-Nitrogen as N	mg/L	1.1		1.1	1.1
Nitrate-Nitrite as N	mg/L	0.16		0.16	0.16
Total Organic Carbon (TOC)	mg/L	1,340		1,340	1,340
Aluminum, Total	mg/L		0.17	0.17	0.17
Antimony, Total	mg/L		<0.005	<0.005	0.0050
Arsenic, Dissolved	mg/L	<0.002		<0.002	0.0020
Arsenic, Total	mg/L		<0.005	<0.005	0.0050
Barium, Dissolved	mg/L	0.26		0.26	0.26
Barium, Total	mg/L		0.78	0.78	0.78
Beryllium, Total	mg/L		<0.004	<0.004	0.0040
Boron, Total	mg/L		2.7	2.7	2.7
Cadmium, Dissolved	mg/L	<0.0005		<0.0005	0.00050
Cadmium, Total	mg/L		<0.002	<0.002	0.0020
Chromium, Dissolved	mg/L	0.030		0.030	0.030
Chromium, Total	mg/L		<0.010	<0.010	0.010
Cobalt, Total	mg/L		0.055	0.055	0.055
Copper, Dissolved	mg/L	<0.05		<0.05	0.050
Copper, Total	mg/L		< 0.05	< 0.05	0.050
Iron, Total	mg/L	0.33	< 0.1	0.33	0.33
Lead, Dissolved	mg/L	<0.0005		<0.0005	0.00050
Lead, Total	mg/L		< 0.005	< 0.005	0.0050
Lithium, Total	mg/L		0.24	0.24	0.24
Manganese, Total	mg/L	<0.05	<0.02	<0.035	0.035
Mercury, Total	mg/L		<0.0001	<0.0001	0.00010
Molybdenum, Dissolved	mg/L	<0.1		<0.1	0.10
Molybdenum, Total	mg/L		0.069	0.069	0.069
Nickel, Total	mg/L		0.061	0.061	0.061
Selenium, Dissolved	mg/L	<0.005		<0.005	0.0050
Selenium, Total	mg/L		<0.005	<0.005	0.0050
Silver, Total	mg/L	<0.0005	<0.005	<0.005	0.0050
Strontium, Dissolved	mg/L	0.32		0.32	0.32
Strontium, Total	mg/L		< 1	< 1	1.0
Thallium, Total	mg/L		<0.005	<0.005	0.0050
Vanadium, Total	mg/L		< 0.01	< 0.01	0.010
Zinc, Total	mg/L		0.059	0.059	0.059

Notes:
SU: standard units
Deg C: Degrees Celcius
µmhos/cm: microohms per centimeter
mg/L: milligrams per liter
mg/L $CaCO_3$: milligrams of calcium carbonate per liter

Table E-2: Cooling Tower Blowdown Water Quality Estimates

Parameter Name	Units	Winter Minimum Case	Summer Peak Full Softening Case	Summer Peak Case	Annual Average Case
pH	SU	8.0 - 8.3	8.0 - 8.3	8.0 - 8.3	8.0 - 8.3
Conductivity (estimated)	µS/cm	9,725	16,298	13,488	11,571
TDS (estimated)	mg/L	5,720	9,586	7,933	6,806
TSS	mg/L	219	244	223	220
HCO3-	mg/L $CaCO_3$	451	308	363	405
CO3 (-2)	mg/L $CaCO_3$	51	23	34	42
CO2	mg/L	ND	ND	ND	ND
Ca	mg/L $CaCO_3$	643	293	525	583
Mg	mg/L $CaCO_3$	909	586	795	849
Sodium	mg/L	1,358	2,982	2,370	1,784
Potassium	mg/L	52	93	76	64
Bromide	mg/L	5.2	9.3	7.6	6.4
Chloride	mg/L	57	101	92	70
Fluoride	mg/L	ND	ND	ND	ND
SO4 (-2)	mg/L	3,211	5,812	4,703	3,930
Ammonia	mg/L	ND	ND	ND	ND
Nitrate	mg/L	0.75	1.3	1.1	0.92
Ortho-PO4 (-3)	mg/L	ND	ND	ND	ND
Aluminum (Al+3)	mg/L	0.62	1.1	0.90	0.76
Arsenic (III & V)	mg/L	ND	ND	ND	ND
Barium	mg/L	<0.1	<0.1	<0.1	<0.1
Boron	mg/L	1.0	1.7	1.4	1.2
Iron (Fe+2/Fe+3)	mg/L	0.81	1.5	1.2	1.0
Manganese (Mn+2)	mg/L	0.20	0.35	0.28	0.24
Si (as SiO2)	mg/L	56	85	63	59
Strontium	mg/L	2.9	5.2	4.3	3.6
Zinc	mg/L	<0.1	<0.1	<0.1	<0.1

Notes:
SU: standard units
µS/cm: microsiemens per centimeter
mg/L: milligrams per liter
mg/L $CaCO_3$: milligrams of calcium carbonate per liter

Table E-3: Scrubber Pond Water Quality Results

Parameter Name	Units	Scrubber Pond Cell 3					Scrubber Pond Cell 4
		7/30/2014	3/23/2015	6/9/2016	12/10/2017	6/26/2018	7/24/2019
pH - Field	SU	7.11	6.02	5.80	5.85	5.86	7.80
pH - Lab	SU	7.0	5.9	5.7	5.7	5.8	
Temperature - Field	Deg C	22	--	23	5.6	25	28
Field Electrical Conductivity	µmhos/cm	42,005	55,580	67,264	59,496	58,791	10,894
Lab Specific Conductance	µmhos/cm	41,946	70,210	71,130	56,823	59,307	10,505
Total Dissolved Solids	mg/L	49,700	69,900	108,000	79,800	98,900	10,400
Total Alkalinity	mg/L $CaCO_3$	185	286	488	306	430	214
Bicarbonate	mg/L $CaCO_3$	185	286	488	306	430	214
Carbonate	mg/L $CaCO_3$	<20	<20	<20	<20	<20	<20
Hydroxide	mg/L $CaCO_3$	<20	<20	<20	<20	<20	<20
Phenolphthalein Alk	mg/L $CaCO_3$	<20	<20	<20	<20	<20	<20
Fluoride	mg/L	60	96	132	123	135	14
Sulfate	mg/L	33,000	49,900	77,600	54,700	70,600	6,980
Chloride	mg/L	431	672	1,270	1,110	992	142
Calcium, Total	mg/L	157	278	389	350	568	332
Magnesium, Total	mg/L	3,580	4,500	7,550	6,580	7,240	820
Sodium, Total	mg/L	11,100	13,000	19,200	15,300	17,400	1,830
Potassium, Total	mg/L	1,310	1,340	1,990	1,530	1,800	174
Nitrate-Nitrite as N	mg/L	0.10	2.2	5.4	5.8	6.6	<0.5
Arsenic, Dissolved	mg/L	0.25	0.26	0.16	0.098	0.092	0.018
Barium, Dissolved	mg/L	0.19	0.30	0.34	0.26	0.35	0.11
Beryllium, Dissolved	mg/L	--	--	--	0.0060	--	
Boron, Dissolved	mg/L	190	273	374	264	279	29
Cadmium, Dissolved	mg/L	0.011	0.018	0.0030	0.0027	<0.01	<0.0005
Chromium, Dissolved	mg/L	<0.04	0.031	0.041	0.020	<0.02	<0.002
Iron, Dissolved	mg/L	--	6.9	2.6	<5	2.8	<0.5
Iron, Total	mg/L	<1	--	--	--	--	
Lead, Dissolved	mg/L	<0.008	0.0074	<0.002	<0.002	<0.002	<0.0005
Manganese, Dissolved	mg/L	--	3.3	2.6	2.7	2.0	0.32
Manganese, Total	mg/L	2.3	--	--	--	--	
Mercury, Dissolved	mg/L	<0.0002	<0.0002	<0.0002	<0.0002	<0.0002	<0.0002
Molybdenum, Dissolved	mg/L	3.3	4.7	4.4	3.8	3.9	0.25
Phosphorus as P, Total	mg/L	0.14	<1	0.28	0.21	0.20	0.31
Selenium, Dissolved	mg/L	0.96	1.5	2.5	2.0	2.3	0.048
Silver, Dissolved	mg/L	<0.02	0.0024	<0.008	<0.002	<0.01	<0.0005

Notes:
SU: standard units
Deg C: Degrees Celcius
µmhos/cm: microohms per centimeter
mg/L: milligrams per liter
mg/L $CaCO_3$: milligrams of calcium carbonate per liter

Table E-4: Formation Mineralogy Results

Sample Location	STAR #	Depth (feet)	Smectite	Glauconite	Clintonite	Kaolinite	Illite/ Muscovite	Chlorite	Orthoclase	Microcline	K-feldspar	Albite	P-feldspar	Quartz	Jarosite	Calcite	Calcite, magnesian
Inyan Kara Formation	129299	3,890								6.4%	6.4%			89.1%			
Inyan Kara Formation	129301	3,893		3.8%		3.8%	3.9%	2.4%	2.9%		2.9%			83.2%			
Inyan Kara Formation	129302	3,895					3.9%		3.9%		3.9%			92.2%			
Inyan Kara Formation	129303	3,900				5.3%	5.9%			4.4%	4.4%			83.5%			
Inyan Kara Formation	129304	3,911				10.5%	14.5%	9.7%		4.4%	4.4%	3.4%	3.4%	57.5%			
Inyan Kara Formation	129305	3,915	4.5%	5.2%		6.7%	17.8%	2.4%		4.4%	4.4%			41.2%			
Inyan Kara Formation	129306	3,917			6.9%	13.7%	5.8%	1.9%	4.1%		4.1%			42.1%			
Inyan Kara Formation	129307	3,918	1.0%			4.9%	2.5%		4.8%		4.8%			78.0%			
Inyan Kara Formation	129308	3,920	5.2%		10.3%	12.3%	22.5%	4.8%	2.8%		2.8%			42.1%			
Inyan Kara Formation	129309	3,925	2.4%		7.5%	8.4%	33.2%	2.6%	5.6%		5.6%	4.1%	4.1%	29.0%			
Inyan Kara Formation	129310	3,935	2.4%		8.7%	9.7%	13.8%			6.0%	6.0%	5.1%	5.1%	51.3%			
Inyan Kara Formation	129311	3,946	2.2%		8.7%	4.4%	12.0%	1.6%		6.3%	6.3%	3.1%	3.1%	58.2%			
Inyan Kara Formation	129312	3,950				6.1%	8.3%							85.6%			
Inyan Kara Formation	129313	3,956				4.8%	11.3%			5.5%	5.5%			78.4%			
Inyan Kara Formation	129314	3,960				2.1%				4.7%	4.7%			92.4%			
Inyan Kara Formation	129315	3,969				10.2%	9.1%		10.4%		10.4%			52.2%			
Inyan Kara Formation	129316	3,975				5.9%	36.5%					3.5%	3.5%	42.9%		11.2%	
Inyan Kara Formation	129318	3,980	0.5%		14.3%	8.7%	22.8%			9.2%	9.2%			29.6%	2.5%		
Inyan Kara Formation	129319	3,989	3.3%		11.0%	9.9%	20.3%			6.5%	6.5%			43.4%			
Inyan Kara Formation	129320	3,995		5.6%		2.1%	8.2%	2.7%	3.0%		3.0%			78.4%			
Inyan Kara Formation	129321	3,999				7.4%	27.7%	2.4%		3.5%	3.5%			56.6%			
Inyan Kara Formation	129322	4,003			100.0%	12.4%	9.7%	2.8%				9.1%	9.1%	49.1%			
Inyan Kara Formation	129323	4,007	2.8%	2.9%	7.2%	14.9%	7.9%					4.8%	4.8%	52.5%			
Inyan Kara Formation	129324	4,011				2.8%	0.8%		1.6%		1.6%			94.0%			
Inyan Kara Formation	129325	4,017					1.5%			4.4%	4.4%			92.3%			
Inyan Kara Formation	129326	4,020				1.3%	3.5%	1.7%	2.2%		2.2%			91.3%			
Inyan Kara Formation	129327	4,021				2.9%	2.7%							94.4%			
Inyan Kara Formation	129328	4,029				0.9%	2.2%			1.8%	1.8%			94.8%			
Inyan Kara Formation	129329	4,032				0.7%	1.5%			3.7%	3.7%			93.5%			
Inyan Kara Formation	129330	4,038				2.9%	2.6%			3.4%	3.4%			87.4%			2.8%
Inyan Kara Formation	129331	4,041			2.1%	1.3%	3.0%			2.6%	2.6%			90.4%			
Inyan Kara Formation	129332	4,047					3.0%			3.4%	3.4%			93.6%			
Inyan Kara Formation	129333	4,050					2.1%		2.9%		2.9%			90.7%			

Notes:
%: percent

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Table E-4: Formation Mineralogy Results

Sample Location	STAR #	Depth (feet)	Dolomite	Siderite	Goethite	Pyrite	Anatase	Rutile	Anhydrite	Sum
Inyan Kara Formation	129299	3,890				4.5%				100%
Inyan Kara Formation	129301	3,893								100%
Inyan Kara Formation	129302	3,895								100%
Inyan Kara Formation	129303	3,900		0.9%						100%
Inyan Kara Formation	129304	3,911								100%
Inyan Kara Formation	129305	3,915		17.8%						100%
Inyan Kara Formation	129306	3,917		22.9%			2.6%			100%
Inyan Kara Formation	129307	3,918		7.2%			1.0%	0.6%		100%
Inyan Kara Formation	129308	3,920								100%
Inyan Kara Formation	129309	3,925					1.2%	1.1%	4.9%	100%
Inyan Kara Formation	129310	3,935		3.0%						100%
Inyan Kara Formation	129311	3,946	0.7%			2.0%	0.8%			100%
Inyan Kara Formation	129312	3,950								100%
Inyan Kara Formation	129313	3,956								100%
Inyan Kara Formation	129314	3,960			0.8%					100%
Inyan Kara Formation	129315	3,969		15.3%	1.3%	1.5%				100%
Inyan Kara Formation	129316	3,975								100%
Inyan Kara Formation	129318	3,980		3.2%	5.0%		1.0%		3.2%	100%
Inyan Kara Formation	129319	3,989			4.0%		1.6%			100%
Inyan Kara Formation	129320	3,995								100%
Inyan Kara Formation	129321	3,999			1.3%		1.1%			100%
Inyan Kara Formation	129322	4,003			1.4%		1.4%		4.1%	100%
Inyan Kara Formation	129323	4,007			1.8%		1.2%	0.9%	3.1%	100%
Inyan Kara Formation	129324	4,011			0.4%			0.4%		100%
Inyan Kara Formation	129325	4,017				1.8%				100%
Inyan Kara Formation	129326	4,020								100%
Inyan Kara Formation	129327	4,021								100%
Inyan Kara Formation	129328	4,029			0.3%					100%
Inyan Kara Formation	129329	4,032			0.6%					100%
Inyan Kara Formation	129330	4,038			0.9%					100%
Inyan Kara Formation	129331	4,041				0.6%				100%
Inyan Kara Formation	129332	4,047								100%
Inyan Kara Formation	129333	4,050			0.6%	3.7%				100%

Notes:
%: percent

Table E-5: Saturation Evaluation Results for Injection Formation, Cooling Tower Blowdown, and Scrubber Pond Waters

Sample Type		Geomean Formation Water (As Sampled)		Formation Water (Simulated with added CO_2)	Blowdown Winter Minimum Case	Blowdown Summer Peak Full Softening Case	Cell 3 Min TDS	Cell 3 Max TDS	Cell 4
Pressure (pounds per square inch)		14.7	1,670	1,670	14.7	14.7	14.7	14.7	14.7
Temperature (degrees Celcius)		50	50	50	5	5	5	5	5
MINERAL PHASES - Saturation Indices									
Anhydrite	$CaSO_4$	-1.6	-1.7	-1.7	-0.8	-1.1	-1.0	-0.6	-0.6
Gypsum	$CaSO_4{:}2H_2O$	-1.5	-1.6	-1.6	**-0.2**	**-0.5**	**-0.4**	**-0.1**	**0.0**
Barite	$BaSO_4$	**1.5**	**1.4**	**1.4**	**1.3**	**1.4**	**1.4**	**1.4**	**1.4**
Calcite	$CaCO_3$	**1.0**	**0.9**	**0.0**	**1.1**	**0.4**	-1.3	-2.0	**0.2**
Magnesite	$MgCO_3$	**-0.4**	**-0.5**	-1.4	**0.8**	**0.3**	**-0.2**	-0.9	**0.3**
Halite	NaCl	-4.8	-4.8	-4.8	-5.9	-5.3	-4.3	-3.5	-5.4

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

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Table E-6: Mixing Model Results for Formation Water as Measured and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Winter Minimum:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-1.0	-1.0	-1.1	-1.1	-1.2	-1.3	-1.3	-1.5	-1.6	-1.8	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.8	-1.0	-1.2	-1.6
Barite	$BaSO_4$	**1.2**	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**
Calcite	$CaCO_3$	**1.0**	**1.0**	**1.0**	**1.0**	**0.9**	**0.9**	**0.9**	**0.8**	**0.7**	**0.6**	**0.2**
Magnesite	$MgCO_3$	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	**0.4**	**0.3**	**0.1**	-0.9
Halite	NaCl	-5.9	-5.6	-5.4	-5.3	-5.2	-5.1	-5.0	-4.9	-4.8	-4.8	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00018	0.00025	0.00032	0.00039	0.00046	0.00053	0.00060	0.00067	0.00073	0.00080	0.00087
Calcite	$CaCO_3$	0.15	0.15	0.14	0.14	0.13	0.12	0.11	0.10	0.085	0.061	0.017
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-6: Mixing Model Results for Formation Water as Measured and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Winter Minimum:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	**-0.5**	-0.5	-0.6	-0.6	-0.7	-0.8	-0.8	-1.0	-1.1	-1.3	-1.7
Gypsum	$CaSO_4{:}2H_2O$	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.8	-0.9	-1.0	-1.2	-1.6
Barite	$BaSO_4$	**0.7**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**1.7**	**1.7**	**1.7**	**1.7**	**1.6**	**1.6**	**1.6**	**1.5**	**1.4**	**1.3**	**0.9**
Magnesite	$MgCO_3$	**1.1**	**1.1**	**1.1**	**1.0**	**1.0**	**1.0**	**0.9**	**0.8**	**0.7**	**0.5**	-0.5
Halite	NaCl	-6.0	-5.7	-5.5	-5.4	-5.3	-5.2	-5.1	-5.0	-4.9	-4.9	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00016	0.00023	0.00030	0.00037	0.00044	0.00051	0.00057	0.00064	0.00071	0.00078	0.00085
Calcite	$CaCO_3$	0.33	0.32	0.31	0.30	0.28	0.27	0.25	0.22	0.19	0.14	0.060
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-6: Mixing Model Results for Formation Water as Measured and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Summer Peak Full Softening:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-1.2	-1.3	-1.3	-1.4	-1.4	-1.5	-1.6	-1.7	-1.8	-2.0	-2.2
Gypsum	$CaSO_4{:}2H_2O$	-0.6	-0.6	-0.7	-0.8	-0.8	-0.9	-1.0	-1.1	-1.2	-1.4	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.5**	**0.5**	**0.4**	**0.4**	**0.3**	**0.2**
Magnesite	$MgCO_3$	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.2**	**0.2**	**0.1**	**-0.1**	-0.9
Halite	NaCl	-5.4	-5.2	-5.1	-5.0	-4.9	-4.9	-4.8	-4.8	-4.8	-4.7	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00019	0.00025	0.00032	0.00039	0.00046	0.00053	0.00060	0.00067	0.00073	0.00080	0.00087
Calcite	$CaCO_3$	0.023	0.029	0.035	0.040	0.044	0.047	0.049	0.048	0.043	0.034	0.017
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-6: Mixing Model Results for Formation Water as Measured and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Summer Peak Full Softening:Formation Water)										
Sample Name		**100:0**	**90:10**	**80:20**	**70:30**	**60:40**	**50:50**	**40:60**	**30:70**	**20:80**	**10:90**	**0:100**
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-0.8	-0.8	-0.9	-0.9	-1.0	-1.0	-1.1	-1.2	-1.3	-1.5	-1.7
Gypsum	$CaSO_4{:}2H_2O$	-0.7	-0.7	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.4	-1.6
Barite	$BaSO_4$	**0.8**	**0.9**	**1.0**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**1.0**	**1.0**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.0**	**0.9**
Magnesite	$MgCO_3$	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**0.6**	**0.6**	**0.6**	**0.5**	**0.3**	-0.5
Halite	NaCl	-5.4	-5.3	-5.2	-5.1	-5.0	-5.0	-4.9	-4.9	-4.9	-4.8	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00016	0.00023	0.00030	0.00037	0.00044	0.00051	0.00058	0.00064	0.00071	0.00078	0.00085
Calcite	$CaCO_3$	0.10	0.11	0.12	0.13	0.14	0.14	0.14	0.13	0.12	0.097	0.060
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Min TDS:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-1.1	-1.1	-1.2	-1.2	-1.3	-1.3	-1.4	-1.5	-1.7	-1.9	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.5**	-0.5	-0.5	-0.6	-0.6	-0.7	-0.8	-0.9	-1.0	-1.2	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.8**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	-1.5	-1.4	-1.2	-1.1	-1.0	-0.8	-0.7	-0.6	**-0.4**	**-0.2**	**0.2**
Magnesite	$MgCO_3$	**-0.4**	**-0.2**	**-0.1**	**0.0**	**0.1**	**0.3**	**0.4**	**0.5**	**0.5**	**0.6**	-0.9
Halite	NaCl	-4.4	-4.4	-4.4	-4.4	-4.4	-4.5	-4.5	-4.5	-4.6	-4.6	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00035	0.00041	0.00046	0.00051	0.00056	0.00061	0.00067	0.00072	0.00077	0.00082	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0.017
Magnesite	$MgCO_3$	0	0	0	0.0076	0.033	0.057	0.078	0.094	0.10	0.100	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Min TDS:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-0.7	-0.7	-0.7	-0.8	-0.8	-0.9	-1.0	-1.1	-1.2	-1.4	-1.7
Gypsum	$CaSO_4{:}2H_2O$	-0.6	-0.6	-0.6	-0.7	-0.7	-0.8	-0.9	-1.0	-1.1	-1.3	-1.6
Barite	$BaSO_4$	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.3**	**1.3**	**1.4**	**1.4**
Calcite	$CaCO_3$	-0.9	-0.7	-0.5	**-0.4**	**-0.3**	**-0.1**	**0.0**	**0.1**	**0.3**	**0.5**	**0.9**
Magnesite	$MgCO_3$	**0.0**	**0.2**	**0.3**	**0.5**	**0.6**	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**	-0.5
Halite	NaCl	-4.4	-4.5	-4.5	-4.5	-4.5	-4.5	-4.6	-4.6	-4.7	-4.7	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00031	0.00036	0.00042	0.00047	0.00053	0.00058	0.00064	0.00069	0.00075	0.00080	0.00085
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0.060
Magnesite	$MgCO_3$	0.0064	0.036	0.063	0.089	0.11	0.14	0.16	0.18	0.19	0.18	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Late:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-0.7	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.3	-1.6	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.1**	**-0.2**	**-0.2**	**-0.2**	**-0.3**	**-0.4**	**-0.4**	-0.5	-0.7	-0.9	-1.6
Barite	$BaSO_4$	**1.3**	**1.3**	**1.4**	**1.4**	**1.5**	**1.5**	**1.6**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	-2.1	-2.0	-2.0	-1.9	-1.8	-1.7	-1.6	-1.5	-1.3	-1.0	**0.2**
Magnesite	$MgCO_3$	-1.0	-0.9	-0.9	-0.8	-0.7	-0.7	-0.6	**-0.4**	**-0.3**	**0.0**	-0.9
Halite	NaCl	-3.5	-3.6	-3.7	-3.7	-3.8	-3.9	-4.0	-4.1	-4.3	-4.4	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00063	0.00066	0.00068	0.00071	0.00073	0.00075	0.00078	0.00080	0.00083	0.00085	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0.017
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Late:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	**-0.3**	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.9	-1.1	-1.7
Gypsum	$CaSO_4{:}2H_2O$	**-0.2**	**-0.3**	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.8	-1.0	-1.6
Barite	$BaSO_4$	**0.7**	**0.7**	**0.8**	**0.9**	**0.9**	**1.0**	**1.1**	**1.2**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	-1.5	-1.4	-1.3	-1.3	-1.2	-1.0	-0.9	-0.7	**-0.5**	**0.0**	**0.9**
Magnesite	$MgCO_3$	-0.6	-0.5	**-0.5**	**-0.4**	**-0.3**	**-0.2**	**-0.1**	**0.0**	**0.3**	**0.6**	-0.5
Halite	NaCl	-3.6	-3.7	-3.7	-3.8	-3.9	-4.0	-4.1	-4.2	-4.3	-4.5	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00053	0.00057	0.00060	0.00063	0.00067	0.00070	0.00073	0.00076	0.00079	0.00083	0.00085
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0.060
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0.018	0.083	0.14	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 4:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.3	-1.5	-1.7	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.1**	**-0.2**	**-0.2**	**-0.3**	**-0.4**	**-0.5**	-0.6	-0.7	-0.8	-1.1	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	**0.0**	**0.1**	**0.2**	**0.3**	**0.4**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.2**
Magnesite	$MgCO_3$	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	-0.9
Halite	NaCl	-5.4	-5.3	-5.2	-5.1	-5.1	-5.0	-4.9	-4.9	-4.8	-4.8	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00020	0.00027	0.00034	0.00041	0.00047	0.00054	0.00061	0.00067	0.00074	0.00081	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0.017	0.017
Magnesite	$MgCO_3$	0.014	0.028	0.040	0.051	0.061	0.069	0.074	0.076	0.071	0.042	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 4:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.8	-1.0	-1.2	-1.7
Gypsum	$CaSO_4{:}2H_2O$	**-0.2**	**-0.3**	**-0.3**	**-0.4**	**-0.4**	-0.5	-0.6	-0.7	-0.9	-1.1	-1.6
Barite	$BaSO_4$	**0.8**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.2**	**1.2**	**1.2**	**0.9**
Magnesite	$MgCO_3$	**0.6**	**0.7**	**0.8**	**0.9**	**0.9**	**1.0**	**1.0**	**1.0**	**1.0**	**0.9**	-0.5
Halite	NaCl	-5.5	-5.4	-5.3	-5.2	-5.1	-5.1	-5.0	-5.0	-4.9	-4.9	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00018	0.00025	0.00032	0.00038	0.00045	0.00052	0.00058	0.00065	0.00072	0.00078	0.00085
Calcite	$CaCO_3$	0.088	0.11	0.13	0.15	0.17	0.18	0.19	0.18	0.15	0.12	0.060
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0.016	0.035	0.043	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-8: Mixing Model Results for Formation Water with Added Carbon Dioxide and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Winter Minimum:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-1.0	-1.0	-1.1	-1.1	-1.2	-1.3	-1.3	-1.5	-1.6	-1.8	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.8	-1.0	-1.2	-1.6
Barite	$BaSO_4$	**1.2**	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**
Calcite	$CaCO_3$	**1.0**	**0.9**	**0.9**	**0.9**	**0.8**	**0.8**	**0.7**	**0.6**	**0.5**	**0.3**	**-0.1**
Magnesite	$MgCO_3$	**0.6**	**0.6**	**0.6**	**0.5**	**0.5**	**0.4**	**0.4**	**0.3**	**0.1**	**-0.2**	-1.2
Halite	NaCl	-5.9	-5.6	-5.4	-5.3	-5.2	-5.1	-5.0	-4.9	-4.8	-4.8	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00018	0.00025	0.00032	0.00039	0.00046	0.00053	0.00060	0.00067	0.00073	0.00080	0.00087
Calcite	$CaCO_3$	0.15	0.14	0.14	0.13	0.12	0.11	0.092	0.077	0.058	0.033	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-8: Mixing Model Results for Formation Water with Added Carbon Dioxide and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Winter Minimum:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	**-0.5**	-0.5	-0.6	-0.6	-0.7	-0.8	-0.8	-1.0	-1.1	-1.3	-1.7
Gypsum	$CaSO_4{:}2H_2O$	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.8	-0.9	-1.0	-1.2	-1.6
Barite	$BaSO_4$	**0.7**	**0.9**	**1.0**	**1.0**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**1.7**	**1.6**	**1.5**	**1.4**	**1.3**	**1.2**	**1.1**	**0.9**	**0.7**	**0.4**	**0.0**
Magnesite	$MgCO_3$	**1.1**	**1.0**	**0.9**	**0.8**	**0.7**	**0.6**	**0.4**	**0.3**	**0.0**	**-0.3**	-1.4
Halite	NaCl	-6.0	-5.7	-5.5	-5.4	-5.3	-5.2	-5.1	-5.0	-4.9	-4.9	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00016	0.00023	0.00030	0.00037	0.00044	0.00051	0.00057	0.00064	0.00071	0.00078	0.00085
Calcite	$CaCO_3$	0.33	0.31	0.29	0.27	0.24	0.21	0.18	0.14	0.10	0.054	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-8: Mixing Model Results for Formation Water with Added Carbon Dioxide and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Summer Peak Full Softening:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-1.2	-1.3	-1.3	-1.4	-1.4	-1.5	-1.6	-1.7	-1.8	-2.0	-2.2
Gypsum	$CaSO_4{:}2H_2O$	-0.6	-0.6	-0.7	-0.8	-0.8	-0.9	-1.0	-1.1	-1.2	-1.4	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.1**	**-0.1**
Magnesite	$MgCO_3$	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**	**0.0**	**-0.1**	**-0.4**	-1.2
Halite	NaCl	-5.4	-5.2	-5.1	-5.0	-4.9	-4.9	-4.8	-4.8	-4.8	-4.7	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00019	0.00025	0.00032	0.00039	0.00046	0.00053	0.00060	0.00067	0.00073	0.00080	0.00087
Calcite	$CaCO_3$	0.023	0.025	0.027	0.028	0.029	0.028	0.027	0.023	0.018	0.0085	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-8: Mixing Model Results for Formation Water with Added Carbon Dioxide and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Summer Peak Full Softening:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-0.8	-0.8	-0.9	-0.9	-1.0	-1.0	-1.1	-1.2	-1.3	-1.5	-1.7
Gypsum	$CaSO_4{:}2H_2O$	-0.7	-0.7	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.4	-1.6
Barite	$BaSO_4$	**0.8**	**0.9**	**1.0**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**1.0**	**0.9**	**0.8**	**0.8**	**0.7**	**0.6**	**0.5**	**0.4**	**0.3**	**0.2**	**0.0**
Magnesite	$MgCO_3$	**0.6**	**0.5**	**0.4**	**0.3**	**0.2**	**0.1**	**0.0**	**-0.1**	**-0.3**	-0.6	-1.4
Halite	NaCl	-5.4	-5.3	-5.2	-5.1	-5.0	-5.0	-4.9	-4.9	-4.9	-4.8	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00016	0.00023	0.00030	0.00037	0.00044	0.00051	0.00058	0.00064	0.00071	0.00078	0.00085
Calcite	$CaCO_3$	0.10	0.096	0.092	0.086	0.079	0.071	0.061	0.050	0.035	0.018	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Min TDS:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices [a]												
Anhydrite	$CaSO_4$	-1.1	-1.1	-1.2	-1.2	-1.3	-1.3	-1.4	-1.5	-1.7	-1.9	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.5**	-0.5	-0.5	-0.6	-0.6	-0.7	-0.8	-0.9	-1.0	-1.2	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.8**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	-1.5	-1.4	-1.2	-1.1	-1.0	-0.9	-0.8	-0.7	-0.6	**-0.4**	**-0.1**
Magnesite	$MgCO_3$	**-0.4**	**-0.2**	**-0.1**	**0.0**	**0.1**	**0.2**	**0.3**	**0.4**	**0.4**	**0.5**	-1.2
Halite	NaCl	-4.4	-4.4	-4.4	-4.4	-4.4	-4.5	-4.5	-4.5	-4.6	-4.6	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00035	0.00041	0.00046	0.00051	0.00056	0.00061	0.00067	0.00072	0.00077	0.00082	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0
Magnesite	$MgCO_3$	0	0	0	0.00043	0.023	0.044	0.062	0.076	0.083	0.074	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Min TDS:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices [a]												
Anhydrite	$CaSO_4$	-0.7	-0.7	-0.7	-0.8	-0.8	-0.9	-1.0	-1.1	-1.2	-1.4	-1.7
Gypsum	$CaSO_4{:}2H_2O$	-0.6	-0.6	-0.6	-0.7	-0.7	-0.8	-0.9	-1.0	-1.1	-1.3	-1.6
Barite	$BaSO_4$	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.3**	**1.3**	**1.4**	**1.4**
Calcite	$CaCO_3$	-0.9	-0.7	-0.6	-0.6	**-0.5**	**-0.4**	**-0.3**	**-0.3**	**-0.2**	**-0.1**	**0.0**
Magnesite	$MgCO_3$	**0.0**	**0.1**	**0.2**	**0.3**	**0.4**	**0.4**	**0.5**	**0.5**	**0.5**	**0.4**	-1.4
Halite	NaCl	-4.4	-4.5	-4.5	-4.5	-4.5	-4.5	-4.6	-4.6	-4.7	-4.7	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00035	0.00041	0.00046	0.00051	0.00056	0.00061	0.00067	0.00072	0.00077	0.00082	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0
Magnesite	$MgCO_3$	0	0	0	0.00043	0.023	0.044	0.062	0.076	0.083	0.074	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

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Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Max TDS:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices [a]												
Anhydrite	$CaSO_4$	-0.7	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.3	-1.6	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.1**	**-0.2**	**-0.2**	**-0.2**	**-0.3**	**-0.4**	**-0.4**	-0.5	-0.7	-0.9	-1.6
Barite	$BaSO_4$	**1.3**	**1.3**	**1.4**	**1.4**	**1.5**	**1.5**	**1.6**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	-2.1	-2.0	-2.0	-1.9	-1.8	-1.7	-1.6	-1.5	-1.3	-1.0	**-0.1**
Magnesite	$MgCO_3$	-1.0	-0.9	-0.9	-0.8	-0.7	-0.7	-0.6	**-0.5**	**-0.3**	**-0.1**	-1.2
Halite	NaCl	-3.5	-3.6	-3.7	-3.7	-3.8	-3.9	-4.0	-4.1	-4.3	-4.4	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00035	0.00041	0.00046	0.00051	0.00056	0.00061	0.00067	0.00072	0.00077	0.00082	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0
Magnesite	$MgCO_3$	0	0	0	0.00043	0.023	0.044	0.062	0.076	0.083	0.074	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Max TDS:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices [a]												
Anhydrite	$CaSO_4$	**-0.3**	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.9	-1.1	-1.7
Gypsum	$CaSO_4{:}2H_2O$	**-0.2**	**-0.3**	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.8	-1.0	-1.6
Barite	$BaSO_4$	**0.7**	**0.7**	**0.8**	**0.9**	**0.9**	**1.0**	**1.1**	**1.2**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	-1.5	-1.4	-1.4	-1.3	-1.2	-1.1	-1.0	-0.9	-0.7	**-0.5**	**0.0**
Magnesite	$MgCO_3$	-0.6	-0.6	**-0.5**	**-0.4**	**-0.4**	**-0.3**	**-0.2**	**-0.1**	**0.0**	**0.2**	-1.4
Halite	NaCl	-3.6	-3.7	-3.7	-3.8	-3.9	-4.0	-4.1	-4.2	-4.3	-4.5	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00053	0.00057	0.00060	0.00063	0.00067	0.00070	0.00073	0.00076	0.00079	0.00083	0.00085
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0.010	0.049	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

GOLDER
MEMBER OF WSP

Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 4:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices [a]												
Anhydrite	$CaSO_4$	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.3	-1.5	-1.7	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.1**	**-0.2**	**-0.2**	**-0.3**	**-0.4**	**-0.5**	-0.6	-0.7	-0.8	-1.1	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	**0.0**	**0.1**	**0.1**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**-0.1**
Magnesite	$MgCO_3$	**0.1**	**0.2**	**0.3**	**0.4**	**0.4**	**0.4**	**0.5**	**0.4**	**0.4**	**0.2**	-1.2
Halite	NaCl	-5.4	-5.3	-5.2	-5.1	-5.1	-5.0	-4.9	-4.9	-4.8	-4.8	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00020	0.00027	0.00034	0.00041	0.00047	0.00054	0.00061	0.00067	0.00074	0.00081	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0.0083	0
Magnesite	$MgCO_3$	0.014	0.025	0.034	0.043	0.049	0.054	0.057	0.055	0.047	0.020	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 4:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices [a]												
Anhydrite	$CaSO_4$	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.8	-1.0	-1.2	-1.7
Gypsum	$CaSO_4{:}2H_2O$	**-0.2**	**-0.3**	**-0.3**	**-0.4**	**-0.4**	-0.5	-0.6	-0.7	-0.9	-1.1	-1.6
Barite	$BaSO_4$	**0.8**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.6**	**0.5**	**0.4**	**0.0**
Magnesite	$MgCO_3$	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	**0.4**	**0.3**	**0.1**	-1.4
Halite	NaCl	-5.5	-5.4	-5.3	-5.2	-5.1	-5.1	-5.0	-5.0	-4.9	-4.9	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00018	0.00025	0.00032	0.00038	0.00045	0.00052	0.00058	0.00065	0.00072	0.00078	0.00085
Calcite	$CaCO_3$	0.088	0.097	0.10	0.11	0.12	0.12	0.11	0.10	0.085	0.051	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

APPENDIX F

Well Design Summary

Table F-1: Casing and Cement Design

Variable	Units	Conductor Casing	Surface Casing	Production Casing	Injection Tubing
Casing					
Borehole diameter	in	26	17.5	12.25	--
Borehole depth	ft bgs	80	1,260	3,940	-
Casing type	-	--	API	API	Internally Lined
Casing outside diameter	in	20	13.375	9.625	7
Casing wall thickness	in	0.375	0.380	0.435	0.272
Casing inside diameter	in	19.250	12.615	8.755	6.456
Drift	in	--	12.459	8.599	6.331
Casing weight	lb/ft	78.7	54.5	43.5	20
Casing grade	-	STD WT	J-55	N-80	J-55
Casing threads	-	--	BT&C	LT&C	LT&C
Collapse pressure	psi	--	1,130	3,810	2,270
Burst pressure	psi	--	2,730	6,330	3,740
Joint strength	1000 lbs	--	909	825	257
Internal lining	-	--	-	-	Lining
Casing seat depth	ft bgs	80	1,260	3,888	3,617
Cementing Program					
Cement type	-	Portland	Haliburton VariCem (or equivalent)	Halliburton ElastiCem (or equivalent)	-
Grout Mix Ratio	lb/gal water		12-15	12-15	-
Grout Volume (neat)	ft^3	120	903	1,296	-

Abbreviations:

API: American Petroleum Institute
BT&C: Buttress Thread and Coupling
ft: feet
ft bgs: feet below ground surface
ft^3: cubic feet
gal: gallon
in: inch
lb: pound
LT&C: Long Thread & Coupling
psi: pounds per square inch
STD WT: standard weight

APPENDIX G

NDDEQ Injectate Chemical Analysis Requirements

Table G-1: List A Hazardous Waste Classification for Injectate

Chemical Name	Units	Regulatory Level
Toxicity Characteristics		
Corrosivity by pH	pH Units	pH < 2 or pH > 12.5
Reactive Cyanides	mg/L	--
Reactive Sulfides	mg/L	--
Setaflash Flashpoint	deg F	Ignitable if Flashpoint is < 140 deg F
TCLP Metals		
Arsenic	mg/L	5.0
Barium	mg/L	100.0
Cadmium	mg/L	1.0
Chromium	mg/L	5.0
Lead	mg/L	5.0
Mercury	mg/L	0.2
Selenium	mg/L	1.0
Silver	mg/L	5.0
TCLP Pesticides		
Endrin	mg/L	0.02
Chlordane	mg/L	0.03
Heptachlor	mg/L	0.008
Heptachlor Epoxide	mg/L	0.008
Methoxychlor	mg/L	10.0
Toxaphene	mg/L	0.5
Lindane	mg/L	0.4
TCLP Herbicides		
2,4-D	mg/L	10.0
2,4,5-TP	mg/L	1.0
TCLP Volatile Organic Compounds		
Benzene	mg/L	0.5
Carbon Tetrachloride	mg/L	0.5
Chlorobenzene	mg/L	100.0
Chloroform	mg/L	6.0
1,2-Dichloroethane	mg/L	0.5
1,1-Dichloroethylene	mg/L	0.7
Methyl Ethyl Ketone	mg/L	200.0
Tetrachloroethylene	mg/L	0.7
Trichloroethylene	mg/L	0.5
Vinyl Chloride	mg/L	0.2

Table G-1: List A Hazardous Waste Classification for Injectate

Chemical Name	Units	Regulatory Level
TCLP Semi Volatile Compounds		
Cresol1	mg/L	200.0
o-Cresol[1]	mg/L	200.0
m-Cresol[1]	mg/L	200.0
p-Cresol[1]	mg/L	200.0
Pentachlorophenol	mg/L	100.0
1,4-Dichlorobenzene	mg/L	7.5
2,4-Dinitrotoluene	mg/L	0.13
Hexachlorobenzene	mg/L	0.13
Nitrobenzene	mg/L	2.0
Pyridine	mg/L	5.0
2,4,5-Trichlorophenol	mg/L	400.0
2,4,6-Trichlorophenol	mg/L	2.0

Table G-2: List B General Waste Characterization for Injectate

Chemical Name	Units
Alkalinity, Total	mg/L
Aluminum	ug/L
Ammonia (as N)	mg/L
Antimony	ug/L
Arsenic (dissolved)	ug/L
Barium (dissolved)	ug/L
Bicarbonate, Alkalinity	mg/L
Bromide	mg/L
Cadmium (dissolved)	ug/L
Calcium	mg/L
Carbonate, Alkalinity	mg/L
Chemical Oxygen Demand (COD)	mg/L
Chloride	mg/L
Copper	ug/L
Cyanide	mg/L
Fluoride	mg/L
Hardness as CaCO3	mg/L
Iron	ug/L
Lead (dissolved)	ug/L
Magnesium	mg/L
Manganese (dissolved)	ug/L
Mercury (dissolved)	ug/L
Molybdenum (dissolved)	ug/L
Nickel (dissolved)	ug/L
Nitrogen (Nitrate)	mg/L
Nitrogen (Nitrite)	mg/L
pH	pH units
Phosphorus (dissolved)	ug/L
Potassium (total)	mg/L
Selenium (dissolved)	ug/L
Semi Volatile Organic Comounds (SVOCs)	
Silver (dissolved)	ug/L
Sodium	mg/L
Specific Conductivity	umhos/cm
Specific Gravity	none
Strontium	ug/L
Sulfate	mg/L
Sulfite	mg/L
Total Chromium (dissolved)	ug/L
Total Dissolved Solids (TDS)	mg/L
Total Kjeldahl Nitrogen	mg/L
Total Organic Carbon (TOC)	mg/L
Total Suspended Solids (TSS)	mg/L
Turbidity	ntu
Viscosity, Kinematic	
Zinc (dissolved)	ug/L

Table G-3: List C Abbreviated Waste Characterization for Injectate

Chemical Name	Units
pH	s.u.
pH (field)	s.u.
Temperature (field)	°C
Specific Gravity	@ 60°/60° F
Total Organic Carbon	mg/L
Sulfate	mg/L
Chloride (Cl-)	mg/L
Total Dissolved Solids	mg/L
Total Calcium	mg/L
Total Magnesium	mg/L
Total Potassium	mg/L

APPENDIX H

Minnkota Power Cooperative Financial Assurance

Minnkota Power
COOPERATIVE
A Touchstone Energy® Cooperative

5301 32nd Ave S
Grand Forks, ND 58201-3312
Phone 701.795.4000
www.minnkota.com

June 1, 2021

NDDEQ
Department of Water Quality
918 East Divide Ave., 4th Floor
Bismarck, ND 58501

RE: Financial Assurance – Injection Wells #1 & #2

Enclosed you will find financial assurance documentation for injection wells for Minnkota Power Cooperative, Inc. (Minnkota).

Also, pursuant to subpart F of 40 CFR part 144, enclosed is an annual report for Minnkota, including an independent certified public accountant's report on examination of financial statements for the latest fiscal year. Also included is an independent accountant's report on applying agreed upon procedures.

If you have any questions regarding the materials submitted, please contact me at (701) 795-4266.

Sincerely,

MINNKOTA POWER COOPERATIVE, INC.

Kay Schraeder

Kay Schraeder
Vice President & CFO

Enclosures

Minnkota Power
COOPERATIVE
A Touchstone Energy® Cooperative

5301 32nd Ave S
Grand Forks, ND 58201-3312
Phone 701.795.4000
www.minnkota.com

June 1, 2021

NDDEQ
Division of Water Quality
918 East Divide Ave., 4th Floor
Bismarck, ND 58501

I am the Vice President and Chief Financial Officer of Minnkota Power Cooperative, Inc. This letter is in support of this firm's use of the financial test to demonstrate financial assurance, as specified in subpart F of 40 CFR part 144.

1. This firm is the owner or operator of the following injection wells for which financial assurance for plugging and abandonment is demonstrated through the financial test specified in subpart F of 40 CFR part 144. The current plugging and abandonment cost estimate covered by the test is shown for each injection well:

Injection Well #1	$232,000
Injection Well #2	232,000
Total	$464,000

2. This firm guarantees, through the corporate guarantee specified in subpart F of 40 CFR part 144, the plugging and abandonment of the following injection wells owned or operated by subsidaries of this firm. The current cost estimate for plugging and abandonment so guaranteed is shown for each injection well: None.

3. In States where EPA is not administering the financial requirements of subpart F of 40 CFR part 144, this firm, as owner or operator or guarantor, is demonstrating financial assurance for the plugging and abandonment of the following injection wells through the use of a test equivalent or substantially equivalent to the financial test specified in subpart F of 40 CFR part 144. The current plugging and abandonment cost estimate covered by such a test is shown for each injection well: None.

4. This firm is the owner or operator of the following injection wells for which financial assurance for plugging and abandonment is not demonstrated either to EPA or a State through the financial test or any other financial assurance mechanism specified in subpart F of 40 CFR part 144 or equivalent or substantially equivalent State mechanisms. The current plugging and abandonment cost estimate not covered by such financial assurance is shown for each injection well: None.

Minnkota Power Cooperative, Inc. is not required to file a form 10K with the securities and exchange commission for the latest fiscal year.

The fiscal year of this firm ends on December 31. Attachment A provides the relevant information concerning the financial statements of this firm for the latest completed fiscal year, ended December 31, 2020.

I hereby certify that the wording of this letter is identical to the wording specified in 40 CFR 144.70(f) as such regulations were constituted on the date shown immediately below.

Effective date: June 1, 2021

Sincerely,

MINNKOTA POWER COOPERATIVE, INC.

Kay Schraeder

Kay Schraeder
Vice President & CFO

Attachment

Attachment A
2020 Financial Assurance
Class 1 Injection Wells (#1 & #2)

1.	Current plugging and abandonment cost	$ 464,000	
2.	Current Credit Rating – Moody's	Baa2	
3.	Date of issuance of bond	N/A	
4.	Date of maturity of bond	N/A	
5.	Tangible net worth	$ 167,592,067	
6.	Total assets in United States	$ 1,139,298,514	
		YES	NO
7.	Is line 5 at least $10 million?	X	
8.	Is line 5 at least 6 times line 1?	X	
9.	Are at least 90% of firm's assets located in the United States?	X	
10.	Is line 6 at least 6 times line 1?	X	

BradyMartz

INDEPENDENT ACCOUNTANT'S REPORT ON APPLYING AGREED-UPON PROCEDURES

To the Management of Minnkota Power
Cooperative, Inc. and the North Dakota
State Department of Environmental Quality,
Division of Water Quality

We have performed the procedures enumerated below, which were agreed to by the Management of Minnkota Power Cooperative, Inc., (the Company), to selected accounting records of Minnkota Power Cooperative, Inc. solely to assist you in connection with the letter from the Vice President and Chief Financial Officer of Minnkota Power Cooperative, Inc. dated June 1, 2021, to the North Dakota State Department of Environmental Quality, Division of Water Quality. This letter is regarding the guarantee by Minnkota Power Cooperative, Inc. for the plugging and abandonment of injection wells. The management of Minnkota Power Cooperative, Inc. is responsible for the accounting records and the letter. The sufficiency of these procedures is solely the responsibility of the parties specified in the report. Consequently, we make no representations regarding the sufficiency of the procedures described below either for the purpose for which this report has been requested or for any other purpose.

The statements, procedures, and associated findings are set forth below:

1. We compared the data referred to in Alternative 2 in the June 1, 2021 letter from the Company's Vice President and Chief Financial Officer to the North Dakota State Department of Environmental Quality, Division of Water Quality, to the Company's December 31, 2020 financial statements audited by Brady, Martz & Associates, P.C.

   No exceptions were noted as a result of these comparisons.

This engagement to apply agreed-upon procedures was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. We were not engaged to, and did not, conduct an examination or review of the data, the objective of which would be the expression of an opinion on the accounting records. Accordingly, we do not express such an opinion. Had we performed additional procedures; other matters might have come to our attention that would have been reported to you.

This report is intended solely for the use of the specified users listed above and should not be used by those who have not agreed to the procedures and taken responsibility for the sufficiency of the procedures for their purposes.

Brady Martz

BRADY, MARTZ & ASSOCIATES, P.C.
GRAND FORKS, NORTH DAKOTA

June 1, 2021

MINNKOTA POWER COOPERATIVE, INC.

We power on.

2020 ANNUAL REPORT

We power on.

Living rooms turned into home offices.

Students occupied small squares on a computer screen as they learned online.

Hospitals and essential businesses showed perseverance and innovation to meet community needs.

Electric cooperatives powered on.

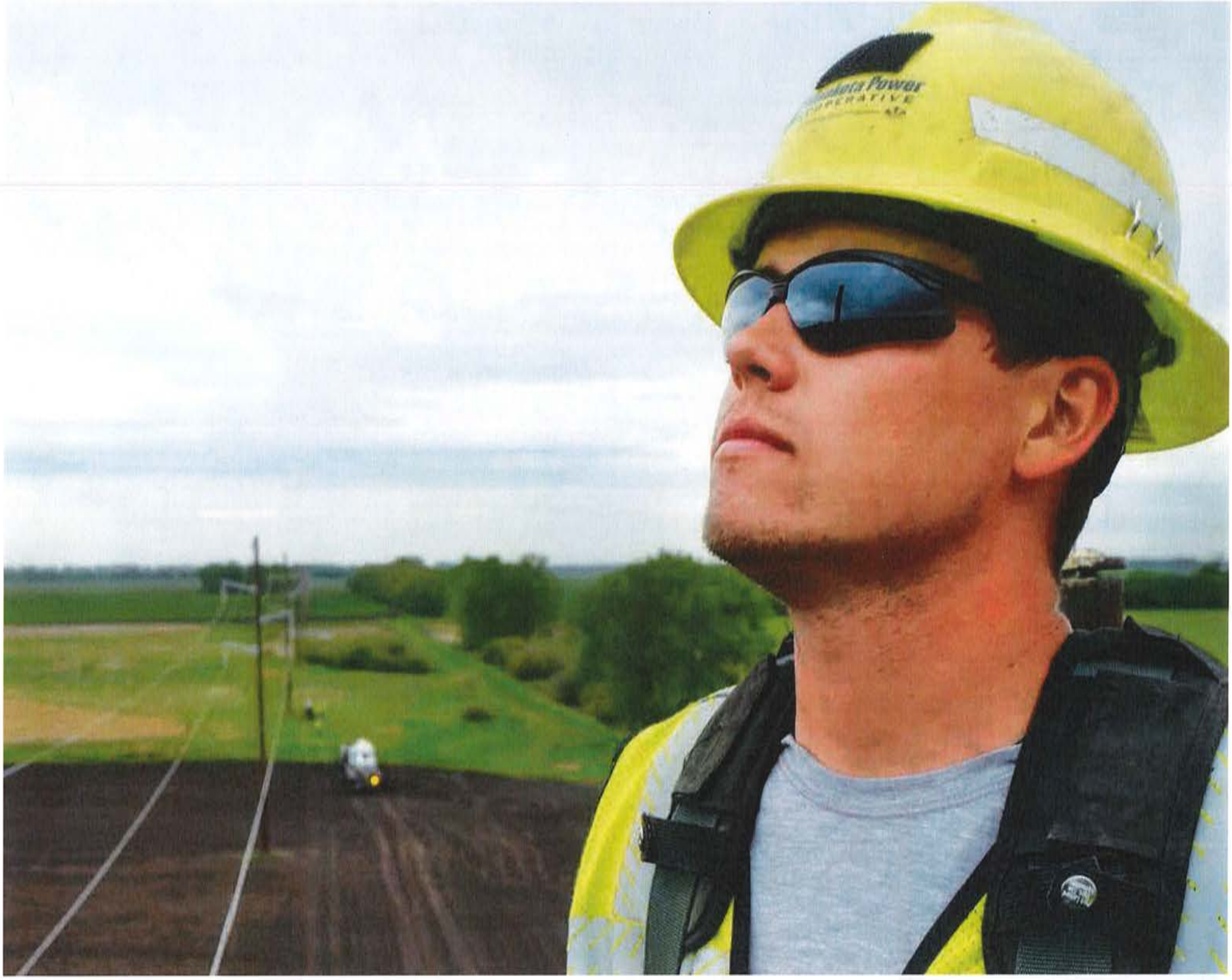
When faced with a global pandemic, reliable electricity is more important than ever. Minnkota took unprecedented actions in 2020 to protect the health of its employees, while continuing to keep power flowing into communities 24 hours a day.

It goes without saying that 2020 was a year like no other. Although there were challenges and turmoil, there were also moments of generosity, compassion and connection. While none of us know what the next chapter of the COVID-19 pandemic will bring, there is optimism for the future. Minnkota and its members will be there every step of the way.

We'll power on to help you power on.

On the cover: Adam Streitz, apprentice electrician, was one of 400 Minnkota employees who helped the cooperative power on despite the challenges and obstacles presented by the COVID-19 pandemic.

Right: From his bucket truck, Minnkota lineworker Shawn Reimers helps string wire on a completely rebuilt section of 69-kilovolt transmission line near Cavalier, N.D.

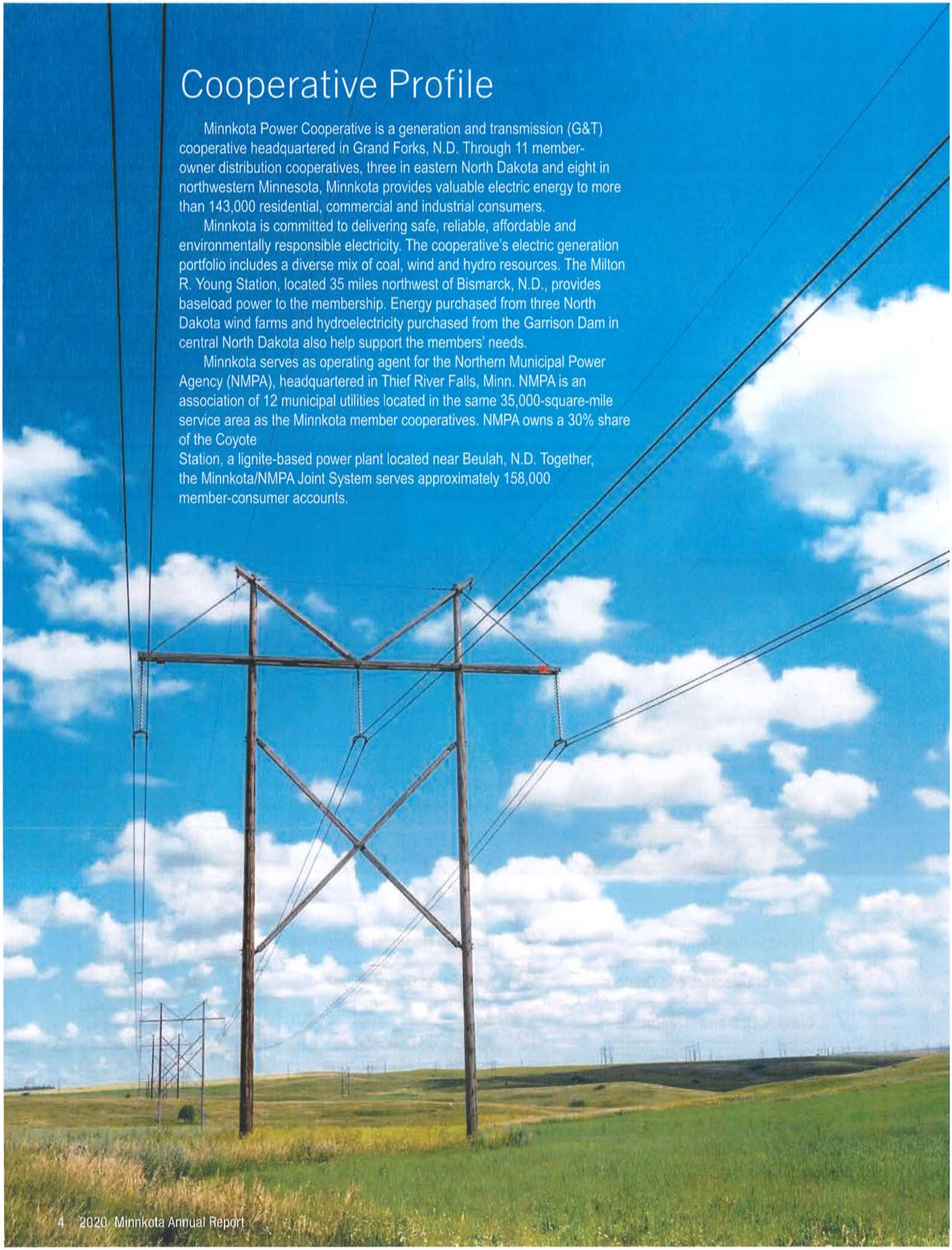


Cooperative Profile

Minnkota Power Cooperative is a generation and transmission (G&T) cooperative headquartered in Grand Forks, N.D. Through 11 member-owner distribution cooperatives, three in eastern North Dakota and eight in northwestern Minnesota, Minnkota provides valuable electric energy to more than 143,000 residential, commercial and industrial consumers.

Minnkota is committed to delivering safe, reliable, affordable and environmentally responsible electricity. The cooperative's electric generation portfolio includes a diverse mix of coal, wind and hydro resources. The Milton R. Young Station, located 35 miles northwest of Bismarck, N.D., provides baseload power to the membership. Energy purchased from three North Dakota wind farms and hydroelectricity purchased from the Garrison Dam in central North Dakota also help support the members' needs.

Minnkota serves as operating agent for the Northern Municipal Power Agency (NMPA), headquartered in Thief River Falls, Minn. NMPA is an association of 12 municipal utilities located in the same 35,000-square-mile service area as the Minnkota member cooperatives. NMPA owns a 30% share of the Coyote Station, a lignite-based power plant located near Beulah, N.D. Together, the Minnkota/NMPA Joint System serves approximately 158,000 member-consumer accounts.



Les Windjue
Board Chair

Mac McLennan
President & CEO

Report to the Members

Despite challenges and obstacles throughout the year, Minnkota's employees continually found creative solutions to problems and proved to be innovative in collaborating and keeping projects moving forward.

The world changed in 2020.

In most years, that would seem like an overstatement, but there are very few periods over the course of modern history that have tested our resiliency and reshaped our communities, culture and politics quite like 2020. Undoubtedly, the start of this decade has been defined by the COVID-19 pandemic. Many families, businesses and schools faced incredible struggle in the wake of stay-at-home orders and general COVID-19 uncertainty. During this difficult time, Minnkota remained committed to keeping the power flowing safely and reliably into local communities. Significant mitigation strategies were implemented to limit potential exposure to the virus among the workforce, including face mask requirements, workplace modifications to accommodate social distancing and enhanced sanitization practices. With the rollout of vaccines at year-end, our hope is for a swift return to normalcy in 2021.

Despite challenges and obstacles throughout the year, Minnkota's employees continually found creative solutions to problems and proved to be innovative in collaborating and keeping projects moving forward. Most importantly, the work was completed safely as overall on-the-job injuries and OSHA-recordable injuries remained low during the year.

In the field, power delivery crews didn't let the pandemic stall progress on the many projects that are important to the membership. Efforts to address aging infrastructure and improve service continued in 2020, as substations and transmission lines were rebuilt, equipment was upgraded and enhanced communication technologies were implemented. This work continues to limit outages and helps crews be more responsive to system issues.

At the Milton R. Young Station, employees kept the units running reliably and efficiently. Strategies were incorporated to be more flexible in responding to wholesale energy market conditions and limiting costs related to maintenance outages. The highlight of the year at the coal-based facility was celebrating Unit 1's 50th year of operation. Commitment from past and present employees has helped the Young Station reach one of its better years of operation in 2020 with each generating unit being available more than 93% of the time.

While there are many positives to take from this year, COVID-19 had financial impacts on Minnkota and its members. The pandemic and mild weather throughout 2020 contributed to less electricity usage and a historically depressed wholesale energy market. Previous years of financial stability and expense-reduction measures helped the cooperative manage through 2020, but we recognize the economic downturn may be our new normal for years to come.

The pandemic has not slowed progress on the research and engineering of a potential carbon capture facility at the Young Station. Minnkota is leading the effort, known as Project Tundra, to significantly reduce CO_2 emissions from the coal-based power plant. State and federal grant funding was utilized in 2020 to support a Front-End Engineering and Design (FEED) study, research of the underground storage facility and the refinement of project economics. We anticipate that our research and evaluation process will be completed in 2021 and a decision will be made on whether to move forward with the project late next year.

In a year full of change, Minnkota experienced a significant leadership transition on the board of directors. Longtime board members Collin Jensen, Jeff Folland, Leroy Riewer and Sid Berg retired in 2020 after many years of service and commitment to the membership. This group exemplified honesty, integrity and sound judgment in our cooperative family. We look forward to working with new directors Marcy Svenningsen, Mark Habedank, Greg Spaulding and Mike Wahl, each of whom brings a wealth of knowledge and experience.

As Minnkota celebrated its 80th anniversary in 2020, it is a good time to reflect on our past. We have faced many challenges since 1940. Storms have destroyed our power delivery system. Floods have inundated our facilities. Unexpected plant outages have required countless hours of labor. Each time, we have become stronger as a cooperative. The common thread is that people pulled together and did the best they could – for their co-workers, their communities and the membership. The same is true today as we face the COVID-19 pandemic and related impacts. We want to thank our employees at the power plant, in the control centers, in the field and at home who helped to safely and effectively energize our region in 2020. Our power will always be our people.

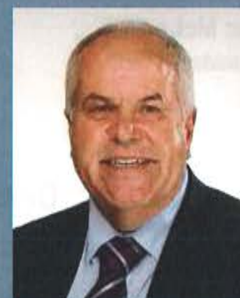
Les Windjue   Mac McLennan

Board of Directors and Officers

Les Windjue
Chair
Nodak
Electric Cooperative

Steve Arnesen
Vice Chair
North Star
Electric Cooperative

Colette Kujava
Secretary/Treasurer
Red Lake
Electric Cooperative



Rick Coe
Beltrami
Electric Cooperative

Mark Habedank
Wild Rice
Electric Cooperative

Roger Krostue
Red River Valley
Cooperative Power
Association

Donald Skjervheim
Cavalier Rural
Electric Cooperative

Greg Spaulding
Clearwater-Polk
Electric Cooperative

Marcy Svenningsen
Cass County
Electric Cooperative

Mike Wahl
Roseau
Electric Cooperative

Tom Woinarowicz
PKM
Electric Cooperative

Lucas Spaeth
Northern Municipal
Power Agency

Mac McLennan
President & CEO

Gerad Paul
General Counsel
and Assistant Secretary

Class A Members

1. **Beltrami Electric Cooperative, Inc.**
   Bemidji, Minnesota
2. **Cass County Electric Cooperative, Inc.**
   Fargo, North Dakota
3. **Cavalier Rural Electric Cooperative, Inc.**
   Langdon, North Dakota
4. **Clearwater-Polk Electric Cooperative, Inc.**
   Bagley, Minnesota
5. **Nodak Electric Cooperative, Inc.**
   Grand Forks, North Dakota
6. **North Star Electric Cooperative, Inc.**
   Baudette, Minnesota
7. **PKM Electric Cooperative, Inc.**
   Warren, Minnesota
8. **Red Lake Electric Cooperative, Inc.**
   Red Lake Falls, Minnesota
9. **Red River Valley Cooperative Power Association**
   Halstad, Minnesota
10. **Roseau Electric Cooperative, Inc.**
    Roseau, Minnesota
11. **Wild Rice Electric Cooperative, Inc.**
    Mahnomen, Minnesota

Class B, C and D Members

Basin Electric Power Cooperative
Bismarck, North Dakota

Central Iowa Power Cooperative
Cedar Rapids, Iowa

Dairyland Power Cooperative
LaCrosse, Wisconsin

Interstate Power Company
Dubuque, Iowa

Lincoln Electric System
Lincoln, Nebraska

Manitoba Hydro
Winnipeg, Manitoba, Canada

MidAmerican Energy
Davenport, Iowa

Midcontinent Independent Transmission System Operator (MISO)
Carmel, Indiana

Minnesota Power
Duluth, Minnesota

Montana-Dakota Utilities Company
Bismarck, North Dakota

Nebraska Public Power District
Columbus, Nebraska

Northern Municipal Power Agency
Thief River Falls, Minnesota

NorthWestern Corporation
Sioux Falls, South Dakota

Omaha Public Power District
Omaha, Nebraska

Otter Tail Power Company
Fergus Falls, Minnesota

U.S. Department of the Air Force
Grand Forks Air Force Base, North Dakota

Western Area Power Administration
Billings, Montana

Wisconsin Power and Light
Madison, Wisconsin

Xcel Energy
Minneapolis, Minnesota

All-of-the-above energy strategy

Minnkota is proud to use North Dakota's home-grown resources to generate reliable, cost-effective and environmentally responsible electricity for its members. Maintaining an all-of-the-above strategy is a critical part of Minnkota's power supply, which currently consists of lignite coal, wind and hydro.

Resilient generators

The Milton R. Young Station is a key resource in Minnkota's portfolio. Performance milestones in 2020 show the coal-based facility, which came online in the 1970s, is well-positioned to have continued success in the years ahead. Safety and environmental compliance remain the primary focuses in plant operations. The Young Station staff had no lost-time injuries in 2020 and only one OSHA-recordable injury during the year. The facility met 100% compliance with air, water and land quality requirements.

From an operations standpoint, Unit 1 was available 93.9% of the time in 2020, while Unit 2 was available 93% of the time. This level of availability well exceeds industry standards.

Strategies have been implemented in recent years that have helped the plant lower maintenance outage costs and become more flexible in responding to wholesale market conditions. Work also continues with BNI Coal, the plant's fuel provider, on initiatives to improve efficiencies and realize cost savings.

Integrated Resource Plan

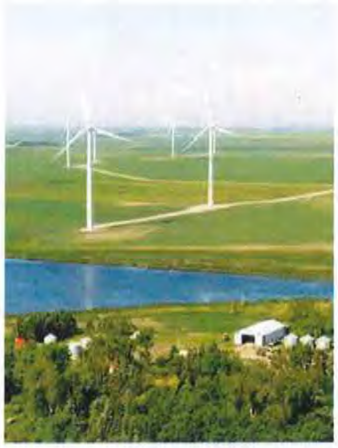
In February 2020, the Minnesota Public Utilities Commission (PUC) accepted Minnkota's Integrated Resource Plan (IRP), which establishes the cooperative's plans to meet the electricity needs of the membership over the next 15 years. The plan highlights how Minnkota will maintain or improve electric service to consumers, maintain competitive electric rates and minimize environmental impacts and the risk of adverse effects from financial, social and technological impacts.

Carbon-managed future

Minnkota believes the utility industry will be faced with the need to manage carbon dioxide (CO_2) emissions through regulation, carbon pricing, cap and trade, or another mechanism. The new presidential administration has indicated that climate change and reducing CO_2 emissions will be a primary focus from all departments and agencies. Minnkota will continue to advocate for achievable outcomes and, more importantly, investments in innovation that can lower the cost of transformational CO_2 reduction technologies.

Plant Availability

Young 1	Young 2	Coyote
93.9%	93.0%	91.4%



The Langdon Wind Energy Center in North Dakota provides renewable energy for Minnkota's membership.

Joint System Energy Requirements

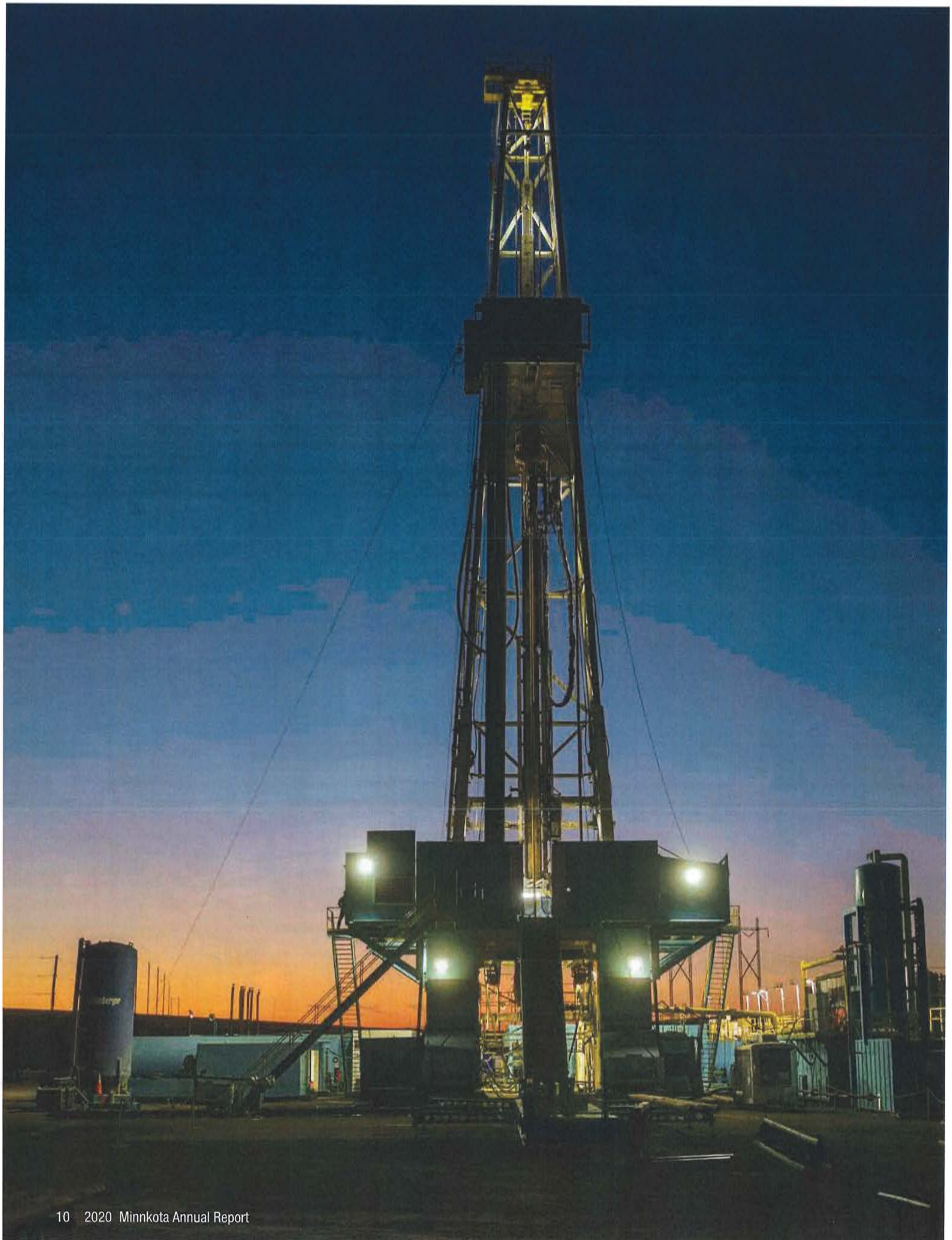
Where it came from	Thousands of MWh	Percent
Young 1	1,734	23.9
Young 2	2,289	31.6
Coyote	713	9.8
WAPA – Firm	535	7.4
Wind – Ashtabula	816	11.2
Wind – Langdon	621	8.6
Wind – Oliver III	456	6.3
Wind – Infinity	4	0.1
MISO	76	1.0
Other	10	0.1
TOTALS	7,254	100.0

Where it went	Thousands of MWh	Percent
Member cooperatives	3,963	54.6
Municipal participants	441	6.1
Off-system sales	2,726	37.6
Other	68	0.9
Losses	56	0.8
TOTALS	7,254	100.0

The coal-based Milton R. Young Station near Center, N.D., is a reliable and resilient resource in Minnkota's all-of-the-above energy strategy.

Generating Plant Performance

	Young 1	Young 2	Coyote
Gross generation – kWh	1,945,599,000	3,229,431,000	2,539,013,000
Net generation – kWh	1,734,357,000	2,933,166,000	2,380,114,000
Station service – kWh	211,240,000	296,265,000	158,899,000
Hours online	8,204	8,104	8,024
Hours offline	580	680	760
Availability – percent	93.9	93.0	91.4
Average net generation – kW	211,000	362,000	297,000



Project Tundra

While about 42% of Minnkota's generation capacity is currently carbon-free, the cooperative is evaluating a project that could significantly increase its percentage of carbon-free power by the end of the decade without sacrificing reliability. Minnkota is in the process of thoroughly evaluating Project Tundra – an effort to build a carbon capture facility at the coal-based Young Station located 35 miles from Bismarck. State-of-the-art technologies are currently being explored to remove an amount of CO_2 equivalent to permanently taking 800,000 gasoline-fueled vehicles off the road. The CO_2 would then be safely and permanently stored more than a mile underground in deep, geologic formations.

Through state and federal grant funding, Minnkota and its partners made progress on a Front-End Engineering and Design (FEED) study that will provide vital technical and economic information. Research is also being conducted on the underground storage facility with leadership from the Energy and Environmental Research Center (EERC) at the University of North Dakota. Test wells have been drilled down 10,000 feet to meticulously review the geology to ensure the injection of CO_2 will be safe. Additional seismic and geophysical surveys have also been conducted.

Project Tundra is estimated to require a more than $1.1 billion capital investment, which would primarily be funded through federal 45Q tax credits. These incentives work similarly to the tax credits that have been used by wind and solar projects for many years. Research, permitting and financing efforts will all continue in 2021 in anticipation of making a decision on whether to continue forward with the project near the end of the coming year.

Minnkota and its members firmly believe that carbon capture technology must be rapidly advanced and deployed if the world is to meet ambitious climate goals. If Project Tundra moves forward, it can help bring this breakthrough technology another step toward widespread adoption.

(Left) Two test wells were drilled approximately 10,000 feet near the Milton R. Young Station to thoroughly study the area's geology and ensure it is safe to store carbon dioxide as part of Project Tundra. (Above) This rendering shows what a carbon capture facility could look like at the Young Station.

A boom truck lifts a Minnkota lineworker up to install blink outage mitigation equipment on a 69-kV transmission structure near Larimore, N.D. This program has helped significantly reduce momentary outages across the system.

Resilient and secure system

Minnkota's power delivery system became smarter, stronger and more resilient in 2020. Even with challenges and delays related to COVID-19, nearly all of the scheduled capital project work was completed during the year. Aging infrastructure and system reliability were the primary focus, as vast stretches of the power delivery system were modified, upgraded or completely rebuilt.

With 3,370 miles of transmission line and 255 substations, prioritizing project work and improvements requires a data-driven and programmatic approach. As Minnkota works methodically to address its legacy infrastructure, positive results are beginning to emerge. Over the last five years, power delivery metrics – including sustained outages, blink outages and total outage time – are all steadily improving thanks to a wide array of programs and routine maintenance.

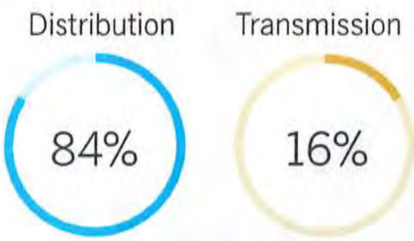
In addition to project work in the field, Minnkota continues to improve its security posture to respond to ever-evolving industry change and potential threats. Security audits, employee training and other efforts are ongoing across the entire organization. From a technology standpoint, staff completed a major upgrade of the Energy Management System (EMS), which is the computer system that allows power system operators to monitor and operate the electric grid from the control center. Staff also completed a redesign of the Information Technology (IT) network to employ a "defense-in-depth" strategy that segregates IT assets and provides additional layers of security.

Minnkota continues to be compliant with North American Electric Reliability Corporation (NERC) standards. In 2020, NERC began enforcement of its Critical Infrastructure Protection supply chain standard. Processes, procedures and review guidelines are now in place to help ensure the cooperative and its equipment vendors are not utilizing equipment that would allow malicious entities cyber access into the bulk electric system.

Power delivery projects

- **Blink outage mitigation:** Minnkota is nearing the end of its accelerated plan to address blink outages. Technologies have been added to about 1,244 miles of existing 69-kV transmission line in recent years, including 216 miles in 2020. This program has shown a blink outage reduction rate of 55-60% over non-mitigated circuits.
- **Northeast North Dakota line rebuild and service improvement:** Minnkota crews rebuilt about 22 miles of 69-kV line in northeastern North Dakota between the Lincoln, Glasston and Hensel substations. The new line includes an enhanced, modern design for greater reliability. Nearby, the cooperative constructed 22 miles of 115-kilovolt transmission line and made major upgrades to the Edinburg substation and Concrete substations to improve service.
- **Substation construction:** Minnkota crews completely rebuilt the Oklee (Minn.) substation, which had aged beyond its useful life. The new substation includes a modern design and new communication technologies. Progress was also made on the Rindal (Minn.) substation rebuild project and the new Berg substation near Grand Forks, both of which will be completed in 2021.
- **Distribution automation:** Minnkota completed 17 distribution automation projects in 2020. This program includes adding new communication technology at existing substation sites, which allows Minnkota personnel to collect, automate, analyze and optimize data. Better system visibility can assist in responding to outages and other issues. Minnkota plans to have all distribution substations equipped with the technology before the end of the decade.
- **Demand response equipment replacement:** To improve the long-term viability and reliability of Minnkota's demand response program, Minnkota replaced the ripple injectors and associated equipment at the West Fargo (N.D.) and Wilton (Minn.) substations in 2020. The equipment, which was originally installed in the 1970s and early 1980s, has reached the end of its useful life. Ten of the 17 injectors have been replaced in recent years, and the current plan is to have all sites completed by the end of 2024.

255 Substations

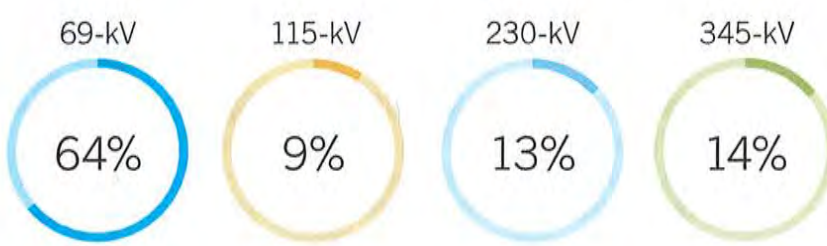


Jason Bjerke, senior technical maintenance technician, adjusts ripple injection equipment at the Wilton substation near Bemidji, Minn. The equipment is critical to Minnkota's demand response system.

From ground level to the top of a transmission structure, Minnkota crews string wire on a rebuilt section of 69-kV line near Cavalier, N.D.

Jimmy Snider, electrician, completes work on the rebuilt Oklee substation in northwest Minnesota. Minnkota budgets to rebuild two of its aging distribution substations annually.

3,370 Miles of Transmission Line



Members of Altru Health System's inpatient care team in Grand Forks enjoyed a Red Pepper sandwich during an appreciation lunch sponsored by Minnkota and member Nodak Electric Cooperative.

We power on

Minnkota has faced many challenges over its 80-year history, but none quite like the COVID-19 pandemic. The cooperative's employees have learned to work and communicate in new ways to ensure they continue to deliver reliable electricity to the members. While many hardships have been experienced over the last year, Minnkota is committed to helping lead the comeback. In addition to reliable electricity, Minnkota and its members can help generate enthusiasm, drive economic development and support a brighter vision for the future.

Commitment to community

Minnkota is grateful for the generosity and inventiveness of its employees, members and consumers in 2020. Minnkota provided financial support to organizations in need, while the cooperative's Employee Jeans Day Fund held special fundraising drives throughout the year to provide additional support to COVID-19 relief funds, food pantries and other critical support organizations. Additional efforts were made to show appreciation for local healthcare workers, the police department and others who bravely served our community throughout the pandemic.

Supporting beneficial electrification

Minnkota and its members continue to support beneficial electrification efforts through rebate programs, education and outreach. In 2020, Minnkota supported members Cass County Electric Cooperative and Nodak Electric Cooperative in installing new Level 3 electric vehicle charging stations in Fargo (3) and Grand Forks (1).

Unmanned Aerial System (UAS) leadership

North Dakota is ranked the #1 most drone-ready state. The cooperative's service area is home to Grand Sky – the United States' first commercial UAS business and aviation park. It is also the first site to receive regulatory approval to host commercial beyond visual line of sight (BVLOS) flights. Minnkota continues to build partnerships with startup UAS companies and supports energy-related research and development.

Business expansion

Reliable electricity is essential to any business. Minnkota works closely with its member cooperatives and associated municipals to ensure local economies can continue to grow and thrive. The following building and expansion efforts are currently being pursued within the Joint System.

- Amazon is constructing a 1.3 million-square-foot distribution center in Fargo. When completed in 2021, it is anticipated to be the largest building in the state of North Dakota.
- Aldevron, a Fargo-based biotechnology company, has begun a major expansion of its campus that will increase its production capacity tenfold, quintuple its warehouse space and create a research and development center.
- Digi-Key Corporation, one of the world's largest electronic components distributors, has begun a 2.2 million-square-foot expansion in Thief River Falls, Minn. The project is scheduled for completion in 2021.
- The North Dakota Mill, the largest flour mill in the United States, has expanded several times over the last decade and is planning another expansion for 2021.

In 2020, Minnkota crews completed an expansion of the existing Anderson substation in Thief River Falls, Minn., which will support the growth of Digi-Key and other areas of the community.

Nodak Electric leaders joined Grand Forks mayor Brandon Bochenski (far left) to cut the ribbon on the new electric vehicle fast charging station the cooperative installed in Grand Forks.

Three new electric vehicle fast charging stations were installed in Fargo by Cass County Electric Cooperative in 2020, including this charger near the Fargo-Moorhead Convention and Visitors Center. Cooperative and city leaders held ribbon-cutting ceremonies in September.

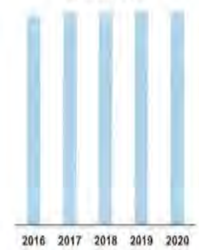
Donning a Santa cap, Minnkota's Troy Karlberg delivers several cots, sleeping bags, pillows and pillow cases to United Way's Lori Ledahl for the homeless shelter in Bismarck before the holiday season.

Minnkota's Jen Regimbal presents a Jeans Day donation check to St. Joseph's Social Care executive director Mickey Munson. The donation was used to combat food insecurity in the Greater Grand Forks area.

Treasurer's Report

Colette Kujava
Secretary/Treasurer

2016	3,813,970
2017	3,926,016
2018	4,114,194
2019	4,107,770
2020	3,962,854



2016	74.56
2017	76.00
2018	75.80
2019	76.38
2020	76.30

This report summarizes the financial results of Minnkota's operations for the year ended Dec. 31, 2020, and its financial position as of Dec. 31, 2020.

Revenues

Revenues in 2020 totaled $391.2 million, down from $402.2 million in 2019. Minnkota's largest revenue source is energy sales to the 11 Class A member-owner distribution cooperatives which were $314.5 million in 2020, or $4.8 million under budget. Class A kilowatt-hour sales were under budget by 4.2%. This prompted the recognition of $12.1 million of previously deferred revenue, as compared to the budgeted recognition of $4.7 million. Minnkota operates with a revenue deferral plan that has been approved by the Rural Utilities Service (RUS). The cooperative had a balance of $27.8 million in its revenue deferral plan at Dec. 31, 2020.

A total of 3.9 billion kWh were sold to Class A members in 2020, down 3.5% from last year. The Class A member average rate was 76.3 mills per kWh in 2020, down slightly from 76.4 mills per kWh in 2019. Energy sales revenue from Class B, C and D members totaled $63.6 million, or $14.4 million under budget. This is mainly due to significantly lower market sales prices and less kWh sold.

Other electric revenue totaled $12.2 million in 2020, which was $0.6 million under budget. The major items included in this category are administrative fees collected from Square Butte Electric Cooperative, sales of renewable energy credits related to Minnkota's purchased power wind contracts, wheeling revenue and transmission services income.

Nonoperating margins in 2020 totaled $0.8 million, or $3.5 million under budget. Nonoperating margins include interest income, capital credit allocations primarily from CoBank, coal royalties received from Square Butte and refined coal revenue.

Expenses

Total expenses were $383.5 million in 2020, down from $390.5 million in 2019. The largest expense category is power supply, which includes generation expenses of Young 1 and purchased power from Young 2, Coyote, Western Area Power Administration, wind farms and other area utilities. Power supply expenses totaled $280.7 million, or $15.1 million under budget. They were under budget primarily due to reduced generation expenses for Young 1 and less purchased power expenses from Square Butte.

Transmission and substation expenses totaled $26.1 million in 2020, or $1.3 million under budget. Administrative and general expenses were $19.3 million in 2020, or $0.8 million under budget. Fixed costs, which include interest and depreciation, totaled $57.4 million in 2020, which is $1.7 million under budget.

Net margins

Margins for 2020 were $7.7 million, down from $11.7 million in 2019. The total margin consisted of an operating margin of $6.8 million and a nonoperating margin of $0.8 million.

Patronage capital

Total patronage capital was $30.8 million at Dec. 31, 2020 and reflects the 2020 operating margin of $6.8 million. The nonoperating margin of $0.8 million will be retained as appropriated margins to be used for future contingencies. Total equity at Dec. 31, 2020, was $167.6 million, 14.7% of total assets.

Electric plant

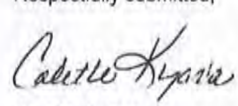
Net electric plant was $985.8 million at Dec. 31, 2020, up $6.8 million from last year. This increase is mainly due to transmission property additions.

Long-term debt

Minnkota's long-term debt, including current maturities, was $865.6 million as of Dec. 31, 2020, up $10.5 million from last year. In 2020, Minnkota had net loan advances of $35.0 million from RUS and CoBank. Minnkota made $23.1 million in debt principal payments during the year.

This has been a brief review of the 2020 financial statements. For further information, I urge you to review the financial statements, the notes to the financial statements and the Independent Auditor's Report contained in this annual report.

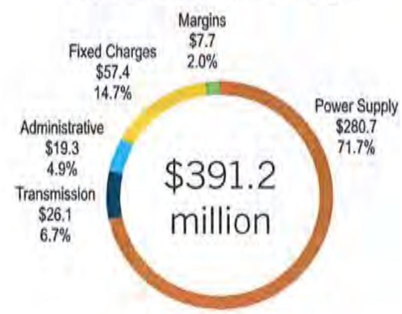
Respectfully submitted,



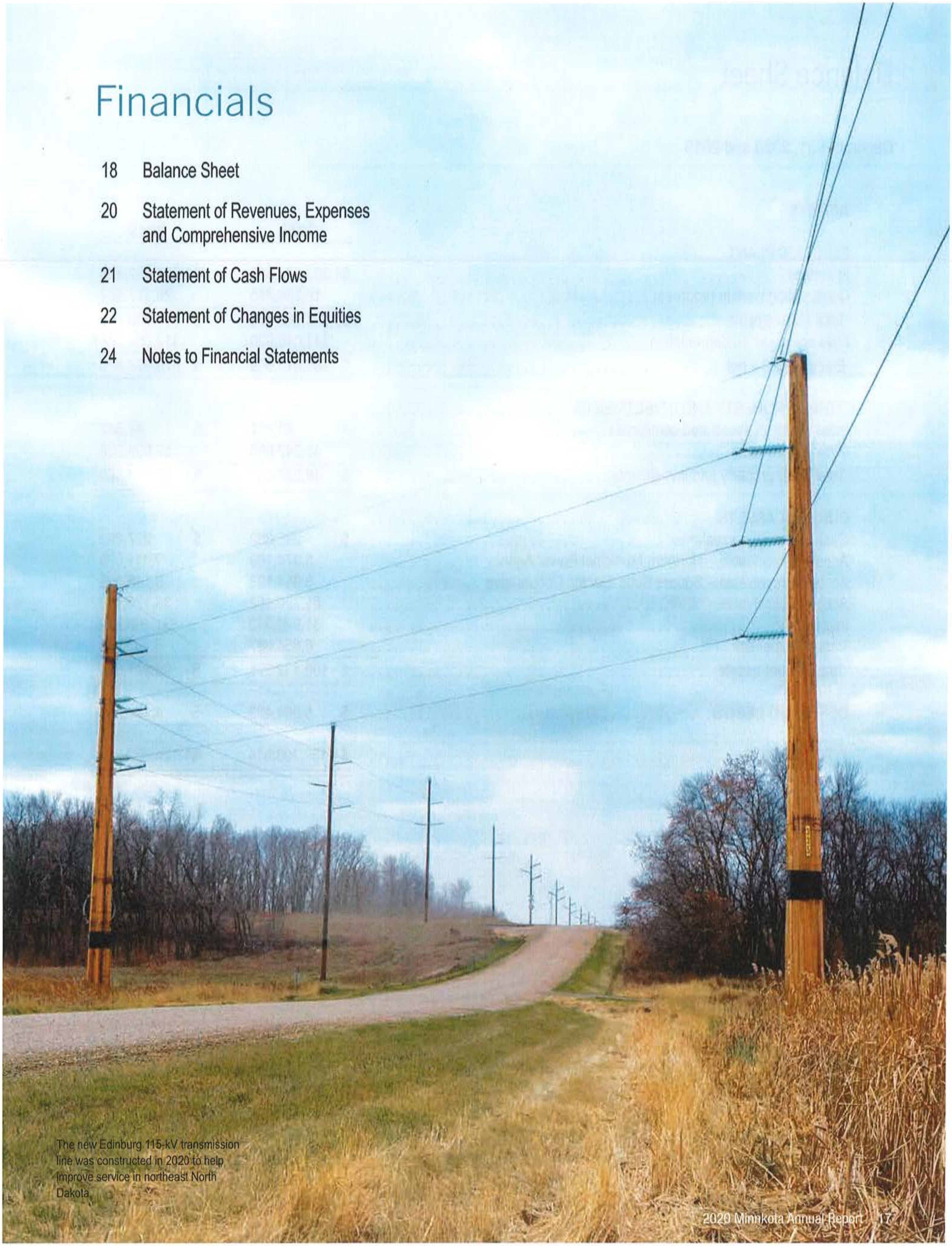
Colette Kujava
Secretary/Treasurer

2020 Total Revenue

2020 Total Expenses & Margins



Financials



The new Edinburg 115-kV transmission line was constructed in 2020 to help improve service in northeast North Dakota.

Balance Sheet

December 31, 2020 and 2019

ASSETS

	2020	2019
ELECTRIC PLANT		
In service	$1,306,873,680	$1,264,952,825
Construction work in progress	19,986,795	26,377,884
Total electric plant	$1,326,860,475	$1,291,330,709
Less accumulated depreciation	(341,046,926)	(312,356,834)
Electric plant – net	$ 985,813,549	$ 978,973,875
OTHER PROPERTY AND INVESTMENTS		
Investments in associated companies	$ 44,917	$ 44,642
Other investments	48,242,650	52,698,923
Total other property and investments	$ 48,287,567	$ 52,743,565
CURRENT ASSETS		
Cash and cash equivalents	$ 295,352	$ 227,693
Accounts receivable – Northern Municipal Power Agency	5,374,169	7,111,095
Accounts receivable – Square Butte Electric Cooperative	3,954,193	5,148,502
Accounts receivable – other	51,729,152	38,370,148
Inventories	31,926,042	31,498,752
Prepaid expenses	6,854,067	6,585,411
Total current assets	$ 100,132,975	$ 88,941,601
DEFERRED DEBITS	$ 5,064,423	$ 4,174,266
TOTAL ASSETS	$1,139,298,514	$1,124,833,307

See Notes to Financial Statements

EQUITIES AND LIABILITIES

	2020	2019
EQUITIES		
Memberships issued	$ 1,136	$ 1,136
Patronage capital	30,791,491	23,966,323
Appropriated margins	141,965,643	141,120,519
Accumulated other comprehensive income (loss)	(5,166,203)	(8,320,585)
Total equities	$ 167,592,067	$ 156,767,393
LONG-TERM DEBT		
Mortgage notes payable, net of current maturities	$ 835,258,078	$ 824,474,677
Accrued pension costs	6,195,270	7,571,592
Total long-term debt	$ 841,453,348	$ 832,046,269
NONCURRENT LIABILITIES		
Postretirement health insurance obligation	$ 4,864,780	$ 4,478,784
Closure cost obligation	2,448,884	2,121,180
Total noncurrent liabilities	$ 7,313,664	$ 6,599,964
CURRENT LIABILITIES		
Accounts payable – Square Butte Electric	$ 9,342,805	$ 8,802,902
Accounts payable – other	28,964,356	25,891,647
Accrued taxes	3,797,957	3,930,899
Accrued interest	829,544	1,038,151
Accrued payroll	628,673	1,846,141
Vested accrued vacation	4,377,695	3,688,636
Current maturities of long-term debt	24,133,599	23,060,926
Line of credit – bank	15,467,000	13,688,000
Total current liabilities	$ 87,541,629	$ 81,947,302
DEFERRED CREDITS	$ 35,397,806	$ 47,472,379
TOTAL EQUITIES AND LIABILITIES	$1,139,298,514	$1,124,833,307

See Notes to Financial Statements

Statement of Revenues, Expenses and Comprehensive Income

Years Ended December 31, 2020 and 2019

	2020	2019
OPERATING REVENUES		
Energy sales to Class A members	$ 314,507,748	$ 308,349,673
Energy sales to Class B, C & D members & other	63,602,524	72,612,269
Other electric revenue	12,228,092	12,509,158
Total operating revenues	$ 390,338,364	$ 393,471,100
OPERATING EXPENSES		
Generation	$ 54,353,815	$ 57,688,257
Power supply cost – Northern Municipal Power Agency	22,924,496	24,272,088
Purchased power – Square Butte Electric Cooperative	80,637,229	81,305,483
Purchased power – other	122,831,779	122,714,834
Transmission and substation	26,069,611	25,226,876
Depreciation and amortization	30,045,351	28,911,758
Administrative and general	19,327,068	18,186,123
Interest on long-term debt	26,818,171	31,921,735
Other interest	504,676	255,200
Total operating expenses	$ 383,513,196	$ 390,482,354
OPERATING MARGIN	$ 6,825,168	$ 2,988,746
NONOPERATING MARGIN		
Interest income	$ 461,737	$ 4,879,670
Coal royalties	1,350,000	1,351,734
Capital credit allocations received	1,195,320	908,333
Nonoperating revenue	1,931,523	1,924,208
Pension and postretirement cost	(4,093,456)	(338,691)
TOTAL NONOPERATING MARGIN	$ 845,124	$ 8,725,254
NET MARGIN	$ 7,670,292	$ 11,714,000
OTHER COMPREHENSIVE INCOME (LOSS)		
Defined benefit pension plans:		
Net income (loss) arising during the period	3,154,382	(5,143,414)
COMPREHENSIVE INCOME	$ 10,824,674	$ 6,570,586

See Notes to Financial Statements

Statement of Cash Flows

Years Ended December 31, 2020 and 2019

		2020		2019
CASH FLOWS FROM OPERATING ACTIVITIES				
Net margins	$	7,670,292	$	11,714,000
Adjustments to reconcile net margin to net cash provided (used) by operating activities				
Depreciation and amortization		30,046,351		28,911,758
Capital credit allocations		(1,195,320)		(908,333)
Effects on operating cash flows due to changes in:				
Accounts receivable		(10,427,769)		181,990
Prepaid expenses		(268,656)		(468,951)
Inventories		(427,290)		(1,676,645)
Deferred debits		(4,557,284)		(2,812,277)
Accounts payable		3,612,612		(4,873,651)
Accrued expenses		726,354		866,978
Deferred credits		(7,511,998)		12,284,656
NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES	$	17,667,292	$	43,219,525
CASH FLOWS FROM INVESTING ACTIVITIES:				
Electric plant additions – net	$	(36,886,025)	$	(43,183,063)
Investment (additions) reductions		5,103,417		(44,988,341)
Capital credits received		547,901		549,979
NET CASH PROVIDED (USED) BY INVESTING ACTIVITIES	$	(31,234,707)	$	(87,621,425)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from long-term debt	$	56,317,000	$	20,380,000
Net proceeds (payments) on line of credit		1,779,000		(2,886,700)
Net proceeds (payments) on bridge loan		(21,400,000)		40,668,000
RUS cushion of credit applied		–		108,295,879
Repayment of long-term debt		(23,060,926)		(122,053,697)
NET CASH PROVIDED (USED) BY FINANCING ACTIVITIES	$	13,635,074	$	44,403,482
NET CHANGE IN CASH AND CASH EQUIVALENTS	$	67,659	$	1,582
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR		227,693		226,111
CASH AND CASH EQUIVALENTS, END OF YEAR	$	295,352	$	227,693
SUPPLEMENTAL DISCLOSURE OF CASH FLOWS INFORMATION				
Cash paid for interest	$	27,158,986	$	32,326,480

See Notes to Financial Statements

Statement of Changes in Equities

December 31, 2020 and 2019

	Memberships Issued	Patronage Capital	Appropriated Margins	Accumulated Other Comprehensive Income (Loss)	Total
BALANCE – JANUARY 1, 2019.	$1,136	$20,977,577	$132,395,265	$(3,177,171)	$150,196,807
Operating margin		2,988,746			2,988,746
Nonoperating margin			8,725,254		8,725,254
Other comprehensive income (loss). . . .				(5,143,414)	(5,143,414)
BALANCE – DECEMBER 31, 2019.	$1,136	$23,966,323	$141,120,519	$(8,320,585)	$156,767,393
Operating margin		6,825,168			6,825,168
Nonoperating margin			845,124		845.124
Other comprehensive income (loss). . . .				3,154,382	3,154,382
BALANCE – DECEMBER 31, 2020.	$1,136	$30,791,491	$141,965,643	$(5,166,203)	$167,592,067

See Notes to Financial Statements

Independent Auditor's Report

To the Board of Directors
Minnkota Power Cooperative, Inc.
Grand Forks, North Dakota

Report on the Financial Statements

We have audited the accompanying financial statements of Minnkota Power Cooperative, Inc., which comprise the balance sheets as of December 31, 2020 and 2019, and the related statements of revenues, expenses and comprehensive income, changes in equities, and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Minnkota Power Cooperative, Inc. as of December 31, 2020 and 2019, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Reporting Required by Government Auditing Standards

In accordance with *Government Auditing Standards*, we have also issued our report dated February 17, 2021, on our consideration of Minnkota Power Cooperative, Inc.'s internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with Government Auditing Standards in considering Minnkota Power Cooperative, Inc.'s internal control over financial reporting and compliance.

BRADY, MARTZ & ASSOCIATES, P.C.
GRAND FORKS, NORTH DAKOTA
February 17, 2021

Notes to Financial Statements

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization. Minnkota Power Cooperative, Inc. (Minnkota or the Cooperative) is a generation and transmission cooperative that was formed on March 28, 1940, under the laws of the State of Minnesota with headquarters in Grand Forks, North Dakota. It operates on a non-profit cooperative basis and is engaged primarily in the business of providing wholesale electric service to its retail distribution cooperative member-owners (Members). The eleven members purchase power and energy from Minnkota pursuant to all-requirements wholesale power contracts, which terminate on December 31, 2055.

Minnkota's service area, aggregating approximately 35,000 square miles, is located in northwestern Minnesota and eastern North Dakota, and contains an aggregate population of approximately 300,000 people.

Minnkota is subject to the accounting and reporting rules and regulations of the Rural Utilities Service (RUS). The Cooperative follows the Federal Energy Regulatory Commission's Uniform System of Accounts prescribed for Class A and B Electric Utilities as modified by RUS.

Rates charged to members are established by the board of directors and are subject to deemed approval by RUS.

As a result of the ratemaking process, the Cooperative applies Accounting Standards Codification (ASC) 980 Regulated Operations. The application of generally accepted accounting principles by the Cooperative differs in certain respects from the application by non-regulated businesses as a result of applying ASC 980. Such differences generally related to the time at which certain items enter into the determination of net margins in order to follow the principle of matching costs and revenues.

Electric Plant and Retirements. Electric plant is stated at cost. The cost of additions to electric plant includes contracted work, direct labor and materials and allocable overheads. The cost of units of depreciable property retired is removed from electric plant and charged to accumulated depreciation along with removal costs less salvage. Repairs and the replacement and renewal of items determined to be less than units of property are charged to maintenance expense.

Depreciation. Depreciation is computed using the straight-line method based upon the estimated useful lives of the various classes of property through use of annual composite rates.

Allowance for Funds Used During Construction (AFUDC). The allowance for funds used during construction is interest that is capitalized on all construction projects with a budgeted cost of greater than $50,000. AFUDC is classified as a reduction of interest expense.

Investments. Investments are U.S. treasury bills, savings and patronage allocations from cooperatives and other affiliates stated at cost plus unretired allocations.

Fair Value Measurements. The Cooperative has determined the fair value of certain assets and liabilities in accordance with generally accepted accounting principles, which provides a framework for measuring fair value.

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. Valuation techniques should maximize the use of observable inputs and minimize the use of unobservable inputs.

A fair value hierarchy has been established, which prioritizes the valuation inputs into three broad levels. Level 1 inputs consist of quoted prices in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the related asset or liability. Level 3 inputs are unobservable inputs related to the asset or liability.

The Cooperative does not have any assets or liabilities subject to level 1, 2, or 3 valuation as of December 31, 2020 and 2019, and does not anticipate participating in transactions of this type in the future.

The fair value of the Cooperative's long-term debt was estimated based upon borrowing rates currently available to the Cooperative for bank loans with similar terms and average maturities. The estimated fair value of the Cooperative's long-term debt was $927,000,000 and $925,000,000 as of December 31, 2020 and 2019, respectively.

Cash and Cash Equivalents. For purposes of reporting cash flows, the Cooperative considers all highly liquid investments purchased with a maturity of three months or less to be cash equivalents.

Receivables and Credit Policies. Trade receivables are uncollateralized customer obligations due under normal trade terms requiring payment within 30 days from the billing date. Management has deemed that no late fees or interest charges are assessed to the receivables. Management has determined that an allowance for doubtful accounts is not necessary, as all balances are considered fully collectible.

Inventories. Uncovered and undelivered coal inventory is stated at cost using a FIFO (first-in, first-out) basis. All other inventories are stated at the lower of average cost or fair market value.

Deferred Debits. Deferred debits consist of deferred pension costs. See also Note 6 and Note 11.

Deferred Credits. Deferred credits consist primarily of transmission service advance, customer construction prepayments and a revenue deferral as approved by RUS. See also Note 13.

Patronage Capital. The Cooperative operates on a non-profit basis. Amounts received from the furnishing of electric energy in excess of operating costs and expenses are assigned to patrons on a patronage basis. All other amounts received by the Cooperative from its operations in excess of costs and expenses are also allocated to its patrons on a patronage basis to the extent they are not needed to offset current or prior losses.

Revenue Recognition. Revenues are primarily from electric sales to members. Electric revenues are recognized over time as electricity is delivered to members. Electric revenues are based on the reading of members' meters, which occurs on a systematic basis throughout each reporting period and represents the fair value of the electricity delivered.

Revenues are recognized equivalent to the value of the electricity supplied during each period, including amounts billed during each period and changes in amounts estimated to be billed at the end of each period. The Cooperative has elected to apply invoice method to measure progress towards completing performance obligations to transfer electricity to their members.

Business and Credit Risk. The Cooperative maintains its cash balances in a locally owned bank. Such balances are insured by the Federal Deposit Insurance Corporation up to $250,000. The cash balances exceeded insurance coverage at various times during the fiscal years.

Accounting Estimates. The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Income Taxes. The Cooperative is exempt from income taxes under Section 501(c)(12). The Cooperative is annually required to file a Return of Organization Exempt from Income Tax (Form 990) with the IRS.

The Cooperative evaluates its tax positions that have been taken or are expected to be taken on income tax returns to determine if an accrual is necessary for uncertain tax positions. As of December 31, 2020 and 2019, the unrecognized tax benefit accrual was zero. The Cooperative will recognize future accrued interest and penalties related to unrecognized tax benefits in income tax expense if incurred. The Company is no longer subject to Federal and State tax examinations by tax authorities for years before 2017.

Advertising Costs. Advertising and promotional costs are expensed as incurred.

Sales Taxes. The Cooperative pays sales tax on material it purchases to operate and maintain its generation and transmission facilities.

Recently Adopted Accounting Standards. In 2014, the FASB issued ASC 606, Revenue from Contracts with Customers (ASC 606), replacing the existing accounting standard and industry-specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. ASC 606 became effective on January 1, 2019, and the Cooperative adopted it using the modified retrospective method applied to open contracts and only to the version of contracts in effect as of January 1, 2019. In accordance with the modified retrospective method, the Cooperative's previously issued financial statements have not been restated to comply with ASC 606 and the Cooperative did not have a cumulative-effect adjustment to retained earnings. The adoption of ASC 606 had no significant impact on the timing of revenue recognition compared to previously reported results; however, it requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers, which are included in Note 10.

NOTE 2 – SQUARE BUTTE ELECTRIC COOPERATIVE

Square Butte owns a 488-megawatt (MW) steam electric generating plant (Young 2) adjacent to Minnkota's 256 MW generating plant (Young 1) near Center, North Dakota.

Minnkota, as agent for Square Butte, operates and maintains Young 2.

The long-term power purchase agreement with Square Butte has been evaluated under the accounting guidance for variable interest entities. We have determined that we have no variable interest in the agreement. This conclusion is based on the fact that we do not have both control over activities that are most significant to the entity and an obligation to absorb losses or receive benefits from the entity's performance. Minnkota Power Cooperative, Inc.'s financial exposure related to the agreement is limited to our capacity and energy payments.

On December 30, 2009, Minnkota, Square Butte and Minnesota Power (MP) completed an agreement in which Minnkota receives additional energy and capacity from Young 2. Between 2014 and 2026, Minnkota has the option to acquire MP's 50% allocation from Young 2. In 2014 Minnkota exercised this option and starting June 1, 2014, purchased an additional 22.5275% allocation of Young 2 from MP. This allocation increased to 28.022% on January 1, 2015. This allocation will increase by approximately 4.4% per year from 2022-2026. From 2027 to 2042, Minnkota will purchase 100% of the output of Young 2 directly from Square Butte. The payment obligation of MP and Minnkota are several and not joint, and are not guarantees of any Square Butte obligations.

As part of this agreement, Square Butte sold its 465-mile, Center to Duluth DC transmission line and related substations to Minnesota Power. Minnesota Power is using the transmission line to deliver wind energy that it is developing near Center, North Dakota, to its service area near Duluth, Minnesota.

In 2014, Minnkota placed in service a new 250-mile, $355 million, 345-kilovolt transmission line from Center, North Dakota, to near Grand Forks, North Dakota. This line allows Square Butte energy to be delivered into the Minnkota system and provides the overall northern Red River Valley service area with additional voltage support.

Minnkota is obligated to pay a proportionate share of Square Butte's annual debt retirement and operating costs based on its entitlement to net capability. Minnkota also receives a minimum annual coal royalty of $1,350,000 from Square Butte.

Minnkota has also issued a $10,000,000 line of credit to Square Butte with a variable interest rate that is 1% below the prime rate. As of December 31, 2020 and 2019, no amounts were outstanding on this line of credit.

Related party transactions include:

	2020	2019
Purchase of wholesale power	$ 80,637,229	$ 81,305,483
Accounts payable to Square Butte	$ 9,342,805	$ 8,802,902
Accounts receivable from Square Butte	$ 3,954,193	$ 5,148,502

NOTE 3 – NORTHERN MUNICIPAL POWER AGENCY

Northern Municipal Power Agency (Northern) is a municipal corporation and a political subdivision of the State of Minnesota. Its membership consists of 10 Minnesota and two North Dakota municipalities each of which owns and operates a municipal electric utility distribution system.

On March 1, 1981, Minnkota entered into a Power Supply Coordination Agreement with Northern. This agreement is effective until the later of December 31, 2041, or the date on which the Coyote Plant is retired from service. All annual debt payments and plant operating cost requirements not provided by Northern's member revenue and the sale of all capacity and energy in excess of Northern's member requirements are an obligation of Minnkota.

Related party transactions include:

	2020	2019
Power supply cost	$22,924,496	$24,272,088
Accounts receivable from Northern	$ 5,374,169	$ 7,111,095

NOTE 4 – ELECTRIC PLANT

	2020		2019	
	Plant	Depreciation Rates	Plant	Depreciation Rates
Production plant	$ 409,343,867	3.13%-5.00%	$ 407,765,727	3.13%-5.00%
Transmission lines	525,099,227	1.78%-2.39%	510,297,171	1.78%-2.39%
Transmission substations	137,156,486	1.69%-4.96%	133,485,386	1.69%-4.96%
Distribution substations	110,906,508	2.48%	97,326,168	2.48%
General plant	124,367,592	2.00%-16.70%	116,078,373	2.00%-16.70%
Electric plant in service	1,306,873,680		1,264,952,825	
Construction work in progress	19,986,795		26,377,884	
Total electric plant	$1,326,860,475		$1,291,330,709	

The Cooperative capitalized interest of $558,763 and $633,927 as of the years ended December 31, 2020 and 2019, respectively.

NOTE 5 – OTHER INVESTMENTS

	2020	2019
CoBank patronage capital credits	$ 6,986,267	$ 7,452,799
US Bank – treasury bills	29,999,924	44,988,341
Associated companies	44,917	44,642
Savings	9,885,000	-
Other	1,371,459	257,783
Total other investments	$ 48,287,567	$52,743,565

Notes to Financial Statements

NOTE 6 – DEFERRED DEBITS

The Cooperative's deferred debit balances are summarized below:

	2020	2019
Deferred pension costs – (see Note 11)	$ 5,064,423	$ 4,174,266
Total deferred debits	$ 5,064,423	$ 4,174,266

NOTE 7 – PATRONAGE CAPITAL AND APPROPRIATED MARGINS

Under provisions of the long-term debt agreements, until the total of equities and margins equals or exceeds 20% of the total assets of the Cooperative, retirement of capital is not permitted.

As provided for in the bylaws, operating margins of the current year not needed to offset operating losses incurred during prior years, shall be capital furnished by the patrons and credited to patronage capital. Nonoperating margins are not assignable to patrons and are credited to appropriated margins and reserved for future contingencies.

NOTE 8 – LONG-TERM DEBT

Long-term debt as of December 31, 2020 and 2019, is shown below. Substantially all of Minnkota's assets are pledged as collateral in accordance with its indenture.

	2020	2019
Rural Utilities Service (RUS)		
Fixed rate mortgage notes (1.074%-5.24%) due in quarterly installments through 2053	$726,388,637	$688,964,773
CoBank		
Fixed and variable rate mortgage notes (1.27%-6.89%) due in quarterly installments maturing at various times through 2039	31,265,647	34,991,543
Variable interest rate bridge loan (see Note 9)	78,600,000	100,000,000
	109,865,647	134,991,543
The Lincoln National Life Insurance Company		
Fixed rate first mortgage note (4.73%) due in semi-annual installments through 2049	22,985,000	23,360,000
Digital press and copier leases	152,393	219,287
Accrued pension costs (see Note 11)	6,195,270	7,571,592
Total long-term debt	865,586,947	855,107,195
Less current portion	(24,133,599)	(23,060,926)
Long-term debt	$841,453,348	$832,046,269

It is estimated that the minimum principal requirements for the next five years will be as follows:

Years Ending December 31,	Amount
2021	$ 24,133,599
2022	26,336,279
2023	26,890,961
2024	104,879,043
2025	24,527,576
Thereafter	658,819,489
Total	$865,586,947

At December 31, 2020, Minnkota had unadvanced loan funds available to the Cooperative in the amount of $11,079,000. Minnkota has a maximum debt limit of $1,100,000,000.

NOTE 9 – LINE OF CREDIT

At December 31, 2020, Minnkota had a line of credit agreement with U.S. Bank-Grand Forks with available borrowings totaling $25,000,000 maturing June 30, 2021. The line of credit had a variable interest rate of 1.6875% and 3.25% at December 31, 2020 and 2019, respectively. Amounts outstanding on the line totaled $15,467,000 and $13,688,000 at December 31, 2020 and 2019, respectively.

The Cooperative also has available a multi-year bridge loan with CoBank totaling $250,000,000 as of the years ended December 31, 2020 and 2019. The purpose of the bridge loan is to temporarily finance projects included in RUS loans. The blended interest rate was 1.35% and 2.95% as of December 31, 2020 and 2019, respectively, and will expire on September 27, 2024. The CoBank bridge loan had an outstanding balance of $78,600,000 and $100,000,000 at December 31, 2020 and 2019, respectively, and is included in long-term debt.

NOTE 10 – REVENUES FROM CONTRACTS WITH CUSTOMERS

The revenues of the Cooperative are primarily derived from providing wholesale electric service to its members. Revenues from contracts with customers represent over 98% of all cooperative revenues. Below is a disaggregated view of the Cooperative's revenues from contracts with customers as well as other revenues, including their location on the statement of revenues, expenses and comprehensive income for December 31, 2020 and 2019:

	2020		
Revenue Streams	Electric Revenue	Other Operating Revenue	Nonoperating Revenue
Energy sales to Class A members	$314,507,748	$ –	$ –
Energy sales to Class B, C and D members	63,602,524	–	–
Other electric revenue	–	12,228,092	–
Other nonoperating revenue	–	–	1,664,851
Total revenue from contracts with customers	$ 378,110,272	$ 12,228,092	$ 1,664,851
Timing of Revenue Recognition			
Services transferred over time	$ 378,110,272	$ 11,242,592	$ 1,664,851
Goods transferred at a point in time	–	985,500	–
Total revenue from contracts with customers	$ 378,110,272	$ 12,228,092	$ 1,664,851

	2019		
Revenue Streams	Electric Revenue	Other Operating Revenue	Nonoperating Revenue
Energy sales to Class A members	$308,349,673	$ –	$ –
Energy sales to Class B, C and D members	72,612,269	–	–

Other electric revenue	-	12,509,158	-
Other nonoperating revenue	-	-	1,616,850
Total revenue from contracts with customers	$380,961,942	$ 12,509,158	$ 1,616,850
Timing of Revenue Recognition			
Services transferred over time	$380,961,942	$ 11,615,235	$ 1,616,850
Goods transferred at a point in time	-	893,923	-
Total revenue from contracts with customers	$380,961,942	$ 12,509,158	$ 1,616,850

Electric Revenue. Electric revenues consist of wholesale electric power sales to members through the member power purchase and service contracts and from participation in the Midcontinent Independent System Operator (MISO) market. All of the electric revenues meet the criteria to be classified as revenue from contracts with customers and are recognized over time as energy is delivered. Revenue is recognized based on the metered quantity of electricity delivered or transmitted at the applicable contractual or market rates.

In 2019, the Cooperative deferred the recognition of $5,394,888 of member electric revenue under regulatory accounting (see Note 12). In 2020, the Cooperative recognized $12,124,900 of deferred member electric revenue.

Other Operating Revenue. Other operating revenue primarily includes: revenue received from wheeling and wind delivery services; revenue received for operating agent fees; revenue for lime preparation facility user fees; and sale of renewable energy credits. All of these revenue streams meet the criteria to be classified as revenue from contracts with customers. Wheeling and wind delivery services revenues is recognized over time as energy in transmitted and delivered based on measured quantities at the contractual rates. Operating agent fees are recognized over time based on actual costs incurred during each month of performance. Lime facility user fees revenue is recognized over time based on an annual fee. Excess renewable energy credits are sold to third parties. Renewable energy credit revenue is recognized at a point in time when the sale is completed with the third party.

Other Nonoperating Revenue. Other nonoperating revenue during 2020 and 2019 included $1,664,851 and $1,616,850 of revenue from coal yard services and license agreements, respectively. Revenue from the coal yard services and license agreements is recognized over time, based on an annual contracted fee.

Balances from accounts receivable and contracts with customers are as follows:

	Accounts Receivable	Contract Liabilities
January 1, 2019	$ 49,721,266	$ 1,847,589
December 31, 2019	$ 45,276,434	$ 7,486,829
December 31, 2020	$ 42,592,663	$ 7,537,156

NOTE 11 – EMPLOYEE BENEFIT PLANS

Minnkota has two pension plans covering substantially all of its employees. Pension Plan A is a defined benefit plan and Pension Plan B is a defined contribution plan. Minnkota's contribution to Plan B was $5,220,104 and $5,024,141 for 2020 and 2019, respectively.

The Plan A benefit is the greater of 1) 1.5 times the average high 60 consecutive months compensation during the 120 months prior to retirement times years of service less the monthly Plan B benefit or 2) 1.1% of the first $417 of monthly salary times years of service to December 31, 1989.

The following table sets forth Plan A's funded status and amounts recognized in Minnkota's balance sheets at December 31:

	2020	2019
Change in benefit obligation:		
Benefit obligation, beginning	$ 7,571,592	$ 2,137,317
Service cost	1,005,252	126,512
Interest cost	205,064	94,646
Actuarial (gain) loss	1,080,489	5,573,224
Benefits paid	(3,667,127)	(360,107)
Benefit obligation, ending	$ 6,195,270	$ 7,571,592
Change in plan assets:		
Fair value of plan assets, beginning	$ 4,174,266	$ 1,722,096
Actual return on plan assets	557,284	312,277
Employer contributions	4,000,000	2,500,000
Benefits paid	(3,667,127)	(360,107)
Fair value of plan assets, ending	$ 5,064,423	$ 4,174,266
Funded status at end of year	$(1,130,847)	$(3,397,326)
Amounts recognized in the balance sheet:		
Noncurrent assets	$ 5,064,423	$ 4,174,266
Noncurrent liabilities	(6,195,270)	(7,571,592)
	$(1,130,847)	$(3,397,326)
Amounts recognized in accumulated other comprehensive income:		
Net loss (gain)	$ 5,166,203	$ 8,320,585
Net periodic benefit cost:		
Service cost	$ 1,005,252	$ 126,512
Interest cost	205,064	94,646
Expected return on plan assets	(189,871)	(102,699)
Amortization of net (gain) loss	821,219	220,232
Settlement expense	3,046,239	-
Net periodic benefit cost	$ 4,887,903	$ 338,691
Assumptions used:		
Discount rate	1.45%	3.15%
Rate of compensation increase	4.00%	4.00%
Expected return on plan assets	6.10%	6.00%
Contributions and benefits:		
Employer contributions	$ 4,000,000	$ 2,500,000
Benefits paid	367,127	360,107
Expected benefit payments:		
2020	N/A	2,123,262
2021	2,372,002	1,361,053
2022	865,713	1,265,007
2023	441,078	682,264
2024	604,433	730,881
2025-2029	N/A	4,407,968
2025	642,085	N/A
2026-2030	5,336,798	N/A
Expected contributions	$ -	$ -

The investment strategy for Pension Plan A is to 1) have the ability to pay all benefits and expense obligations when due, 2) maintain a "funding cushion" for unexpected developments and for possible future increases in benefit structure and expense levels and 3) meet a 6.0% return target for the aggregate portfolio, over a full market and economic cycle, while minimizing risk and volatility. The expected return is based on historical returns. The asset classes are 1) US Equity Large Cap Growth: Target – 25.0%, 2) US Equity Large Cap Value: Target – 25.0%, 3) International Equity Growth and Value: Target – 20.0% and 4) Fixed Income: Target – 30.0%. Allowable investments include individual domestic equities, mutual funds, private placements and pooled asset portfolios (e.g. money market funds). Stock options, short sales, letter stocks, Real Estate Investment Trust securities and commodities are not allowable investments.

Plan assets at December 31 were:

	2020	2019
Equity securities:		
Large cap growth	22.13%	18.30%
Large cap value	22.50%	18.24%
International growth	9.21%	7.28%
International core	9.04%	7.27%
Fixed income	37.12%	48.91%
Total	100.00%	100.00%

NOTE 12 – POSTRETIREMENT HEALTH INSURANCE OBLIGATION

Minnkota sponsors a defined benefit postretirement health care plan that covers certain full-time employees. The plan pays varying percentages of health care premiums for retirees from age 60 to age 65. Upon reaching 60, all Center Union participants hired before February 1, 2014, are immediately eligible to receive a 50% premium payment. Upon reaching age 60, only Grand Forks Union participants hired before April 1, 2010, and 50 years of age before April 1, 2013, are immediately eligible to receive a 100% premium payment. Grand Forks Union participants hired before April 1, 2010, and less than 50 years of age at April 1, 2013, will receive a 50% premium payment upon reaching age 60. Upon reaching age 60 and completing 10 years of service, Non-Union participants hired before January 1, 2012, are eligible to receive a 50% premium payment.

Minnkota does not fund this plan. There are no plan assets.

The following table reconciles the plan's funded status to the accrued postretirement health care cost liability as reflected on the balance sheet as of December 31:

	2020	2019
Change in benefit obligation:		
Benefit obligation, beginning	$ 4,478,784	$ 4,215,886
Service cost	175,191	153,484
Interest cost	146,599	187,607
Actuarial (gain) loss	64,206	(78,193)
Benefit obligation, ending	$ 4,864,780	$ 4,478,784
Accrued postretirement health care cost liability	$ 4,864,780	$ 4,478,784
Amounts recognized in the balance sheet:		
Noncurrent liabilities	$ 4,864,780	$ 4,478,784
Net periodic benefit cost:		
Service cost	$ 175,191	$ 153,484
Interest cost	146,599	187,607
Amortization of net (gain) loss	64,206	(78,193)
Net periodic benefit costs (income)	$ 385,996	$ 262,898

For measurement purposes, a 10% annual rate increase in health care premiums was assumed for 2020 and 2019, declining to 5% in five years. The weighted-average discount rate used in determining the accumulated postretirement benefit obligation was 1.45% for 2020 and 3.15% for 2019, respectively.

Benefits paid in 2020 totaled $423,145 and in 2019 totaled $427,484. Benefits expected to be paid in each of the next five years and the aggregate for the next five years thereafter are as follows:

Years Ending December 31,	Amount
2021	$507,677
2022	422,358
2023	361,197
2024	301,931
2025	204,181
2026-2030	769,737

Changing the rate of assumed health care costs by a 1% increase or decrease would change the benefit obligation as of December 31, 2020 and 2019, by approximately $510,550 and $373,805, respectively.

Minnkota has elected to recognize any gains or losses immediately.

NOTE 13 – DEFERRED CREDITS

During the year ended December 31, 2011, the Cooperative implemented a revenue deferral plan. This plan was amended in 2017. Under the plan, the Cooperative may defer revenue to achieve a targeted annual margin between 2.0% and 3.0% of the Cooperative's total cost of service. This plan complies with GAAP and has been approved by RUS. The amount of revenue deferred was $27,759,870 and $39,884,770 as of December 31, 2020 and 2019, respectively. The Cooperative implemented a new plan in 2020 to recognize the remaining $27,759,870 through 2022. RUS requires the Cooperative to segregate cash in an amount equal to the amount of revenue being deferred. The Cooperative had deposits in US Bank investments at December 31, 2020 and 2019, to satisfy this requirement.

Customer construction prepayments are the funds received for construction of transmission related projects in excess of completed construction costs as of December 31, 2020 and 2019.

Deferred credit balances are summarized below:

	2020	2019
Deferred revenues	$ 27,759,870	$39,884,770
Customer construction prepayments	565,015	662,910
Transmission service advance payments	6,972,141	6,823,919
Other deferred credits	100,780	100,780
Total deferred credits	$ 35,397,806	$47,472,379

NOTE 14 – OPERATING LEASE

Minnkota had operating leases for 10 diesel generators and related environmental equipment. The original generator lease began in April 2003 and has been renewed several times. The lease for environmental equipment began in December 2014. The leases ended in 2019.

Minnkota has entered into a Heating Demand Waiver Generation Agreement with Cass County Electric Cooperative, Inc. (Cass). Under the terms of this agreement, Cass is obligated to pay all rent under these leases, as well as all other operating and maintenance expenses related to the diesel generators.

NOTE 15 – ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS

The FASB has issued guidance which provides accounting requirements for retirement obligations associated with tangible long-lived assets. Retirement obligations associated with long-lived assets are those for which there is a legal obligation to settle under existing or enacted law, statute, ordinance, written or oral contract or by legal constructions under the doctrine of promissory estoppels.

Assets considered for potential asset retirement obligations include generating plants and transmission assets on property under easement agreement or license. Asset retirement obligations for generating plant are not recorded as a liability, due to the fact that governmental authorization for construction did not impose post-closure obligations.

In general, retirement actions for transmission assets are required only upon abandonment or cessation of use of the property for the specified purpose. The liability for transmission assets that fall into this category is not estimable because Minnkota intends to utilize these properties indefinitely. For those transmission assets for which there are post-closure obligations (e.g., licenses, permits, and easements of limited duration issued by governmental authorities), the costs do not appear to be material and no liability has been recognized.

Under the current power supply agreement with Square Butte, Minnkota will be obligated for its proportionate share of any of Square Butte's closure obligations. According to the power supply agreement, payment of these obligations is not due until the actual costs of closure are incurred. During the years ended December 31, 2020 and 2019, Minnkota recognized expenses of $327,704 and $832,882, respectively, which were related to the closure cost obligations of Square Butte. A long-term liability of $2,448,884 and $2,121,180 has been recorded as of December 31, 2020 and 2019, respectively.

NOTE 16 – GUARANTEES

Minnkota has provided to the North Dakota Department of Environmental Quality a corporate guarantee on behalf of Northern up to a maximum of $719,221. The guarantee is for closure and post-closure costs relating to solid waste facilities of Northern. Minnkota is bound by the guarantee for as long as Northern must comply with the applicable financial assurance requirements for the solid waste facilities. The guarantee may be terminated upon 120 days notice. Minnkota entered into the guarantee because it was more economical than other financial assurance mechanisms such as reserve accounts, trust funds, surety bonds, letters of credit or insurance. If Northern fails to perform closure and/or post-closure of the solid waste facilities in accordance with plans, permits or other interim status requirements, Minnkota would be required to do so or to establish a trust fund in the amount of the current closure or post-closure cost estimates.

NOTE 17 – COMMITMENTS AND CONTINGENCIES

Minnkota's power plant utilizes North Dakota lignite coal, which is being supplied from the Center Mine by BNI Coal Ltd. Minnkota and BNI Coal Ltd. have a cost-plus contract, which expires in 2037, with an additional 5-year extension at Minnkota's option.

Minnkota has various long-term contracts for the purchase of wind energy. These contracts require Minnkota to purchase all of the output generated by these wind farms for the term of the contracts which expire between 2039 and 2051.

Minnkota participates in federal grant programs, which are governed by various rules and regulations of the grantor agency. Costs charged to the respective grant programs are subject to audit and adjustment by the grantor agency; therefore, to the extent that the Cooperative has not complied with the rules and regulations governing the grants, refunds of any money received may be required.

As of the date December 31, 2020, Minnkota has approximately 50% of its employees covered by collective bargaining agreements. The collective bargaining agreements for Locals 1593 and 1426 are in force through March 31, 2022, and December 31, 2020, respectively.

NOTE 18 – SUBSEQUENT EVENTS

No significant events occurred subsequent to Minnkota's year end. Subsequent events have been evaluated through February 17, 2021, which is the date these financial statements were available to be issued.

Associated Cooperative Statistics

	Beltrami	Cass	Cavalier	Clearwater-Polk	Nodak
Balance Sheet					
Total electric plant	$154,172,460	$296,818,430	$21,662,942	$29,081,193	$169,011,326
Accumulated depreciation	49,055,475	74,490,317	8,400,446	10,585,052	65,637,035
Net electric plant	$105,116,985	$222,328,113	$13,262,496	$18,496,141	$103,374,291
Current and accrued assets	14,653,171	46,272,255	2,350,843	1,384,271	27,006,368
Other assets	10,869,433	20,561,054	1,331,864	1,758,271	12,458,017
Total assets	$130,639,589	$289,161,422	$16,945,203	$21,638,683	$142,838,676
Total equity	$ 47,743,526	$126,085,669	$ 7,103,794	$ 11,812,935	$ 55,573,161
Long-term debt	73,117,251	132,239,289	9,202,676	8,035,221	69,920,612
Other liabilities and credits	9,778,812	30,836,464	638,733	1,790,527	17,344,903
Total liabilities and equity	$130,639,589	$289,161,422	$16,945,203	$21,638,683	$142,838,676
Operations					
Operating revenue	$ 55,937,215	$137,051,334	$ 5,565,974	$ 9,700,653	$102,119,330
Purchased power	37,712,304	101,711,502	2,986,051	6,209,953	83,243,014
Other operating expenses	8,949,245	16,271,823	1,236,267	2,145,111	9,229,905
Depreciation	4,146,050	8,063,313	521,907	778,128	4,492,760
Interest	2,843,336	4,590,972	241,308	313,270	2,222,005
Total cost of electric service	$ 53,650,935	$130,637,610	$ 4,985,533	$ 9,446,462	$ 99,187,684
Operating margin	$ 2,286,280	$ 6,413,724	$ 580,441	$ 254,191	$ 2,931,646
Nonoperating margin	1,373,003	3,443,200	(40,643)	215,493	2,103,749
Total margin	$ 3,659,283	$ 9,856,924	$ 539,798	$ 469,684	$ 5,035,395
Consumers – End of Year					
Residential	20,062	46,933	1,189	4,184	19,989
Residential – seasonal	0	0	0	0	0
Commercial and other	1,579	6,488	314	260	516
Total	21,641	53,421	1,503	4,444	20,505
Increase (decrease) – percent	1.2%	2.6%	-5.8%	1.4%	1.1%
Energy Sales – kWh					
Residential	287,060,736	615,620,376	14,595,125	60,612,312	390,637,948
Residential – seasonal	0	0	0	0	0
Commercial and other	190,710,309	640,940,727	20,550,158	10,792,530	678,799,895
Total	477,771,045	1,256,561,103	35,145,283	71,404,842	1,069,437,843
Increase (decrease) – percent	-3.0%	-2.4%	-1.8%	-3.2%	-5.2%
Miscellaneous					
kWh consumption/resident/month	1,192	1,093	1,023	1,207	1,629
Miles of line	3,537	5,748	1,375	1,510	8,095
Consumers/miles of line	6.12	9.29	1.09	2.94	2.53
Number of employees	61	93	11	15	65
Average rate – residential – (¢/kWh)	13.94	11.74	17.65	13.62	11.75

North Star	PKM	Red Lake	Red River	Roseau	Wild Rice	Total
$48,545,287	$38,101,441	$44,781,036	$52,734,641	$60,554,798	$82,390,243	$997,853,797
17,329,548	14,616,654	19,857,921	16,432,515	30,718,682	27,211,956	334,335,601
$31,215,739	$23,484,787	$24,923,115	$36,302,126	$29,836,116	$55,178,287	$663,518,196
6,976,449	6,839,601	3,548,985	3,741,640	6,104,760	8,768,857	127,647,200
1,664,449	2,465,513	1,801,026	1,993,435	3,283,451	4,330,688	62,517,201
$39,856,637	$32,789,901	$30,273,126	$42,037,201	$39,224,327	$68,277,832	$853,682,597
$15,064,648	$17,330,728	$11,680,070	$17,915,087	$19,688,014	$29,019,612	$359,017,244
21,769,569	13,476,660	15,802,822	20,989,189	16,791,623	34,893,669	416,238,581
3,022,420	1,982,513	2,790,234	3,132,925	2,744,690	4,364,551	78,426,772
$39,856,637	$32,789,901	$30,273,126	$42,037,201	$39,224,327	$68,277,832	$853,682,597
$15,187,703	$14,675,809	$14,867,305	$15,388,122	$19,160,895	$33,205,414	$422,859,754
8,763,420	9,599,253	10,310,114	9,980,606	11,445,320	22,063,271	304,024,808
3,882,207	2,721,524	2,496,459	2,847,626	3,659,875	6,497,997	59,938,039
1,249,865	981,658	1,266,779	1,233,001	1,962,464	2,218,553	26,914,478
675,582	591,326	400,475	794,353	726,446	1,174,458	14,573,531
$14,571,074	$13,893,761	$14,473,827	$14,855,586	$17,794,105	$31,954,279	$405,450,856
$ 616,629	$ 782,048	$ 393,478	$ 532,536	$ 1,366,790	$ 1,251,135	$ 17,408,898
102,364	86,009	48,919	428,001	279,004	214,683	8,253,782
$ 718,993	$ 868,057	$ 442,397	$ 960,537	$ 1,645,794	$ 1,465,818	$ 25,662,680
5,348	3,660	5,198	4,050	5,853	13,586	130,052
613	0	0	0	429	0	1,042
737	272	488	653	308	861	12,476
6,698	3,932	5,686	4,703	6,590	14,447	143,570
1.3%	1.2%	0.9%	0.5%	0.5%	0.4%	1.5%
68,901,367	67,447,486	92,872,160	81,939,006	91,793,349	207,819,552	1,979,299,417
1,158,686	0	0	0	7,405,731	0	8,564,417
36,350,071	50,744,739	28,679,620	36,829,132	50,572,926	54,536,081	1,799,506,188
106,410,124	118,192,225	121,551,780	118,768,138	149,772,006	262,355,633	3,787,370,022
-4.3%	-4.1%	-5.2%	-4.4%	-2.3%	-3.6%	-3.6%
1,074	1,536	1,489	1,686	1,307	4,014	1,268
1,452	2,284	2,637	1,808	2,175	3,997	34,618
4.61	1.72	2.16	2.60	3.03	3.61	4.15
21	17	19	21	27	42	392
14.54	13.67	12.42	12.90	14.41	13.01	12.66

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Alan Brunner	Director of Operations

Operating Statistics

	2020	2019	2018	2017	2016
Electric plant investment	$ 1,326,860,475	$ 1,291,330,709	$ 1,252,290,053	$ 1,217,284,986	$ 1,166,677,001
Accumulated depreciation	(341,046,926)	(312,356,834)	(287,587,483)	(269,842,873)	(244,518,068)
Net electric plant	$ 985,813,549	$ 978,973,875	$ 964,702,570	$ 947,442,113	$ 922,158,933
Total assets	$ 1,139,298,514	$ 1,124,833,308	$ 1,060,797,950	$ 1,039,451,568	$ 1,017,654,497
Long-term debt	$ 841,453,348	$ 832,046,269	$ 777,323,355	$ 775,582,909	$ 772,842,453
Members' equity	$ 167,592,067	$ 156,767,393	$ 150,196,807	$ 139,893,680	$ 130,156,542
Equity – percent of assets	14.7	13.9	14.2	13.5	12.8
Total revenues	$ 391,183,488	$ 402,196,354	$ 414,061,515	$ 395,642,680	$ 378,425,640
Total expenses	383,513,196	390,482,354	403,962,515	385,992,680	369,195,640
Net margin	$ 7,670,292	$ 11,714,000	$ 10,099,000	$ 9,650,000	$ 9,230,000
Energy sales – MWh					
Class A member co-ops	3,962,855	4,107,770	4,114,194	3,926,016	3,813,970
Other utilities	2,851,123	2,563,245	2,925,749	3,514,078	2,488,220
Total	6,813,978	6,671,015	7,039,943	7,440,094	6,302,190
Energy sources – MWh					
Net generation	4,739,829	4,692,432	5,064,942	5,360,722	4,572,767
Coyote retained by NMPA	(440,546)	(446,011)	(452,702)	(442,681)	(448,447)
Purchases	2,514,695	2,424,594	2,427,703	2,522,053	2,177,870
Total	6,813,978	6,671,015	7,039,943	7,440,094	6,302,190
Connected consumers – December	143,570	141,493	138,188	136,447	134,755
Class A member sales Increase (decrease) – percent	(3.5)	(0.2)	4.8	2.9	(0.8)
Average power rate to Class A members – mills/kWh	76.3	76.4	75.8	76.0	74.6
Miles of transmission line	3,372	3,350	3,350	3,348	3,340
Full-time employees	400	397	386	381	388

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President & CEO

Lowell Stave
Vice President & Chief Operating Officer

Gerad Paul
General Counsel
Vice President – Legal, Compliance & Risk

Kay Schraeder
Vice President & Chief Financial Officer

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APPENDIX I – UNANTICIPATED DISCOVERIES PLAN

Unanticipated Discoveries Plan

North Dakota CarbonSAFE: Project Tundra
Oliver County, North Dakota

Prepared for
Minnkota Power Cooperative, Inc.

June 2023

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Minneapolis, MN 55435
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Unanticipated Discoveries Plan

Tundra Pipeline Project

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Abbreviations

APE	Area of Potential Effects
MPC	Minnkota Power Cooperative, Inc.
NDCC	North Dakota Century Code
NHPA	National Historic Preservation Act
NRHP	National Register of Historic Places
Project	North Dakota CarbonSAFE: Project Tundra
SHPO	State Historic Preservation Officer
UDP	Unanticipated Discoveries Plan

1 Introduction

This Unanticipated Discoveries Plan (UDP) provides the procedures that Minnkota Power Cooperative, Inc. (MPC) will implement in the event cultural resources and/or human remains are identified during construction of the Tundra Pipeline Project (Project).

Unanticipated discoveries typically occur when previously undetected cultural resources are exposed during construction or other permitted surface disturbing activities, but after the federal agency has completed the Section 106 process.

The purpose of this UDP is to properly identify and protect any cultural resource materials such as artifacts, sites, human skeletal remains, or any other cultural resources eligible, or potentially eligible, for listing in the National Register of Historic Places (NRHP) that are discovered during construction of the Project. This UDP provides guidance to MPC and their contractors so they can:

- Comply with any applicable federal and state laws regarding cultural resources;
- Describe to regulatory agencies, review agencies, and Tribal Historic Preservation Offices (THPOs) the procedures MPC will follow to prepare for and deal with unanticipated discoveries; and
- Provide direction and guidance to Project personnel for the proper procedures to be followed should an unanticipated discovery occur.

2 Roles and Responsibilities

The following roles and responsibilities have been defined for this UDP.

- **MPC Environmental Specialist**: MPC Representative. Responsible for Notifying the State Historic Preservation Office (SHPO) in the event of an accidental discovery.
- **State Historic Preservation Officer (SHPO)**: State-appointed official responsible for consulting with Federal, State, and local governments in matters of historic preservation and NRHP eligibility pursuant to Section 106 of the NHPA.
- **SHPO-permitted Archaeological Consultant**: Qualified archaeologist as defined in 36 CFR Part 61 and in receipt of the Annual Archaeological Permit required by North Dakota Century Code (NDCC) section 55-03-01.
- **Archaeological Monitor**: SHPO-permitted Archaeological Consultant on-site during construction to monitor ground disturbing activities for the presence of cultural resources. Has authority to stop construction to further investigate potential resources.
- **Supervisor**: Supervisory construction personnel. Responsible for ensuring that any unanticipated discoveries are promptly reported to the MPC Environmental Specialist and further disturbance halts as required in this plan. Supervisors are also responsible for confirming that workers under their direction are familiar with and adhere to the requirements of this plan.

3 Protocol for the Unanticipated Discovery of Cultural Resources

Cultural resources typically consist of archaeological and historic architectural resources. Archaeological resources are defined as any site location that contains material remains of past human life or activities, or other places and/or items that possess cultural importance to individuals or a group. They are typically identified on the surface or below ground. Historic architectural resources include "buildings, bridges, tunnels, statues, and other structures that create tangible links to the American past, whether in relation to historical events and people, traditional ways of life, architectural design, or methods of construction"[1]. Historic architectural resources are above ground resources.

3.1 Recognizing Cultural Resources

A cultural resource discovery could be precontact (i.e., from a time period that predates Native American contact with Europeans) or historic in nature. Examples include, but are not limited to:

- An accumulation of shell, burned rocks, or other food-related materials.
- Bones, intact or in small pieces and burned or unburned.
- An area of charcoal or very darkly stained soil, with or without artifacts.
- Stone tools or waste flakes (for example, an arrowhead or stone chips), or precontact ceramics.
- Modified natural features, such as rock drawings.
- Agricultural or industrial materials that appear older than 50 years. These could include equipment, fencing, canals, derelict buildings, tools, and many other items.
- Clusters of tin cans, bottles, or other debris that appear older than 50 years.
- Old munitions casings. **Always assume these are live and never touch or move**.
- Railroad tracks, decking, foundations, or other industrial materials.
- Foundation remnants, cisterns, and wells.
- Remnants of homesteading. These could include bricks, nails, household items, toys, food containers, and other items associated with homes or farming sites.

The above list does not cover every possible cultural resource. When in doubt, assume the material is a cultural resource. Example photographs of cultural resources that could be encountered during the Project are included in Attachment 1.

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[1] https://www.nps.gov/orgs/1027/architecture.htm

3.2 Protocol

If an archaeological monitor, employee, contractor, or subcontractor believes that they have uncovered cultural resources or human remains at any point in the Project, take the following steps to **Stop-Notify-Protect**. If you suspect that the discovery includes **human remains**, follow the protocol outlined in **Section 4**. A flow chart with additional information regarding the procedures to be followed in the event that cultural resources are inadvertently discovered is included in Attachment 2.

STEP 1: Stop Work

All work must stop within the immediate vicinity, defined as within 100 feet of the discovery.

STEP 2: Notify the Appropriate Personnel

Either the Archaeological Monitor (if present) or the Supervisor will notify the MPC Environmental Specialist of the accidental discovery. The MPC Environmental Specialist then has 48 hours to notify the SHPO and THPOs by email or telephone.

During the discovery, the Supervisor in charge is responsible for informing persons in the area who are associated with the Project that they will be subject to prosecution for knowingly disturbing historic or archaeological sites or collecting artifacts.

STEP 3: Protect the Discovery

Leave the discovery and the surrounding area untouched and create a clear, identifiable, and wide boundary of 100 feet or larger with temporary fencing, flagging, stakes, or other clear markings. Provide protection of the discovery until cleared by the MPC Environmental Specialist.

Do not permit vehicles, equipment, or unauthorized personnel to traverse the discovery site. Do not allow work to resume within the boundary until clearance is received from the MPC Environmental Specialist.

STEP 4: Archaeological Investigation

The SHPO-permitted archaeological consultant or Archaeological Monitor will determine if the discovery is cultural and, if so, record and evaluate the discovery and make a recommendation of eligibility and effect. The archaeological investigation and evaluation will follow North Dakota SHPO standards.

STEP 5: Clearance

Following the appropriate archaeological investigation and eligibility determination for the cultural resource(s), the SHPO will issue a written letter of concurrence and construction will be allowed to resume in the area of the discovery. Work may not resume within the 100-foot buffer until SHPO concurrence and the the Supervisor in charge has received authorization to proceed from the MPC Environmental Specialist.

3.3 Points of Contact, Unanticipated Discovery of Cultural Resources

The following points of contact have been identified for the Project in the event that cultural resources are discovered.

Table 3-1 Points of Contact, Unanticipated Discovery of Cultural Resources

Position	Name	Phone Number
MPC Environmental Specialist	Samantha Roberts	(701) 795-4289
SHPO	Andrew Robinson	(701) 328-3575
SHPO-permitted Archaeological Consultant	John Morrison	(701) 400-3575
Archaeological Monitor	Pending	
Supervisor	Pending	
Chairman, Apache Tribe of Oklahoma	Durell Cooper or Bobby Komardley	(405) 247-9493
THPO, Fort Belknap Indian Community of the Fort Belknap Reservation of Montana	Michael Blackwolf	(406) 353-2295
THPO, Three Affiliated Tribes of the Forth Berthold Reservation, North Dakota	Allan Demaray	(701) 421-6640

4 Protocol for the Unanticipated Discovery of Human Remains

Any human remains or suspected human remains, regardless of antiquity or ethnic origin, will always be treated with dignity and respect. Human remains or suspected human remains may be associated with any of the following: funerary objects, sacred objects, or objects of cultural patrimony. Follow these steps to **Stop-Notify-Protect**. A flow chart with additional information regarding the procedures to be followed in the event that human remains are inadvertently discovered is included in Attachment 3.

STEP 1: Stop Work

All work must stop within the immediate vicinity, defined as within **300 feet** of the discovery. It is very important for law enforcement personnel and the SHPO or North Dakota Department of Health to examine the location as it was found.

STEP 2: Notify the Appropriate Personnel

Notify the Supervisor and Archaeological Monitor (if present) of the accidental discovery and suspected human remains. In turn, the Supervisor will **immediately** notify the MPC Environmental Specialist by telephone with follow-up written confirmation. The MPC Environmental Specialist will contact and coordinate with the appropriate Law Enforcement Agency and the SHPO. The SHPO will notify the North Dakota Department of Health.

During the time of the discovery, the Supervisor in charge is responsible for informing persons in the area who are associated with the Project that they will be subject to prosecution for knowingly disturbing human remains or collecting artifacts.

STEP 3: Protect the Discovery

Leave the discovery and the surrounding area untouched and create a clear, identifiable, and wide boundary of **300 feet** or larger with temporary fencing, flagging, stakes, or other clear markings. Provide protection of the discovery until cleared by the MPC Environmental Specialist.

Cover the remains with a tarp or other materials (not soil or rocks) for temporary protection and shield them from being photographed by others or disturbed.

Do not permit vehicles, equipment, or unauthorized personnel to traverse the discovery site or 300-foot buffer area. Do not allow work to resume within this boundary until clearance is received from the MPC Environmental Specialist.

DO NOT speak with the media, allow photography or disturbance of the remains, or release any information about the discovery on social media.

STEP 4: Investigation of Human Remains

If the Law Enforcement Agency determines the human remains are not part of a crime scene, the SHPO will determine if the human remains are Native American in origin. If it is determined that the human remains are not Native American and the remains cannot be avoided by Project activities, the SHPO-permitted Archaeological Consultant will proceed in a similar manner to the Unanticipated Discovery procedures listed in Step 4, Section 3.2 above. If it is determined that the human remains are Native American, or if the discovery includes funerary objects, sacred objects, or objects of cultural patrimony, the SHPO will notify the North Dakota Intertribal Reinterment Committee and consultation with tribes will need to occur regarding avoidance or disinterment.

STEP 5: Clearance

Construction activities will not be allowed to resume within 300 feet of the discovery until the MPC Environmental Specialist provides authorization.

4.1 Points of Contact, Unanticipated Discovery of Human Remains

The following points of contact have been identified for the Project in the event that human remains are discovered.

Table 4-1 Points of Contact, Unanticipated Discovery of Human Remains

Position	Name	Phone Number
MPC Environmental Specialist	Samantha Roberts	(701) 795-4289
SHPO	Andrew Robinson	(701) 328-3575
SHPO-permitted Archaeological Consultant	John Morrison	(701) 400-3575
Archaeological Monitor	Pending	
Supervisor	Pending	
Local Law Enforcement	Center Police Department	(701) 794-3591
County Law Enforcement	Oliver County Sheriff	(701) 794-3450 (office)
County Coroner/Medical Examiner	Thomas Kaspari	(701) 873-4445
Chairman, Apache Tribe of Oklahoma	Durell Cooper or Bobby Komardley	(405) 247-9493
THPO, Fort Belknap Indian Community of the Fort Belknap Reservation of Montana	Michael Blackwolf	(406) 353-2295
THPO, Three Affiliated Tribes of the Forth Berthold Reservation, North Dakota	Allan Demaray	(701) 421-6640

Attachment 1

Example Cultural Resources

Photographs

Stone Tool

Stone Tool and Waste Flakes

Precontact Ceramics

Precontact Ceramics

Darkly Stained Soil; Accumulation of Burned Rocks

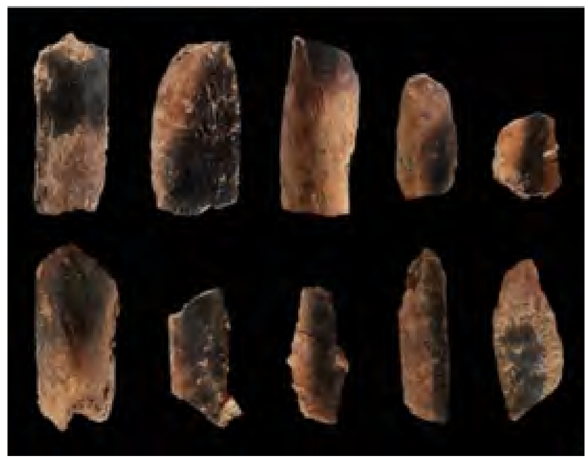
Stone Circle[2]

[2] Ed Horner, Fratermanor (https://commons.wikimedia.org/wiki/File:Teepee_rings.jpg), https://creativecommons.org/licenses/by-sa/4.0/legalcode


Derelict Building


Agricultural/Industrial Tool


Cluster of Historic Cans and Bottles


Burned and Unburned Bone[3]


Foundation Remnant

[3]Ruth Blasco (https://commons.wikimedia.org/wiki/File:Qesem_Cave_burned_animal_bones.jpg), https://creativecommons.org/licenses/by/4.0/legalcode

Foundation Remnant

Remnant Well

Homesteading Remnants (Historic Artifacts)

Homesteading Remnants (Historic Artifacts)

Abandoned Historic Vehicle[4]

[4] Jim Choate (https://www.flickr.com/photos/jimchoate/51532927587), https://creativecommons.org/licenses/by-nc/2.0/legalcode

Attachment 2

Flow Chart for Unanticipated Discoveries

Cultural Resources

Accidental Discovery Occurs
Halt all work within 100 ft radius (Stop Work Order)
Notify the MPC Environmental Specialist
Flag off the avoidance area
Within 24 hours, the SHPO-permitted archaeological consultant will examine the discovery and determine if a cultural resource has been identified
The SHPO-permitted archaeological consultant determines the discovery is NOT a cultural resource
The SHPO-permitted archaeologist notifies the MPC Environmental Specialist
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume
The SHPO-permitted archaeological consultant determines the discovery IS a cultural resource
The SHPO-permitted archaeologist notifies the MPC Environmental Specialist
The MPC Environmental Specialist notifies the SHPO within 24 hours of the determination
The SHPO-permitted archaeological consultant finds the resource to be NOT SIGNIFICANT
The SHPO-permitted archaeological consultant prepares a written summary of findings
MPC Environmental Specialist submits findings to SHPO for permission for construction to recommence
SHPO permission received
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume
SHPO permission NOT received
Additional consultation occurs between the MPC Environmental Specialist, the SHPO-permitted archaeological consultant, and the SHPO
The SHPO-permitted archaeo-logical consultant finds the resource MAY BE SIGNIFICANT
Scope-of-work for evaluating the significance of the resource and potential project effects on the resource (Evaluation Plan) prepared and submitted to the SHPO
Evaluation Plan approved by the SHPO
Additional archaeological testing com-pleted pursuant to the Evaluation Plan
Resource determined to be SIGNIFICANT
Finding Report and Treatment Plan prepared and submitted to the SHPO
SHPO agrees with the Findings and Treatment Plan
SHPO does not agree with the Findings and/or Treatment Plan
Additional consultation occurs between the MPC Environmental Specialist, the SHPO-permitted archaeological consultant, and the SHPO
Treatment measures completed
Treatment Report prepared and submitted to SHPO
SHPO approves Treatment Report
SHPO does not approve Treatment Report
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Additional consultation occurs between the MPC Environmental Specialist, the SHPO-permitted archaeological consultant, and the SHPO
Construction activities can resume

Attachment 3

Flow Chart for Unanticipated Discoveries

Human Remains


Accidental Discovery Occurs
Discovery determined to be human remains
Halt all work within 300 ft radius (Stop Work Order)
Notify the MPC Environmental Specialist
Flag off the avoidance area
MPC Environmental Specialist will notify the appropriate law enforcement agency and SHPO
The human remains are forensic in nature
Law enforcement coordinates with the Supervisor and the MPC Environmental Specialist regarding removal of the remains
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume
The human remains are archaeological in nature
The human remains can be avoided by Project activities
SHPO notifies the North Dakota Intertribal Reinterment Committee (if remains are precontact)
The SHPO-permitted archaeological consultant prepares a Finding Report and Avoidance Plan for submittal to SHPO
SHPO approves the Report and Avoidance Plan
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume
The human remains cannot be avoided by Project activities
Historic Burial
Consultation occurs between the SHPO, the SHPO-permitted archaeological consultant and MPC to determine disinterment methodology and reinterment location
The SHPO-permitted archaeological consultant prepares a Disinterment Plan for submittal to SHPO
Disinterment Plan approved
Disinterment occurs
The SHPO-permitted archaeological consultant prepares a Finding Report and for submittal to SHPO
SHPO approves the Report
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume
Precontact Burial
SHPO notifies the North Dakota Intertribal Reinterment Committee
Consultation occurs between the SHPO, the North Dakota Intertribal Reinterment Committee, Native American tribes, the SHPO-permitted archaeological consultant and MPC to determine disinterment methodology and reinterment location
The SHPO-permitted archaeological consultant prepares a Disinterment Plan for submittal to SHPO and tribes
Disinterment Plan approved
Disinterment occurs
The SHPO-permitted archaeological consultant prepares a Finding Report and for submittal to SHPO and tribes
SHPO and tribes approve the Report
MPC Environmental Specialist notifies the Supervisor that the Stop Work Order is lifted
Construction activities can resume

APPENDIX J – AIR PERMIT TO CONSTRUCT, AIR QUALITY EMISSIONS ANALYSIS, AND AIR QUALITY IMPACT ANALYSIS

December 29, 2023

Mr. Robert McLennan
President and CEO
DCC East Project LLC
5301 32nd Avenue South
Grand Forks, ND 58201

Re: Air Pollution Control
Permit to Construct No. ACP-18194 v1.0

Dear Mr. McLennan,

Pursuant to the Air Pollution Control Rules of the State of North Dakota, the Department of Environmental Quality (Department) has completed its final review of your permit application dated June 2, 2023, to obtain a Permit to Construct for initial construction and operation of the Dakota Carbon Center CO2 Separation and Purification Plant to be located in Oliver County, North Dakota.

Based on the results of the documents reviewed, the Department hereby issues the enclosed North Dakota Air Pollution Control Permit to Construct No. ACP-18194 v1.0. A public comment period was held regarding this project from September 21, 2023, through October 21, 2023. Comments were received from three parties which consisted of two individual commentors and Region 8 of the Environmental Protection Agency. This information is included in Appendix A – Public Record. The Department provided written response to each applicable comment, also included in Appendix A. The Department made logical-outgrowth changes from the draft Permit to Construct and Air Quality Effects Analysis that do not depart from the terms or substance of the proposed action. Therefore, the Department hereby issues the final permit to construct for the project.

Please notify the Department within 15 days after completing the project to allow for an inspection by the Department.

Note that the above-referenced permit addresses only air quality requirements applicable to your facility. Other divisions (Water Quality, Waste Management and Municipal Facilities) within the Department of Environmental Quality may have additional requirements. Contact information for the various divisions is listed at the bottom of this letter.

If you have any questions regarding air quality, please contact me at (701)328-5229 or destroh@nd.gov.

Sincerely,

David Stroh

David Stroh
Manager, Permit Program
Division of Air Quality

DS:
Enc:
xc: Adam Eisele, EPA Region 8 (email - eisele.adam@epa.gov)

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AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT

Pursuant to Chapter 23.1-06 of the North Dakota Century Code, and the Air Pollution Control Rules of the State of North Dakota (Article 33.1-15 of the North Dakota Administrative Code), and in reliance on statements and representations heretofore made by the owner designated below, a Permit to Construct is hereby issued authorizing such owner to construct and initially operate the source unit(s) at the location designated below. This Permit to Construct is subject to all applicable rules and orders now or hereafter in effect of the North Dakota Department of Environmental Quality (Department) and to any conditions specified below:

I. **General Information**:

A. **Permit to Construct Number**: ACP-18194 v1.0

B. **Source**:

1. Name: Dakota Carbon Center CO_2 Separation and Purification Plant

2. Location: 3401 24th Street SW
NE ¼ of Section 5, T.141N, R.83W
Lat/Long: 47.0648/-101.2178
Oliver County, ND

3. Source Type: Carbon dioxide (CO_2) separation and purification plant

4. Facility Emission Units:

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment
Carbon dioxide (CO_2) absorber column	D01	D01	N/A [A]
Cooling tower	D02	D02	Drift eliminators
Emergency diesel fire pump engine rated at 460 brake horsepower	D03	D03	None
Haul roads [B]	D04	D04	None
Storage tanks [B]	D05	D05	None
Fugitive components	FUG	FUG	None

[A] Process design and controls (i.e., construction material selection and intermediate cooling). No add-on controls.

[B] Insignificant unit

5. Storage Tanks (Insignificant Units):

Emission Unit Description	**Emission Unit (EU)**
Diesel fire pump storage tank	D05A
Solvent tank	D05B
Solvent sump tank	D05C
Reclaimed waste tank	D05D
Wash water tank	D05E
Dilute wash water tank	D05F
Fresh solvent tank	D05G
Triethylene glycol tank	D05H

C. **Owner/Operator (Permit Applicant)**:

1. Name: DCC East Project LLC

2. Address: 3401 24th Street SW
   Center, ND 58530

3. Application Date: June 2, 2023
   August 25, 2023 (Revised modeling analysis)

II. **Conditions**:
This Permit to Construct allows the construction and initial operation of the above-mentioned new or modified equipment at the source. The source may be operated under this Permit to Construct until a Permit to Operate is issued unless this permit is suspended or revoked. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Environmental Quality and to the conditions specified below.

A. **Emission Limits**: Emission limits from the operation of the new source unit(s) identified in Item I.B of this Permit to Construct (hereafter referred to as "permit") are as follows. Source units not listed are subject to the applicable emission limits specified in the North Dakota Air Pollution Control Rules.

Emission Unit Description	**Emission Unit (EU)**	**Emission Point (EP)**	**Pollutant / Parameter**	**Emission Limit**
Cooling tower	D02	D02	$PM/PM_{10}/PM_{2.5}$	Condition II.E

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Pollutant / Parameter	Emission Limit
Emergency diesel fire pump engine	D03	D03	Various SO_2	NSPS IIII, Table 4 Condition II.B

B. **Fuel Restrictions**: The emergency fire pump engine (EU D03) is restricted to combusting only distillate oil containing no more than 0.0015 percent sulfur by weight.

C. **New Source Performance Standards (NSPS)**: The permittee shall comply with all applicable requirements of the following NSPS subparts, in addition to Subpart A, as referenced in Chapter 33.1-15-12 of the North Dakota Air Pollution Control Rules and 40 CFR 60.

1. 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (EU D03).

D. **National Emissions Standards for Hazardous Air Pollutants (NESHAP)**: The permittee shall comply with all applicable requirements of the following NESHAP subparts, in addition to Subpart A, as referenced in Chapter 33.1-15-22 of the North Dakota Air Pollution Control Rules and 40 CFR 63.

1. 40 CFR 63, Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (EU D03).

E. **Cooling tower (EU D02)**: The cooling tower shall be equipped with and operated with mist eliminators that are guaranteed to limit drift to 0.0005% or less of the circulating flow.

F. **Emissions Testing**: All initial testing will require a minimum of 3 runs, one hour each, unless otherwise specified in a federal subpart.

Emission Unit Description	Emission Point (EP)	Contaminant	Method
CO_2 absorber column	D01	Acetaldehyde [A] Formaldehyde [A, B]	Method 320 [C] Method 320 [C]

[A] Acetaldehyde is projected to account for approximately 93% of all HAPs and is expected to be a surrogate for HAPs. Formaldehyde is projected to account for approximately 5%, meaning aldehyde HAPs are projected to account for 98% of all HAPs.

[B] If testing formaldehyde indicates results below Method detection limits, they will be considered insignificant by the Department.

[C] An equivalent reference method approved by the Department may be used.

A signed copy of the test results shall be furnished to the Department within 60 days of the test date. The basis for this condition is NDAC 33.1-15-01-12 which is hereby incorporated into this permit by reference. To facilitate preparing for and conducting such tests, and to facilitate reporting the test results to the Department, the permittee shall follow the procedures and formats in the Department's Emission Testing Guideline[1].

1. Initial Testing: Within 180 days after initial startup, the permittee shall conduct emissions tests at the emission units listed above using an independent testing firm. Emissions testing shall be conducted for the pollutant(s) listed above in accordance with EPA Reference Methods listed in 40 CFR 60, Appendix A and/or 40 CFR 63, Appendix A. Test methods other than those listed above may be used upon approval by the Department.

2. Notification: The permittee shall notify the Department using the form in the Emission Testing Guideline, or its equivalent, at least 30 calendar days in advance of any tests of emissions of air contaminants required by the Department. If the permittee is unable to conduct the performance test on the scheduled date, the permittee shall notify the Department at least five days prior to the scheduled test date and coordinate a new test date with the Department.

3. Sampling Ports/Access: Sampling ports shall be provided downstream of all emission control devices and in a flue, conduit, duct, stack or chimney arranged to conduct emissions to the ambient air.

   The ports shall be located to allow for reliable sampling and shall be adequate for test methods applicable to the facility. Safe sampling platforms and safe access to

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[1] See February 7, 2020, North Dakota Department of Environmental Quality Division of Air Quality Emissions Testing Guidelines. Available at: https://www.deq.nd.gov/publications/AQ/policy/PC/Emission_Testing_Guide.pdf

the platforms shall be provided. Plans and specifications showing the size and location of the ports, platform and utilities shall be submitted to the Department for review and approval.

4. Other Testing:

a) The Department may require the permittee to have tests conducted to determine the emission of air contaminants from any source, whenever the Department has reason to believe that an emission of a contaminant not addressed by the permit applicant is occurring, or the emission of a contaminant in excess of that allowed by this permit is occurring. The Department may specify testing methods to be used in accordance with good professional practice. The Department may observe the testing. All tests shall be conducted by reputable, qualified personnel. A signed copy of the test results shall be furnished to the Department within 60 days of the test date.

All tests shall be made available, and the results calculated in accordance with test procedures approved by the Department. All tests shall be made under the direction of persons qualified by training or experience in the field of air pollution control as approved by the Department.

b) The Department may conduct tests of emissions of air contaminants from any source. Upon request of the Department, the permittee shall provide necessary holes in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices, as may be necessary for proper determination of the emission of air contaminants.

G. **Best Management Practices**: At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

1. Intermediate cooling in the CO_2 absorber column (EU D01) by cooling over the packing shall be always operated when the unit is in operation.

2. Periodic monitoring and recordkeeping demonstrating compliance with the CO_2 absorber column operations in accordance with the original equipment manufacturers specifications and good engineering practices.

3. Recordkeeping that demonstrates compliance with the MACT determination for materials selection in the CO_2 absorber column.

H. **Stack Heights**: Emissions from D01 shall be vented through stacks that meet the following height requirements. Stack heights may be no less than those listed in the table below without prior approval from the Department.

Emission Unit (EU)	Emission Point (EP)	Stack Height (Feet)
Carbon dioxide (CO_2) absorber column	D01	335

I. **Construction**: Construction of the above described facility shall be in accordance with information provided in the permit application as well as any plans, specifications and supporting data submitted to the Department. The Department shall be notified ten days in advance of any significant deviations from the specifications furnished. The issuance of this Permit to Construct may be suspended or revoked if the Department determines that a significant deviation from the plans and specifications furnished has been or is to be made.

Any violation of a condition issued as part of this permit to construct as well as any construction which proceeds in variance with any information submitted in the application, is regarded as a violation of construction authority and is subject to enforcement action.

J. **Startup Notice**: A notification of the actual date of initial startup shall be submitted to the Department within 15 days after the date of initial startup.

K. **Like-Kind Engine Replacement**: This permit allows the permittee to replace an existing engine with a like-kind unit. Replacement is subject to the following conditions:

1. The Department must be notified within 10 days after change-out of the unit.

2. The replacement unit shall operate in the same manner, provide no increase in throughput and have equal or less emissions than the unit it is replacing.

3. The date of manufacture of the replacement unit must be included in the notification. The facility must comply with any applicable federal standards (e.g. NSPS, MACT) triggered by the replacement.

4. The replacement unit is subject to the same state emission limits as the existing unit in addition to any NSPS or MACT emission limit that is applicable. Testing shall be conducted to confirm compliance with the emission limits within 180 days after start-up of the unit.

L. **Organic Compounds Emissions**: The permittee shall comply with all applicable requirements of NDAC 33.1-15-07 – Control of Organic Compounds Emissions.

M. **Permit Invalidation**: This permit shall become invalid if construction is not commenced within eighteen months after issuance of such permit, if construction is discontinued for a period of eighteen months or more; or if construction is not completed within a reasonable time, unless an extension is granted by the Department.

N. **Title V Permit to Operate**: Within one year after startup of the units covered by this Permit to Construct, the permittee shall submit a permit application for a Title V Permit to Operate for the facility.

O. **Fugitive Emissions**: The release of fugitive emissions shall comply with the applicable requirements in NDAC 33.1-15-17.

P. **Annual Emission Inventory/Annual Production Reports**: The permittee shall submit an annual emission inventory report and/or an annual production report upon Department request, on forms supplied or approved by the Department.

Q. **Source Operations**: Operations at the installation shall be in accordance with statements, representations, procedures and supporting data contained in the initial application, and any supplemental information or application(s) submitted thereafter. Any operations not listed in this permit are subject to all applicable North Dakota Air Pollution Control Rules.

R. **Alterations, Modifications or Changes**: Any alteration, repairing, expansion, or change in the method of operation of the source which results in the emission of an additional type or greater amount of air contaminants or which results in an increase in the ambient concentration of any air contaminant, must be reviewed and approved by the Department prior to the start of such alteration, repairing, expansion or change in the method of operation.

S. **Air Pollution from Internal Combustion Engines**: The permittee shall comply with all applicable requirements of NDAC 33.1-15-08-01 – Internal Combustion Engine Emissions Restricted.

T. **Recordkeeping**: The permittee shall maintain any compliance monitoring records required by this permit or applicable requirements. The permittee shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report or application. Support information may include all calibration and maintenance records and all original strip-chart recordings/computer printouts for continuous monitoring instrumentation, and copies of all reports required by the permit.

U. **Nuisance or Danger**: This permit shall in no way authorize the maintenance of a nuisance or a danger to public health or safety.

V. **Malfunction Notification**: The permittee shall notify the Department of any malfunction which can be expected to last longer than twenty-four hours and can cause the emission of air contaminants in violation of applicable rules and regulations.

W. **Operation of Air Pollution Control Equipment**: The permittee shall maintain and operate all air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

X. **Transfer of Permit to Construct**: The holder of a permit to construct may not transfer such permit without prior approval from the Department.

Y. **Right of Entry**: Any duly authorized officer, employee or agent of the North Dakota Department of Environmental Quality may enter and inspect any property, premise or place at which the source listed in Item I.B of this permit is located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules. The Department may conduct tests and take samples of air contaminants, fuel, processing material, and other materials which affect or may affect emissions of air contaminants from any source. The Department shall have the right to access and copy any records required by the Department's rules and to inspect monitoring equipment located on the premises.

Z. **Other Regulations**: The permittee of the source unit(s) described in Item I.B of this permit shall comply with all State and Federal environmental laws and rules. In addition, the permittee shall comply with all local burning, fire, zoning, and other applicable ordinances, codes, rules and regulations.

AA. **Permit Issuance**: This permit is issued in reliance upon the accuracy and completeness of the information set forth in the application. Notwithstanding the tentative nature of this information, the conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has, or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23.1-06.

BB. **Odor Restrictions**: The permittee shall not discharge into the ambient air any objectionable odorous air contaminant which is in excess of the limits established in NDAC 33.1-15-16.

CC. **Sampling and Testing**: The Department may require the permittee to conduct tests to determine the emission rate of air contaminants from the source. The Department may observe the testing and may specify testing methods to be used. A signed copy of the test results shall be furnished to the Department within 60 days of the test date. The basis for this condition is NDAC 33.1-15-01-12 which is hereby incorporated into this permit by reference. To facilitate preparing for and conducting such tests, and to facilitate reporting the test results to the Department, the permittee shall follow the procedures and formats in the Department's Emission Testing Guideline.

FOR THE
NORTH DAKOTA DEPARTMENT
OF ENVIRONMENTAL QUALITY

Date: 12/29/2023 By: James L. Semerad

James L. Semerad
Director
Division of Air Quality

AIR QUALITY EFFECTS ANALYSIS
FOR
PERMIT TO CONSTRUCT
ACP-18194 v1.0

Applicant:

DCC East Project LLC
3401 24th Street SW
Center, North Dakota 58530

Facility Location:

Dakota Carbon Center CO_2 Separation and Purification Plant
3401 24th Street SW
Center, North Dakota 58530
Lat/Long: 47.0648/-101.2178
NE ¼ of Section 5, T.141N, R.83W

Introduction and Background:

DCC East Project LLC (DCC) submitted a permit to construct application to the North Dakota Department of Environmental Quality – Division of Air Quality (Department) on June 2, 2023. The air dispersion modeling analysis for the project was revised and submitted to the Department on August 25, 2023. The application was for the construction of the Dakota Carbon Center Carbon Dioxide (CO_2) Separation and Purification Plant (Project). The Project will be located adjacent to the existing Milton R. Young (MRY) Station and is designed to capture, purify, and sequester up to 13,000 tons per day (~4.75 million tons per year) of CO_2 from MRY Station's coal-fired boilers (MRY Unit 1 and MRY Unit 2).

DCC's Project will be considered a separate stationary source from the MRY Station for the purposes of the applicable air pollution control rules (40 CFR Part 63 and 40 CFR Part 70). Part 63 requires two criteria to be met for two (or more) sources to be considered a single major source, the sources must be "located within a contiguous area and under common control". Part 70 contains the same first two criteria and adds a third criteria, that sources must belong to the same major industrial grouping. DCC will be responsible for operational control of the Project, including control over air emitting activities that affect permit compliance (i.e., not under common control), and the owner of MRY Station will not hold a majority ownership in DCC. DCC's Project has standard industrial classification (SIC) code 2813 compared to MRY Station SIC code of 4911 (i.e., do not belong to the same industrial grouping). DCC will be adjacent to MRY Station, so the facilities will be located within a continuous area. Of the Part 63 and Part 70 criteria the Project only meets one of the necessary criteria; therefore, the Project is considered a separate source.

<u>Note</u>: MRY Station operates under Title V Permit to Operate (PTO) T5-F76009 (AOP-28368 v5.0) which expires on May 12, 2025. T5-F76009 contains all the equipment onsite at MRY Station and has incorporated all previously issued air pollution control construction permits. T5-F76009 monitoring requirements and conditions will be updated upon issuance of this permit to ensure MRY Station will be able to continually demonstrate compliance with the limits in T5-F76009 at existing MRY Station emission points (EPs) and proposed EP D01.

Table 1 lists all the emissions units associated with the Project and Table 2 contains a list of all insignificant storage tanks.

Table 1 – Project Emission Units and Emission Points

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment
Carbon dioxide (CO_2) absorber column	D01	D01	N/A [A]
Cooling tower	D02	D02	Drift eliminators
Emergency diesel fire pump engine rated at 460 brake horsepower	D03	D03	None
Haul roads [B]	D04	D04	None
Storage tanks [B]	D05	D05	None
Fugitive components	FUG	FUG	None

[A] Process design and controls (i.e., construction material selection and intermediate cooling). No add-on controls.

[B] Insignificant unit

Table 2 – Project Insignificant Units (Storage Tanks)

Emission Unit Description	Emission Unit (EU)
Diesel fire pump storage tank	D05A
Solvent tank	D05B
Solvent sump tank	D05C
Reclaimed waste tank	D05D
Wash water tank	D05E
Dilute wash water tank	D05F
Fresh solvent tank	D05G
Triethylene glycol tank	D05H

Facility Wide Emissions Profile
Potential to Emit (PTE) from Standalone Project

Table 3 - PTE (tons per year) [A]

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	CO	NO_X	SO_2	VOCs	PM	PM_{10}	$PM_{2.5}$	Total HAPs	Acetaldehyde (Largest HAP)
CO_2 absorber	D01	D01	--	--	--	35.2	--	--	--	35.2	32.9
Cooling tower	D02	D02	--	--	--	--	22.2	4.0	0.0	--	--
Fire water pump engine	D03	D03	0.1	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Haul roads	D04	D04	--	--	--	--	0.2	0.0	0.0	--	--
Storage tanks	D05	D05	--	--	--	0.3	--	--	--	0.0	--
Fugitive components	FUG	FUG	--	--	--	4.3	--	--	--	--	--
		Total:	**0.1**	**0.2**	**0.0**	**39.9**	**22.4**	**4.1**	**0.0**	**35.2**	**32.9**

[A] Abbreviations:
PM: total filterable and condensable particulate matter
$PM_{2.5}$: filterable and condensable particulate matter with an aerodynamic diameter less than or equal to 2.5 microns (≤2.5 µm)
PM_{10}: filterable and condensable particulate matter with an aerodynamic diameter less than or equal to 10 microns (≤10 µm) including $PM_{2.5}$
SO_2: sulfur dioxide
NO_X: oxides of nitrogen
CO: carbon monoxide
VOCs: volatile organic compounds
HAPs: hazardous air pollutants as defined in Section 112(b) of the Clean Air Act

Rules Analysis
Potentially Applicable Rules and Expected Compliance Status

A. NDAC 33.1-15-01 - General Provisions:

Multiple topics are included in the General Provisions chapter, these include: entry onto premises - authority, variances, circumvention, severability, land use plans and zoning regulations (only to provide air quality information), measurement of air contaminants, shutdown and malfunction of an installation - requirements for notification, time schedule for compliance, prohibition of air pollution, confidentiality of records, enforcement, and compliance certifications.

Applicability and Expected Compliance

Based on the review of the information provided, the Project will comply with all applicable sections of this rule.

B. NDAC 33.1-15-02 - Ambient Air Quality Standards:

The facility must comply with the North Dakota and Federal Ambient Air Quality Standards (AAQS). In addition to these standards, compliance with the "Criteria Pollutant Modeling Requirements for a Permit to Construct" guidelines[1] and the "Policy for the Control of Hazardous Air Pollutant Emissions in North Dakota (Air Toxics Policy)"[2] is required.

Applicability and Expected Compliance

The Project does not trigger the prevention of significant deterioration (PSD) program emissions thresholds which require modeling nor do the Project emissions meet thresholds required for non-PSD required modeling under the "Criteria Pollutant Modeling Requirements for a Permit to Construct". Notwithstanding that the emissions thresholds are below North Dakota's modeling guidelines, modeling for this project was required and is appropriate and necessary since the current emissions from MRY Station will be diverted and emitted through a stack with significantly different stack characteristics. Therefore, preconstruction modeling for the Project was required to demonstrate the Project will not significantly impact the existing airshed and will not cause an AAQS violation.

The results of the preconstruction modeling demonstrate the altered dispersion characteristics associated with the Project are not expected to cause or contribute to an exceedance of the AAQS. The preconstruction permit modeling was also used to demonstrate compliance with the Department's Air Toxics Policy. Modeling demonstrated that the Project is expected to comply with both the AAQS and the Department's Air Toxic Policy. Details regarding the preconstruction permit modeling analysis and results are

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[1] See October 6, 2014, Criteria Pollutant Modeling Requirements for a Permit to Construct. Available at: https://www.deq.nd.gov/publications/AQ/policy/Modeling/Criteria_Modeling_Memo.pdf

[2] See August 25, 2010, Policy for the Control of Hazardous Air Pollutant (HAP) Emissions in North Dakota. Available at: https://www.deq.nd.gov/publications/AQ/policy/Modeling/Air_Toxics_Policy.pdf

discussed in the Air Quality Impacts Analysis (AQIA) associated with this permitting action. See "ACP-18194 v1.0_AQIA" for details.

C. NDAC 33.1-15-03 - Restriction of Emission of Visible Air Contaminants:

This chapter requires all non-flare sources from new facilities to comply with an opacity limit of 20% except for one six-minute period per hour when 40% opacity is permissible. This chapter also requires facility flares to comply with an opacity limit of 20% except for one six-minute period per hour when 60% opacity is permissible. Lastly, this chapter restricts opacity of fugitive emissions transported off property to 40% except for one six-minute period per hour when 60% opacity is permissible. This chapter also contains exceptions under certain circumstances and provides the method of measurement to determine compliance with the referenced limits.

Applicability and Expected Compliance

Based on the emissions units associated with the Project, the Department expects the Project will comply with the non-flare source and fugitive emissions opacity requirements.

The CO_2 absorber column (EU D01), the cooling tower (EU D02) and the emergency diesel fire pump engine (EU D03) are subject to the non-flare source 20% opacity limit and are expected to comply. EU D01 is not expected to have any significant opacity associated with routine operations. Opacity from EU D01 would indicate an issue with the Project operations that would require investigation and resolution. EU D02 is designed with drift elimination technology. Any opacity will be associated with routine operations and expected to be well below 20%. EU D03 is also not expected to have any significant opacity associated with its emergency operations. EU D03 is also subject to NDAC 33.1-15-08 and NDAC 33.1-15-12 (Subpart IIII).

The haul roads (EU D04) are subject to the fugitive emissions transported offsite limit of 40%. The Project will maintain EU D04 using reasonable practices to comply with this limit.

D. NDAC 33.1-15-04 - Open Burning:

No person may dispose of refuse and other combustible material by open burning, or cause, allow, or permit open burning of refuse and other combustible material, except as provided for in Section 33.1-15-04-02 or 33.1-15-10-02, and no person may conduct, cause, or permit the conduct of a salvage operation by open burning.

Applicability and Expected Compliance

The Project is subject to this chapter and will comply with all open burning regulations.

E. NDAC 33.1-15-05 - Emissions of Particulates Matter Restricted:

This chapter establishes particulate matter emission limits for industrial process equipment and fuel burning equipment used for indirect heating.

Applicability and Expected Compliance

The Project will not emit any particulate matter which results from industrial process equipment, nor will the facility operate any fuel burning equipment used for indirect heating.

F. NDAC 33.1-15-06 - Emissions of Sulfur Compounds Restricted:

This chapter applies to any installation in which fuel is burned and the SO_2 emissions are substantially due to the sulfur content of the fuel; and in which the fuel is burned primarily to produce heat. This chapter is not applicable to installations which are subject to an SO_2 emission limit under Chapter 33.1-15-12, Standards for Performance for New Stationary Sources, or installations which burn pipeline quality natural gas.

Applicability and Expected Compliance

The Project will not emit any SO_2 which results from industrial process equipment, nor will the Project operate any fuel burning equipment used for indirect heating. The emergency fire water pump (ED D03) will comply with this chapter by burning ultra-low sulfur diesel.

G. NDAC 33.1-15-07 - Control of Organic Compounds Emissions:

This chapter establishes requirements for organic compound facilities and the disposal of organic compounds.

Applicability and Expected Compliance

The Project is not considered an organic compound facility, but the Project will emit organic compounds via the CO_2 absorber column (EU D01) exhaust. The organic compounds concentration in this stream is expected to be less than 1 part per million by volume dry (ppmvd) and D01 contains process controls (e.g., material selection and intermediate cooling) which limit the generation of organic compounds in the CO_2 absorber column. These controls are considered maximum achievable control technology (MACT). Therefore, the Project is expected to comply with the requirements of this chapter.

The Department encourages DCC to conduct periodic leak detection monitoring on the process equipment to minimize losses of valuable materials.

H. NDAC 33.1-15-08 - Control of Air Pollution from Vehicles and Other Internal Combustion Engines:

This chapter restricts the operation of internal combustion engines which emit from any source unreasonable and excessive smoke, obnoxious or noxious gas, fumes or vapor. This chapter also prohibits the removal or disabling of motor vehicle pollution control devices.

Applicability and Expected Compliance

The emergency diesel fire pump (EU D03) is also subject to opacity requirements under NDAC 33.1-15-03-02 and subject to the requirements of NSPS Subpart IIII. As a result of expected compliance with these provisions, the engine is not expected to emit any unreasonable and excessive smoke, obnoxious or noxious gases, fumes, or vapor. Any vehicles used onsite are also expected to comply with this chapter's provisions.

I. NDAC 33.1-15-09 - [repealed]

J. NDAC 33.1-15-10 - Control of Pesticides:

This chapter provides restrictions on pesticide use and restrictions on the disposal of surplus pesticides and empty pesticide containers.

Applicability and Expected Compliance

The Project is subject to this chapter and is expected to comply with all applicable requirements should pesticides be used.

K. NDAC 33.1-15-11 - Prevention of Air Pollution Emergency Episodes:

When an air pollution emergency episode is declared by the Department, the Project shall comply with the requirements in Chapter 33.1-15-11 of the North Dakota Air Pollution Control (NDAPC) rules.

L. NDAC 33.1-15-12 - Standards of Performance for New Stationary Sources [40 Code of Federal Regulations Part 60 (40 CFR Part 60)]:

This chapter adopts most of the Standards of Performance for New Stationary Sources (NSPS) under 40 CFR Part 60. The Project is subject to the following subparts under 40 CFR Part 60 which have been adopted by North Dakota:

Subpart A – General Provisions

Subpart A contains general requirements for plan reviews, notification, recordkeeping, performance tests, reporting, monitoring and general control device requirements.

Applicability and Expected Compliance

The Project will comply with the general provisions of Subpart A through submission of timely notifications, performance testing, reporting, and following the general control device and work practice requirements under Subpart A. In addition, any changes to the Project after it is built will be evaluated with respect to this subpart as well as others.

Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII establishes emissions standards (NO_X, CO, PM, and Non-methane hydrocarbons) and compliance schedules for all new, modified and reconstructed stationary compressions ignition (CI) internal combustion engines (ICE). CI ICE are categorized in this subpart by usage, size and age.

Applicability and Expected Compliance

The Project emergency fire water pump (EU D03) is rated at 460 brake horsepower and is subject to the requirements of Subpart IIII. Subpart IIII requires EU D03 to be certified to the standards listed in Table 4 to Subpart IIII[3]. Based on the information provided in the permit application, EU D03 will comply with the applicable requirements of this subpart.

M. NDAC 33.1-15-13-Emission Standards for Hazardous Air Pollutants [40 Code of Federal Regulations Part 61 (40 CFR Part 61)]

This chapter adopts most the National Emission Standards for Hazardous Air Pollutants (NESHAP) under 40 CFR Part 61.

Applicability and Expected Compliance

The Project does not appear to have any applicable requirements under this chapter.

N. NDAC 33.1-15-14-Designated Air Contaminant Sources, Permit to Construct, Minor Source Permit to Operate, Title V Permit to Operate

This chapter requires the facility to obtain a Permit to Construct and a Permit to Operate.

Applicability and Expected Compliance

DCC has submitted an application for a permit to construct for the Project and has met all requirements necessary to obtain a permit to construct. The Project will be considered a minor PSD source, a major source of HAPs, and a future major stationary source under 40 CFR Part 70 (Title V).

The permit must undergo public comment per NDAC 33.1-15-14-06.5.a.

Once the Project completes construction and meets the permit to construct requirements, a facility inspection will be performed by the Department. After Project start-up, DCC will be required to submit a timely Title V permit to operate application.

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[3] See https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-IIII#Table-4-to-Subpart-IIII-of-Part-60 for Table 4 of NSPS Subpart IIII.

O. NDAC 33.1-15-15-Prevention of Significant Deterioration of Air Quality [40 CFR 52.21]

This chapter adopts the federal provisions of the prevention of significant deterioration of air quality (PSD) program. A facility is subject to PSD review if it is classified as a "major stationary source" under Chapter 33.1-15-15.

Applicability and Expected Compliance

The Project does not meet the definition of a "major stationary source" under 40 CFR 52.21(b)(1)(i)(a) since the regulated NSR pollutant[4] emissions do not meet the applicable requirements. The PTE for this facility, as shown in Table 3, is below the 100 tpy threshold and therefore not subject to PSD review.

P. NDAC 33.1-15-16 - Restriction of Odorous Air Contaminants

This chapter restricts the discharge of objectionable odorous air contaminants which measures seven odor concentration units or greater outside the property boundary.

Applicability and Expected Compliance

Based on Department expectations considering the source units, the Project should not emit any objectionable odorous air contaminants. Therefore, the Project is expected to comply with this chapter.

Q. NDAC 33.1-15-17 - Restriction of Fugitive Emissions

This Chapter restricts fugitive emissions from particulate matter or other visible air contaminates and gaseous emissions that would violate Chapter 2 (ambient air quality standards), Chapter 15 (PSD), Chapter 16 (odor), or Chapter 19 (visibility).

Applicability and Expected Compliance

DCC will be required to take reasonable precautions to prevent fugitive emissions in violation of the above referenced NDAC chapters.

R. NDAC 33.1-15-18 - Stack Heights

This chapter restricts the use of stack heights above good engineering practices (GEP). This chapter also restricts the use of dispersion techniques to affect the concentration of a pollutant in the ambient air.

Applicability and Expected Compliance

The main proposed stack (EU D01) for the Project does not exceed GEP and will not use dispersion techniques to affect the pollutant concentration in the ambient air.

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[4] See 40 CFR 52.21(b)(50). Available at: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-52/subpart-A/section-52.21#p-52.21(b)(50)

The required stack heights at the facility are listed in the following table:

Emission Unit	Emission Point (EP)	Stack Height (Feet)
D01	D01	335

S. NDAC 33.1-15-19 - Visibility Protection

This chapter applies to new major stationary sources as defined in Section 33.1-15-15-01.

Applicability and Expected Compliance

The Project is not an existing major stationary source and cannot experience a major modification. The Project is also not a new major stationary source; therefore, this Project is not subject to the requirements of this chapter. Given the minor source levels of the visibility impairing air pollutants, such as $PM_{2.5}$, it is expected that the Project will not adversely contribute to visibility impairment within the three units of the Theodore Roosevelt National Park (nearest federal Class I areas) or at the Lostwood National Wildlife Refuge.

T. NDAC 33.1-15-20 - Control of Emissions from Oil and Gas Well Production Facilities

The Project is not an oil or gas well facility and is therefore not subject to the requirements of this chapter.

U. NDAC 33.1-15-21 - Acid Rain Program

This chapter adopts the acid rain provisions of the Clean Air Act specified under 40 CFR Parts 72-78. The Project is not subject to the acid rain provision as it is not an electric utility.

V. NDAC 33.1-15-22 - Emissions Standards for Hazardous Air Pollutants for Source Categories [40 Code of Federal Regulations Part 60 (40 CFR Part 63)]

This chapter adopts the 40 CFR Part 63 regulations which regulates hazardous air pollutants (HAPs) from regulated source categories. Typically, these standards apply to major sources of air pollution that are a regulated source category. In addition to the major source requirements, some of the regulations have “area source” standards (for non-major sources). Some of the area source standards have not been adopted by the Department and compliance will be determined by the United States Environmental Protection Agency (USEPA) (i.e. 40 CFR 63, Subpart ZZZZ area source provisions have not been adopted by the Department).

Applicability and Expected Compliance

The Project’s potential HAP emissions are greater than 10 tons/year of any single HAP and are greater than 25 tons/year of any combination of HAPs, so the Project is expected to be a major source of HAPs. As shown in the Table 3, total potential HAPs from the Project are approximately 35.2 tons/year. The greatest single potential HAP is acetaldehyde at approximately 32.9 tons/year.

DCC shall perform HAP emissions testing upon Project start-up to confirm the representations made in the permit application as outlined in Condition II.F of ACP-18194 v1.0.

Subpart A – General Provisions

Subpart A contains general requirements for prohibited activities and circumvention, preconstruction review and notification, standards and maintenance requirements, performance tests, monitoring, recordkeeping, reporting, and control device work practice requirements.

Applicability and Expected Compliance

The Project will comply with the general provisions of Subpart A through submission of timely notifications, performance testing, monitoring, recordkeeping, reporting, and following the control device work practice requirements under Subpart A.

Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)

Under the Clean Air Act Amendments of 1990, EPA is required to regulate large or "major" industrial facilities that emit one or more of the listed HAPs. Air toxics are those pollutants that are known or suspected of causing cancer or other serious health effects, such as developmental effects or birth defects. On July 16, 1992, EPA published a list of industrial source categories that emit one or more of these hazardous air pollutants. EPA is required to develop standards for listed industrial categories of "major" sources (those that have the potential to emit 10 tons/year or more of a listed pollutant or 25 tons/year or more of a combination of pollutants) that will require the application of stringent controls, known as maximum achievable control technology (MACT).

The section 112(g) provision is designed to ensure that emissions of toxic air pollutants do not increase if a facility is constructed or reconstructed before EPA issues a MACT or air toxics regulation for that particular category of sources or facilities.

In effect, the 112(g) provision is a transitional measure to ensure that facilities adequately protect the public from toxic air pollutants until EPA issues a MACT standard that applies to the facility in question.

Newly constructed facilities or reconstructed units or sources at existing facilities would be subject to 112(g) requirements if they have the potential to emit hazardous air pollutants (air toxics) in "major" amounts (10 tons or more of an individual pollutant or 25 tons or more of a combination of pollutants).

Sources or facilities subject to 112(g) would be subject to stringent air pollution control requirements, referred to as "new source MACT." Under the Clean Air Act, new source

MACT control is required to be no less stringent than the best controlled similar source or facility.

EPA anticipates that the new source MACT requirements will be equally or more stringent than the requirements in the air toxics or MACT standard that EPA will later issue for the industrial source category in question. However, should the new source MACT requirements prove to be less stringent than the air toxics regulation that EPA later issues, the source or facility would be provided additional time to comply with the air toxics or MACT standard.[5]

Applicability and Expected Compliance

The Project's potential HAP emissions are greater than 10 tons/year of any single HAP and are greater than 25 tons/year of any combination of HAPs. EPA has not established MACT standards for the Project's source category; therefore, a new source MACT determination was made for the Project.

DCC's permit to construct application included a detailed analysis of potentially available controls to reduce VOC/HAP emissions from the CO_2 absorber (EU D01).[6] The Department supports the analysis and agrees with the conclusions reached in the selection of MACT for the CO_2 absorber. The Department has determined MACT for the Project's CO_2 absorber to be process controls integrated into the design of the system, which consists of CO_2 absorber material selection and intermediate cooling. Material selection to limit iron scavenging and intermediate cooling to prevent excess heat are expected to reduce the amount of amine degradation in the CO_2 absorber column, thereby lessening the amount of VOC/HAP formation. It is estimated that these changes will result in approximately 40% less VOC/HAP emissions when compared to pre-design integrated process control levels based on vendor calculations. The selection of MACT for the Project is also consistent with the control approach implemented at the Petra Nova carbon capture facility in Texas.

The permit application projects that acetaldehyde emissions account for approximately 93% of the expected combined (or total) HAPs and that acetaldehyde will be emitted from the CO_2 absorber at a rate of 7.5 pounds per hour (lb/hr). Formaldehyde is the projected next largest HAP and is expected to account for approximately 5% for the total HAPs. DCC will be required to perform performance testing for acetaldehyde and formaldehyde upon start-up of the Project to confirm the HAP representations made in the permit application. Initial performance testing is also anticipated to confirm that the emissions do not pose an adverse risk to human health and the environment.

EPA Guidance provides that MACT control technology may be based on the specific design and process controls. The MACT controls are not dependent on a percent control or allowable ratio of acetaldehyde/HAP formation per unit of CO_2 capture (i.e., pounds of acetaldehyde/HAP per amount of CO_2 recovered) but are based on the design and process controls used to limit the formation of HAPs during operation. Future compliance

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[5] See: https://www3.epa.gov/airtoxics/112g/112gpg.html

[6] DCC East Project LLC, Dakota Carbon Center CO_2 Separation and Purification Plan Permit to Construct Application. Appendix C. June 2, 2023.

assurance with the MACT determination will be based on initial performance testing, documentation of compliance with the absorber material selection, and continuous monitoring of operation of the intermediate cooling system to ensure that the represented level of HAP control is being achieved.

Should initial acetaldehyde and formaldehyde emission testing indicate results vary significantly from what was provided in the permit application, additional review/analysis may be required by the Department.

Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Subpart ZZZZ establishes national emission limitations and operating limitations on HAPs emitted from RICE located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

Applicability and Expected Compliance

The Project has one engine (EU D03) subject to the requirements under this subpart. The requirements of Subpart ZZZZ for the engine are met by complying with the requirements of NDAC 33.1-15-12 [40 CFR 60], Subpart IIII.

W. NDAC 33.1-15-23 - Fees

This chapter requires a filing fee of $325 for permit to construct applications, plus any additional fees based on actual processing costs. The additional fees based on processing costs will be assessed upon issuance of the draft permit to construct.

The applicant has paid the $325 filing fee and may be required to pay the additional fees associated with the permit processing.

X. NDAC 33.1-15-24 - Standards for Lead-Based Paint Activities

The Project will not perform any lead-based painting and is therefore not subject to this chapter.

Y. NDAC 33.1-15-25 - Regional Haze Requirements

This chapter is specific to existing stationary sources or groups of sources which have the potential to "contribute to visibility impairment" as defined in Section 33.1-15-25-01.2. Existing stationary sources or groups of sources determined to contribute to visibility impairment may be required to implement emissions reduction measures to help the Department make reasonable progress toward North Dakota's reasonable progress goals established in accordance with 40 CFR 51.308.

Applicability and Expected Compliance

The Project is a new source and based on low PTE of visibility impairing pollutants is not expected to contribute to visibility impairment. Therefore, the facility is not subject to the requirements of this chapter.

Summary:

A complete review of the proposed project indicates that the Project is expected to comply with the applicable federal and state air pollution rules and regulations. The Department will make a final recommendation on the issuance of a Permit to Construct for the Project following completion of a 30-day public comment period. The public comment period will begin on September 21, 2023, and end on October 21, 2023.

The Department will hold a public meeting followed by a public hearing in Center, North Dakota on October 19, 2023, for interested parties. Upon completion of the public comment period, the Department will address all comments applicable to the state and federal air quality rules and regulations and make a final determination regarding the issuance of a Permit to Construct for the Project.

Update post comment period:
A public comment period was held regarding the above draft Air Pollution Control Permit to Construct from September 21, 2023, through October 21, 2023. Comments were received from three parties which consisted of two individual commentors and Region 8 of the Environmental Protection Agency. This information is included in Appendix A – Public Record, attached to this permit document. The Department has provided written response to each applicable comment, also included in Appendix A.

The Department made logical-outgrowth changes from the draft Permit to Construct and Air Quality Effects Analysis that do not depart from the terms or substance of the proposed action.

Therefore, based on the comments received and Department responses, the Department recommends issuance of a final Permit to Construct for DCC Project East LLC to construct and initially operate the Dakota Carbon Center Carbon Dioxide Separation and Purification Plant.

Date of Draft Analysis: September 18, 2023
Date of Final Analysis: December 29, 2023

Analysis By:

David Stroh

David Stroh
Manager, Permit Program
Division of Air Quality

DES:

Appendix A – Public Record

A.1 – Public Hearing Notice

September 18, 2023

Mr. Gerad Paul
Secretary
DCC East Project LLC
5301 32nd Ave. S.
Grand Forks, ND 58201

Re: Air Pollution Control
Draft Permit to Construct No. ACP-18194 v1.0

Dear Mr. Paul:

Pursuant to the Air Pollution Control Rules of the State of North Dakota, the Department of Environmental Quality (Department) has reviewed the permit application dated June 2, 2023, and the revised modeling dated August 25, 2023, to obtain a Permit to Construct for initial construction and operation of the Dakota Carbon Center CO_2 Separation and Purification Plant to be located in Oliver County, North Dakota.

Before making final determination on the draft Permit to Construct, the Department must solicit public comment by means of the enclosed public notice. As indicated in the notice, the public comment period will begin on September 21, 2023, and end on October 21, 2023. The Department's analysis and a draft copy of the Permit to Construct may be found at https://deq.nd.gov/AQ/PublicCom.aspx. The documents will be posted on or before September 21, 2023.

All comments received will be considered in the final determination concerning issuance of the permit. You will be notified in writing of our final determination.

If you have any questions, please contact me at (701)328-5229 or destroh@nd.gov.

Sincerely,

David Stroh

David Stroh
Environmental Engineer
Division of Air Quality

DS:lc
Enc:
xc: Adam Eisele, EPA Region 8 (email - eisele.adam@epa.gov)
Julia Witteman, EPA Region 8 (email - witteman.julia@epa.gov)
Shannon Mikula, Minnkota Power Cooperative (email - smikula@minnkota.com)

NOTICE OF MACT APPROVAL AND INTENT TO ISSUE AN AIR POLLUTION CONTROL PERMIT TO CONSTRUCT

Take notice that the North Dakota Department of Environmental Quality (NDDEQ) proposes to issue an Air Pollution Control Permit to Construct to DCC East Project LLC in accordance with the North Dakota Air Pollution Control Rules. The proposed air pollution control permit is for initial construction and operation of the Dakota Carbon Center CO_2 Separation and Purification Plant to be located in Oliver County, North Dakota. Preliminary evaluations made by NDDEQ staff indicate that the proposed project will comply with all applicable Air Pollution Control Rules and is protective of human health and the environment.

The project required NDDEQ to perform a case-by-case maximum achievable control technology (MACT) determination. NDDEQ is providing an opportunity for public comment on the MACT determination consistent with 40 CFR 63.43(h). Details regarding the MACT determination can be found in the NDDEQ's Air Quality Effects Analysis.

An air dispersion modeling analysis was conducted to determine the cumulative impact from the project, existing Milton R. Young Station sources, other significant nearby sources within 50 kilometers, and background. Modeled impacts were below ambient air quality standards for each pollutant, as follows: 42% for the NO_2 1-hour standard, 6% for the NO_2 annual standard, 25% for the PM_{10} 24-hour standard, 55% for the $PM_{2.5}$ 24-hour standard, 46% for the $PM_{2.5}$ annual standard, 31% for the SO_2 1-hour standard, 5% for the SO_2 3-hour standard, 7% for the SO_2 24-hour standard, 6% for the SO_2 annual standard, 3% for the CO 1-hour standard, and 12% for the CO 8-hour standard. More detail regarding the projected modeled impacts can be found in the NDDEQ's Air Quality Impacts Analysis.

A 30-day public comment period for the proposed permit to construct and MACT determination will begin September 21, 2023, and end on October 21, 2023. Direct comments in writing, including Re: Public Comment Permit Number ACP-18194 v1.0, to AirQuality@nd.gov or the NDDEQ, Division of Air Quality, 4201 Normandy Street, 2nd Floor, Bismarck, ND 58503-1324. Emailed comments must be sent to the email address above to be considered. Comments must be received by 11:59 p.m. central time on the last day of the public comment period to be considered in the final permit determination.

In accordance with NDAC 33.1-15-14-02, a public information meeting and public hearing regarding issuance of the Air Pollution Control Permit to Construct will be held October 19, 2023, beginning at 5:30 p.m. CDT at the Betty Hagel Memorial Civic Center, 312 Lincoln Ave, Center, ND 58530.

The application, NDDEQ's Air Quality Effects Analysis, NDDEQ's Air Quality Impacts Analysis, and NDDEQ's proposed air pollution control permit are available for review at NDDEQ's office and on-line at http://deq.nd.gov/AQ/PublicCom.aspx. A copy of these documents may be obtained by writing to the Division of Air Quality or contacting David Stroh at (701)328-5229 or by email at destroh@nd.gov.

The NDDEQ will consider every request for reasonable accommodation to provide an accessible meeting facility or other accommodation for people with disabilities, language interpretation for people with limited English proficiency (LEP), and translations of written material necessary to access programs and information. Language assistance services are available free of charge to you. To request accommodations or language assistance, contact the NDDEQ Non-discrimination/EJ Coordinator at 701-328-5150 or deqEJ@nd.gov. TTY users may use Relay North Dakota at 711 or 1-800-366-6888.

Dated this 18th day of September 2023

James L. Semerad
Director
Division of Air Quality

A.2 – Invoice of Publication

North Dakota Newspaper Association

1435 Interstate Loop
Bismarck, North Dakota 58503
Phone: 1-701-223-6397 Fax: 1-701-223-8185

INVOICE

October 16, 2023

Order: 23094ND0 Invoice# 13696

Attn: David Stroh
ND Department of Environmental Quality
4201 Normandy Street
Bismarck, North Dakota 58503-1324

Voice: Fax:
Email: DEQ-Invoice@nd.gov

Advertiser: Division of Air Quality
Brand:
Campaign
Client Order Number:
Amount Due: $87.74

Please detach and return this portion with your payment

Division of Air Quality Invoice# 13696 P.O.#: Client Order Number:

Run Date	Ad Size	Rate Type	Rate	Color Rate	Total	Discount	(%)	Amount after Discount	Page
Center Republican (Hazen, North Dakota)									
09/21/2023	107.00	Notice A Line	$0.82		$87.74	$0.00	(0.00%)	$87.74	
Caption: Notice of Mact Approval and Intent to issue an air pollution									
Subtotal:	107.00		$0.82	$0.00	$87.74	$0.00		$87.74	

Gross Advertising	$87.74	Total Misc	$0.00	Amount Paid	$0.00
Agency Discount	$0.00	Tax	$0.00	Adjustments	$0.00
Other Discount	$0.00	Total Billed	$87.74	Payment Date	
Service Charge	$0.00	Unbilled	$0.00	Balance Due	$87.74

If you'd like to pay your invoice online, go to www.ndna.com/billpay. We accept Visa/Mastercard. A 3% fee will automatically be added to your total. We also accept checks and ACH, with no additional fee added. Contact accounting@ndna.com for ACH information. Thank you!

A.3 – Registration List of Attendees

Public Hearing Sign-in Sheet | **DCC East Project LLC** **ACP-18194 v1.0** | **October 19, 2023**

Name (please print)	Address	Representing	Check Here to Testify
Shannon Mikula	28 Conklin Ave Grand Forks ND	DCC East Project LLC	
Andy Freidt	1307 Eagles View Place Bismarck ND	Minnkota Power	
Ben Fladhammer	3795 Haleigh Dr, Grand Forks, ND	Minnkota Power	
Chris Benner	2200 3rd Ave NE Beulah	Minnkota/IBEW 1593	✓
David Gureeson	600 Country Club, Richmond, TX	Minnkota	
John Mannee	PO Box 353 Center ND 58530	Center/Oliver County	
TROY KARLBERG	411 SHADY LANE, BISMARCK, ND 58501	MINNKOTA POWER	
Mike Heger	105 Dakota Ridge Underwood	BNI Coal	
Jaden Schmidt	2207 36th Ave SW Center	Oliver County	
Brita Endrud	1126 157th Ave NE	Minnkota Power	
[illegible]	3204 Bayshore [illegible]	Minnkota Power	
Casey Aktan	856 San Angelo Dr B.S	Minnkota Power	

Public Hearing Sign-in Sheet

DCC East Project LLC
ACP-18194 v1.0

October 19, 2023

Name (please print)	Address	Representing	Check Here to Testify
Darla Potter	4201 Normandy St Bismarck ND	NDDEQ	
Stacy Dahl	6020 E Prairiewood Dr, Grand Forks, ND	Minnkota Power	
Andrew Sorbo	418 Cole Creek Way NE, Thompson ND	Minnkota Power	
Scott Hoffauer	2767 Springfield St Bismarck ND	Minnkota Power	
Jim Semerad	4201 Normandy St. Bismarck	NDDEQ	
[illegible]	1680 40th Ave SW Center	Minnkota Power	
Doug Schettz	7618 Cortland Pl Bismarck ND	BNI Coal	
Tucker Olson	2638 10th Ave SE Mandan	BNI Coal	
Casey Christmann	5219 Cornice Drive Bismarck ND	BNI Coal	
Craig Bleth	5300 Cornice Dr BMK ND	Minnkota	
Cheryl Froehlich	3918 Lakewood Dr. SE Mandan, ND	BNI Coal	

Public Hearing Sign-in Sheet | DCC East Project LLC ACP-18194 v1.0 | October 19, 2023

Name (please print)	Address	Representing	Check Here to Testify
David Stroh	4201 Normandy St. Bismarck, ND 58503	NDDEQ	
Rama Cardwell	↓	NDDEQ	
Santosh Kumar	"	"	
Rhannon Thorton	"	NDDEQ	
Jon Madison	5407 Country Creek Dr. Bis, ND 58503	Minnkota Power	
John El-Hallal	4007 Oakwood Rock, Katy, TX	TC ENERGY	
Sally Johnson	Minot, ND - Washburn ND	Senator John Hoeven	
Tony Aman	Washburn ND	Minnkota Power	
Tim Hagerott	901 Longhorn drive, Bismarck, ND 58503	Minnkota Power	
Adam Undem	P.O. Box 272 Center ND 58530	BNI / IBEW	
Chris Simon	1935 46th Ave SW Hannover	BNI - Self	
Darrell Berger	1962 Hwy 48 Center	Co Commissioner	
Cheryl Hanggi	PO Box 28310, Center	~~Cen~~ BNI - IBEW	
Russ Keller		MINNKOTA	
Joe Roeder	Po Box 527 Hazen, ND	IBEW Local 1593	✓
Kevin Thomas	2628 Springfield St Bis	MySelf	
Lukas Massetti	4503 Columbus Ct Mandan	BNI	
Dave Berger	MPC Janitor	Just me	
Kale Kolcker	~~23~~3159 Hwy 25 Center	BNI	
JASON NELSON	705 14TH ST SE MANDAN	MPC	
Wyatt Eckroth	2490 High country Dr N	MPC	

A.4 – Hearing Transcript

DCC Hearing Testimony from 10/19/2023.

Jim Semerad: Good evening, everybody. My name is Jim Semerad. I'm the Director of Air Quality Division for the North Dakota Department of Environmental Quality, and I'll be acting today as the hearing officer for this public hearing. I will now open the public hearing portion of today's meeting at the Memorial Civic Center in Center, North Dakota. Let the record show that the time is approximately 6:16 p.m. on October 19th, 2023. This is the time and place that was scheduled for the public hearing for the DCC East Project, LLC Draft Air Pollution Control Permit to Construct pursuant to North Dakota Century Code Title 23.1 and North Dakota Administrative Code, Chapter 33.1-15-14. Anyone wishing to present verbal testimony on the draft permit to construct will be allowed to speak. Anyone presenting testimony is asked to state their name, their address, and the organization they represent, if any. Also, anyone presenting testimony is required to sign the registration sheet for the record. And I have those up front now. They're not no longer up. The purpose of the hearing is to receive input, such as additional data or viewpoints from interested parties, especially for those who have not or will not have the opportunity to submit written testimony. Both written and oral testimony will be considered equally. It will not be necessary to repeat testimony or comments that have been or will be submitted in writing, or that have been previously submitted during the hearing. I would like to emphasize that this hearing is not a question-and-answer session, and the department will not be responding to comments made during the hearing. However, if there's clarification needed on a proposed permit, we will be listening to your testimony and we'll be happy to provide clarification after the public testimony portion of the hearing has concluded. Also, please remember that the proposed permit only relates to health environmental impacts associated with issuing the permit to construct under the North Dakota Century Code, Title 23.1 and North Dakota Administrative Code chapter 33.1-15-14, relating to air quality controls and emissions. It does not relate to social and economic impacts or compatible land use. Therefore, we ask you to limit your comments to those concerns relating to the proposed air Permit to ensure that all interested parties have the opportunity to provide a comment for the record. Given that there's only two people that have signed up for comments, we likely won't have to impose a five-minute limit on comments that you may have, but we'll track that as time goes on. Otherwise, we'll ask that you limit your comments to five minutes to allow for everybody to give their testimony. Again, my name is Jim Semerad. If the time remains at the end, commenters who request more time may be allowed additional time to provide comments. It is important to note that the comment period remains open through October 21st, 2023, and written comments to be considered as part of the record may be submitted until then. Additional information relating to the proposed DCC East project can be found at the North Dakota Department of Environmental Quality web page at DEQ.nd.gov.

With that, when your name is called, we ask that you please come forward and speak into the microphone to ensure that your comments are recorded for the hearing record. First one is Chris Renner. Chris.

Chris Renner: My name is Chris Renner. Do I have to? My address here. My address is 2200 3rd Avenue Northeast. Beulah, North Dakota. I work for Minnkota Power Cooperative as an electrical instrumentation and controls technician. I am also a unit president of the IBEW 1593 here at Beulah. I personally support Project Tundra, and this is why. We are living in a world in which we are trying to reduce CO_2 emissions. This is the right thing to do, but we have to do it safely and intelligently. We have to be realistic. Milton R Young station is a coal powered thermal energy power plant. This nation's thermal energy sources such as natural gas, nuclear and of course coal, are what we call baseload energy and dispatchable energy sources. They can be turned on or off at will, within reason, and run at 100% output all day, every day. In other words, these thermal energy sources, such as Milton R Young Station are safe, predictable, and reliable. We cannot replace a megawatt of coal energy with a megawatt of intermittent wind energy and expect to keep the lights and heaters on during the cold winter months here in North Dakota and Minnesota. As I write this, I see on the Midcontinent Independent System Operator the Miso grid, that wind is at 2494MW. Last summer I saw the grid at 655MW. Today, as I review this, I see that the wind energy is at 16,679MW. While wind and solar both provide energy on occasion, it provides a roller coaster like swing and actual output due to a reliance on nature itself. Right now, it is a beautiful fall day, and there are only 68,975MW on the Miso grid as a whole. What happens in December and January when we run into a situation where there is no wind, there is over 100,000MW of load and we have eliminated too many baseload coal plants. When the next polar vortex hits, the wind towers will shut themselves down, produce nothing, and use power off the grid to run their onboard electric heaters. However, at this point in time, we still have just enough baseload coal to power the grid through these extreme weather conditions. Probably. This nation's electric utilities have been heavily regulated since at least 1968 by organizations such as the North American Energy Reliability Corporation (NERC) and the Federal Energy Regulatory Commission (FERC). These two organizations work together to provide standards to ensure just and reasonable rates, respond to emergencies or threats to the grid, and to ensure a safe and reliable electric grid. This is particularly important up here in the northern states during the winter months. As we shudder, more and more thermal energy sources such as coal, the production of electricity becomes much less stable. Due to the loss of dispatchable energy, we lose reliability. The price of energy fluctuates like a roller coaster, and we run into the threat of blackouts and brownouts in a region. To me, as far as reliability goes, this transition from thermal energy sources to renewables is going in the opposite direction of the reliable grid that NERC and FERC envision. There is nothing just in transitioning from reliable energy to potential blackouts and brownouts. It seems like we are going in a dangerous direction. I have seen several electric utilities promised to shutter their coal plants down for good, in favor of replacing them with solar. I have seen other utilities promise to shut down their coal in favor of wind energy. We need dispatchable energy, and we cannot afford to lose more than we have already lost. We can turn our thermal energy sources on at will, and we can control the output in a coal fired plant with a nameplate rating of, say, 700MW. We can expect 700MW out of that plant between 92 and 95% of the year, all day, every day. With wind and solar, we are stuck with what nature tells us we get. A 700-megawatt wind or solar plant may, on rare occasions, put out 700MW, but how often can one rely on that? Like I said earlier, the entire Miso grid may provide 655MW, or it may be 17,000MW. That is a very substantial swing. We need reliability on the grid and Milton R Young station, provides that.

It seems that as these utilities shutter their thermal plants and replace them with green energy, they are expecting or hoping to buy energy from their neighboring utilities when they run into shortfalls of energy of their own. The problem lies in the fact that their neighbors are also planning on shuttering their coal in favor of wind and solar. The question is, who is going to be responsible for the blackouts and brownouts in the ice-cold Midwest when we run out of wind and solar? Are the utilities themselves going to be held accountable? Are the politicians that help force their hand into closing their thermal energy sources going to be held accountable? Are the banks that refuse to give loans to coal companies going to be held accountable? You know, you may hear arguments that battery banks are the future, but why would we want to spend the money, time, and resources on batteries at this point when we do not produce enough green energy to provide the grid, let alone power the grid and charge a giant battery bank? What we need is reliability in energy production. The coal industry is required by regulation to maintain a stockpile of at least two weeks of fuel stockpiled in the event of a disruption in fuel supply. I don't know how many battery banks or the size of these battery banks we would need to power the grid for two weeks during the winter, when the daily grid demand is over 100,000MW.

Another argument you may hear in opposition to Project Tundra is that coal is expensive. In a way it is, I suppose, but there are many factors that make it so. One of the major contributing factors in the price of coal is the fact that coal is forced to reduce load or shut down completely when the wind is blowing, or the sun is shining. This causes a loss of income in the coal sector. Imagine if Napa Auto Parts were banned from selling their goods unless Rock auto could not keep up with demand. Napa would have no choice but raise their prices or just go under. I have seen some people call Project Tundra a waste of money. How can anyone truly consider investing in clean, reliable energy a waste of money? Again, reliability is key. Doing nothing to preserve our baseload and dispatchable power sources means a future of blackouts and brownouts due to intermittent energy sources. Doing nothing is a danger to everyone that relies on the grid. Sometimes innovation and reliability are expensive, but necessary. In fact, the EPA administrator, Michael Regan himself sees huge potential for carbon capture here in North Dakota. Minnkota also spends countless dollars and hours working to meet and exceed all governmental safety, reliability, and environmental regulations. I have heard people call the coal industry names such as Dirty coal, Obsolete Coal, Killer coal, and I have heard the same people call the industry as a whole, greedy coal. You know, I don't know if we can classify modern cooperatives like Minnkota greedy when we spend so much time and revenue working to eliminate our emissions and safeguard our environment. On a separate note, I have seen state governments promise to abolish the sales of gas cars in favor of electric cars. As a nation, we are looking at adding countless megawatts of load to our already strained grid. We need to keep our powerful and reliable sources of baseload and ready to dispatchable thermal utilities such as Milton R Young station operating if we want to keep the furnaces running when it is 20 below outside. From the day I first started work at Minnkota, Minnkota has already worked hard and spared no expense to meet and exceed all rules of law, as well as all safety and environmental regulations. There is no doubt in my mind that Minnkota will work very hard to meet and exceed all safety regulations and standards to make tundra a safe, successful, and innovative project. So, with Project Tundra, we will be eliminating many tons of CO2 from entering the atmosphere while providing the safe, stable and reliable grid that the member owners and users and our many regulatory agencies demand. Tundra is a great solution for a climate issue. It is my hope that Minnkota may one day become not only a producer of reliable energy that it already is, but also a producer of energy with zero carbon emissions or perhaps a negative carbon producer, meaning we eliminate more carbon from the atmosphere than we actually create.

Thank you.

Jim Semerad: Thank you, Chris. Next is Joe.

Joe Roeder: Hi, my name is Joe Roeder. I'm a representative of the International Brotherhood of Electrical Workers Local Union 1593. We represent over a thousand members in the western part of the state here in this community. The industries we represent are mostly coal based, but we also have gas, Dakota Gas. We also have a wind farm by Max North Dakota and a nursing home in Beulah. Uh, we represent the workers at Milton R Young station in the adjacent coal mine of BNI Coal. We're here today to pledge our support for this project. We believe that Minnkota has done their due diligence, and we believe this project is a safe and efficient project that can be developed. And we would urge you to pass this air permit in their favor. We believe it'll bring a lot of economic benefit to this community and to all the workers that are represented here. That’s all I have to say. Thank you.

Jim Semerad: That's all I see that signed up to testify. Is there anybody else who would like to testify?

Last call on testifying. Okay. Again, we want to say thank you all for coming. All information gathered at this hearing will be provided to the Department of Environmental Quality, which is the decision-making body. The record will be held open for written comments through October 21st, 2023. And at this time, I close the hearing on the Department of Environmental Quality's Draft Air Pollution Control Permit to Construct for the DCC East project. The hearing is closed at 6:33 p.m. Thank you all.

A.5 – Comments Received During the Public Comment Period

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
www.epa.gov/region8

Ref: 8ARD-PM

David Stroh
North Dakota Department of Environmental Quality, Division of Air Quality
4201 Normandy Street, 2nd Fl
Bismark, ND 58503-1324

Re: EPA Comments to Dakota Carbon Center East Project LLC, Permit to Construct

Dear David Stroh:

This letter is in response to the North Dakota Department of Environmental Quality's (NDDEQ) public notice of the draft permit to construct for the Dakota Carbon Center East Project LLC (DCC). The NDDEQ's public comment period for this permit ends October 21st, 2023.

After reviewing the draft permit to construct, EPA submits the following comments. As explained in more detail below, these technical comments are related to source aggregation, incorporation by reference, monitoring, recordkeeping, reporting requirements, modeling found in the permit and corresponding air quality effects analysis, and Clean Air Act (CAA) Section 112(g).

<u>Comments Related to Aggregation</u>

The DCC Air Quality Effects Analysis (AQEA) discusses the potential of aggregating the DCC facility with the existing Milton R. Young (MRY) Station coal-fired power plant. DCC is located next to the existing MRY facility. DCC will capture, purify, and sequester up to 13,000 tons per day of CO_2 from MRY's boilers (MRY Unit 1, MRY Unit 2). The AQEA states:

> *DCC's Project will be considered a separate stationary source from the MRY Station for the purposes of the applicable air pollution control rules (40 CFR Part 63 and 40 CFR Part 70). Part 63 requires two criteria to be met for two (or more) sources to be considered a single major source, the sources must be "located within a contiguous area and under common control". Part 70 contains the same first two criteria and adds a third criteria, that sources must belong to the same major industrial grouping. DCC will be responsible for operational control of the Project, including control over air emitting activities that affect permit compliance (i.e., not under common control), and the owner of MRY Station will not hold a majority ownership in DCC. DCC's Project has standard industrial classification (SIC) code 2813 compared to MRY Station SIC code of 4911 (i.e., do not belong to the same industrial grouping). DCC will be adjacent to MRY Station, so the facilities will be located within a continuous area. Of the Part 63 and Part*

70 criteria the Project only meets one of the necessary criteria; therefore, the Project is considered a separate source.

AQEA at page 1

Region 8 has reviewed the NDDEQ's discussion of the DCC project source determination and has concerns about the record of support for the decision that the DCC project and MRY facility should be considered separate facilities. The NDDEQ's analysis is correct in that both 40 CFR part 70 and 40 CFR part 63 have separate definitions of what constitutes a major source for each regulation and that if the case-specific facts support that only one of the necessary criteria in either definition is met then the two sources in question should be considered separate stationary sources for the purposes of those regulations. However, as laid out in the following discussions, the EPA recommends enhancement of the permit record to support the NDDEQ's conclusions.

The draft permit action available for EPA review and for public comment is a permit to construct. Therefore, the EPA believes the NDDEQ should first determine whether these two entities should be considered part of the same "stationary source" under the New Source Review (NSR) preconstruction permit programs under title I of the CAA. This determination will dictate whether or not the project requires a permit to construct a minor or major new source or a minor or major "modification" to an existing source. That exercise will inform whether the facilities are considered part of the same "major source" under title V and part 63 of the CAA and any required application of those programs.

Under the federal rules governing both the NSR and title V permitting programs, entities may be considered part of the same "stationary source" or "major source" if they (1) belong to the same industrial grouping: (2) are located on one or more contiguous or adjacent properties: and (3) are under the control of the same person (or persons under common control).

The NDDEQ's AQEA indicates that the DCC and MRY facilities are located on contiguous and adjacent properties. On the question of common control, NDDEQ has described DCC and MRY as having separate controlling entities. EPA has long determined that establishing the relationship for common control is done on a case-by-case basis. The 2018 Meadowbrook source determination[1] states:

For the reasons discussed further in the Attachment, the agency believes clarity and consistency can be restored to source determinations if the assessment of "control" for title V and NSR permitting purposes focuses on the power or authority of one entity to dictate decisions of the other that could affect the applicability of, or compliance with, relevant air pollution regulatory requirements.

Meadowbrook at page 2.

A review of available information on the internet indicates that MRY is directly owned by Minnkota Power Cooperative.[2] Further, the same Minnkota Power Cooperative website contains links to "Project Tundra".[3] Project Tundra would "retrofit the Milton R. Young Station with CO_2 capture technology" and "Final air permits are being pursued and are anticipated in 2023".

[1] https://www.epa.gov/sites/default/files/2018-05/documents/meadowbrook_2018.pdf, accessed October 16, 2023
[2] https://www.minnkota.com/minnkota-website/our-power/coal, accessed October 16, 2023.
[3] https://www.projecttundrand.com/about, accessed October 16, 2023.

Further, the June 2, 2023 permit application refers to the proposed project as Project Tundra. This information may suggest the that the Minnkota Power Cooperative has control over both the MRY and DCC projects. The EPA recommends that the NDDEQ enhance the permit record with additional information supporting the conclusion that a common control relationship does not exist between the DCC and MRY facilities.

The third source determination criteria is whether both facilities belong within the same industrial grouping, commonly indicated by Standard Industrial Classification (SIC) code. The NDDEQ states that DCC has the SIC code of 2813 and MRY has the SIC code of 4911. The preamble to the 1980 PSD rule discussed the EPA's view on how to evaluate what SIC code applies to facilities that support the operation of a primary facility. The preamble[4] to the rule, discusses that "each source is to be classified according to its primary activity, which is determined by its principal product or group of products produced or distributed, or services rendered. Thus, one source classification encompasses both primary and support facilities, even when the latter includes units with a different two-digit SIC code. Support facilities are typically those which convey, store, or otherwise assist in the production of the principal product."

The AQEA states:

> *The Project will be located adjacent to the existing Milton R. Young (MRY) Station and is designed to capture, purify, and sequester up to 13,000 tons per day (~4.75 million tons per year) of CO_2 from MRY Station's coal-fired boilers (MRY Unit 1 and MRY Unit 2).*

The EPA recommends that the NDDEQ include additional information in the permit record to support the conclusion that a support facility relationship does not exist between the DCC project and MRY. Recommended details to consider or clarify in supplementing the permit record on the appropriate industrial classification for DCC includes the role of DCC and its principal product produced or distributed (if any), or services rendered, and the source of power to operate DCC.

If upon additional review, the NDDEQ determines that that the MRY and DCC facilities should be aggregated as one source under the CAA Title I permitting programs, (and by extension 40 CFR Part 63 and 40 CFR Part 70) then the EPA recommends the NDDEQ modify the permit and supporting documentation according to the North Dakota State Implementation Plan.

Comments Related to Incorporation by Reference

Incorporation by reference into permits is an allowable way for permitting authorities to cite requirements applicable to permitted sources. One of the earliest documents recognizing the utility of this process was the March 5, 1996, *White Paper Number 2 for Improved Implementation of The Part 70 Operating Permits Program* (*White Paper 2*).[5] This document states:

> *Citations, cross references, and incorporations by reference must be detailed enough that the manner in which any referenced material applies to a facility is clear and is not*

[4] 45 FR at 52694
[5] https://www.epa.gov/sites/default/files/2015-08/documents/wtppr-2.pdf, accessed October 16, 2023, accessed October 16, 2023.

> *reasonably subject to misinterpretation. Where only a portion of the referenced document applies, applications and permits must specify the relevant section of the document. Any information cited, cross referenced, or incorporated by reference must be accompanied by a description or identification of the current activities, requirements, or equipment for which the information is referenced.*

White Paper 2 at 37. Further, the EPA stated:

> *Incorporation by reference in permits may be appropriate and useful under several circumstances. Appropriate use of incorporation by reference in permits includes referencing of test method procedures, inspection and maintenance plans, and calculation methods for determining compliance. One of the key objectives Congress hoped to achieve in creating title V, however, was the issuance of comprehensive permits that clarify how sources must comply with applicable requirements. Permitting authorities should therefore balance the streamlining benefits achieved through use of incorporation by reference with the need to issue comprehensive, unambiguous permits useful to all affected parties, including those engaged in field inspections.*

White Paper 2 at 38.

The EPA has also addressed the subject of incorporation by reference more recently in Administrative Orders for title V operating permit Petitions to Object. The March 18, 2022, Exxon Baytown Order[6] and the March 10, 2020 Waha Gas Plant Order[7] both address the issue and cite to *White Paper 2* as the basis for establishing the appropriate methodologies in the correct us of incorporation by reference.

In the DCC permit to construct there are instances were only a portion of the referenced applicable requirement applies and the permit does not specify that portion. Condition II.C.1 of the draft permit incorporates by reference 40 CFR Part 60 Subpart IIII. While Condition II.C.1 does not state which emission unit at the proposed facility is subject to the cited Subpart, the table above Condition II.C.1 does indicate the that the emergency diesel fire pump engine is subject to the Subpart. However, neither Condition II.C.1 nor the table provide enough information for the reader to determine which emission limit and associated monitoring, recordkeeping and reporting applies to the emission unit. The level of incorporation by reference used in the draft permit is insufficient for the applicant and public to determine what standard applies to the unit and how the source is to achieve compliance with that standard.

In addition, Condition II.D.1 incorporates by reference 40 CFR Part 63 Subpart ZZZZ. Unlike the previous Condition, this Condition does not have any associated Table stating which unit the standard applies to, nor does the Condition itself state which emission unit is subject to the standard. It is up to the reader of the permit to assume it is the emergency diesel fire pump engine, and similar to Condition II.C.1, there is no information available in the permit to determine which of the Subpart ZZZZ standards, monitoring, recordkeeping or reporting apply.

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[6] https://www.epa.gov/system/files/documents/2022-02/etc-waha-order_1-28-22.pdf, accessed October 16, 2023.
[7] https://www.epa.gov/system/files/documents/2022-02/etc-waha-order_1-28-22.pdf, accessed October 16, 2023.

This level of incorporation by reference is similarly insufficient for the applicant and public to determine which standard applies and what are the associated compliance requirements.

EPA recommends that the NDDEQ revises the draft permit to construct to include which portions of the associated regulations apply to each permit condition and to clearly state the standard or associated limit and compliance requirements. The references should be unambiguous and useful to all affected parties.

Comments Related to the Ambient Air Boundary used in Modeling

Appendix 2 of the AQEA document supplied in the record discusses the air dispersion modeling done to demonstrate compliance with the North Dakota Ambient Air Quality Standards. As a part of this document, the applicant included site layout maps and maps expressing a visual representation of the established air dispersion modeling receptor grid.

These maps contain the ambient air boundary for the MRY facility. The EPA defines ambient air within 40 CFR 50.1(e) as "that portion of the atmosphere, external to buildings, to which the general public has access". The EPA has long followed a policy that allows for the exclusion of certain areas, outside of a building, from ambient air. As described in a 1980 letter from then-Administrator Douglas Costle to Senator Jennings Randolf, this "exemption from ambient air is available only for the atmosphere over land owned or controlled by the source and to which the public is precluded". The December 2019 *Revised Policies on Exclusions from "Ambient Air"*[8] continues to support that concept of exclusions from ambient air and establishes what requirements are needed to demonstrate that the public is precluded.

Figure A-1 in Appendix 2 of the AQIA establishes what appears to be an ambient air boundary for the facility that is used to delineate where the air dispersion modeling receptor grid is located. This receptor grid is shown in Figure A-4 and excludes the area inside the defined ambient air boundary.

However, in the permit's June 2, 2023 application, in Figure 2-1, the larger ambient air boundary contains a smaller defined area labeled as the DCC Separation and Purification Plant and locates the MRY facility's Unit 1 and Unit 2 in relationship to the DCC facility. The larger ambient air boundary area used in the air dispersion modeling process to establish the modeling receptor grid appears to be the MRY ambient air boundary and the DCC ambient air boundary, according to Figure 2-1 appears to be a smaller area located within the MRY boundary. As it contains MRY Unit 1 and Unit 2, this would appear to be the MRY ambient air boundary.

The EPA provided guidance for the treatment of ambient air in a June 22, 2007 memorandum to the Regional Air Division Directors.[9] With respect to a particular source, EPA's practice has been to exempt an area from ambient air when the source (1) owns or controls the land or

[8] https://www.epa.gov/sites/default/files/2019-12/documents/revised_policy_on_exclusions_from_ambient_air.pdf, accessed October 16, 2023.
[9] *Interpretation of "Ambient Air" In Situations Involving Leased Land Under the Regulations for Prevention of Significant Deterioration (PSD)*, June 22, 2007, available at https://www.epa.gov/sites/default/files/2015-07/documents/leaseair.pdf, accessed October 16, 2023.

property; and (2) precludes public access to the land or property using a fence or other effective barrier. As discussed above within the aggregation section, the permit states that DCC and MRY are separate facilities and are not under common control. However, for the purposes of modeling, areas are exempted because they are owned or controlled by the same party. Both scenarios are unlikely to be both simultaneously true. The EPA also discussed situations where a lessor/lessee situation exists and one facility is nested within the ambient air boundary established by the other in the June 22, 2007 guidance. This discussion may be useful in determining the extent and location of ambient air for the DCC project.

EPA recommends that the NDDEQ review the cited documents and confirm that the ambient air boundary and associated receptor grid used in the air dispersion modeling for the DCC project is accurate based on definitions of ambient air and the boundary that DCC establishes. If that boundary is different than the one used to define the model's receptor grid, the EPA recommends that the NDDEQ or the applicant rerun the model to determine no NAAQS concerns exist.

Comments Related to CAA Section 112(g)

The EPA has concerns with the CAA section 112(g) case-by-case maximum achievable control technology (MACT) analysis for hazardous air pollutants (HAPs) in the permit application, particularly regarding the use of acetaldehyde as a surrogate pollutant for all organic HAPs. The DCC permit also has emissions testing for acetaldehyde only, and asserts it is a suitable surrogate for all HAPs. In a MACT analysis, a surrogate is allowed when the control of the surrogate indicates a similar or identical control of the other pollutants. In this case, acetaldehyde and amines (including nitrosamines) exhibit different behaviors under different control scenarios. The effectiveness of controls for amine HAPs should therefore be evaluated separately from the effectiveness of controls for aldehyde HAPs (acetaldehyde and formaldehyde). The EPA recommends that the NDDEQ address this deficiency in the MACT analysis.

Conclusion

We are committed to working with the NDDEQ to ensure that the final Permit to Construct is consistent with all applicable EPA-approved North Dakota state implementation plan requirements.

If you have questions or wish to discuss this further, please contact me, or your staff can contact Donald Law at (303) 312-7015 or law.donald@epa.gov.

Sincerely,

Recoverable Signature

X Adrienne Sandoval

Signed by: Environmental Protection Agency

Adrienne Sandoval
Director
Air and Radiation Division

A.5.i – DCC East Project LLC Response to Comments

5301 32nd Ave. South
Grand Forks, ND 58201
Phone 701.795.4000

DCC EAST PROJECT LLC

November 16, 2023

Jim Semerad, Director, Division of Air Quality
David Stroh, Environmental Engineer
North Dakota Department of Environmental Quality
4201 Normandy Street, 2nd Floor
Bismarck, ND 58503-1324

Re: Application of DCC East Project LLC for Permit to Construct No. ACP-18194 for Dakota Carbon Center CO_2 Separation and Purification Plant

Dear Mr. Semerad and Mr. Stroh:

Please accept this letter as a further supplement to the record for the application of DCC East Project LLC (DCC East) for Permit to Construct No. ACP-18194 for the Dakota Carbon Center CO_2 Separation and Purification Plant (the DCC Facility) in Oliver County, North Dakota. This letter responds to the comments received from EPA Region 8 on the Draft Permit to Construct. DCC East does not intend to waive confidentiality privilege for the underlying agreements discussed in this response letter that contain trade secret-business proprietary information under NDCC 44-04-18.4(1) and confidential business information under 40 CFR Part 2. DCC East offers the following discussion of agreements to further supplement the record subject to confidentiality treatment of the agreements.

Comments related to Aggregation

DCC East Response: In its comments, EPA Region 8 recommended that NDDEQ include additional information in the permit record to support the separate source determination that NDDEQ made for the DCC Facility under the New Source Review (NSR) preconstruction permitting program. As correctly noted by EPA Region 8, NDDEQ found the existing Milton R. Young (MRY) Station and the proposed DCC Facility to be separate sources based on its determinations that (1) the two facilities are not under the control of the same person (or persons under common control) and (2) the two facilities do not belong to the same industrial grouping (and one entity is not support facility for the other). NDDEQ summarized its review of the application in the Air Quality Effects Analysis (AQEA) stating that:

> *DCC will be responsible for operational control of the Project, including control over air emitting activities that affect permit compliance (i.e., not under common control), and the owner of MRY Station will not hold a majority ownership in DCC.*

DCC's Project has standard industrial classification (SIC) code 2813 compared to MRY Station SIC code of 4911 (i.e., do not belong to the same industrial grouping).

Based on these findings, NDDEQ concluded that two of the three criteria that are necessary to find that the two facilities are located at the same stationary source are absent and therefore aggregation would not be appropriate. DCC East supports NDDEQ's conclusion and provides the following additional responsive information to support the permit record.

Common Control. The MRY Station and the proposed DCC Facility are not under the control of the same person or persons under common control. In its April 30, 2018 *Meadowbrook* determination, EPA established that the focus of the common control analysis is on whether one entity has power or authority to dictate decisions over any aspect of another entity's operations that could affect the applicability of, or compliance with, permitting requirements.[1] Neither owner of the electric generating units at the MRY Station will have such power or authority over the proposed DCC Facility.

First, the MRY Station and the proposed DCC Facility are not owned by the same person. The MRY Station consists of a two-unit electric generation plant, Unit 1 owned by Minnkota Power Cooperative, Inc. (Minnkota), and Unit 2, owned by Square Butte Cooperative (Square Butte). Minnkota operates both units at the MRY Station. In contrast, the proposed DCC Facility will be owned and operated by a separate legal entity named DCC East.

Second, the MRY Station and proposed DCC Facility are not owned by persons under common control. If one person owns a majority interest in two facilities, or the persons owning the two facilities, then it may be possible for a reviewing agency to presume that the two facilities or persons are under common control.[2] But that is not the case here. Neither Minnkota nor Square Butte will own a majority interest in the DCC Facility or DCC East. Instead, a majority interest in both the DCC Facility and DCC East will be owned by an unrelated third party or third parties, including TC Energy Carbon Capture LLC, which is a subsidiary of TC Energy Corporation.

The DCC Facility is being developed pursuant to the terms of commercial agreements, including a Joint Development Agreement (JDA), dated June 23, 2023, between Minnkota and TC

[1] EPA Letter: William L. Wehrum, Assistant Administrator, Office of Air and Radiation, U.S. Environmental Protection Agency, to the Honorable Patrick McDonnell, Secretary, Pennsylvania Department of Environmental Protection (April 30, 2018) (hereinafter "*Meadowbrook* Letter").

[2] EPA Region 8 has found that two wholly or majority-owned subsidiaries are "persons under common control" and thus meet that criterion for source determinations. EPA stated that it expects that common ownership inherently involves the parent company's ability to dictate, at a certain level, a substantial portion of the activities of its subsidiaries in a manner that could impact compliance with, or the applicability of, air permitting requirements. Thus, based on the principles outlined in the Meadowbrook and Ameresco letters, common ownership is a sufficient basis for determining that multiple entities are "persons under common control…given that common ownership inherently involves a significant amount of control, the EPA thinks it would be reasonable for permitting authorities to rely on the existence of common ownership when determining entities are "persons under common control" rather than undertaking a more detailed analysis." EPA Region 8, *Single Source Determination for Jaques Compressor Station,* (2019).

Energy Carbon Capture LLC (TC Energy CC).[3] These agreements provide for TC Energy CC's majority ownership share of the DCC Facility through its equity interest in DCC East. Accordingly, the owner of one unit at the MRY Station, Minnkota, will at most own a minority interest in the proposed DCC Facility and DCC East. Given this project development structure, the two facilities are not owned by persons under common control.

EPA Region 8 included in its comment letter references to "Project Tundra" on Minnkota's website to suggest that Minnkota has control over both the MRY Station and the DCC Facility. Information contained on the website does not alter the structure reflected in the recently executed commercial agreements. Rather, the Project Tundra website reflects Minnkota's historical role as a project sponsor to lead the development and advancement of CCS technology in the electric generation industry. Minnkota has been promoting Project Tundra since 2015, first acting as host site for carbon capture research and geologic sequestration characterization efforts under many federal and state funded research programs. However, a CO_2 gas separation plant of the economic and financing scale and requirements such as this cannot be constructed and operated primarily by Minnkota. Minnkota has been transparent throughout Project Tundra's development by clearly communicating to its members, the community, and stakeholders that Minnkota cannot and will not be a majority owner of the proposed DCC Facility. Through project financing, equity, and debt investment, Minnkota will own no more than a minority interest, as is confirmed by the June 28, 2023 press release on that website, announcing the foregoing commercial agreements with TC Energy, among others, to move "Project Tundra into its final stage of project development."

Finally, neither Minnkota nor Square Butte will have the power or authority to dictate decisions over any aspect of the DCC Facility's operations that could affect the applicability of, or compliance with, permitting requirements.[4] The DCC Facility will be operated and managed by DCC East, as confirmed by the commercial agreements between Minnkota and TC Energy CC, including the JDA and a separate Flue Gas Supply Agreement (FGSA), dated June 23, 2023.[5] These agreements also confirm that DCC East holds all environmental responsibility and liabilities, including the obligation to obtain permits and authorizations under and comply with all environmental requirements for the emissions generated by proposed DCC Facility. Contractual provisions such as these further highlight the absence of any common power or authority over the facilities relevant to the common control test articulated by EPA in the *Meadowbrook* letter.

Same Industrial Grouping. EPA Region 8 recommended providing additional details for the permit record regarding the role of DCC East and its principal product produced or distributed (if any) or services rendered, and the source of power to operate the DCC Facility. NDDEQ's

[3] DCC East identifies and provides information from confidential commercial agreements for the limited purposes of supporting the permit record. DCC East does not intend to waive any claim to confidentiality for the referenced agreements that contain trade secret-business proprietary information under NDCC 44-04-18.4(1) and confidential business information under 40 CFR Part 2.
[4] *Meadowbrook* Letter.
[5] DCC East identifies and provides information from confidential commercial agreements for the limited purposes of supporting the permit record. DCC East does not intend to waive any claim to confidentiality for the referenced agreements that contain trade secret-business proprietary information under NDCC 44-04-18.4(1) and confidential business information under 40 CFR Part 2.

permit record correctly documents the industrial grouping for MRY as 4911 (Electric Services) and for the proposed DCC Facility as 2813 (Industrial Gases). The operations of the MRY Station and the DCC Facility are classified under different two-digit SIC codes, and therefore this source determination criterion is also not met. As noted in EPA Region 8 comments, EPA has stated in guidance that one source classification may encompass both primary and support facilities, even when the latter includes units with a different two-digit SIC code: "[s]upport facilities" that "convey, store, or otherwise assist in the production of the principal product or group of products produced or distributed, or services rendered" should be considered under one source classification.[6]

In this case, no such support facility relationship exists because the facilities produce different principal products. Minnkota exists for the sole purpose of meeting the electricity needs of rural member cooperatives in eastern North Dakota and northwestern Minnesota. The MRY Station is part of Minnkota's portfolio of generation assets that have and will continue to be used to provide electricity in Minnkota's service area. The operation of the MRY Station will not be dependent on or supported by the construction and operation of the DCC Facility. The primary product of the MRY Station is electricity, and MRY will continue to provide this electrical product irrespective of the DCC Facility.

In contrast, the principal product of the DCC Facility is a concentrated CO_2 gas stream.. The concentrated CO_2 gas will be sequestered to generate tax credits for the benefit of the owners of DCC East. The DCC Facility will manufacture the CO_2 product from flue gas that is fully authorized to be emitted to the atmosphere from the MRY Station. The proposed DCC Facility will be powered by electricity from Minnkota via an arms-length contractual arrangement.

The relationship of the MRY Station and the DCC Facility is similar to the relationship of Red Cedar Gathering Company's Arkansas Loop and Simpson Treating Plant and a proposed carbon capture facility evaluated by EPA Region 8 in its August 24, 2023 determination. EPA Region 8 concluded there that "the facts do not establish a support relationship of the proposed new CO_2 Plant to the Arkansas Loop and Simpson Treating Plants." In *Red Cedar*, EPA Region 8 noted that the permit for the treating plants did not prohibit venting of waste CO_2 gas, stating "[i]n that sense, while an environmental benefit, in taking the waste CO_2 gas from the treating plants to make a secondary product, the CO_2 Plant would not convey, store, or otherwise assist in the production of the principal product for the treating plants." Here, the MRY Station air permit does not prohibit venting of the MRY Station flue gas, and in taking the CO_2 from MRY Station to make a product, DCC would not be conveying, storing, or assisting in the production of the "principal product" for MRY Station. EPA Region 8 also emphasized the established nature of Red Cedar, highlighting that if the carbon capture facility is not built, Red Cedar would continue operating as it has for years. EPA Region 8 stated that "[e]xisting EPA policy…does not reasonably support consideration of an existing source long established with a primary activity that supplies a waste gas from that activity to be considered a support facility of a proposed new source." Likewise,

[6] Requirements for Preparation, Adoption, and Submittal of Implementation Plans; Approval and Promulgation of Implementation Plans, 45 Fed. Reg. 52,676, 52,695 (August 7, 1980).

MRY Station went into service decades ago, and MRY Station will continue to operate, even if the DCC Facility is not built. No support facility relationship exists between MRY Station and the DCC Facility based on these facts and Region 8 precedent.

Facility Emissions. EPA Region 8 also stated in its comments with respect to aggregation that "[t]his determination will dictate whether or not the project requires a permit to construct a minor or major new source or a minor or major 'modification' to an existing source." That consequence is not accurate in this case. Even if the DCC Facility had been improperly evaluated under NSR permitting program as a modification to the MRY Station, only a minor modification permit would have been required. The DCC Facility potential to emit for each regulated NSR pollutant does not equal or exceed the significant amount for that pollutant under the modification thresholds found at 40 CFR § 52.21(b)(23).

Conclusion. NDDEQ properly determined the MRY Station and the proposed DCC Facility to be separate sources for NSR permitting purposes based on the information in the record.

Comment: Ambient air boundary

DCC Response: In its comments, EPA Region 8 recommended that NDDEQ review the cited documents and confirm that the ambient air boundary and associated receptor grid used in the air dispersion modeling for the DCC Facility for accuracy. If that boundary is different than the one used to define the model's receptor grid, then EPA recommended that the NDDEQ or the applicant rerun the model to confirm that no NAAQS concerns exist.

The permit record confirms that the use of the property boundary of the MRY Station as the ambient air boundary is appropriate. EPA defines "ambient air" as "that portion of the atmosphere, external to buildings, to which the general public has access."[7] Applying this definition, EPA has stated "that portion of the atmosphere over land owned or controlled by the stationary source may be excluded where the source employs measures, which may include physical barriers, that are effective in precluding access to the land by the general public."[8]

Minnkota maintains a fenced physical barrier preventing unauthorized entry of the public into the MRY Station. DCC East used the fenced MRY Station property boundary in its modeling demonstrations. The fenced barrier will remain after the start-up of the DCC Facility. The proposed operation plan for the DCC Facility consists of use of the existing MRY Station security gate for designated access across Minnkota property to the DCC Facility secured site. The DCC Facility will be located on leased property, adjacent to the MRY Station, and will be considered "nested" within the footprint of Minnkota's access restrictions. The MRY Station is a critical infrastructure site and requires strict adherence to security protocols to mitigate access risk. As

[7] 40 CFR 50.1(c).
[8] EPA Memorandum: Andrew R. Wheeler, U.S. Environmental Protection Agency, to Regional Administrators, regarding Revised Policy on Exclusion from "Ambient Air" (December 2, 2019).

such, authorized employees and contractors of the DCC Facility will be required to comply with security and access requirements of the MRY Station and invitee practices and policies.

Given the physical barrier and access control of Minnkota for the MRY Station, there is no access of the general public. Moreover, even the parcel leased to DCC East is not ambient air to Minnkota as lessor for the evaluation of MRY Station emissions. EPA has acknowledged that ambient air over land that a lessor owns and leases to a lessee is not ambient air to the lessor:

> *When two (or more) companies operate separate sources on property owned by one company and leased in part to the other, and the lessor retains control over public access to the entire property and actually maintains a physical barrier around it to preclude public access – the air over the entire property (including the leased portion) is not ambient air to the lessor.*[9]

For this reason, the DCC East leased parcel is not ambient air for any evaluation of the emissions from the MRY Station. This is true both for the direct emissions from MRY Station and the indirect, pass-through flue gas that will exit the new absorber stack following processing in the proposed DCC Facility. The FGSA confirms that title to the flue gas from the MRY Station will remain in the name of the MRY owners when the flue gas is emitted from the absorber stack.[10] Consequently, the modeling of the impacts of the pass-through emissions from the Station may use the MRY Station boundary as the ambient air boundary for NAAQS modeling. While the DCC Facility will also emit pollutants that are not considered pass-through emissions, the modeled impacts of those pollutants are not expected to be materially affected by a change in the ambient air boundary, given that they represent such a small percentage of emission rates modeled.

Comment: Case-by-Case MACT

DCC Response: EPA Region 8 noted that a surrogate is allowed when the control of the surrogate indicates a similar or identical control of the other pollutants. In this case, EPA Region 8 commented that acetaldehyde and amines may exhibit different behaviors under different control scenarios, and that the effectiveness of controls for amine hazardous air pollutants (HAPs) should therefore be evaluated separately from the effectiveness of controls for aldehyde HAPs.

As described in section 7.1 of the Case-by-Case MACT Analysis, aldehydes, including acetaldehyde and formaldehyde, are expected to make up a large majority of the HAP emissions from the carbon absorber column, accounting for more than 98 percent of all HAP emissions (MACT Analysis, Table 2-1). The remaining HAP constituents, accounting for approximately 2

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[9] EPA Memorandum: Stephen D. Page, Director, Office of Air Planning & Standards, U.S. Environmental Protection Agency, to Regional Air Division Directors (June 22, 2007).

[10] DCC East identifies and provides information from confidential commercial agreements for the limited purposes of supporting the permit record. DCC East does not intend to waive any claim to confidentiality for the referenced agreements that contain trade secret-business proprietary information under NDCC 44-04-18.4(1) and confidential business information under 40 CFR Part 2.

percent of total HAP emissions, are generally classified as amines. An amine is a derivative of ammonia in which one, two, or all three hydrogen atoms are replaced by hydrocarbon groups.

Control systems and technologies available to reduce HAP emissions from the carbon absorber column were evaluated in the MACT Analysis for their ability to reduce HAP formation in the absorption process and to control HAP emissions at the CO_2 absorber column exhaust stacks. Potentially available controls included:

- Process and Design Modifications
    - Absorber Intermediate Cooling
    - Materials of Construction
- Post-Absorber Column Controls
    - Thermal and Catalytic Oxidation
    - Water Wash
        - Acid Wash

Each control option was evaluated for technical feasibility, effectiveness, and applicability to the carbon absorber column. The MACT Analysis included an assessment of the formation mechanisms for both amine and aldehyde HAPs, as well as the technical feasibility and effectiveness of post-absorber controls with respect to both amine and aldehyde HAP emissions. The MACT Analysis concluded that process design upgrades, including absorber column intermediate cooling systems, upgraded materials of construction, and pre-absorber column pollution control systems, would reduce the formation of <u>both</u> amine and aldehyde HAPs.

Process Controls and Design Upgrades. As described in Section 7.2.1 of the MACT Analysis, the solvent used for CO_2 capture is separated from the CO_2-rich solvent in the stripper column and recycled for reuse in the capture process. Emissions from the absorber column generally consist of liquid entrainment (*i.e.,* solvent carryover), aerosol/mist emissions, and gas-phase or vapor solvent degradation byproducts. The amine solvent used to absorb CO_2 from the flue gas is susceptible to degradation due to heat (thermal degradation) and the presence of oxygen (oxidative degradation). Thermal and oxidative degradation of the solvent can lead to the formation of both amine and aldehyde HAPs; thus, process controls or design modifications that reduce degradation will reduce the formation of both amine and aldehyde HAPs.

Oxidative degradation of the solvent occurs due to the presence of oxygen and metal ions, primarily iron in the flue gas. The highest oxygen concentration will occur in the absorber column which is the most likely place for oxidative degradation of the amine. Degradation products include fragments of the amine, such as ammonia and the formation of byproducts such as acetaldehyde, formaldehyde, and ammonia.[11] Oxidative degradation mainly depends on the metal ion

[11] Shao, Renjie and Strangeland, Aage; Amines Used in CO2 Capture – Health and Environmental Impacts, The Bellona Foundation, September 2009, available at: https://network.bellona.org/content/uploads/sites/3/fil_Bellona_report_September_2009_-_Amines_used_in_CO2_capture.pdf, accessed November 1, 2023.

concentration and oxygen concentration in the absorber column. Metal ions, especially iron (Fe), is an important catalyst in oxidation of amines. Metal ions will generate oxide radical which will increase the oxidation rate of amines. Reducing metal ion concentrations in the absorber column will limit the oxidative degeneration and the formation of both amine and aldehyde HAPs.

Thermal degradation may occur in the absorber column and stripper column and is generally dependent upon process operating temperatures. High temperatures will break the chemical bonds of amines and increase the reaction rate of amines reacting with CO_2 to form the thermal degradation byproducts, which will also cause loss of amines in the system. Studies indicate that thermal degradation primarily takes place during the solvent regeneration process in the stripper column, at elevated temperatures and in the presence of CO_2;[12] however, thermal degradation may occur in the absorber column at elevated temperatures. Products of the thermal degradation process are often more volatile than amine solvent and are likely to evaporate in the absorber, resulting in increased emissions.[13] Designing the absorber column with intermediate cooling systems to reduce temperatures within the column will reduce thermal oxidation and the formation of both amine and aldehyde HAPs.

As described in Section 7.2.1 of the MACT Analysis, process controls and design changes incorporated into the design of the DCC Facility, including absorber column intermediate cooling and upgraded materials of construction to eliminate introducing Fe into the absorber, are expected to reduce solvent degradation and the formation of both amine and aldehyde HAPs. Based on information provided by the carbon capture system vendor, design changes implemented to reduce both thermal and oxidative degradation of the solvent will reduce HAP formation by approximately 40% percent from pre-design change levels.

Post-Absorber Column Controls. Post-absorber column control systems were evaluated for the control of both amine and aldehyde HAPs (MACT Analysis, Sections 7.2.3 and 7.2.4). Based on an assessment of technical feasibility and applicability to the absorber column exhaust, it was determined that water wash and acid wash were the only technically feasible post-absorber column control systems. As EPA Region 8 noted, the amine- and aldehyde-based HAP emissions will react differently in the post-absorber column control systems. However, the water wash and acid wash systems are generally designed to address amine carryover from the absorber column and reduce aerosol amine and amine droplets that can result in VOC emissions. The systems also play an important role in curtailing amine losses and maintaining the water balance of the solvent in the absorber column.

Although aldehydes are water soluble, they do not dissociate in water and may not be effectively controlled using a water wash system. In addition, aldehydes are weak acids as the hydrogen atom in the carbonyl group of an aldehyde molecule provide H^+ ions; thus, the acid wash system is not expected to provide effective aldehyde-based HAP emission control. No emissions

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[12] Buvik, V, Hoisaeter, K, Vevelstad, S., Knuutila, H., A Review of Degradation and Emissions in Post-Combustion CO_2 Capture Pilot Plants, International Journal of Greenhouse Gas Control, February 18, 2021, pg. 2.
[13] *Id.*

data were identified from the carbon capture system vendor or technical literature demonstrating effective aldehyde control using either water wash or acid wash systems. Therefore, no aldehyde-based HAP control was assumed with these systems. These systems are instead designed for reduction of amines.

Projected HAP Emissions and Exhaust Gas Concentration. Based on vendor emission estimates, HAP emissions from the CO_2 absorber column are summarized in the following table. HAP emissions were provided by the carbon capture system vendor, taking into account reduced HAP formation with the intermediate cooling and upgraded materials of construction. Emission estimates assumed no additional control in the water/acid wash systems, other than reducing amine solvent carryover and reducing VOC emissions.

Projected Project-Related §112 Potential-to-Emit HAP Emissions

Hazardous Air Pollutant	**Projected Emission Rate[14]* (lb/hr)**	**Concentration ppbvd @ 15% O_2**
Clean Air Act §112 Listed HAPs		
Acetaldehyde	7.5	464
Formaldehyde	0.4	36
Acetamide	0.12	5.5
Ethylenimine	0.0041	0.3
N-nitrosodiethylamine	0.005	0.1
Nitrosodimethylamine	0.010	0.4
N'-Nitrosomorpholine	0.004	0.09
Total § 112 Listed HAPs	8.04	NA

The feasibility of testing for amine-based HAPs must also be considered. Given the low concentration of amine-based HAPs in the exhaust gas, stack testing would not be feasible. EPA Test Method 320 (Vapor Phase Organic and Inorganic Emissions by Extractive FTIR) would be used to measure both aldehyde and amine-based organic HAP emissions. Test Method 320 specifies a number of analytical uncertainty parameters that the analyst must calculate to characterize the FTIR system performance; however, it does not provide analytical detection limits for all organic compounds. Based on published information it appears that the test method by itself may achieve a minimum detection limit of approximately 100 ppb, and an optimal minimum detection limit as low as 10 ppb for formaldehyde in a natural gas fired turbine field test using optimized hardware and software.[15] No specific information was identified regarding method

[14] Projected lb/hr emission rates are estimated for each HAP based on emissions data and modeling conducted by the control system vendor, and represent worst-case conditions for each individual constituent, which could not occur simultaneously for all constituents.

[15] See, Montrose Environmental, Enhanced Measurements of Low-Concentration Emissions from Combustion Units, available at: https://montrose-env.com/wp-content/uploads/2017/09/CIBO-Low-Level-Emissions-Technologies-Updated.pdf, accessed November 2, 2023; Clean Air, An Alternative Option in EtO Testing, June 18, 2020, available at: https://www.cleanair.com/alternative-option-in-eto-testing/, accessed November 1, 2023.

detection limits for amine-based organic constituents using Test Method 320; however, it appears likely based on optimal minimum detection limit reported for formaldehyde emissions, that the amine concentrations in the exhaust gas (all less than 0.5 ppb) will be well below the minimum detection limit.

Conclusion. Aldehyde HAPs are expected to account for more than 98 percent of all HAP emissions from the absorber column, with acetaldehyde being the individual HAP emitted at the highest rate. Acetaldehyde is proposed as a surrogate for all HAP emissions because (1) acetaldehyde accounts for approximately 93 percent of all HAP emissions; and (2) the design and process changes proposed to reduce thermal and oxidative degradation of the amine solvent will reduce the formation of both amine and aldehyde HAPs.

Sincerely,

DCC East Project LLC

Robert N. McLennan
President and CEO

A.5.ii – DCC East Project LLC Supplemental Response to Comments

5301 32nd Ave. South
Grand Forks, ND 58201
Phone 701.795.4000

DCC EAST PROJECT LLC

December 26, 2023

Jim Semerad, Director, Division of Air Quality
David Stroh, Environmental Engineer
North Dakota Department of Environmental Quality
4201 Normandy Street, 2nd Floor
Bismarck, ND 58503-1324

Re: Supplemental Response for Application of DCC East Project LLC for Permit to Construct No. ACP-18194 for Dakota Carbon Center CO_2 Separation and Purification Plant

Dear Mr. Semerad and Mr. Stroh:

Please accept this letter as a further supplement to the record for the application of DCC East Project LLC (DCC East) for Permit to Construct No. ACP-18194 for the Dakota Carbon Center CO_2 Separation and Purification Plant (the DCC Facility) in Oliver County, North Dakota. This letter offers additional information concerning NDDEQ's determination in the draft Air Permit to Construct that acetaldehyde would be tested as a surrogate for validation of the Section 112 HAPs emissions.

DCC East provides the enclosed report authored by third-party consultant TRC entitled, "Evaluation of the Feasibility of EPA Method 320 to Measure Air Emissions from a Carbon Dioxide Removal System," dated December 15, 2023 (the TRC Report). The TRC Report provides expert analysis of Method 320 as applied to the emissions estimates represented in the application. Consistent with our discussion in our Response Comment dated November 16, 2023, aldehyde HAPs are expected to account for more than 98 percent of all HAP emissions from the absorber column, with acetaldehyde being the individual HAP emitted at the highest rate. The TRC Report further supports acetaldehyde as a surrogate for all HAP emissions because it is the only CAA Section 112 HAP emitted in a greater than 1.0 part per million quantity that is measurable by EPA Method 320. The Report provides discussion of the remaining estimated HAPs, identifying whether they are not detectable (1) due to the lack the availability of a reference standard in the spectral library for the HAPor (2) due to a concentration value below the FTIR spectrometer lowest detection limits, thereby resulting in no quantity value being detected.

DCC East continues to support the use of acetaldehyde as a surrogate for validation of the Section 112 HAPs emissions. While DCC East does not believe that additional verification testing is necessary for the Permit to Construct, formaldehyde could be tested using Method 320. It is the second highest estimated Section 112 HAP emissions value, albeit infinitesimal at 0.4 lb/hr.

Formaldehyde, at its estimated emissions value, is projected to be unmeasurable. For this reason, adding formaldehyde would be a conservative measure to validate emissions estimates.

Thank you for your consideration of this additional information in the permit record.

Sincerely,

DCC East Project LLC

Robert N. McLennan
President and CEO

FINAL REPORT
Evaluation of the Feasibility of EPA Method 320 to Measure Air Emissions from a Carbon Dioxide Removal System

Performed For
DCC East Project LLC

Draft Report No.
TRC Environmental Corporation Report 581624

Report Submittal Date
12/15/23

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Introduction

The Project Sponsors of DCC East Project LLC are developing Project Tundra, the goal of which is to produce CO_2 from the flue gas emissions from the Milton R. Young Station in Center, North Dakota and inject the captured gases into permeable bedrock thousands of feet below the facility("Project"). A key component of the Project is the Carbon Capture system. CO_2 produced by the capture system is injected into bedrock as described above, and the remaining gases from the flue gas emissions and the capture facility absorber are exhausted to the atmosphere. The North Dakota Department of Environmental Quality (DEQ) has proposed measurement of the CO_2 production facility emissions at the outlet of the absorber using EPA Method 320 (extractive Fourier Transform Infrared (FTIR) spectroscopy).

The Project Sponsors retained Thomas A. Dunder, Ph.D. from TRC to evaluate the feasibility of measuring these emissions with FTIR technology. Dr. Dunder has over 30 years of experience conducting air emissions measurements by FTIR and has detailed knowledge of the technology and its capabilities.

This report summarizes data provided by the CO_2 capture technology vendor (expected emissions, effluent conditions) ("Vendor") and details the conversion from lb/hr emission rates quoted by the vendor to parts per million concentrations necessary to determine the applicability of FTIR measurements in terms of detection limits.

Results Summary

The table below summarizes the results of the calculations. Detailed explanations and sample calculations of the data conversions and interpretation and provided in the succeeding sections.

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Compound	Emission Rate	Reference Spectrum	MW	SCFM	DSCFM	ppmvd	Measureable
HAPS	lb/hr	Available?	g/mol	Standard ft^3/min	Dry Standard ft^3/min	parts per million, dry basis	By M320
Acetaldehyde	**7.5**	**Y**	**44.053**	**1266249.6**	**1178878.4**	**0.93**	**Y**
Formaldehyde	**0.4**	**Y**	**30.026**	**1266249.6**	**1178878.4**	**0.073**	**N**
Acetamide	0.12	N	59.07	1266249.6	1178878.4	0.011	N
Ethyleneimine	0.0041	N	43	1266249.6	1178878.4	0.00052	N
N-nitrosodiethylamine	**0.0**	**Y**	**102.14**	**1266249.6**	**1178878.4**	**0.00027**	**N**
Nitrosodimethylamine	**0.0**	**Y**	**74.082**	**1266249.6**	**1178878.4**	**0.00074**	**N**
N'-Nitrosomorpholine	**0.0**	**Y**	**116.12**	**1266249.6**	**1178878.4**	**0.00019**	**N**
Other HAPS							
Ammonia	**2.9**	**Y**	**17.031**	**1266249.6**	**1178878.4**	**0.93**	**Y**
Diethylamine	**2.0**	**Y**	**73.14**	**1266249.6**	**1178878.4**	**0.15**	**N**
Ethanolamine	**1.1**	**Y**	**61.08**	**1266249.6**	**1178878.4**	**0.098**	**N**
Ethylamine	**0.8**	**Y**	**45.08**	**1266249.6**	**1178878.4**	**0.093**	**N**
Ethylenediamine	0.25	N	60.1	1266249.6	1178878.4	0.023	N
Formamide	1.2	N	45.04	1266249.6	1178878.4	0.15	N
Methylamine	**0.5**	**Y**	**31.1**	**1266249.6**	**1178878.4**	**0.088**	**N**
Morpholine	0.25	N	87.1	1266249.6	1178878.4	0.016	N

The Vendor provided the first 2 columns of data (compounds and lb/hr estimated emissions) as well as gaseous effluent conditions (temperature, pressure, flow, moisture). For a compound to be measured by Method 320, a set of quantitative reference spectra must be available to identify and determine concentrations. TRC uses the MKS 2030 FTIR instrument that has a spectral library provided with the instrument. TRC determined if each compound was present in the library. The table lines in **BLUE** show compounds for which reference standards are available. Therefore Method 320 can only be used to measure this subset of compounds.

The Vendor provided flow rate in ACFM (actual cubic feet per minute) and this must be converted to DSCFM (dry standard cubic feet per minute) to obtain concentrations in ppmvd (parts per million by volume, dry basis). The FTIR detection limits for different compounds varies depending on the compound (how efficiently it absorbs infrared light) and the presence of interferents whose spectral absorbance overlaps the compound. For a modern FTIR spectrometer equipped with a high sensitivity detector and long pathlength gas cell such as the MKS 2030 instrument, the lowest detection limits are generally in the 0.5-1 ppm range. Reviewing the calculated ppmvd concentrations in the table, some concentrations are in the ppt (parts per trillion) range, and many are in the ppb (parts per billion range). These ppb and ppt concentrations cannot be detected by the MKS FTIR.

TRC

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Only 2 compounds from the Vendor estimates, acetaldehyde and ammonia, would be above detection limits based on these calculations. TRC has measured these compounds in many emissions tests and can confirm that they are readily detectable at these concentrations.

Detailed Calculations

The Vendor provided the data in the two tables below.

Compounds and Estimated Emissions

Compound	Emission Rate
HAPS	lb/hr
Acetaldehyde	7.5
Formaldehyde	0.4
Acetamide	0.12
Ethyleneimine	0.0041
N-nitrosodiethylamine	0.005
Nitrosodimethylamine	0.01
N'-Nitrosomorpholine	0.0041
Other HAPS	
Ammonia	2.9
Diethylamine	2
Ethanolamine	1.1
Ethylamine	0.77
Ethylenediamine	0.25
Formamide	1.2
Methylamine	0.5
Morpholine	0.25

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Process Data

Process Data	
Flow	1342800 ACFM
T	99.9 ^oF
% H_2O	6.9
% O_2	7.7
P (static)	29.92 " Hg

The flow in ACFM must be first converted to SCFM (actual basis to standard basis) using the following equation:

$$Qscfm = \frac{Qacfm \times (459.67\ ^oR\ + 68\ ^oF) \times P_o}{(459.67\ ^oR + T_o) \times P_s}$$

Where:
Qscfm = gas flow rate at standard temperature and pressure
Qacfm = gas flow rate at actual temperature and pressure (1342800 ft^3/min)
P_o = pressure at actual conditions (inches Hg) (29.92 "Hg)
T_o = temperature at actual conditions (^oF) (99.9 ^oF)
P_s = pressure at standard conditions (29.92 "Hg)
^oR = temperature on Rankine scale

The SCFM flow is converted to dry basis DSCFM using the equation below:

$$Qdscfm = Qscfm \times (1 - \%\ Moisture)$$

Where:
Qscfm = gas flow rate at standard temperature and pressure (Calculated above)
Qdscfm = gas flow rate at standard temperature and pressure, dry basis
% Moisture = Moisture at actual conditions (6.9%)

The final calculation step is to convert the lb/hr emissions to parts per million, dry basis using the data in the summary table presented on page 2. The equation is shown below:

$$Emission\ Rate\ \left(\frac{lb}{hr}\right) = Concentration(ppmvd) \times Molecular\ Weight\left(\frac{g}{mole}\right) \times Flow\ Rate\ (dscfm) \times 60\ min/hr \times \frac{1}{3.853x10^8}$$

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Respectfully submitted,

TRC Environmental Corporation

Thomas Dunder, Ph.D.
Technical Director

A.6 – Department Response to Public Comments

Response to Comments Received
by
The North Dakota Department of Environmental Quality
on
Draft Air Pollution Permit to Construct No. ACP-18197 v1.0
DCC East Project LLC - Dakota Carbon Center CO2 Separation and Purification Plant
Oliver County, North Dakota

December 2023

A public comment period was held regarding the above draft Air Pollution Control Permit to Construct (PTC) from September 21, 2023, through October 21, 2023. The comments received by the North Dakota Department of Environmental Quality (NDDEQ) and the response to each comment by NDDEQ is shown below.

Comments were received from three parties which consisted of two individual commentors and Region 8 of the Environmental Protection Agency (EPA R8). The two individual comments provided verbal testimony during the public hearing held on October 19, 2023, in Center, North Dakota. EPA Region 8 submitted written comments to NDDEQ staff on October 20, 2023.

Note on EPA Comment Submittal:
NDDEQ acknowledges EPA's comments on the draft PTC and will introduce them into the record despite EPA R8 not following NDDEQ's stated requirements. When commenting on future actions proposed by the NDDEQ, please read the notice of intent (NOI) and follow the instructions provided within, see Appendix A.1.

As stated in the NOI *"Direct comments in writing, including* ***Re: Public Comment Permit Number ACP-18194 v1.0****, to* **AirQuality@nd.gov** *or the NDDEQ, Division of Air Quality, 4201 Normandy Street, 2nd Floor, Bismarck, ND 58503-1324.* ***Emailed comments must be sent to the email address above to be considered****." (****emphasis added****)*.

NDDEQ makes this clear statement in the NOI to help mitigate the potential for staff to miss comments received in their personal email inbox which are required to be introduced into the record. Further, emailing comments directly to staff is unreliable since staff turnover can happen rapidly.

Verbal Comment No. 1:

Both individual commentors who provided verbal testimony on October 19, 2023, expressed strong support for the Project. The commentors indicated how important the Project was for the area, for North Dakota, and for decarbonization goals. The complete transcript of the hearing can be found in Appendix A.4.

Response to Verbal Comment No. 1:

Thank you for the comments and overall support for the proposed Project. NDDEQ generally agrees with the statements raised. The concerns expressed are outside the scope of the PTC, however, these concerns are important items for North Dakota.

Written Comment No. 1:

EPA R8 comments on the potential for source aggregation between DCC East Project LLC's proposed Dakota Carbon Center CO_2 Separation and Purification Plant (DCC) and Minnkota's Milton R, Young Station (MRY). EPA recommended NDDEQ enhance the permit record to support NDDEQ's source aggregation conclusion and better outline the relationship between the entities.

Embedded within this comment is a notion that if DCC and MRY are determined to be part of the same "stationary source", it will dictate whether the project requires a Permit to Construct a minor or major new source or a minor or major "modification" to an existing source.

Response to Written Comment No. 1:

NDDEQ agrees with EPA R8 that the permit record regarding the relationship and source aggregation conclusion could be enhanced. To address this comment, DCC has better documented the nature of the relationship between DCC and MRY. This information is provided in Appendix A.5.i, pages 1-5.

NDDEQ affirms that DCC's supplemental information adequately explains the nature of the relationship between DCC and MRY and supports the determination that the sources should not be aggregated. As a result of introducing this information into the permit record, no changes to the Permit to Construct are necessary.

Regarding the embedded comment that, if DCC and MRY are considered the same "stationary source" then a minor or major "modification" to an existing source should be evaluated, NDDEQ notes that the potential to emit for DCC is below the significant emissions increase[1,2] thresholds for regulated NSR pollutants[3] that triggers the major modification[4] for existing major stationary sources. In other words, regardless of source aggregation (one source or two), DCC would be considered a "PSD minor source" – as currently proposed, or DCC would be a minor "modification" to an existing major source – if aggregated with MRY. No further modification to the Permit to Construct or Air Quality Effects Analysis is warranted.

Written Comment No. 2:

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[1] See: https://www.ecfr.gov/current/title-40/part-52/section-52.21#p-52.21(b)(40)
[2] See: https://www.ecfr.gov/current/title-40/part-52/section-52.21#p-52.21(b)(23)(i)
[3] See: https://www.ecfr.gov/current/title-40/part-52/section-52.21#p-52.21(b)(50)
[4] See: https://www.ecfr.gov/current/title-40/part-52/section-52.21#p-52.21(b)(2)(i)

EPA R8 comments on the level of incorporation by reference in the proposed Permit to Construct. EPA recommended NDDEQ revise the permit to include more detailed incorporation by reference.

Response to Written Comment 2:
NDDEQ agrees that the permit record could be enhanced and will add the rated horsepower for the emergency diesel fire pump engine (EU D03) to the emission unit description in the final Permit to Construct (see table under Condition I.B.4 of ACP-18194 v1.0) and final Air Quality Effects Analysis (see page 8 of ACP-18194 v1.0 AQEA).

As proposed, Condition II.C.1 and Condition II.D.1 of ACP-18194 v1.0 both state the emission unit, emergency diesel fire pump engine EU D03, at the proposed facility specifically subject to 40 CFR 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ, respectively.

Condition II.C.1 "*40 CFR 60,* ***Subpart IIII*** *– Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* ***(EU D03)****.*" (**emphasis added**).

Condition II.D.1 "*40 CFR 63,* ***Subpart ZZZZ*** *– National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* ***(EU D03)****.*" (**emphasis added**).

NDDEQ's experience as the Clean Air Act implementation and enforcement authority has shown that the level of incorporation by reference as written in the Permit to Construct requirements for 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ including emission unit identification has been sufficient and useful to the applicant and public to determine what standard applies to the emission unit and how the source is to achieve compliance with each standard. NDDEQ will consider specifying which portions of the above-mentioned regulations apply in the future Title V permit to operate.

Written Comment No. 3:
EPA R8 comments on the ambient air boundary used for the air dispersion modeling for the proposed DCC project with relation to MRY. EPA recommended NDDEQ confirm the accuracy of the ambient air boundary and associated receptor grid used for the air dispersion modeling.

Response to Written Comment 3:
NDDEQ has confirmed the accuracy of the ambient air boundary and associated receptor grid used for the air dispersion modeling. To address this comment, DCC has better outlined the site access and security requirements, the lessor/lessee relationship, and reference to contractual agreements which transfers the "pass through[5]" flue gas back to MRY. This information is provided in detail in Appendix A.5.i, pages 5 and 6.

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[5] DCC's objective is to remove the carbon dioxide from the MRY flue gas stream. The remaining species (e.g., nitrogen oxides, sulfur oxides, particulate matter, uncaptured carbon dioxide) are transferred back to MRY at the absorber stack discharge.

NDDEQ concurs with the information provided by DCC. Therefore, the ambient air boundary and associated receptor grid are accurate and no further air dispersion modeling is warranted.

Written Comment No. 4:
EPA R8 comments on the Clean Air Act 112(g) case-by-case maximum achievable control technology (MACT) analysis for hazardous air pollutants (HAPs), particularly regarding the use of acetaldehyde as a surrogate pollutant for all organic HAPs. EPA recommended NDDEQ separately evaluate the effectiveness of controls for amine HAPs from aldehyde HAPs.

Response to Written Comment 4:
DCC's Permit to Construct application included a detailed analysis of potentially available controls to reduce VOC and organic HAP emissions from the CO_2 absorber.[6] The analysis was inclusive of organic HAP emissions and noted that aldehydes make up the majority of the HAP emissions and the remaining HAP constituents are generally classified as amines. Of note, the total of all the expected Clean Air Act Section 112 amine HAPs is approximately 0.10 tons per year (tpy), or significantly below HAP major source thresholds for any individual HAP.[7] As explained in the case-by-case MACT, amine HAPs are reduced using water wash and acid wash to limit the amine solvent loss. Aldehyde HAPs are not expected to be affected by the water and acid wash. The analysis also recognized that aldehydes and amines are generally classified as VOCs and the available controls were evaluated for effectiveness included technologies in industry to reduce VOC emissions.[8] The NDDEQ found no deficiency in the case-by-case MACT analysis.

DCC has also provided a more succinct response, largely based on information already in the record[9], to help EPA R8 understand the aldehyde/amine relationship as it relates to DCC. This can be found in Appendix A.5.i, pages 6-10.

As part DCC's response to EPA R8's comment, DCC discussed the lack of feasibility for testing[10] amine-based HAPs due to the projected low concentrations of these species and limited published information on detection limits for amine-based organic compounds. DCC provided additional technical information on the feasibility of HAP testing using Method 320 in a supplemental response to comment, included in Appendix A.5.ii. DCC indicated that any amine-based organic HAPs would be well below the minimum detection limit of Method 320 or do not have reference spectra. NDDEQ does not possess any technical information to dispute this claim and will not require DCC to test for amine-based organic HAPs.

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[6] DCC East Project LLC, Dakota Carbon Center CO2 Separation and Purification Plan Permit to Construct Application. Appendix C. June 2, 2023
[7] DCC East Project LLC, Dakota Carbon Center CO2 Separation and Purification Plan Permit to Construct Application. Appendix B, page 2. June 2, 2023
[8] DCC East Project LLC, Dakota Carbon Center CO2 Separation and Purification Plan Permit to Construct Application. Appendix C, page 9. June 2, 2023
[9] DCC East Project LLC, Dakota Carbon Center CO2 Separation and Purification Plan Permit to Construct Application. Appendix C.
[10] Using EPA Test Method 320 – Vapor Phase Organic and Inorganic Emissions by Extractive FTIR

Since DCC project is the first of its kind and size in the world[11], NDDEQ's position is that initial testing of the second largest projected Section 112 HAP species (formaldehyde) is reasonable and will be required. NDDEQ does not dispute the projected project related HAP emission determined from emissions testing and modeling conducted by the carbon capture system vendor but is of the opinion that evaluation of formaldehyde in addition to acetaldehyde is warranted for the initial testing required after DCC project start-up.

NDDEQ's conclusion as it relates to HAP testing is that initial testing will be required to confirm the HAP representations made in the permit application for acetaldehyde as a suitable surrogate and has added emissions testing in the final Permit to Construct (See Condition II.F of ACP-18194 v1.0) and final Air Quality Effects Analysis (see page 12 and 13 in ACP-18194 v1.0 AQEA). NDDEQ is requiring EPA Method 320 – Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy as the means to confirm the representations made in the Permit to Construct application. Undetectable organic compounds (i.e., below detection limit) will be considered insignificant.

[11] Given that this is the first of its kind in scale carbon capture project on lignite coal-fired electrical generating utilities and has yet to be constructed, carbon capture and sequestration/storage (CCS) has not yet been "adequately demonstrated" in practice to be identified as a "best system of emissions reduction".

AIR QUALITY IMPACT ANALYSIS

DCC East Project LLC
CO_2 Separation and Purification Plant

Prepared By:

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September 15, 2023

Project 232401.0032

Approved By:

North Dakota Department of Environmental Quality
Division of Air Quality
Air Pollution Control Program

David Stroh, Environmental Engineer

Rhannon Thorton, Environmental Scientist

Trinity Consultants

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1. EXECUTIVE SUMMARY

DCC East Project LLC (DCC) completed air dispersion modeling to demonstrate compliance with the North Dakota Ambient Air Quality Standards (ND AAQS) for a proposed project to construct a carbon dioxide (CO_2) separation and purification plant (Project) to generate commodity CO_2 from the flue gas produced by the Milton R. Young (MRY) Station's coal-fired boilers (MRY Unit 1 and MRY Unit 2). The modeling was completed using potential emissions from the project under two operating scenarios. Based on the data provided in the Permit to Construct (PTC) application and Trinity Consultants' (Trinity's) independent review and modeling analysis, it is expected that the proposed project will comply with applicable ND AAQS. Results for the modeled ND AAQS analysis are shown in Table 1-1.

Table 1-1. ND AAQS Analysis Results Summary

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	ND AAQS ($\mu g/m^3$)
NO_2	1-hr[1]	44.20	35.0	79.20	188
	Annual[2]	1.33	5.0	6.33	100
PM_{10}	24-hr[3]	7.97	30.0	37.97	150
$PM_{2.5}$	24-hr[4]	5.56	13.7	19.26	35
	Annual[5]	0.71	4.8	5.46	12
SO_2	1-hr[6]	48.33	13.0	61.33	196
	3-hr[7]	60.70	11.0	71.70	1,309
	24-hr[7]	16.16	9.0	25.16	365
	Annual[2]	1.54	3.0	4.54	80
CO	1-hr[7]	32.24	1,149.0	1,181.24	40,000
	8-hr[7]	10.98	1,149.0	1,159.98	10,000

1 Eighth-highest maximum daily 1-hour concentration (98th percentile) averaged over the 5 years.
2 Maximum annual concentration over the 5 years.
3 Sixth-highest maximum 24-hour concentration averaged over the 5 years.
4 Eighth-highest maximum 24-hour concentration averaged over the 5 years.
5 Maximum annual concentration averaged over the 5 years.
6 Fourth-highest maximum daily 1-hour concentration (99th percentile) averaged over the 5 years.
7 Second-highest maximum concentration over the 5 years.

2. INTRODUCTION AND BACKGROUND

In June 2023, DCC submitted a revised PTC application to the North Dakota Department of Environmental Quality, Division of Air Quality (Department) to construct the Project. A revised air dispersion modeling protocol and modeling report that reflects the information in this PTC application was submitted by DCC in August 2023. The revised modeling report summarizes the ND AAQS modeling analysis that was completed, using AERMOD v22112 for the Project. The analysis demonstrates compliance with the ND AAQS. Trinity was contracted to assist the Department with a third-party review of the modeling analysis and preparation of an Air Quality Impact Analysis (AQIA) report. This AQIA summarizes Trinity's findings based on a thorough review and independent modeling of the Project.

DCC is proposing to construct a CO_2 separation and purification plant to generate commodity CO_2 from the flue gas produced by the MRY Station's coal-fired boilers (MRY Unit 1 and MRY Unit 2). The carbon capture system includes a new CO_2 absorber stack where processed flue gas from MRY Units 1 and 2 will be emitted. The Project will receive commingled flue gases from MRY Units 1 and 2, which will be processed to remove CO_2, and the uncaptured emissions (e.g., nitrogen oxides) will be emitted through the Project's CO_2 absorber stack (emission unit and emission point D01 in ACP-18194 v1.0). Capability to exhaust all or a portion of the exhaust from MRY Units 1 and 2 through the existing stacks for MRY Units 1 and 2 will be retained. The Project will consist of installation of the following emission sources:

- One (1) carbon capture system,
- One (1) cooling tower,
- One (1) emergency diesel-fired fire water pump engine,
- Amine solvent storage tanks and handling system, and
- Haul roads.

3. MODEL REQUIREMENTS

The Project's potential to emit (PTE) for the regulated New Source Review (NSR) pollutants are below major source thresholds. Therefore, the project will not trigger Prevention of Significant Deterioration (PSD) permitting and does not explicitly require modeling per the Department's non-PSD project modeling policy.[1] However, because the carbon capture stack will have considerably different stack characteristics (e.g., shorter stack) than the existing MRY Unit 1 and MRY Unit 2 stacks; the Department required that DCC complete a modeling assessment for this project to demonstrate compliance with the ND AAQS for operating scenarios when emissions are exhausted through the new carbon capture system stack.

Per Department guidance, modeling for PTC applications not subject to PSD are only required to address compliance with the ND AAQS. Therefore, the DCC modeling analysis did not include a modeling assessment against the PSD increment standards. Additionally, the MRY facility is not located within 50 km of any Class I area; therefore, in accordance with Department guidance a Class I increment assessment is not required for the Project.

Emissions from the carbon capture system stack and the cooling towers were included in the ND AAQS modeling analysis. The diesel fire water pump engine was not included in accordance with the Department's policy.[2] The haul roads associated with the project were not included in modeling because they are paved and Department convention is to exclude paved haul roads from ND AAQS modeling. Finally, the amine solvent storage tanks and handling system has only insignificant emissions of VOCs that need not be included in the ND AAQS modeling analysis.

[1] https://deq.nd.gov/publications/aq/Policy/modeling/Criteria_Modeling_Memo.pdf

[2] https://deq.nd.gov/publications/AQ/policy/Modeling/Emergency_Unit_Modeling.pdf

4. MODELING METHODOLOGY

4.1 Model Version

The current U.S. EPA regulatory model, AERMOD (version 22112) was used in this analysis to calculate ground-level concentrations with the regulatory default parameters. Appropriate averaging periods, based on federal and state ambient air quality standards, and model options were considered in the analysis, in conjunction with the U.S. EPA's *Guideline on Air Quality Models* 40 CFR 51, Appendix W (Revised, January 17, 2017).

4.2 Meteorological Data

Surface and upper-air data are pre-processed by AERMET to generate the boundary layer parameters required by AERMOD to calculate plume dispersion. AERMET processes hourly meteorological data to determine plume transport and dispersion downwind of a source. Per Appendix W Section 8.4.2.e, a *minimum* of either one year of site-specific data (i.e., an onsite monitor) or five years of representative National Weather Service (NWS) data or at least 3 years of prognostic meteorological data should be used to ensure a sufficiently conservative result which addresses hourly and seasonal variation in meteorological conditions over a year which affect plume movement due to atmospheric conditions.

Hourly meteorological data for the 5-year period of 2017 to 2021 were used from a state-operated meteorological observation station in Beulah, ND. Data from this site were supplemented with concurrent cloud cover and upper air observations from the Bismarck Airport in Bismarck, ND. Missing upper air data from Bismarck were substituted with data from Glasgow, MT and Aberdeen, SD.[3]

See Table 4-1 for MET stations used. AERMET uses hourly surface observations of wind speed and direction, ambient temperature, sky cover (opacity), and (optionally) local air pressure. AERMET then includes the pre-processed AERSURFACE output values (see Table 4-2) to compile the appropriate surface meteorological inputs for AERMOD. AERMET version 22112 was used to process meteorological data for this analysis.

Surface roughness length, albedo, and Bowen ratio are required values used by AERMET to preprocess meteorological data for AERMOD. AERSURFACE allows users to develop these values using inputs based on set seasonal variability in the vegetative landscape (e.g. landcover). The Department has compiled a set of recommended inputs to be used for the AERSURFACE pre-processor for various regions of the state as listed in the *Recommended AERSURFACE Inputs (North Dakota)* guidance as shown in Table 4-2.[4] Seasonal category assignments for each month were based on recommendations for the southwest geographic area. Four sectors were used in the analysis to define surface roughness length, as shown in Figure 4-1. AERSURFACE version 20060 was used for this analysis with land cover, impervious surface, and tree canopy data from the USGS National Land Cover Data (NLCD) archives for 2016.

[3] A total of 22 days over the 5 years to be modeled were substituted.

[4] https://deq.nd.gov/publications/AQ/policy/Modeling/AERSURFACE_InputsND.pdf

Table 4-1. Meteorological Data Stations

Location	Latitude (deg)	Longitude (deg)	Base Elevation (m)	Distance / Direction from Source*	Data Type
Beulah, ND	47.229	-101.767	630	45 km W-NW	Surface
Bismarck Airport - Bismarck, ND	46.774	-100.748	506	48 km SE	Surface
Bismarck, ND	46.774	-100.748	503	48 km SE	Upper Air
Glasgow, MT	48.200	-106.620	693	430 km W-NW	Upper Air
Aberdeen, SD	45.455	-98.420	397	280 km SE	Upper Air

* Approximate distances using Google Earth's measuring tool.

Table 4-2. AERSURFACE Input Values

Parameter	Value Used
Radius of study area used for surface roughness.	1 km
Define the surface roughness length for multiple sectors?	Yes
Temporal resolution of surface characteristics	Monthly
Continuous snow cover for at least one month?	Yes
Reassign the months to different seasons?	Yes
Specify months for each season.	
Late autumn after frost and harvest, or winter with no snow.	Oct, Nov, Dec, Feb, Mar
Winter with continuous snow on the ground.	Jan
Transitional spring.	Apr, May
Midsummer with lush vegetation.	Jun, Jul, Aug
Autumn with unharvested cropland.	Sep
Is the site at an airport?	No
Is the site in an arid region?	No
Surface moisture condition at the site.	Average

Figure 4-1. Sectors Used for Surface Roughness Characteristics at Beulah Station

4.3 Receptor Grid

Receptors are the locations where the model calculates ground-level pollutant concentrations. The receptor grid included discrete receptors at specific intervals around the facility extending out in a square shape with the facility at the center.

- Fence line receptors along the secured MRY property boundary with spacing of 25 meters
- 50 meter spacing, extending out approximately 500 meters from the boundary
- 100 meter spacing, extending out approximately 3 kilometers from the boundary
- 250 meter spacing, extending between approximately 3 to 5 kilometers from the boundary
- 500 meter spacing, extending between approximately 5 to 10 kilometers from the boundary

Receptor points within the MRY Station boundary are not modeled as they are not considered ambient air.[5] Ambient air has been interpreted to be air located outside of a boundary (e.g., a fence) which restricts general public access to a facility or source.

4.4 Terrain Elevations

The terrain elevation for each receptor point was determined using USGS 1/3 arc-second National Elevation Dataset (NED) data. The data, obtained from the USGS, has terrain elevations at 10-meter intervals. The terrain height for each individual modeled receptor was determined by assigning the interpolated height from the digital terrain elevations surrounding each modeled receptor.

In addition, the AERMOD terrain processor, AERMAP (version 18081), was used to compute the hill height scales for each receptor. AERMAP searches all NED data points for the terrain height and location that has the greatest influence on each receptor to determine the hill height scale for that receptor. AERMOD then uses the hill height scale in order to select the correct critical dividing streamline and concentration algorithm for each receptor. The elevations of the sources and buildings involved in the modeling demonstration were set using AERMAP.

4.5 NO_2 Modeling Methodology

For nitrogen dioxide (NO_2) modeling, the USEPA approved Tier 3 Plume Volume Molar Ratio Method (PVMRM) was utilized. USEPA Appendix W and subsequent guidance recommends a three tier NO_2 modeling approach for the conversion of nitric oxide (NO) to NO_2. These tiers are regulatory options provided in AERMOD and each consider increasingly complex considerations of NO to NO_2 conversion chemistry.

- Tier 1 assumes total conversion of NO to NO_2;
- Tier 2 utilizes the revised Ambient Ratio Method 2 (ARM2) approach; and,
- Tier 3 incorporates the Ozone Limiting Method (OLM) and Plume Volume Molar Ratio Method (PVMRM) as regulatory options in AERMOD.

Numerous studies and reports that analyze use of PVMRM and OLM show that for a given NO_X emission rate and ambient ozone concentration, the NO_2/NO_X conversion ratio for PVMRM is primarily controlled by the volume of the plume, whereas the conversion ratio for OLM is primarily controlled by ground-level NO_X concentration. EPA memoranda do not indicate any preference between PVMRM and OLM. EPA guidance

[5] https://www.epa.gov/nsr/ambient-air-guidance

suggests that PVMRM is preferred for isolated, elevated point sources.[6] This modeling analysis is specifically examining impacts from three relatively isolated, elevated point sources. As such, PVMRM was selected as the Tier 3 approach to be utilized in the modeling analysis using the ozone data discussed in Section 4.5.1 and NO_2 to NO_X ratios discussed in Section 4.5.2.

4.5.1 Ozone Data

Hourly ozone data from 2017 through 2021 for the Hannover ozone monitor (AQS Site ID: 38-065-0002) was used as the primary ozone data for the Tier 3 PVMRM analysis. Missing Hannover observations were filled using a three-step process:

1) Missing observations were filled with observations from the nearby Beulah North ozone monitor (AQS Site: 38-057-0004).
2) After supplementing Hannover observations with observations from Beulah North, remaining single missing hourly observations were filled using linear interpolation.
3) Data gaps of more than one hour were filled using a table of monthly and diurnal varying maximum hourly observations developed from the combined Hannover/Beulah North dataset.

4.5.2 In-Stack and Ambient Equilibrium Ratios

PVMRM in AERMOD uses an in-stack ratio (ISR) that specifies the ratio of NO_2 /NO_X present in each stack. In lieu of using the default ISR of 0.5, an ISR of 0.1 was used for the absorber stack, MRY Unit 1, and MRY Unit 2. This ISR was justified by the applicant using NO_2 and NO_X emissions data from MRY Unit 1 and MRY Unit 2. An ISR of 0.2 was used for nearby sources based on EPA guidance that indicates this value can be used for nearby sources located greater than 1-3 km away from the source being permitted.[7]

The default ambient equilibrium ratio of 0.9 was used.[8]

4.6 Rural / Urban Option Selection in AERMOD

For any dispersion modeling exercise, the “urban” or “rural” determination of the area surrounding the subject source is important in determining the applicable atmospheric boundary layer characteristics that affect a model’s calculation of ambient concentrations. Thus, a determination was made of whether the area around the MRY Station was urban or rural.

One method discussed in Section 5.1 of the *AERMOD Implementation Guide*[9] (also referring therein to Section 7.2.3c of the Guideline on Air Quality Models, Appendix W) is called the “land use” technique because it examines the various land use within 3 km of a source and quantifies the percentage of area in various land use categories. If greater than 50% of the land use in the prescribed area is considered urban, then the urban option should be used in AERMOD.

There is much less than 50% compact residential and industrial development in the 3-km radius surrounding the MRY Station. Therefore, rural dispersion characterization was used for this modeling effort.

[6] https://www.epa.gov/sites/default/files/2015-07/documents/appwno2_2.pdf

[7] https://www.epa.gov/sites/default/files/2020-10/documents/no2_clarification_memo-20140930.pdf

[8] https://www.epa.gov/sites/default/files/2015-07/documents/appwno2_2.pdf

[9] https://gaftp.epa.gov/Air/aqmg/SCRAM/models/preferred/aermod/aermod_implementation_guide.pdf

4.7 Building Downwash

The purpose of a building downwash analysis is to determine if the plume discharged from a stack will become caught in the turbulent wake of a building (or other structure), resulting in downwash of the plume. The downwash of the plume can result in elevated ground-level concentrations.

The Building Profile Input Program (BPIP) with Plume Rise Model Enhancements (PRIME) (version 04274) was used to determine the building downwash characteristics for each stack in 10-degree directional intervals. The PRIME version of BPIP features enhanced plume dispersion coefficients due to turbulent wake and reduced plume rise caused by a combination of the descending streamlines in the lee of the building and the increased entrainment in the wake. For PRIME downwash analyses, the building downwash data include the following parameters for the dominant building:

- Building height,
- Building width,
- Building length,
- X-dimension building adjustment, and
- Y-dimension building adjustment.

The Good Engineering Practice (GEP) stack height determined using BPIP for the stacks for the absorber stack (ABSORB), cooling tower stacks (CT 1-18), MRY Unit 1 (Unit 1), and MRY Unit 2 (Unit 2) are shown in Table 4-3 compared with the physical stack heights. The preliminary GEP stack height value is greater than the physical stack heights for the absorber and cooling tower stacks; therefore, the full physical stack heights were modeled for these stacks. For the MRY Unit 1 and MRY Unit 2 stacks, the preliminary GEP stack height values are slightly less than the physical stack heights. In the model supporting the PTC application for the Project, the full physical stack height of MRY Unit 1 and MRY Unit 2 was used. A sensitivity analysis for stack height was completed by AECOM, who prepared the modeling, indicating that the percentages of the ND AAQS in the modeled results (rounded to the nearest whole number) are unaffected if the preliminary GEP stack height values were modeled. As shown later, the model results are well less than the ND AAQS; therefore, the conclusions of the modeling report with respect to ND AAQS compliance would be unaffected by modeling a reduced stack height compared with the physical stack height.

Table 4-3. GEP Stack Height Analysis

Stack ID	Physical Stack Height (m)	GEP Equation Height (m)	Preliminary GEP Stack Height Value (m)
ABSORB	102.44	123.60	123.60
CT1-CT4; CT10-CT14	16.76	41.90	65.00
CT5-CT9; CT15-CT18	16.76	72.20	72.20
UNIT1	171.91	170.93	170.93
UNIT2	167.64	164.45	164.45

4.8 Representation of Emission Sources

AERMOD allows for emission units to be represented as point, area, volume, or open pit sources, among other less commonly used source types. A source with a stack is most appropriately modeled as a point source. For point sources with unobstructed vertical releases, it is appropriate to use actual stack parameters (i.e., height, diameter, exhaust gas temperature, and gas exit velocity) in the modeling analyses.

4.8.1 Emission Sources at MRY Station

The modeled sources at the MSY Station include point sources with upward unrestricted releases, which were modeled with the POINT source type. Allowable emission rates were used with other stack parameters for the absorber stack, MRY Unit 1, MRY Unit 2, and the cooling tower for two operating modes. In Mode 1, all of Unit 2's flue gas is treated while only 25% of Unit 1's flue gas is treated. In Mode 2, all of Unit 1's flue gas is treated while only 57% of Unit 2's flue gas is treated. For either Mode 1 or Mode 2 operations, the balance of the untreated plume is assumed to be emitted out its original stack (Mode 1 – 75% of Unit 1 is emitted out the Unit 1 stack; Mode 2 – 43% of Unit 2 is emitted out the Unit 2 stack).

Stack parameters and emission rates for the two operating mode scenarios are shown in Table 4-4.

Table 4-4. Absorber, Cooling Tower, MRY Unit 1, and MRY Unit 2 Emission Rates and Stack Parameters

Mode No.	Source	Stack ID	Unit	% Flue Gas Treated	Stack Ht. (m)	Stack Diam. (m)	Flue Gas Temp (K)	Flue Gas Velocity (m/s)	SO_2 (g/s)	NO_X (g/s)	PM_{10} (g/s)	$PM_{2.5}$ (g/s)	CO (g/s)
1	All Unit 2, Partial Unit 1	ABSORB	Unit 1 Unit 2	25% 100%	102.13	5.49	310.87	26.81	82.81	314.11	56.47	56.47	26.84
	Remaining Unit 1	UNIT1	Unit 1	75%	171.91	6.20	334.76	11.55	35.44	108.86	19.11	19.11	9.07
2	All Unit 2, Partial Unit 2	ABSORB	Unit 1 Unit 2	100% 57%	102.13	5.49	310.87	26.81	87.72	303.51	54.04	54.04	25.67
	Remaining Unit 2	UNIT2	Unit 2	43%	167.64	9.14	335.76	5.47	30.53	119.46	21.54	21.54	10.24
	Cooling Tower	CT1-CT18	CT1-CT18[1]	N/A	16.76	9.75	310.04	11.46	N/A	N/A	6.43E-03	4.88E-05	N/A

1 Parameters represent each cooling tower cell exhaust.

4.8.2 Nearby and Other Sources

As described in Section 8.3 of the *Guideline*, background concentrations consist of two categories: 1) nearby sources and 2) other sources. "Nearby sources" are those individual sources located in the vicinity of the sources that are the primary focus on the modeling analysis that are not adequately represented by ambient monitoring data. These sources should be few in number (Appendix W Section 8.3.3(b)(iii)) and are accounted for by explicitly modeling their emissions. "Other sources" are that portion of the background attributable to natural sources, other unidentified sources in the vicinity, and regional transport contributions from more distant sources. Other sources are typically accounted for through use of ambient monitoring data.

Nearby sources explicitly modeled in this analysis include stacks at all three coal-fired electric generating stations located within 50 km of the MRY Station. Point source parameters and emission rates for these sources are shown in Table 4-5.

Table 4-5. Nearby Source Emission Rates and Stack Parameters

Facility	Stack Ht. (m)	Stack Diam. (m)	Flue Gas Temp (K)	Flue Gas Velocity (m/s)	SO_2 (g/s)	NO_X (g/s)	PM_{10} (g/s)	$PM_{2.5}$ (g/s)	CO (g/s)
Coal Creek	206.41	7.86	334.26	18.59	92.56	103.72	1.25	0.14	6.79
Coal Creek	206.41	7.86	332.04	18.01	89.62	83.11	2.46	0.26	13.17
Coyote	151.79	6.40	378.15	27.86	362.90	181.93	1.13	0.09	17.90
Leland Olds	182.88	5.64	335.37	14.17	17.14	26.71	1.65	0.67	24.15
Leland Olds	182.88	8.23	335.37	9.48	33.81	107.63	1.21	0.49	24.23

Ambient air quality data are used to represent the contribution to total ambient air pollutant concentrations from natural and non-modeled anthropogenic sources. The Department modeling guidance provides fixed background concentrations for criteria pollutants that reflect default values which are representative for the entire State of North Dakota.[10] These values are provided in Table 4-6 and were used in the air quality modeling analysis.

Table 4-6. Background Concentrations (µg/m³)

	Averaging Period				
Pollutant	1-hour	3-hour	8-hour	24-hour	Annual
SO_2	13	11	---	9	3
NO_2	35	---	---	---	5
PM_{10}	---	---	---	30	15
$PM_{2.5}$	---	---	---	13.7	4.75
CO	1,149	---	1,149	---	---

[10] https://deq.nd.gov/publications/AQ/policy/Modeling/ND_Air_Dispersion_Modeling_Guide.pdf

5. NAAQS MODELING ANALYSIS

A ND AAQS analysis was conducted to determine the cumulative impact from the Project, existing MRY sources, nearby sources, and background in the vicinity of the MRY Station. The modeling results in micrograms per cubic meter ($\mu g/m^3$) are summarized in Tables 5-1 and 5-2. As shown in the tables, the modeled impacts of the proposed project were below the ND AAQS for each pollutant and averaging period for both operating modes modeled.

Table 5-1. ND AAQS Modeling Results for Mode 1

Pollutant	Averaging Period	Rank of Modeled Impacts	Mode 1 Modeled Conc. ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Conc. ($\mu g/m^3$)	ND AAQS ($\mu g/m^3$)	% of Criteria
NO_2	1-hr[1]	H8H	43.48	35.0	78.48	188	42
	Annual[2]	H1H	1.31	5.0	6.31	100	6
PM_{10}	24-hr[3]	H6H	7.81	30.0	37.81	150	25
$PM_{2.5}$	24-hr[4]	H8H	5.47	13.7	19.17	35	55
	Annual[5]	H1H	0.71	4.75	5.46	12	45
SO_2	1-hr[6]	H4H	47.25	13.0	60.25	196	31
	3-hr[7]	H2H	60.40	11.0	71.40	1,309	5
	24-hr[7]	H2H	15.20	9.0	24.20	365	7
	Annual[2]	H1H	1.48	3.0	4.48	80	6
CO	1-hr[7]	H2H	31.82	1,149.0	1,180.82	40,000	3
	8-hr[7]	H2H	10.74	1,149.0	1,159.74	10,000	12

1 Eighth-highest maximum daily 1-hour concentration (98th percentile) averaged over the 5 years.
2 Maximum annual concentration over the 5 years.
3 Sixth-highest maximum 24-hour concentration averaged over the 5 years.
4 Eighth-highest maximum 24-hour concentration averaged over the 5 years.
5 Maximum annual concentration averaged over the 5 years.
6 Fourth-highest maximum daily 1-hour concentration (99th percentile) averaged over the 5 years.
7 Second-highest maximum concentration over the 5 years.

Table 5-2. ND AAQS Modeling Results for Mode 2

Pollutant	Averaging Period	Rank of Modeled Impacts	Mode 2 Modeled Conc. ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Conc. ($\mu g/m^3$)	ND AAQS ($\mu g/m^3$)	% of Criteria
NO_2	1-hr[1]	H8H	44.20	35.0	79.20	188	42
	Annual[2]	H1H	1.33	5.0	6.33	100	6
PM_{10}	24-hr[3]	H6H	7.97	30.0	37.97	150	25
$PM_{2.5}$	24-hr[4]	H8H	5.56	13.7	19.26	35	55
	Annual[5]	H1H	0.71	4.75	5.46	12	46
SO_2	1-hr[6]	H4H	48.33	13.0	61.33	196	31
	3-hr[7]	H2H	60.70	11.0	71.70	1,309	5
	24-hr[7]	H2H	16.16	9.0	25.16	365	7
	Annual[2]	H1H	1.54	3.0	4.54	80	6
CO	1-hr[7]	H2H	32.24	1,149.0	1,181.24	40,000	3
	8-hr[7]	H2H	10.98	1,149.0	1,159.98	10,000	12

1 Eighth-highest maximum daily 1-hour concentration (98th percentile) averaged over the 5 years.
2 Maximum annual concentration over the 5 years.
3 Sixth-highest maximum 24-hour concentration averaged over the 5 years.
4 Eighth-highest maximum 24-hour concentration averaged over the 5 years.
5 Maximum annual concentration averaged over the 5 years.
6 Fourth-highest maximum daily 1-hour concentration (99th percentile) averaged over the 5 years.
7 Second-highest maximum concentration over the 5 years.

6. AIR TOXICS ANALYSIS

The Policy for the Control of Hazardous Air Pollutant Emissions in North Dakota (Air Toxics Policy)[11] outlines the methods used to evaluate new or modified emission sources which release Hazardous Air Pollutants (HAPs) into the ambient air for their potential carcinogenic and non-carcinogenic health risks. The acceptable risk is evaluated by determining the maximum individual carcinogenic risk (MICR) for all toxics with known or possible carcinogenic effects. A MICR value of 1.0 x 10-5 (i.e., 1 in 100,000 risk), and Hazard Index (HI) of 1 are the accepted thresholds, any value greater will trigger further review by the Department.

6.1 Method

The Air Toxics Policy outlines a three-tier approach for use in determining compliance. Tier 1 uses lookup tables (provided in pages 16-17 of the Air Toxics Policy), which lists normalized maximum 1-hr concentrations for various stack heights and downwind distances.

Tier 2 involves using EPA's SCREEN3 model to produce the highest predicted 1-hr concentration from a matrix of predictions for a given set of source conditions and downwind distances in all plausible meteorological conditions. The use of SCREEN3 is considered conservative, but less conservative than Tier 1.

Tier 3 involves the use of refined EPA computer models, such as AERMOD. The use of refined modeling uses actual hour-by-hour meteorological and actual site terrain data. The use of refined modeling also treats each stack or emission point independently. DCC implemented a Tier 3 analysis.

The specifics of each Tier's methods for calculating MICR and the Hazard Index can be found in the Air Toxics Policy.

6.2 Air Toxics Results

DCC performed a conservative Tier 3 approach to determine the MICR and HI which would result from the Project. This conservative approach consisted of DCC normalizing total toxic emissions from the absorber stack to 1 g/s. The unit modeled impacts were then scaled based on the emission rates of HAP emitted and divided by the pollutant specific unit risk factor to obtain calculated risk and hazard indices. These results are shown in Table 6-1. The results are well below the thresholds and indicate that the expected MICR and HI concentrations are well in compliance with the Air Toxics Policy. Refer to DCC's permit application for the detailed discussion regarding the Air Toxics analysis and results.

Table 6-1. Air Toxics MICR and Hazard Index Results

Standard	Limit	Results	Pass (Y/N)
MICR	1.0E-05	5.14E-07	Y
Hazard Index	1	0.016	Y

[11] https://deq.nd.gov/publications/AQ/policy/Modeling/Air_Toxics_Policy.pdf

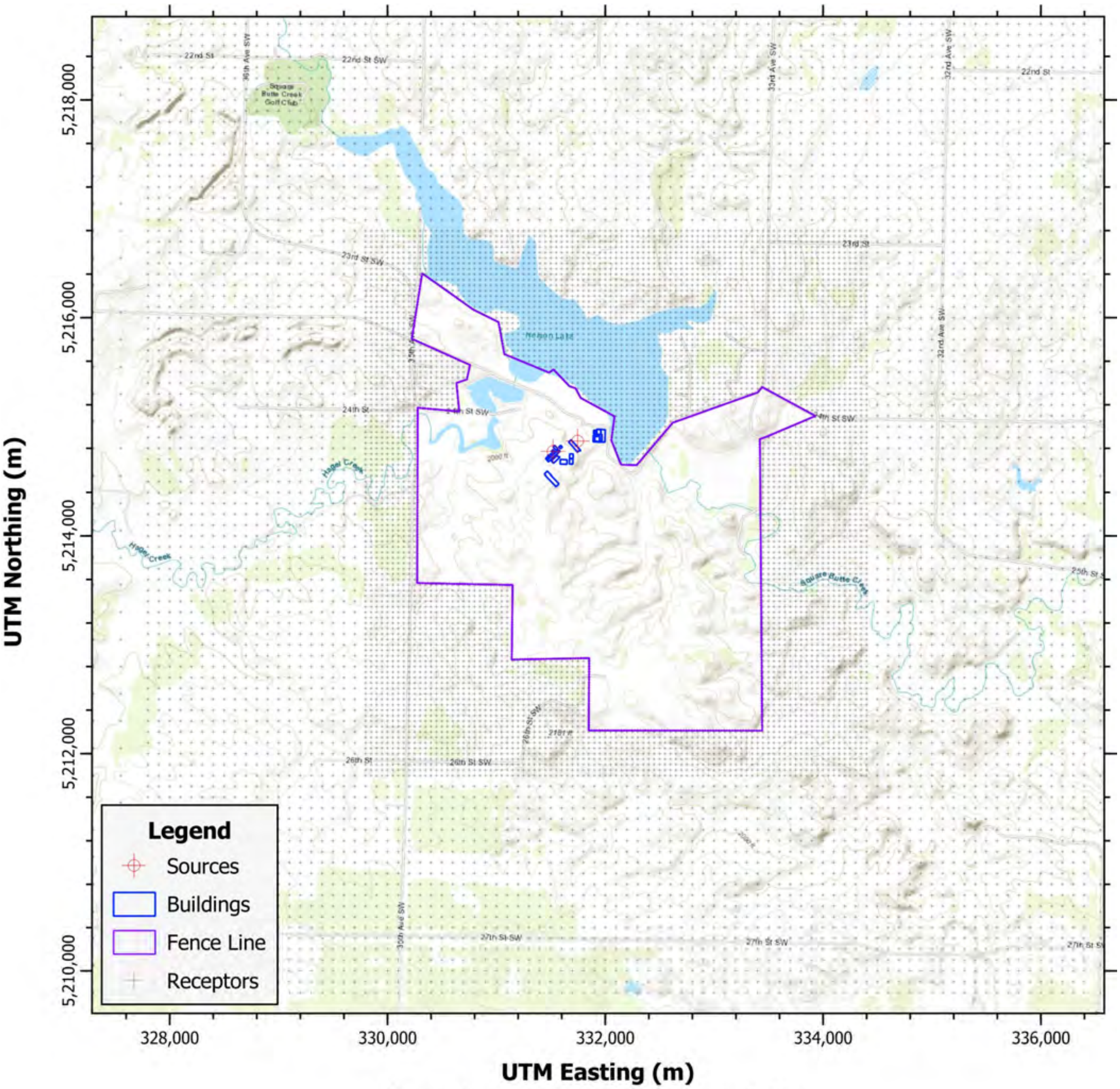
7. SUMMARY AND CONCLUSIONS

Upon Trinity's review and third-party analysis of the modeling submitted by DCC, the following is concluded:

- DCC followed applicable state and Federal guidance in their modeling protocol.
- DCC's modeling was conducted to demonstrate that emissions from the Project are expected to comply with North Dakota Ambient Air Quality Standards (ND AAQS). Emissions associated with operating the facility after the Project are not expected to cause or contribute to a violation of the ND AAQS as listed in NDAC 33.1-15-02-04. Results of the modeled impacts for the ND AAQS are displayed in Figures 1-1, 5-1, and 5-2.
- The air toxics analysis conducted by DCC follows the procedure put forth in the Department's Air Toxics Policy. The results indicate that the expected MICR and HI thresholds are in compliance with the Air Toxics Policy.

APPENDIX A. PLOTS AND FIGURES

Figure A-1. Site Layout



All coordinates shown in UTM Coordinates,
UTM Zone 14, NAD 83 Datum

Figure A-2. Terrain

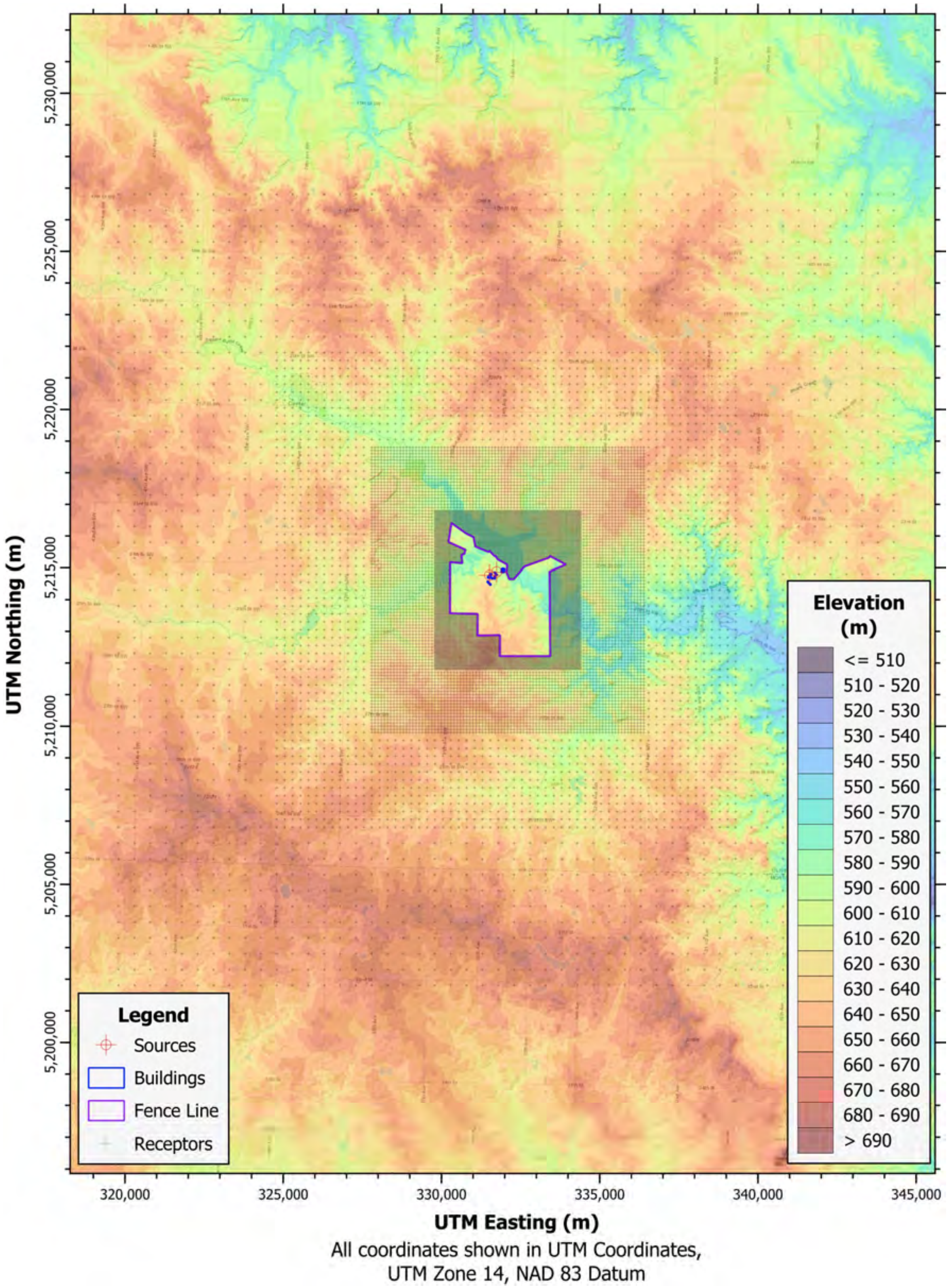


Figure A-3. Wind Rose for Beulah Station (10-meter level) for 2017-2021

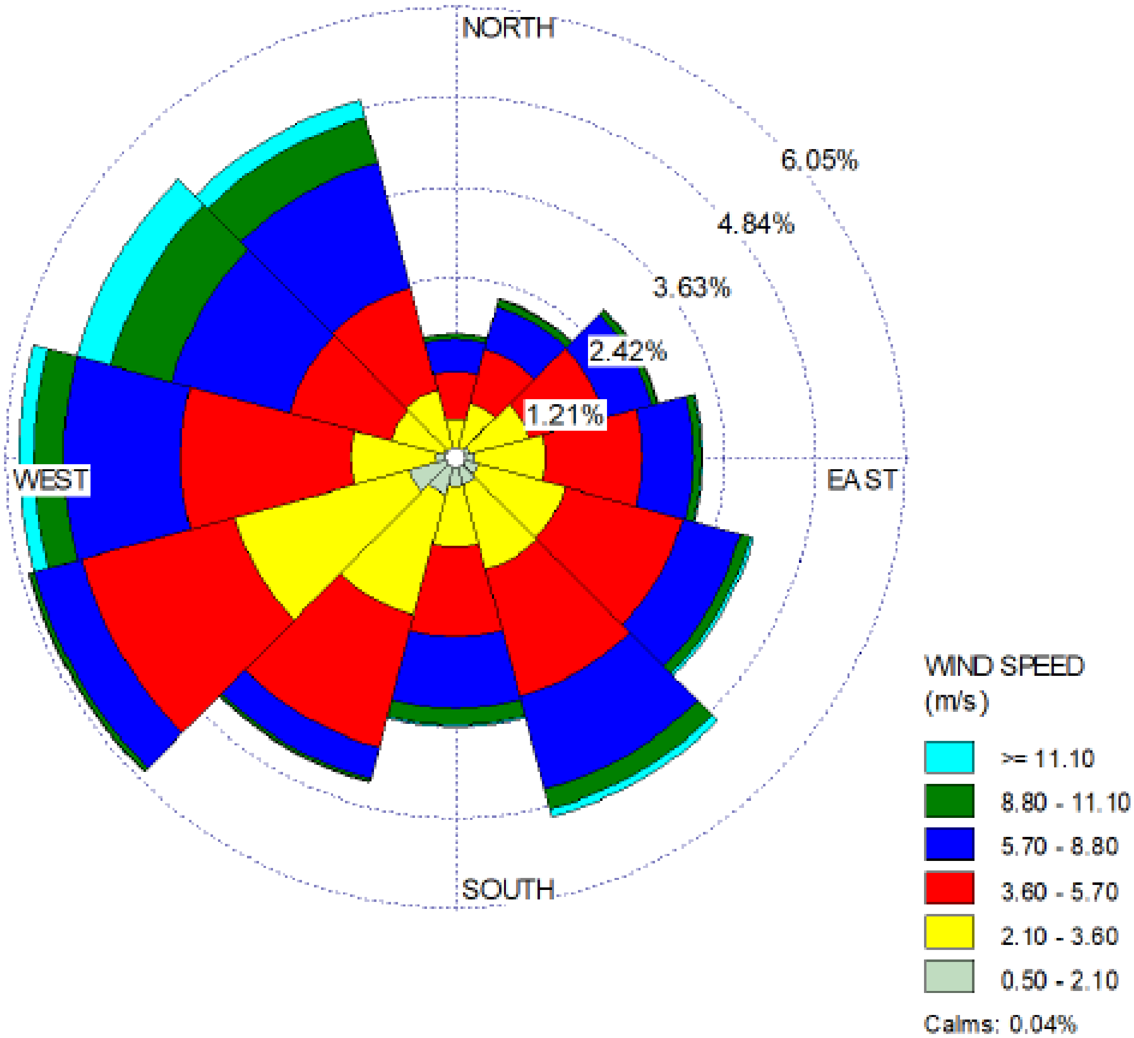


Figure A-4. Receptor Grid

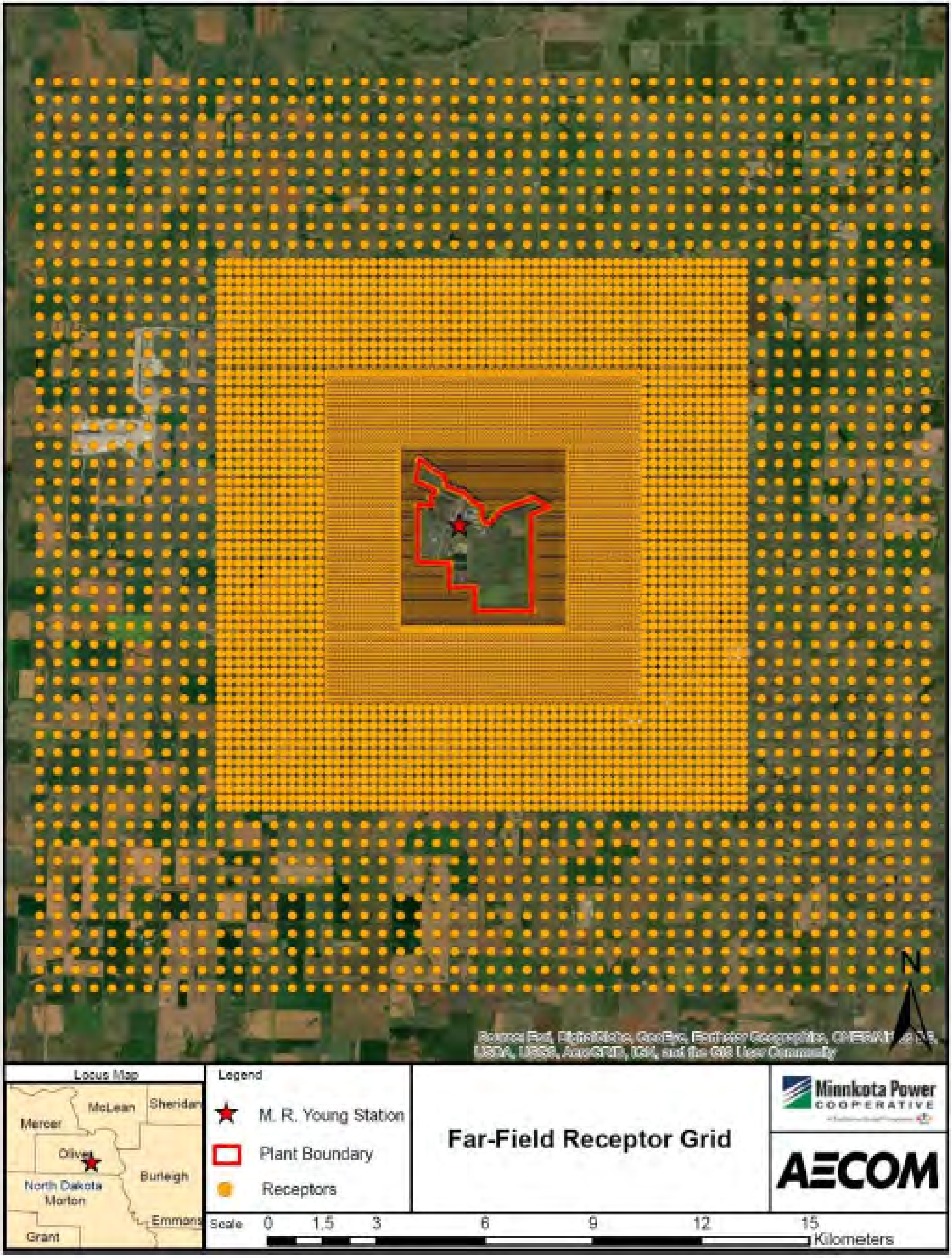
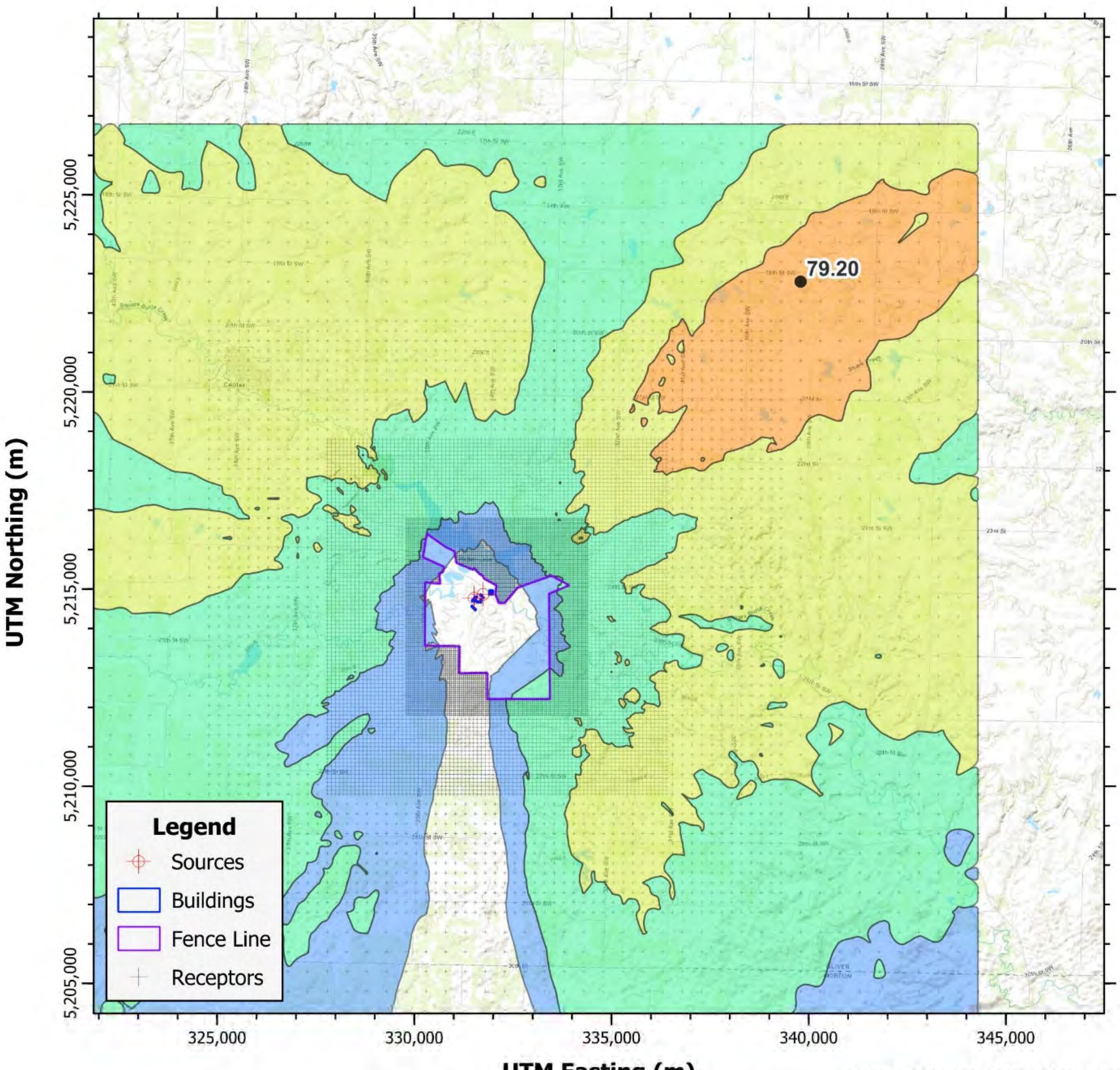


Figure A-5. 1-Hour NO_2 ND AAQS Concentrations for Mode 2



All coordinates shown in UTM Coordinates,
UTM Zone 14, NAD 83 Datum

1-Hour NO2 ND AAQS: 188 µg/m³

NO2 Concentrations* (µg/m³)	
	60 - 65
	65 - 70
	70 - 75
	> 75
●	Max

*All values shown include background concentration.

Figure A-6. Annual NO_2 ND AAQS Concentrations for Mode 2

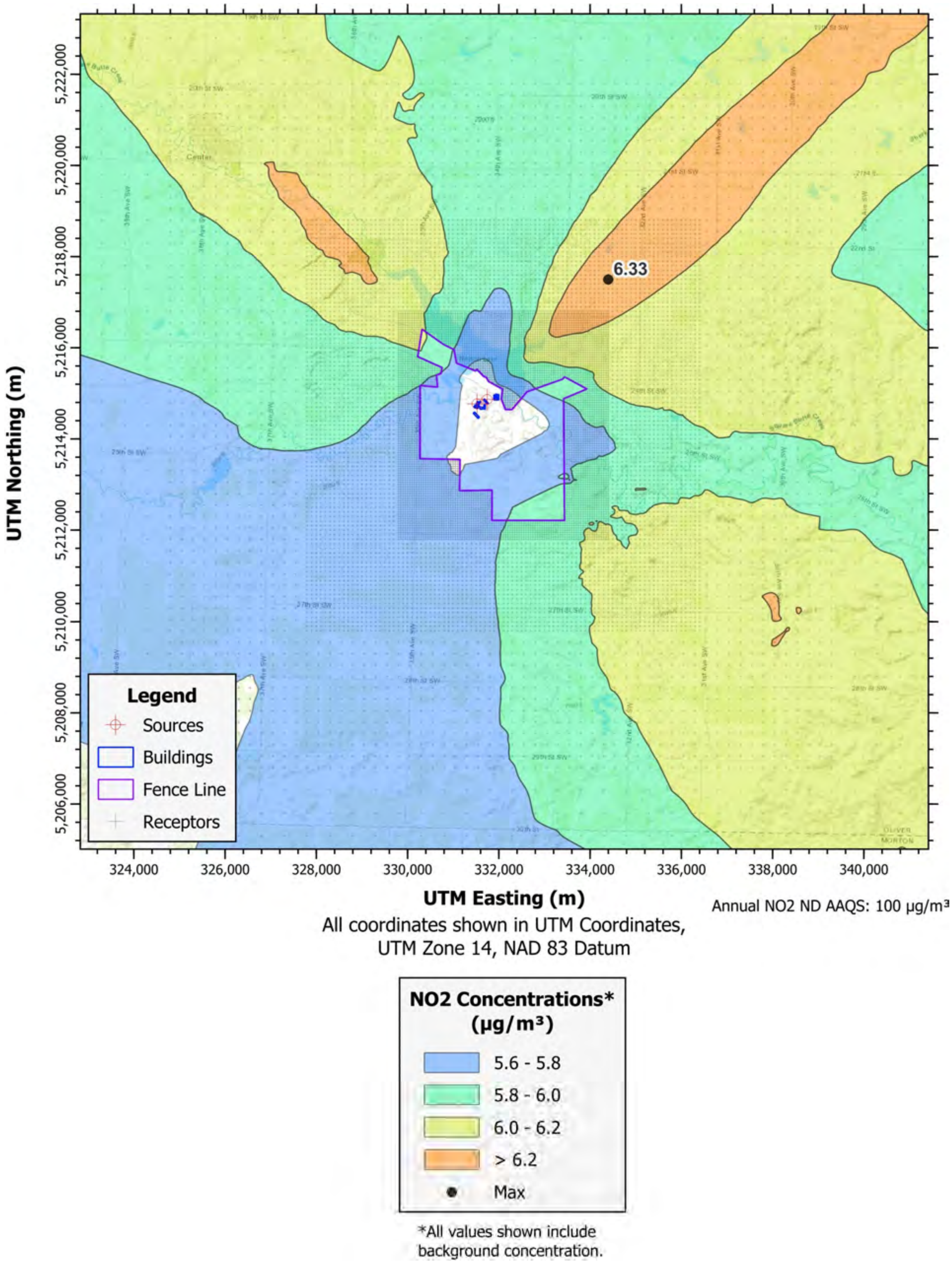


Figure A-7. 24-hour PM_{10} ND AAQS Concentrations for Mode 2

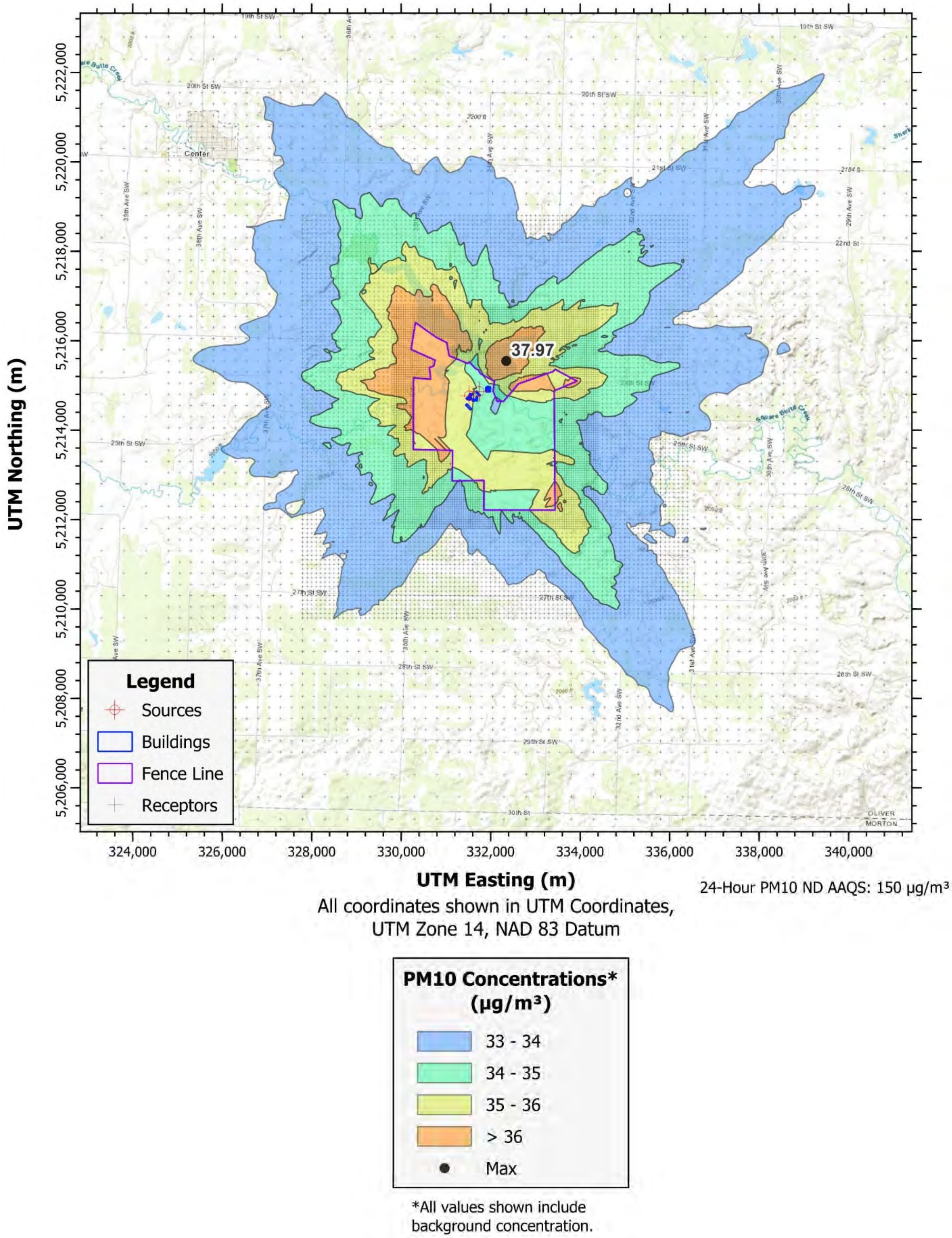


Figure A-8. 24-hour $PM_{2.5}$ ND AAQS Concentrations for Mode 2

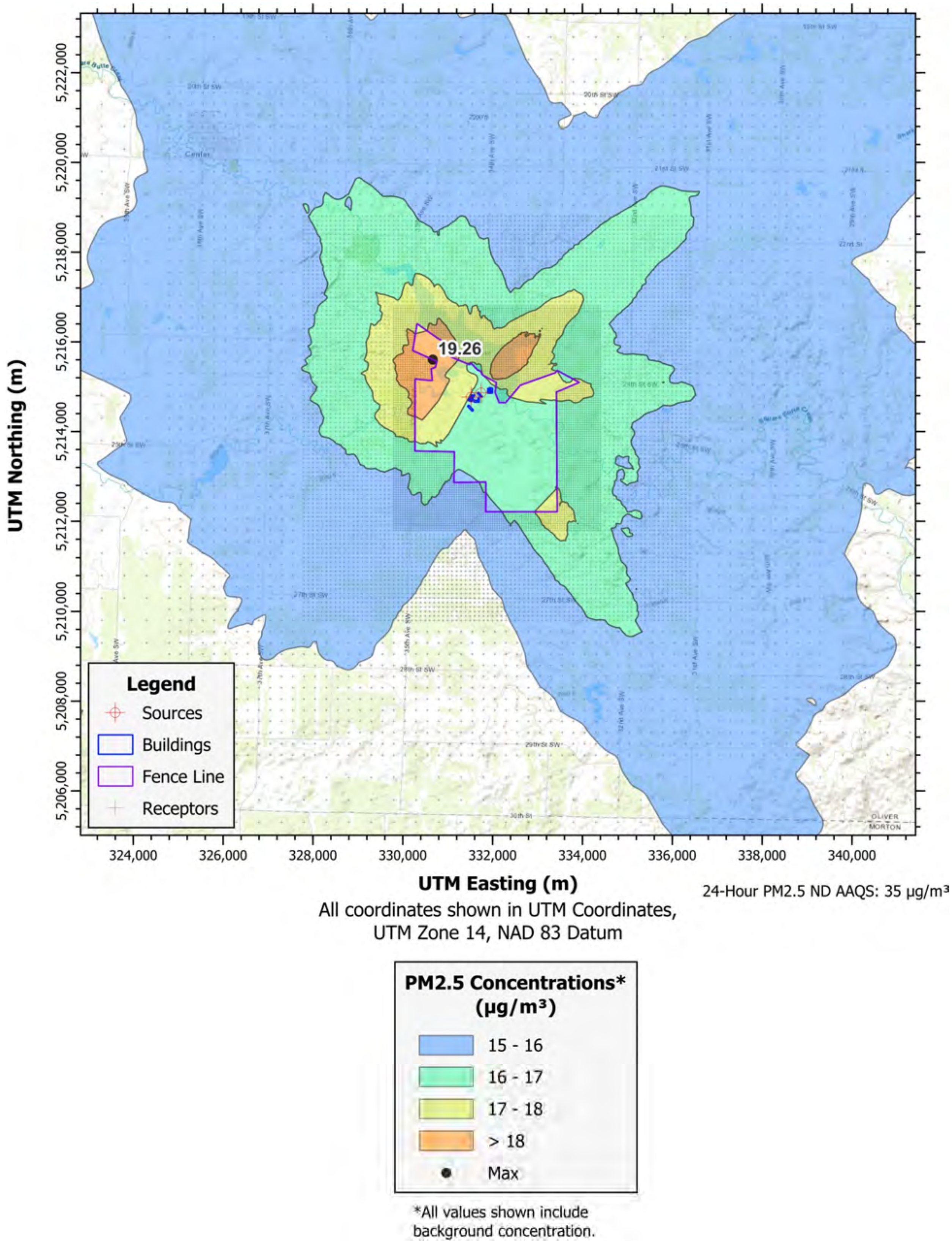


Figure A-9. Annual $PM_{2.5}$ ND AAQS Concentrations for Mode 2

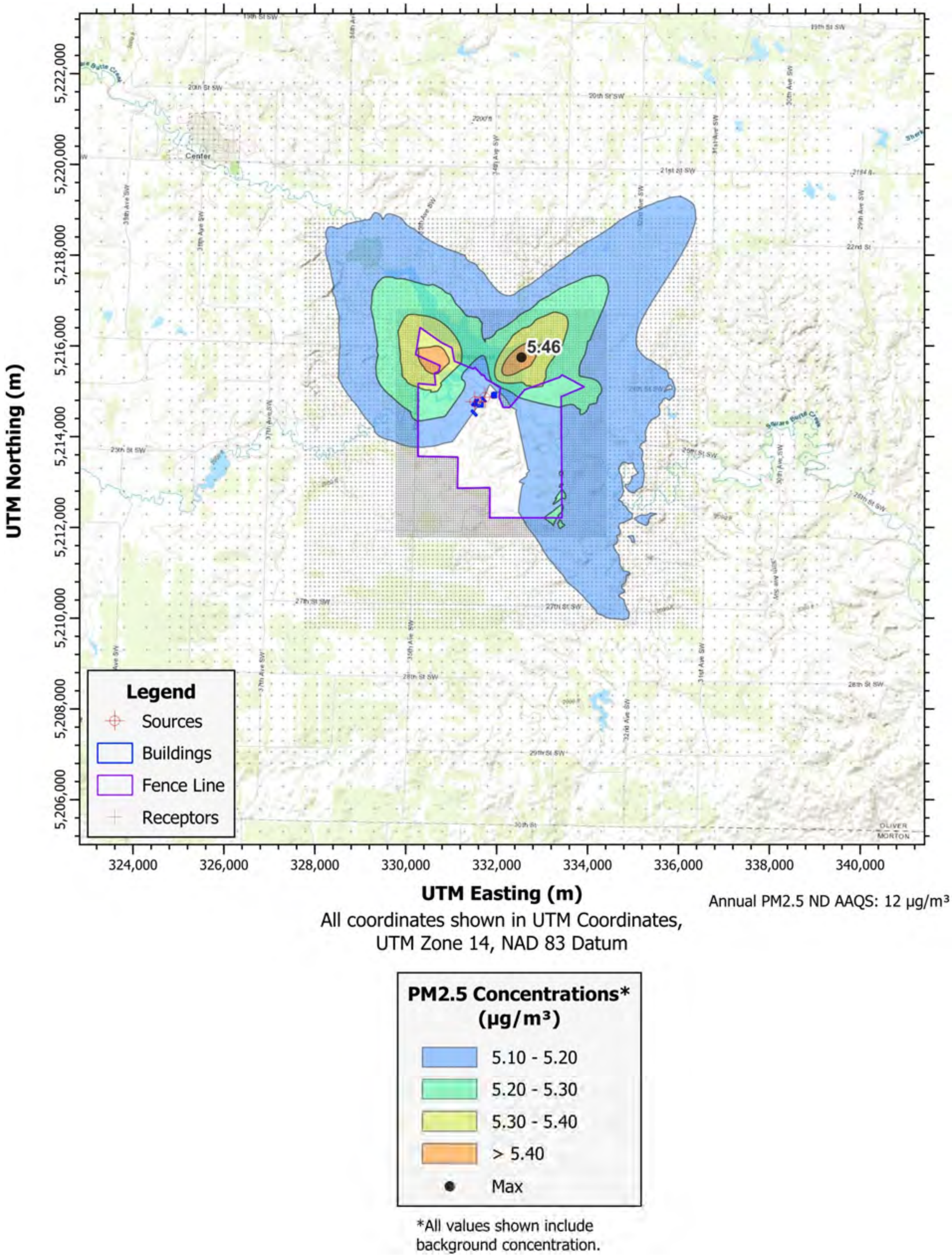


Figure A-10. 1-hour SO_2 ND AAQS Concentrations for Mode 2

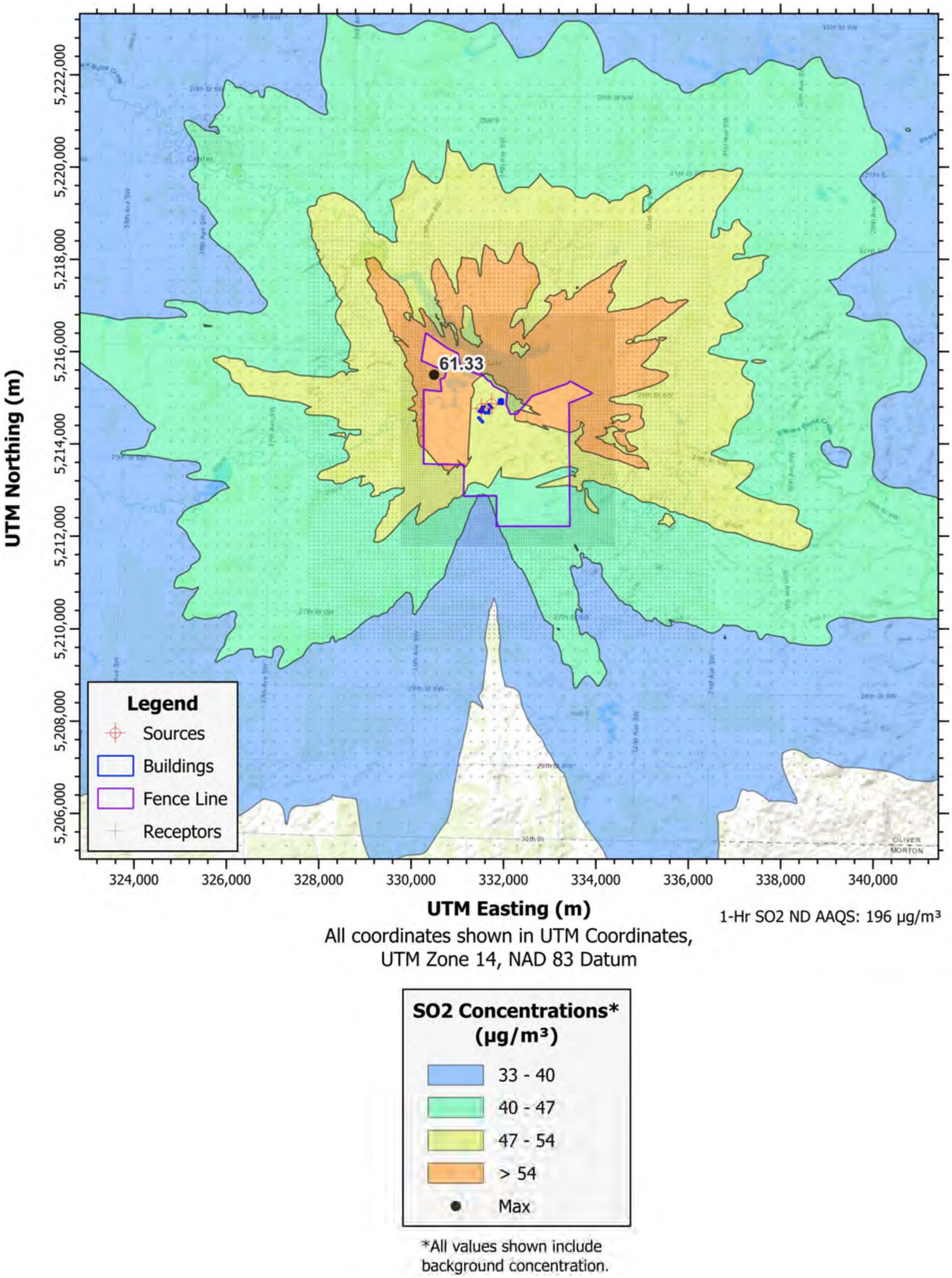
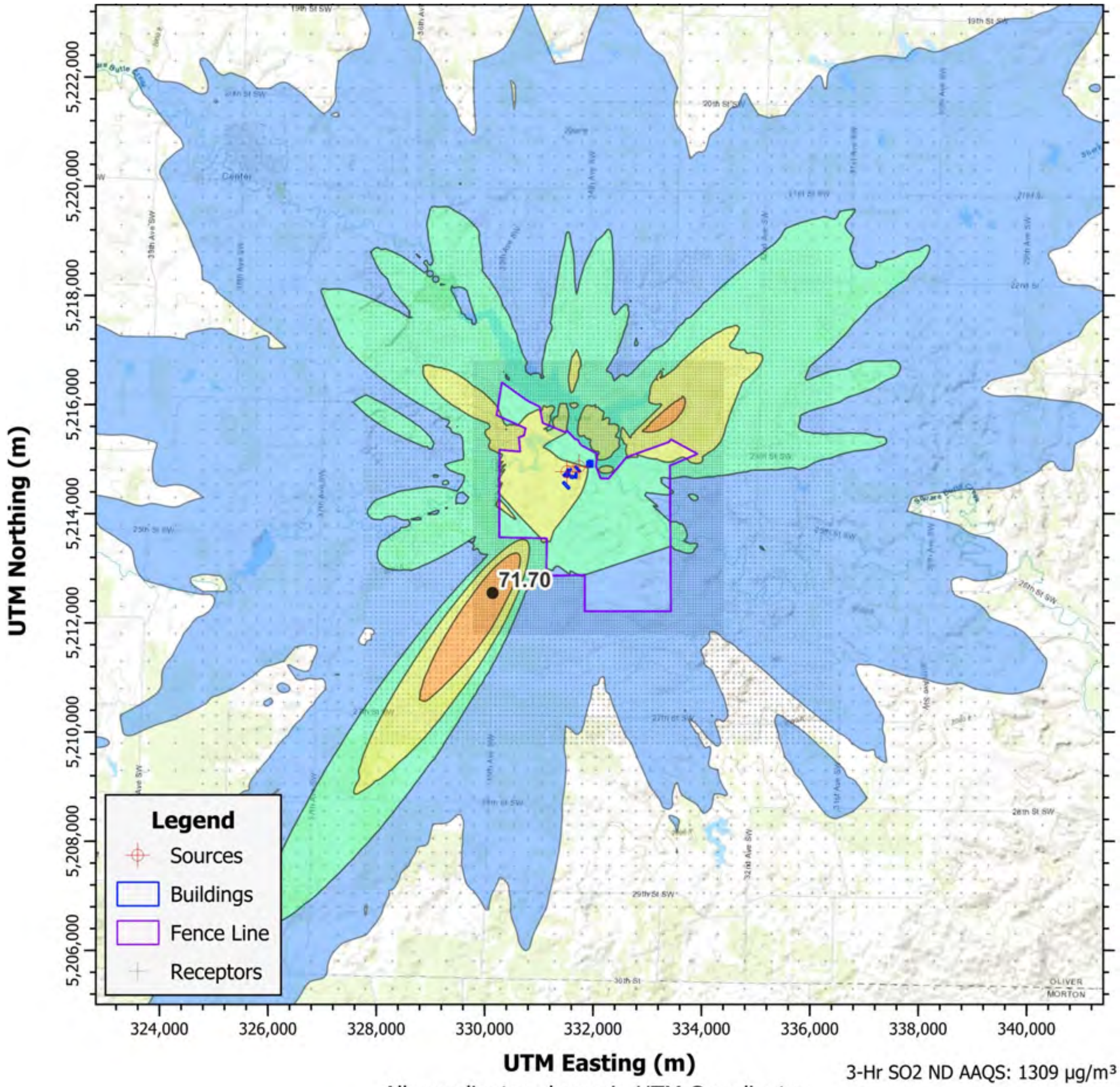


Figure A-11. 3-hour SO_2 ND AAQS Concentrations for Mode 2



3-Hr SO2 ND AAQS: 1309 µg/m³

All coordinates shown in UTM Coordinates,
UTM Zone 14, NAD 83 Datum

SO2 Concentrations* **(µg/m³)**

- 32 - 42
- 42 - 52
- 52 - 62
- > 62
- Max

*All values shown include background concentration.

Figure A-12. 24-hour SO_2 ND AAQS Concentrations for Mode 2

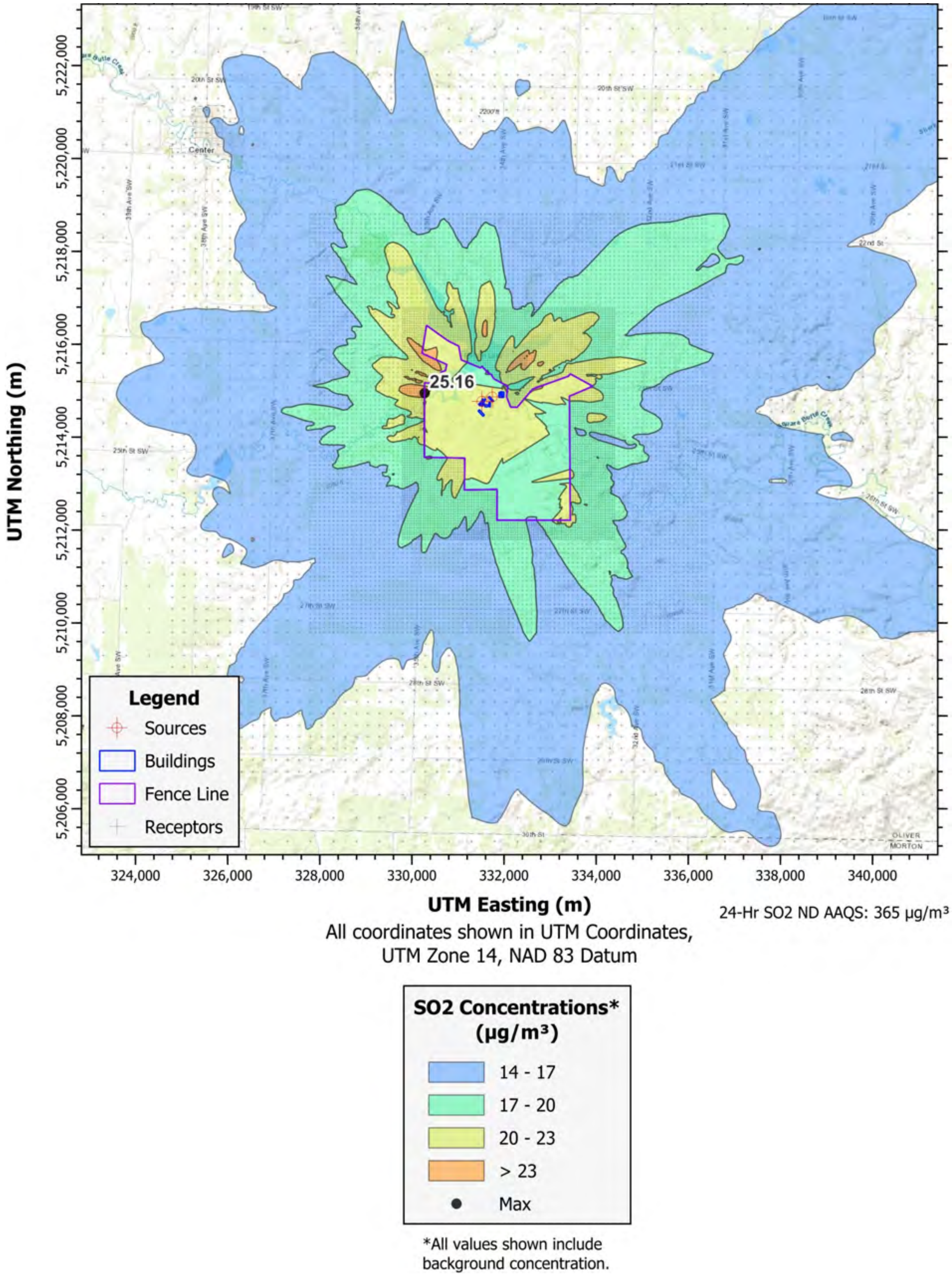


Figure A-13. Annual SO_2 ND AAQS Concentrations for Mode 2

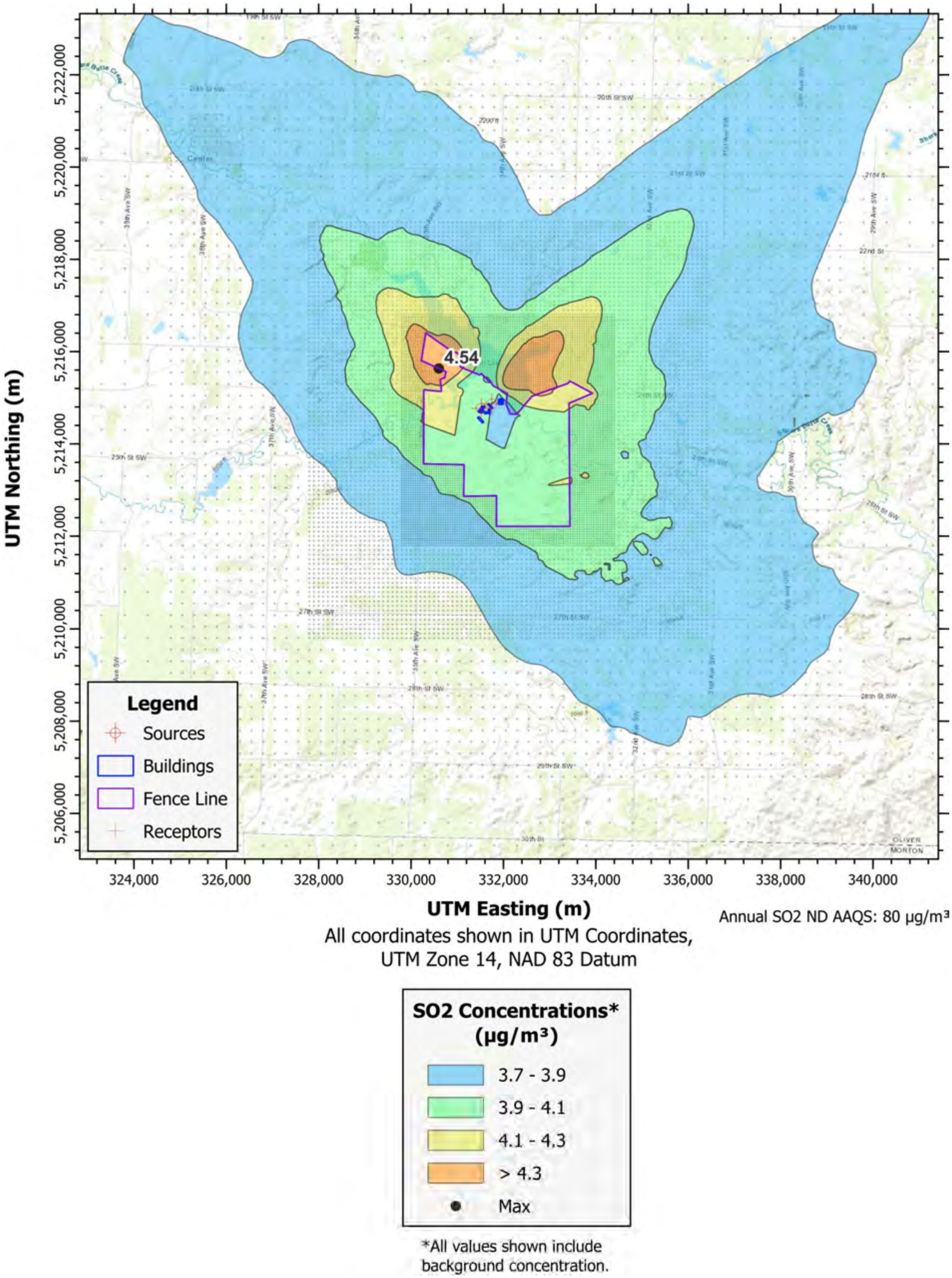
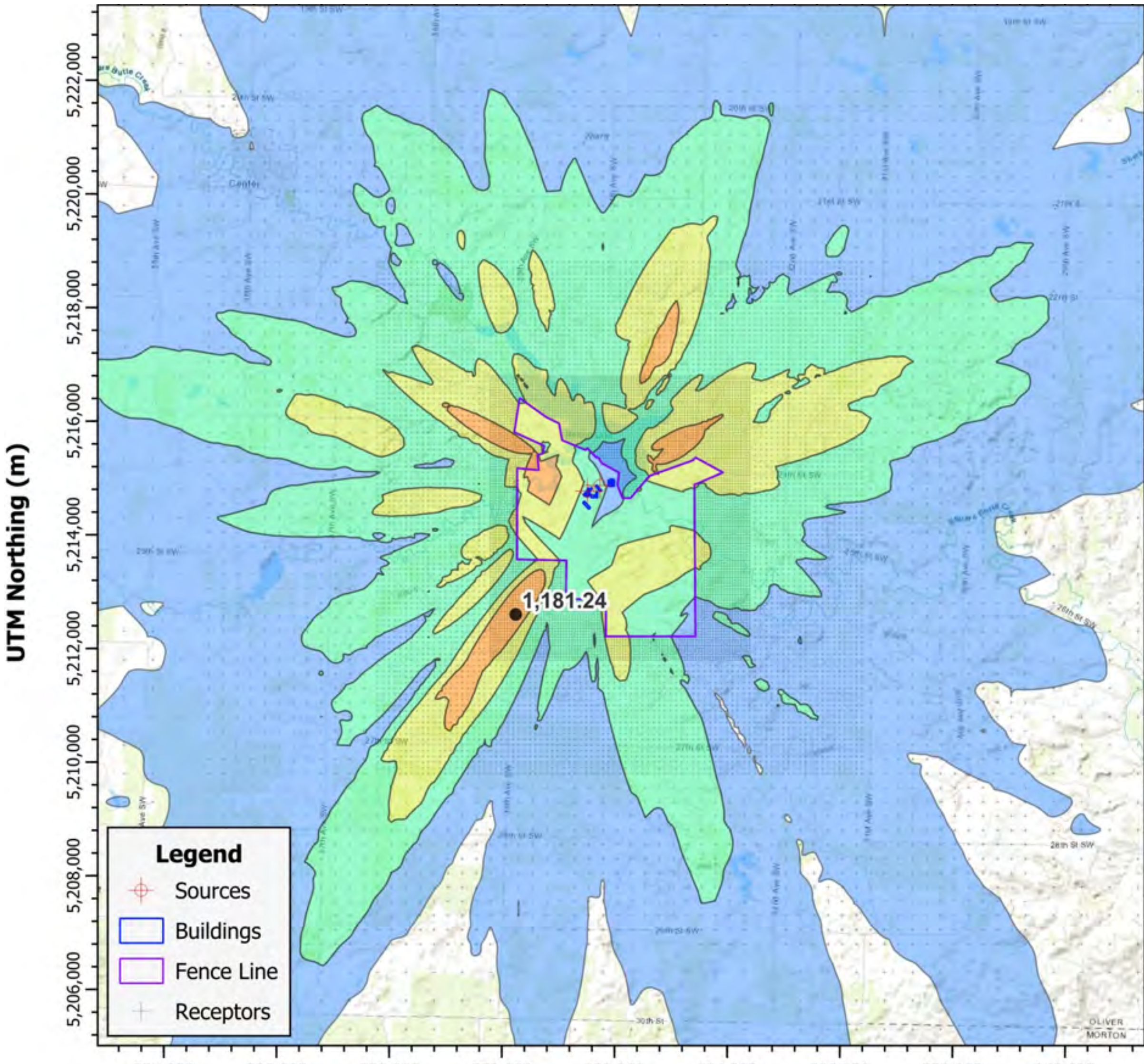
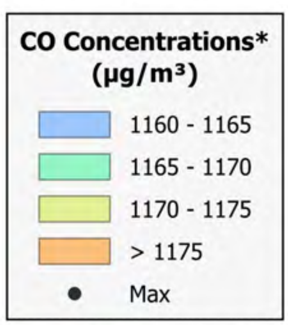


Figure A-14. 1-hour CO ND AAQS Concentrations for Mode 2



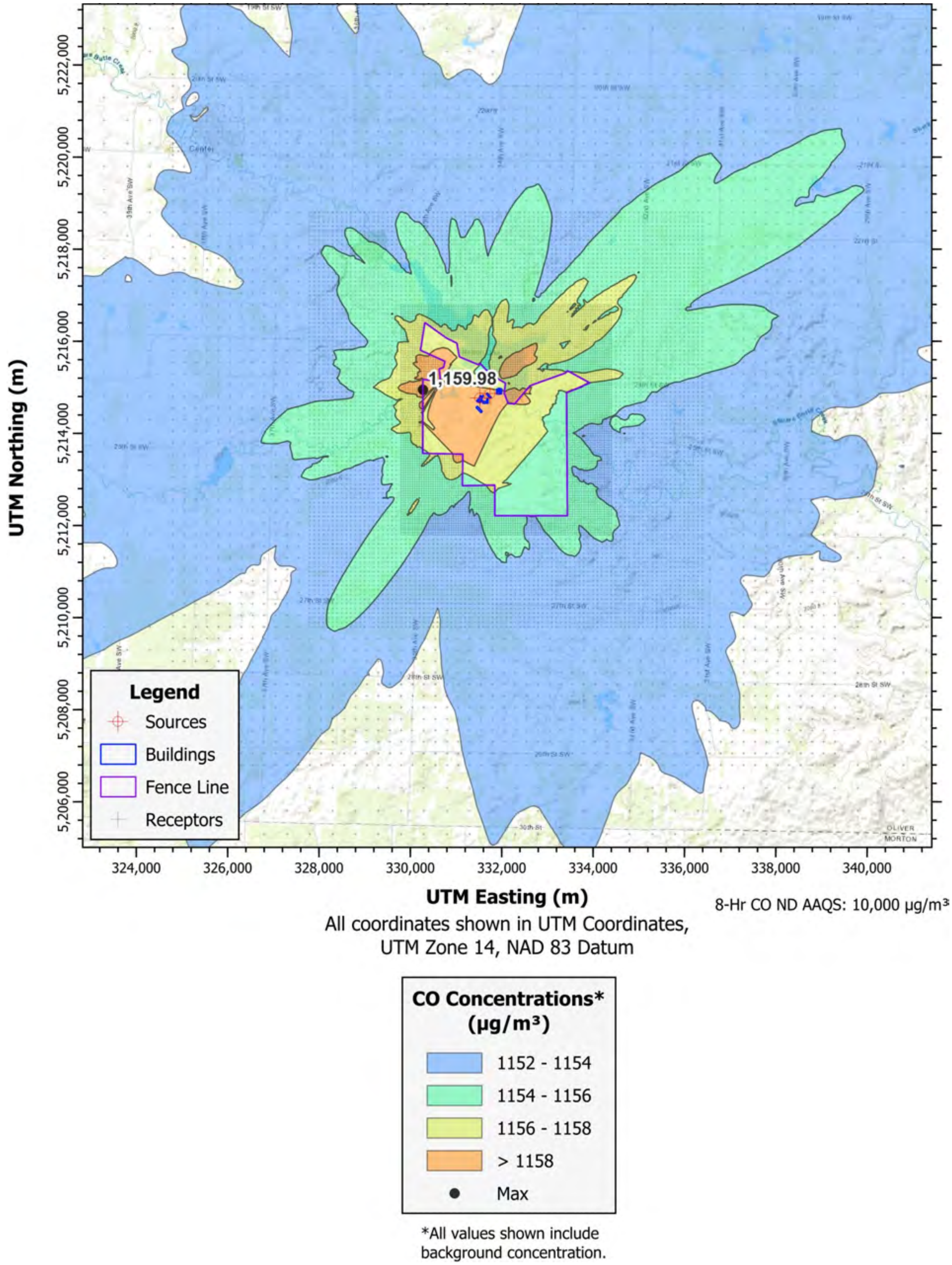
1-Hr CO ND AAQS: 40,000 µg/m³

All coordinates shown in UTM Coordinates, UTM Zone 14, NAD 83 Datum



*All values shown include background concentration.

Figure A-15. 8-hour CO ND AAQS Concentrations for Mode 2



APPENDIX K – COMMENT RESPONSE DOCUMENT

U.S. Department of Energy

DOE/EA-2197D

North Dakota CarbonSAFE: Project Tundra

Draft
Environmental Assessment

APPENDIX K
COMMENT RESPONSE DOCUMENT

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APPENDIX K COMMENT RESPONSE DOCUMENT

LIST OF TABLES

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ACRONYMS AND ABBREVIATIONS

Acronym	Definition
BIL	Bipartisan Infrastructure Law
BND	Bank of North Dakota
CCS	carbon capture and storage
CFR	Code of Federal Regulations
CH_4	methane
CJEST	Climate and Economic Justice Screening Tool
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
DAS	Distributed Acoustic Sensor
DOE	U.S. Department of Energy
DTS	Distributed Temperature Sensor
EA	Environmental Assessment
EIS	Environmental Impact Statement
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ERRP	Emergency Remediation and Response Plan
FOA	Funding Opportunity Announcement
GHG	greenhouse gas
GWh	gigawatt-hour
GWP	Global Warming Potential
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
kg	kilogram
KM CDR	Kansai Mitsubishi Carbon Dioxide Recovery
kWh	kilowatt-hour
LCA	Life Cycle Analysis
MHI	Mitsubishi Heavy Industries
Minnkota	Minnkota Power Cooperative, Inc.
MRY	Milton R. Young Station
MW	megawatt
MWh	megawatt-hour
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
ND Water Commission	North Dakota State Water Commission
NDAC	North Dakota Administrative Code
NDDEQ	North Dakota Department of Environmental Quality
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGO	non-governmental organization
NMPA	Northern Municipal Power Agency

Acronym	Definition
NO_2	nitrogen dioxide
NPDES	National Pollutant Discharge Elimination System
OCED	Office of Clean Energy Demonstrations
PM	particulate matter
Project Tundra	North Dakota CarbonSAFE: Project Tundra
PTE	Potential-To-Emit
REMI	Regional Economic Modeling, Inc.
SC-GHG	Social Cost of Greenhouse Gas
SF_6	sulfur hexafluoride
SO_2	sulfur dioxide
SPCC Plan	Spill Prevention, Control, and Countermeasure Plan
Summit Pipeline	Summit Carbon Solutions' Midwest Carbon Express CO_2 Pipeline Project
SWPPP	Stormwater Pollution Prevention Plan
UIC	Underground Injection Control
UST	underground storage tank
Wet ESP	Wet Electrostatic Precipitator
Wh	watt-hour

APPENDIX K COMMENT RESPONSE DOCUMENT

K.1 INTRODUCTION

The U.S. Department of Energy (DOE) prepared the Environmental Assessment (EA) for "North Dakota CarbonSAFE: Project Tundra" (Project Tundra) to evaluate the potential environmental, cultural, and socioeconomic impacts of partially funding a proposed project to design, construct, and operate an amine-based post-combustion carbon dioxide (CO_2) capture technology to treat flue gas from a separate but adjacent coal-fired power plant. Consistent with the National Environmental Policy Act (NEPA), DOE released the Draft EA for a 30-day public comment period, which ran from August 19 to September 19, 2023.

This appendix summarizes the Project Tundra Draft EA public review process and provides information on responses to the comments received during the 30-day public comment period. The appendix is organized into the following sections:

- Section K.2 presents an overview of the agency and public review and comment process initiated by DOE. It also presents the number of comments submitted during the public comment period by entity and submission method and describes the processing of comments received.
- Section K.3 outlines the major themes associated with comments received during the comment period.
- Section K.4 provides DOE responses to the major themes outlined in Section D.3.
- Section K.5 presents comments provided by regulatory agencies, other governmental agencies, non-governmental organizations (NGOs), and the public.

K.2 AGENCY AND PUBLIC REVIEW AND COMMENT PROCESS

DOE published a Notice of Availability on its website and in the Bismarck Tribune Newspaper announcing the availability of the Draft EA and the 30-day comment period running from August 19, 2023 to September 19, 2023. Along with the newspaper notifications, DOE sent letters to notify stakeholders and potentially interested parties. The notifications contained a link to an electronic version of the Draft EA posted on the DOE's National Energy Technology Laboratory (NETL) website and announced the availability of hard copies at two libraries in North Dakota. Chapter 5 of the EA, Distribution List, specifies the agencies, NGOs, Federally recognized Native American Tribes, and individuals to whom notifications were sent. Table K-1 summarizes the hard copies and notifications sent to stakeholders.

Table K-1. Draft EA Notification and Distribution

Group	Number of Hard Copies	Number of Notification Letters
Federal Agencies	0	6 (via email)
State Agencies	0	6 (via email)
Native American Tribes	6	6
Non-Governmental Organizations	0	17 (via email)
Libraries	2	2

During the public comment period, federal agencies, state and local governmental entities, North Dakota Tribal governments, and members of the public were invited to submit electronic comments via regulations.gov or email, or written comments via the U.S. mail. Table K-2 summarizes the number of comments received by method of submission and entity type. Entities submitting comments included federal and state government agencies, NGOs, and the general public. No comments were received from Tribal representatives.

Table K-2. Numbers of Comment Documents Received by Entity and Method of Submission

Entity	Method of Submission		Total
	askNEPA@hq.doe.gov	Email	
Elected Official	0	0	0
Federal Agency	0	1	1
State Agency	0	1	1
Local Agency	0	0	0
NGO/Advocacy Group	0	3	3
General Public	1	4	5

Upon receipt, all written comment documents were assigned a unique number for tracking during the comment response process. All comment documents were then reviewed for inclusion in this appendix and development of major comment themes. In processing the comment documents, each document was analyzed to identify individual comments and DOE prepared responses to the applicable comment themes.

In preparing this revised Draft EA, DOE reviewed all comments received as part of the public comment period. The public comment period closed on September 19, 2023, but DOE considered late comments in preparation of the revised Draft EA. Comments that DOE determined to be outside the scope of the Project Tundra EA are acknowledged as such in this appendix. Policy experts, subject matter experts, and NEPA specialists responded to the remaining substantive comments, as appropriate. This approach served to focus the revision process and ensure consistency throughout the final document. The comments were considered in determining whether the alternatives and analyses presented in the Draft EA should be modified or augmented, whether information presented in the Draft EA needed to be corrected or updated, and generally whether additional clarification was appropriate to facilitate clearer communication of information. Areas where DOE made changes to the revised Draft EA are noted in Section K.4, Comment Responses. Change bars in the margins of pages indicate where substantive changes were made and where text was added or deleted. Editorial changes are not marked. Notable changes made to the revised Draft EA include clarifications regarding the proposed federal action, purpose and need; and no-action alternative; and revisions to the Life Cycle Analysis (LCA) and Social Cost of Greenhouse Gases (SC-GHG).

K.3 MAJOR COMMENT THEMES

Upon review of the comments received on the Draft EA, DOE categorized topics of interest or “themes” to be addressed. These include topics of common interest or concern, as indicated by their recurrence in comments, or technical topics that warrant a more detailed discussion. This section summarizes the comments received on a topic of interest, followed by DOE’s response.

Table K-3 presents the major themes and sub-themes on which DOE received substantive comments. This table also provides the location(s) in the revised Draft EA where the topic is discussed and lists comment sub-themes related to the central topic.

Table K-3. Major Comment Themes

Theme	Revised Draft EA Location	Sub-Theme Coding System[a]
NEPA Process	Chapter 1	Summary Comment 1: General/NEPA Process Summary Comment 2: Purpose and Need Summary Comment 3: National Climate Goals Summary Comment 4: Request for Environmental Impact Statement Summary Comment 5: Agency and Tribal Consultation
Proposed Action	Chapter 1	Summary Comment 6: Connected Actions
Alternatives	Chapter 2	Summary Comment 7: Alternatives Considered Summary Comment 8: No-Action Alternative
Project Facilities and Carbon Capture Technology	Chapter 2	Summary Comment 9: Carbon Capture and Sequestration Technology/Design Summary Comment 10: Co-Benefits of Carbon Capture Summary Comment 11: 45Q Tax Credits
Impact Analysis	Chapter 3	Summary Comment 12: Geology/Geologic Storage Summary Comment 13: Water Resources Summary Comment 14: Solid and Hazardous Waste Summary Comment 15: Reliability and Safety
Socioeconomics and Environmental Justice	Sections 3.13 and 3.15	Summary Comment 16: Socioeconomic Benefits Summary Comment 17: Environmental Justice
Social Cost of Greenhouse Gases (SC-GHG)	Sections 3.3 and 3.17	Summary Comment 18: SC-GHG Summary Comment 19: SC-GHG Equivalencies
Initial Life Cycle Analysis (LCA)	Sections 2.5.6, 3.3, and Appendix E	Summary Comment 20: Initial LCA Approach Summary Comment 21: Initial LCA Functional Unit Summary Comment 22: Sulfur Hexafluoride (SF_6) Summary Comment 23: Initial LCA Methodology and Assumptions Summary Comment 24: Initial LCA Conclusions Summary Comment 25: Air Emissions and Modeling Summary Comment 26: Presumption of Zero Measurable Leakage

K.4 THEMATIC COMMENT RESPONSES

This section provides a summary of each major comment theme identified in Table K-3 and a synopsis for the related sub-themes; refer to the table key for finding responses for a specific topic. Commenters can refer to the theme and sub-theme topics in this appendix to view DOE responses. DOE provides a response to each sub-theme that includes references to relevant information presented in the EA and documents any changes incorporated into this revised Draft EA as a result of the comments.

K.4.1 NEPA Process

DOE received comments related to the purpose of and need for the project. This included comments regarding general opposition to the project, the NEPA process, the purpose and need statement, general quality of the August 2023 Draft EA document, and agency and Tribal consultation/coordination.

Theme	Revised Draft EA Location	Sub-Themes
NEPA Process	Chapter 1	Summary Comment 1: General/NEPA Process Summary Comment 2: Purpose and Need Summary Comment 3: National Climate Goals Summary Comment 4: Request for Environmental Impact Statement Summary Comment 5: Agency and Tribal Consultation

Summary Comment 1: General/NEPA Process

Synopsis:

These comments were general in nature and were related to the NEPA process, opposition to the project, or other topics outside the scope of the EA.

Response to Comments 1-3, 2-1, 4-1, and 10-2:

The NEPA process seeks to include environmental considerations in any federal agency planning, undertaking, or decision-making. The EA is prepared to objectively assess the environmental impacts of partially funding the proposed Project Tundra. The project would include new equipment for the capture and geologic storage of CO_2 adjacent to the existing, separately owned lignite-fired Milton R. Young Station (MRY) in Center, Oliver County, North Dakota. The project would utilize Mitsubishi Heavy Industries' (MHI) Kansai Mitsubishi Carbon Dioxide Recovery (KM CDR) amine-based post-combustion carbon capture technology. The project would purchase and treat the flue gas from MRY to produce a final CO_2 product. The purpose of the EA is to provide decision-makers and other stakeholders with information needed to understand the potential environmental impacts resulting from an action, including mitigation and conservation measures warranted to protect a resource or minimize impact to a resource. Analyses are based on best available data, results of surveys, and academic and agency research and reports to characterize the resources present within the project area (region of influence) and the potential for adverse effects. Where possible, the project design would incorporate best management practices and/or mitigation measures to reduce potential for adverse impacts.

The purpose of a Draft EA is to publish, for public review and comment, an unbiased review of the direct and indirect impacts to the human environment that would potentially result if DOE were to fund a project. A Draft EA is pre-decisional and is intended to inform DOE and the public of potential impacts and to elicit comments from the public, stakeholders, and other agencies. Its function is not to recommend any action by DOE or to promote the merits of a project or technology. Thus, the Draft EA did not include a recommendation regarding the project.

Regarding comments in opposition to the project, DOE understands there are opposing viewpoints on whether this project should proceed and appreciates the public input in the NEPA process. The revised Draft EA builds upon the previously completed Draft EA by incorporating additional text into the purpose and need and alternatives narratives and updating the LCA and SC-GHG analyses to assist in determining the potential adverse and beneficial effects on resources from the construction, operation, and maintenance of the project.

One commenter inquired about a previous Government Accountability Office (GAO) audit on an unrelated project. While GAO audit reports are tools used to assist DOE with improving future approaches on relevant activities, the topic presented is outside the scope of the EA.

Summary Comment 2: Purpose and Need

Synopsis:

Several commenters questioned the purpose and need for the project, requested a broader purpose and need statement, and expressed concerns regarding federal funding of the project.

Response to comments 2-1, 4-1, 5-1, 5-3, 5-4, 7-2, 7-3, 8-1, 8-3, 8-6, 8-7, 8-8, and 8-9:

As described in Section 1.4 of the revised Draft EA, the purpose and need for DOE action is to advance the commercial readiness of carbon capture and storage (CCS) by supporting the construction of a commercial-scale geologic storage complex and associated CO_2 transport infrastructure. In 2021, Congress passed the Bipartisan Infrastructure Law (BIL). The BIL is a once-in-a-generation investment in modernizing and upgrading American infrastructure to enhance United States competitiveness, drive the creation of good-paying union jobs, tackle the climate crisis, and ensure stronger access to economic and environmental benefits for disadvantaged communities. The BIL appropriated more than $62 billion to the DOE to invest in American manufacturing and workers; expand access to energy efficiency and clean energy; deliver reliable, clean and affordable power to more Americans; and demonstrate and deploy the technologies of tomorrow through clean energy demonstrations. DOE's BIL investments "support efforts to build a clean and equitable energy economy that achieves a zero-carbon electricity system by 2035, and to put 'the United States on a path to achieve net-zero emissions economy-wide by no later than 2050' to benefit all Americans."

Through BIL, Congress appropriated funds under both the CarbonSAFE Initiative and the Carbon Capture Demonstration Projects Program to further the development, deployment, and commercialization of technologies to capture and geologically store CO_2 emissions securely in the subsurface. Thus, DOE issued Funding Opportunity Announcement (FOA) DE-FOA-00002711 entitled "Storage Validation and Testing (Section 40305): Carbon Storage Assurance Facility Enterprise (CarbonSAFE)." Project Tundra was selected under the FOA to begin negotiations to receive a federal financial assistance award with Project Tundra.

Successful implementation of Project Tundra would potentially contribute to the rapid growth of a geographically and geologically diverse industry for secure geologic carbon storage by reducing risks and costs for future projects and bringing more storage resources into commercial classifications.

Because DOE has been instructed by Congress on how to utilize this funding, DOE does not have the authority to utilize these funds for any purpose other than commercial-scale CCS projects.

Summary Comment 3: National Climate Goals

Synopsis:

Commenters objected to the (1) characterization of the project as the only way of furthering the U.S. climate goals. Commenters further expressed that (2) the project should align with the Paris Agreement and pursue immediate retirement, and that (3) North Dakota has already shown momentum to shift to wind and solar by retiring Coal Creek Station.

Response to Comments 5-5, 5-8, and 8-26:

(1) It was not the intent of Section 1.4 to imply that a single project would be responsible for meeting the nation's goals with respect to CO_2 emissions. If selected, the project would contribute to a diverse portfolio of projects that collectively research, advance, and demonstrate the reduction of CO_2 from the energy economy, which includes the electricity generation and other industrial sectors. Section 1.4 has been updated for clarity.

(2) DOE does not speculate on the future of proposed regulations, the life-cycle decisions of a plant operator, or any other future decisions outside of its delegated statutory authority. The operational life span and future retirement of MRY Unit 1 and Unit 2 are based on many factors outside of DOE's purview and the scope of this EA. Projecting the remaining years of operation would be highly speculative due to the range of assumptions regarding equipment longevity, infrastructure, market conditions, fuel cost, future demand, and regulatory requirements. It is not reasonably foreseeable to identify a specific life span limit for MRY.

(3) The commenter is mistaken. Although wind farms have been created nearby, Coal Creek Station was not retired. The current owner/operator of Coal Creek Station clearly states that its climate objectives culminate with CCS at Coal Creek. Coal Creek Station has been selected for a CarbonSAFE Phase III project.

Summary Comment 4: Request for Environmental Impact Statement

Synopsis:

Several commenters recommended that the DOE find the environmental impacts would be significant, and therefore an Environmental Impact Statement (EIS) should be prepared.

Response to Comments 5-27, 8-1, 8-5, 8-11, 8-13, 8-15, 8-18, and 8-25:

As required by NEPA and its supporting regulations, DOE prepares an EA for a proposed DOE action that is described in the classes of actions listed in Title 10 of the Code of Federal Regulations (CFR) Part 1021, Subpart D, Appendix C and for a proposed DOE action that is not described in any of the classes of actions listed in Appendices A, B, or D to subpart D. An EA may result in a Finding of No Significant Impact (FONSI) or a determination to prepare an EIS, if significant impacts are present that are not mitigated. At this time, DOE is utilizing the information it has gathered while preparing this EA to determine whether preparation of an EIS is appropriate.

Summary Comment 5: Agency and Tribal Consultation

Synopsis:

One commenter suggested that DOE failed to consult with local agencies and Tribes, Indigenous Peoples, and leaders.

Response to Comment 5-23:

As part of the NEPA process, DOE consulted the federal, state, Tribal governments, and local agencies listed in Chapter 5 (Distribution List) of the revised Draft EA. In accordance with Section 106 of the National Historic Preservation Act, this outreach included consulting with the following federally recognized Tribal Nations in the project area: Apache Tribe of Oklahoma; Fort Belknap Indian Community of the Fort Belknap Reservation of Montana; and Three Affiliated Tribes of the Fort Berthold Reservation, North Dakota.

K.4.2 Proposed Action

DOE received comments related to potential connected actions to the proposed project, specifically the proposed Summit Pipeline.

Theme	Revised Draft EA Location	Sub-Themes
Proposed Action	Chapter 2	Summary Comment 6: Connected Actions

Summary Comment 6: Connected Actions

Synopsis:

One commenter asserts that the proposed project and the Summit Carbon Solutions' Midwest Carbon Express CO_2 Pipeline Project (Summit Pipeline) are connected actions. Two commenters suggested that potential use of captured CO_2 for enhanced oil recovery (EOR) carry environmental impacts that are within the scope of this EA.

Response to Comments 5-26, 8-29, 8-30, 8-31, and 8-32:

Project Tundra is not connected to the proposed Summit Pipeline. Project Tundra does not require CO_2 from the proposed Summit Pipeline to meet the goals and objectives of the project. As currently designed, the CCS project would only operate when MRY is operating, because the CO_2 is captured from the flue gas of MRY. The reference to the Summit Pipeline in Section 3.17, Cumulative Impacts, was referring to the reasonably foreseeable case that the storage reservoir developed under Project Tundra could be used to permanently sequester other anthropogenic CO_2, such as the geographically proximate proposed Summit Pipeline, in the future.

The objective of the CarbonSAFE Initiative is to permanently sequester commercial quantities of CO_2 in subsurface geologic formations. Projects proposing EOR are disallowed under the CarbonSAFE Initiative because they do not meet the requirements DOE has set forth in FOAs DE-FOA-0002711 for CarbonSAFE Phase IV (Construction) or DE-FOA-0002962 for Carbon Capture Demonstration. Use of captured CO_2 for EOR is therefore not in the scope of the EA.

K.4.3 Alternatives

DOE received comments related to consideration of alternatives in addition to the no-action alternative.

Theme	Revised Draft EA Location	Sub-Themes
Alternatives	Chapter 2	Summary Comment 7: Alternatives Considered Summary Comment 8: No-Action Alternative

Summary Comment 7: Alternatives Considered

Synopsis:

Comments stated that DOE should consider a variety of effects and variations of alternatives in addition to the no-action alternative, including operator decision on maintenance and operations of the MRY facility, proposed regulations from other agencies, and resource replacement impacts.

Response to Comments 3-1, 5-6, 5-7, 5-9, 7-1, 7-2, 7-3, 7-4, 8-2, 8-10, 8-11, 8-12, 8-18, 8-20, 8-23, and 8-26:

NEPA requires agencies to consider a reasonable range of alternatives to the proposed agency action, including an analysis of any negative environmental impacts of not implementing the proposed agency action in the case of a no action alternative that are technical and economically feasible and meet the purpose and need of the proposal.

In 2016, Congress directed DOE to develop CCS at a commercial scale. DOE created the CarbonSAFE Initiative in order to comply with that directive. The purpose and need for agency action is not "tailored to the applicant's goals;" rather, it is responsive to DOE's "statutory authority and goals" as well as Congressional mandates that require commercial-scale CCS. Thus, DOE only has the authority to choose to fund or not to fund any of the projects applying for funding under a competitive FOA. DOE does not have the ability to use the Congressionally appropriated funds for any purpose other than commercial-scale CCS. DOE's **Proposed Action** is to provide cost-shared funding for Project Tundra and the only alternative is not funding the proposed project. Alternatives to Minnkota's **proposed project** include funding a different project that meets the goals and objectives of the same FOA or not funding any projects submitted under the FOA. In this case, the projects that are eligible to apply for funding under DE-FOA-00002711 consist of the other CarbonSAFE Phase III projects, which will undergo separate NEPA analysis and documentation. There are currently four other projects undergoing NEPA review:

- DOE/EA-2194: Wyoming CarbonSAFE
- DOE/EA-2196: Establishing an Early CO_2 Storage Complex in Kemper County, Mississippi: Project ECO_2S
- TBD: San Juan Basin CarbonSAFE
- TBD: Illinois Storage Corridor CarbonSAFE

There are additional projects being selected for CarbonSAFE Phase III, which will also undergo NEPA review. Please see DOE's website https://netl.doe.gov/carbon-management/carbon-storage/carbonsafe for a current list of those projects. The CarbonSAFE Initiative Draft EA and EIS documents will continue to be published for review at https://netl.doe.gov/node/6939 and https://netl.doe.gov/library/eis, respectively. All CarbonSAFE Phase III projects will be analyzed for potential impacts separately and will not be discussed further in this EA. DOE's consideration of reasonable alternatives to this project in this document is therefore limited to the no-action alternative.

Moreover, an agency is not expected to engage in forecasting and speculation that would ultimately be unhelpful in its decision making, especially when the agency lacks any power to act on such speculation. "NEPA's purpose is not to generate paperwork or litigation, but to provide for informed decision making and foster excellent action" (40 CFR § 1500.1). Additionally, DOE has no control over the continued operation of MRY, so an alternative that involves shutting down or reducing power levels is outside the scope of DOE's authority.

Summary Comment 8: No-Action Alternative

Synopsis:

Comments stated that DOE should consider a no-action alternative that does not include continued operation of MRY at current levels, and instead includes decommissioning of the plant at intervals selected by the commenters.

Response to Comments 3-1, 5-6, 5-7, 5-9, 7-1, 7-3, 8-2, 8-8, 8-10, 8-11, 8-12, 8-13, 8-18, 8-20, 8-23, 8-26:

In Section 2.3, it is clearly stated that the no-action alternative, in which DOE would not fund the project, is assumed to be a no-build option, with CO_2 emissions continuing from MRY. This no-action alternative provides a meaningful comparison between the current environment at the proposed project location and the potential impacts attributable to DOE's proposed action. DOE does not speculate on the future of proposed 111(b) and 111(d) regulations, the life-cycle decisions of a plant operator, or any other future decisions outside of its delegated statutory authority. Similarly, DOE does not speculate that the CCS project will proceed with independent funding, which would result in a Draft EA analysis with no net impacts. The operational life span and future retirement of Unit 1 and Unit 2 is based on many factors outside of DOE's purview and the scope of this EA. Projecting the remaining years of operation would be highly speculative due to the range of assumptions regarding equipment longevity, infrastructure, market conditions, fuel cost, future demand, and regulatory requirements. It is not reasonably foreseeable to identify a specific life span limit for MRY in the alternatives for this EA.

K.4.4 Project Facilities and Carbon Capture Technology

DOE received comments related to the effectiveness of the proposed CCS technology, the co-benefits of carbon capture, and the applicability of the 45Q tax credits.

Theme	Revised Draft EA Location	Sub-Themes
Project Facilities and Carbon Capture Technology	Chapter 2	Summary Comment 9: Carbon Capture and Sequestration Technology/Design Summary Comment 10: Co-Benefits of Carbon Capture Summary Comment 11: 45Q Tax Credits

Summary Comment 9: Carbon Capture and Sequestration Technology/Design

Synopsis:

DOE received several comments on the design of the CCS that asserted that DOE incorrectly accounted for the capture design in the EA and LCA analysis.

Response to Comments 5-5, 5-13, 5-14, 5-25, 5-26, 6-1, 6-2, 6-3, 6-4, 8-13, 8-15, 5-16, 8-17, 8-19, 8-22, 8-24, and 8-25:

DOE appreciates that there is not one uniform capture goal, standard or requirement across agency programs and legislation for carbon capture. Thus, DOE offers a responsive narrative to assist the public in reviewing the EA and the proposed project's ability to meet DOE program goals.

Specifically, Project Tundra's CCS is designed and guaranteed by the technology vendor, MHI, to capture 95% of the CO_2 in flue gas treated by the CCS system. This corresponds to 13,000 short tons per day (11,793 metric tons per day) of CO_2 when operating at its full design capacity. For this generating station, the CCS capacity is approximately the equivalent of 530 megawatts (MW) out of the 734 MW total station gross capacity (Unit 2 gross rating is 477 MW and Unit 1 gross rating is 257 MW).

The design of this CCS system to simultaneously accept and process flue gas from Unit 1 and Unit 2 permits the system to capture much more CO_2 than capture systems that are paired with a single generating unit. The CCS is designed and sized to process 100% flue gas from Unit 2 (the larger of the two units at the site) plus an estimated 20% of the flue gas from Unit 1 when both generating units are operating at their full capacities including flexible operational mode variations. The agility of this project design is advantageous, particularly when grid conditions require the generating units to operate at less than full capacity. During those hours that the Units are operating at a less than full capacity level, the CCS is designed to be able to process all the flue gas from the entire generating station. For example, when either of the generating units is in outage, the CCS system can continue to capture CO_2 from the other operating unit. Also, when either or both generating units are operating at lower capacity to accommodate wind power in the region, the CCS can remain at full capacity thereby maximizing the utilization of the CCS system.

The Initial LCA calculation was based upon projected annual coal usage to account for both the outages and the operation variability of the MRY facility, and thus provided a comprehensive approach to the project's LCA.

Summary Comment 10: Co-benefits of Carbon Capture

Synopsis:

Commenters requested that the co-benefits of the upstream controls of the CCS to provide flue gas inputs to the carbon processing plant be addressed.

Response to Comments 6-1 and 6-4:

Pre-treatment controls are upstream of the CO_2 absorber that ensure the desired capture efficiency in the absorber. These pre-treatment devices include a Wet Electrostatic Precipitator (Wet ESP) and a quencher that will reduce sulfur dioxide (SO_2) and particulate matter (PM) in the flue gas stream prior to reaching the absorber. These devices will only be operational during times when the CCS is operating. As such, these controls are considered a co-benefit of the carbon capture system, when it is operating.

MRY meets all state and federal standards for SO_2, nitrogen dioxide (NO_2), and PM and these emissions are monitored as required by its air permit. Any reductions in pollutant emissions in MRY flue gas that occur as a result of the CCS and its associated pretreatment are co-benefits from the project, above and beyond the emissions reduction technologies employed by Minnkota at MRY to meet the limits in its air permit and ambient air quality standards. DOE is not quantifying those co-benefits at this time, but it is a valid assumption that additional health benefits may arise from the reduction of these pollutants. In addition, these National Ambient Air Quality Standards (NAAQS) are established for these pollutants to protect public health including sensitive populations such as asthmatics, children, and the elderly. Currently, all counties in North Dakota are classified as attainment or unclassified areas for all ambient air quality standards, including the county in which the CCS would be operating. The Project air quality analysis concludes that the CCS project would not cause or contribute to an exceedance of the NAAQS.

Summary Comment 11: 45Q Tax Credits

Synopsis:

Commenters questioned the applicability of 45Q tax credits to the CCS project, as well as whether the operation of the MRY facility would increase as a result of 45Q tax credit incentives.

Response to Comments 5-19, 8-19, 8-21, 8-22, 8-23, 8-24, and 8-25:

Congress creates tax credits like 45Q to encourage the deployment of new technologies. DOE does not have any jurisdiction over power plant operation or the 45Q tax credit program. The CCS unit is structured physically and commercially to have no impact on the operation or dispatch of the MRY (see response to summary comment 9). Because the dispatch of the power plant is forecasted based on its market position, and because the project sponsors have structured the CCS project to not impact power plant economics, including impacts due to available tax credits, then in both the "no build" and the "build" cases under the LCA, the dispatch should be the same.

K.4.5 Impact Analysis

DOE received comments related to the impact analysis provided in Chapter 4 of the Draft EA. Comments relate to geology, water resources, solid and hazardous waste, and reliability and safety.

Theme	Revised Draft EA Location	Sub-Themes
Impact Analysis	Chapter 3	Summary Comment 12: Geology/Geologic Storage Summary Comment 13: Water Resources Summary Comment 14: Solid and Hazardous Waste Summary Comment 15: Reliability and Safety

Summary Comment 12: Geology/Geologic Storage

Synopsis:

A commenter expressed concerns regarding the complexity of geologic carbon storage and the diverse geological conditions across regions that demand a more nuanced and site-specific approach to assessing the feasibility and reliability of such projects, and the proposed project in North Dakota alone will not be representative of geological conditions of other commercial coal-fired power plants to reduce the risks for commercial development of CCS.

Response to Comment 5-2:

DOE agrees that funding a single CCS project would not fully demonstrate the technology at a commercial scale. It is for that reason that DOE continues to issue FOAs and select a project portfolio that is geographically and geologically diverse. For a map of current CarbonSAFE projects in all phases of development, see https://netl.doe.gov/carbon-management/carbon-storage/carbonsafe, There are currently no projects selected for CarbonSAFE Phase IV, which includes construction of the geologic storage site. In December 2023, DOE's Office of Clean Energy Demonstrations (OCED) announced the selection of three carbon capture demonstration projects under DE-FOA-00002962.

DOE notes that the development of a geologic storage unit to sequester CO_2 is complex and not all states have the geologic factors that are conducive to sequestration. North Dakota is an oil-producing state that does have extensive data on the formations making up the subsurface stratum, which has been gained through numerous seismic efforts, geologic cores, and well logging activities that have occurred over the last 70 years. Further, much data and analysis surrounding permanent geologic storage was gathered on the proposed project as a result of tasks performed under CarbonSafe Initiative Phase I, II, and III projects at this location. Finally, the state of North Dakota and the U.S. Environmental Protection Agency (EPA) have approved injection through the Underground Injection Control (UIC) Class VI permitting process. To be approved for this permit, extensive evaluations and monitoring are required. All of the project's data may be used to determine other settings in which the CCS technology may be applied.

Summary Comment 13: Water Resources

Synopsis:

Two commenters expressed concerns regarding potential impacts to surface waters, including waterbodies, non-community well protection areas, and the potential effects of the project water appropriation from the Missouri River on users downstream. These comments recommended that the project site its facilities and route the pipeline (i.e., CO_2 flowline) to avoid source water protection areas, and sensitive surface and groundwater environments. The commenters also inquired about required permits and/or permit amendments; mitigation measures that Minnkota would implement to prevent erosion and sediment loss and potential impacts to water resources, wetlands, and riparian zones/delicate flora; and restoration of areas affected by project construction.

Responses to Comments 8-4, 8-27, 8-28, 9-1, 9-2, 9-3, 9-4, 9-7, 9-10, 9-11, 9-12, and 9-13:

Surface Water and Groundwater:

As described in Section 2.5 of the Draft EA, the project involves the construction of a less than 0.5-mile-long CO_2 flowline to carry the compressed CO_2 to an injection site for deep geologic storage. The flowline would be located on previously disturbed Minnkota-owned property and has been routed to avoid sensitive surface and groundwater environments.

As described in Section 3.5.2.1 of the Draft EA, project construction would require the development of a Stormwater Pollution Prevention Plan (SWPPP), which would contain site-specific measures to avoid and minimize erosion and sediment transport to surface waters wetlands, and riparian zones, as well as measures to contain and clean up accidental petrochemical spills. Potential impacts to Nelson Lake and Square Butte Creek would be mitigated using site-specific measures and best practices identified in the SWPPP and associated National Pollutant Discharge Elimination System (NPDES) permit (Clean Water Act Section 402), designed for water quality protection and to ensure water quality standards of nearby surface waters are not exceeded. If necessary, the current MRY NPDES permits would be amended as needed to address any operational changes Project Tundra would cause. However, as designed, Project Tundra would operate as a "zero liquid discharge" facility. All regulatory agencies would be consulted prior to implementation of future changes.

Hazardous materials and wastes would be stored and disposed of in accordance with standard operating health and safety procedures of the project sponsor, which will be at least as stringent as those of the site owner Minnkota. Project areas temporarily affected by construction (i.e., not retained for facility operation) would be restored to original conditions.

As described in Section 3.5.1.1.1 of the Draft EA, it is not anticipated that a Clean Water Act Section 404 permit would be required from the U.S. Army Corps of Engineers because project construction and operation would not result in the placement of dredged or fill material into Waters of the United States. Therefore, it is not anticipated that a water quality certification will be required.

The project does overlay a non-community well protection area. Care will be taken to avoid spills via the SWPPP and associated state permit. Spill reporting will follow the SWPPP reporting requirements of 40 CFR 110, 40 CFR 117, and 40 CFR 302, the reporting requirements found in North Dakota Administrative Code (NDAC) 33.1-16-02.1, and any release which meets any reporting requirement in accordance with Part IV(A)(7).

Water Appropriations:

Regarding the proposed water appropriation from the Missouri River, the North Dakota State Water Commission (ND Water Commission) has approved the 15,000-acre-feet water appropriation as described in Section 2.5.2.1 of the Draft EA. The permitting authority has the responsibility of determining whether the proposed amount of additional water is attainable or not. The agency's review of the permit application included a detailed analysis of the potential effect on existing water appropriations, which determined that approval of the requested appropriation was acceptable.

In an October 2023 follow-up query, the ND Water Commission confirmed that permitted drinking water appropriations from the Missouri River, Lake Sakakawea, and Lake Oahe total 201,041 acre-feet of consumptive use (or 65,509,432,046 gallons). This number was determined based on municipal appropriations. Note that this value is the water allocated, but allocations may not be developed or currently in use. A large percentage of Missouri River appropriations are authorized for multiple uses associated with the original Garrison Diversion Unit Project and derived water permits associated with the Garrison Diversion Reformulation Act of 1986, Northern Area Water Supply Project, and the Red River Valley Water Supply Project. Multiple uses comprise 3,145,000 acre-feet of consumptive use (or 1,024,801,200,000 gallons).

The mean daily flow of the Missouri River at Lake Sakakawea during water years 1955 through 2019 is estimated to be 9,518,363 gallons per minute, 21,207 cubic feet per second, or 42,179 acre-feet per day. The mean annual discharge over the same period, water years 1955 through 2019, is estimated to be 15,363,704 acre-feet. The 15,000 acre-feet of water requested for the project is 0.10 percent of the mean annual discharge recorded at Garrison Dam and the requested withdrawal rate of 13,480 gallons per minute, or 30.0 cubic feet per second, is 0.14 percent of the mean daily discharge rate.

Given the remaining water availability via mean daily flow data and mean annual discharge data, the proposed project does not represent a significant change to daily flow or annual discharge. Therefore, the project would not preclude other water users from exercising their right to appropriate water, subject to ND Water Commission permitting requirements and regulatory requirements at NDAC Title 89-03 and North Dakota Century Code 61-04. It is the responsibility of state agencies to regulate water withdrawals and initiate conditions for approval, which would include any future consideration of potential worsening drought conditions in the region, if applicable.

Summary Comment 14: Solid and Hazardous Waste/Spill Response

Synopsis:

DOE received comments regarding proper management and transport of solid and hazardous wastes and the development of a spill response plan, which emphasizes rapid containment/cleanup of spills and surveillance and monitoring for early detection of leaks. Additionally, one commenter inquired about the presence of a potential historical underground storage tank (UST) within the MRY.

Response to Comments 9-3, 9-6, 9-8, and 9-9:

As described in Section 3.8.1 of the Draft EA, all waste, both hazardous and non-hazardous, would be managed pursuant to federal and state environmental regulations. Stormwater generated from the construction site would be managed as specified in the project SWPPP.

All new waste streams would be profiled and either sent offsite to be disposed of by properly licensed disposal providers or may be contracted for disposal with Minnkota in the MRY landfill in accordance with the landfill's existing permits. Hazardous waste would not be expected from any of the new waste streams, but if a waste was determined to be hazardous it would be disposed of in accordance with state and federal regulations.

As described above and in Section 3.5.2.1 of the Draft EA, the project sponsors would develop a SWPPP prior to project construction. In addition to containing site-specific measures to avoid and minimize erosion and sediment transport to surface waters, the SWPPP would also include measures to contain and clean up accidental petrochemical spills. Spill prevention and containment measures would be considered during project engineering design to prevent pollutant discharges to the surface, and all attempts would be made to prevent contamination of water from construction activities, such as fuel spillage, lubricants, and chemicals, by following safe handling and storage procedures. Stormwater runoff would be managed to minimize sediment and silt movement, and other potential pollutants. In addition to developing a site-specific SWPPP, a site-specific Spill Prevention, Control, and Countermeasure Plan (SPCC Plan) is maintained for the MRY facility. If applicable, one will also be developed for Project Tundra as a separate facility. Additional spill response measures would be included as part of the standard operational environmental, health, and safety planning.

Regarding the inquiry into a potential historical UST at MRY, Minnkota removed the North Dakota Department of Environmental Quality (NDDEQ) UST permit #046 on May 18, 2021. No UST is associated with the project.

Summary Comment 15: Reliability and Safety

Synopsis:

One commenter recommended consideration of resiliency and emergency remediation and response plan be made available for public consideration.

Response to Comment 7-9:

The inclusion of an Emergency Remediation and Response Plan (ERRP) is beyond the scope of this EA; however, the preliminary ERRP is publicly readily available on the North Dakota Industrial Commission website for Class VI permits at https://www.dmr.nd.gov/dmr/oilgas. Updates and additions to this plan may be made during final design and construction.

The proposed project is located in North Dakota, which is a state of extreme weather conditions. One of the benefits of the proposed project's location is that demonstrating technology and process in a location with extreme weather patterns will require the team to account for these variable extremes in design and engineering.

North Dakota	Maximum Temperature	121°F
North Dakota	Minimum Temperature	-60°F
North Dakota	24-Hour Precipitation	8.1 in.
North Dakota	24-Hour Snowfall	27 in.
North Dakota	Snow Depth	65 in.

K.4.6 Socioeconomics and Environmental Justice

DOE received comments related to the socioeconomic and environmental justice analysis provided in Section 3.13 of the Draft EA. Comments relate to the validity of the assessment of economic benefits and the need for more in-depth analysis of impacts to environmental justice populations.

Theme	Revised Draft EA Location	Sub-Themes
Socioeconomics and Environmental Justice	Sections 3.11 and 4.11	Summary Comment 16: Socioeconomic Benefits Summary Comment 17: Environmental Justice

Summary Comment 16: Socioeconomic Benefits

Synopsis:

Commenters encouraged DOE to include consideration of impact to consumer rates for electricity due to "retrofitting" impacts on the MRY's operating performance.

Response to Comments 1-15, 5-20, and 5-21:

As an initial matter, DOE observes that the project is a stand-alone facility adjacent to MRY. It is not a "retrofit." The project is owned by a separate owner, who bears the operating costs and maintenance of the CCS facility. Consequently, there is no direct, project-specific impact caused by the project on ratepayers, as suggested by the commenter.

With respect to indirect rate impacts, the CCS unit is structured physically and commercially to have no impact on the dispatch of MRY and therefore would not have impact on the dispatch characteristics or the cost to operate the power plant. For further information about MRY rates in general, DOE directs the commenter to Minnkota's most recent 2022 Integrated Resource Plan (IRP) filed with the Minnesota Public Utility Commission to provide additional information and data on resource planning and adequacy. Minnkota's utility rates are discussed throughout the IRP**,** which also includes a discussion of its member-consumers participation in the planning process and potential impacts to member rates.

Summary Comment 17: Environmental Justice

Synopsis:

One commenter suggested additional discussion of environmental justice and socioeconomics of the proposed project be included in the EA and questioned the data used to establish environmental justice thresholds.

Response to Comments 5-15, 5-17, 5-18, 5-22, 5-23, and 5-24:

DOE wishes to further clarify the potential environmental justice and economic impact of building the project to the immediate community and the state of North Dakota. The EPA defines environmental justice as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies."[1]

The proposed project includes the construction and operation of a CCS facility adjacent to the MRY. Environmental justice considerations include the potential impact of the CCS operation on the electricity

[1] https://www.epa.gov/environmentaljustice

generated and transmitted from the MRY. The MRY is owned by Minnkota Power Cooperative, which is a not-for-profit regional generation and transmission cooperative, that provides about 1,300 MWs of wholesale power capacity (generated from 13 resources) to 11 member-owner distribution cooperatives in eastern North Dakota and northwestern Minnesota (see Figure 1). These members serve approximately 149,000 consumer accounts in a 34,500 square-mile area, including rural homes, farms, schools, and businesses. Minnkota also serves as the operating agent for the Northern Municipal Power Agency (NMPA), which supplies the electric needs of 12 associated municipalities that serve approximately 16,000 consumer accounts.

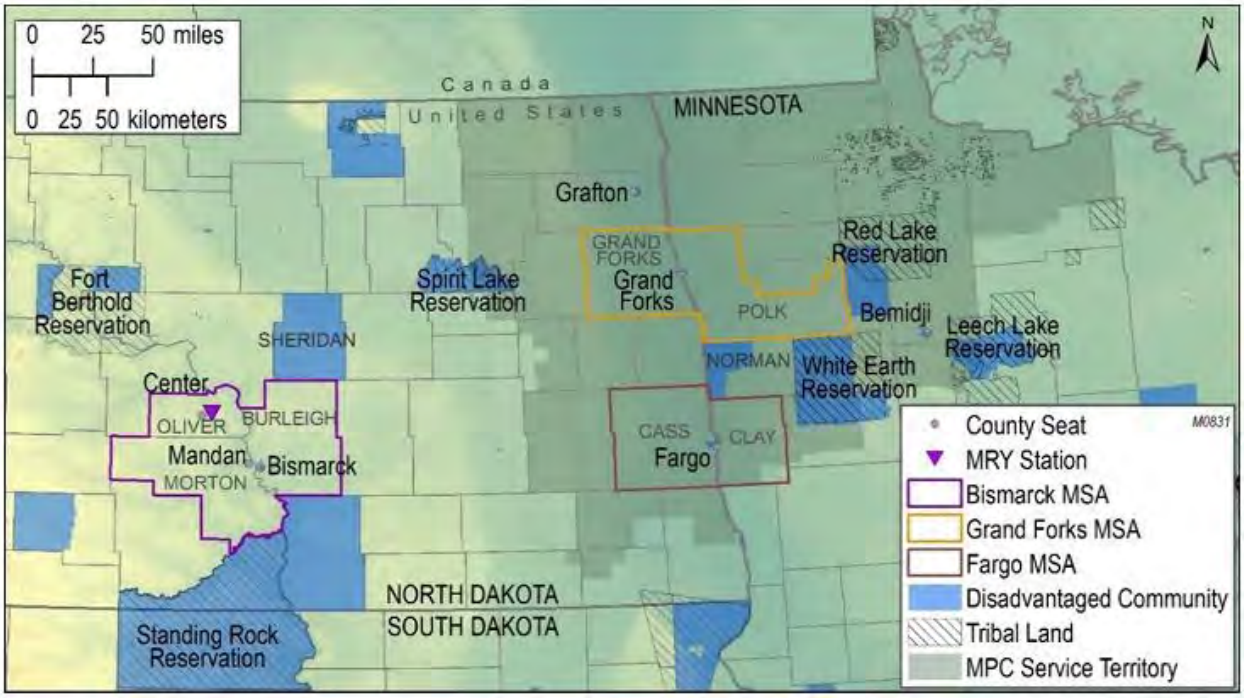


Figure 1: Minnkota's service territory and impacted disadvantaged communities, tribal lands, and Metropolitan Statistical Areas (MSA).

These distribution and municipal cooperatives have end-use consumers who are also stakeholders, and it is the mission of Minnkota to meet the electricity needs of those end-use stakeholders. For the Minnkota service area members, access to safe, reliable, affordable, and environmentally responsible electricity is vitally important to the region's continued success, quality of life, and regional security. Minnkota has worked for more than 80 years to provide the electricity that supports and unites rural communities across eastern North Dakota and northwestern Minnesota (Figure 1).

The geographical areas investigated include the Burleigh–Morton–Oliver County MSA, Tribal Nations within Minnkota's service territory, and the service territory as a whole (Figure 1). These areas were assessed through the DOE's Disadvantaged Communities Reporter. Additional data were referenced from The Council on Environmental Quality's Climate and Economic Justice Screening Tool (CJEST) and the EPA's EJScreen tool. These tools detail potential burdens within affected communities. To be considered a disadvantaged community, a census tract must rank in the 80th percentile of the cumulative sum of the 36 burden indicators and have at least 30% of households classified as low-income. Additionally, federally recognized tribal lands are categorized as disadvantaged communities in accordance with the Office of Management and Budget's "common conditions" definition of a community.

Energy democracy is one of the DOE's Justice40 policy priorities. Minnkota is owned by 11 member-owner distribution cooperatives, each of which oversees a portion of Minnkota's service area. Membership is open to anyone who can use its services and is willing to accept the responsibilities of membership. Cooperatives are run democratically. Minnkota's generation portfolio also includes wind and hydroelectric; member-consumers can choose how much of their energy is produced by renewable resources. Minnkota has also supported member-cooperatives pursuing independent solar projects. Democratic Member Control is one of the seven foundational principles on which all cooperatives operate. The proposed project will reduce carbon emissions from a base-load generating resource. These steps support the DOE Justice40 policy priority of increased parity in clean energy technology access and adoption in disadvantaged communities. This project presents opportunities for an increase in clean energy creation and contracting for minority or disadvantaged businesses in disadvantaged communities.

The project sponsors engaged the Bank of North Dakota (BND) and FTI Consulting to produce a study on the economic impact of the proposed project related to job creation. This process used Regional Economic Modeling, Inc. (REMI) software to gauge the impact of the project on associated positions within the impacted territory. REMI grew from the University of Massachusetts and has had its underlying model structure and equations published in the American Economic Review. For the proposed project, the REMI software was used as an initial analysis to determine the direct jobs and investments needed to develop and construct the world's largest CO_2 CCS plant at the MRY facility.

The REMI software results show the "direct" effect of jobs or expenditures and their related "indirect" effect on industrial supply chains and "induced" effects on consumer expenditures. This analysis included labor market quality, job availability, wages relative to the cost of living, domestic migration, and demand for housing. Using this model and timeline inputs, it was found that during construction, the total number of jobs peaks at 1,175 before stabilizing at around 250 jobs during operations.

During the construction phases, constructions jobs make up over half of the impacted jobs. Government, Retail, Healthcare, Hotels, Real Estate, and Personal, Professional, and Business Services all show marked increases. During later operations phases, these position types hold, with the addition of Utilities. See Figure 2.

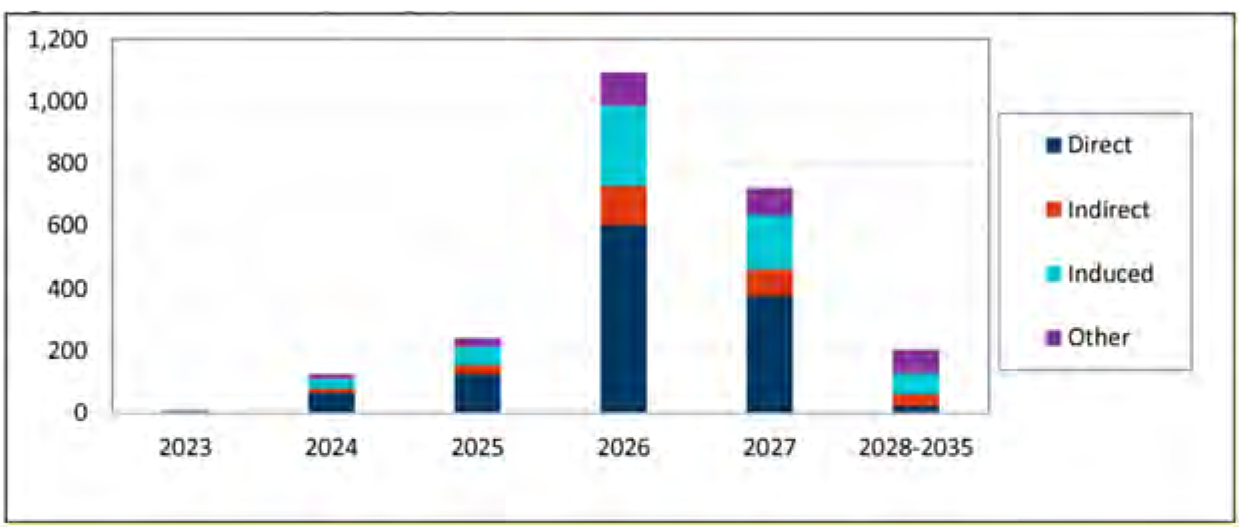


Figure 2: Jobs created by Category

The project is also likely to increase clean energy jobs, job pipelines, and job training for individuals from disadvantaged communities, another DOE Justice40 policy priority. The primary energy and environmental justice benefits of this project are twofold: a steep reduction in emissions and the creation of clean energy jobs. The latter has the most potential of direct benefit to disadvantaged communities.

The construction of the capture plant will require approximately 400 to 600 science, technology, and engineering and construction professionals, in addition to approximately 25 permanent operations positions needed from commissioning throughout the life of the project. The REMI data reinforces and agrees with these estimates. Project ownership will ensure that the project attracts and retains a highly skilled and diverse workforce by offering highly competitive compensation that will meet or exceed Davis–Bacon wage and benefits requirements. This is a fundamental imperative, given the especially competitive high-wage labor market; North Dakota is ranked second nationally for its low unemployment rate: 1.9% in September 2023, and per capita income is about 10% above the national average. Prevailing North Dakota wages for the major job categories to be created by the project are outlined in Table K-4. Project ownership will ensure that the project's wage and benefits requirements will be applied consistently for all workers involved in the construction and operations of the project with clear and consistent requirements for all subcontractors.

Table K-4. May 2021 State Occupational Employment and Wage Estimates, North Dakota

Occupation Title	Employment	Employment per 1000 Jobs	Median Hourly Wage	Mean Hourly Wage	Annual Mean Wage
Architecture and Engineering Occupations	5270	13.34	$37.61	$39.92	$83,020
Project Management Specialists	1490	3.762	$37.38	$40.06	$83,320
Construction and Extraction Occupations	28,000	70.87	$23.63	$27.69	$57,600
Installation, Maintenance, and Repair Occupations	21,120	53.47	$23.65	$27.35	$56,880

One commenter expressed concerns that DOE should conduct a comprehensive analysis of potential project air quality impacts on Center, North Dakota due to concerns regarding pollutants (e.g., fly ash and PM) from the coal-fired MRY facility. Emissions from the proposed CCS project and the existing MRY coal-fired power plant emissions were modeled as part of the NDDEQ air permit application process. DOE has included the current background air quality and the projected emissions changes due to operation of the proposed CCS project for MRY in Section 3.2.1.1 of the revised Draft EA. The project's Air Permit to Construct, Air Quality Emissions Analysis, and Air Quality Impact Analysis are included in Appendix J to the revised Draft EA.

As part of the air permitting process, a 30-day public comment period for the proposed air permit began on September 21, 2023, and ended on October 21, 2023. On October 19, 2023, NDDEQ hosted an air permit public hearing at the Betty Hagel Memorial Civic Center in Center, North Dakota to obtain feedback on the air permit. Approximately 50 people attended the meeting. Two people spoke, both in support of the project. NDDEQ staff concluded that the project would comply with all applicable air pollution control rules and is protective of human health and the environment and, on December 29, 2023, issued Air Permit to Construct No. ACP-18194 v1.0 (see Appendix J of the revised Draft EA). According to CJEST, Center is not considered a community that is economically disadvantaged or overburdened by pollution. Therefore, it is not anticipated that Center would experience high adverse health or environmental effects from air emissions associated with the MRY facility or project.

See also the response to Summary Comment 25.

K.4.7 Social Cost of Greenhouse Gases (SC-GHG)

DOE received several comments related to greenhouse gases (GHGs) and climate change, specifically regarding the SC-GHG analysis and the LCA.

Theme	Revised Draft EA Location	Sub-Themes
Social Cost of Greenhouse Gases (SC-GHG)	Sections 3.19 and 4.19	Summary Comment 18: SC-GHG Methodology Summary Comment 19: SC-GHG Equivalencies

Summary Comment 18: SC-GHG Methodology

Synopsis:

These comments recommend providing additional clarity to the scope of emissions included in the analysis and clearly defining the no-build alternative that is being represented in the SC-GHG analysis. Further, it was recommended the 95th percentile of estimates based on the 3 percent discount rate be included within this analysis.

Response to Comments 7-5, 7-6, 7-9, and 8-14:

The purpose of the SC-GHG is to show estimates, in dollars, of the economic damages that would result from emitting one additional ton of a GHG (CO_2, nitrous oxide [N_2O], methane [CH_4]) into the atmosphere each year. The "social cost" puts the effects of climate change into economic terms to help policymakers and decisionmakers understand the economic impacts of decisions that would increase or decrease emissions. For this analysis, two scenarios were represented: a proposed action alternative (build scenario), where the proposed CCS is constructed and operated, and a no-action alternative (no-build scenario) where the CCS is not constructed. The SC-GHG utilizes the expected emissions of MRY with and without the construction of the CCS as a means of comparison. For more information on the selection of the no-action alternative, reference Summary Comments 7 and 8.

The SC-GHG analysis uses future projected fuel consumption at the MRY plant for the years 2028 through 2048, as well as the expected carbon sequestration in those years. Projected annual fuel consumption at MRY was determined to be a more realistic estimate of future operations as opposed to MRY's Potential-To-Emit (PTE). PTEs are based on units running at maximum capacity and inform a worst-case scenario of expected emission, which is often an unrealistic representation of actual annual operations. Thus, the annual use of the fuel consumption projections in this analysis allows for a more realistic representation of the SC-GHG. Upstream and downstream emissions are not included in this analysis because the scope of the proposed project is limited to the carbon capture system and sequestration system which does not affect the upstream (coal/fuel oil extraction) activities or the downstream (transmission and distribution of electricity) activities.

The SC-GHG analysis has been updated to utilize the DOE standardized SC-GHG workbook. The workbook (and the analysis presented in the Draft EA document) utilize the Interagency Working Group Technical Support Document[2] that sets interim estimates of SC-CO_2, SC-N_2O, SC-CH_4, known cumulatively as SC-GHG. The interim estimates have been developed using the average of three different annual discount rates: 2.5%, 3%, and 5%. Additionally, an estimate is provided for the 95th percentile of an

[2] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. 2021.

applied 3% discount rate for future economic effects. This is a low probability but high damage scenario that represents an upper bound of damages within the 3% discount rate model. The updated SC-GHG results rounded to the nearest million value are present below in Table K-5.

Table K-5. Present Value (in Base Year 2028) of Estimated SC-GHG Comparison of Proposed Action and No-Action Scenarios (2020$, Rounded)

Discount Rate	5%	3%	2.5%	3%
Statistic	Average	Average	Average	95th Percentile
No-Action	$1,717,000,000	$6,106,000,000	$9,071,000,000	$18,629,000,000
Proposed Action	$393,000,000	$1,391,000,000	$2,066,000,000	$4,231,000,000
Difference	**-$1,324,000,000**	**-$4,715,000,000**	**-$7,005,000,000**	**-$14,398,000,000**

The updates to the SC-GHG analysis do not change the DOE's conclusion that the proposed CCS is projected to reduce total GHG emissions and associated social costs compared to the no-action alternative. For discount rates high to low over the analysis lifespan, the reduction in the SC-GHG was calculated to be approximately -$1.3, -$4.7, and -$7.0 billion in 2020 dollars if the proposed project is constructed and operational. For the 95th percentile of an applied 3% discount rate, the reduction in the SC-GHG that is attributed to the proposed project is approximately -$14 billion.

Summary Comment 19: SC-GHG Equivalencies

Synopsis:

The EPA recommends providing the GHG emissions in carbon dioxide equivalents (CO_2e) and translating emissions in equivalencies that are more easily understood to the public. Additional recommendations include additional discussion of the GHG emissions in respect to reduction goals and ensuring that appropriate context has been provided to verify the EA meets the requirement of "disclosing and providing appropriate context for GHG emissions".

Response to Comments 7-5, 7-6, 7-8, 8-14, and 10-1:

The Draft EA provided a SC-GHG analysis which follows the outline set by the Council on Environmental Quality to "*provide additional context for GHG emissions including through the use of best available SC-GHG estimates, to translate climate impacts into a more accessible metric of dollars…*"[3]. The discussion regarding the revised SC-GHG analysis is available in Summary Comment 18.

Annual GHG emissions (CO_2, CH_4, and N_2O) were estimated to calculate the SC-GHG. Refer to the discussion regarding the revised SC-GHG analysis in Summary Comment 18 for methodology. To satisfy the request for additional context regarding the expected GHG emissions and the subsequent reduction that is expected due to the construction and operation of the CCS, the annual GHG emissions were converted into a representative CO_2e value by multiplying each GHG by its respective 100-year Global Warming Potential[4] (GWP). GWP are factors applied to each individual GHG to convert their emissions to their potency to affect global warming compared to that of CO_2. Representative equivalencies are calculated utilizing methodology outlined by the EPA Greenhouse Gas Equivalencies Calculator References[5]. Please

[3] https://www.federalregister.gov/d/2023-00158 published January 09, 2023.
[4] Table A-1 to Subpart A of Part 98, Title 40, https://www.ecfr.gov/current/title-40/appendix-Table%20A-1
[5] https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

note that the presented annual CO_2e emissions and equivalencies are estimates based on projected fuel use at MRY and expected CO_2 sequestration.

The annual CO_2e reduction value stays constant on an annual basis. This assumes that 11,793 metric tons of CO_2 will be processed daily, and that all CO_2 will be sourced from the MRY Plant. The overall annual reduction value is equivalent to approximately 4 million metric tons of CO_2e annually. Utilizing EPA emission factors for GHG emissions from gasoline-powered passenger vehicles, the reduction in CO_2e from implementing and operating the CCS project is equivalent to taking just under 950,000 cars off the road annually. For another reference, the CCS project is equivalent to the CO_2e sequestration potential of 3,600,570 acres of U.S. forests in one year, assuming one acre of average U.S. forests sequesters 0.84 metric tons of CO_2 per year.

K.4.8 Initial Life Cycle Analysis (LCA)

DOE received several comments related to GHGs and climate change, specifically regarding the Initial LCA presented in Appendix E of the Draft EA.

Theme	Revised Draft EA Location	Sub-Themes
Initial Life Cycle Analysis (LCA)	Sections 2.5.6, 3.3, and Appendix E	Summary Comment 20: Initial LCA Approach Summary Comment 21: Initial LCA Functional Unit Summary Comment 22: Sulfur Hexafluoride (SF_6) Summary Comment 23: Initial LCA Methodology and Assumptions Summary Comment 24: Initial LCA Conclusions Summary Comment 25: Air Emissions and Modeling Summary Comment 26: Presumption of Zero Measurable Leakage

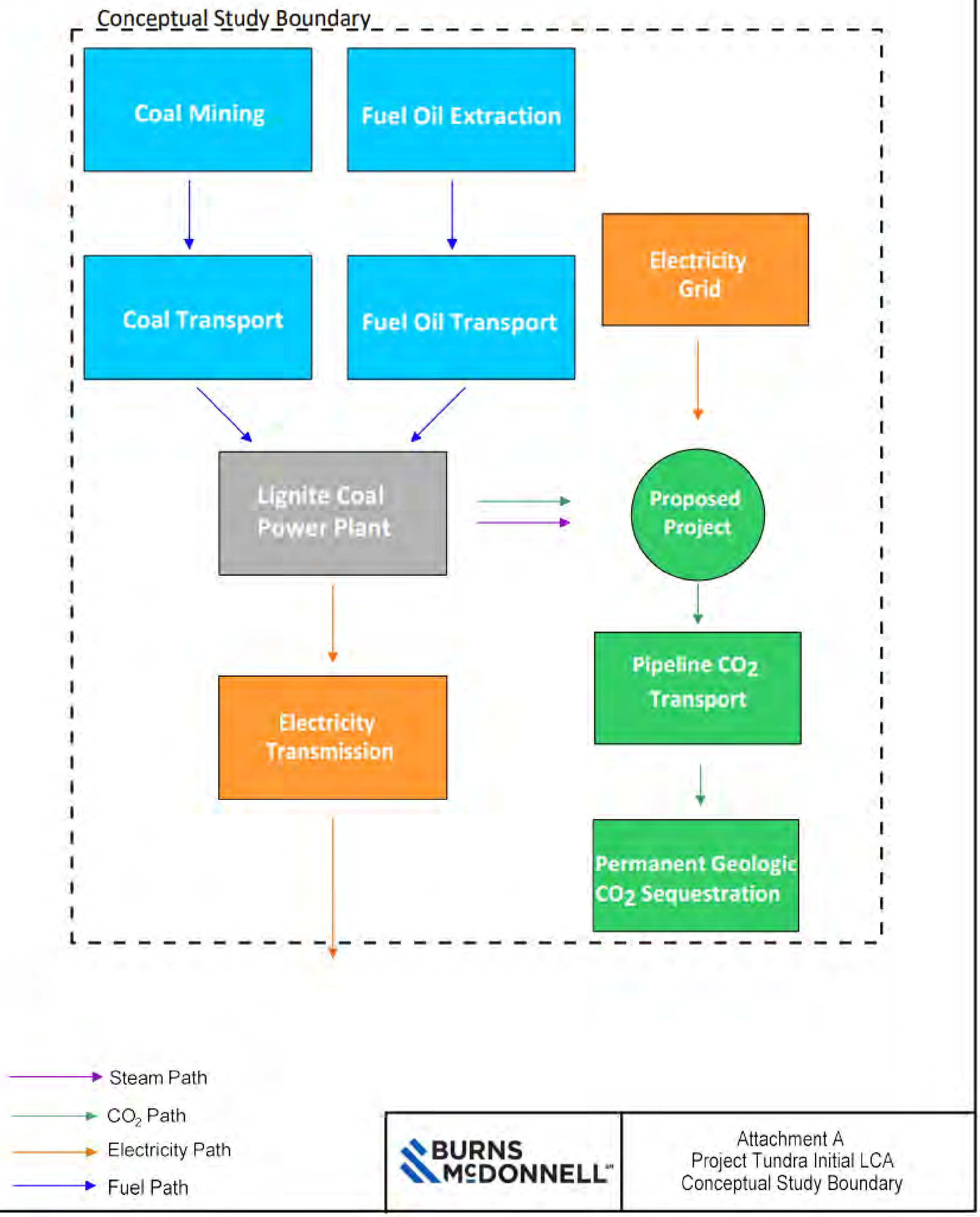
Summary Comment 20: Initial LCA Scope

Synopsis:

There were multiple comments on the scope of the LCA posing the following concerns: (1) the inclusion of electricity transmission and distribution, as well as the omission of (2) non-GHG impacts and a sensitivity analysis, (3) emission contribution sources such as reservoir leakage, (4) the emissions from the carbon capture plant operation including parasitic load, (5) CO_2 transportation (pipeline fugitive emissions), and (6) construction and manufacturing.

Response to Comments 1-2, 1-4, 1-8, 1-9, 1-12, 1-13, 1-14, and 7-7:

An Initial Life Cycle Assessment, which is required for projects applying for funding under DOE FOA DE-FOA-00002962, is a screening-level assessment of GHGs only. Appendix J of FOA 2962 states that the scope of the Initial LCA is "cradle to delivered electricity, inclusive of transmission of the electricity to the final customer," and a "contribution analysis showing at a minimum the impacts from fuel extraction and delivery, plant direct emissions, and CO_2 transport and storage." The Initial LCA Conceptual Study Boundary diagram printed here to assist readers, shows the scope of the Initial LCA in diagram format.



Attachment A
Project Tundra Initial LCA
Conceptual Study Boundary

This diagram shows the scope of the Initial LCA to include GHG emissions for mining/extraction of coal and fuel oil, transport of the coal and fuel oil, use of the fossil fuels at MRY, the operation of the proposed CCS project, and the transmission of electricity. The proposed project and associated activities are shown in the green boxes, GHG emissions associated with these activities are the direct[6] emissions that would occur because of the project moving forward. Indirect emissions, all other emission activities identified within the analysis boundary, are considered consequences of the proposed project operating but are ultimately not controlled or operated by the same entity as the proposed project. Therefore, the sequestration of CO_2 from flue gas is ultimately not expected to change the GHG emissions of any of the other upstream or downstream activities.

The largest emissions of GHG originate from sources categorized as Upstream Fuel Extraction and Delivery (inclusive of Coal Electricity Production) and Electricity Transportation. These categories account for emission processes that are already in operation and are not dependent on the operation of the proposed facility. In other words, these sources of GHG already exist and will not be affected by the presence or absence of the proposed project. It should be noted that CO_2 emissions account for most of the GHG emissions for all categories except for Electricity Transportation. This is due to the comparatively large GWP value of sulfur hexafluoride (SF_6)[7], which is utilized in the transmission and distribution process. SF_6 is further explained in Summary Comment 22.

(1) As established above, the Initial LCA follows the guidance presented in FOA 2962, which specifies the scope of the Initial LCA to be cradle-to-delivered electricity. As such, electricity transmission is included in the Initial LCA. However, electricity distribution and its associated losses are not included in the scope of this analysis. This is noted explicitly in the footnotes under each table.

(2) The Initial LCA is defined for this purpose as a screening-level, GHG-only analysis. Non-GHG impacts and a sensitivity analysis are beyond the scope of a screening level analysis.

(3) For a discussion of reservoir leakage, see Summary Comment 26.

(4) For a discussion of the capture plant emissions, see Summary Comment 25.

(5) Contribution sources such as the carbon capture facility operations, pipeline fugitive emissions, and reservoir leakage (direct emissions) were considered and accounted for in this analysis. These are shown in Table K-7 under the "Proposed Project" and "Downstream" headings.

(6) Upon review, Energy consumption occurring at the carbon capture facility was determined to be within the scope of the analysis and is now incorporated in the revised analysis[8]. Construction and manufacturing of the proposed carbon capture facility was determined to be outside the scope of a "screening-level" analysis. Construction and manufacturing emissions are temporary in nature and, as such, they were excluded from the Initial LCA.

[6] Direct defined as GHG emissions from sources that are owned or controlled by the operating (and ultimately reporting) entity.
[7] Note: SF6 emission factor units and the Initial LCA functional units have been revised. This is further discussed in Summary Comments 21 and 22.
[8] Further discussion can be found in Summary Comment 23.

Summary Comment 21: Initial LCA Functional Unit

Synopsis:

As noted by commenters on the Initial LCA, the methodology of the analysis presented in the Draft EA follows the requirements as outlined in FOA 2962. Comments identify that the FOA LCA requires calculation of impacts per unit of delivered electricity (1 megawatt-hour [MWh] of electricity). In looking at the Initial LCA, a number of commenters misinterpreted the results of the Initial LCA and concluded that 3 kilograms (kg) of CO_2e emitted per kg of CO_2 sequestered meant that the project was emitting more CO_2 than it was capturing.

Response to Comments 1-1, 1-2, 1-5, 1-6, 1-8, 1-10, 1-11, 1-12, and 7-4:

DOE has reprinted the original table, with updates related to SF_6 (See Summary Comment 22 for a discussion of SF_6) and the inclusion of energy consumption. DOE's intent is to first clarify changes to the original table prior to converting it to different units. DOE has provided additional Initial LCA outputs in a standardized unit of MWh in order to provide the public with further details that better demonstrate the Initial LCA analysis and conclusions.

The comments identified that the Initial LCA failed to properly net out the sequestered CO_2 emissions and thus incorrectly overestimated the emissions resulting from the "build" scenario. As a result, the CO_2 emissions from the coal electricity plant upstream of the project are significantly reduced. Specifically, CO_2 emissions seen at the coal plant have been updated from 1.35 kg CO_2 to 0.43 kg CO_2. This value correctly accounts for the CO_2 captured, and therefore not emitted to the atmosphere, when the CO_2 capture plant is operating. This error has been corrected and revised tables have been provided below and in Appendix E.

Table K-6. Revised Initial LCA (kg of Emissions per kg CO_2 Sequestered)

Emission Source	kg of Emissions per kg CO_2 Sequestered				
	CO_2	N_2O	CH_4	SF_6	CO_2e
Upstream					
Coal Mining	***$7.52x10^{-04}$***	***$5.94x10^{-06}$***	***$8.09x10^{-04}$***	-	***$3.16x10^{-02}$***
FO Extraction	$8.87x10^{-05}$	$2.68x10^{-09}$	$4.76x10^{-07}$	-	$1.07x10^{-04}$
Coal Transportation	***$9.35x10^{-04}$***	***$3.79x10^{-08}$***	***$7.59x10^{-09}$***	-	***$9.47x10^{-04}$***
FO Transportation	$5.53x10^{-07}$	$1.42x10^{-11}$	$1.11x10^{-11}$	-	$5.58x10^{-07}$
Coal Electricity Plant	***0.34***	$2.15x10^{-05}$	$1.47x10^{-05}$	-	***0.34***
Proposed Project					
CO_2 Capture Plant	0.01	-	-	-	0.01
Electricity Consumption[a]	***0.04***	***$1.81x10^{-06}$***	***$1.24x10^{-06}$***	--	***0.04***
Downstream					
CO_2 transportation	$8.58x10^{-05}$	-	-	-	$8.58x10^{-05}$
CO_2 storage[b]	-		-	-	-
Electricity Transmission[c]	-	-	-	***$9.25x10^{-08}$***	***$2.17x10^{-03}$***
TOTAL LCA	***0.39***	***$2.93x10^{-05}$***	***$8.26x10^{-04}$***	***$9.25x10^{-08}$***	***0.43***

[a] Electricity Consumption emission source is a new categories added into the revised Initial LCA.
[b] Assumes no measurable losses at the wellhead to the reservoir and a reservoir leakage rate of zero.
[c] Does not account for electricity losses from transmission and distribution.
****Bolded Italicized*** numerical values are called out as changes from the original analysis.

The revised initial LCA shows that 0.43 kg of CO_2e is emitted to the atmosphere for every 1 kg of permanently sequestered CO_2. However, it is important to note that the initial LCA includes indirect emission sources including upstream and downstream emissions that are created from electricity production that is not dependent on the presence (or absence) of the proposed project. The revised Table K-6 confirms that the proposed project will not create CO_2 emissions more than the emissions it is designed to prevent from being emitted from the atmosphere.

The functional unit in the Initial LCA was reconfigured to present results in terms of kg emissions per 1 MWh electricity produced. Below are the updated Proposed Action (Table K-7) and No-Action (Table K-8) Initial LCA summary tables. Refer to Appendix E for the Initial LCA Analysis.

Table K-7. Proposed Action, Initial LCA Results Normalized to 1 MWh

Emissions Source	kg of Emissions per MWh				
	CO_2	N_2O	CH_4	SF_6	CO_2e
Upstream					
Coal Mining	0.79	0.01	0.85	-	33.27
FO Extraction	0.09	6.25×10^{-03}	5.00×10^{-04}	-	0.11
Coal Transportation	0.98	2.81×10^{-06}	7.98×10^{-06}	-	1.00
FO Transportation	5.81×10^{-04}	1.50×10^{-08}	1.16×10^{-08}	-	5.86×10^{-04}
Coal Electricity Plant	352.34	0.02	0.02	-	360
Proposed Project					
CO_2 Capture Plant	8.56	-	-	-	8.56
Electricity Consumption	49.90	1.92×10^{-03}	1.32×10^{-03}	--	50.52
Downstream					
CO_2 Transportation	0.09	-	-	-	0.09
CO_2 Storage*	-	-	-	-	-
Electricity Transmission**	-	-	-	7.85×10^{-05}	1.84
TOTAL LCA	412.76	0.03	0.87	7.85×10^{-05}	455

*Assumes no measurable losses at the wellhead to the reservoir and a reservoir leakage rate of zero.
**Does not account for electricity losses from transmission and distribution.

Table K-7 shows that 455 kg of CO_2e are emitted for every MWh at the upstream coal electricity production plant when the CCS project is in place. The scope of the LCA, as discussed in Summary Comment 20, includes sources of emissions which will remain unchanged by the presence or absence of the project. Therefore, the values related to uncontrolled CO_2e emissions are necessary to understand the impact of the project.

Table K-8. No-Action Alternative, Initial LCA Results Normalized to 1 MWh.

Emissions Source	kg of Emissions per MWh				
	CO_2	N_2O	CH_4	SF_6	CO_2e
Upstream					
Coal Mining	0.64	5.05×10^{-03}	0.69	-	26.89
FO Extraction	0.08	2.27×10^{-06}	4.04×10^{-04}	-	0.09
Coal Transportation	0.79	3.22×10^{-05}	6.45×10^{-06}	-	0.80
FO Transportation	4.70×10^{-04}	1.21×10^{-08}	9.40×10^{-09}	-	4.74×10^{-04}
Coal Electricity Plant	1,134	0.02	0.01	-	1,140
Downstream	0.64	5.05×10^{-03}	0.69	-	
Electricity Transmission	-	-	-	7.85×10^{-05}	1.84
TOTAL LCA	1,136	0.02	0.70	7.85×10^{-05}	1,170

*Assumes no measurable losses at the wellhead to the reservoir and a reservoir leakage rate of zero.
**Does not account for electricity losses from transmission and distribution.

Table K-8 shows that without the CCS project, 1,170 kg of CO_2e is emitted for each MWh. The net impact of the project is found by subtracting the controlled emission numbers from the uncontrolled emissions, resulting in the net capture and permanent storage of 751 kg CO_2e/MWh. Table K-9 provides a comparison of the change in CO_2e for the No-Action and Proposed Action scenarios.

Table K-9. No-Action and Proposed Action Comparison, Initial LCA Results Normalized to 1 MWh

Emission Source	kg of CO_2e Emissions per MWh		
	No Action	Proposed Action	Percent Change *
Upstream			
Coal Mining	26.89	33.27	24%
FO Extraction	0.09	0.11	24%
Coal Transportation	0.80	1.00	24%
FO Transportation	4.73×10^{-04}	5.86×10^{-04}	24%**
Coal Electricity Plant	1,140	360	-68%***
Proposed Project			
CO_2 Capture Plant	NA	8.56	NA
Electricity Consumption	NA	50.52	NA
Downstream			
CO_2 transportation	NA	0.09	NA
CO_2 storage	-	-	-
Electricity Transmission	1.84	1.84	0%
TOTAL LCA	1,170	455	-61%

* Percent change, by definition, cannot be calculated for scenarios where the initial value is zero; such is the case in terms of the CO_2 capture plant, energy consumption, transportation, and storage.
** The heat input at MRY does not change as a result of the CO_2 plant operating.
*** The capture unit has a s 95% capture efficiency of flue gas that is treated by the system. For a complete discussion of the capture percentage, see Summary Comment 9.

It is important to understand the context for the results of the Initial LCA for Project Tundra. The Initial LCA analysis is a standardized methodology the DOE has created to estimate "cradle to transmission" emissions from the mining of the coal through delivery of the electricity through the transmission grid. This standardized methodology is instructive for comparison between projects. *It does not provide a forecast of the actual quantity of GHG emissions that will be emitted* because the standardized Initial LCA must be conducted on an assumed single operating point for both the generating unit and the CCS system. In actual practice, during most of the hours of the year, neither the generating station nor the CCS will be operating at the level of that assumed point. Instead, the generating units will be responding to an infinite set of grid and operating conditions.

Summary Comment 22: Sulfur Hexafluoride (SF_6)

Synopsis:

One commenter questioned the SF_6 emission factor as utilized in the Initial LCA as well as the supposed erroneous use of the SF_6 GWP within the same calculation.

Response to Comment 1-4:

After further investigation, DOE determined that FOA 2962 Appendix J has a clerical error labeling the emission factor for SF_6 as "$7.87x10^{-05}$ kg SF_6 emissions per kg CO_2 stored". DOE confirmed that this number was misprinted and should have instead read "$7.87x10^{-05}$ kg SF_6 emissions per MWh." This is a standardized emission factor utilized by the DOE to represent SF_6 emissions during electricity transmission. However, to present results in terms of CO_2e emissions, this value must be multiplied by the SF_6 100-year horizon GWP (GWP-100) of 23,500. The application of the GWP was entirely correct in the Initial LCA; however, the tables had to be updated to correct the error in units from FOA 2962. The emission factor unit's correction was made throughout the analysis and is reflected in the results presented in Summary Comment 21. The table shows that the SF_6 emissions from transportation of electricity are 1.84 kg CO_2e/MWh.

Summary Comment 23: Initial LCA Methodology and Assumptions

Synopsis:

Commenters criticized the emissions identified in the LCA as a result of the "build" scenario, proposed expansion of the LCA, and further identified the electrical and steam requirements of the CCS were not properly accounted for in the LCA.

Response to Comments 1-6, 1-7, 1-14, 1-16, 5-18, 5-21, 5-22, 7-10, 7-11, 7-12, 8-15, and 8-16:

Actual projected operations at MRY as well as the compressor vendor estimates for start-up and shutdown annually were utilized for estimating emissions as identified in the "build" scenario. The emissions attributed to the carbon capture facility are a result of routine emissions and those associated with startup, shutdown, and potential malfunction of the system. The emission values presented in the Initial LCA analysis (38,338 short tons CO_2 per year) are based upon preliminary engineering estimates of the CO_2 compressor's annual activities, considering that there may be more of these startup/shutdown and malfunctions in the first couple of years of operation. In summary, emission rates presented in the Initial LCA are based upon engineering estimates available at the time of this analysis and reasonable assumptions as disclosed in Appendix E.

Energy use associated with the CCS has been incorporated in the revised Initial LCA project scope (Summary Comment 20) and has been incorporated as a new emission category. As an independent operation, the CCS system owners have chosen to purchase the electric and steam energy needed from Minnkota's electricity system. The steam and electricity offering to the CCS system is on terms and conditions similar to other large, unique loads on their system (e.g., computing and server centers). For the Initial LCA analysis, it is assumed that steam will be sourced directly from MRY following terms as agreed upon by the CCS system owners and Minnkota[9]. Similarly, it is assumed that the CCS system will receive electricity from the Minnkota electricity system (i.e., grid) that includes multiple generation sources.

Electricity and steam consumption occurring at the carbon capture plant has been incorporated into the analysis in order to fully account for inputs that reside within DOE's scope of a "screening-level GHG only" Initial LCA but several disclaimers are required to fully address this addition. First, Minnkota has disclosed that there are no operational changes upcoming at MRY or any of their existing generating stations as a result of the CCS project. Secondly, although steam is expected to be sourced directly from MRY, the heat rate at the plant will remain unchanged regardless of the operation (or lack of operation) of the CCS.

Recognizing that the proposed project will not impact the operation of Minnkota's generating facilities, the emissions from energy consumption have been incorporated into the Initial LCA analysis as indirect emission sources. Energy consumption is widely accepted as an indirect emission source as the emissions associated with the production of the electricity or steam occur physically at generating stations and not at the consumption site. In this case, the steam and electricity consumed by the CCS will be produced by Minnkota's generating system regardless of the existence of the CCS.

DOE has determined that further expansion of the Initial LCA scope goes beyond the requirements as outlined in FOA 2962 Appendix J.

Summary Comment 24: Initial LCA Conclusions

Synopsis:

A few commenters identified concerns over the Draft EA statement "The estimated 1,836 MW of electricity consumption and 600 gigajoules per day of thermal (steam) energy consumption for project operation would result in a similar reduction in net energy output of the MRY to serve Minnkota's load and would therefore result in minimal cumulative impact on GHG emissions from MRY."

Response to Comments 1-7, 7-10, 7-11, and 7-12, and 8-25:

The statement has been revised to correct for a typographical error in the value of steam consumption and unit of electricity consumption. The correct values are 1,836 MWh of power per day and 35,247 gigajoules per day. The 600 gigajoules value applied to a demonstration pilot plant by MHIA, the technology provider, and must be scaled up to represent the commercial scale capture unit. In any event, these values did not have a material impact on the LCA results because the values used for estimating emissions were from actual projected coal usage as well as the compressor vendor estimates for start-up and shutdown annually.

[9] Any referenced agreements are not finalized at this time and any terms aside from the stated assumptions are not relevant to the outcomes represented in the initial LCA.

Further, MW and MWh are different units and cannot be directly compared. The output of MRY, which is nameplated to 734 MW (gross), is equivalent to 17,616 MWh per day. To further provide clarification around the units of measure, DOE offers the following:

Units of demand and capacity

A watt (or kilowatt or megawatt) is a measure of power. Power is the *rate* of energy transfer, which is usually discussed as demand or capacity for energy.

Demand reflects the instantaneous amount of work required to perform the function desired (such as creating light or physical force, powering a microchip, etc.). Similarly, capacity reflects the instantaneous ability to provide energy required to do work (such as generator capability to provide electricity, transmission capability to transmit electricity, etc.). For example, a watt is defined as 1 joule per second, where you can think of a joule as one nicely measured packet of energy. Demand and capacity are commonly measured in the following units:

W = watt
kW = kilowatt
MW = megawatt
GW = gigawatt

To convert between these, you can use the following:

1 kW = 1,000 W
1 MW = 1,000 kW
1 GW = 1,000 MW

Units of energy/usage

Watt-hours (or kilowatt-hours or megawatt-hours) is just another way of measuring energy, it describes a unit of energy usage. A way to think about it is that watts measure the rate of energy demand (analogous to speed) while watt-hours measure the amount of energy used (distance traveled). The electric grid deals with large power levels and large energy transfers, so the electric industry expresses energy in MWh and kWh because that is more directly relevant to how energy is transferred and used. Energy or usage reflects demand or capacity multiplied by the amount of time that demand or capacity is in use.

For example, a 15-watt light bulb used for 2 hours creates 15 watts X 2 hours = 30 watt-hours of usage. Energy and usage are commonly measured in the following units:

Wh = watt-hour
kWh = kilowatt-hour
MWh = megawatt-hour
GWh = gigawatt-hour

The conversions between the units are:

1 kWh = 1,000 Wh
1 MWh = 1,000 kWh
1 GWh = 1,000 MWh

Another example would be a kWh is one kW of power flowing for one hour, which is 1,000 joules going by every second for one hour. Since there are 3,600 seconds in an hour, 1 kWh is therefore exactly the same as 3.6 megajoules.

Summary Comment 25: Air Emissions and Modeling

Synopsis:

A number of commenters discussed and proposed additional air emissions and air modeling considerations that DOE should consider.

Response to Comments 5-10, 5-11, 5-12, 5-14, 5-15, 5-16, 6-5, 7-10, 7-11, 7-13, 7-14, 7-15, 7-16, 7-17, 8-15, and 9-5:

DOE has included the current air emissions for MRY and the projected emissions changes due to operation of the proposed CCS project in Section 3.2 of the revised Draft EA.

MRY permitting activities are outside the scope of an EA analysis. Regardless, DOE understands that Minnkota as the owner and operator of MRY, in coordination with NDDEQ, is evaluating whether it is necessary to amend any aspect of the Title V permit to account for the separately owned, but geographically proximate CCS project facility. The owners of MRY have and will continue to evaluate compliance with all Clean Air Act regulations, including New Source Review provisions that could be implicated by the construction of the adjacent CCS project. We direct the commenters to the supporting documents for the Air Permit to Construct approved by the NDDEQ on December 29, 2023, which includes air quality modeling results that take into account emissions from the CCS project and MRY, fully and conservatively characterizing the emissions profile of the two facilities together even though they are separate sources.

Permitting is completed through NDDEQ. The project's application and Air Permit to Construct, Air Quality Emissions Analysis and Air Quality Impact Analysis are included in Appendix J of the revised Draft EA. The air impact analyses and tables generated were performed based upon best engineering estimates and followed EPA and NDDEQ modeling guidelines under National Ambient Air Quality regulations. Any comments regarding the NDDEQ analyses are not within the purview of this EA or within the jurisdiction of DOE.

Finally, developing a construction equipment roster is premature and beyond the scope of an EA. A qualitative assessment of types and sources of minor and temporary impacts due to the presence of heavy equipment and the disturbance of soil is included in Section 3.2.2. As stated, air impacts related to construction would be minimized using the industry standard best management practices including, but not limited to the use of water sprays for fugitive dust suppression and the use of properly maintained construction equipment with emissions controls.

Summary Comment 26: Presumption of Zero Measurable Leakage

Synopsis:

DOE received comments regarding the reasonableness of the presumption of zero measurable leakage from the sequestration reservoir.

Response to Comments 1-9, 1-13, and 5-25:

The historical precedent of assuming 1% leakage from the storage reservoir has been propagated since the earliest days of the Intergovernmental Panel on Climate Change (IPCC) and was carried through subsequent

LCAs that evaluated systems with CCS. However, recent studies on storage permanence suggest that only under an assumed condition of a leaky wellbore would there be measurable amounts of CO_2 leakage, and further, there is a near-zero CO_2 leakage rate over a 100-year interval when plausible input values are used to represent potential leakage pathways like wellbores. Examining 1) the characteristics of the proposed project sequestration area of review (no wellbores intersect the CO_2 plume except for the injection wells; see Section 3 of Storage Facility Permit), 2) required design standards for Class VI wells, and 3) the presumption of proper construction and permitting as CO_2 injection or monitoring wells (following the requirements detailed in NDAC 43-05-01-11), and leak detection and monitoring (i.e., Distributed Temperature Sensor [DTS] and Distributed Acoustic Sensor [DAS] on the injection wells), *a presumption of zero measurable leakage was determined to be a plausible and reasonable assumption*.

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K.5 PUBLIC COMMENTS

25 August 2023

Pierina N. Fayish
NEPA Compliance Officer
National Energy Technology Laboratory
626 Cochran Mill Rd, Pittsburgh, PA 15236

Re: Response to DOE/EA-2197D: Project Tundra, Environmental Assesssment

Dear Dr. Fayish:

Please find enclosed comments on DOE/EA-2197D: Project Tundra, Environmental Assesssment. I am an Associate Professor of Sustainable Energy Policy at the University of Notre Dame, submitting comments on behalf of myself as an individual. My expertise includes life cycle assessment, the US power sector, and carbon management.

My comment primarily addresses the critically flawed GHG life cycle analysis presented in the Draft EA, which contains both significant mathematical and structural errors. Given the importance of life cycle GHGs of a carbon management project for evaluating its prudence, this highly erroneous LCA presents a significant impediment to public engagement.

Sincerely,

Dr. Emily Grubert, PE
Associate Professor of Sustainable Energy Policy
Concurrent Associate Professor of Civil and Environmental Engineering and Earth Sciences
University of Notre Dame
egrubert@nd.edu
574.631.5911

Summary

1-1 The draft environmental assessment (EA) provided for Project Tundra, a proposed carbon capture and storage (CCS) retrofit of the Milton R. Young (MRY) coal-fired power plant in North Dakota, includes an unacceptable life cycle assessment (LCA) – arguably one of the most critical elements of the EA. The LCA does not provide accurate and meaningful information to the public.

The LCA only addresses greenhouse gases (GHGs) and contains numerous serious errors that should have been obvious to anyone familiar with life cycle methods, and should have prompted questions even for people unfamiliar with life cycle methods. Although the Draft EA is in response to a National Environmental Policy Act (NEPA) requirement associated with funding under Funding Opportunity Announcement (FOA) 1999, rather than to either of the two funding opportunities (FOA 2711 and FOA 2962) that might fund future project activities, note that one of the two – FOA 2962, focused on CCS rather than carbon storage alone – requires an LCA. The LCA presented in the Draft EA is fundamentally nonresponsive to the guidance put forth in
1-2 FOA 2962, most significantly by 1) not evaluating impacts per unit of delivered electricity (LCA results "shall be normalized to 1 MWh of electricity"); 2) not providing sensitivity analysis ("A sensitivity analysis shall be provided for key model inputs…") and 3) not evaluating non-GHG impacts ("the scope of environmental impacts shall include all the additional impact categories listed in Section 2.1.8.2 of the NETL CO2U LCA Guidance Document").

Recognizing that the terms of the current funding under FOA 1999 might not require the same level of detail under an LCA as FOA 2962, not making an LCA at the level of detail required by 2962 available to the public severely limits the public's ability to meaningfully engage on the environmental implications of Project Tundra. Not providing a 2962-compatible LCA is particularly puzzling if such an LCA already exists (e.g., if Project Tundra applied for a grant under FOA 2962, as has been reported in the media[1]). In any case, what has been provided in the Draft EA is unacceptably flawed, regardless.

Particularly given that GHG reductions are the main purpose of CCS on a plant like MRY, the LCA is crucial for understanding whether public investment is prudent and is a critical evaluation tool for both project evaluators and the public. Publicly issuing this LCA is both confusing and disrespectful to stakeholders for whom accurate information is now delayed, and who are asked to spend time to respond to a critically flawed analysis. Given the increasing attention to LCA in numerous federal processes, including statutory requirements for LCA in some cases, the fact that this LCA was issued publicly by DOE with such serious flaws raises
1-3 significant questions about capacity. Moreover, the fact that DOE recommended proceeding with this CCS project, despite (incorrect) LCA results suggesting that the CCS project would generate more than 3 kilograms (kg) of carbon dioxide-equivalent (CO_2e) per kg CO_2 sequestered, is deeply concerning for the integrity of the carbon management program and its ability to provide meaningful climate benefits in exchange for substantial investment.

The remainder of this comment addresses major errors of the LCA and its incompatibility with requirements under FOA 2962 (the CCS demonstration program under the Infrastructure Investment and Jobs Act, also known as the Bipartisan Infrastructure Law), then describes additional needs for the future LCA. Given the seriousness of the problems with the LCA in the Draft EA, this comment is not intended to be exhaustive in its critiques, but rather highlights major concerns.

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[1] https://bismarcktribune.com/news/state-regional/business/experts-say-project-tundra-carbon-capture-plans-may-not-be-worth-climate-financial-risks/article_cfa437f2-24b6-11ee-9769-2f63d327da25.html

Errors

1-4 The LCA in the Draft EA contains numerous serious errors. Possibly most significantly, the LCA interprets a sulfur hexafluoride (SF_6) emissions factor provided in the FOA as being in SF_6 rather than CO_2e terms, despite stating correctly on page 3 of Appendix E that the emissions factor is given as CO_2e. The LCA multiplies the CO_2e value by the SF_6 100-year horizon global warming potential (GWP-100) of 23,500, and thus reports a value that is off by a factor of 23,500. This error leads the Draft EA to conclude that SF_6 emissions from transportation and distribution of electricity, which is not relevant to the functional unit of CO_2 stored in any case, contribute 1.84 kg CO_2e/kg CO_2 stored. Although the document notes in several places that such emissions would have occurred with or without the CCS project, which also should have been a signal that it was inappropriate to include this value in the LCA scope, there is no reflection on the implication of such a large value. This result is obviously in error: given any familiarity with GHG emissions profiles for the United States, or observation of the extensive attention to GHG mitigation from power plants but essentially none given to GHG mitigation from transmission and distribution lines, the preparers should have recognized immediately that something was wrong. The fact that this error not only was submitted, but passed (ostensibly) several stages of review, is a serious issue that should have been identified at numerous points before the Draft EA was released. The GHG balance of the CCS plant is arguably among the most important elements of the Draft EA, so this level of inattention is extremely concerning relative to the rest of the Draft EA as well.

It is worth acknowledging that OCED's FOA 2962 guidance bears some responsibility here, namely for offering the SF_6 inventory value without a clear unit (as "7.87E-05 kg/kg CO_2 stored" without noting "kg CO_2e") – but again, the impact of this misinterpretation is so large that someone should have noticed and clarified with OCED if there was any confusion.
1-5 Relatedly, OCED provided AR5 GWP values but labeled them as AR6 values (despite clearly linking to AR5, which is stated in the web link address): again here, an experienced LCA analyst should have noticed this and commented on it, particularly because the methane GWP meaningfully changed between the AR5 and AR6 issuances, but this is an error within the FOA itself. Note, however, that the way the EA references the GWP table (repeatedly referring to the AR6 Appendix J) suggests that the preparers do not know what AR6 is – AR6, the Intergovernmental Panel on Climate Change's 6th Assessment Report, is one of the most important documents in climate analysis and should be familiar to LCA preparers. OCED's errors are also cause for concern, given that they dictate how the LCAs must be carried out, but these errors reflect sloppiness rather than incompetence.

Other errors in the LCA are potentially even more concerning given that they both
1-6 indicate further analytical inattention and stem from deep misunderstandings of the way that both CCS and LCA work. Most significantly, the LCA claims that the total emissions associated with the capture facility are 38,000 tonnes/year associated with startup, shutdown, and malfunction of the carbon capture system – a trivial value. Anyone familiar with carbon capture should be well aware that carbon capture is energy intensive, and therefore carries a GHG emissions burden when that energy is provided by GHG-emitting fuels, like lignite coal in the case of MRY. Ignoring the emissions associated with the capture unit's operations is puzzling and deeply concerning. One potential explanation is that the preparers lumped together all emissions from coal combustion into one process without allocating emissions to either carbon capture and storage or electricity production, which is inappropriate for an LCA and also contradicts statements (e.g., page 3-9) within the Draft EA that all emissions from the power plant would

happen with or without the intervention (in which case they should not be assigned to the
functional unit). Relevant notes in the LCA also suggest gross errors in evaluation that should
1-7 have been readily apparent to reviewers with or without LCA experience. Namely, the LCA does
acknowledge the energy intensity of carbon capture – claiming that the capture unit would
consume 1,836 megawatts (MW) of power and 600 gigajoules (GJ) per day of steam, and that
this consumption would simply reduce the output of MRY with "minimal cumulative impact on
GHG emissions." The source of these values is unclear, but note that the entire capacity of MRY
is only about 680 MW – a factor of 2.7 smaller than the claimed parasitic power load. As such,
the claim of 1,836 MW of power draw (which, according to the LCA, results in 0 additional
emissions) is on its face incorrect, and otherwise would have extremely significant impact on
cumulative GHG emissions. The claim of 600 GJ per day of steam consumption is unusually
small (accounting for an estimated <0.05% of the plant's typical energy inputs), and steam
demand is usually characterized as parasitic power load for coal CCS (because steam is
otherwise used to make power), which also raises questions about the nature, source, and
accuracy of these values.

In general, given the LCA's purported functional unit of a tonne of CO_2 stored, the stated
1-8 scope of the analysis reveals serious flaws. I discuss below that it is also incompatible with the
FOA 2962 LCA guidance that it repeatedly references, which requires normalization to 1 MWh
of electricity. For the LCA as presented, though, the scope includes numerous activities that are
irrelevant to the function of storing 1 tonne of CO_2, which the analysis claims as its functional
unit. Electricity transmission and distribution in particular should not be assigned to CO_2 storage,
and only the MRY emissions generated in order to capture and store the CO_2 are relevant. Such
an LCA of GHGs associated with per-tonne stored CO_2 could be useful for identifying carbon
return on carbon invested or similar metrics, but is fundamentally not very useful for evaluating
the effectiveness of a CCS project on a power plant (whose primary function is to deliver
electricity) – likely why FOA 2962 requires an LCA based on electricity delivered, not CO_2
1-9 stored. Regardless, the inclusion of irrelevant unit processes, and the failure to include well
known contributions to the CO_2 intensity of CO_2 storage – including reservoir leakage and, as
mentioned above, the emissions associated with energy used to capture, compress, and transport
CO_2 – is puzzling and incorrect even under the terms of the LCA as presented.

<u>Incompatibility with Requirements for FOA 2962</u>

Although this EA is not directly responding to FOA 2962, note that the MRY CCS project
1-10 is likely eligible under Topic Area 1 (TA-1), "CCS Demonstration at a Coal Electric Generation
Facility," of FOA 2962 and might have already applied (the FOA closed in May 2023, with
selection notifications expected in August 2023 – and potentially will have been released prior to
the closure of this public comment period). As such, it is reasonable to wonder whether an LCA
responsive to FOA 2962 already exists, in which case its exclusion from this Draft EA could be
an inappropriate withholding of information from the public.

The LCA presented in the Draft EA is incompatible with the FOA 2962 requirements,
1-11 most notably in that it selects a functional unit of 1 kg CO_2 stored rather than the required
functional unit of 1 MWh delivered electricity. It also fails to provide a required sensitivity
1-12 analysis and excludes required data on "chemical inputs to the facility" and "construction of the
facility and manufacturing impacts for the required materials/equipment." Further, the LCA does
not use the required CO_2 transport and saline aquifer storage life cycle inventory values
1-13 presented in the FOA, indeed, ignoring any potential reservoir leakage. The guidance also

1-14 requires results for several non-GHG impacts: Acidification Potential, Eutrophication Potential, Photochemical Smog Formation Potential, Ozone Depletion Potential, Particulate Matter Formation Potential, and Water Consumption, which are neither included nor mentioned, but are highly relevant for public engagement with LCA information.

Given that the LCA preparers clearly had access to FOA 2962, and specifically had access to Appendix J (the LCA guidance), it is extremely unclear why they failed to generate information compatible with these highly relevant requirements, which both ensure a greater degree of public access to environmental impact information and provide guidelines for conducting a rigorous LCA. This failure not only contributed to the highly erroneous analysis presented in the Draft EA, but has delayed public access to accurate and decision-relevant information about a project being proposed for substantial public support.

Other notes

The LCA presented in the Draft EA is unacceptably flawed for numerous reasons. Attention to addressing these basic flaws can unfortunately distract from more nuanced critiques, which is a major challenge given the complexity of high quality LCA, and that federal efforts increasingly rely on LCA that, as this draft shows, might not meet basic quality requirements and thus require significant capacity building even before more advanced concerns can be raised, often because problems might not be visible until details are clear. One obvious problem with the
1-15 Draft EA, though, is that the No-Action Alternative does not account for implications of not retrofitting MRY. The two units at MRY are 53 (Unit 1) and 46 (Unit 2) years old, respectively. On average, US units with the same fuel and technology retire after 50 years of operation. A CCS retrofit would likely lead to a lifespan extension given both the significant investment and likely upgrades/repairs to the units to accommodate capture, but without the retrofit, plant retirement should be expected in the near- to medium-term. This expectation is particularly relevant given recent EPA proposed rules under Section 111 of the Clean Air Act, requiring coal plants to either close by 2032, restrict capacity factor to 20% and close by 2035, co-fire with natural gas and
1-16 close by 2040, or install CCS. Although the rulemaking is not final, it is inappropriate for the the "No-Action Alternative" to assume that MRY will indefinitely operate unabated, both because of infrastructure lifespan limits and because of potential GHG rules. As such, emissions abatement caused by CCS over the planned CCS operational period are more appropriately compared to emissions expected in a scenario where MRY does not receive lifespan-extending capital investment and might be subject to closure or other compliance requirements. This nuance also means that estimating abatement potential based on the highest fuel use year, rather than based on individual operational year projections, is inappropriate.

From: Drew Harper
To: Fayish, Pierina M.
Subject: [EXTERNAL] Project Tundra
Date: Friday, September 15, 2023 6:30:02 PM

Hello,

2-1 I would like to submit a public comment in relation to the proposed carbon capture and sequestration project known as 'Project Tundra'. I consider this a significant waste of taxpayer funds, since I believe a thorough economic analysis would show that the coal-fired power plant could likely be substituted for renewable technologies at a lower cost than even the carbon capture technologies. Further, I find it deeply alarming that the costs continue to increase, timelines continue to extend, and technical estimates for the amount of sequestered carbon continue to decrease. I wish to leave a world with minimal impacts of climate change for future generations. I do not believe Project Tundra is a step forward in making that a reality. For these reasons, I hope the Department of Energy chooses NOT to provide grant funding to Project Tundra.

Thanks for your consideration,
Drew Harper

From: Charlie Botsford
To: Fayish, Pierina M.
Subject: [EXTERNAL] Project Tundra Comments on NEPA Draft Environmental Assessment
Date: Sunday, September 17, 2023 10:21:34 PM

3-1 The socioeconomic Section 3.13 appears deficient. At a minimum, Section 3.13 should include an additional subsection that addressed impacts to electricity customers of MRYS (or equivalent station). For example, addition of the carbon capture and storage system will substantially increase electricity prices to the electricity cooperative customers that MRYS services.

This increase in electricity price should be compared with the "no project" alternative in which MRYS would retire operations in 3-5 years and new, lower cost power generation would take its place. MRYS, at ~50 years in operation, in any analysis would be deemed near end-of-life. DOE analyses show that only one coal-fired power plant in the US is marginally profitable, and that particular plant does not have the economic burden of carbon capture and storage. Thus, adding carbon capture and storage to MRYS would increase the price of electricity for its few remaining years in operation until it retires for market reasons. The draft EA notes that local socioeconomic impacts would be minimal. Retiring MRYS and replacing it with low cost power generation should also have minimal socioeconomic impacts, but in any case, this analysis should also be presented in the draft EA.

Best Regards,
Charles Botsford
****

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From: Justin Paynter
To: Fayish, Pierina M.
Subject: [EXTERNAL] Project Tundra public comment
Date: Monday, September 18, 2023 9:54:42 PM

4-1 Project Tundra should not be allowed to proceed based on the current information available. This project is an example of greenwashing in an attempt to keep fossil fuels online. The carbon emissions projections have bounced around and gradually gotten lower. Under scrutiny it is shown that the projections are overestimating the amount of carbon that can be captured and underestimated the amount of carbon released.

If this carbon capture project moves forward it will emit more carbon emissions than it sequesters, pushing our climate goals in the wrong direction. DOE funds will be better spent in other climate projects such as transmission buildout and new large renewable energy projects. The economics of coal are already poor, and adding additional cost while increasing overall emissions is the wrong way to go.

Thank you,
Justin Paynter
Epping NH

Sent from my iPhone

Indigenous Environmental Network

PO Box 485
Bemidji, MN 56619

19 September, 2023

Pierina N. Fayish
NEPA Compliance Officer
Department of Energy, National Energy Technology Laboratory
626 Cochran Mill Rd
Pittsburgh, PA 15236
412.386.5428

Re: Comments on the Draft Environmental Assessment (EA) for the proposed North Dakota CarbonSAFE: Project Tundra (DOE/EA-D2197).

To: The Department of Energy and the Office of National Energy Technology Laboratory,

The Indigenous Environmental Network (IEN) submits this document based on the call for comments on the Draft Environmental Assessment (EA) for the proposed North Dakota Carbon SAFE: Project Tundra (DOE/EA-D2197). IEN is a non-profit 501(c)3 Indigenous-led organization based in Minnesota, United States with remote offices throughout North America, Turtle Island. IEN is an alliance of Indigenous Peoples whose mission it is to protect the sacredness of Mother Earth from contamination and exploitation by strengthening, maintaining and respecting Indigenous teachings and natural laws.

General Comment

After thorough review of the proposed North Dakota CarbonSAFE: Project Tundra and the draft environmental assessment prepared by the Department of Energy (DOE), the Indigenous Environmental Network has serious concerns about the DOE's assertion that there are "no significant adverse environmental impacts," and unequivocally oppose the approval of the project.

IEN finds that the Draft EA has a flawed analysis of the potential impacts of the project and fails to demonstrate the essential need for the project, raising questions about its fundamental purpose and justifiability. The No-Action Alternative presented in the assessment is deeply troubling, as they appear under-researched, misrepresented, and misleading. The assessment fails to adequately explore a reasonable and more desirable range of impacts from the No-Action Alternative to the proposed project.

The assessment's lack of attention to the socio-economic implications of the project is another pressing concern. Issues regarding environmental justice were poorly presented and not well integrated into the analysis, which raises significant concerns about the project's potential impacts on Tribes, Indigenous Peoples, and marginalized communities near Center, Oliver County, and North Dakota at large.

Another troubling shortcoming in the assessment lies in its inadequate evaluation of the cumulative impacts of the project on greenhouse gas (GHG) emissions and climate change. There is a wealth of empirical evidence and examples showing that engineered carbon removal technologies consistently underperform, are unproven and end up releasing more emissions than they promise to capture. Additionally, the risks associated with Minnkota deciding to pursue enhanced oil recovery (EOR) in the future due to economic inefficiencies from carbon capture and storage (CCS) technologies and applications were completely omitted.

IEN recognizes CCS technologies as a false solution to the climate crisis. Over the course of two decades, IEN has consistently resisted and opposed carbon trading and carbon offset projects, and IEN has witnessed CCS repeatedly fail to uphold Tribal sovereignty and Indigenous Peoples' rights, address climate change, and/or reduce emissions. Instead, CCS has often facilitated polluting industries, particularly coal, oil and gas, to continue business-as-usual practices, perpetuating environmental exploitation and destruction.

In light of these concerns, IEN urges the DOE to abandon the North Dakota CarbonSAFE: Project Tundra and select the No-Action Alternative. However, should the DOE choose to persist with the project despite its devastating environmental, economic, social, cultural, and climate impacts, we implore the DOE to reassess the scope of the analysis and continue to conduct a thorough Environmental Impact Assessment (EIA) as mandated by the National Environmental Policy Act (NEPA). Such an assessment must fully account for the risks and potential impacts of the proposed project, fully explore no-action alternatives, and adhere to robust consultation processes and Free, Prior, and Informed Consent (FPIC) with Indigenous Peoples. The CarbonSAFE: Project Tundra project should be rejected as it will lock-in coal and fossil fuels for years to come in a time when coal and fossil fuel phase out and a just energy transition is crucial for the future of this planet.

Detailed Comments

A. **The Draft EA fails to demonstrate that the proposed project is needed and justifiable.**

5-1 The Draft EA attempts to justify the need for the proposed North Dakota CarbonSAFE: Project Tundra by citing the need for the advancement of commercial Carbon Capture and Storage (CCS) technologies. However, a closer examination reveals serious deficiencies in this argument.

Firstly, the assertion that this project is needed to reduce the risks and costs for future CCS projects and to bring more storage resources into commercial classification lacks substantial evidence and reasoning. The presumption that this project alone will pave the way for a dangerous and unproven industry for "secure" geologic carbon storage is problematic, given the complexity of geologic carbon storage and the varying geological conditions across regions (Song et al., 2023). For instance, the determination of the total pore volume within a prospective storage formation, which constitutes one of the initial steps in estimating the capacity of a deep

5-2 saline reservoir, necessitates the multiplication of several geological parameters. These parameters include the areal extent, thickness, and porosity of the storage formation(s) at depths suitable for carbon storage. While the mathematical process may seem straightforward, it introduces a considerable degree of variability across assessments. This variability arises due to disparities in geological data, reservoir conditions, the definition of storage space, data quality, and the level of detail considered in different assessments (Global CCS Institute, 2016). Consequently, the complexity of geologic carbon storage and the diverse geological conditions across regions demand a more nuanced and site-specific approach to assessing the feasibility and reliability of such projects, and the proposed project in North Dakota alone will not be representative of geological conditions of other commercial coal-fired power plants to reduce the risks for commercial development of CCS.

Additionally, the claim that the project is necessary for supporting the President's

5-3 emissions reduction goals remains unsubstantiated. While addressing climate change by reducing emissions is paramount, the direct link between this specific project in Oliver County and the achievement of these objectives remains unclear, particularly given the absence of empirical evidence demonstrating that CCS technologies and development correlate with emission reductions. On the contrary, research continues to demonstrate that CCS requires more energy input to function and provides polluting industries a license to increase extraction and combustion of fossil fuels, which causes climate change (Climate Council, 2023).

5-4 To assist the public and decision-makers in determining whether the DOE should invest taxpayer dollars in the proposed project, it is imperative that the EA address the fundamental questions of whether this project is genuinely necessary for its intended goals. The EA fails to address even the most fundamental issues. For example, if the purpose of this project is to showcase that the successful implementation of CCS in North Dakota will lead to commercial success, the DOE must provide robust scientific evidence and analysis to support this assertion. This should entail comprehensive studies demonstrating how the North Dakota project can serve

5-4 cont'd as a representative model for other facilities and regions while ensuring safety and real carbon emissions reductions. Moreover, the evidence would include how and whether it is possible for

5-5 the outcomes of the proposed project, including GHG emissions reductions and carbon sequestration capacity, could align with national climate objectives.

As it stands, the EA is unclear at best. This is likely due to the lack of evidence for CCS to *permanently* capture, store and/or reduce GHG emissions. Without clear and accurate information on how the proposed project can achieve its intended goals as identified by the Draft EA, it is impossible to make a reasonable determination of whether the project is needed, or whether to invest taxpayers' dollars into dangerous, unproven, and unsustainable technologies such that of CCS.

B. The Draft EA fails to adequately explore the reasonable range of impacts from the No-Action Alternative, making the analysis inaccurate and misleading.

5-6 The Draft EA falls short of adequately exploring a reasonable range of impacts under the No-Action Alternative, leading to a fundamentally flawed analysis that is inaccurate and misleading. The EA makes the assumption that under the No-Action Alternative, "Minnkota would continue to operate the Milton R. Young (MRY) facility under normal conditions." This assertion fails to consider crucial contextual and historical factors of the facility. The age and condition of the MRY facility are essential elements that cannot be overlooked under the No-Action Alternative analysis. According to the U.S. Energy Information Administration (EIA), the average operating coal-fired generating unit in the United States is 45 years old, and units built in the 1980s and 1990s are scheduled to retire. Globally, historical data also suggests that the average retirement is around 37 years (Montrone et al., 2023). In contrast, the MRY facility has been in operation since 1970 (Minnkota Power Cooperative, 2020), making it more than 50 years old, exceeding its expected operational life span and nearing retirement. As stated in the Draft EA, the facility's Title V permit is set to expire in May 2025, requiring significant retrofitting and renovating or rebuilding efforts for continued operation, if even possible.

Contrary to the DOE's assumption, it is virtually certain that the MRY facility will not continue to operate under "normal conditions." Expert consensus supports the notion that the plant will inevitably be retired, most likely upon the expiration of its Title V permit, creating opportunities to explore cleaner, more sustainable and equitable sources of energy (Gearino, 2023). Consequently, the environmental consequences attributed to the No-Action Alternative presented in the Draft EA are rendered invalid and inaccurate. This begs the question if the facility plans to use the potential influx of CCS funding to retrofit the aging facility, which is not the purpose of the funding and could open the project up to legal action in the future.

For instance, IEN is confident that under the No-Action Alternative, the recipient will not pursue the project, and the MRY will be forced to be decommissioned. Thus, air quality in the proposed project area, Center, and North Dakota as a whole, would significantly improve as the plant is phased out. Similarly, the retirement of the MRY facility will open doors for the opportunity for Oliver County and North Dakota to embrace the renewable energy transition by investing in and building cleaner, lower-cost alternative sources of energy. The upstream emissions reduction resulting from the decommissioning and investment in alternatives would have a substantial and cumulative positive impact on GHG emissions and climate change. This is only one example to underscore how the impact analysis under the No-Action Alternative could have been further explored had it accurately accounted for the context and conditions of the aging MRY facility and recognized the inevitability of its decommissioning.

5-7

5-8 Furthermore, the Draft EA's statement that the President's emissions reduction goals would not be advanced is predicated on the incorrect assumption that the CCS technologies of the proposed project are the sole means of achieving these objectives. The portrayal of CCS technologies as a necessity in the fight against climate change in the Draft EA is not only false but also concerning, especially when applied to facilities of this scale and age. For example, Cui et al. (2019) conducted a comprehensive quantitative analysis to assess the operational lifetimes of coal power plants in alignment with the Paris Agreement's climate goals. Their findings indicate that, in a scenario where no new capacity comes online, the global phase-out of coal can be brought into alignment with the 2°C warming limit by reducing the operational lifetimes of coal-fired power plants to 35 years. This scenario involves the retirement of all coal-fired units after they have served for 35 years, including immediate retirement for plants that have already exceeded this limit. In a more ambitious 1.5°C scenario, the operational lifetime threshold is further reduced to just 20 years. Furthermore, in North Dakota, there has already been momentum to phase out coal-powered energy production. Great River Energy (GRE) retired their relatively younger, larger, and better-running Coal Creek Station, and replaced it with cheaper, cleaner wind and solar technologies (Kandiyohi Power Cooperative, 2022).

5-9 In light of these deficiencies, IEN emphatically urges the DOE to rectify the inadequacies in exploring a reasonable range of impacts under the No-Action Alternative, giving due consideration to the facility's life cycle and outdated infrastructure to ensure safety and efficiency. Such measures are crucial to conducting a rigorous, comprehensive, and accurate assessment and portrayal of the benefits and trade-offs of the proposed project. Communities deserve to know the full extent of the impacts and consequences of the No-Action Alternative in order to make informed decisions that align with the realities of energy infrastructure transition and address climate change in an reliable way.

C. The Draft EA fails to address the potential impacts and risks to air quality from the suite of pollutants that would result from the proposed project.

5-10 The analysis of the potential impacts on air quality in the Draft EA failed to address the risks associated with the full suite of pollutants that would result from the proposed project. While the analysis focuses on the MRY facility's current compliance with existing state and federal air quality standards, it neglects to adequately consider the substantial increase in hazardous air pollutants (HAPs) stemming from the proposed project, which go beyond CO_2. These additional pollutants are associated with both on-site direct emissions during the construction and operation of the CCS facility and the indirect upstream emissions from fuel extraction processes.

It is imperative that the analysis underscore the fact that CCS technologies, designed primarily for CO_2 emissions, do not address other critical pollutants, including sulfur dioxide (SO_2), nitrogen dioxide (NOx), organic gasses, mercury, toxins, black and brown carbon, fly ash, and various aerosol components (Jacobson, 2019). Although the Draft EA highlights investments
5-11 made between 2006 and 2015 to reduce SO_2 and NOx emissions at the MRY station, it is essential to contextualize this investment as a result of legal action from the Department of Justice and the U.S. EPA. The facility was found violating the Clean Air Act in 2006, and in that year, MRY was the second-largest emitter of NOx pollution in the nation. As a result of the settlement, the MRY was required to install NOx reduction systems along with a new SO_2 pollution flue gas desulfurization device (scrubber) to reduce SO_2 emissions (Global Energy Monitor).

5-12 However, the critical issue unaddressed in the Draft EA is how the proposed project will manage the increased emissions of pollutants other than CO_2, especially since the emissions modeling of the facility is already creating maximum projected fuel consumption scenarios.
5-13 Furthermore, introducing CCS technology to a power plant adds a significant demand for energy to operate the system. This increased demand for energy translates into the need for more fuel to be extracted and consumed, resulting in electricity generation coupled with CCS requiring up to 44 percent more fuel than standalone power generation (Clean Energy Group, 2023). The additional fuel consumed to power the technology can lead to a significant increase in particulate and NOx emissions, ranging from 5 percent to as much as 60 percent (Hertwich et al., 2014).
5-14 Even if power plants install supplementary pollution controls, they may still emit pollutants at rates comparable to existing, newer natural gas plants. The Draft failed to mention whether existing pollution control systems at the MRY facility, such as the current scrubbers, are capable of limiting emissions or will be retrofitted or expanded to accommodate these additional HAPs. It appears that the model used in the air quality analysis assumes the static efficiency of the scrubbers without factoring in capacity loads or the necessary adjustment to address the influx of pollutants introduced by the CCS technology. This oversight is particularly concerning given that
5-15 the EA defines Center as an environmental justice (EJ) area. Numerous studies have shown that pollutants, including fly ash and fine particulate matter (PM10), emitted from coal-fired power plants can disperse over significant distances as far as 30 km away from the location of the plant

5-15 cont'd due to wind patterns (Kravchenko et al., 2018; Iordanidis et al., 2008). Given that Center is located within a mere 4.5 miles (7.2 km) from the proposed project site, the Center community is directly put in a position of harm. It is imperative to conduct a comprehensive analysis of how air quality in this environmental justice community could be affected by the project's elevated emissions.

5-16 Furthermore, the Draft EA's conclusion that the impacts on air quality during the project's construction would be minor and temporary, solely based on the implementation of "best practices," warrants a more thorough review and examination. Given the historical necessity of legal action to install pollution reduction systems at the MRY facility, local communities deserve transparency and scientific evidence regarding Minnkota's plans to address the increased HAPs.

D. The Draft EA fails to address the potential adverse impacts on socio-economic conditions that could result from the proposed project.

5-17 The Draft EA's treatment of socio-economic impacts stemming from the proposed project is inadequate and incomplete. While the assessment does acknowledge potential short-term economic benefits during the project's construction, it did not provide a sufficient analysis of the complex, long-term socio-economic dynamics that could significantly impact Tribes, Indigenous Peoples and local communities. For example, the benefits expected from the construction of the project on the labor market, housing market, business, and sales tax were presented in the absence of empirical evidence and data inputs to substantiate such claims.

5-18 More troublingly, the analysis on socio-economic failed to analyze how the proposed project would affect the cost of electricity to local communities and energy consumers in the region, which is a major socio-economic issue. A comprehensive report published by the Institute for Energy Economics and Financial Analysis (IEEFA) in 2020 highlights the immense uncertainty surrounding the financial aspects of adding the CCS technology to the exciting MRY facility infrastructure, and the implications it has on energy consumers. IEN would like to highlight some of the critical concerns expressed in the report:

5-19
1. Uncertainty over the project's ability to capture enough CO_2 to be financed through federal 45Q tax credits. If additional funds are required for construction and operation, these unexpected costs would ultimately be borne by ratepayers.

5-20
2. Retrofitting could impact the plant's operating performance, raise operating costs, and necessitate significant maintenance expenditures, especially when it comes to Unit 2, ultimately further burdening ratepayers who are already paying above-average prices for power relative to the scenario where their co-ops purchased the same amount of power from competitive wholesale markets.

5-21
3. The impact on Minnkota's customers depends on how the co-op decides to charge for electricity and steam used by the CCS technology. Different financial

5-21 cont'd relationships and charging structures could result in consumers carrying the cost more than investors and developers.

5-22 The potential impacts on the cost of electricity and power are crucial socio-economic consequences that were troublingly absent in the Draft EA. A more robust and comprehensive analysis of the project's intended cost structure, along with its potential repercussions on ratepayers and energy consumers is necessary. Furthermore, future assessments must include plans to ensure energy equity in cases of incurring additional costs and expenditures, ensuring transparency regarding the long-term implications and cumulative impacts for local communities and the socio-economic status of the affected regions. This analysis will also have significant implications on the analysis regarding environmental justice and how local communities could be affected by inequitable cost structure.

E. The Draft EA presents a limited and inadequate analysis of Environmental Justice implications that would result from the proposed project.

5-23 The Draft EA's handling of Environmental Justice (EJ) issues raises serious concerns. The Draft asserts that environmental, health, and occupational safety impacts would be minimal and "affect all populations in the area equally" without providing a sound scientific basis for such claims. These considerations do not address environmental justice. This oversight contributes to the flawed reliance on state-level data to establish thresholds for EJ consideration. Instead of engaging in due processes of consultation with the Tribes, Indigenous Peoples and leaders, the DOE's approach to defining EJ oversimplifies the local context of Center and the surrounding area, and overlooks the unique social dynamics of the project's surroundings.

5-24 The claim that "the project would be constructed and operated in a manner consistent with environmental justice considerations," and that "it would have positive socioeconomic effects on minority and economically disadvantaged populations, as well as the general population in the socioeconomic impact area because it would generate new temporary and permanent jobs and economic activity while reducing air pollutant emissions in the local community" lack supporting evidence. On the contrary, EJ advocates express significant concerns about CCS technologies. EJ communities are wary that the application of CCS could perpetuate the existence of polluting infrastructure and potentially lead to an expansion of pipelines, historically routed through marginalized communities (Chemnick, 2022). The White House Environmental Justice Advisory Council's recommendation to exclude CCS projects from the Justice40 Initiative underscores the danger CCS technologies pose to marginalized and disadvantaged communities. The overall potential of CCS funding being used to retrofit a polluting and aging facility would have devastating socio-economic and cultural impacts on Tribes, Indigenous Peoples and surrounding communities by creating a lock-in effect that would

5-24 cont'd guarantee the continuation of fossil fuel extraction, rather than build towards an inclusive and just energy transition.

F. The Draft EA fails to adequately explore the cumulative impacts of the proposed project.

5-25 The Draft's approach to assessing the cumulative impacts of the proposed project on climate change and society is fundamentally flawed and leaves critical questions unanswered. While "cumulative impacts" are defined as the incremental effect when added to other past, present, and foreseeable future actions, the draft's analysis predominately focuses on comparing the build versus no-build scenarios. This approach disregards the wealth of research and empirical evidence pointing to the likelihood of malfunction and the project's unproven ability to deliver the expected carbon sequestration capacity post-construction (Kelemen 2019; Cushing 2018; Chen, et. al., 2022; Onyebuchi et.al., 2018; Batres, et. al. 2021). Case examples of CCS technologies most similar to the case of the MRY facility are the only two carbon capture projects at coal-fired power plants in the entire world–Petra Nova and Boundary Dam 3 in Saskatchewan.

Petra Nova's carbon capture facility was installed at a coal-fired power station near Houston, Texas in 2017 and, at the time, was hailed as a promising endeavor to reduce emissions from fossil fuels. However, a report by NRG published in March 2020, which owns 50% of Petra Nova, revealed significant performance problems during the project's initial three years of operation. According to Petra Nova's technical report submitted to the DOE, the facility only captured 1.071 million metric tons of carbon dioxide in 2017, **a mere 7% of the 15.295 million metric tons emitted** by the W.A. Parish Generating Station. In 2018, the project only captured 1.017 metric tons, representative of 6.9%, of the plant's total 14.620 million tons (Smyth, 2020). The report submitted also showed that Petra Nova received Notices of Violations from the Texas Commission on Environmental Quality and from the Texas Railroad Commission, the latter concerning the carbon dioxide pipeline. Furthermore, the captured carbon from Petra Nova had been used for EOR, contributing to an unknown amount of additional CO_2 into the atmosphere, along with other dangerous pollutants. Eventually, even with EOR in place, the operation was considered economically unviable and the CCS facility, along with the gas plant used to power it, were shut down, leaving the coal-fired plant as emissions-intensive as ever.

Boundary Dam 2 was another notable CCS project that failed to deliver on its promises. The facility aimed to capture CO_2 emissions from a 110MW coal-fired power plant, with the goal of capturing 1 million metric tons of CO_2 annually. However, data published by SaskPower, the project's operator, indicated that the facility experienced significant challenges with a low capture rate from 2014 to 2019 (Schlissel, 2020). The issues faced by Boundary Dam 3 echoed those of Petra Nova, falling way short of the project's stated objectives.

5-26 The Draft EA dismisses substantial scientific and empirical evidence that suggests that CCS technologies frequently fail to meet their objectives and are more likely to use funding to retrofit aging facilities that in the long-term increase costs and economic inefficiencies. Especially since its inception in the 1970s, CCS was designed to squeeze out the remaining oil from deep wells through a process known as **Enhanced Oil Recovery (EOR)**. Currently, EOR is used in 21 of 27 CCS projects, which means that CCS is effectively a tool to further extract fossil fuels and leads to more carbon being released into the atmosphere –a reality that CCS lifecycle analyses (LCAs) routinely fails to address. These risks were troublingly absent from the life cycle analyses provided in this Draft EA. The DOE must account for these risks and include emissions from extracted and combusted fossil fuels that use EOR in the extraction process and in the EA's greenhouse gas assessments.

Conclusion

5-27 Due to the list of concerns and substantive comments, The Indigenous Environmental Network urges the Department of Energy to reject the proposed action and abandon the proposed North Dakota CarbonSAFE: Project Tundra. The DOE lacks significant and substantive evidence to consider this a viable project. IEN implores the DOE to reject this project due to the lock-in effect that this coal-fired and fossil fuel-based combustion facility will produce for years to come. If the DOE continues to consider this project, it must take into account the need for a full Environmental Impact Assessment as mandated by the National Environmental Policy Act (NEPA) to fully account for the risks and potential impacts of the proposed project. However, it is clear from the evidence presented above that Project Tundra should be rejected and the aging coal-fired power plant should be given a phase-out deadline.

Sincerely,

Tom Goldtooth

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August 19, 2023

Pierina N. Fayish
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Submitted via email to Pierina.Fayish@netl.doe.gov

Re: Clean Air Task Force Comment on North Dokota CarbonSAFE: Project Tundra Draft EA, DOE/EA-2197

Clean Air Task Force ("CATF") submits this comment on the draft Environmental Assessment ("EA") for the proposed North Dakota CarbonSAFE: Project Tundra (DOE/EA-D2197). CATF is a global nonprofit organization working to safeguard against the worst impacts of climate change by catalyzing the rapid development and deployment of low-carbon energy and other climate-protecting technologies. With over 25 years of internationally recognized expertise on climate policy, science, and law, and a commitment to exploring all potential solutions, CATF is a pragmatic, non-ideological advocacy group focused on climate change and the clean energy transition. CATF has offices in Boston, Washington, D.C., and Brussels, with staff working remotely around the world.

6-1 CATF is commenting on the EA solely regarding the co-benefits of reducing sulfur dioxide ("SO_2)", nitrogen oxides ("NOx"), and particulate matter ("PM") that can be expected to result from adding carbon capture to the Milton Young Station. The installation of carbon capture on a given facility can be expected to reduce emissions of these pollutants due to the need to install additional pretreatment controls necessary for the efficient operation of the carbon dioxide ("CO_2") absorber, or via absorption of co-pollutants (air pollutants other than CO_2) in the CO_2 absorber. The draft EA includes an analysis of the potential emissions from the facility during periods when the carbon capture equipment has been turned off, but does not present the potential emission co-benefits that will occur when, as is expected to be the case, the carbon capture equipment is operating.

I. Expected Emissions Reductions

6-2 The draft EA should present the expected benefits from reductions in SO_2, NOx, and PM emissions that will occur when the capture unit is operating. The 2020 National Emissions Inventory shows the Milton R. Young Station ("MRY") emits a significant amount of these pollutants:

SO_2	NOx	PM_{10} (Filt + Cond)	$PM_{2.5}$ (Filt + Cond)
2,676.8	8,558.5	616.4678	372.5578

6-2 cont'd These pollutants can interfere with the amine used to remove CO_2 in the absorber column by binding with the amine to form heat stable salts. Pretreating the flue gas prior to entering the column removes many of these pollutants to ensure the efficient operation of the capture unit.

As noted in the air permit application, the project includes both a wet electrostatic precipitator ("WESP") to control particulate matter and a quencher with caustic injection to control sulfur compounds:

- Wet Electrostatic Precipitator (ESP)

  The wet ESP, located upstream of the flue gas Quencher, will be installed to treat the flue gas prior to the carbon absorption process. The WESP will reduce the concentration of both particulate matter (PM) with an aerodynamic diameter of 10 microns or less (PM10) and PM with an aerodynamic diameter of 2.5 microns or less (PM2.5) in the flue gas as needed to support treatment in the CO2 absorber column.

- Quencher

  This unit cools the flue gas from MRY Units 1 & 2. Caustic may be added to the Quencher to further reduce sulfur dioxide (SO2), sulfur trioxide (SO3) and sulfuric acid mist (H2SO4) in the flue gas as needed prior to treatment in the CO2 absorber column.[1]

6-3 For amine-based CO_2 capture systems proposed at the Milton Young station, SO_2 concentrations of 10 ppm or lower are typically preferred.[2] These requirements could reduce SO_2 emissions from the plan by 99% or more, as compared with emissions before the application of these systems.

CATF is preparing a report on the co-benefits of carbon capture in the refining and cement industries. The consultant CATF retained contacted vendors of WESPs. Two vendors expected removal efficiencies of the WESP to be 90% with a single field, and 99% with the addition of a second field (although the second field nearly doubled the capital cost of the ESP).

6-4 NOx emission reductions are unlikely to be as dramatic at the Milton R. Young station as the sulfur and PM emissions reductions. Flue gas NOx consists of different species, including nitric oxide ("NO") and nitrogen dioxide ("NO_2"). These two species impact the amine solvent differently in a CO_2 capture system. NO has low solubility and does not impact the amine solvent or the CO_2 capture unit. However, NO_2 dissolves in water, and forms nitrous and nitric acids which neutralize the amine solvent. Appendix A of the air permit application contains the 2019 RATA test data showing that between approximately 6% to 8% of the NOx emissions from

[1] DCC East Project LLC, Dakota Carbon Center CO2 Separation and Purification Plant Permit to Construct Application Revision 2, Appendix C: Case-by-Case MACT Determination (June 2, 2023) at 1 (pdf page 87), *available at* https://ceris.deq.nd.gov/ext/nsite/map/results/detail/-8992368000928857057/documents.

[2] Nat'l Energy Tech. Lab., *IECM Technical Documentation: Amine-based Post-Combustion CO_2 Capture* (Jan. 2019).

6-4 cont'd the plant are NO_2. Therefore, the likely co-benefit of carbon capture in this instance on NOx emissions is likely to be no greater than an 8% reduction.

6-5 Secondary PM emissions arise downwind of the stack as SO_2 and PM undergo chemical changes after emission. Both secondary (post-emissions) and primary PM emissions contribute to premature death, and increased incidence of respiratory illnesses, for example, an increased risk of developing asthma, and of asthma attacks.

II. Expected Health Benefits from Emissions Reductions

To quantify the health benefits that arise from reducing SO_2, NOx, and PM from the project, the EA should use a model such as COBRA. COBRA was developed by Abt Associates in 2002 to support assessments of the human health damages from air pollution and their associated monetized economic damages. Abt Associates has for years served as U.S. EPA's air quality benefits consultant. The model has been updated periodically, with version 4.1 reflecting base-year emissions and calibrations for 2016 and a projection inventory for 2023 and 2028. To assess health impacts, the model uses a damage function approach, which involves modeling changes in ambient air pollution levels, calculating the associated change in adverse health effects, such as premature mortality, and then assigning an economic value to these effects. The baseline version of COBRA uses 2016 data: (1) model calibration to 2016 baseline monitored $PM_{2.5}$, (2) 2016 population estimates, (3) 2016 disease incidence rates, and (4) the most recent concentration-response functions; future years 2023 and 2028 have emissions, population and disease incidences grown from the base year, as appropriate.

The health impact functions are derived from concentration-response functions reported in the peer-reviewed, published epidemiological literature. A typical health impact function has four components:

1. an effect estimate, which quantifies the change in health effects per unit of change in a pollutant, and is derived from a particular concentration-response function from an epidemiology study;
2. a baseline incidence rate for the health effect;
3. the affected population; and
4. the estimated change in the concentration of the pollutant.

The result of applying these functions is an estimated change in the incidence of a particular health effect for a given increment of air pollution. Examples of health effects that have been associated with changes in air pollution levels include increased incidence of premature mortality, increased hospital admissions for respiratory and cardiovascular illnesses, and asthma exacerbation.

The second step in the damage function approach involves estimated unit values that give the economic value of avoiding a single case of a particular endpoint – a single death, for example, or a single hospital admission. These unit values are derived from the economics literature and

6-5 cont'd come in several varieties. By quantifying these impacts, the results can be added to the social cost of greenhouse gas ("SC-GHG") benefits described on page 3-54 of the EA.

Respectfully submitted,

Clean Air Task Force

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September 19, 2023

Ref: 8ORA-N

Pierina N. Fayish
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Laboratory
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Pittsburgh, PA 15236

Re: North Dakota CarbonSAFE: Project Tundra EA (DOE/EA-D2197)

Dear NEPA Compliance Officer Fayish,

The U.S. Environmental Protection Agency Region 8 has reviewed the U.S. Department of Energy's (DOE) August 2023 Draft Environmental Assessment (EA) for the proposed North Dakota CarbonSAFE: Project Tundra (hereinafter, "Project"). In accordance with our responsibilities under Section 102(2)(C) of the National Environmental Policy Act (NEPA) and Section 309 of the Clean Air Act (CAA), we are providing comments to convey additional resource management considerations that we recommend addressing in the Final EA.

The Project proposes to construct a carbon capture facility at the Milton R. Young lignite-fired coal power plant (hereinafter, "plant") in Oliver County, North Dakota with an estimated carbon dioxide storage capacity of 4 million metric tons per year. To reach this storage potential the Project would include a 0.5-mile-long carbon dioxide flowline, up to three Class VI injection wells, up to two Class I disposal wells, and three monitoring wells on private land near the existing power plant.

Our detailed comments and recommendations for the EA are enclosed for your consideration. These comments focus on considerations regarding the operational life of the plant; the range of alternatives; analysis of greenhouse gas (GHG) emissions, impacts, and resiliency; and analysis of non-GHG air pollutant emissions.

We appreciate your consideration of our comments. If further explanation of these comments is desired, please contact me at (303) 312-6155 or mccoy.melissa@epa.gov. You may also contact Carolyn Gleason, Lead Reviewer for this project, at (303) 312-6441 or gleason.carolyn@epa.gov

The EPA is encouraging electronic submissions for all future NEPA notifications and document transmissions. The Final EA and any future DOE NEPA documents for EPA Region 8 review can be emailed to EPA-R8-NEPA@epa.gov.

Sincerely,

MELISSA MCCOY
Digitally signed by MELISSA MCCOY
Date: 2023.09.19 15:25:34 -06'00'

Melissa W. McCoy, Ph.D., J.D.
Manager, NEPA Branch
Office of the Regional Administrator

Enclosure

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Enclosure -EPA Comments
North Dakota CarbonSAFE: Project Tundra EA

Operational Planning

7-1 According to the August 19, 2023, invitation to comment on the Project prepared by DOE, the Project as proposed would be the world's largest post-combustion carbon dioxide capture and sequestration effort if built. Due to this scale and the diverse funding necessary for the Project sequestration rates to become fully realized, continuity of operations at the plant is also important. We therefore recommend developing a discussion on the anticipated operational life of the plant and any reasonably foreseeable maintenance or infrastructural upgrades that would need to occur in order for the Project to meet its goals in the EA. This discussion should consider the potential implications of reasonably foreseeable future air quality and GHG regulations on coal-fired power plants on costs and continued operation of the plant. The potential environmental impacts related to these actions should also be explored in this discussion and in the resource analysis sections included in the Draft EA as applicable. Alternatively, the Final EA could consider a second No-Action Alternative that does not assume the units will continue operating indefinitely and may retire in the near future due to lifespan limits and potential air quality and GHG rules.

7-2 The federal funding decision being proposed may also impact the resources available to the Project proponents to facilitate its regular maintenance and may enable additional operational life for the plant beyond what its existing infrastructure would have otherwise allowed. This may create viability for coal-based power generation in this region that may disincentivize the development of alternative lower GHG-emitting technologies. These options may include natural gas-based power sources which produce fewer carbon dioxide emissions per kilowatt-hour or other less carbon intensive power sources such as biomass, hydro, solar, or wind.[1] We recommend discussing the general operational status of the plant in the Final EA and describing the alternative power generation options that could take its place. This would help illustrate to the public the comparative environmental advantage or disadvantage of supporting coal-based power generation in the region under the Project.

Range of Alternatives

7-3 Section 1.2 details that the CarbonSAFE funding program was developed to "fulfill the need for research into safe, efficient, and effective characterization and permitting of commercial-scale Carbon Capture, Utilization, and Storage projects." However, this need behind the program was not fully coordinated with the alternatives development process presented in the Draft EA. Instead, the NEPA document only explores the preferred Alternative and the No-Action Alternative because response to a funding application has been set as the Project purpose. This approach is discordant with the 2022 NEPA Implementing Regulations Revisions as the Council on Environmental Quality notes:

> "There may be times when an agency identifies a reasonable range of alternatives that includes alternatives—other than the no action alternative—that are beyond the goals of the applicant or outside the agency's jurisdiction because the agency concludes that they are useful for the agency decision maker and the public to make an informed decision. Always tailoring the purpose and need to an applicant's goals when considering a request for an authorization could prevent an

[1] https://www.eia.gov/tools/faqs/faq.php?id=74&t=11

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7-3 cont'd agency from considering alternatives that do not meet an applicant's stated goals, but better meet the policies and requirements set forth in NEPA and the agency's statutory authority and goals."[2]

7-4 This approach is further exclusionary of the types of lower-GHG emission alternatives mentioned above which may be more efficient at mitigating the effects of climate change if their lower emission rates result in fewer fugitive emissions during the power production and carbon sequestration process. EPA therefore recommends that the Draft EA expand on DOE's alternatives development process to consider any potential alternatives that may be less environmentally impactful than the preferred alternative while allowing for the advancement or carbon sequestration technology in the region. If other alternatives were not deemed practicable then we also recommend explaining why they were eliminated from detailed study in this segment.

Greenhouse Gas Analysis

The life cycle assessment (LCA) estimates GHG emissions for the plant from the extraction and transportation of the coal to the facility (i.e., upstream emissions), combustion of the coal and fuel (i.e., plant emissions), and the transmission of electricity along transmissions lines (i.e., downstream emissions of sulfur hexafluoride). The LCA also estimates carbon dioxide emissions captured by the Project from the combustion of coal and fuel (i.e., plant emissions); direct emissions from startup, shutdown, and malfunctions of the carbon capture system; and losses of carbon dioxide from transmission along the flowline to the carbon capture plant (i.e., fugitive emissions).

7-5 The analysis monetizes the climate damages associated with these GHG emissions using the Social Cost of Greenhouse Gases (SC-GHG) for the two alternatives presented in the Draft EA. Using the information provided, EPA was unable to replicate the SC-GHG values presented in Table 3-18. For transparency and replicability of results, we recommend providing a more detailed explanation of how the SC-GHG values were estimated and exactly which emissions are being valued. It would be helpful if the explanation clarifies the following:

- Whether the upstream emissions from coal and fuel extraction and transportation, and downstream emissions from electricity transmission, are the same in both scenarios.
- Whether the SC-GHG values for both scenarios include the social cost of other GHGs (e.g., methane and nitrous oxide).
- Whether the difference between the scenarios presented in Table 3-18 represents only the monetary damages of CO_2 emissions not captured by the Project under the No-Action Alternative.

7-6 We also recommend including the 95th percentile of estimates based on the 3% discount rate in Table 3.17 in addition to the 2.5%, 3%, and 5% discount rates already included. This fourth estimate would clarify the SC-GHG analysis presented in the Draft EA by making it consistent with the Interagency Working Group on SC-GHG's *Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis* (86 Fed. Reg. 7037, January 20, 2021).[3]

[2] https://www.govinfo.gov/content/pkg/FR-2022-04-20/pdf/2022-08288.pdf
[3] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

4

Climate Change

7-7 Consistent with Executive Order 14008 – *Tackling the Climate Crisis at Home and Abroad* (86 Fed. Reg. 7619, January 25, 2021)[4] – the EPA recommends that DOE further discuss the climate pollution and benefits resulting from the proposed action. The LCA suggests the plant contributes 3.23 CO_2e per kg of CO_2 sequestered by the Project. This is largely due to incorporation of the emissions from transmission and distribution, which would occur with or without the Project (Table 3-6). The EPA recommends DOE remove these emissions from the scope of the LCA or provide a more robust discussion justifying significant investment in a project that generates roughly three kg of CO_2e for every one kg sequestered. In

7-8 addition to the LCA, we recommend using the CEQ's *National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions and Climate Change.*[5] The CEQ issued this interim guidance to assist Federal agencies in assessing and disclosing climate impacts during environmental reviews. Based on this guidance, we recommend addressing the following for each alternative in the EA:

- Estimate GHG emissions in CO_2-equivalent terms and translating the emissions into equivalencies that are more easily understood by the public (e.g., annual GHG emissions from x number of motor vehicles, see https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator).
- Include a detailed discussion of the preferred alternatives' GHG emissions in the context of state, national and international GHG emissions reduction goals, including the U.S. 2030 Paris GHG reduction target in addition to the 2050 net-zero pathway.[6] This discussion should address how reasonably foreseeable GHG emissions associated with the Project may support these policies and goals and over what timescale. While this information was partially represented for the No-Action Alternative, the proposed action did not get the same level of effective comparison to these goals in the Draft EA.

7-9 We further recommend evaluating the Project on its potential resiliency through climate change. Climate change may cause more extreme weather events which challenge existing infrastructure and can create points of failure. In order to more effectively communicate the climate change resiliency planning that has already been considered in the Draft EA, we also recommend making the Emergency Remediation and Response Plan mentioned in Appendix F publicly accessible and available for comment under the current NEPA development process.

Air Resources

7-10 The Milton R. Young power plant is a 705 MW plant with two units. The source is a major stationary source subject to permitting requirements, noted in the Draft EA. However, the details of existing air emissions and impacts as well as any necessary modifications to the permit have not been included in the Draft EA. Additionally the parasitic load of the carbon capture system is listed in the Draft EA as being 1836 MW, greater than the plant capacity. Therefore, we have included recommendations to assist in characterizing the project and disclosing existing impacts and to what degree those impacts would change should the project be implemented.

[4] https://www.federalregister.gov/documents/2021/02/01/2021-02177/tackling-the-climate-crisis-at-home-and-abroad
[5] https://ceq.doe.gov/guidance/ceq_guidance_nepa-ghg.html
[6] https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/

5

Project Specifications

7-11 The Draft EA states that implementation of the project will require 1836 MW of electricity consumption and 600 gigajoules per day (GJ/day) of steam (see page 3-6). The EA does not detail the equipment and specifications for all equipment that will contribute to this plant parasitic load. One of the largest energy usages may be CO_2 compression. Therefore, we recommend including the specifications and energy usage of equipment that will be major contributors to the parasitic load. We also recommend verifying the overall load, cited above, since it is greater than 705 MW plant capacity.

7-12 For steam consumption, we recommend explaining whether or not the modification would diminish plant steam available for turbine generation. To put the value of steam needed into context we recommend explaining what amount of steam is generated by the boilers at Milton R. Young in the same context (units of measure) as that used for the steam needed for the project. This additional information will be helpful when assessing the validity of the description of plant requirements as well as informing the lifecycle assessment of the project.

Existing Conditions

7-13 We recommend the Final EA include existing background concentrations that were used in the ND air quality modeling study discussed in the Draft EA for the modification to the plant (see page 3-3). These background concentrations serve as the basis for the existing air quality near the plant.

7-14 The plant is an existing major stationary source under the Clean Air Act, with air quality permits. While the Draft EA mentions the title V operating permit (see page 3-3), it does not include relevant information from the permit, or other New Source Review (NSR) permits that would be relevant to the existing air quality impacts at the plant, such as the plant Potential to Emit (PTE) and any air quality modeling for the existing plant configuration. We recommend that the current title V Operating Permit and Statement of Basis (SOB) be included as an appendix to the Final EA and further characterization of existing plant emissions be included in the Final EA.

Environmental Consequences

7-15 We recommend that the Final EA discuss what activities would be necessary to construct the project. Based on the necessary construction, we recommend generating an equipment roster and schedule. Based on the intensity of emission generating activity, it may be appropriate to develop an emission inventory in order to inform any potential emission reduction strategies for substantially contributing emitting units.

7-16 The Draft EA discloses that modeling has been conducted that considers the addition of the project (see page 3-3 and 3-4). However, the details of the modeling analysis are not included in the EA. Additionally, Table 3-2 does not include the modeling results or background concentrations, but rather includes the source parameter inputs for the modeling. We recommend including the modeling results and the location(s) (receptor(s)) associated with the results. Because modeling analyses can be quite complex, we recommend including supporting information related to the modeling analysis as an appendix to the Final EA.

7-17 We recommend comparing the existing emissions from the plant to the projected emission profile should the project be constructed. Any reduction in emissions at the plant due to increased control resulting from the carbon capture system should be noted.

6

September 19, 2023

VIA EMAIL

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RE: Comments on the Draft Environmental Assessment for Project Tundra On Behalf of Sierra Club and CURE

Dear Ms. Fayish:

Sierra Club and CURE submit these comments on the draft Environmental Assessment (EA) for DOE/EA-2197: North Dakota CarbonSAFE: Project Tundra.

The Sierra Club is a national nonprofit organization with 67 chapters, including in North Dakota and Minnesota, and more than 832,000 members dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. In North Dakota, we have nearly 3,000 members and supporters; in Minnesota, we have nearly 57,000. Our goals include restoring clean air and water, providing affordable clean energy, supporting family-sustaining jobs, and addressing inequities in our response to climate disruptions. A key component of meeting this goal is achieving 80% carbon pollution-free electricity by 2030.

CURE is rural-based, with staff across Minnesota. CURE knows rural people, lands, and ecosystems are vital to helping solve some of the biggest problems faced by Minnesota and the nation. We help to tell the story of a vibrant rural future, lift-up people to lead, and work for policies and laws to make a better future possible for everyone. CURE's work includes a long-term focus on rural electric cooperative governance and evolution to advance a clean, healthy, and sustainable energy future. Minnkota Power Cooperative serves member co-ops in North Dakota and Minnesota, providing electricity to the rural Minnesotans that CURE hears from and works with on a regular basis. It is of paramount importance to CURE that the Department of Energy not shortchange these Americans with an inadequate environmental review.

1

I. Introduction

Project Tundra "would be the world's largest post-combustion CO2 capture and geologic storage
project," and includes a proposal to capture and permanently store CO2 emissions from
Minnkota's existing Milton R. Young Station, a lignite coal-fired power plant in Oliver County,
North Dakota.[1] The project consists of the carbon capture facility, a 0.5-mile-long CO2 flowline;
8-1 injection and disposal wells; and sequestration. And yet, despite the project's scale and multiple
self-evident impacts—from air pollution to water withdrawals—DOE's draft environmental
assessment (EA) inappropriately failed to conclude that an environmental impact statement (EIS)
is required. DOE defined the purpose and need statement so narrowly as to eliminate any
alternatives from consideration, in contravention of NEPA. The EA also has mischaracterized the
8-2 "no action" alternative by asserting, without basis, that without the DOE grant the Milton Young
plant will continue to operate at current levels for the next 20 years. In fact, the evidence
indicates that without the DOE funding, the plant would likely retire by 2035, resulting in a
100% reduction in its carbon emissions. When the "No Action" baseline is corrected, it is clear
that the carbon emissions impacts of pursuing Project Tundra would be significant. The EA also
8-3 overstates the project's efficacy. In fact, Project Tundra appears so poorly designed that it raises
questions as to whether it meets DOE's purpose and need of advancing carbon reductions, and
therefore should not even be considered a "feasible" alternative for NEPA purposes. The EA also
8-4 neglects to sufficiently address impacts to the Missouri River and surrounding communities from
the project's proposal to withdraw nearly 5 billion gallons of water. For all of these reasons, and
8-5 as further discussed herein, we recommend that DOE find that the environmental impacts of
Project Tundra would be significant, and therefore that an EIS is required before taking any
further steps to advance this project. The EIS should address all of the issues identified in these
comments.

II. The Agency Has Defined the Purpose and Need of This Project Too Narrowly, Blinding It to the Range of Appropriate Alternatives that Would be Better for the Environment.

8-6 The EA states that "[t]he purpose and need for DOE action is to advance the commercial readiness of CCUS by constructing a commercial-scale geologic storage complex and associated CO2 transport infrastructure" and to "further the development, deployment, and commercialization of technologies to capture and geologically store CO2 emissions securely in the subsurface." (1-3.) It further states that "Oliver County, North Dakota was proposed because a fully characterized storage complex: (1) is able to receive and safely store CO2 in sufficient quantities to meet the DOE goals of 50 million metric tons over a 30-year period; (2) is located in proximity to one or more CO2 sources that can supply those quantities; and (3) can be connected to the sources by a transport system that can be built and operated economically." This

[1] EA at 2-2.

2

8-6 cont'd purpose and need is so narrow and specific as to preclude from consideration all alternatives other than the Proposed Action, in contravention of NEPA requirements.[2]

8-7 First, the agency has constrained its analysis of better alternatives by limiting the purpose and need to the particular technology proposed by the applicant. While the agency must analyze the impacts for the proposed project, it does not need to fully constrain its analysis to one technology when the federal government is pursuing multiple pathways to advancing decarbonization.

Considering the broad purview of federal agencies' programs and policies to decarbonize the economy, it would be appropriate for DOE to expand its purpose and need statement to include analysis of any viable technology that would reduce carbon emissions from energy that would replace the current coal plant. As discussed further below, coal plants of similar age to Milton Young are increasingly uneconomic compared to portfolios of clean energy alternatives that can replace their energy, capacity and reliability benefits. DOE should consider whether incentivizing alternatives to Project Tundra would deliver far greater benefits for the amount of tax dollars spent.

This type of analysis of alternative generation sources would help inform both the agency and the public about better uses of federal funding under myriad other programs administered by DOE and other federal agencies, such as USDA. CEQ has stated that "Agencies have long considered myriad factors in developing a purpose and need statement. These include the agency's mission and the specifics of the agency decision, including statutory and regulatory requirements. Factors also may include national, agency, or other policy objectives applicable to a proposed action, such as a discretionary grant program targeted to achieve certain policy goals." CEQ Phase I regs, 2022.[3] But CEQ also makes clear that "There may be times when an agency identifies a reasonable range of alternatives that includes alternatives—other than the no action alternative—that are beyond the goals of the applicant or outside the agency's jurisdiction because the agency concludes that they are useful for the agency decision maker and the public to make an informed decision." *Id.* Here, it would be appropriate for DOE to adopt a broader purpose and need of advancing the goal of decarbonizing the economy in line with President Biden's commitments.

[2] The CEQ Phase I regulations further state: "It is contrary to NEPA for agencies to "contrive a purpose so slender as to define competing 'reasonable alternatives' out of consideration (and even out of existence)." *Simmons* v. *U.S. Army Corps of Engineers*, 120 F.3d 664, 666 (7th Cir. 1997) (citing 42 U.S.C. 4332(2)(E)). Constricting the definition of the project's purpose could exclude "truly" reasonable alternatives, making an EIS incompatible with NEPA's requirements. *Id. See also, e.g., Nat'l Parks & Conservation Ass'n* v. *Bureau of Land Mgmt.*, 606 F.3d 1058, 1070 (9th Cir. 2010) ("Agencies enjoy 'considerable discretion' to define the purpose and need of a project. However, 'an agency cannot define its objectives in unreasonably narrow terms.'" (internal citations omitted)).
[3] Available at https://www.federalregister.gov/documents/2022/04/20/2022-08288/national-environmental-policy-act-implementing-regulations-revisions

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8-8 Moreover, the EA's purpose and need statement is too narrow even within the scope of advancing commercially viable carbon storage and sequestration. The EA states that "[t]he purpose and need for DOE action is to advance the commercial readiness of CCUS by constructing a commercial-scale geologic storage complex and associated CO2 transport infrastructure," and to "further the development, deployment, and commercialization of technologies to capture and geologically store CO2 emissions securely in the subsurface." (EA at 1-3.) But there are likely many other geologic areas and sources that are worthy of consideration, and that are likely to deliver far greater benefits in terms of advancing commercialization of carbon sequestration and storage.

DOE's funding could be better used to achieve the objective of "advanc[ing] the commercial readiness of CCUS and "further[ing] the development, deployment, and commercialization of technologies to capture and geologically store CO2 emissions securely in the subsurface" by pursuing CCS at other sources. It is widely accepted that it does not make economic sense to put billions of new dollars into old coal plants like Milton Young that are near the end of their design life. Plants like Milton Young are already likely more expensive to operate than cleaner alternatives, even before installing a technology that will make it even costlier to operate. For that reason, research models designed to examine the most cost-effective decarbonization pathways, such as the Princeton REPEAT study, indicate that most coal plants of Young's age should be retired rather than retrofitted with CCS.[4] In contrast, there are other sectors of the economy that many experts believe will require use of CCS in order to achieve decarbonization, such as certain types of heavy industry. At minimum, then, DOE should have evaluated whether it could better serve the goal of advancing decarbonization by seeking projects at the types of sources that are more likely to deploy CCS on a widespread basis. The EA impermissibly excludes such sources from consideration by circumscribing the purpose and need so narrowly that only this specific geologic formation and Milton Young meet its criteria.

8-9 A broader statement of purpose and need is particularly needed here, where the proposed Project is so poorly-designed that it is unclear whether it would even advance the narrow goal stated by DOE at all. As discussed in section III.B.3.c, below, the Project Tundra design is so questionable and shoddy that it appears unlikely to advance DOE's larger goal of commercializing carbon capture at coal plants, as it likely will not meet IRS standards to gain the tax credits necessary to make it financially viable. The EA should fully assess the opportunity-cost of funding a weak project design, namely Project Tundra, over saving this scarce public funding for a better proposal from a more reliable applicant.

DOE's funding for demonstration projects should not be used to prop up uneconomic designs for carbon capture. Both the agency and Project Tundra's own consultants assume that it would not

[4] Study results available at https://repeatproject.org/results?comparison=benchmark&state=national&page=1&limit=25#data

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8-9 cont'd be built without significant support from DOE at this stage.[5] DOE should broaden the purpose and need to consider other alternatives that would more cost-effectively advance decarbonization goals, such as replacing the Young plant with clean energy. At minimum, the purpose and need should be expanded to other sources and geologic sites.

III. Project Tundra Will Have Significant Impacts on the Environment, and So Further Consideration Requires a Full Environmental Impact Statement.

A. The EA mischaracterizes the "no action" or "baseline" alternative, resulting in a flawed analysis of Project Tundra's comparative environmental impacts.

8-10 The EA wrongly assumes the baseline "no action" alternative would result in Young continuing to emit its current levels of carbon emissions, uncontrolled, until 2048. This assertion is without basis and is unsupported by the record. Rather, the evidence indicates that the "no action" alternative would result in the Young plant's retirement (closure) by no later than 2032, at which point its carbon emissions and (many other environmental impacts) would be eliminated. It also asserts that Project Tundra will reduce carbon emissions, when in fact the evidence shows it might actually increase them—even under DOE's faulty assumption that the No Action alternative would include operating Young until 2048.

DOE wrongly asserts that if Project Tundra is not funded, the Milton Young coal-fired power plant will continue to operate at its current levels, with its carbon emissions unabated, until 2048. (EA 3-1 and 3-54.) This assertion is arbitrary and lacks any evidentiary support.

It is entirely unrealistic and irrational to assume, as the EA does, that a coal plant that is already 50 years old will continue to operate for another 25 years. The average age of a coal plant when it is retired is 50.[6] Moreover, experts widely agree that most coal plants of Young's age in the United States are uneconomic compared to portfolios of clean energy alternatives such as wind, solar, and battery storage, which are plentiful in North Dakota and the surrounding states.[7] In the

[5] In a presentation last year to the National Association of Regulatory Utility Commissioners, Project Tundra consultant David Greeson said that "we're really counting on a demonstration grant from the Department of Energy." The DOE environmental assessment also found that Project Tundra likely "would not be constructed" without federal funding. https://www.youtube.com/watch?feature=shared&t=1258&v=gaZpKtEetNQ.

[6] *See, e.g.*, Energy Information Administration (EIA), December 2021. Of the operating U.S. coal-fired power plants, 28% plan to retire by 2035. "Since 2002, around 100 GW of coal capacity has retired in the United States; the capacity-weighted average age at retirement was 50 years." *Available online at https://www.eia.gov/todayinenergy/detail.php?id=50658*

[7] *See, e.g.*, Energy Innovation, "Coal Cost Cross-Over 3.0," at 1-2 ("This study finds 99 percent of all coal-fired power plants in the U.S. are more expensive to operate on a forward-looking basis than the all-in cost of replacement renewable energy projects, and 97 percent are more expensive than renewable energy projects sited within 45 kilometers (approximately 30 miles), a significant acceleration from our

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8-11 last decade, the capacity factors of coal plants have fallen substantially as lower cost renewables have come online.[8] The value of having pure "baseload" facilities has dropped markedly, particularly in high wind regions, such as North Dakota. Coal plants like Milton Young are cycling offline on a more regular basis in response to these changing economics, and thus are trending towards lower capacity factors. Coal plants have high operating costs and are inflexible compared to more modern, cleaner alternatives like portfolios of wind, solar and battery storage. Indeed, the grid operator for North Dakota and Minnesota, the Midcontinent Independent System Operator (MISO), states that "as wind capacity continues to grow, this may place increasing pressure on older, uneconomic baseload resources to cycle off overnight. It also will increase the value of having dispatchable conventional resources that can cycle on and off for much shorter periods."[9]

DOE must support its assertion that Milton Young will continue to operate at its current levels until 2048 with evidence. This evidence should include standard public utility industry modeling demonstrating that the plant is cost-competitive with replacement alternatives (such as portfolios of clean energy) and can be expected to operate at current levels until 2048. Without such analysis, the most reasonable assumption is that, without DOE funding, the plant will retire in the near future. Retirement would avoid not only 100% of future carbon emissions, but also would eliminate all other criteria air pollutants;[10] would entirely avoid water consumption at the plant; and would also indirectly reduce the impacts of the lignite mine associated with the plant. The EA does not account for any of these benefits, which must be addressed in an EIS.

8-12 Moreover, under draft 111(d) rules promulgated by the Environmental Protection Agency, it would be illegal for the plant to maintain its current operations through 2048 without carbon emissions controls starting no later than 2030. Under EPA's 111(d) proposed rule for existing coal plants, Milton Young would not be able to operate after 2039 unless it installed CCS technology and began capturing more than 90 percent of its carbon pollution in 2030.[11] Furthermore, coal plants retiring between the end of 2031 and the end of 2039 would be

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two previous analyses. For more than three quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace."). Available online at https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf

[8] *See, e.g.*, Energy Information Administration (EIA), September 2020. As U.S. coal-fired capacity and utilization decline, operators consider seasonal operation. *Available online at* https://www.eia.gov/todayinenergy/detail.php?id=44976

[9] MISO. 2022 State of the Market Report, at 19. *Available online at* https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf

[10] See EA Table 3-2

[11] US EPA. Fact Sheet: Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, Proposed Rule. May, 2023. *Available online at* https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG-for%20Power%20Plants%20FINAL%20CLEAN.pdf

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8-12 cont'd obligated to start combusting at least 40 percent natural gas by heat input starting in 2030 unless they agree to limit their annual capacity factor to no more than 20% as of 2030, in which case they could operate at a business-as-usual emission rate through the end of 2034.

DOE admits that, without its funding, it is "likely" that "the commercial-scale CCUS project (Project Tundra) would not be constructed." (EA at 2-1.) At minimum, then, the baseline "no action" alternative should include retirement of Young no later than 2035 and a 20% capacity cap beginning in 2030, or retirement of Young no later than 2039 if the facility is willing to start burning at least 40% gas by 2030, which would entail substantially higher fuel costs for the facility and any necessary capital retrofits. DOE must revise the No Action alternative to reflect this.

8-13 Because the agency has misstated the baseline, it has wrongly concluded that Project Tundra will result in a significant reduction in carbon emissions compared to the "no action" alternative. When the baseline is corrected to assume retirement of Young by no later than 2035, it is apparent that the preferred alternative in fact would act as a life extension project and encourage more than a decade of additional carbon emissions (at a rate of at least 25-26 percent of the plant's carbon emissions, even if the technology works perfectly as designed) that would be avoided in the baseline scenario of earlier retirement. As discussed further in section III.B.2, below, this life extension can be expected to result in a net *increase* in emissions of between 9.4 and 12.7 million tonnes of CO2-equivalent, relative to closing the plant earlier.

Thus, the preferred alternative of funding Project Tundra will have significant impacts on the environment simply by increasing overall net carbon emissions in the atmosphere, requiring an EIS. The EA should be corrected to reflect an accurate baseline that is rooted in evidence and supported by analysis, and the environmental impacts should be updated to demonstrate the
8-14 significant likely harms caused by the preferred alternative. This includes updating the calculations of the Project's social cost of greenhouse gas emissions to reflect the significant climate damages likely to result from the Project.

B. The EA makes clear that Project Tundra will not have the environmental benefits claimed by DOE and in fact will result in an emissions increase; the Project is also so deficient that it is unreasonable to even consider it a "feasible alternative."

8-15 A close review of the EA shows that Project Tundra is likely to result in a significant emissions *increase* compared to the No Action alternative. Moreover, the EA repeatedly overstates the amount of carbon the project is likely to capture: it is only designed to capture, at most, 73% of emissions. At such a low capture rate, the Project is unlikely to qualify for the lucrative tax credits that are necessary to make the Project financially viable. It is therefore unclear whether the Project even is a "feasible alternative" that would advance DOE's CarbonSAFE

8-15 cont'd programmatic goal. At minimum, the Project will result in a significant impact to the environment via increased carbon emissions compared to the status quo, and so an Environmental Impact Statement is required.

1. The Project Tundra Environmental Assessment fails to disclose that the greenhouse gas emissions of the resulting project will be worse than existing natural gas power plants.

8-16 The EA for Project Tundra indicates that "construction of the project would result in an estimated net reduction in CO2 emissions (emissions that would otherwise be released to the atmosphere in the status quo scenario) of 4.0 million tpy over the anticipated operating life of the project."[12] As discussed elsewhere, this statement mischaracterizes the status quo scenario over the proposed life of the project. But in addition, it fails to follow CEQ guidance that NEPA documentation "should disclose and provide context for GHG emissions."[13] A critical element of disclosure and comparison with respect to a carbon capture project on an energy generation facility would be an equivalency to known power generation options. Following CEQ guidance, the Draft EA should have clearly specified that as proposed, Milton Young coal plant, as retrofitted with Project Tundra, would have a net emissions rate worse than that of a standard gas-fired power plant. This context is critically important for decision makers, both in assessing the value of investing government dollars in the project, and in assessing emissions outcomes.

Information in the EA shows that the project proponents estimate that Milton Young will produce between 5.8 and 6.3 million tons of CO_2 every year,[14] and "capture up to 4 million tons of CO2 on an annual basis."[15] Information presented in the Front End Engineering and Design (FEED) study presentation from May 2023 indicates that an average of 40% of generation and heat input at Milton Young will be consumed by the carbon capture retrofit.[16] Assessing the emissions remaining after capture and the net generation after consumption by the CCS island

[12] Draft EA at 3-6
[13] 88 FR 1202
[14] Following information available in Appendix F, converting from lignite consumption using heat content and the CO_2 content of coal. Details provided later in these comments.
[15] Draft EA at 3-6
[16] Department of Energy. Front-End Engineering & Design: Project Tundra Carbon Capture System. Virtual Closeout Meeting; Project DE-FE0031845. May, 22, 2023, at 20. *Available online at* https://netl.doe.gov/projects/files/Front-End%20Engineering%20and%20Design%20Project%20Tundra%20Carbon%20Capture%20System.pdf. 83.3 MWe of energy for auxiliary electricity consumption, plus 37,124 MMBtu/day of steam load, at a heat rate of 11.47 MMBtu/MWh (derived from Appendix F) reveals that Project Tundra will consume about 1.9 million MWh per year, or 38-41% of generation.

8-16 cont'd reveals an average emissions rate of approximately 0.55-0.60 tCO_2/MWh[17]—or worse than the stack emissions of a gas-fired power plant.[18]

This form of context, comparing the net emissions of this project to a widely known alternative generation source—is the type of context that is required under NEPA. These emissions are significant, and require DOE to conduct a full environmental impact statement.

2. **The EA mischaracterizes Project Tundra as capturing 95% of the entire flue stream from Milton Young, when it will in fact capture less than 75% of emissions.**

8-17 The EA incorrectly states, multiple times, that Project Tundra has a "design specification of at least 95 percent CO2 capture from the processed MRY [Milton Young] Unit 1 (250 megawatts gross [MWg] owned by Minnkota) and Unit 2 (455 MWg owned by Square Butte Electric) flue gas."[19] In fact, Project Tundra has been designed to capture less than 75% of Milton Young's carbon dioxide emissions, according to the project sponsors and the EA itself.

According to the project's proponents, Project Tundra is actually designed to capture around 74% of Milton Young's emissions,[20] a number that can also be derived from the EA. According to the EA and the project proponents, Project Tundra is expected to capture approximately 4 million metric tonnes of emissions per year, or an average of 73 percent of its projected generated emissions from 2028 to 2043, according to Appendix E (life cycle assessment) of the EA. Appendix E provides projected annual coal consumption (from 4-4.4 million tons of lignite per year),[21] lignite heating values for both units (13.09 and 13.23 MMBtu/short tons), and an emissions factor for coal (217.74 lb/MMBtu). From these factors, we can assess that the Milton

[17] Draft EA Appendix F (pdf page 186) indicates 2028 expected generation of 4.8 million MWh, less 1.9 million MWh of expected Project Tundra auxiliary load and steam load, resulting in net generation to grid of 2.9 million MWh. Using the heat content and emissions factor for coal as provided on the same page indicates an expected emissions generation of 6.0 million short tCO_2, less 4.4 million tons of capture per year (*see* Draft EA at 3-6, conversion to short tons), results in net stack emissions of 2 million short tCO_2. Taken together, in 2028, Milton Young, with the Project Tundra retrofit, would have a net emissions rate of 0.55 short tCO_2/MWh. In other years, the net emissions rate rises as high as 0.60 short tCO_2/MWh.
[18] According to EPA Clean Air Markets Program Data, the average stack emission rate for natural gas-fired combined cycle power plants was 0.43 short tCO_2/MWh in 2022, from a total of 602.7 million tons CO_2 and a gross generation of 1.386 billion MWh.
[19] Draft EA at 2-2. A similar statement appears at 3-6, "an LCA demonstrates the potential environmental impacts of capturing a minimum of 95 percent of unit-wide CO_2 emissions and storing the captured CO_2 in secure subsurface geologic formations."
[20] Minnesota Public Utilities Commission, Public Meeting. August 24, 2023. Docket ET6/RP-22-312. At 39 minutes. "...on station as a whole basis, it's about 74% reduction of CO_2 off the baseline, is what the design indicates." Available online at https://minnesotapuc.granicus.com/player/clip/2153?meta_id=237764&redirect=true&h=4d1e97b59e6cc16eb5a4aa0467ee8058
[21] Draft EA, Appendix F, pdf page 186

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8-17 cont'd Young units will generate between 5.8 and 6.3 million tons of CO_2 every year.[22] Capturing 4.0 million metric tonnes per year, or 4.4 million short tons, would indicate that Project Tundra is projected to only capture 73 percent of CO_2 emissions.

Even from a design standpoint, the EA indicates that the carbon capture project at Milton Young is only designed to capture around 72 percent of emissions. Table 3-2 in the EA shows several different configurations of Project Tundra, where the first two cases indicate full capture on one unit, and partial capture on the other unit.[23] Assuming both units are fully operational, the cases show that Project Tundra could capture, at most, 73 percent of emissions.[24]

DOE has therefore overstated the carbon emissions reduction benefits of the proposed action—
8-18 and in fact, the Project is likely to result in a significant net *increase* in carbon emissions. As discussed in section III.A above, the project will effectively be extending the life of the Milton Young coal-fired power plant past its owners' assumed 2042 end-of-life (and beyond a likely 2035 retirement) until 2048. The emissions impact of this life extension with 73% carbon capture is entirely absent from the EA. By 2042, it is reasonable to assume that any replacement energy and capacity of Milton Young would be largely renewable and non-emitting. Therefore, if the EA were correct that with Project Tundra, Milton Young will operate until 2048 rather than 2042, then Project Tundra will result in an additional 13 million tons of CO_2 between 2043 and 2048, even if the CCS were operating at the expected level in the Draft EA.[25] Under the more reasonable assumption that the No Action alternative would result in Milton Young's retirement by 2035 and a 20% capacity factor between 2030-2035, the Proposed Action—and CCS operation through 2048—would result in a net emissions increase of 9.4 million tons relative to the No Action alternative.[26] Either way, the Proposed Action would result in a significant impact to the environment and requires an EIS. The EIS must correct the baseline No Action alternative to account for the likelihood of an earlier retirement date for the plant, and address the range of likely *increased* carbon emissions from moving forward with funding Project Tundra based on a capture rate of no more than 73 percent.

[22] For example, in 2023, 4.376 million tons of lignite represent a heat input of 57.68 million MMBtu, and therefore emissions of 6.28 million short tons CO_2.
[23] Draft EA at Table 3-2: Comparison of Air Quality Concentrations with Ambient Air Quality Standards
[24] Refer to "Case 1 - All U2 [Milton Young Unit 2] Partial U1 (25%)", or proportionally to the instantaneous output of each unit, 455 MW (U2) + 25% * 250 MW (U1) = 517 MW of flue gas of a 705 MW total plant is 73% of total output.
[25] From 2043 to 2048, assuming 3.5 million metric tons of capture per year (*see* Draft EA, Appendix F at 7), project Tundra would release approximately 2.1 million short tCO_2 per year, or 13 million tons over a 6 year period.
[26] The EA also includes a life cycle analysis that determined that "[t]here is an expected 3.23 kg of CO_2e emitted per kg of CO_2 stored." This point alone is a significant impact that requires an EIS.

3. The EA fails to account for the impact of the 45Q tax credit on Project Tundra's carbon capture lifetime, on the project's net greenhouse gas emissions, and on the Project's overall feasibility.

8-19 Fundamental to Project Tundra's financial viability is its ability to harvest a lucrative tax incentive, the 45Q tax credit for carbon dioxide sequestration.[27] And while the proponents are clearly aware of the importance of the tax credit to financing the project,[28] the EA fails to incorporate reasonable expectations about the impacts of that tax credit on the operations and lifetime emissions of the project. The EA also fails to assess the impact of carbon capture tax credits on increased operations at the coal plant, and fails to consider whether the project is appropriately designed to meet the statutory requirements of carbon capture tax credits that would allow the project to achieve operations.

a. The EA misstates the likely carbon capture lifetime of Project Tundra, mischaracterizing the project's greenhouse gas emissions reduction benefit.

8-20 The EA states that the proposed project will result in reduced greenhouse gas emissions, using multiple different assessments of the emissions reductions achieved. None of the assumptions are correct. The EA states that the life of the project will be 20 years,[29] from 2028 to 2048,[30] and that over that time period the project will either sequester 77.5 million tons[31] or 80 million tons.[32] The calculations are both based on faulty premises, and are inconsistent with the business

[27] Project Tundra. April 1, 2022. Virtual Briefing on Project Tundra. Provided to National Association of Regulatory Utility Commissioners (NARUC). *Available online at* https://www.youtube.com/watch?v=gaZpKtEetNQ. David Greeson, Development Lead for Project Tundra at 9:29. "In project tundra this one's a little simpler. We're going to be storing the CO_2, not using it in enhanced oil recovery. We're going to be depending on 45Q tax credits for a revenue stream, and the capture system is really the main thing that we're doing." *See also* at 18:33. "It's interesting to note that for 4 million metric tons per year when the tax credit gets to $50 that'll be $200 million a year of tax credits, and there's also some non-operating losses that the storage company can monetize for us and those add up to another $20-$30 million. So it's a lot of money just for one project; a lot of money changing hands here, but it's a structure that we think will work and allow us to raise the capital needed to move forward."

[28] *See* Project Tundra web site at https://www.projecttundrand.com/progress. "The project is currently seeking financial partners to help utilize existing 45Q federal tax credits, which are currently $85 per ton of CO_2 that is captured and stored in a geologic formation deep underground."

[29] Draft EA at Appendix F, page 1; "Project Tundra proposes 20 years of operation and the secure geologic storage of an approximate cumulative total of 77.5 MMt of carbon dioxide (CO_2) over the course of the
20 years of injection into two saline aquifer reservoirs."

[30] Draft EA at 3-54. "Therefore, this analysis calculates the SC-GHG from 2028 to 2048 (analysis lifespan).

[31] Draft EA at Appendix F, page 1.

[32] Draft EA at 3-6: "construction of the project would result in an estimated net reduction in CO_2 emissions (emissions that would otherwise be released to the atmosphere in the status quo scenario) of 4.0 million tpy over the anticipated operating life of the project." Over 20 years, 4.0 million tons per year results in 80 million tons sequestered.

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8-20 cont'd proposition of Project Tundra, because they assume the project will operate continuously for 20 years.

8-21 The operations of Project Tundra are premised entirely on the continuous ability to receive the lucrative 45Q carbon capture credit, at \$85 per metric tonne CO_2 captured and sequestered, over that 20 year period. However, the 45 Q credit is only available for a 12-year period.[33] After the exhaustion of that 12-year period and the expiration of the 45Q tax credit, capturing the carbon is so costly that continued operation is no longer financially viable at the plant. Of the expected \$80.60/tCO_2 cost of capture,[34] at least \$20.57/tCO_2 are incremental operational costs incurred to operate the carbon capture equipment.[35] Without the monetary incentive of the \$85 per metric tonne CO_2 45Q credit, no rational operator would continue to incur excess costs not otherwise required by law or for safety and reliability. And since there is no evidence that Milton Young is needed for reliability or safety, it is unreasonable for DOE to assume the plant will continue to operate after the expiration of the tax credit.

In sum, even assuming that the project works flawlessly, it will result in just 12 years of carbon capture and sequestration, or from 2028 to 2040. Out of the 19 years of projected remaining life for the host power plant, through 2042,[36] Project Tundra would—at best—support 12 years of sequestration. DOE should revise its carbon capture estimates to reflect this.

b. <u>The EA ignores the way in which the carbon capture tax credits will in fact incentivize *increased* operations (and emissions) at the Milton Young coal plant.</u>

8-22 For purposes of calculating the amount of emissions the Project is likely to capture over 20 years, the EA assumes that Milton Young will maintain its current levels of operation.[37] This fails to account for how the lucrative 45Q tax credits will perversely incentivize an increase in the operations of the coal units at Milton Young, and must be corrected in DOE's analysis.

The 45Q tax credit is designed to help carbon capture projects both pay down the capital cost of expensive carbon capture projects, as well as subsidize the cost of operating the equipment. It is designed such that a producer is theoretically incentivized to capture as much as feasible, but is formulated as a production credit: a tax credit is awarded for the production of, and then capture and sequestration of, carbon dioxide. Because the tax credit is designed to pay down initial capital costs, it is a very large credit, and when applied to production costs, acts as an enormous incentive to increase operations. Accounting for the auxiliary (or parasitic) load requirements of

[33] 26 U.S. Code § 45Q(a)
[34] Department of Energy. Front-End Engineering & Design: Project Tundra Carbon Capture System. Virtual Closeout Meeting; Project DE-FE0031845. May, 22, 2023, at 11. *Available online at* https://netl.doe.gov/projects/files/Front-End%20Engineering%20and%20Design%20Project%20Tundra%20Carbon%20Capture%20System.pdf
[35] *Id*, at 35.
[36] *Id*, at 34.
[37] Draft EA at Appendix E, pdf page 186

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8-22 cont'd carbon capture, a 90% capture facility awarded \$85/tCO_2 will generate nearly \$120 per megawatt-hour (MWh) of generation at a coal-fired power plant. For most coal plants, including Milton Young, the operational costs (even accounting for the carbon capture equipment) are far less than \$120/MWh, and thus the resulting net operating cost of the power plant falls to zero, or even well below zero. Accordingly, a coal-fired power plant with carbon capture equipment is incentivized to operate as often as feasible, a dynamic that is not accounted for in the Project Tundra EA.

This dynamic can be illustrated by looking at the operations of the Milton Young plant in 2022. In 2022, the two Milton Young units emitted 4.965 million short tons of CO_2 from their stacks,[38] of which Project Tundra would theoretically be able to capture 4.745 million tons, or 13,000 short tons CO_2 (stCO_2) per day.[39] However, in most days of 2022, Milton Young emitted far more than 13,000 stCO_2/d; if the project worked flawlessly, and Milton Young continued to operate exactly like it did in 2022, Project Tundra would have captured 3.917 million stCO_2.

But it is highly unlikely that Milton Young would operate as it did in 2022 if equipped with carbon capture—rather, Milton Young can be expected to operate *more* post-CCS installation. In 2022, Milton Young had 135 days (37% of the year) where it emitted <u>less</u> than 13,000 stCO_2 per day. In each of those days, operations post-installation of carbon capture would be financially inefficient, because the project owners would collect less tax credit than is optimal. The operators would be incentivized to minimize the number of days in which less than 13,000 tons of emissions were generated (in order to capture them), which would <u>increase</u> the operations of Milton Young relative to its already high output in 2022. The operators of the coal plant would also seek to reduce any days on which either unit of Milton Young was not operating in order to ensure that there was a continuous supply of carbon dioxide to the capture unit. This kind of increase in operations would result in a gross emissions increase, to which the 73% capture rate should then be applied. Increased operations can also be expected to increase emissions of co-pollutants like nitrogen oxide, sulfur dioxide and particulate matter, effluent, and toxic coal ash wastes while also increasing water consumption. The EA fails to account for any of these increases.

8-23 In addition, the EA assumes that in baseline conditions, the operations of Milton Young will remain high enough for the entirety of the analysis period that capture at the plant offsets any increased operations. In other words, the EA's assumption of an emissions benefit only makes sense if in the baseline, Milton Young is assumed to continue to exist <u>and</u> operate at an extraordinarily high level of output even if it were not retrofitted with carbon capture.

As discussed in section III.A above, this is an unreasonable and unjustified assumption. It is more reasonable to assume that under the No Action alternative, Milton Young will be retired by

[38] US EPA, Clean Air Markets Program Database. Hourly Emissions, 2022.
[39] Draft EA at 2-2 "The project would be designed to capture up to 13,000 short tons per day (STPD) of CO_2."

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8-23 cont'd 2042 at the latest, but more likely by 2035 (with its capacity factor reduced to 20% between 2030-2035). In comparison, the Proposed Alternative of implementing carbon capture could further result in a net increase in emissions, particularly once the incentive to increase operations from the 45Q tax credit is accounted for. This phenomenon is discussed at length in comments by energy analysts in comments on 45Q, and must be addressed by DOE in its analysis.[40]

c. The EA ignores serious design problems with Project Tundra that call into question its financial viability and therefore its feasibility as an alternative.

8-24 Given the importance of the 45Q tax credit to the viability of Project Tundra, and therefore to the project's likelihood of leading to the transport and sequestration of CO_2, it is imperative for DOE to consider whether the project would even be eligible for this tax credit under the statutory requirements of 45Q. Using government funds to advance a project that will be financially infeasible based on its design specifications today is a waste of valuable taxpayer dollars.

At present, it appears questionable whether Project Tundra would actually meet the statutory requirements for 45Q eligibility. Under 26 USC §45Q(d)(2)(B)(ii), a 'qualified facility' (i.e. a carbon capture project) at an electricity generating facility must capture at least 18,750 metric tons of CO_2 per year and be designed to capture at least **75 percent** of historic (or 'baseline') emissions at the unit for which it was designed. Specifically, the text reads that "with respect to any carbon capture equipment for the applicable electric generating unit at such facility," the unit must have "a capture design capacity of not less than 75 percent of the baseline carbon oxide production of such unit."[41]

As described in section B2 above, it is clear that the project would achieve a total capture rate that does not meet this 75% statutory minimum. On August 18, 2023, Shannon Mikula, Special Projects Counsel for Minnkota, in response to a question from the Minnesota Public Utilities Commission, stated that "on a station as a whole basis, it's about a 74% reduction of CO_2 off the baseline, is what the design indicates." This statement, issued during the design phase of Project Tundra, would indicate that the capture design capacity of Project Tundra is less than the carbon oxide production of the electrical generating units to which it is attached - i.e., Milton Young coal plant. Such a failure at the design stage provides credible doubt that the project would qualify for the 45Q tax credit, and thus likely would be financially infeasible.

The proponents appear to argue that Project Tundra is designed to capture more than the statutory minimum of one unit, thereby providing it access to the tax credit, and the option to monetize additional capture. In proceedings before the Minnesota PUC, Minnkota argued that Project Tundra was designed around just one of Milton Young's coal units, and its ability to capture more than that unit's emissions provides the option to capture from either, or both, coal

[40] Treasury Docket IRS-2022-0028-0001. December 5, 2022. Comment from Synapse Energy Economics. https://www.regulations.gov/comment/IRS-2022-0028-0027
[41] 26 USC §45Q(d)(2)(B)(ii)

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8-24 cont'd units. The Draft EA confirms this in Table 3-2, which shows several different possible configurations of Project Tundra. In one configuration (Case 1), Project Tundra would capture "all" of the emissions of the 455 MW Unit 2, and just 25% of the emissions of the 250 MW Unit 1; under a second configuration (Case 2), the project would capture "all" of Unit 1, and just 57% of Unit 2.

It is highly questionable whether the sizing and configuration proposed by the project proponents would actually meet statutory requirements of 45Q. Under one reading, the CCS equipment was clearly designed to capture emissions from both units, and therefore fails to capture the statutory minimum. Under a second reading, the CCS equipment, designed only to capture emissions from one unit, may not qualify for the 45Q credit for emissions captured from the second unit for which it was not designed.

8-25 Providing federal funding for a project that is only designed to capture a small fraction of a flue stream (the emissions from the second unit, at either 25% or 57% capture) is simply bad policy, both for Treasury and DOE. Because 45Q offers a substantial operational subsidy, the second unit from which CO_2 is captured would be heavily incentivized to operate, even under suboptimal market conditions, in order to generate the maximum 45Q subsidy. But a unit that only achieves 25% or 57% capture while incentivizing additional output is—under a wide variety of conditions—a net contribution of emissions, rather than a reduction of emissions. Taking into account the substantial parasitic load required to operate CCS equipment and the additional operations of the second coal unit, partial capture achieves little or no climate benefit, and would also result in substantial additional emissions of sulfur dioxide, oxides of nitrogen, heat and waste effluent, and coal ash. Such a configuration should not be subsidized by DOE. The EA fails to account for the expected net increase in carbon emissions and other criteria pollutant emissions from the second unit. These emissions impacts are significant and require conducting an EIS.

C. The EA overstates the environmental impacts of the No Action Alternative.

8-26 The EA asserts that under the No Action alternative, "Consequently, the commercial-scale geologic storage complex would not be constructed, and the risks would not be reduced for future storage complexes." (2-1.) But it does not follow that the failure of one bad proposal would doom either geologic storage of carbon in North Dakota or elsewhere. If not this project, perhaps one will come later that has better design or supportive policies, but there is no proof here that the failure of this project leads to a permanent failure of this technology or its use at this location.

Further, there is no evidence in the EA or elsewhere that this project's failure would negatively impact carbon emissions in the United States. Indeed, it is irrational for the EA to state that without the Project "[t]he President's goals of 50 to 52 percent reduction in GHG emissions from 2005 levels by 2030, a carbon pollution free power sector by 2035, and achieving a net-zero

8-26 cont'd GHG emissions economy by 2050 would not be advanced." (2-1.) Deciding not to fund the Project makes it more likely that this uneconomic coal plant will retire sooner, which would advance the President's overall GHG goals far more than installing a partly-functional capture system on it and continuing coal combustion and carbon emissions for decades down the road at the Project site.

D. The Impacts of Project Tundra on the Missouri River are Significant and Require an EIS, Particularly in Light of Significant Environmental Justice Concerns.

8-27 The project's impacts on water availability are significant. As the EA states, "A new water appropriation of 15,000 acre-feet from the Missouri River has been approved by the North Dakota State Water Commission to supply the water needs." (2-8) This is nearly **5 billion gallons** (specifically, 4,887,771,428.6 gallons) of water being drawn from the longest river in the United States, in an arid region that is frequently impacted by drought and other natural disasters.[42] Currently, about half of North Dakota is experiencing abnormally dry to extreme drought conditions,[43] but recent years have seen drought conditions worse than the Dust Bowl with untold negative impacts on the agricultural economy and natural resources.[44] Furthermore, ongoing multi-year drought in neighboring states[45] within the Missouri River watershed necessitates a full review of how this project's large new appropriation of water will affect the regional agricultural economy and downriver natural resources.[46] This review must consider the likelihood of worsening drought conditions in the region due to climate change. Considering the importance of continued access to the Missouri for agricultural and human uses, it is arbitrary and capricious to propose removing another 4.9 billion gallons of water from the river system without fully analyzing how this will affect other users.

8-28 These significant water impacts also necessitate an environmental justice impact review. Both Bismark and Standing Rock are downriver communities on the Missouri River. The EA ignores

[42] While potentially not as frequent of a disaster as drought, North Dakota also experiences significant flooding, which will occur more frequently due to climate change and will need to be discussed in the EA as regards how this plant and the water appropriation will function under such conditions. *See* https://www.weather.gov/safety/flood-states-nd.

[43] *See* North Dakota State University. Drought webpage and report. Last updated September 7, 2023. https://www.ndsu.edu/agriculture/ag-hub/ag-topics/disasters/drought

[44] National Public Radio. October 6, 2021. A mega-drought is hammering the U.S. In North Dakota, it's worse than the Dust Bowl. https://www.npr.org/2021/10/06/1043371973/a-mega-drought-is-hammering-the-us-in-north-dakota-its-worse-than-the-dust-bowl

[45] *See e.g.* Brownfield Agricultural News. December 12, 2022. Drought Still Top of Mind for Minnesota Cow/Calf Producers. https://brownfieldagnews.com/news/drought-still-top-of-mind-for-minnesota-cow-calf-producers/

[46] Minnesota farmers are experiencing severe drought and the overall watershed will not receive as much water as needed from Minnesota as a result of the ongoing multi-year drought. *See* Minnesota Public Radio. September 14, 2023. More than 5 million Minnesotans now live in the drought zone. https://www.mprnews.org/story/2023/09/14/over-5-million-minnesotans-now-live-in-the-drought-zone

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8-28 cont'd the Project's impacts on water availability for downstream communities. The Summit pipeline,
8-29 discussed below, is also proposed to cross the river. DOE must address the cumulative impacts of this project on the Missouri for downstream environmental justice communities.

E. The EA fails to account for the cumulative impacts from the Project's connection to the Summit Pipeline.

8-30 The EA fails to acknowledge significant impacts that would result from this project's planned connection to the Summit Carbon Solutions' Midwest Carbon Express CO_2 Pipeline Project (Summit pipeline). The EA states that the route for the Summit pipeline has a planned connection proximate to the Project Tundra sequestration site. The Summit pipeline is expected to be used to ship carbon dioxide to North Dakota for Enhanced Oil Recovery (EOR), a type of "carbon storage" that has significant impacts on the environment — namely, producing significantly more oil than would be available without carbon dioxide injection. North Dakota officials have made clear that they will not be able to continue producing oil without additional carbon dioxide pipelines such as the Summit pipeline, and that they need nearly ten times the currently-available carbon dioxide to continue EOR as planned.[47] Moreover, Summit's representatives, speaking in a regulatory proceeding in Iowa, recently confirmed that carbon dioxide shipped through the Summit pipeline can be used for EOR because Summit is merely a common carrier and it cannot prevent its shippers from using the material they ship for EOR.[48] As a result, the EA must address the high likelihood that this project's partnership with Summit will increase EOR in the state, and fully analyze the foreseeable impacts of that oil extraction. Additionally, to the extent that Project Tundra may accept or provide carbon dioxide for the Summit pipeline, the EA must further assess the anticipated land and water impacts of that pipeline, which will be made more likely to occur as a result of the funding that the agency proposes to provide here.

8-31 Secondly, the EA incorrectly describes Summit's application status before state regulators as having one "pending application" for the Summit pipeline in North Dakota. In reality, Summit has seen all of its applications (both for the pipeline and with local authorities regarding construction at injection well sites) rejected by the relevant authorities — the company has since

[47] KFYR TV News. August 16, 2023. North Dakota Department of Mineral Resources warns more CO2 needed to sustain oil production long-term. https://www.kfyrtv.com/2023/08/16/north-dakota-department-mineral-resources-warns-more-co2-needed-sustain-oil-production-long-term/ ("State Department of Mineral Resources Director Lynn Helms . . . . said the state needs to get the gas from somewhere to help with enhanced oil recovery. The emerging technology uses CO_2 and other materials to help producers to take more oil than traditional methods. Helms said current CO_2 production only meets about 10 percent of what is needed for enhanced oil recovery.")

[48] Agweek News. September 5, 2023. Summit Carbon Solutions leaves open transporting CO_2 for oil wells https://www.agweek.com/news/policy/summit-carbon-solutions-leaves-open-transporting-co2-for-oil-wells

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8-31 cont'd asked North Dakota's pipeline regulator to reconsider,[49] but it does not have a "pending" application at this point. It is more accurate to say that it was denied permits to operate and it is attempting to overturn those decisions.

8-32 The fact that Project Tundra's apparent back-up plan for carbon shipping or sequestration/utilization increasing seems to have no viable project in North Dakota should be discussed and assessed in the EA. To the extent that the Summit pipeline is never built, the EA should assess the potential impacts of Project Tundra capturing large amounts of carbon dioxide with nowhere to go with it. Providing tens of millions of dollars in public funding for a project with no clear end point for injection is the definition of wasteful bureaucracy, and should be avoided through full and accurate analysis of the potential failure to obtain permits that is strongly suggested by the recent history of the Summit company in North Dakota.

IV. Conclusion

For the reasons identified herein, the impacts of Project Tundra would be significant, and DOE must conduct a full EIS before moving forward.

Respectfully submitted,

/s/ Hudson Kingston
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[49] Agweek News. August 19, 2023. Summit Carbon Solutions asks North Dakota to reconsider pipeline route denial, seeks new path around Bismarck. https://www.agweek.com/news/policy/summit-carbon-solutions-asks-north-dakota-to-reconsider-pipeline-route-denial-seeks-new-path-around-bismarck

NORTH Dakota | Environmental Quality
Be Legendary.™

September 18, 2023

Pierina Fayish
NEPA Compliance Officer
Dept. of Energy, National Technology Laboratory
626 Cochran Mill Rd.
Pittsburgh, PA 15236

Re: Project Code: DOE/EA-D2197, Project Tundra Draft Environmental Assessment in Oliver County

Dear Ms. Fayish:

The North Dakota Department of Environmental Quality has reviewed the information concerning the above-referenced project received at the department on August 21, 2023, with respect to possible environmental impacts.

9-1 1. Care is to be taken during construction activity near any water of the state to minimize adverse effects on a water body. This includes minimal disturbance of stream beds and banks to prevent excess siltation, and the replacement and revegetation of any disturbed area as soon as possible after work has been completed. Caution must also be taken to prevent spills of oil and grease that may reach the receiving water from equipment maintenance and/or the handling of fuels on the site. Guidelines for minimizing degradation to waterways during construction are attached.

9-2 2. Projects disturbing one or more acres are required to have a permit to discharge stormwater runoff until the site is stabilized by the re-establishment of vegetation or other permanent cover. Further information on the stormwater permit may be obtained from the department's website or by calling the Division of Water Quality at 701-328-5210. Also, cities may impose additional requirements and/or specific best management practices for construction affecting their storm drainage system. Check with the local officials to be sure any local stormwater management considerations are addressed.

9-3 Minnkota Power Cooperative, Inc. (Minnkota) must notify the North Dakota Pollutant Discharge Elimination System (NDPDES) Program in advance of any planned changes at Milton R. Young Station due to Project Tundra which may affect current and future NDPDES permits for the facility (ND-000370 and NDR05-0012). This includes facility expansions, production increases, and process modifications which result in new, different, or increased discharges of pollutants. In particular, Minnkota must work with the NDPDES Program to determine what effects the amine-based post-combustion carbon capture, ultra-filtration, and nano-filtration technologies will have on Nelson Lake, Square Butte Creek, and/or other receiving streams, and how changes to the Missouri River intake structure

918 East Divide Avenue | Bismarck ND 58501-1947 | Fax 701-328-5200 | deq.nd.gov

Director's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality	Division of Chemistry
701-328-5150	701-328-5188	701-328-5211	701-328-5166	701-328-5210	701-328-6140 2635 East Main Ave Bismarck ND 58501

Pierina Fayish 2 September 18, 2023

9-3 (cont'd.) could affect impingement and entrainment requirements. Changes which may result in a facility being designated as a "new source" as determined by 40 CFR 122.29(b) must also be reported to the NDPDES Program.

9-4 3. The construction project does not overlie a defined surficial aquifer; however, it does overlie a non-community well protection area. Care should be taken to avoid spills of any materials that may have an adverse effect on groundwater quality. All spills must be immediately reported to this Department and appropriate remedial actions performed.

9-5 4. The proposed project appears to have the potential to be a source of emissions to the air capable of causing or contributing to air pollution and may be required to have an Air Pollution Control Permit to Construct/Operate as required by Chapter 33.1-15-14 of the North Dakota Air Pollution Control Rules. The applicant should contact the department's Air Pollution Control Program at 701-328-5188 prior to commencing construction.

9-6 5. All solid waste materials must be managed and transported in accordance with the state's solid and hazardous waste rules. Appropriate efforts to reduce, reuse and/or recycle waste materials are strongly encouraged. As appropriate, segregation of inert waste from non-inert waste can generally reduce the cost of waste management. Further information on waste management and recycling is available from the department's Division of Waste Management at 701-328-5166.

9-7 6. Projects that involve construction of pipelines should select locations that minimize the potential for impacts to human health and the environment during and after construction by avoiding, when possible, source water protection areas and sensitive surface and groundwater environments. Additionally, when possible, pipeline routes should select areas with natural barriers to both surface and ground waters. Human health and the environment
9-8 should be further protected by developing a spill response plan that emphasizes rapid deployment of prepositioned assets necessary to contain spills and subsequent cleanup. Proper surveillance and monitoring for early detection of leaks should be required.

<u>Division of Waste Management – UST Program</u>

9-9 The department's UST Program does have historical underground storage tanks within the Tundra (Milton R. Young Station/Minnkota Power Coop) facility in Center, ND. (See attachment.)

If the construction or demolition will require the removal, installation or replacement of any UST system (tanks, piping or associated components) or the reporting of any release, it will need to follow the TECHNICAL STANDARDS AND CORRECTIVE ACTION REQUIREMENTS FOR OWNERS AND OPERATORS OF UNDERGROUND STORAGE TANKS, CHAPTER 33.1-24-08 regarding notification, installation, closure and compliance. The regulations can be found at https://www.legis.nd.gov/information/acdata/pdf/33.1-24-08.pdf

Pierina Fayish 3 September 18, 2023

9-10 These comments are based on the information provided about the project in the above-referenced submittal. The U.S. Army Corps of Engineers may require a water quality certification from this department for the project if the project is subject to their Section 404 permitting process. Any additional information which may be required by the U.S. Army Corps of Engineers under the process will be considered by this department in our determination regarding the issuance of such a certification.

The department owns no land in or adjacent to the proposed improvements, nor does it have any projects scheduled in the area. In addition, we believe the proposed activities are consistent with the State Implementation Plan for the Control of Air Pollution for the State of North Dakota.

If you have any questions regarding our comments, please feel free to contact this office.

Sincerely,

L. David Glatt, P.E., Director
North Dakota Department of Environmental Quality

LDG:ll
Attach.

Construction and Environmental Disturbance Requirements

The following are the minimum requirements of the North Dakota Department of Environmental Quality for projects that involve construction and environmental disturbance in or near waters of the State of North Dakota. They ensure that minimal environmental degradation occurs as a result of construction or related work which has the potential to affect waters of the state. All projects must be constructed to minimize the loss of soil, vegetative cover, and pollutants (chemical or biological) from a site.

9-11 **Soils**

Prevent the erosion and sediment loss using erosion and sediment controls. Fragile and sensitive areas such as wetlands, riparian zones, delicate flora, and land resources must be prohibited against compaction, vegetation loss and unnecessary damage.

9-12 **Surface Waters**

All construction must be managed to minimize impacts to aquatic systems. Follow safe storage and handling procedures to prevent the contamination of water from fuel spills, lubricants, and chemicals. Stream bank and stream bed disturbances must be contained to minimize silt movement, nutrient upsurges, plant dislocations, and any physical chemicals, or biological disruption. The use of pesticides or herbicides in or near surface waters is allowed under the department's pesticide application permit with notification to the department.

9-13 **Fill Material**

Any fill material placed below the ordinary high-water mark must be free of topsoil, decomposable materials, and persistent synthetic organic compounds, including, but not limited to, asphalt, tires, treated lumber, and construction debris. The department may require testing of fill material. All temporary fills must be removed. Debris and solid waste must be properly disposed or recycled. Impacted areas must be restored to near original condition.

Facility Form Report

Tuesday, September 5, 2023

Facility Information

Name	Minnkota Power Cooperative Inc	ID	46
Sub Name	Milton R Young Station	EPA ID	
Address	3401 24th St SW	PTRCF ID	447
Address 2	Box 127	Latitude	47.068796
City State Zip	Center ND 58530 -	Longitude	-101.218347
County	Oliver	Collection Method	Address Matching
Phone	(701) 794-8711	Reference Point	Entrance Point
Region	4	Facility Directory	46
UST Status	Inactive	Facility Profiler ID	3384
LUST Standing	Inactive	Mail Delivered To	Facility
Archived	☐	Notification Rec	02/26/1990
		DSR Hard Copy	☐

Type of Owner

Type	Commercial ID 1276
Owner	Minnkota Power Cooperative Inc
Address	5301 32nd Avenue South
City State Zip	Grand Forks ND 58201-

Indian Lands

Indian Lands ☐
Tribe Owned ☐
Tribe

Type of Facility

Describe the kind of facility: Utilities
SIC Codes: 4939
NAICS Codes: 221

Dispenser Information:
☐ Single Hose Dispenser
☐ Credit Card/Cardtrol Only
☐ No Retail Sale
☐ Blender Pump

Comments

Financial Responsibility

Financial responsibility requirements met for less than 100 tanks / $1 million ☑

Self-Insured ☑	State Fund ☑		
Insurance ☐	Letter of Credit ☐		
Risk Retention Group ☐	Trust Fund ☐		
Guarantee ☐	Other ☐		
Surety Bond ☐	Not Listed ☐		
Federal Governement ☐	Railroad ☐		

Comments #447

Financial responsibility requirements met for more than 100 tanks / $2 million ☐

Self-Insured ☐	
Insurance ☐	Letter of Credit ☐
Risk Retention Group ☐	Trust Fund ☐
Guarantee ☐	Other ☐
Surety Bond ☐	Not Listed ☐
Federal Government ☐	Railroad ☐

FR Agency
FR Policy No
FR Exp Date
Comments

Certification

Name John T Graves | Title Environmental Supervisor | Date 12/17/1991

Tank

Number:	1	Tank Status:	Permanently Out of Use	Compartments:	1	Date Installed:	10/6/1984
Alt ID:	1	Total Capacity:	10000				
Material:	Fiberglass Reinforced Plastic			Secondary Material:	None		

Federally Regulated ☑ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment: 1 Capacity: 10000 Substance: Gasoline
Pipe Material: Fiberglass Reinforced Plastic - None Pipe Type: Pressurized

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☑		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☑
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☑	Not listed	☐	☐

Number: 2 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/15/1969
Alt ID: E-7 Total Capacity: 15000
Material: Asphalt Coated or Bare Steel Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment: 1 Capacity: 15000 Substance: Heating Oil
Pipe Material: Unknown - None Pipe Type: Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 3 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/15/1969
Alt ID: E-8 Total Capacity: 15000
Material: Asphalt Coated or Bare Steel Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment: 1 Capacity: 15000 Substance: Heating Oil
Pipe Material: Unknown - None Pipe Type: Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 4 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1978
Alt ID: R-2 Total Capacity: 2000
Material: Fiberglass Reinforced Plastic Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 2000 Substance Heating Oil
Pipe Material Unknown - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 5 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1978
Alt ID: R-3 Total Capacity: 6000
Material: Fiberglass Reinforced Plastic Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 6000 Substance Heating Oil
Pipe Material Unknown - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 6 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1978
Alt ID: R-4 Total Capacity: 550
Material: Fiberglass Reinforced Plastic Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 550 Substance Heating Oil
Pipe Material Unknown - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 7 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1978
Alt ID: R-5 Total Capacity: 1000
Material: Fiberglass Reinforced Plastic Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 1000 Substance Heating Oil
Pipe Material Unknown - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 8 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1978
Alt ID: R-6 Total Capacity: 2000
Material: Fiberglass Reinforced Plastic Secondary Material: None
Federally Regulated ☐ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 2000 Substance Heating Oil
Pipe Material Unknown - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 9 Tank Status: Permanently Out of Use Compartments: 1 Date Installed: 1/15/1969
Alt ID: R-9 Total Capacity: 280
Material: Asphalt Coated or Bare Steel Secondary Material: None
Federally Regulated ☑ AST ☐ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 280 Substance Diesel
Pipe Material Copper - None Pipe Type Safe Suction

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☑		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☑	Not listed	☐	☐

Number: 10 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/1/1992
Alt ID: A10 Total Capacity: 1000
Material: Not Listed Secondary Material: None
Federally Regulated ☐ AST ☑ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 1000 Substance Diesel
Pipe Material Not Listed - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 11 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/1/1992
Alt ID: A-11 Total Capacity: 500
Material: Not Listed Secondary Material: None
Federally Regulated ☐ AST ☑ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 500 Substance Gasoline
Pipe Material Not Listed - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 12 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/1/1992
Alt ID: A-12 Total Capacity: 500
Material: Not Listed Secondary Material: None
Federally Regulated ☐ AST ☑ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 500 Substance Gasoline
Pipe Material Not Listed - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 13 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/1/1992
Alt ID: A13 Total Capacity: 300
Material: Not Listed Secondary Material: None
Federally Regulated ☐ AST ☑ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 300 Substance Diesel
Pipe Material Not Listed - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 14 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/1/1992
Alt ID: A-14 Total Capacity: 30000
Material: Not Listed Secondary Material: None
Federally Regulated ☐ AST ☑ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 30000 Substance Diesel
Pipe Material Not Listed - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 15 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/1/1992
Alt ID: A-15 Total Capacity: 280
Material: Not Listed Secondary Material: None
Federally Regulated ☐ AST ☑ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 280 Substance Diesel
Pipe Material Not Listed - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line leak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Number: 16 Tank Status: Currently In Use Compartments: 1 Date Installed: 1/1/1992
Alt ID: A-16 Total Capacity: 280
Material: Not Listed Secondary Material: None
Federally Regulated ☐ AST ☑ Compartment ☐ Manifolded ☐ Standby Power Generation ☐

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Interstit. Dbl-wall Monitor	☐		Interstit. Sec. Con. Monitor	☐		Vapor monitoring	☐	☐
Automatic	☐		Manual	☐		Groundwater monitoring	☐	☐

Compartment 1 Capacity 280 Substance Diesel
Pipe Material Not Listed - None Pipe Type Not Listed

	Tank	Pipe		Tank	Pipe		Tank	Pipe
Automatic tank gauging	☐		Interstit. Sec. Con. Monitor		☐	Mechanical line eak detector		☐
Manual tank gauging	☐		SIR	☐	☐	Electronic line leak detector		☐
Interstit. Dbl-wall Monitor		☐	Inventory control	☐		Other method	☐	☐
Visual Monitoring		☐	Tank tightness testing	☐		Deferred	☐	☐
Sump Alarms		☐	Line tightness testing		☐	Not listed	☑	☑

Dispenser

Number	1	Status / Construction of UDC	
Alternate ID	1/2	Installation Date	
Dispenser Status	Currently In Use	Closure Date	
UDC	No	Total Capacity	0
Received Date		Material	
Comments		Secondary Material	None
		Material Comments	

Release Detection UDC — UDC
Interstit. Dbl-wall Monitor ☐
UDC Tightness Testing ☐
Release Comments

UDC Meets 2009 N.D.A.C Requirements ☐
Single Hose Dispenser ☐
Credit Card / Cardtrol Only ☐
Blender Dispenser ☐
Satellite Dispenser ☐

Contacts

Name/ Address	City State Zip/ Phone	Email/ Status	Operator	Manager	Outreach	Corrective	DSR	Location	Other
Mr. Scott C Hopfauf 3401 24 St SW	Center ND 58530- 7017947220	shopfauf@minnkota.com Active	☑	☐	☐	☐	☑	☐	☐
Tony J Aman PO Box127	Center ND 58530- 7017947237	taman@minnkota.com Active	☑	☐	☐	☐	☐	☐	☐
Kevin Thomas 3401 24th St SW	Center ND 58530- 7017947278	kthomas@minnkota.com Inactive	☐	☐	☐	☐	☐	☐	☑ Plant Super
Mr Mike A Tietz 3401 24th St SW	Center ND 58530- 7017947266	MTietz@minnkota.com Inactive	☐	☐	☐	☐	☐	☐	☑ Permitting & Compliance En

Testing

	Test Type	Date	Company	Docs Received	Result
Tank: 1 Comp: 1	Tightness	09/29/2009		☑	Pass
	Tightness	09/29/2009		☑	Pass
	Tightness	10/11/2012	Valley Electric & Petroleum Equip	☑	Pass
	Tightness	10/11/2012	Valley Electric & Petroleum Equip	☑	Pass

Tightness	10/16/2013		☑	Pass
Tightness	10/16/2013		☑	Pass
Tightness	10/19/2015	Valley Electric & Petroleum Equip	☑	Pass
Tightness	10/19/2015	Valley Electric & Petroleum Equip	☑	Pass
Tightness	10/18/2016	Valley Electric & Petroleum Equip	☑	Pass
Tightness	10/18/2016	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/27/2017	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/27/2017	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/25/2018	Valley Electric & Petroleum Equip	☑	Pass
LLD	09/25/2018	Valley Electric & Petroleum Equip	☑	Pass
LLD	09/25/2018	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/25/2018	Valley Electric & Petroleum Equip	☑	Pass
LLD	09/18/2019	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/18/2019	Valley Electric & Petroleum Equip	☑	Pass
LLD	09/18/2019	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/18/2019	Valley Electric & Petroleum Equip	☑	Pass
Tightness	09/17/2020	Tanknology	☑	Pass
LLD	09/17/2020	Tanknology	☑	Pass
LLD	09/17/2020	Tanknology	☑	Pass
Tightness	09/17/2020	Tanknology	☑	Pass

LUST

Date	Current Status	How Found	Reporting Party	Inspector	Comment
12/17/1991	Site Cleanup Complet		David J Swillick	David Swlick	Contaminated Soil was Removed; Amount = 5; City = Center; Land Farm;

Fuel Sample

Correspondence

Type Date	Compliance	Fuel Sample	Inspection	LUST	DSR	Staff Contact	RE File	Dept Initiated	Description
Reports 05/20/2021	☐	☐	☑	☐	☐	LeonVetter Stephanie	UST 46 Inspection Report UST 46 20210518 Closure Inspection.pdf	☑	Filed Inspection Report
EMail 01/01/2021	☐	☐	☐	☐	☐	System COC Contact	Testing Reminder Email UST 46 20210406 Reminder Email.pdf	☑	ram Region #4– UST system testing OVERDUE – Enforc
QuickNote 11/18/2020	☐	☐	☐	☐	☐	LeonVetter Leon Vetter	UST 46 20201118 QuickNote UST 46 20201118 QuickNote.pdf	☐	Water in tank
EMail 10/01/2020	☐	☐	☐	☐	☐	System COC Contact	Testing Reminder Email UST 46 20201016 Reminder Email.pdf	☑	ram Region #4– UST system testing OVERDUE
Email 07/08/2020	☐	☐	☐	☐	☐	LeonVetter Tony J Aman	UST 46 UST 46 20200708 Compliance Inspection Email.pdf	☐	Sent Compliance Inspection Request Email
Email 05/21/2020	☐	☐	☐	☐	☐	LeonVetter Scott C Hopfauf	UST 46 UST 46 20200521 Compliance Inspection Email.pdf	☐	Sent Compliance Inspection Request Email
DSR 02/27/2020	☐	☐	☐	☐	☐	LeonVetter Kevin Thomas	UST 46 UST 46 20200227 COC Doc1.pdf	☐	Received 2019 COC Supporting Documents
DSR 02/27/2020	☐	☐	☐	☐	☑	LeonVetter Kevin Thomas	UST 46 UST 46 20200227 COC Certificate.pdf	☐	Sent 2019 COC Certificate
Letter 01/17/2020	☐	☐	☐	☐	☑	LeonVetter Kevin Thomas	COC Questionnaire - 2019	☑	Sent COC Form (System) 2019
EMail 11/01/2019	☐	☐	☐	☐	☐	System COC Contact	Testing Reminder Email UST 46 20191105 Reminder Email.pdf	☑	ram Region #4– UST system testing OVERDUE

Reports 11/01/2019	☐ ☐ ☐ ☐ ☐	Robin A Schiermeister Thomas Mortrud	UST 46 20191101 2019 MLLD And ELL UST 46 20191101 2019 MLLD And ELLD Test 74715.pdf	☐ 2019 MLLD And ELLD Test
EMail 10/01/2019	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20191002 Reminder Email.pdf	☑ UST system testing OVERDUE
EMail 07/01/2019	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20190703 Reminder Email.pdf	☑ UST system testing DUE
DSR 02/12/2019	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20190212 COC Doc1.pdf	☐ Received 2018 COC Supporting Documents
DSR 02/12/2019	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	UST 46 UST 46 20190212 COC Certificate.pdf	☐ Sent 2018 COC Certificate
Letter 01/14/2019	☐ ☐ ☐ ☐ ☑	LeonVetter Scott C Hopfauf	COC Questionnaire - 2018	☑ Sent COC Form (System) 2018
EMail 01/01/2019	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20190102 Reminder Email.pdf	☑ UST system testing DUE
Reports 09/26/2018	☐ ☐ ☐ ☐ ☐	Carl E Ness	UST 46 20180926 Line Tightness and UST 46 20180926 Line Tightness and MLD tests 65102.pdf	☐ Line Tightness and MLD tests
Email 07/19/2018	☐ ☐ ☐ ☐ ☐	DaveCameron Scott Hopfauf	Approve Operator Updates	☑ Sent Approve Operator Updates Email
DSR 03/15/2018	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	UST 46 UST 46 20180315 COC Certificate.pdf	☐ Sent 2017 COC Certificate
EMail 02/01/2018	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20180201 Reminder Email.pdf	☑ UST system testing OVERDUE – Enforcement action
Letter 01/26/2018	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	COC Questionnaire - 2017	☑ Sent COC Form (System) 2017
EMail 11/01/2017	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20171101 Reminder Email.pdf	☑ UST system testing OVERDUE
EMail 10/01/2017	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20171002 Reminder Email.pdf	☑ UST system testing DUE
Complnc Test 09/27/2017	☐ ☐ ☐ ☐ ☐	LeonVetter	UST 46 20170927 LTT and ALLD tests UST 46 20170927 LTT and ALLD tests 52368.pdf	☐ LTT and ALLD tests
Complnc Test 09/25/2017	☐ ☐ ☐ ☐ ☐	LeonVetter	UST 46 20170925 LTT results 50893.p UST 46 20170925 LTT results 50893.pdf	☐ LTT results
EMail 09/01/2017	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20170901 Reminder Email.pdf	☑ UST system testing DUE
EMail 08/01/2017	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20170801 Reminder Email.pdf	☑ UST system testing DUE
DSR 02/21/2017	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20170221 COC Doc1.pdf	☐ Received 2016 COC Supporting Documents
DSR 02/21/2017	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	UST 46 UST 46 20170221 COC Certificate.pdf	☐ Sent 2016 COC Certificate
Letter 02/03/2017	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	COC Questionnaire - 2016	☑ Sent 2016 COC Form (System)
Complnc Test 10/18/2016	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 20161018 ltt and atg resutls.pdf	☐ ltt and atg resutls
EMail 10/01/2016	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20161005 Reminder Email.pdf	☑ UST system testing DUE
EMail 09/01/2016	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20160907 Reminder Email.pdf	☑ UST system testing DUE

EMail 08/01/2016	☐ ☐ ☐ ☐ ☐	System COC Contact	Testing Reminder Email UST 46 20160907 Reminder Email.pdf	☑ UST system testing DUE
DSR 02/19/2016	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20160219 COC Doc1.pdf	☐ Received 2015 COC Supporting Documents
DSR 02/19/2016	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	UST 46 UST 46 20160219 COC Certificate.pdf	☐ Sent 2015 COC Certificate
Letter 02/03/2016	☐ ☐ ☐ ☐ ☑	dohustowner Kevin Thomas	COC Questionnaire - 2015	☑ Sent COC Form (System) 2015
Email 08/20/2015	☐ ☐ ☐ ☐ ☐	LeonVetter Mike Tietz	Approve New Operator	☑ Sent Approve New Operator Email
DSR 03/16/2015	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20150316 COC Doc1.pdf	☐ Received 2014 COC Supporting Documents
DSR 03/16/2015	☐ ☐ ☐ ☐ ☑	LeonVetter Kevin Thomas	UST 46 UST 46 20150316 COC Certificate.pdf	☐ Sent 2014 COC Certificate
Letter 03/02/2015	☐ ☐ ☐ ☐ ☑	DOHUSTowner Kevin Thomas	COC Questionnaire - 2014	☑ Sent COC Form (System) - 2014
DSR 08/25/2014	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20140825 COC Doc1.pdf	☐ Received 2013 COC Supporting Documents
DSR 08/25/2014	☐ ☐ ☐ ☐ ☐	LeonVetter Kevin Thomas	UST 46 UST 46 20140825 COC Doc2.pdf	☐ Received 2013 COC Supporting Documents
Letter 08/06/2014	☐ ☐ ☐ ☐ ☑	CarlNess Craig Bleth	COC Questionnaire - 2013	☑ Sent COC Form (System) 2013
Maps 04/19/2013	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 20130419 site map google earth.jpg	☐ site map google earth
Other 03/08/2013	☐ ☐ ☐ ☐ ☑	Leon J Vetter	UST 46 UST 46 20130308 2012 COC.pdf	☐ 2012 COC
Letter 02/22/2013	☐ ☐ ☐ ☐ ☑	DOHUSTOwner Craig Bleth	COC Questionnaire - 2012	☑ Sent 2012 COC Form (System)
Email 07/11/2012	☐ ☐ ☐ ☐ ☐	LeonVetter Tony Aman	Approve New Operator	☑ Sent Approve New Operator Email
Email 07/11/2012	☐ ☐ ☐ ☐ ☐	LeonVetter Scott Hopfauf	Approve New Operator	☑ Sent Approve New Operator Email
Other 06/27/2012	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 20120627 2011 COC and documents.pdf	☐ 2011 COC and documentation
Letter 07/29/2011	☐ ☐ ☐ ☑ ☐	Leon J Vetter	UST 46 UST 46 20110729 ltr.pdf	☐ petroleum contaminated soil
Other 02/08/2011	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 20110208 Various documents UST 46 20110208 Various documents 1984 -2011 87418.pdf	☐ Various documents 1984 -2011
Reports 09/20/1994	☐ ☐ ☐ ☐ ☐	Alison Harries	UST 46 19940920 WQ Release Summa UST 46 19940920 WQ Release Summary Report 84470.pdf	☐ WQ Release Summary Report
Other 08/03/1994	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 19940803 suspected release.pdf	☐ UST suspected release
Reports 12/17/1991	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 19911217 UST removal report with associated documents.pdf	☐ UST removal report and associated documents
Notification 12/17/1991	☐ ☐ ☐ ☐ ☐	Leon J Vetter	UST 46 UST 46 19911217 SFN 10980 Notification Form.pdf	☐ SFN 10980 Notification Form

Inspections

Date	Type	Inspector	Contact	Comment

05/18/2021	Closure	Leon Vetter	Stephanie	
07/16/2020	Routine	Leon Vetter		Had all LD records. Spill/overfill good. CP good. They are thinking of removing tank.
09/27/2016	Routine	Leon Vetter	Scott Hopfauf	Have flapper valve in drop tube.
09/25/2013	Routine	Leon Vetter	Scott Hopfauf	Had all records. Pump in uncontained sump.
05/24/2010	Routine	Carl Ness	Scott Hopfauf	
06/22/2006	Routine	Carl Ness	Not Entered	Inp Carl

Compliance

History

Date From Date To	Facility Name Facility Location	Description
03/23/2011	(1276) Minnkota Power Cooperative Inc - (46) Minnkota Power Cooperative Inc 3401 24th Street SW, Center ND 58530	System Conversion

LUST Form Report

Tuesday, September 5, 2023

Facility Name	Minnkota Power Cooperative Inc	**LUST ID**	46
Address	3401 24th St SW	**LUST Standing**	Inactive
City State Zip	Center, ND 58530-	**Date**	12/17/1991
Phone	(701) 794-8711 **Facility ID** 46	**Status**	Site Cleanup Completed
Comments	Contaminated Soil was Removed; Amount = 5; City = Center; Land Farm;	**Staff Lead**	David Swlick
		Lead Party	RP-Lead
		AST or Exempt	☐

Status

Date	Status/Lead Party	Priority	Comments
12/18/1991	Site Cleanup Completed RP-Lead	50	Approximately 5 yards of contaminated sand fill removed.
12/17/1991	Tank Release Under Control RP-Lead	29	Contamination confined to sandfill..
12/17/1991	LUST Cleanup Initiated: Petroleum RP-Lead	27	Contaminated sand backfill removed.
12/17/1991	Confirmed Release RP-Lead	19	Petroleum contamination detected during ust removal.
12/17/1991	Routine Removal : Petroleum RP-Lead	18	280 gallon diesel ust removed.

Reporting Party

Party Type	State Official
Title	Env. Engineer
Name	David J Switlick
Company	
Address	918 E Divide Avenue
City State Zip	Bismarck ND 58502 -
Phone	)

How was release first discovered?

Comments

Contamination discovered removal

Responsible Party

Release Information

Tank Number 0001 Alt Tank ID 1 Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost	How Discovered	Date Discovered
g		12/17/1991

Company 0

Comments

This record was added after conversion.

Tank Number 0002 Alt Tank ID E-7 Tank Status Currently In Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991

Company 0

Comments

This record was added after conversion.

Tank Number 0003 Alt Tank ID E-8 Tank Status Currently In Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991

Company 0

Comments

This record was added after conversion.

Tank Number 0004 Alt Tank ID R-2 Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991

Company 0

Comments

This record was added after conversion.

Tank Number 0005 Alt Tank ID R-3 Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991

Company 0

Comments

This record was added after conversion.

Tank Number 0006 Alt Tank ID R-4 Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g How Discovered Date Discovered 12/17/1991

Company 0

Comments

This record was added after conversion.

Tank Number 0007 | Alt Tank ID R-5 | Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g | How Discovered | Date Discovered 12/17/1991

Company 0

Comments
This record was added after conversion.

Tank Number 0008 | Alt Tank ID R-6 | Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g | How Discovered | Date Discovered 12/17/1991

Company 0

Comments
This record was added after conversion.

Tank Number 0009 | Alt Tank ID R-9 | Tank Status Permanently Out of Use

Source(s) of Release	Spill	Overfill	Phys/Mech Damage	Corrosion	Install Problem	Other	Unknown
Tank	☐	☐	☐	☐	☐	☐	☐
Pipe	☐	☐	☐	☐	☐	☐	☐
Dispenser	☐	☐	☐	☐	☐	☐	☐
Turbine Pump	☐	☐	☐	☐	☐	☐	☐
Delivery Problem	☐	☐	☐	☐	☐	☐	☐
Other	☐	☐	☐	☐	☐	☐	☐

Qty Lost g | How Discovered | Date Discovered 12/17/1991

Company 0

Comments
STAINING OBSERVED NEAR THE FILL PIPE, POSSIBLE OVERFILLS.; ROUTINE UST REMOVAL.

Receptor Information

Date	Offsite Receptor	Contaminant	Impact	Mitigated Date	Comment
12/17/1991	Tank Basin	Diesel	Unlikely	12/18/1991	Sand backfill in basin.

From: Susan Richman <susan7richman@gmail.com>
Sent: Tuesday, September 26, 2023 9:15:25 PM (UTC-02:00) Mid-Atlantic - Old
To: askNEPA <asknepa@hq.doe.gov>
Subject: [EXTERNAL] Draft EA for North Dakota CarbonSAFE: Project Tundra (DOE/EA-2197)

To NEPA:

Please accept my comments, in opposition to:

the draft EA for *North Dakota CarbonSAFE: Project Tundra* (DOE/EA-2197), which assesses the potential environmental impacts of DOE providing cost-sharing financial assistance to Minnkota Power Cooperative, Inc. (Minnkota) for the project.

10-1 I have read, in ***Energy and Policy Institute*** dated Sept 14, 2023, https://energyandpolicy.org/department-of-energy-analysis-says-coal-carbon-capture-project-would-emit-more-greenhouse-gases-than-it-stores/

"There is an expected 3.23 kg of CO2e emitted per kg of CO2 stored."

Since carbon emissions are expected to exceed stored carbon, more than three times over, there is no reason for this project to go forward.

10-2 However, the article uncovered an even more disturbing fact:

"A Government Accountability Office report in 2021 documented problems with DOE's carbon capture program, including that 'DOE's process for selecting coal projects and negotiating funding agreements increased the risks that DOE would fund projects unlikely to succeed.' The GAO report specifically noted: 'According to DOE documentation and officials, senior leadership directed actions to support projects even though they were not meeting required key milestones.' "

It appears that the DOE is ensuring a project goes forward that does NOT meet their own requirements. That project will further spew

10-2 (cont'd.) carbon emissions into the atmosphere. Public safety and US climate goals are being sacrificed for a business opportunity. It is terrifying to think this is how our US government operates.

Please ensure a safe future on a livable planet, and a government body that abides by its own rules. A carbon capture project should create negative emissions. This project should not be funded. The DOE should be held to its own standards.