January 15, 2026

—Via Electronic Filing—

Sasha Bergman
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101

RE: CERTIFICATE OF NEED APPLICATION
IN THE MATTER OF THE APPLICATION FOR A CERTIFICATE OF NEED FOR THE BISON TO ALEXANDRIA SECOND CIRCUIT 345 KV TRANSMISSION LINE PROJECT
DOCKET NO. E002, ET2, E015, E017, ET6135/CN-25-116

Dear Ms. Bergman:

Northern States Power Company, doing business as Xcel Energy, along with Great River Energy, Minnesota Power, Otter Tail Power Company, and Missouri River Energy Services on behalf of Western Minnesota Municipal Power Agency (collectively, the Applicants) respectfully submit the enclosed Application for a Certificate of Need (Application) to the Minnesota Public Utilities Commission (Commission) for approval to construct the Minnesota portion of the Bison to Alexandria Second Circuit 345 kilovolt (kV) Transmission Project (Project).

On December 12, 2024, the Midcontinent Independent System Operator, Inc. (MISO), a federally registered planning authority and regional transmission organization, approved its Long-Range Transmission Planning (LRTP) Tranche 2.1 Portfolio of projects as part of its 2024 MISO Transmission Expansion Plan (MTEP24). MISO's LRTP Tranche 2.1 Portfolio is made up of 24 projects, including this Project.

MISO's LRTP Tranche 2.1 Portfolio reflects the region's continued coordinated transmission planning effort to ensure the future reliability, efficiency, and sustainability of the electric transmission system. The Project, identified as project No. 19 in the MTEP24 report, plays a critical role in addressing current and future system requirements by focusing on grid reliability, congestion mitigation, and the integration of a growing array of different generation resources. This Project, as part of the LRTP Tranche 2.1 Portfolio, advances the multi-state effort towards grid modernization and resilience, and facilitates changes to the electric grid of Minnesota in response to evolving generation and load demands.

The Project involves adding a new 345 kV transmission circuit on mostly existing transmission line structures from the existing Bison Substation near Fargo, North Dakota to the existing Alexandria Substation in Alexandria, Minnesota. The existing 345 kV structures were previously permitted and constructed as double-circuit capable as part of the Fargo – St. Cloud 345 kV Transmission Project.

We have electronically filed this letter and the Application with the Commission. A short summary of this Application is being distributed, as required by Minn. R. 7829.2500, subp. 3. The Application filing fee, as required by Minn. R. 7849.0210, subp. 1, was sent to the Commission under separate cover.

Please contact Jody Londo at jody.l.londo@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/ Jody Londo

JODY LONDO
DIRECTOR, REGULATORY AND STRATEGIC ANALYSIS
NORTHERN STATES POWER COMPANY

/s/ Priti Patel

PRITI PATEL
VICE PRESIDENT & CHIEF TRANSMISSION OFFICER
GREAT RIVER ENERGY

/s/ Daniel Gunderson

DANIEL GUNDERSON
VICE PRESIDENT – TRANSMISSION SYSTEM PLANNING & OPERATIONS
MINNESOTA POWER

/s/ JoAnn Thompson

JOANN THOMPSON
VICE PRESIDENT, ASSET MANAGEMENT
OTTER TAIL POWER COMPANY

/s/ Terry Wolf

TERRY WOLF
SECOND ASSISTANT SECRETARY
WESTERN MINNESOTA MUNICIPAL POWER AGENCY

Enclosures
cc: Service List

APPLICATION FOR A CERTIFICATE OF NEED FOR THE BISON TO ALEXANDRIA SECOND CIRCUIT 345 KV TRANSMISSION PROJECT

Docket No. E002, ET2, E015, E017, ET6135/CN-25-116

January 15, 2026

Submitted by
Northern States Power Company
Great River Energy
Minnesota Power
Otter Tail Power Company
Western Minnesota Municipal Power Agency

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ACRONYMS AND ABBREVIATIONS

ACS	American Community Survey
AC	alternating current
APC	adjusted production cost
Application	Certificate of Need Application
BGEPA	Bald and Golden Eagle Protection Act
BMP	best management practice
the Commission	Minnesota Public Utilities Commission
CO_2	carbon dioxide
CPCN	Certificate of Public Convenience and Necessity
CREP	Conservation Reserve Enhancement Program
CT	Census Tract
dB	decibel
dBA	A-weighted decibel
DC	direct current
DEED	Minnesota Department of Employment and Economic Development
DPP	Definitive Planning Process
ECS	Ecological Classification System
EJ	environmental justice
EMF	electric and magnetic fields
ERAS	Expediated Resource Addition Study
ESA	Endangered Species Act
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
GPS	Global Positioning Systems
GW	gigawatt
HHS	U.S. Department of Health and Human Services
HUC	hydrologic unit code
HVDC	High Voltage Direct Current
IPaC	Information for Planning and Consultation
kV	kilovolt
kV/m	kilovolt per meter
LRTP	Long-Range Transmission Planning
LRTP20	Maple River – Cuyuna 345 kV Transmission Project
LRTP21	Iron Range – St. Louis County – Arrowhead 345 kV Transmission Project
LRZ	Local Resource Zone
MDNR	Minnesota Department of Natural Resources
mG	milliGauss
MISO	Midcontinent Independent System Operator, Inc.
MnDOT	Minnesota Department of Transportation

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MPCA	Minnesota Pollution Control Agency
MRES	Missouri River Energy Services
MTEP24	MISO's 2024 Transmission Expansion Plan
MVP	Multi-Value Project
MW	megawatt
MWh	megawatt-hour
NAC	Noise Area Classification
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
NHIS	Natural Heritage Inventory System
NO_2	nitrogen dioxide
NRHP	National Register of Historic Places
NSPM	Northern States Power Company, a Minnesota corporation
NWR	National Wildlife Refuge
Otter Tail	Otter Tail Power Company
ppb	parts per billion
ppm	parts per million
the Project	Bison to Alexandria 345 kV 2nd Circuit Transmission Project
Project 20	Maple River – Cuyuna 345 kV
Project 21	Iron Range – St. Louis County – Arrowhead 345 kV
PROMOD	PROduction MODeling
PWI	Public Water Inventory
RIM	Reinvest in Minnesota
ROW	right-of-way
RTO	regional transmission organization
SNA	Scientific and Natural Area
SWPPP	Stormwater Pollution Prevention Plan
TO	Transmission Owner
USDA	United States Department of Agriculture
USFWS	United States Fish and Wildlife Service
V	voltage
Western Minnesota	Western Minnesota Municipal Power Agency
WHO	World Health Organization
WMA	Wildlife Management Area
Working Group	Interagency Working Group
WPA	Waterfowl Production Area
WRP	Wetland Reserve Program
Xcel Energy	Northern States Power Company, doing business as Xcel Energy

1 EXECUTIVE SUMMARY

1.1 Introduction

Northern States Power Company, doing business as Xcel Energy (Xcel Energy), along with Great River Energy, Minnesota Power, Otter Tail Power Company (Otter Tail), and Missouri River Energy Services, on behalf of Western Minnesota Municipal Power Agency (Western Minnesota), (collectively, the Applicants) request a Certificate of Need from the Minnesota Public Utilities Commission (Commission) for the Minnesota portion of the Bison to Alexandria 345 kilovolt (kV) 2nd Circuit Transmission Project (the Project). The Project consists of adding a second 345 kV transmission circuit on mostly existing transmission structures between the existing Bison Substation located northwest of Fargo, North Dakota, in Cass County and the existing Alexandria Substation in Alexandria, Minnesota, in Douglas County.

The Project represents a critical investment identified as part of Midcontinent Independent System Operator, Inc.'s (MISO)[1] Long-Range Transmission Planning (LRTP) Tranche 2.1 Portfolio, reflecting the region's continued coordinated transmission planning efforts to ensure the future reliability, efficiency, and sustainability of the electric transmission system. In December 2024, MISO's Board of Directors reviewed and approved this Project in its 2024 Transmission Expansion Plan (MTEP24) report.[2]

The Project, identified as project no. 19 in the MTEP24 report, plays a critical role in addressing current and future system requirements by focusing on congestion mitigation, grid reliability, and the integration of a growing array of energy resources. This Project, as part of the LRTP Tranche 2.1 Portfolio, advances the multi-state effort

[1] MISO is a member-based non-profit regional transmission organization (RTO) that is responsible for the planning and operation of transmission grid and wholesale energy market across 15 states and the Canadian province of Manitoba. MISO's members include 48 transmission owners with more than 65,800 miles of transmission lines and $34.5 billion in transmission assets that are under MISO's functional control.

[2] A copy of the MTEP24 Report that discusses the need for the LRTP Tranche 2.1 Portfolio, including the Project, is provided as **Appendix E-1**. **Appendix E-1** was prepared from the version of the MTEP24 Report that was posted to MISO's website on October 8, 2025.

towards grid modernization and resilience, and facilitates changes to the electric grid of Minnesota in response to evolving generation and load demands.

The Applicants are submitting this Certificate of Need Application (Application) for the entire Minnesota portion of the Project pursuant to Minn. Stat. § 216B.243 and Minn. Rule Ch. 7849. To facilitate review of this Application, a completeness checklist is included as **Appendix A**, which provides a roadmap identifying where in this Application information required by Minnesota statutes and rules can be found.

The Applicants will also apply for a Route Permit Amendment for the Project under Minn. Stat. § 216I.09. Xcel Energy is leading the Certificate of Need and Permit Amendment for the Minnesota portion of the Project on behalf of the Applicants.

Project approvals are also required for the portion of the Project located in North Dakota. Xcel Energy plans to submit applications for an amended Certificate of Public Convenience and Necessity (CPCN), Certificate of Corridor Compatibility, and Route Permit during the first or second quarter of 2026.

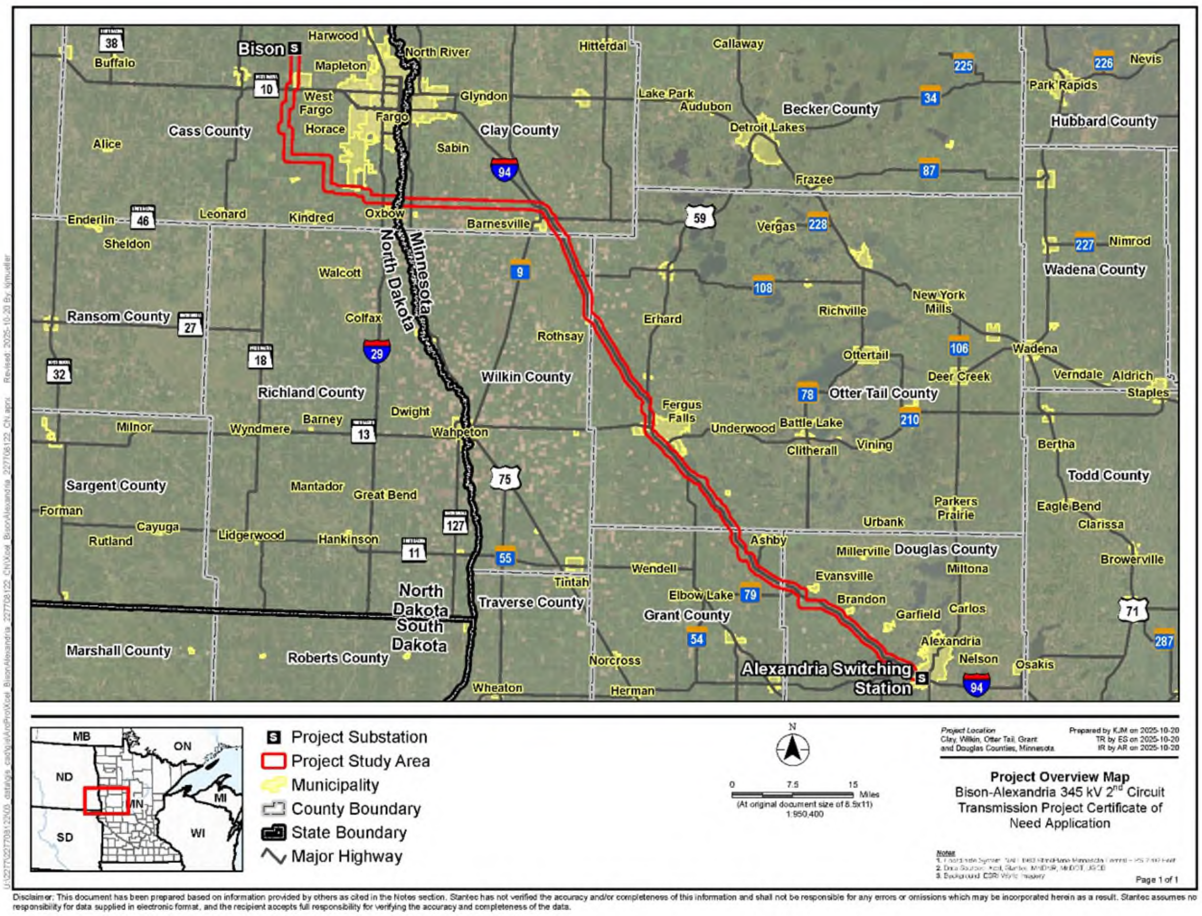
1.2 Project Description

The Project consists of adding a second new 345 kV transmission circuit on mostly existing transmission structures from the existing Bison Substation near Fargo, North Dakota, to the existing Alexandria Substation in Alexandria, Minnesota. The existing 345 kV line was previously permitted and constructed as double-circuit capable as part of the Fargo – St. Cloud 345 kV Transmission Project.[3] The Project will consist of adding a second circuit to existing transmission infrastructure, as well as the installation of an estimated 107 new monopoles (86 structures within Minnesota) in specific areas along the existing transmission corridor to address alignment changes (such as directional turns) and certain highway crossings. Within Minnesota, the Project extends from the Minnesota - North Dakota border in Holy Cross Township in Clay County, crossing Clay, Wilkin, Otter Tail, Grant, and Douglas counties, before terminating at Alexandria Substation in Alexandria, Minnesota, in Douglas County.

[3] Docket No. E002, ET2/TL-09-1056.

The Project also includes modifications to the existing Bison Substation in North Dakota and the existing Alexandria Substation in Minnesota. The proposed Project is shown in **Map 1-1**.

Map 1-1
Project Study Area



1.3 Need for the Project

This Project, together with the other LRTP Tranche 2.1 Portfolio transmission projects, is essential to ensure the regional transmission system is reliable, resilient, and cost-effective given generation resource mix transitions and rising demand for electricity in the coming years.

Specifically, this Project, along with two other LRTP Tranche 2.1 projects, Maple River – Cuyuna 345 kV Transmission Project (LRTP20) and Iron Range – St. Louis County – Arrowhead 345 kV Transmission Project (LRTP21) (collectively, Northern Minnesota Projects), are needed to address reliability issues on the existing 345 kV transmission system in northern Minnesota. This existing 345 kV system is at its capacity, leading to thermal and voltage issues. The Northern Minnesota Projects will help to resolve these issues by adding new 345 kV transmission lines to the system that connect to the Tranche 1 projects. As part of its analysis in MTEP24, MISO concluded that the Northern Minnesota Projects resolve more than 50 percent of the constraint violations for the transmission systems both above 200 kV and below 200 kV. In addition to addressing the current constraint issues, the Northern Minnesota Projects provide additional transmission capacity to accommodate additional generation from North Dakota and reduce transmission system congestion.

The Project, along with the rest of the LRTP Tranche 2.1 portfolio will also provide economic benefits to offset a portion of its costs. MISO found that the entire LRTP Tranche 2.1 portfolio delivers benefits in excess of costs, totaling $23.1 billion to $72.4 billion over the first 20 years these projects are in service, with an overall benefit-to-cost ratio ranging from 1.8 to 3.5.[4] These benefits were calculated under MISO's Future 2A. In addition, Xcel Energy, on behalf of the Applicants, conducted additional economic analysis of the Project and determined that the Project will provide up to $76.3 million in economic savings across MISO over the first 20 years that the Project is in service. These economic savings will help offset the capital cost of the Project.

The Project was also included in the 2025 Minnesota Biennial Transmission Projects Report.[5]Additional information on the need for the Project is provided in **Chapter 4**.

The Applicants considered several alternatives to the Project including (1) new generation; and (2) different transmission solutions, including upgrading other existing transmission facilities, transmission lines with different endpoints, and transmission

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[4] **Appendix E-1** at 144 (MTEP24 Report).

[5] *In the Matter of the 2025 Minnesota Biennial Transmission Projects Report,* Docket No. E999/M-25-99, 2025 MINNESOTA BIENNIAL TRANSMISSION PROJECTS REPORT at 36 (Oct. 31, 2025).

lines with different voltage levels. A complete discussion of the alternatives to the Project evaluated by the Applicants is provided in **Chapter 5**.

1.4 Project Schedule and Costs

Construction of the Project is anticipated to be completed by the end of 2031. The Project timeline depends on several factors, including required system outages, coordination with other transmission projects of the Applicants, and obtaining necessary Project approvals.

The estimated total capital cost to construct the Project is $249.2 million (2025$), with an estimated cost of $186.6 million (2025$) for construction work in Minnesota. Additional details regarding the schedule and cost for the Project are provided in **Chapter 2**.

1.5 Project Ownership

The 345 kV transmission line between the Bison and Alexandria substations will be jointly owned by Xcel Energy, Great River Energy, Minnesota Power, Otter Tail, and Western Minnesota. As the Project Manager, Xcel Energy will be responsible for the construction of the proposed 345 kV transmission line.

The equipment and improvements required inside the Alexandria Substation will be owned solely by Western Minnesota. The equipment and improvements required inside the Bison Substation will be owned solely by Xcel Energy. Each party will be responsible for the construction and maintenance of its own substation.

Xcel Energy is a Minnesota corporation headquartered in Minneapolis, Minnesota, that is engaged in the business of generating, transmitting, distributing, and selling electric power and energy and related services in the states of Minnesota, North Dakota, and South Dakota. In Minnesota, Xcel Energy provides electric service to 1.5 million customers. Xcel Energy is a wholly-owned utility operating company subsidiary of Xcel Energy Inc. and operates its transmission and generation system as a single integrated system with its sister company, Northern States Power Company, a Wisconsin corporation, known together as the NSP Companies. The NSP Companies are vertically integrated transmission-owning members of MISO. Together, the NSP Companies have over 46,000 conductor miles of transmission lines and approximately 550 transmission and distribution substations.

Great River Energy is a not-for-profit wholesale electric power cooperative which provides electricity to approximately 1.7 million people through its 26 member-owner cooperatives and customers. Through its member-owners and customers, Great River Energy serves two-thirds of Minnesota geographically and parts of Wisconsin. Great River Energy's 5,100 mile transmission network is interconnected with the regional transmission grid to promote reliability, and Great River Energy is a transmission-owning member of MISO. Great River Energy is based in Maple Grove, Minnesota.

Minnesota Power is an investor-owned public utility headquartered in Duluth, Minnesota. Minnesota Power supplies retail electric service to 150,000 retail customers and wholesale electric service to 14 municipalities in a 26,000-square-mile electric service territory located in northeastern Minnesota. Minnesota Power generates and delivers electric energy through a network of transmission and distribution lines and substations throughout northeastern Minnesota. Minnesota Power's transmission network is interconnected with the regional transmission grid to promote reliability, and Minnesota Power is a member of MISO.

Otter Tail Power Company is an investor-owned electric utility headquartered in Fergus Falls, Minnesota, that provides electricity and energy services to over 133,000 customers spanning 70,000 square miles in western Minnesota, eastern North Dakota, and northeastern South Dakota. Otter Tail wholly or jointly owns approximately 6,000 miles of transmission lines and approximately 1,100 megawatts (MW) of generation capacity in these three states and is a transmission-owning member of MISO.

Western Minnesota is a municipal corporation and political subdivision of the State of Minnesota, headquartered in Ortonville, Minnesota. Western Minnesota owns generation and transmission facilities, the capacity and output of which are sold to Missouri River Energy Services (MRES). MRES, which is based in Sioux Falls, South Dakota, provides electricity, including conservation program services, to its 61-member municipal utilities in Iowa, Minnesota, North Dakota, and South Dakota, who in turn serve approximately 174,000 customers.

1.6 Potential Environmental Impacts

The Applicants analyzed the potential environmental impacts of the Project and identified measures that can be implemented to avoid, minimize, or mitigate these impacts. **Chapter 8** of this Application provides a general description of the environmental setting, land use and human settlement, land-based economies, archeological and historical resources, hydrological features, vegetation and wildlife, and rare and unique natural resources that are known to occur or may potentially occur in the Project Study Area. **Chapter 8** also identifies potential impacts to existing resources and identifies measures that can be implemented to avoid, minimize, or mitigate impacts. As discussed in **Chapter 8**, the Applicants have not identified any potential environmental impacts that would preclude construction of the Project.

1.7 Public Input and Involvement

The public can review this Application and submit comments on the Project to the Commission. A copy of the Application is available at the Commission's website: https://mn.gov/puc/. On the Commission's website, click on the eDockets link in the menu at the top of the page, click on "Go to eDockets," enter 25-116 in the "Docket #s" section, and then click "Search."

A copy of the Application is also available on the Project website: www.fargotoalexandria.com. This Application will also be available at the following locations for the public to review:

- Barnesville Public Library, 104 Front St. N., Barnesville, MN 56514
- Fergus Falls Public Library, 205 E. Hampden Ave., Fergus Falls, MN 56537
- Thorson Memorial Library, 117 Central Ave. N., P.O. Box 1040 Elbow Lake, MN 56531
- Douglas County Library, 720 Fillmore St., Alexandria, MN 56308
- West Fargo Public Library, 215 Third St. E., West Fargo, ND 58078

- Dr. James Carlson Library, 2801 32nd Ave. S., Fargo, ND 58103
- Kindred Public Library, 330 Elm St., Kindred, ND 58051

Persons interested in receiving notices and other filings about the Application can subscribe to the Project's Certificate of Need docket by visiting the Commission's website: https://mn.gov/puc/, clicking on the eDockets link in the menu at the top of the page, clicking on "Subscribe to eDockets" at the bottom of the page, then following the instructions under "How to Subscribe to eDockets" and enter Docket Number 25-116.

To be placed on the Certificate of Need mailing list, send an email to eservice.admin@state.mn.us or call (651) 201-2204 . When sending an email or leaving a phone message, please include (1) mail preference (U.S. mail or email); and (2) the docket number (CN-25-116), full name, and complete mailing address or email address.

Questions about the state regulatory process can be directed to the Minnesota state regulatory staff listed below:

Minnesota Public Utilities Commission
Energy Infrastructure Permitting Staff
Cezar Panait
121 7th Place East, Suite 350
St. Paul, Minnesota 55101
651.201.2207
800.657.3782
Email: cezar.panait@state.mn.us
Website: www.mn.gov/puc/

1.8 Project Meets Certificate of Need Criteria

Minnesota rules and statutes specify the criteria the Commission should apply in determining whether to grant a Certificate of Need. Subdivision 3 of Minn. Stat. § 216B.243 identifies the criteria the Commission must evaluate when assessing need. Specifically, Minn. Stat. § 216B.243, subd. 3(9) provides that in assessing whether to grant a Certificate of Need for a high-voltage transmission line, the Commission should consider:

> the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota.

The Project, along with the other Northern Minnesota Projects, will relieve constraints and congestion on the existing transmission system in northern Minnesota and eastern North Dakota. This will lower wholesale energy costs by improving the access and deliverability of lower cost renewable generation. The Project will also enable the transmission system to be more resilient during contingency situations.

Minnesota Rule 7849.0120 further provides that the Commission shall grant a Certificate of Need if the Commission determines that:

> (A) The probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states;
>
> (B) A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record;
>
> (C) By a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health; and,
>
> (D) The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

The Applicants' proposal satisfies these four criteria as discussed below.

(A) The probable result of denial of the Project would have an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, applicant's customers, or to the people of Minnesota and the neighboring states.

Denial of a Certificate of Need for this Project would result in adverse effects upon the present and future efficiency of energy supply to the Minnesota electric customers and other end users. This Project is one of 24 new transmission initiatives comprising the LRTP Tranche 2.1 Portfolio, as identified by MISO. The LRTP Tranche 2.1 portfolio builds upon, and is made possible by, the LRTP Tranche 1 portfolio (consisting of 18 other projects), which were initially developed to address immediate reliability requirements. These efforts are expected to deliver significant benefits to the Midwest subregion within the MISO footprint by enhancing reliability, safety, and affordability of energy delivery. In conjunction with the existing 345 kV network, this infrastructure will facilitate efficient electricity transmission across multiple states to local communities, supporting each state's policy and reliability objectives in a more cost-effective and minimally disruptive manner. Specifically, this Project is designed to provide additional transmission capacity to the current transmission system in northern Minnesota and eastern North Dakota. The Project is needed to provide additional transmission capacity and to maintain electric system reliability throughout the region as more generation resources are added to the electric system in and around the region.

(B) A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence.

In the MTEP24 process, MISO analyzed 97 projects representing 47 solutions. These alternatives underwent reliability analysis to verify adequate transmission system performance both before and after contingencies. Economic analyses were also conducted, examining congestion, generation curtailment, regional price separation, overall service costs, and the portfolio's adjusted production cost savings. Based on these analyses, 24 projects were added to the Tranche 2.1 Portfolio. MISO determined that this portfolio enhances reliability and economic value while supporting use of diverse energy generation sources, accommodating load growth, and facilitating regional power transfers within the MISO system.

In addition to the study work conducted by MISO, Applicants considered multiple alternatives to the Project, including (1) size alternatives (different voltages); (2) type alternatives (upgrades to existing lines, double-circuiting, direct current (DC) lines, underground lines, and alternative conductors); (3) generation alternatives and consideration of conservation and demand-side management alternatives; and (4) no build alternative. After reviewing these alternatives, the Applicants concluded that none are a more reasonable and prudent alternative to the Project.

> *(C) The proposed transmission lines will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments.*

The proposed Project will reduce congestion and allow the transmission system to operate more efficiently and more cost-effectively, and pursuant to the Commission's routing criteria is routed in a manner compatible with protecting the natural and socioeconomic environments.

> *(D) The proposed transmission lines will comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.*

Applicants will secure all necessary permits and authorizations prior to commencing construction on the portions of the Project requiring such approvals. Minnesota Rule 7849.0240, subp. 2, requires the applicant for a Certificate of Need to address the socially beneficial uses of the facility output, promotional activities that may have given rise to the demand, and effects of the facility in inducing future development.

The socially beneficial uses of the Project are a reduction of the current transmission congestion in this area, increased market access to lower cost renewable generation, and economic benefits in terms of reduced wholesale energy costs, increased robustness of the regional grid, and support for future renewable generation facilities in Minnesota and North Dakota.

The Applicants have not conducted any promotional activities or events that have triggered the need for the Project. As noted above, the Project is needed to address reliability issues on the existing 345 kV transmission system in northern Minnesota. This existing 345 kV system is at its capacity leading to thermal and voltage issues. This

Project, along with other LRTP Tranche 2.1 Portfolio projects, will help to resolve these issues by adding new 345 kV transmission lines to the system that connect to the LRTP Tranche 1 projects.

1.9 Applicants' Request and Contact Information

For the reasons discussed above and in the remainder of this Application and Appendices, the Applicants respectfully request that the Commission find this Application complete and, upon completion of its review, grant a Certificate of Need for the portions of the Project located in Minnesota. The Commission has established criteria in Minn. R. 7849.0120 to apply in determining whether a Certificate of Need should be granted for a proposed high-voltage transmission line.

The Applicants have demonstrated in this Application that the proposed Project meets all the requirements to obtain a Certificate of Need. The Project will provide additional transmission capacity that is needed to mitigate current constraint issues and to improve electric system reliability throughout the region as more renewable energy resources are added to the electric system. The proposed Project will support the State's goals to conserve resources, minimize environmental and human settlement impacts and land use conflicts by considering the use of existing corridors to the extent feasible, and ensure the State's electric energy security through the construction of efficient, cost-effective transmission infrastructure. All correspondence relating to this Application should be directed to:

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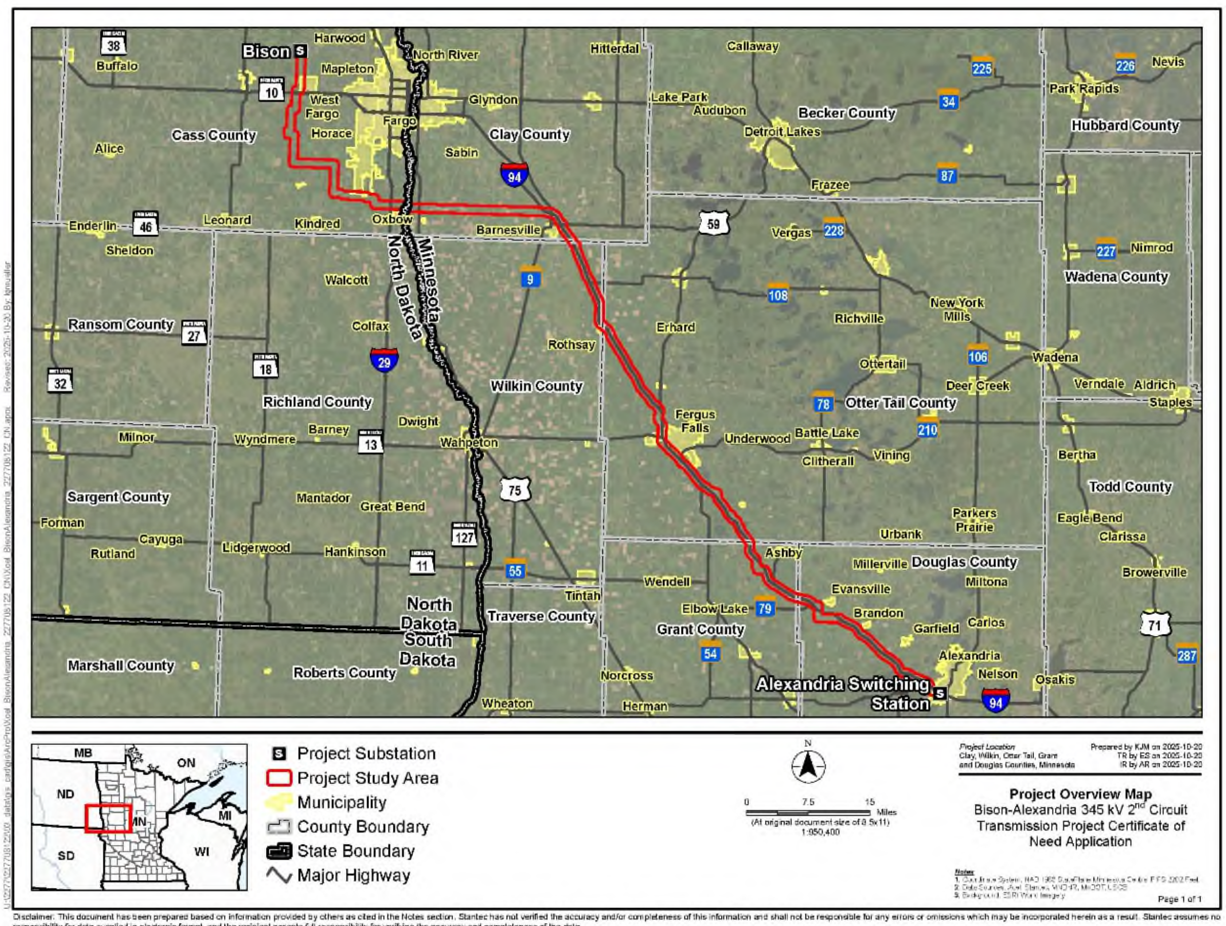
2 PROJECT DESCRIPTION

2.1 Project Description

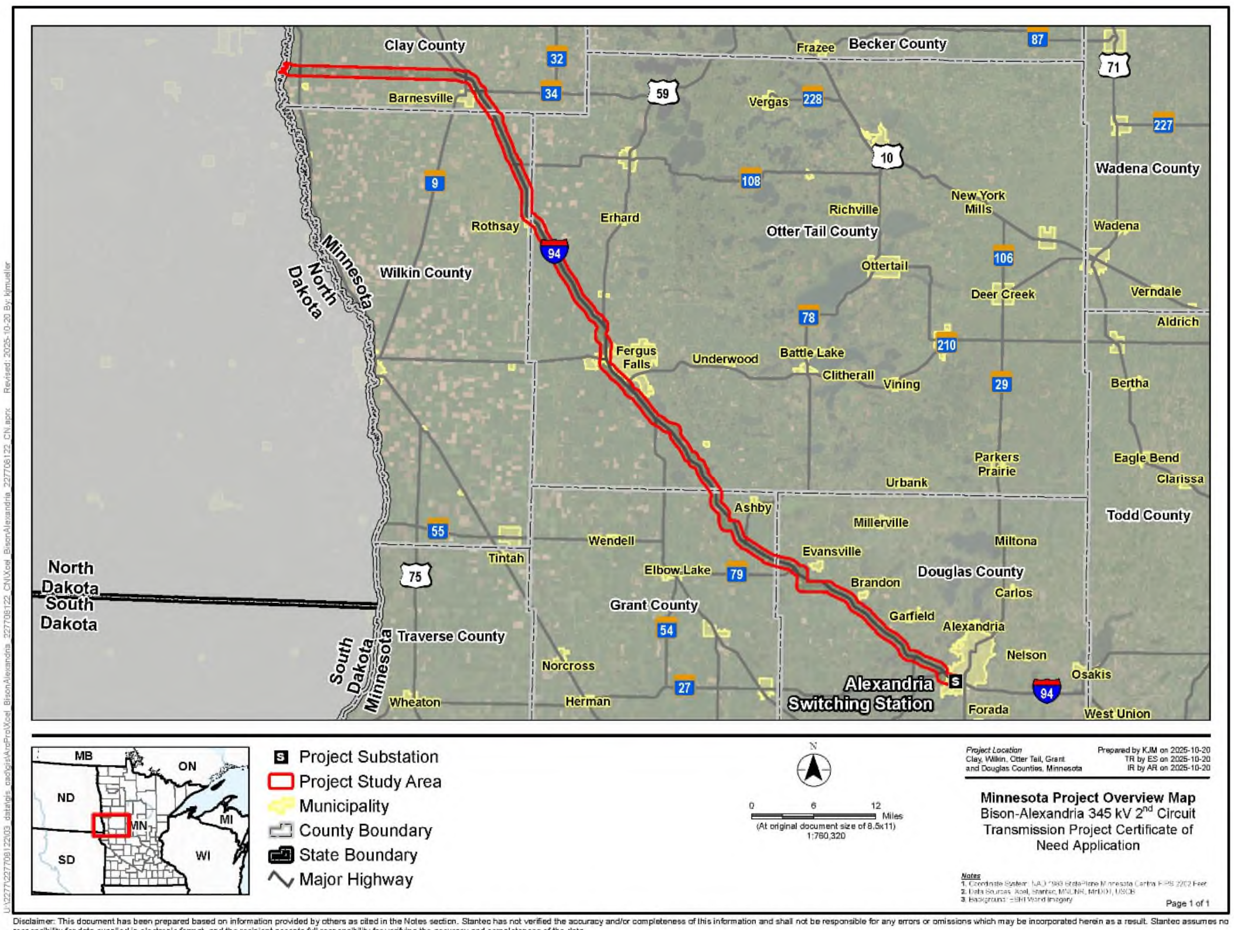
The Applicants propose to construct a new 345 kV transmission line between Douglas County, Minnesota, and Cass County, North Dakota. Within Minnesota, the Project extends from the Minnesota-North Dakota border in Holy Cross Township in Clay County, crossing Clay, Wilkin, Otter Tail, Grant, and Douglas counties, before terminating at Alexandria Substation in Alexandria, Minnesota, in Douglas County. An overview map of the Project is shown in **Map 2-1**.

Map 2-1
Project Overview Map



The Project will be jointly owned by Xcel Energy, Great River Energy, Minnesota Power, Otter Tail, and Western Minnesota and involves the installation of a new 345 kV transmission circuit between the existing Bison Substation and Alexandria Substation that will be strung on existing double-circuit capable infrastructure. The Applicants plan to file a Route Permit Amendment for the Project in the first or second quarter of 2026 in the docket for the CapX2020 Fargo – St. Cloud 345 kV Transmission Project (Docket No. E002, ET2/TL-09-1056). An overview map of the Project within Minnesota is provided in **Map 2-2**.

Map 2-2
Minnesota Project Overview Map



2.1.1 345 kV Transmission Line and Structures

The Project, including all proposed transmission line and substation components, will be sited within existing easements or within property owned by the Applicants. The Project involves adding a second 345 kV circuit to existing double-circuit capable transmission infrastructure within the existing 150-foot right-of-way (ROW). **Figure 2-1** provides a photo of the existing double-circuit capable 345 kV infrastructure with one of the 345 kV circuits strung.

Figure 2-1
Existing 345 kV Structures

When the existing infrastructure was originally installed, space was left for this future second circuit, allowing electrical capacity to be increased by the addition of a second circuit on the same infrastructure.

Additionally, an estimated 107 new monopoles (86 structures within Minnesota) are proposed in specific areas along the current transmission line to address alignment changes (such as directional turns) and certain highway crossings. The original design of the angle structures featured a two-pole configuration, which is standard for double-circuit 345/345 kV lines. When only the first 345 kV circuit was installed, the second monopole was not required. In the absence of wires for the second 345 kV circuit, installing the second monopole during the original construction of the first circuit would have increased vulnerability to vibration-induced damage. Where it is necessary to add a second monopole adjacent to an existing structure, it will be located within the established ROW, at a distance of 40 feet to 60 feet offset from the existing structure. **Figure 2-2** shows two monopole structures constructed side-by-side.

Figure 2-2
Typical Monopole 345 kV Structures Side-by-Side

The existing and proposed new structures typically range in height from approximately 75 feet to 170 feet tall. New monopoles will be installed on top of concrete foundations, some which were already excavated during construction of the first circuit.

Technical diagrams of these proposed structure types are provided in **Appendix G**.

The Applicants anticipate using a double bundled 2x397.5 kcmil 26/7 ACSR "Ibis" conductor. The proposed transmission line will be designed to meet or surpass relevant local and state codes including National Electric Safety Code (NESC) and the Applicants' standards. Applicable standards will be met for construction and installation, and applicable safety procedures will be followed during design, construction, and after installation.

2.1.2 Associated Facilities

The Project will include modifications to the existing Alexandria Substation in Minnesota and the Bison Substation in North Dakota. The Bison Substation and portion of the Project within North Dakota will be addressed in separate filings to the North Dakota Public Service Commission.

2.1.2.1 Bison Substation

The existing Bison Substation, owned by Xcel Energy, is located in Cass County, North Dakota, and is the western endpoint for the Project. The substation is located approximately 1 mile west of Fargo, North Dakota. The existing ring bus configuration will be modified to a breaker and half configuration by adding one additional row to the 345 kV portion of the substation. This new row will allow for new breaker positions added for the 345 kV line to the Bison Substation and additional reactive power equipment. The Applicants will seek all appropriate permits in North Dakota for the Bison Substation and the portion of the Project that will be located in North Dakota.

2.1.2.2 Alexandria Substation

The existing Alexandria Substation, owned by Western Minnesota, is the endpoint of the Project. This substation is located on the southern edge of the city of Alexandria just south of Interstate 94. New substation equipment necessary to accommodate the proposed 345 kV transmission line will be installed at the Alexandria Substation. Equipment will include new termination structures, circuit breakers, reactor, relays, and associated control equipment. No expansion of the substation is anticipated; work will take place within the existing substation fence.

2.2 Proposed Route

Between the Bison Substation and the Alexandria Substation (approximately 136 miles total, 101 miles within Minnesota) the Project consists of adding a second 345 kV circuit to existing transmission line infrastructure that was constructed as double-circuit capable as part of the CapX2020 Fargo – St. Cloud 345 kV Transmission Project (Docket No. E002, ET2/TL-09-1056). As part of the Project, up to 107 steel monopoles and 94 foundations will be installed at certain locations to accommodate the new 345 kV transmission line circuit. Eighty-six of these steel monopoles and 82 foundations are within Minnesota.

These structures are required in locations where the original line was designed for two structure angles but only one structure was installed during construction of the Fargo – St. Cloud 345 kV Transmission Project. These new monopoles will be installed within the existing transmission line ROW.

2.3 Project Costs

2.3.1 Estimated Construction Costs

There are several main components of the cost of constructing new transmission infrastructure. These main components are the costs of (1) transmission line infrastructure and materials; (2) transmission line construction and restoration; (3) transmission line permitting and design; (4) transmission line ROW acquisition; and (5) substation materials, substation land acquisition, permitting, design, and construction. Each of these components also may include a risk reserve and financing expenses, such as Allowance for Funds Used During Construction (AFUDC) or Construction Work in Progress (CWIP).

To prepare a cost estimate for the Project, the Applicants relied in part upon the actual costs incurred for constructing prior similar transmission projects. The Applicants then updated this data based on current market conditions and included a risk reserve. The cost estimates are based on matching the existing design on the first circuit constructed as part of the CapX2020 Fargo – St. Cloud 345 kV Transmission Project. The introduction of new foundations and structures will increase the Project costs.

To calculate an appropriate risk reserve, the Applicants identified potential risks that could result in additional costs. These risks could include, for example, unexpected weather conditions, environmental sensitivities resulting in the need for mitigation measures, poor soil conditions in areas where no soil data was obtained, transmission line outage constraints, potential shallow rock, river crossings, labor shortages, market fluctuations in material pricing and availability, and labor costs. The Applicants then developed an appropriate reserve amount for each of these risks and applied them to each of the cost categories. **Table 2-1** provides estimates of total Project construction costs. These costs include all transmission line costs (including materials, associated construction, permitting and design costs, and risk reserves), substation modification costs (including materials, construction, permitting and design costs, and risk reserve), and ROW costs.

Table 2-1
Construction Cost Estimates

Project Components	Capital Expenditures (2025$) ($Millions)
Bison – MN/ND State Line 345 kV Transmission Line	$52
MN/ND State Line – Alexandria 345 kV Transmission Line	$176
Bison Substation Modifications	$10.6
Alexandria Substation Modifications	$10.6
Total Project Costs*	**$249.2**
There may be differences between the sum of the individual component amounts and Total Project Costs due to rounding* **Capital Expenditures include AFUDC	

The Applicants note that **Table 2-1** includes cost estimates in 2025 dollars (2025$). These cost estimates will increase over time for any number of reasons, including, but not limited to, escalation, inflation, and commodity pricing, especially for these types of large-scale 345 kV transmission projects that have multi-year schedules. Therefore, the Applicants are also developing escalated cost estimates for each component of the Project in nominal dollars that will be provided during the course of this proceeding once they are available.

2.3.2 MISO's Estimated Project Costs

As part of developing the LRTP Tranche 2.1 Portfolio, MISO developed cost estimates for each of the 24 transmission projects. MISO's cost estimate for this Project was $93.8 million (2024$). The Applicants' cost estimate for the Project is higher than MISO's cost estimate for several reasons. The MISO cost estimate did not include the costs associated with the 107 new structures and 94 new foundations that will be required to string the second 345 kV transmission line circuit between the Bison Substation and the Alexandria Substation. For the existing Bison Substation, the MISO cost estimate did not include the conversion of a rung over and the addition of four breakers and four reactors. Additionally, the MISO cost estimate did not include costs related to prolonged construction duration due to an increased likelihood of mandatory and emergency service restorations, as outage taking for the entire duration of construction is unlikely. Further, commodity prices in general (material and labor) have also increased since the MISO cost estimate was developed.

2.3.3 Effect on Rates

Minn. R. 7849.0270, subp. 2(E) requires an applicant for a Certificate of Need to provide the annual revenue requirement to recover the costs of the proposed Project. Minn. R. 7849.0260, subp. C(5), requires an applicant to provide an estimate of the Project's effect on rates system wide and in Minnesota. The Applicants requested an exemption from these rule requirements and instead committed to providing: (1) an explanation of how the costs for LRTP Tranche 2.1 Portfolio of projects will be shared across the MISO footprint and (2) an annual revenue requirement impact for the capital costs of the Project for a 20-year period for Xcel Energy. Both of these items are discussed below.

2.3.3.1 Cost Allocation under MISO Tariff

The Project is part of the MISO LRTP Tranche 2.1 Portfolio, which has been determined by MISO to meet the criteria for being designated a Multi-Value Project (MVP) under the MISO tariff. As a result, the Project, along with the rest of the LRTP Tranche 2.1 Portfolio, qualifies for regional cost allocation. The costs of the LRTP Tranche 2.1 Portfolio will be recovered from MISO load and exports associated with the MISO Midwest Subregion,[6] where these projects are located and provide benefits, through the energy-based MVP Usage Rate ($/megawatt-hour [MWh]). The allocation of the Project's costs to transmission customers is governed by Schedule 26-A, Multi-Value Project Usage Rate, in MISO's tariff. The annual revenue requirement for the Project is determined by the formula rate in Attachment MM-MVP Charge in the

[6] The MISO Midwest Subregion includes MISO transmission customers in Minnesota, Montana, North Dakota, South Dakota, Iowa, Wisconsin, Missouri, Illinois, Indiana, Michigan, and Kentucky.

MISO tariff. Withdrawing Transmission Owners, as defined by the MISO tariff, in the MISO Midwest Subregion pay the annual revenue requirement through Schedule 26-A charges assessed based on actual monthly energy consumption by customers. Minnesota customers' allocated share of the annual revenue requirement is determined by the percent of total MISO energy used by Minnesota utilities, which is estimated at approximately 18 to 24 percent based on MISO's posted 2023 energy withdrawal data. MISO provided an estimate of these MVP usage charges by pricing zone in Appendix A-4 of MTEP24.[7]

2.3.3.2 Xcel Energy Annual Revenue Requirement Impact

Appendix H provides the annual revenue requirement impact for the capital costs of the Project for a 20-year period for Xcel Energy customers starting with the MISO approved in-service date of June 1, 2032. This revenue requirement calculation is for the NSP system (both Northern States Power Company, a Minnesota corporation [NSPM], and Northern States Power Company, a Wisconsin corporation) and are then adjusted to a Minnesota jurisdictional basis for NSPM. This revenue requirement calculation does not account for any future operation and maintenance costs for the Project or fuel impacts. The calculation also assumes the Project is jointly owned with the other Applicants as discussed in Section 1.5. Applicants note the rate impacts for customers of other Minnesota utilities will be different than those provided for Xcel Energy customers in **Appendix H**.

2.4 Project Schedule

Table 2-2 provides the permitting and construction schedule currently anticipated for the Project. This schedule is based on information known as of the date of filing and may be subject to change as further information develops or if there are delays in obtaining the necessary federal, state, or local approvals that are required prior to construction.

[7] MISO LRTP Tranche 2.1 MTEP24 Appendix A-4 Schedule 26A *available at* https://cdn.misoenergy.org/MTEP24720395.zip.

Table 2-2
Anticipated Project Schedule

Activity	Estimated Dates
Minnesota Certificate of Need and Route Permit Amendment Filings	Third Quarter 2025 through Fourth Quarter 2026
Survey and Transmission Line Design Begins	Third Quarter 2025
Other Federal, State, and Local Permits Issued	First Quarter 2028
Start Project Construction	July 2028
Project In-Service	June 2032

Challenges associated with material lead times, contractor availability, and weather conditions are variables that could cause the in-service date of the Project to be delayed. Additional clarity on the schedule for the Project will be known once certain milestones are reached through the Project's development process and will be shared with interested stakeholders through various communication channels, including the Project website.

3 ELECTRICAL SYSTEM AND CHANGING GENERATION PORTFOLIO OVERVIEW

3.1 Electrical System Overview

When a customer turns on a light switch, a circuit is completed that connects the light with the wires that serve the customer's building. The building wires are connected to a transformer that connects to a distribution line outside of the building. The distribution lines, in turn, are then connected to substations and then finally through larger transformers that connect to transmission lines that comprise the bulk power system. The bulk power system is comprised of large power transformers and high voltage transmission lines and can carry large amounts of electric power and energy (generally referred to below as electricity) from electric generating facilities to meet the demand for electricity at any given moment.

Electricity is produced at both large and small generating facilities. Electricity can be generated using a variety of sources or fuels, including solar, wind, and hydro; internal and external combustion of biomass, biofuels, natural gas, and coal; and heat and steam created through nuclear fission. Electric energy is generated at a specific voltage and frequency. For it to be useful, electricity must be transmitted from the generation source to substations with transformers and then to consumers at acceptable voltages. Unlike other consumables, where excess product can be easily and economically stored for future use, electricity must largely be generated simultaneously with its consumption. This means that generators connected to the bulk power system must instantaneously adjust their electric output to respond to changes in customer demand. However, energy storage technologies, including battery energy storage systems, are advancing, which could help reduce the need for generators to adjust instantaneously with customer demand.

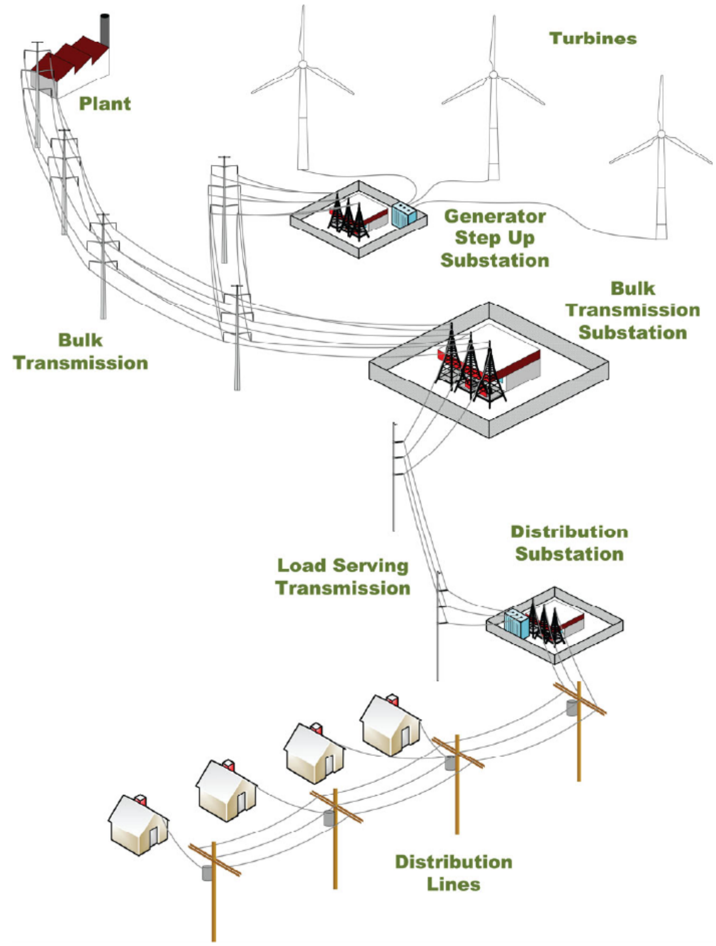
Typically, the voltage of electricity generated in a power plant is increased (stepped-up) by transformers installed close to the generating plant. The electricity is then transported over high voltage transmission lines, often at voltages in excess of one hundred thousand volts (e.g., 115 kV, 230 kV, and 345 kV).[8] Voltage is stepped-up on

[8] One kV equals 1,000 volts.

high voltage transmission lines because it is more efficient to move electricity over longer distances at higher voltages because the system experiences less electrical losses. Once the electricity reaches a location where it will be consumed, the transmission voltage (e.g., 115 kV and higher) is reduced (stepped-down) by substation transformers to a lower voltage, called a load serving transmission system, that is more appropriate to connect to a distribution substation. The electricity is further transformed at distribution substations where it is distributed at "primary" distribution voltages (e.g., 13.8 kV, 12.5 kV) within communities, which delivers power for individual customer use to the end location where it is stepped-down further to, most commonly, 240 volts or 120 volts.

A diagram of the transfer of electricity from a generator to a consumer is shown in **Figure 3-1**. Note that this figure is an artistic portrayal of the electric system and is not an actual representation of all electric system components.

Figure 3-1
Electrical System



3.2 Transmission System Overview

The transmission system is made up of high-voltage transmission lines that can efficiently carry electricity long distances. The transmission system delivers power to distribution substations that serve distribution systems that meet customer needs in specific locations. The transmission system is designed to be an integrated system that is able to withstand the outage of a single transmission line without a major disruption to the overall power supply to consumers.

3.2.1 High-Voltage Transmission Lines

Transmission lines throughout this region are primarily made up of conductors, which comprise a three-phase circuit and are usually accompanied by a shield wire that provides protection from lightning strikes. These conductors are several strands of wire grouped together, usually made from aluminum and steel, and most commonly held up by poles or towers that are made from wood or steel.

High-voltage transmission lines carry electricity from the generation source to distribution systems where the power is needed. The rate at which electricity moves through a conductor is called current and is measured in amperes (amps). The force that moves the electricity through the conductor is called voltage (V). Voltage is measured in terms of volts (or kV for 1,000 volts). Conductors carrying the current have resistance that can hinder its ability to allow current to flow freely. This resistance is measured in a unit called ohms. The wire conductors used by utilities on the high voltage transmission system carry electricity with relatively little resistance.

3.2.2 Substations

Substations are a part of the system that contain high-voltage electric equipment to monitor, regulate, and distribute electricity. Generally, substations allow transmission lines to connect with one another or allow electricity to be transformed from a higher transmission voltage to a lower transmission voltage or from a lower transmission voltage to a distribution voltage.

Substation property dimensions depend on the ultimate planned design for the specific substation and physical characteristics of the site, such as shape, elevation, above and below ground geographical characteristics, and proximity of the site to transmission lines. Substation sites need to be large enough to accommodate both the planned ultimate fenced area and the required surrounding areas. The required surrounding areas include applicable setbacks, stormwater ponds, wetlands, grading, access roads, and new transmission line rights-of-way. Depending on the timing of future load growth and electrical system needs, the configuration of a substation may change over time, resulting in multiple construction stages over an extended period of years.

3.3 The Changing Energy Landscape

Minnesota and surrounding states are facing urgent electric grid reliability challenges due to a combination of factors: rapid retirement of coal and nuclear generation, rising electricity demand, and a shift to the use of renewable generation sources. These challenges are driving a need to build out the high-voltage transmission system in the region to ensure generation can be efficiently and economically delivered across the region.

The following sections discuss the federal and state policies on transmission development, including provisions for the integration of diverse energy sources in Minnesota and the Upper Midwest.

3.3.1 Federal Energy and Transmission Policies

Complex challenges to the electric system have been steadily materializing throughout the U.S. and within the MISO region in recent years. The challenges are driven by a combination of economic, technological, policy-related, and extreme weather factors. Growth in electricity demand, particularly from data centers, advanced manufacturing facilities, and other major energy consumers, is outpacing the capacity of existing grid infrastructure. Current federal energy policy prioritizes the rapid expansion of generation and transmission capacity to reliably and cost-effectively meet rising demand nationwide.

Federal policy recognizes that additional high-voltage transmission infrastructure is critical to accessing diverse generation sources and to maintaining a resilient and reliable bulk power system. The *Inflation Reduction Act* of 2023 and the *One Big Beautiful Bill Act* of 2025 both reflect the urgency of investment in transmission. Both laws provide funding, incentives, and streamlined permitting processes aimed at accelerating the buildout of critical transmission projects. By supporting long-range planning and interregional coordination, these policies help address reliability risks, unlock clean energy potential, and support economic growth tied to electrification and decarbonization goals.

In 2024, the Federal Energy Regulatory Commission (FERC) issued Order No. 1920[9], mandating that transmission providers formulate long-term regional transmission plans covering at least a 20-year horizon. The order further requires planners to evaluate seven distinct benefits of transmission projects—including reductions in congestion costs and resilience to extreme weather—and to analyze a wider array of future planning scenarios. Transmission providers, including MISO through its LRTP efforts, have begun proactively adopting the best practices outlined in the regulation.

Despite these initiatives, progress on expanding the transmission network remains slow. In 2024, only 322 miles of new high-voltage transmission lines (345 kV and above) were constructed, marking the third lowest year for such additions over the past decade and a half. By comparison, nearly 4,000 miles were installed in 2013 alone.[10] This rate of development falls significantly short of national requirements, as highlighted in the U.S. Department of Energy's 2024 National Transmission Planning Study, which recommends at least doubling current regional transmission capacity and quadrupling interregional capacity by 2050.[11]

3.3.2 State of Minnesota

The State of Minnesota recognizes the critical role the regional high-voltage transmission system plays in providing reliable electricity to Minnesota and has been a leader in approving transmission projects with regional benefits. In 2024, Minnesota was the first state to approve a transmission project that was part of the MISO Tranche 1 Portfolio when it approved a Certificate of Need for the Big Stone South – Alexandria – Big Oaks 345 kV Project and a Route Permit for the Eastern Segment, the Alexandria – Big Oaks 345 kV Project (Docket Nos. CN-22-538 and TL-23-159).

In addition to building new transmission lines, the state is exploring alternatives to continued transmission build out. Methods to address the near-term need for new transmission include energy savings initiatives, programs to manage electric demand,

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[9] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation,* Order No. 1920 (May 13, 2024)

[10] ACEG, Grid Strategies LLC. *Fewer New Miles.* (July 2025), available at ACEG_Grid-Strategies_Fewer-New-Miles-2025_Rev-1.pdf

[11] U.S. Department of Energy, Grid Deployment Office (2024) *The National Transmission Planning Study*, available at https://www.energy.gov/gdo/national-transmission-planning-study

the build-out of distributed energy generation near sources of electricity demand, the build-out of strategically located short- and long-duration energy storage, and the implementation of a wide variety of grid-enhancing technologies. Minnesota has adopted new policies related to all of those possible options over the last few legislative sessions.

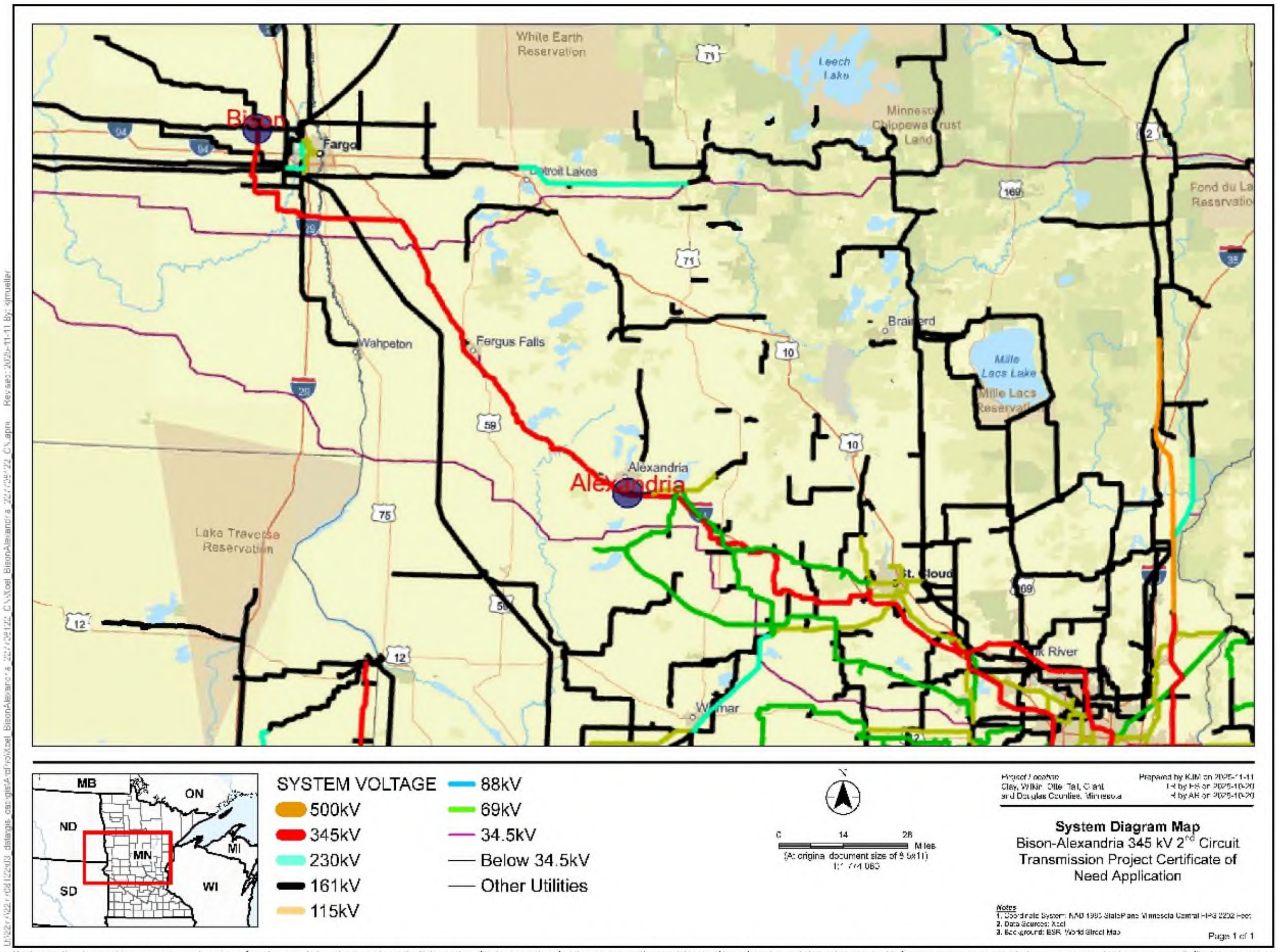
However, the state recognizes that upgrades to the high-voltage transmission system are necessary in the upcoming years to maintain system reliability, meet growing electrical demand, and to meet Minnesota's carbon-free electricity by 2040 law. Enacted in February 2023, the 100 Percent Carbon-Free by 2040 law directs electric utilities to transition to meeting the needs of Minnesota retail customers with 100% carbon-free electricity by the end of 2040.[12]

While continuing expansion of renewable energy generation is planned, there is currently not enough transmission capacity on the high-voltage transmission system to accommodate all the renewable energy projects that wish to interconnect. The existing 230 kV transmission system in northwest Minnesota and eastern North Dakota plays a key role in transporting and delivering energy to customers in Minnesota, but the existing 230 kV system is currently at capacity.

The Project is a key component of the LRTP Tranche 2.1 Portfolio, building on the initiatives of the Tranche 1 Portfolio, and providing a new 345 kV transmission line, which is designed to provide additional transmission capacity to mitigate current capacity issues on the existing 230 kV and 115 kV transmission system and to improve electric system reliability as more renewable energy resources are added throughout the region. This Project will play a crucial role in providing additional transmission capacity, mitigating current capacity issues, and improving electric system reliability throughout the region as more renewable energy resources are added to the high-voltage transmission system in and around the region. **Map 3-1** provides an overview of the transmission system in the Project area and **Map 3-2** provides an overview of the load centers in and near the Project area.

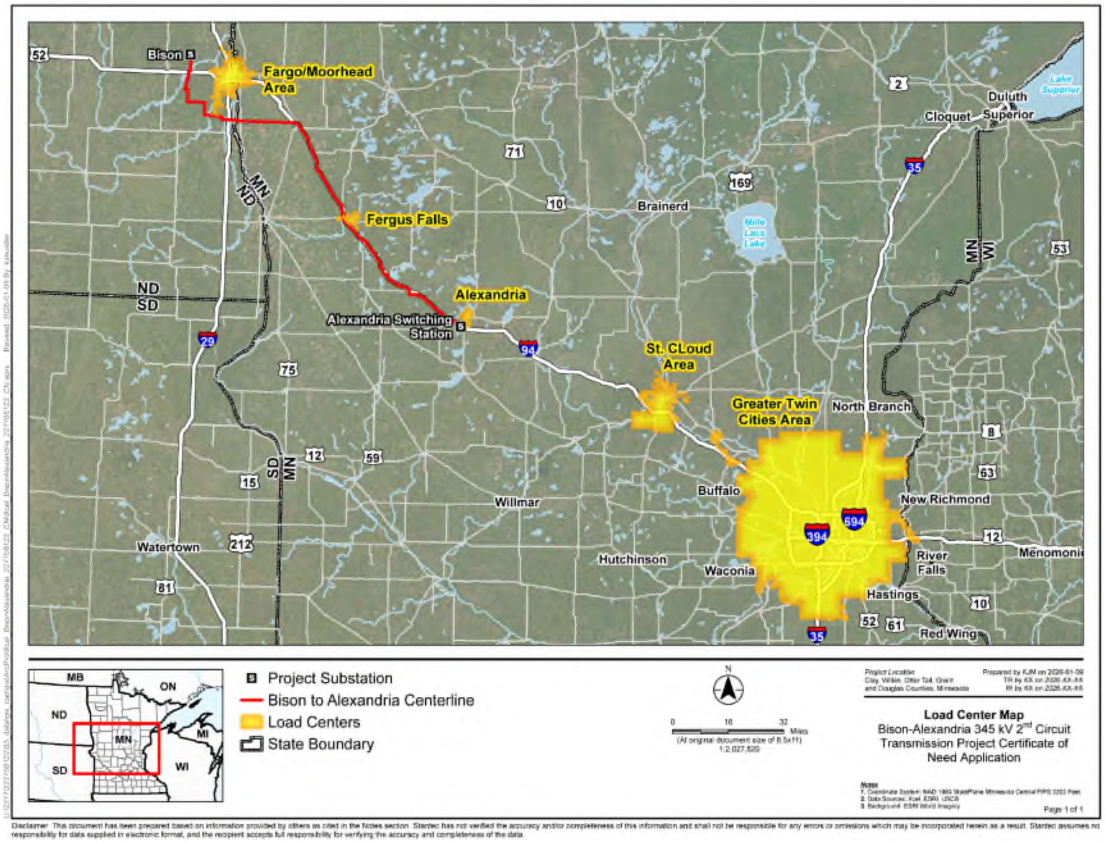
[12] Minn. Stat. § 216B.1691, subd. 2g.

Map 3-1
Project Area Transmission System Map



Disclaimer: This document has been prepared based on information provided by others as cited in the Notes section. Stantec has not verified the accuracy and/or completeness of this information and shall not be responsible for any errors or omissions which may be incorporated herein as a result. Stantec assumes no responsibility for data supplied in electronic format, and the recipient accepts full responsibility for verifying the accuracy and completeness of the data.

Map 3-2
Load Center Map



3.3.2.1 MISO Interconnection Queue

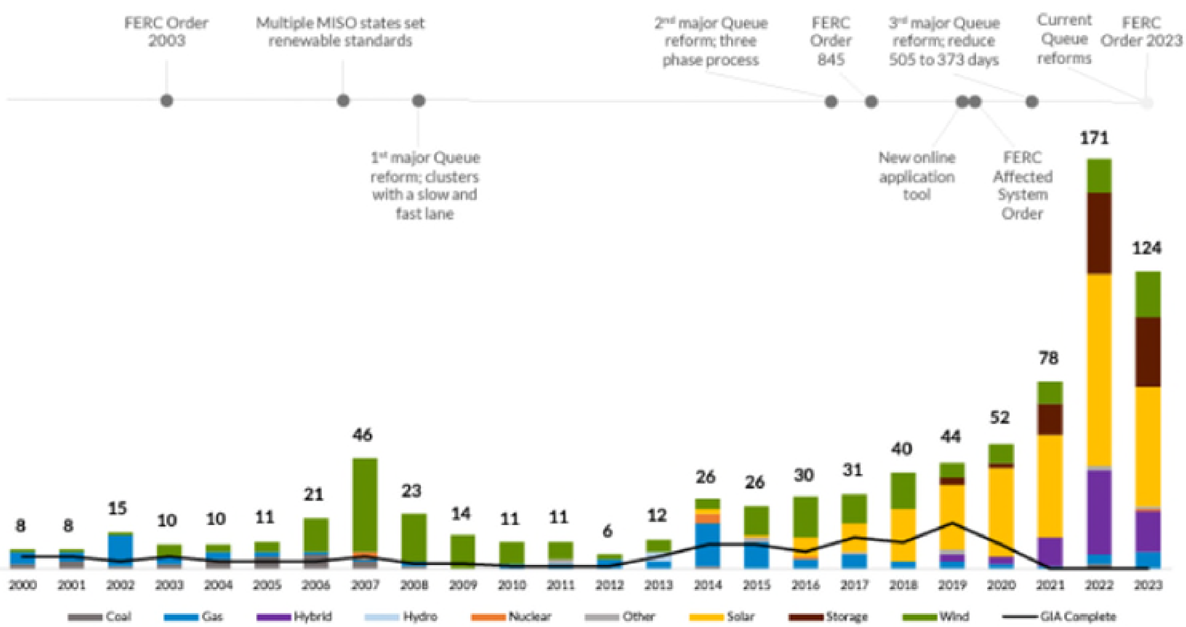
The additional transmission capacity provided by this Project is also needed to support the interconnection of the new generation that is approved or awaiting approval through MISO's generator interconnection queue process.

MISO's generator interconnection process is designed to allow generators non-discriminatory access to the electric transmission system and to ensure system reliability is maintained during certain operating conditions. MISO's standard generation interconnection process currently has one study cycle per year in which new generator requests are grouped into a common study group. MISO is currently running several interconnection studies for subsequent queue cycles in parallel in an attempt to address the backlog currently present in their generator interconnection process. Once a developer submits an application for a new generation project into MISO's Generator

Interconnection Queue, their request enters MISO's queue on a first-ready, first-served basis. Once a developer gains preliminary information through either a feasibility study or the System Planning and Analysis phase, the developer typically proceeds to the Definitive Planning Process (DPP) phase, during which time MISO undertakes more detailed generation interconnection studies for their specific generation project(s).[13]

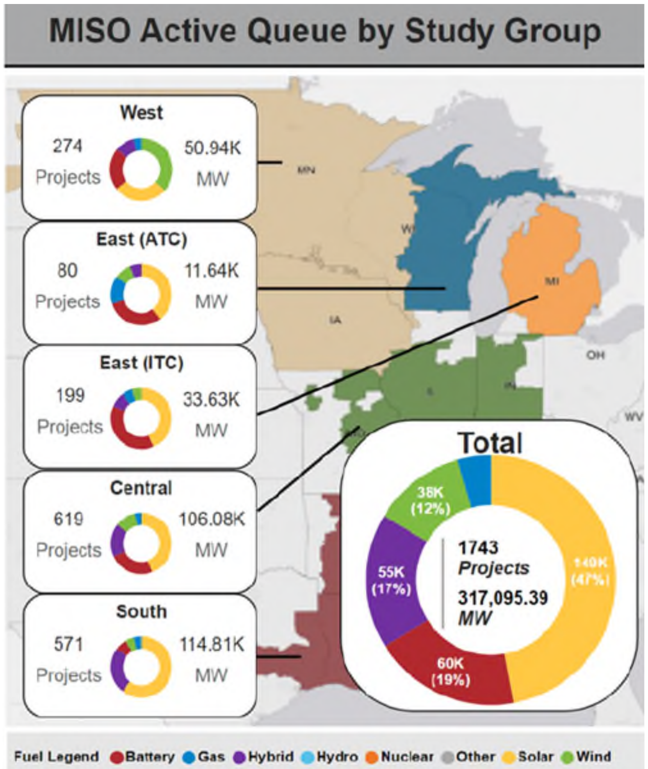
The MISO generator interconnection queue has experienced extremely high volume over the last several years as shown in **Figure 3-2**. In the 2023 Study Cycle, MISO received 600 individual project requests totaling roughly 124 gigawatts (GW). Solar, storage, and hybrid applications make up the bulk of the queue. Additionally, as of September 2024, the MISO interconnection queue had 1,743 projects representing 317 GW of total capacity (see **Figure 3-3**).

Figure 3-2
Historical View of MISO Interconnection Queue
(values in gigawatts)



[13] In July 2025, MISO received FERC approval for a proposed Expediated Resource Addition Study (ERAS) process, which would allow projects that meet certain criteria to sidestep MISO's standard generation interconnection queue and possibly receive an interconnection agreement within 90 days. The ERAS process is capped at 68 projects, with MISO studying only 10 projects each year. MISO plans to end the ERAS process by August 31, 2027, or after its 68 project cap is met, whichever happens first.

Figure 3-3
MISO Queue as of September 2024



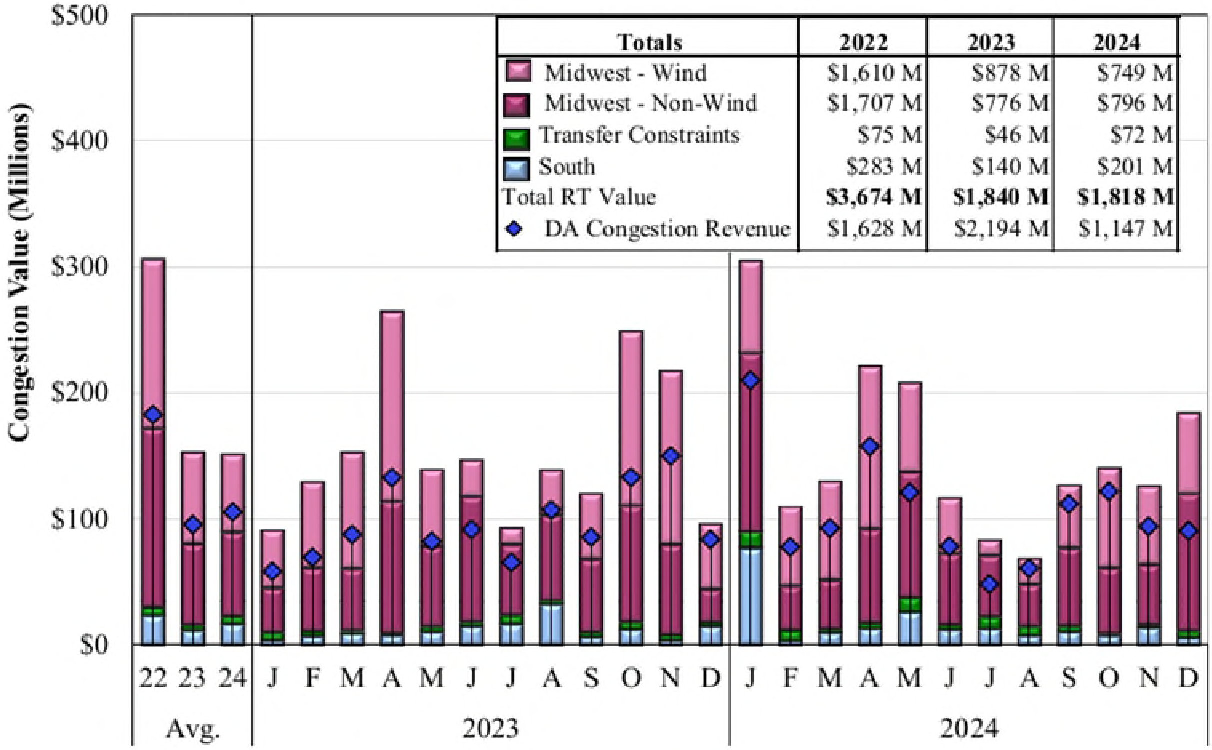
The existing high-voltage transmission system does not have sufficient capacity to interconnect new generation projects without substantial upgrades.

3.3.2.2 Transmission Congestion Issues

Transmission congestion costs arise on the MISO network when a higher-cost generation resource is dispatched in place of a lower-cost one to avoid a reliability issue, such as overloading a transmission facility. Congestion costs are reflected in MISO's location-specific energy prices, which represent the marginal costs of serving load at each location on the transmission system. The energy price at each location is comprised of the marginal energy costs, network congestion costs, and losses.

Congestion leads to higher energy costs for Minnesota customers because more expensive generation must be dispatched when congestion occurs on the high-voltage transmission system. **Figure 3-4** shows the monthly real-time congestion value over the past two years across the MISO footprint. The total value of real-time congestion was $1.8 billion in 2024, virtually unchanged from 2023. A significant share of the total congestion occurred during Winter Storm Heather in January 2024, as well as severe congestion that occurred in May caused by storm-related outages. Wind-driven congestion constituted a slightly lower share of congestion than it did in 2023 (at roughly 41 percent) partly because operators' manual interventions to manage this congestion often prevented it from being fully priced in the market. Continued expansion of nearby wind resources in other neighboring regional transmission organizations (RTOs), as well as retirements of dispatchable resources, is likely to increase wind-related congestion in future years. The Project will play a key role in providing additional transmission capacity to reduce the severity of these current congestion issues.

Figure 3-4
Monthly Congestion Values from 2023–2024 across MISO Footprint[14]



3.3.2.3 Summary

The evolving energy landscape and ongoing changes to Minnesota's generation portfolio will require increasing the capacity of the existing high voltage transmission system in the region to ensure existing generation and new generation projects can be efficiently and economically delivered to load centers. The next chapter discusses MISO's development of LRTP Tranche 1 and 2.1, as well as the Applicants' analysis of the need for this Project.

[14] *2024 State of the Market Report for the MISO Electricity Markets* at 49, Independent Market Monitor for MISO (June 2025) available at: https://www.potomaceconomics.com/wp-content/uploads/2025/07/2024-MISO-SOM_Appendix_Final.pdf

4 NEED ANALYSIS

4.1 Summary of Need Analysis

This Project is a key component of MISO's LRTP Tranche 2.1 portfolio. The LRTP Tranche 2.1 portfolio includes 24 projects totaling approximately 3,600 miles of new and upgraded transmission in MISO's Midwest subregion. The LRTP Tranche 2.1 builds upon and is enabled by the LRTP Tranche 1 and the existing transmission grid, which serve as "on and exit ramps" for the LRTP Tranche 2.1 765 kV "super-network," as well as contingency backup to meet North American Electric Reliability Corporation (NERC) reliability standards. Combined, the existing 765 kV and 345 kV networks would work together to move electricity across the multiple states to each local community where it is consumed and allow each state to meet their policy and reliability needs in a less costly and impactful manner.

The LRTP Tranche 2.1 Portfolio is needed to provide greater transfer capability within the MISO region to ensure reliability and resilience is maintained. In addition to providing more reliable and resilient energy delivery, the LRTP Tranche 2.1 Portfolio will also provide congestion and fuel savings, leverage existing ROW and transmission infrastructure, improve transfer capability, avoid the risk of load shedding, and enable a reduction in carbon dioxide (CO_2 or carbon) emissions by supporting a higher integration of renewable resources. Overall, MISO concluded that the entire LRTP Tranche 2.1 Portfolio is expected to provide net economic savings of $23.1 billion to $72.4 billion over the first 20 years of service under Future 2A.[15]

The LRTP Tranche 2.1 Portfolio was developed as a collection of 24 projects that are designed to work together. In particular, this Project, along with other northern Midwest projects (Maple River – Cuyuna 345 kV [Project 20] and Iron Range – St. Louis County – Arrowhead 345 kV [Project 21]), is needed to resolve regional reliability issues on the existing electrical system in northwestern Minnesota and eastern North Dakota. This existing transmission system plays a key role in transporting generation from North Dakota and South Dakota into Minnesota. As discussed in Chapter 3, the electric system is undergoing a transition as aging fossil-fueled baseload generation is

[15] **Appendix E-1** at 144 (MTEP24 Report).

retired and new renewable generation is being added to the system. This additional renewable generation is placing additional strain on the already constrained transmission system in this area. The Project alleviates these constraints by providing additional capacity and additional outlet for the generation from North Dakota and South Dakota into and through Minnesota. As part of its analysis in MTEP24, MISO concluded that the Northern Minnesota projects resolves more than 50 percent of the constraint violations in northern Minnesota, including several overloaded 115 kV and 230 kV transmission lines.[16]

In addition to meeting system reliability needs, the Project will also provide economic benefits to help offset its costs. Xcel Energy, on behalf of the Applicants, conducted additional economic analysis of the Project and determined that the Project will provide up to $76.3 million in economic savings across the MISO footprint over the first 20 years that the Project is in service. These economic savings will help offset the capital cost of the Project.

MISO's analysis demonstrated the implementation of the LRTP Tranche 2.1 Portfolio is estimated to reduce carbon emissions by 127 million metric tons over the first 20 years and 199 million metric tons over the first 40 years that the LRTP Tranche 2.1 Portfolio is in service.[17]

This Project has been extensively studied by both MISO and the Applicants and this chapter summarizes this study work.

4.2 MISO's Analysis of Need for the Project

The Project is part of MISO's LRTP Tranche 2.1 Portfolio, a portfolio of 24 regionally beneficial transmission projects identified by MISO and approved by the MISO Board of Directors in December 2024. This section provides background on MISO's role in planning the regional transmission grid, the reliability implications of the Midwest's changing generation fleet, and MISO's LRTP study process. This section also includes a detailed discussion of MISO's analysis and justification of the LRTP Tranche 2.1

[16] **Appendix E-1** at 100 (MTEP24 Report).

[17] **Appendix E-1** at 161 (MTEP24 Report).

Portfolio, including its specific evaluation of the Project. Additional details on MISO's analysis and justification for the Project can be found in **Appendix E-1**, which is MISO's MTEP24 Report that discusses the need for the LRTP Tranche 2.1 Portfolio and how MISO analyzed and evaluated these transmission projects.

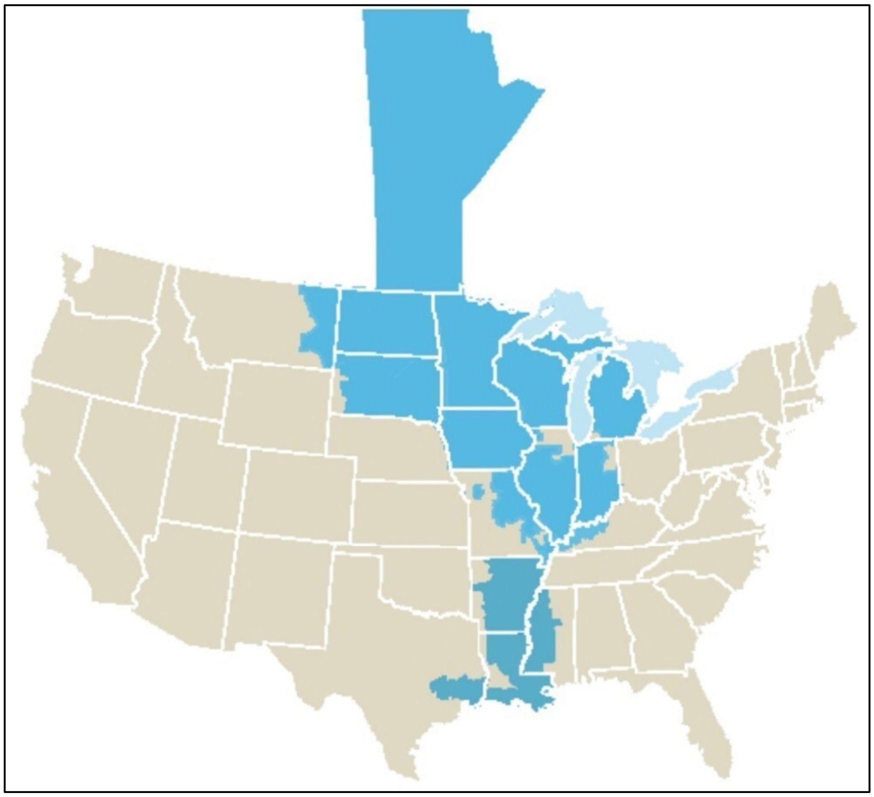
4.2.1 MISO Overview

MISO is an independent not-for-profit RTO which operates the transmission system and energy market in parts of 15 states and the Canadian province of Manitoba. As an RTO, MISO is responsible for planning and operating the transmission system within its footprint in a reliable manner. MISO also provides operational oversight and control, market operations, and oversees planning of the transmission systems of its member Transmission Owners (TOs). MISO has 56 TO members, including Xcel Energy, Great River Energy, Minnesota Power, Otter Tail, and Missouri River Energy Services,[18] with more than 79,000 miles of transmission lines under MISO's functional control.[19] MISO members also include 174 non-TOs, such as independent power producers and exempt wholesale generators, municipals, cooperatives, transmission dependent electric utilities, and power marketers and brokers. A map of MISO's geographic footprint is provided in **Figure 4-1**.

[18] Missouri River Energy Services is designated as the Transmission Owner of transmission facilities owned by Western Minnesota.

[19] Information from MISO fact sheet as of October 2025 available at: https://www.misoenergy.org/about/media-center/corporate-fact-sheet/.

Figure 4-1
MISO Reliability Footprint



4.2.2 MISO Transmission Expansion Plan Process

MISO has a responsibility, established by the FERC, to study the transmission system within its footprint, including planning necessary transmission projects to provide for efficient, reliable, and non-discriminatory transmission service. This study includes the development of the MISO MTEP in collaboration with TOs and other stakeholders. The MTEP is developed each year in an 18-month overlapping cycle of model building, stakeholder input, reliability analysis, economic analysis, resource assessments, and drafting of the MTEP report. In developing the MTEP, MISO adheres to the planning principles outlined in FERC Order Nos. 890[20] and 1000,[21] and is aligned with the planning principles in FERC Order No. 1920. These FERC Orders require an open

[20] FERC Order No. 890, 18 C.F.R. parts 35, 36 (2007), available at https://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

[21] FERC Order No. 1000, 18 C.F.R. part 35 (2011), available at https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

and transparent regional transmission planning process and include the requirement to plan for public policy objectives and for coordinated inter-regional planning and cost allocation. Each MTEP cycle, MISO undergoes a rigorous, open, and transparent stakeholder process that offers numerous opportunities for advice and input from a diverse stakeholder community, which includes utilities, state regulators, and public interest organizations including environmental and consumer groups.

The MTEP process is a "top-down, bottom-up" process which simultaneously considers both local needs as identified by local utilities (bottom-up) and regional needs as identified by MISO (top-down) to identify the optimal plan to meet all the MISO region's reliability needs. Each year as part of the MTEP process, the bottom-up planning process assesses transmission system needs based on changes in demand and generation plans. Should these changing factors result in the grid no longer meeting national reliability standards or policy, MISO, in coordination with the TOs and working through its stakeholder process, will identify mitigation to ensure the system stays reliable and in compliance.

The first MTEP report was released in 2003. Since then, there have been over 20 annual MTEP cycles. In the last three MTEP cycles (2022-2024), MISO approved approximately 1,500 transmission projects. Most projects are smaller-scale and incremental in nature – many being replacements of older transmission lines and substations for age and condition purposes. MISO's top-down process examines regional transmission needs over the long-term planning horizon. In response to fundamental shifts in electricity usage and production, MISO has also identified three regional transmission portfolios consisting of higher-voltage transmission projects which, when combined, span the Midwest Subregion of MISO: the MVP Portfolio, MISO LRTP Tranche 1 Portfolio, and MISO LRTP Tranche 2.1 Portfolio.

4.2.3 Multi-Value Projects and CapX2020

In the 2000s, Minnesota's transmission grid was at a point where incremental improvements were exhausted, and a step-change was needed to meet the reliability needs of the time. In 2004, CapX2020, now known as Grid North Partners, formed to develop a long-term vision for the Upper Midwest power grid to maintain system reliability in the most cost-effective manner with these transformational changes.

CapX2020 identified the need for, and ultimately developed, an approximately 800-mile 345 kV network across Minnesota, North Dakota, and South Dakota. CapX2020's vision was optimized for the entire Midwest via MISO's first regional transmission portfolio, the 2011 MVP Portfolio, which consisted of 17 projects, primarily 345 kV, totaling approximately 2,200 miles across nine Midwest states.[22] All CapX2020 lines were constructed and in-service as of 2017. All the 2011 MVP projects were constructed and in-service as of 2024.

To optimally meet immediate needs with longer-term goals in mind, at the recommendation of the Department[23] and approval of the Commission,[24] the 345 kV CapX2020 projects originally proposed as single-circuit 345 kV transmission lines were built using double-circuit capable structures. Today, the second circuit has been added or is in the process of being added to nearly all the original CapX2020 projects, which has doubled the transmission capacity of each corridor with minimal physical impacts and significantly less costs than would be required for a new stand-alone option. In fact, the Project, that is the subject of this Application, involves adding a second 345 kV circuit to one of these CapX2020 projects, the St. Cloud – Fargo 345 kV Transmission Project.

4.2.4 MISO Long Range Transmission Planning

The MISO footprint is experiencing a fundamental change. In 2001, generation across MISO was largely provided by coal generation and some natural gas, and customer demand was the largest source of day-to-day operating variation. By 2023, coal generation shrunk to approximately 28 percent of MISO's annual energy production and annual energy from wind and solar generation rose to 17 percent.[25] Driven by a

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[22] MISO, *Regionally Cost Allocated Project Reporting Analysis. 2011 MVP Portfolio Analysis Report* (August 2025). available at https://cdn.misoenergy.org/MVP%20Dashboard117055.pdf.

[23] *In the Matter of the Application for Certificates of Need for Three 345 kV Transmission Line Projects with Associated System Connections*, Docket No. ET2, E002, *et al.*/CN-06-1115, SURREBUTTAL TESTIMONY OF DR. STEVE RAKOW ON BEHALF OF THE MINNESOTA OFFICE OF ENERGY SECURITY at page 21 (July 3, 2008).

[24] *In the Matter of the Application of Great River Energy, Northern States Power Company (d/b/a Xcel Energy) and Others for Certificates of Need for the CapX 345-kV Transmission Projects*, Docket No. ET-2, E-002, *et al.*/CN-06-1115, ORDER GRANTING CERTIFICATES OF NEED WITH CONDITIONS at page 43 (May 22, 2009).

[25] Information from MISO fact sheet as of October 2025 available at: https://www.misoenergy.org/about/media-center/corporate-fact-sheet/.

combination of state and federal policy, including Minnesota's carbon-free by 2040 law,[26] customer preferences, economics, and utility goals, the retirement of legacy fossil fuel generators and the replacement with largely geographically dispersed wind and solar units is expected to continue and accelerate across the MISO footprint over the foreseeable future.

Recognizing that transformational changes in the generation fleet require significant changes to the transmission grid to maintain reliability, MISO launched the LRTP in 2019. The LRTP is a multi-year, multi-phase study to identify a regional transmission network necessary to cost-effectively maintain reliability and serve future needs.

The LRTP is one component of MISO's Reliability Imperative,[27] a shared responsibility of electricity providers (like the Applicants), states, and MISO to address the urgent and complex challenges facing the electric grid in the MISO region. MISO's response to the Reliability Imperative consists of a host of initiatives grouped into four categories: Market Redefinition, Transmission Evolution (i.e., LRTP), System Enhancements, and Operations of the future. The objective of MISO's LRTP is to provide an orderly and timely transmission expansion plan that supports these primary goals:

- **Reliable System** – maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply.
- **Cost Efficient** – enable access to lower-cost energy production.
- **Accessible Resources** – provide cost-effective solutions allowing the future resource fleet to serve load across the footprint.
- **Flexible Resources** – allow more flexibility in the fuel mix for customer choice.

MISO evaluates the projects in the LRTP in accordance with MISO's federally approved Tariff. For any project to be deemed needed under MISO's Tariff, it must meet defined criteria, which may vary depending on the type of project. The

[26] Minn. Stat. § 216B.1691, subd. 2g.

[27] Additional information on MISO's Reliability Imperative is available at: https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/.

transmission projects resulting from the LRTP effort meet the MISO Tariff criteria for being MVP. For a project to be deemed needed as an MVP by MISO it must address three primary areas of value:

- **Reliability** – address transmission issues to maintain national reliability standards;

- **Economic** – provide multiple types of economic value across multiple pricing zones with a benefit-to-cost ratio of 1.0 or higher; or

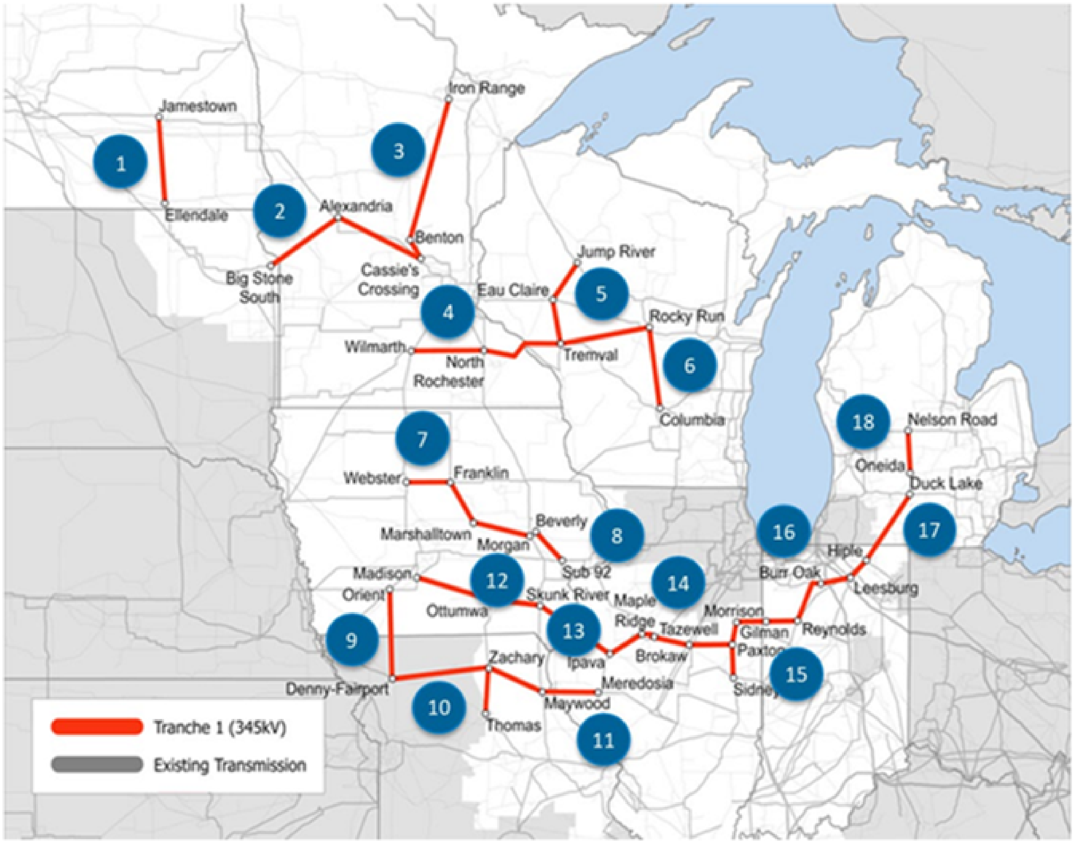
- **Policy** – support the reliable and economic delivery of energy in support of documented energy policy mandates or laws.

In addition to meeting the above criteria, MVP transmission projects must be developed as part of a portfolio of complementary projects. As MVP portfolios, LRTP Tranche 1 and Tranche 2.1 are eligible for cost allocation under the MISO Tariff.

4.2.5 LRTP Tranche 1

In July 2022, MISO approved the first phase, or "tranche," of the LRTP. The MISO LRTP Tranche 1 Portfolio consists of 18 transmission projects totaling approximately 2,000 miles of new and upgraded transmission lines to enhance connectivity and help maintain adequate reliability for the Midwest by 2030 and beyond. **Figure 4-2** depicts the projects in the MISO LRTP Tranche 1 Portfolio.

Figure 4-2
MISO LRTP Tranche 1 Portfolio



MISO LRTP Tranche 1 includes three 345 kV projects in Minnesota:

- the Big Stone South to Alexandria to Big Oaks Transmission Projects;[28]
- the Northland Reliability Project;[29] and
- the Mankato to Mississippi River Project.[30]

MISO LRTP Tranche 1 was intentionally designed as a first step to address immediate reliability needs driven by a changing generation fleet mix and to increase primarily

[28] Docket Nos. CN-22-538, TL-23-159, and TL-23-160. This Project connects to the Alexandria to Big Oaks Transmission Project.

[29] Docket Nos. CN-22-416 and TL-22-415.

[30] Docket Nos. CN-22-532 and TL-23-157.

intra-state, but also inter-state, transfers to meet NERC standards. More specifically, the MISO LRTP Tranche 1 Portfolio:

- Addresses reliability violations, as defined by NERC, at over 300 different sites across the Midwest. In addition, the portfolio increases transfer capability across the MISO Midwest subregion to allow reliability to be maintained for all hours under varying dispatch patterns driven by differences in weather conditions.

- Provides $23.2 billion in net economic savings over the first 20 years of the LRTP Tranche 1 Portfolio's service, which results in a benefit-to-cost ratio of at least 2.6. This amount increases to $52.2 billion in net economic savings over 40 years, resulting in a benefit-to-cost ratio of 3.8.[31]

- Supports the reliable interconnection of approximately 43,431 MW in new, primarily renewable, generation capacity across the MISO Midwest subregion, 8,339 MW of which is in Minnesota and the surrounding region.

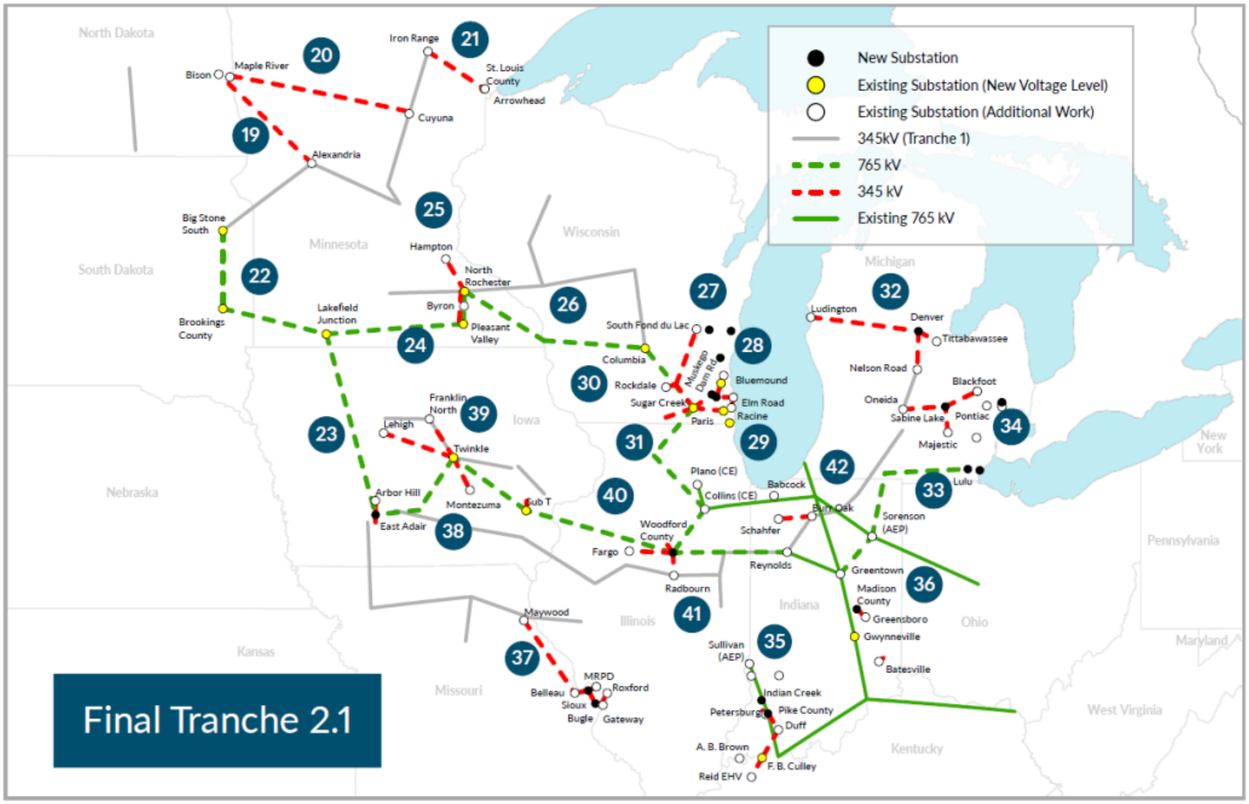
The MISO LRTP Tranche 1 Portfolio also was designed to bolster the existing 345 kV to position the grid for future LRTP tranches.

4.2.6 LRTP Tranche 2.1

In 2024, MISO approved the next phase of the LRTP, LRTP Tranche 2.1, consisting of 24 transmission projects, including the Project, identified on **Figure 4-3** as project number 19. The MISO LRTP Tranche 2.1 Portfolio includes approximately 3,600 miles of new and upgraded high voltage transmission, equaling approximately $21.8 billion in investment, to enhance connectivity and maintain reliability for the Midwest by 2032 and beyond.

[31] Values as of July 2022. While market forces, have driven project costs to increase since 2022, the same forces will also cause benefits to increase.

Figure 4-3
MISO LRTP Tranche 2.1 Portfolio[32]



The LRTP Tranche 2.1 builds upon and is enabled by the LRTP Tranche 1 and the existing transmission grid, which serves as "on and exit ramps" for the LRTP Tranche 2.1 765 kV "super-network," as well as contingency backup to meet NERC reliability standards. Combined, the existing 765 kV and 345 kV networks would work together to move electricity across the multiple states to each local community where it is consumed and allow each state to meet their policy and reliability needs in a less costly and impactful manner.

[32] **Appendix E-1** at 163, Figure 2.156 (MTEP24 Report).

MISO followed an extensive stakeholder process, spending more than 40,000 staff hours, facilitating more than 300 meetings, and capturing feedback to arrive at the LRTP Tranche 2.1 Portfolio.[33] The LRTP Tranche 2.1 Portfolio is needed for:

- **Reliability** – The portfolio relieves significant levels of transmission line overloads, including 961 unique overloads identified in power flow modeling, in addition to voltage violations, stability limits, and other reliability constraints across the Midwest.[34] The portfolio also addresses 924 reliability violations across the Local Resource Zone (LRZ) 1.[35]

- **Economic Efficiency** – The $21.8 billion portfolio has a benefit-to-cost ratio of 1.8 to 3.5 under Future 2A.[36] This means every dollar invested in transmission will result in economic benefits of $1.8 to $3.5 dollars. Per MISO's analysis the LRTP Tranche 2.1 is expected to provide net economic savings of $23.1 billion to $72.4 billion over the first 20 years of service.[37]

- **Policy** – Alleviates congestion and enables interconnection of approximately 115.7 GW of primarily carbon-free resources[38] to reduce Midwest CO_2 emissions by 127 million metric tons to 199 million metric tons over 20 to 40 years to help states like Minnesota comply with decarbonization laws.[39] This also provides $7.2 billion to $9.0 billion in decarbonization benefits over a 20- to 40-year period.[40]

A copy of MISO's full MTEP24 report can be found in **Appendix E-1**.

[33] **Appendix E-1** at 26 (MTEP24 Report).

[34] **Appendix E-1** at 49, Figure 2.19 (MTEP24 Report).

[35] **Appendix E-1** at 98, Figure 2.81 (MTEP24 Report).

[36] **Appendix E-1** at 144, Figure 2.137 (MTEP24 Report).

[37] **Appendix E-1** at 144, Figure 2.137 (MTEP24 Report). Net savings are 20-year NPV in 2024$.

[38] **Appendix E-1** at 95 (MTEP24 Report).

[39] **Appendix E-1** at 161 (MTEP24 Report).

[40] *Id.*

4.2.7 MISO Futures Development

As part of each MTEP cycle, MISO and its stakeholders engage in a robust process to develop a range of forward-looking scenarios, or Futures, which forecast multiple paths and timelines for states and utilities to meet their energy goals. The Futures are designed to "bookend" the potential range of future economic and policy outcomes, ensuring the actual future is within the range of the Futures. These Futures, which envision system conditions 20 years into the future, are then used to assess and identify transmission needed to deliver the necessary energy reliably and efficiently from generation resources to customers.

As part of Tranche 1 of the LRTP initiative, MISO collaborated with stakeholders to develop the three future planning scenarios, which are now referred to as the Series 1 Futures. These Series 1 Futures were developed over an 18-month period beginning in mid-2019 through the end of 2020 and were the foundation of the LRTP Tranche 1 analysis.

Following MISO's approval of the LRTP Tranche 1, members' and states' plans were refined, new legislation and policies took effect, and prices, along with incentives for various resources, saw significant changes.[41] These developments required MISO to update the Series 1 Futures with the latest data while maintaining their original number and defining characteristics. To help distinguish the updated Futures from the original Series 1 Futures, the "refreshed" set is referred to as the Series 1A Futures. The effort to refresh the Futures began during the summer of 2022 and concluded during the fall of 2023. Results from the Series 1A refresh continue to reflect a significant fleet transition over the next 20 years. However, compared to the Series 1 Futures, the Series 1A Futures reflect an increase in the pace of the generation transition.

Three different futures were developed as part of the Series 1A Futures used to evaluate Tranche 2.1: Future 1A, Future 2A, and Future 3A. For Tranche 2.1, MISO determined Future 2A is "most aligned with an optimized, least-cost expansion that meets member goals."[42] Future 2A incorporates 100 percent of utility IRPs and announced state and

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[41] **Appendix E-3** at 4 (MISO Futures Report: Series 1A).

[42] **Appendix E-1** at 30 (MTEP24 Report).

utility goals within their respective timelines. MISO also evaluated need under Future 1A – the "low bookend" scenario - which assumes only 85 percent of announced state and utility goals are met. [56] Future 2A was the focus of MISO's LRTP Tranche 2.1 analysis.[43] Unless noted otherwise, the Applicants' analysis in this Application is performed using Future 2A. **Appendix E-3** "MISO Futures Report: Series 1A" provides a detailed description of each of these three futures.[44] A summary of the key assumptions for each of the Series 1A Futures is shown in **Figure 4-4**, **Figure 4-4** Summary of MISO Futures

Figure 4-5**, and Figure 4-6**.

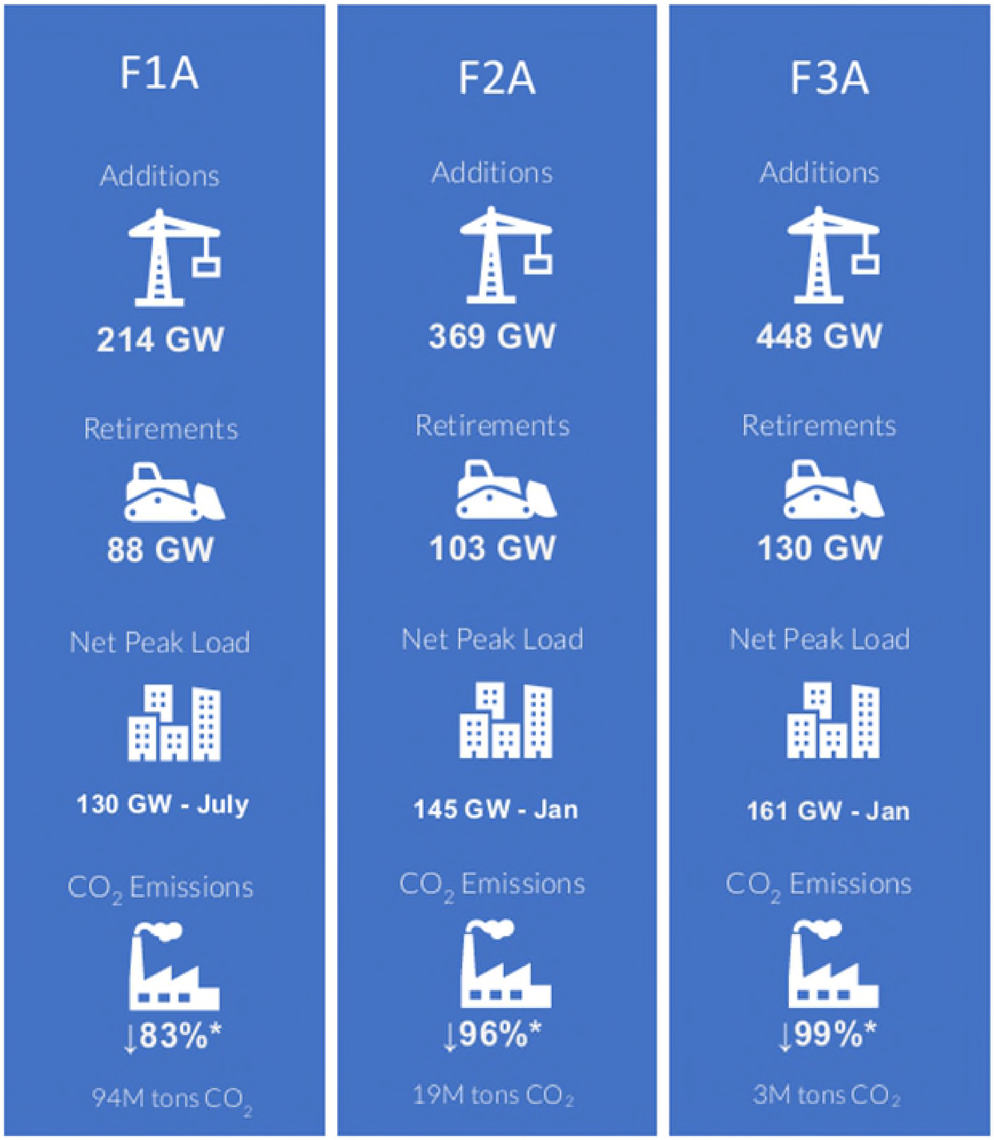
[43] **Appendix E-3** at 4 (MISO Futures Report: Series 1A).

[44] **Appendix E-3** (MISO Futures Report: Series 1A).

Figure 4-4
Summary of MISO Futures[45]

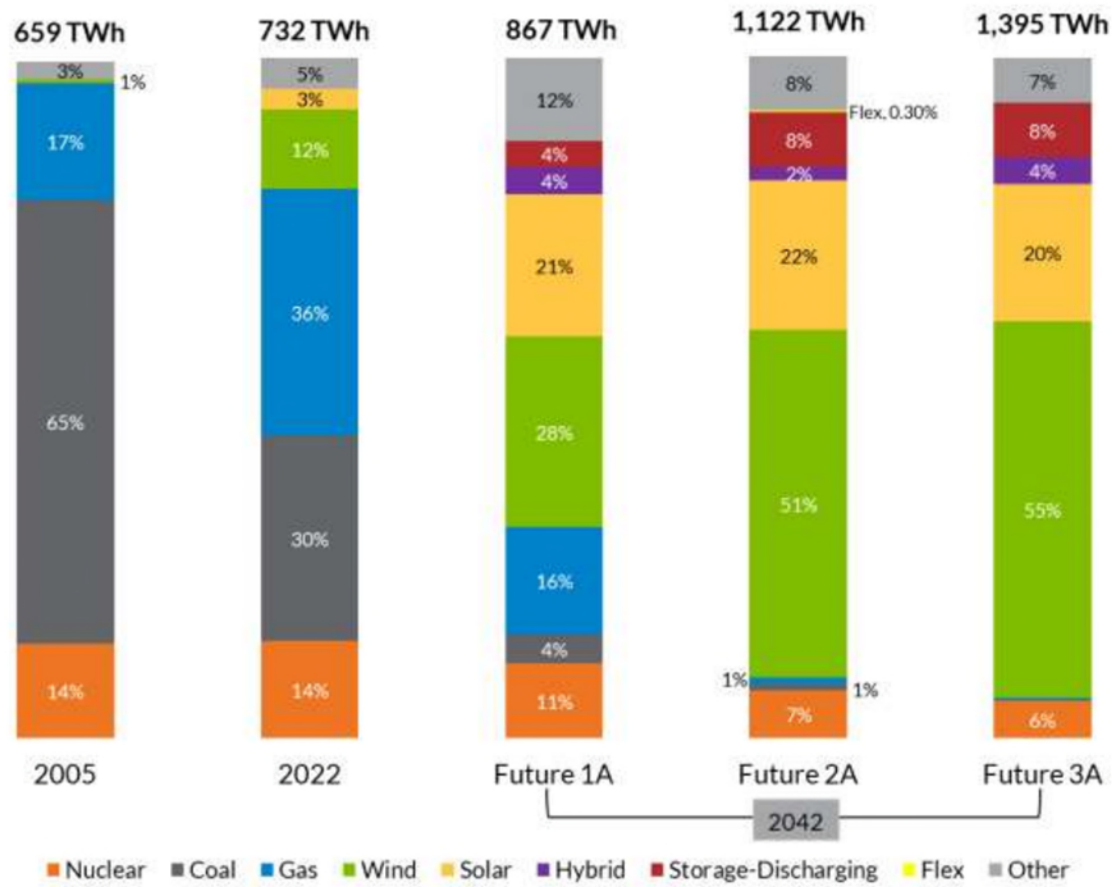
[45] **Appendix E-1** at 29, Figure 2.4 (MTEP24 Report).

Figure 4-5
Series 1A Futures Generation Assumptions[46]



[46] **Appendix E-3** at 6 (MISO Futures Report: Series 1A Futures).

Figure 4-6
Series 1A Futures Generation Fleet Transitions[47]



As shown in the figures above, the generation assumptions of these three Future scenarios vary to encompass reasonable bookends of the MISO footprint over the next two decades. Future 1A represents a scenario driven by state and MISO members' plans, with demand and energy growth driven by existing economic factors. Future 2A builds upon Future 1A by fully incorporating state and MISO members' plans and includes a significant increase in load driven by electrification. In the final scenario analyzed, Future 3A advances from Future 2A, evaluating the effects of large load

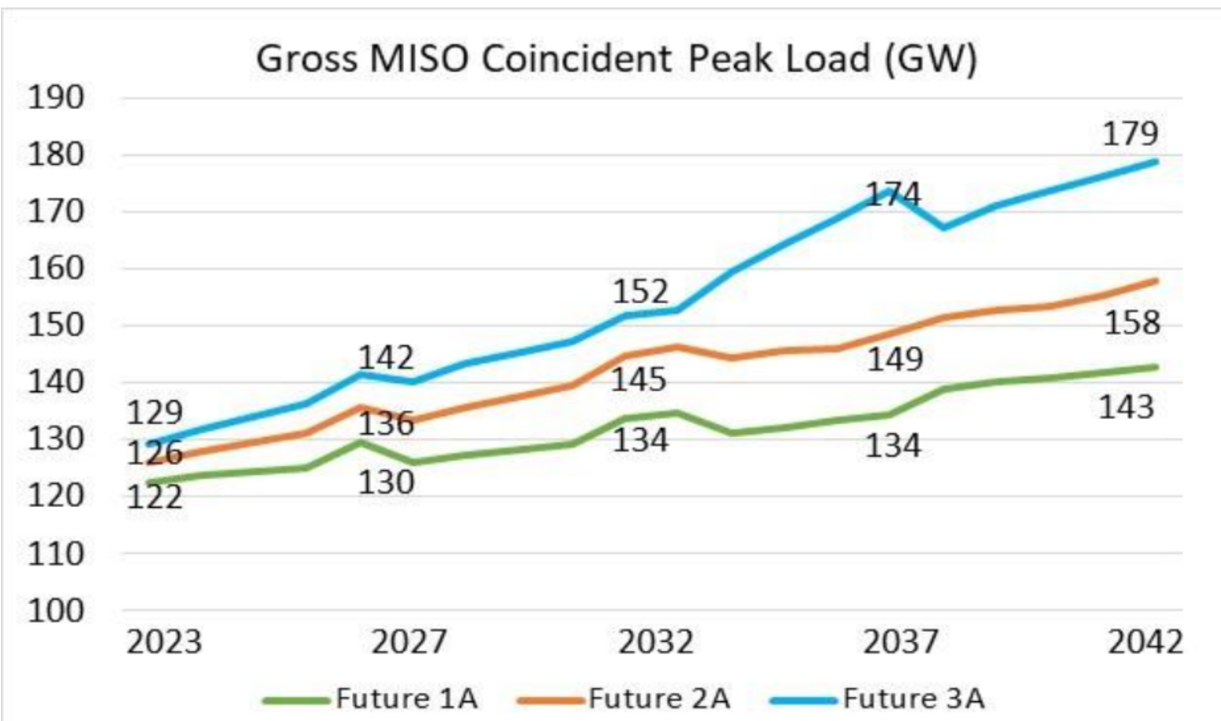
[47] **Appendix E-3** at 5 (MISO Futures Report: Series 1A Futures).

increases due to electrification, increased penetration of wind and solar, and decarbonization.[48]

The MISO Series 1A futures also considered a range of demand and energy forecasts. MISO's load forecasts consider different rates for demand response, energy efficiency, distributed generation, and electrification. MISO's demand and energy forecasts are developed for each of MISO's 10 LRZs to consider regional differences. MISO's 10 LRZs forecasts are then aggregated to a MISO-wide forecast.

The MTEP24 Futures' gross peak demand and annual energy forecast for the MISO footprint are provided in **Figure 4-7** and **Figure 4-8**.

Figure 4-7
MISO Gross Coincident Peal Load (GW) Forecast by Future[49]



[48] **Appendix E-3** at 11 (MISO Futures Report: Series 1A Futures).

[49] **Appendix E-3** at 33 (MISO Futures Report: Series 1A Futures).

Figure 4-8
MISO Gross Annual Energy (TWh) Forecast by Future[50]

4.2.8 Summary of Need for LRTP Tranche 2.1

To identify the transmission projects for Tranche 2.1, MISO performed reliability and economic analyses. The purpose of reliability analysis is to ensure the transmission system can reliably deliver energy from future generation resources to future loads under a range of projected load and dispatch patterns associated with the Future 2A scenario in the 10-year and 20-year time horizons. The purpose of the economic analysis is to identify issues like congestion, generation curtailment, widespread price separation, and price to serve load. The reliability analysis and economic analysis are iterative processes that are coordinated with each other to determine cost-effective and reliable solutions. MISO's Tranche 2.1 study work focused on resource changes contemplated by Future 2A. The reliability and economic issues identified through this study work ensured that the Tranche 2.1 portfolio of projects is a no-regrets and stand-alone first step towards the transmission required to enable Future 2A.[51]

[50] **Appendix E-3** at 33 (MISO Futures Report: Series 1A Futures).

[51] **Appendix E-1** at 41 (MTEP24 Report).

MISO's economic and reliability analysis of Future 2A showed significant congestion across the Midwest, with widespread price separation and generation curtailment, along with significant levels of overload on lower and higher voltage equipment and decreased reactive support across the system. MISO's analysis also found that the addition of generation located further away from load requires longer-distance transmission lines, and the lower stability limits of these lines increase stress on the system. Similar results were seen in MISO's economic analysis with the widespread locational marginal price separation due to lack of a regional high-voltage backbone. MISO also found that there were opportunities to provide additional benefits by resolving energy losses from power transfers on existing transmission and by mitigating economic congestion on the system.[52]

4.2.8.1 Reliability Need

MISO's reliability analysis found that the West Region needs more higher voltage transmission facilities to support large power transfers and to deliver generation from remote areas to load centers.[53] Under the Future 2A scenario, MISO's analysis showed significant overloads and curtailments. In fact, 20 percent of facilities were overloaded, curtailments exceeded 15 percent, and energy losses from transmission lines increased from 2.5 percent to 11 percent under the Future 2A scenario. **Table 4-1** summarize these reliability issues.

Table 4-1
West Region – Reliability and Economic Issues[54]

kV	Reliability Issues		Economic Issues	
	Unique Overloads	Max Loading	Unique Needs	Binding Hours
345	66	206	28	1,000 – 4,000
230	41	208	17	150 – 4,100
<200	496	263	76	50 – 6,000

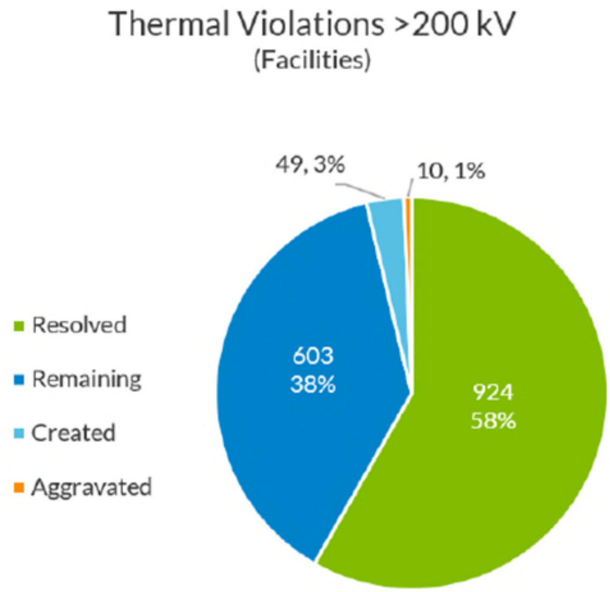
[52] **Appendix E-1** at 41 (MTEP24 Report).

[53] **Appendix E-1** at 52 (MTEP24 Report).

[54] **Appendix E-1** at 52 (MTEP24 Report).

MISO concluded that the LRTP Tranche 2.1 Portfolio resolves over half of the thermal and voltage reliability violations on all voltage levels within LRZ1.[55] Within LRZ1, the Tranche 2.1 Portfolio resolves 924 thermal violations as shown in **Figure 4-9**.[56]

Figure 4-9
Thermal Constraints Resolved in LRZ1[57]



Overall, the MISO LRTP Tranche 2.1 Portfolio is needed to ensure that the MISO transmission grid can continue to reliably deliver energy from future generation resources to future load under a range of projected system conditions associated with the Future 2A scenario in the 10-year and 20-year time horizons. The LRTP Tranche 2.1 Portfolio is needed to prevent numerous thermal and voltage reliability issues across the MISO footprint as summarized on **Figure 4-10**.

[55] **Appendix E-1** at 98 (MTEP24 Report).

[56] **Appendix E-1** at 98, Figure 2.81 (MTEP24 Report).

[57] **Appendix E-1** at 98, Figure 2.81 (MTEP24 Report).

Figure 4-10
MISO Summary of Reliability Issues[58]

RELIABILITY ISSUES

WEST

- 20% of the facilities were found to be overloaded
- Annual curtailments exceeded 40%
- Energy losses over transmission lines increased from 2.5% to 11%

kV	Unique overloads	Max loading%
345	66	206
230	41	208
<200	496	263

CENTRAL

- 10% of the facilities were found to be overloaded
- Annual curtailments exceeded 15%
- Transmission enabled transfer of regional power
- Needs were refined through transfer sensitivities and multi-element contingencies

kV	Unique overloads	Max loading%
345	21	171
230	13	142
<200	158	191

EAST

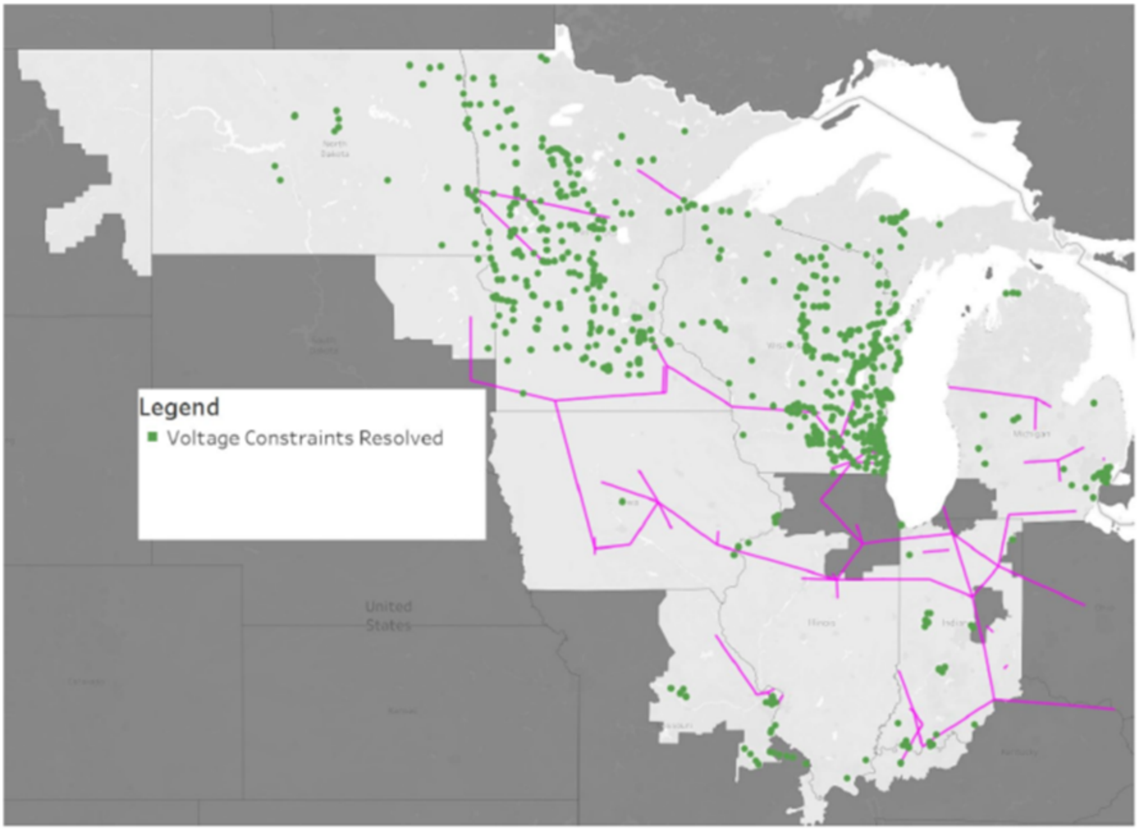
- 10% of the facilities were found to be overloaded
- Annual curtailments exceeded 15%
- Transmission supported daily and nightly import / exports

kV	Unique overloads	Max loading%
345	7	113
<200	159	223

Figure 4-11 summarizes the voltage constraints that were relieved by the LRTP Tranche 2.1 Portfolio.

[58] **Appendix E-1** at 49, Figure 2.19 (MTEP24 Report).

Figure 4-11
Voltage Constraints Resolved by LRTP Tranche 2.1 Portfolio[59]



4.2.8.2 Enabled Generation

MISO's analysis shows that the LRTP Tranche 2.1 Portfolio supports the reliable interconnection of approximately 115.7 GW of new generation in addition to the 20.1 GW of generation previously enabled with the Tranche 1 Portfolio.[60] As shown in **Table 4-2** and **Table 4-3**, of the capacity supported by the LRTP Tranche 2.1 Portfolio, 32.1 GW is in Minnesota and the surrounding region (MISO LRZ 1).[61]

[59] **Appendix E-1** at 86, Figure 2.65 (MTEP24 Report).

[60] **Appendix E-1** at 95 (MTEP24).

[61] **Appendix E-1** at 95 (MTEP24 Report).

Table 4-2
Generation Enabled by Tranche 2.1 by Resource Type

Resource Type	GW
Storage	15.4
Gas & Flex	16.9
Solar	14.1
Hybrid	1.2
Wind	68.1
Total	**115.7**

Table 4-3
Generation Enabled by the Tranche 2.1 by Resource Zone[62]

Resource Zone	GW
LRZ 1	32.1
LRZ 2	9.5
LRZ 3	27.4
LRZ 4	16.1
LRZ 5	2.8
LRZ 6	16.6
LRZ 7	11.2
Total	**115.7**

As shown in **Figure 4-12**, the Tranche 2.1 Portfolio also reduces generation curtailment across the MISO Midwest Subregion by 11.2 percent (27.1 million MWh), including a reduction of 16.1 percent (31.6 million MWh) in the MISO West Region.

[62] **Appendix E-1** at 95, Figure 2.78 (MTEP24 Report).

Figure 4-12
Year 20 Curtailment of Energy from Reference Case to Change Case[63]

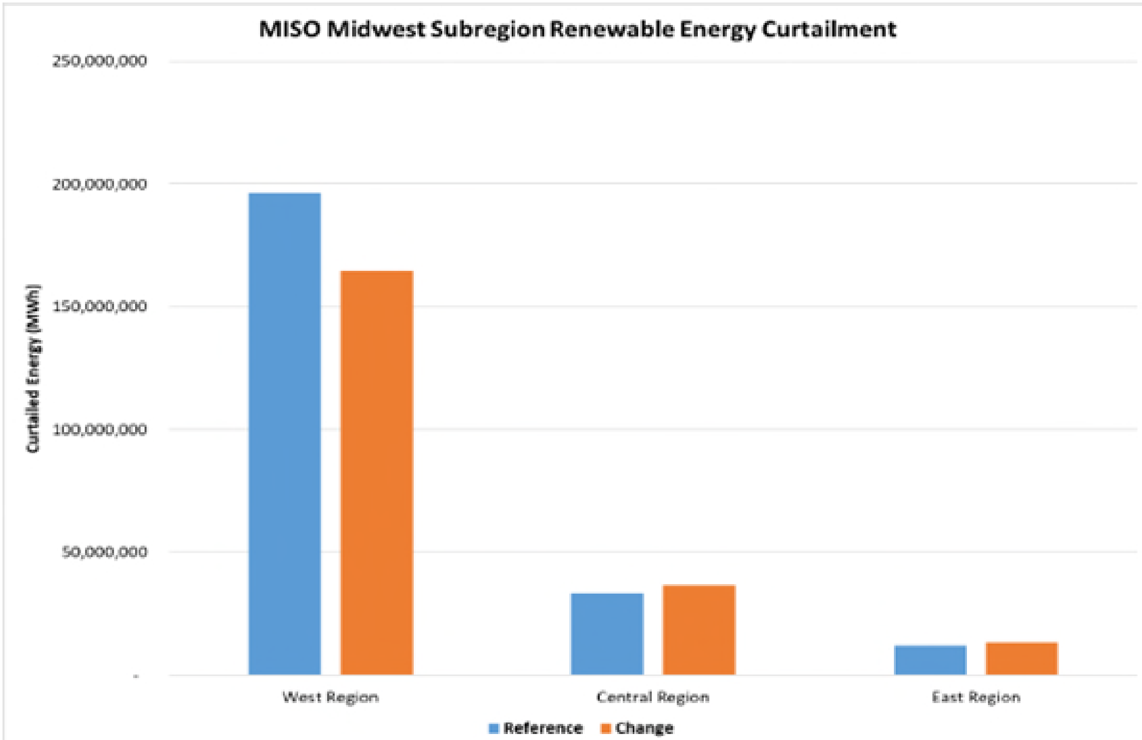
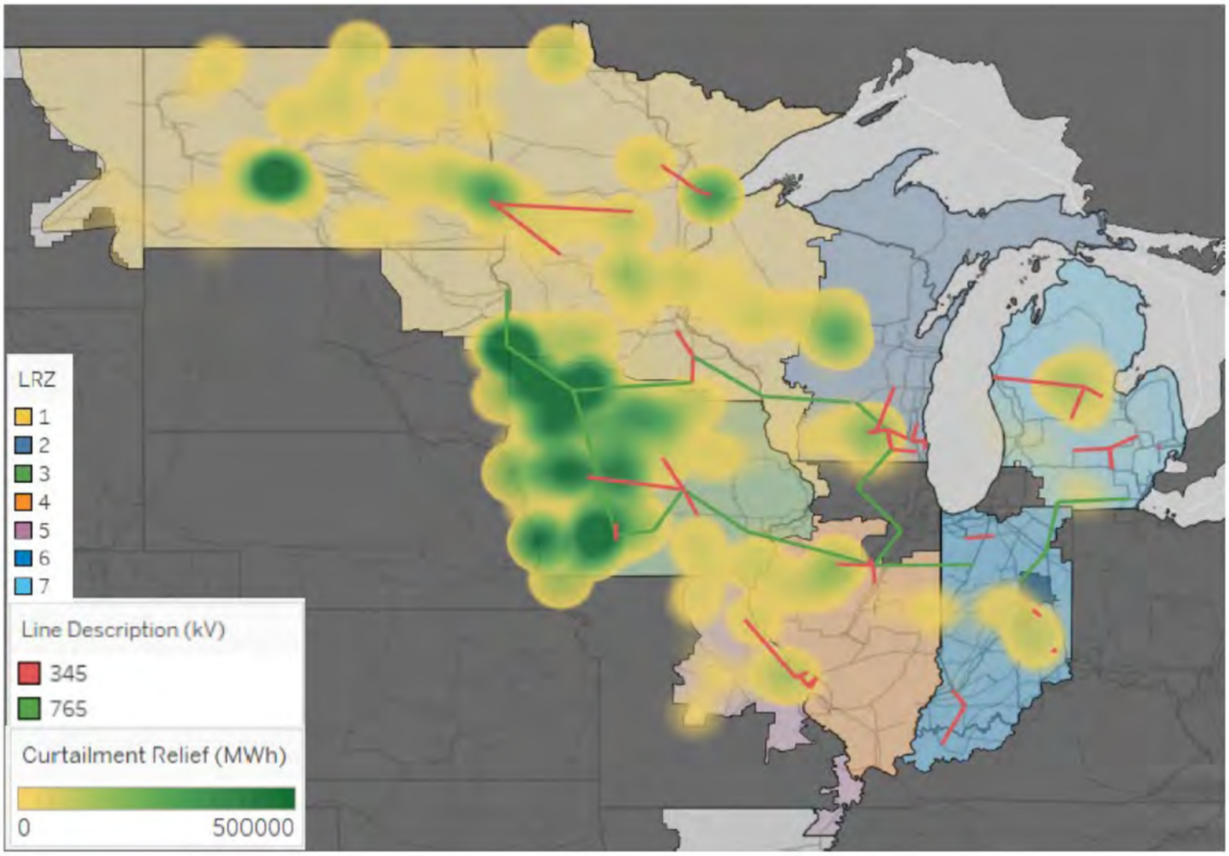


Figure 4-13 shows the curtailment reduction achieved by the Tranche 2.1 Portfolio. The redlines on this figure depict the 345 kV facilities that are part of the Tranche 2.1 Portfolio, including the Project, and the significant curtailment relief provided in northwestern Minnesota and central North Dakota as a result of these new 345 kV facilities.

[63] **Appendix E-1** at 93, Figure 2.75 (MTEP24 Report).

Figure 4-13
Generation Curtailment Relieved by the LRTP Tranche 2.1 Portfolio[64]



The generation supported by the LRTP Tranche 2.1 Portfolio is expected to reduce CO_2 emissions by 127 million metric tons over the first 20 years of service and 199 million metric tons over the first 40 years of service.[65] The LRTP Tranche 2.1 Portfolio is expected to result in approximately $7.2 billion to $9.0 billion in carbon reduction benefits across the MISO footprint over the first 20 to 40 years these projects are in service.[66]

[64] **Appendix E-1** at 93, Figure 2.74 (MTEP24 Report).

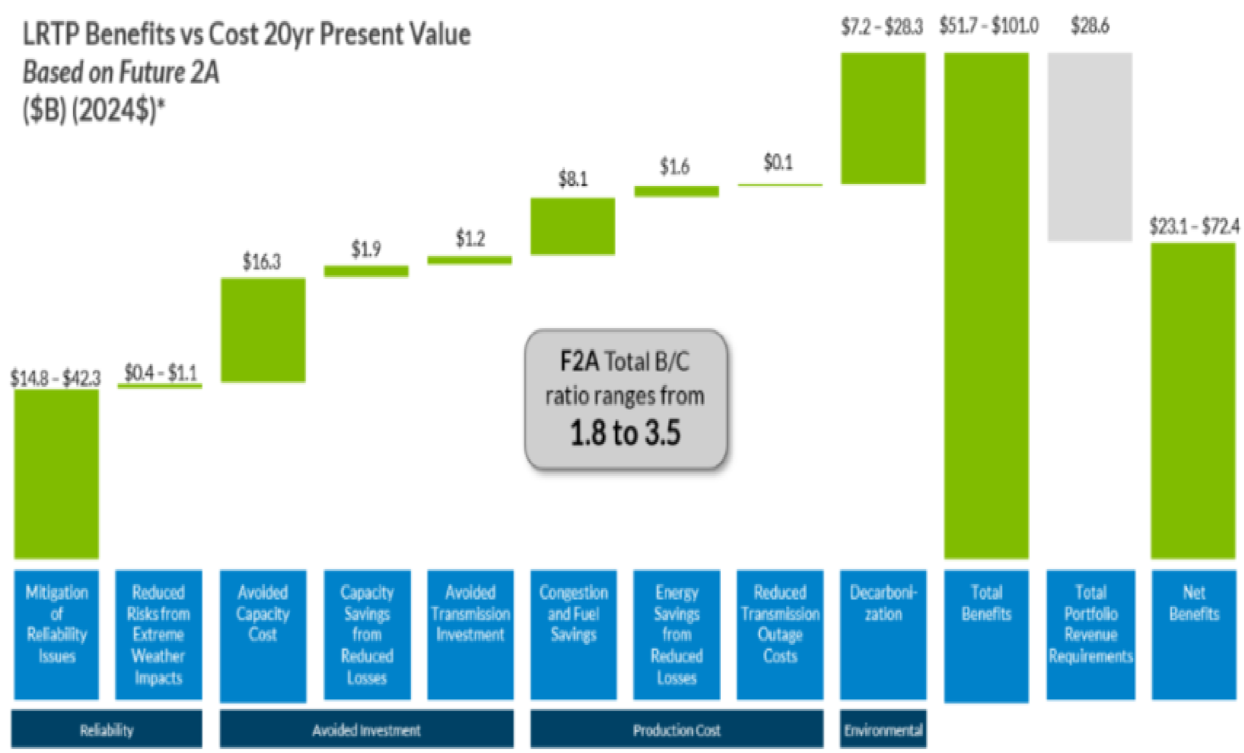
[65] **Appendix E-1** at 161 (MTEP24 Report).

[66] **Appendix E-1** at 161 (MTEP24 Report).

4.2.8.3 Cost-Effectiveness

MISO evaluated the economic benefits of the LRTP Tranche 2.1 portfolio under the Future 2A assumptions.[67] Under the Future 2A scenario, the MISO LRTP Tranche 2.1 Portfolio will provide net economic savings estimated at $23.1 billion to $72.4 billion over the first 20 years of service, as shown in **Figure 4-14**.[68] MISO estimates these projected savings will offset the capital cost of the MISO LRTP Tranche 2.1 Portfolio by a ratio of 1.8 to 3.5, meaning net savings are expected relative to what would be needed without the MISO LRTP Tranche 2.1 Portfolio under the Future 2A scenario.[69]

Figure 4-14
Economic Savings from the MISO LRTP Tranche 2.1 Portfolio Under Future 2A[70]



67 **Appendix E-1** at 144 (MTEP24 Report).

68 *Id.*

69 *Id.*

70 **Appendix E-1** at 144, Figure 2.137 (MTEP24 Report).

As shown in **Figure 4-14,** MISO quantified the economic savings of the LRTP Tranche 2.1 Portfolio using nine different metrics. The inclusion of each metric is approved in MISO's federally approved tariff and further supported by FERC Order 1920.

In MTEP24, MISO also estimated the potential economic development impacts of the Tranche 2.1 investments by conducting a survey of literature on the impacts of transmission investment on direct jobs, total jobs, and total economic output. MISO concluded that the Tranche 2.1 investments are estimated to power roughly 22,000 to 65,000 direct jobs within the MISO region.[71] These jobs are also high-quality jobs, with wages estimated to be about 30% higher than a typical worker's wages. MISO also found that the Tranche 2.1 investments are estimated to power between 44,000 and 131,000 total jobs in the MISO region and between $4 and $24 billion in total economic output.[72]

4.2.8.4 Other Qualitative Benefits

The LRTP Tranche 2.1 Portfolio also provides multiple other qualitative benefits. MISO expects the addition of the LRTP Tranche 2.1 Portfolio will increase operational flexibility to better allow timely outage scheduling to maintain the reliability of the system and reduce the economic impact due to congestion caused by outages. The operational flexibility also helps reduce the economic impacts of natural gas price changes by providing access to a broader pool of generation resources.[73]

The LRTP Tranche 2.1 Portfolio also gives more flexibility to better support diverse policy needs. The proactive long-range approach to planning regional transmission provides regulators greater confidence in achieving policy goals by reducing uncertainty around future resource expansion plans. Elimination of much of the high transmission cost barriers allows resource planners to assume less risk in making resource investment decisions.

[71] **Appendix E-1** at 169 (MTEP24 Report).

[72] **Appendix E-1** at 169 (MTEP24 Report).

[73] **Appendix E-1** at 160 (MTEP24 Report).

4.2.9 MISO's Summary of Need for the Project

The MISO LRTP Tranche 2.1 Portfolio was developed as a portfolio of projects designed to work together. MISO identified that the Project is a critical component of the LRTP Tranche 2.1 Portfolio and also the most effective option to maintain regional reliability in western and central Minnesota and eastern North Dakota. MISO summarized the need for the Project, along with other Northern Minnesota projects (Project 20 and Project 21, shown in **Figure 4-15**) as follows:

> The 345 kV projects in Northern Minnesota (indicated by the dashed red lines in the map below) resolve more than 50% of the constraint violations for both the 200 kV above and below systems. The Northern Minnesota group provides outlets to North Dakota generation, resolves constraint violations in this area and connects to Tranche 1 lines. Congestion in Northern Minnesota is reduced and the increased generation outlet in North Dakota, South Dakota, and Minnesota shifts congestion to new flowgates, which are addressed with the portfolio.[74]

Figure 4-15
Northern Minnesota LRTP 2.1 Projects[75]

[74] **Appendix E-1** at 100 (MTEP24 Report).

[75] **Appendix E-1** at 100 (MTEP24 Report).

MISO's analysis identified that the Northern Minnesota projects addressed many of the thermal and voltage issues identified in northern Minnesota and eastern North Dakota. Specifically, MISO found:

> There is a significant reduction in the loadings in northern Minnesota and eastern North Dakota because of the portfolio. The top 20 lines with the most reduction in the loadings are shown in [**Table 4-4**]. The criteria for selecting these lines were a combination of the number of violations resolved as well as the degree of reduction in loadings. The third column shows the highest loading for these elements in the models without the portfolio, and the fourth column shows the highest loadings after applying the portfolio. The top resolved facilities are also displayed geographically in [**Figure 4-16**].[76]

Table 4-4
Top Loading Resolved by the Northern Minnesota Projects[77]

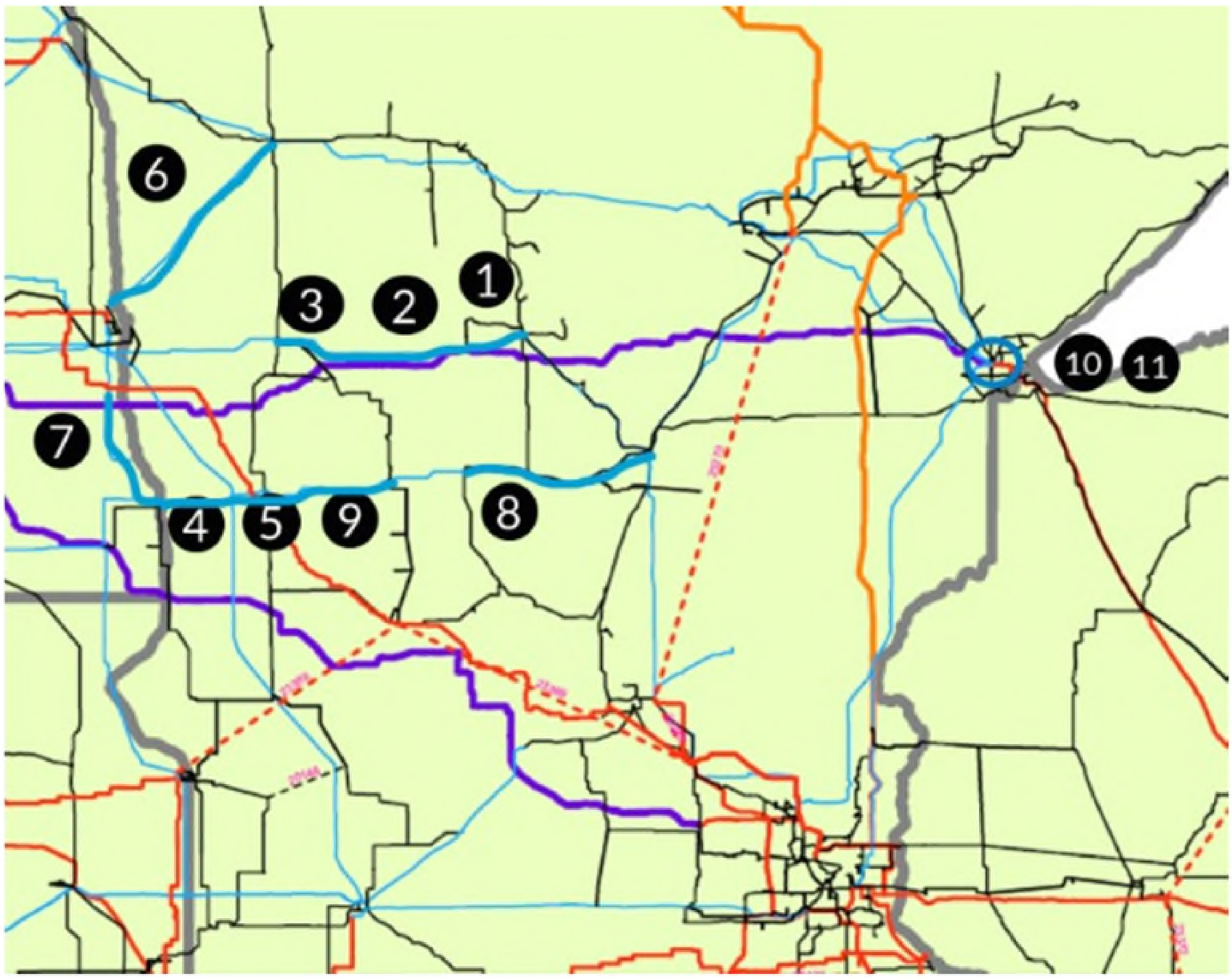
#	Element	Initial Worst Loading %	Final Worst Loading %
1	[MP] Badoura-[GRE] Hubbard 230 kV	138	84
2	[GRE] Hubbard-[OTP] Erie Jct 230 kV	121	78
3	[OTP] Erie Jct-[OTP] Audubon 230 kV	124	83
4	[OTP] Wahpeton-[MRES] Fergus Falls 230 kV	124	84
5	[GRE] Silver Lake-[MRES] Fergus Falls 230 kV	107	74
6	[MPC] Maple River-[MPC] Winger 230 kV	124	66
7	[OTP] Wahpeton-[MPC] Frontier 230 kV	110	51
8	[MP] Rivertone-[GRE] Wing River 230 kV	123	74
9	[GRE] Silver Lake-[GRE] Henning 230 kV	104	68
10	[MP] Hibbard-[MP] Winter St. 115 kV	243	97
11	[MP] Dahlberg-[MP] Stinson 115 kV	211	Reconfigured
12	[XEL] Sheyenne-[WAPA] Fargo 230 kV	130	56
13	[XEL] Sheyenne-[OTP] Maple River 230 kV	114	51
14	[MP] Fairmount Park-[MP] Winter St. 115 kV	259	95
15	[MP] Fairmount Park-[MP]Stinson 115 kV	230	74
16	[OTP] Wilton-[OTP] Scribner 115 kV	126	86

76 **Appendix E-1** at 100 (MTEP24 Report).

77 **Appendix E-1** at 100-101 (MTEP24 Report).

17	[OTP] Wilton Tap-[OTP] Scribner 115 kV	123	86
18	[OTP] Solway-[OTP] Wilton Tap 115 kV	114	81
19	[XEL] Wakefield-[XEL] Stockade Tap 115 kV	111	90
20	[MP] Arrowhead-[MP] Gary 115 kV	123	74

Figure 4-16
Top Reliability Constraints Resolved by Northern Minnesota Projects[78]



MISO's analysis also demonstrated that the northern Minnesota projects improved the deliverability of generation from western Minnesota, North Dakota, and South Dakota to load centers in northern Minnesota and central Minnesota. MISO summarized its findings as follows:

[78] **Appendix E-1** at 101 (MTEP24 Report).

These projects reduce congestion overall, and reduce congestion on the most heavily congested flowgate in LRZ1. The increase in energy delivery shifts the dispatch throughout LRZ1, and some congestion shifts to different flowgates associated with more localized issues.

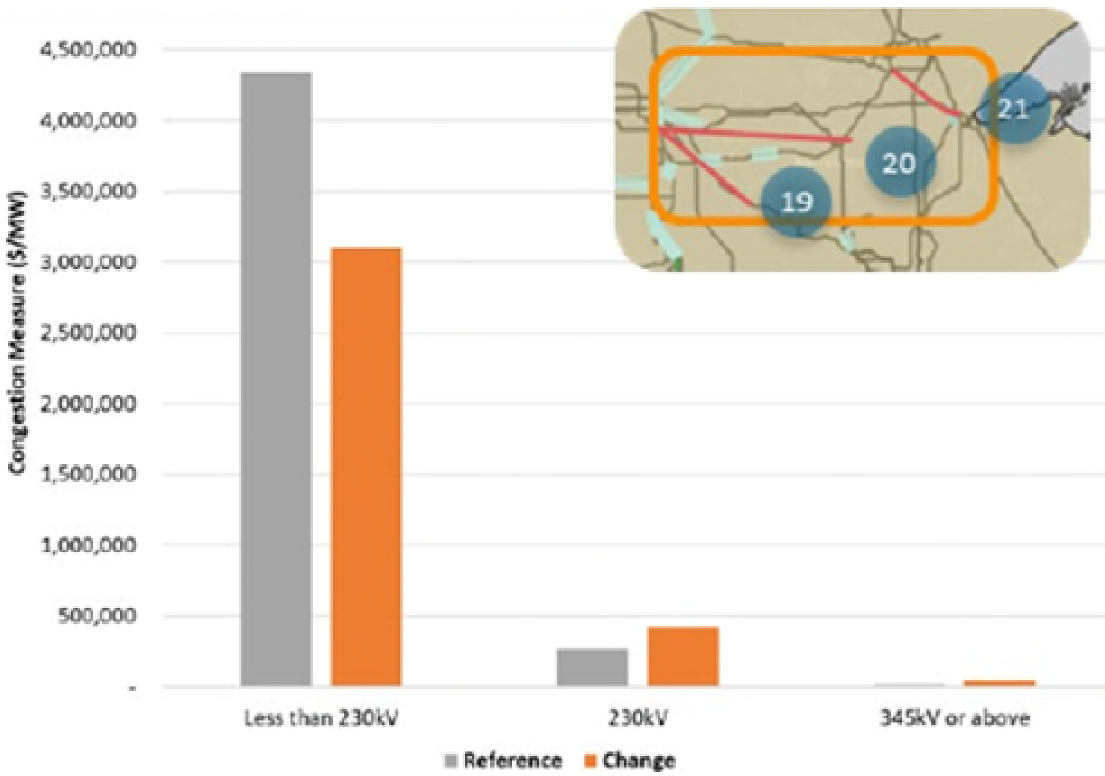
[**Table 4-5**] shows top relieved flowgates ranked by congestion measure relief for projects 19, 20, & 21. The combined congestion measure impact for flowgates assessed for projects 19, 20, & 21 is shown in [**Figure 4-17**].[79]

Table 4-5
Top Relieved Flowgates – Projects 19, 20, and 21

Top Relieved Flowgates	Congestion Measure ($/MW) Reference	Change Case	Total Relief
Event 1117: **[MP] HIBBARD-[MP] WNTR ST 115 kV 1**	1,621,984	876,000	745,984
Event 270: [NSP] CASS CO7-[NSP] REDRIVR7 115 kV 1	158,693	-	158,693
Event 192: [MP] LONG PR7-[GRE] GRE-LTLSKTP7 115 kV 1	454,591	329,864	124,727
Base Case: [NSP] CASS CO7-[NSP] REDRIVR7 115 kV 1	112,246	-	112,246
Event 1033: [MP] AITKNMN7-[GRE] GRE-AITKIN 7 115 kV 1	47,573	-	47,573
Event 586: [GRE] GRE-INMAN 4-[GRE] GRE-WINGRIV4 230 kV 1	64,442	24,550	39,892
Event 1355: [MP] CLOQUET7-[MP] CANOSIA7 115 kV 1	58,902	19,317	39,585
Event 1391: [NSP] CASS CO7-[NSP] REDRIVR7 115 kV 1	38,318	-	38,318
Event 1045: [MP] FLDWDTP7-[MP] MDWLNDS7 115 kV 1	31,812	-	31,812
Event 592: [NSP] SHEYNNE4-[OTP] LAKE PARK T4 230 kV 1	40,486	11,028	29,457

79 **Appendix E-1** at 102 (MTEP24 Report).

Figure 4-17
Congestion Measure for Projects 19, 20, and 21[80]



Based on its evaluation, MISO determined that the Project was an important component of the overall LRTP Tranche 2.1 Portfolio to ensure a reliable, resilient, and cost-effective transmission system as the generation mix within the MISO footprint continues to evolve to include more renewables. The Project, along with the entire LRTP Tranche 2.1 Portfolio, was approved by the MISO Board of Directors in December 2024.

4.3 Applicants' Analysis of Need

In addition to MISO's need analysis, Xcel Energy, on behalf of the Applicants, further examined system reliability improvements related to the Project and conducted additional economic analyses. These analyses, described in the following sections,

[80] **Appendix E-1** at 102 (MTEP24 Report).

focused on the Project under a variety of modeling assumptions to further illustrate the incremental benefits of the Project.

4.3.1 Applicants' Reliability Need Analysis

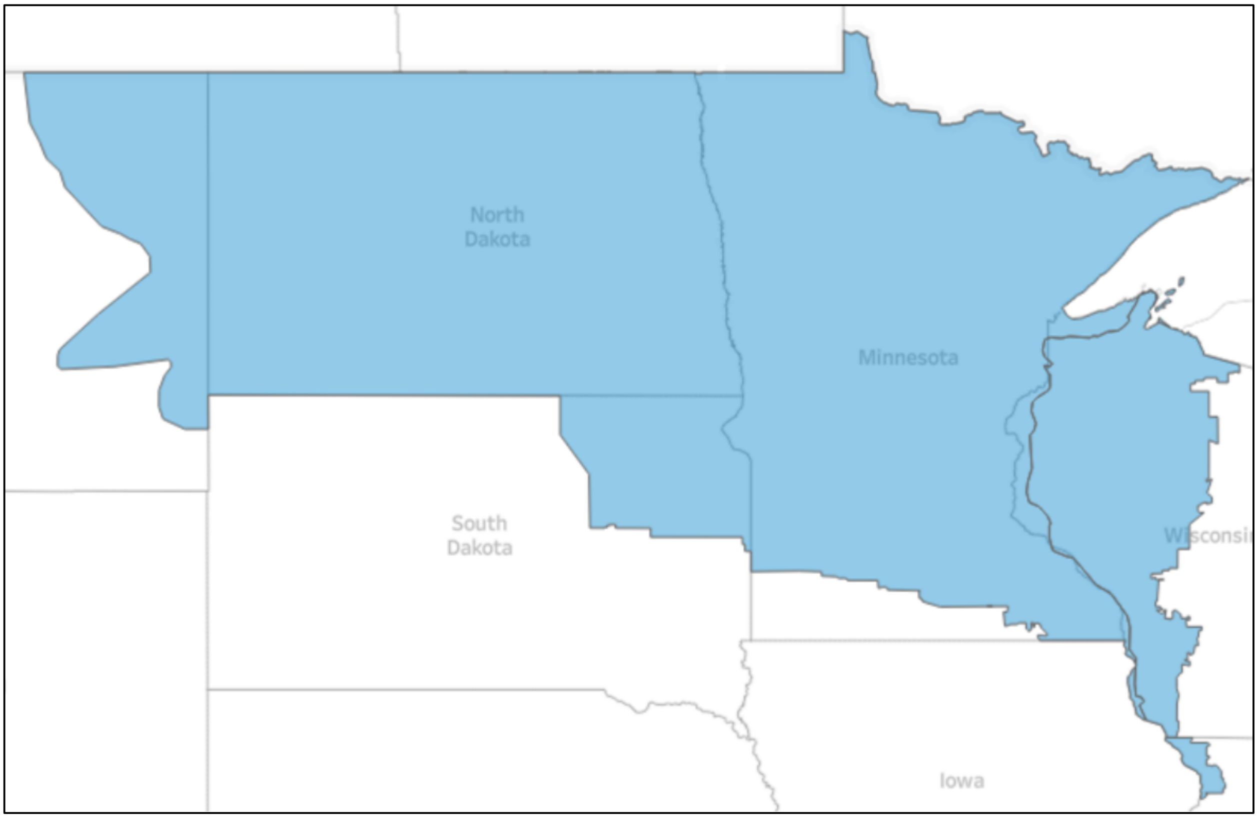
As discussed in Section 4.2.6, MISO's reliability analysis concluded that construction of the Project and LRTP2.1 Portfolio addressed many of the thermal and voltage issues in western/central Minnesota and eastern North Dakota and South Dakota by providing additional capacity to relieve the currently constrained 230 kV and 115 kV system.

In addition to the reliability analysis conducted by MISO, the Applicants further examined system reliability improvements yielded by the Project based on the most current assumptions on transmission topology and generation retirements and additions contained in MISO's most current transmission system model (MTEP25). As demonstrated in the following sections, the Applicants' analysis further confirms MISO's reliability analysis that the Project is needed to uphold reliability in western and central Minnesota and eastern North Dakota and South Dakota.

The Applicants conducted analyses based on the MISO LRTP Tranche 2.1 (at year 20) to show improvements to system reliability related to the Project in the future when additional generation is online.

For both analyses, Applicants studied reliability in the MISO Local Resource Zone 1 (LRZ1) area, which is shown in **Figure 4-18**.

Figure 4-18
MISO Local Resource Zone 1



The analyses looked at transmission system performance using Summer Peak and Shoulder Light Load models, which represent the most stressed conditions for this portion of the transmission system. The Project is designed to alleviate constraints on the existing 230 kV and 115 kV transmission systems in western Minnesota and neighboring states, which play a key role in delivering energy into Minnesota and are currently at capacity. The existing systems are particularly stressed under light load conditions, generally defined as 70 to 80 percent of Peak Summer load, combined with high wind conditions. When there is high wind generation available without peak demand to consume that energy, considerable stress is placed on certain elements of the transmission system.

Reliability analyses studied all NERC contingency categories (P1-P7) and looked at facility overloads under a variety of transmission system modeling assumptions, including the following:

- "LRTP2.1 no LRTP19" – assuming construction of all LRTP Tranche 2.1 projects except the Project; and
- "LRTP Tranche 2.1" – assuming construction of all LRTP Tranche 2.1 projects.

While LRTP Tranche 2.1 is a portfolio of 24 individual projects designed to work together to provide benefits, the Applicants' reliability analyses provides an alternative way to look at the reliability improvements resulting from the Project. The results of the reliability studies are provided in the following sections and illustrate which overloads are remedied with implementation of the Project.

4.3.1.1 MTEP LRTP 2.1 – Reliability Results

Applicants conducted an analysis for the LRZ1 area based on the MISO LRTP Tranche 2.1 (at year 20) to show improvements to system reliability related to the construction of the Project in the future when additional generation is online. This analysis shows the impact the Project has under a summer peak model with the added generation that the LRTP Tranche 2.1 Portfolio will enable.

The results of this analysis are provided in **Table 4-6**. The table lists the overloaded facilities and provides the number of different contingencies that cause thermal issues on the overloaded facility for each transmission model studied. The table also includes the "Fixed By LRTP19" column showing the number of thermal issues resolved by the Project. A thermal overload was considered resolved by the Project if the overload showed up in the "Without LRTP19" but not the "Full Tranche 2.1" model.

Table 4-6
Reliability Results LRTP Tranche 2.1 (Year 20)

Overloaded Facility	Area	Contingency Type	LRTP2.1 Summer Peak Without LRTP19	LRTP2.1 Summer Peak Full Tranche 2.1	LRTP2.1 Shoulder Light Load Without LRTP19	LRTP2.1 Shoulder Light Load Full Tranche 2.1	Fixed By LRTP19
Bison - Buffalo 345kV Ckt 1	ND	N-1-1	0	0	3	1	2
Sheyenne - Lake Park 230kV Ckt 1	ND	N-1-1	Base Case	2,461	12	0	2,388
Wahpteton - Frontier 230kV Ckt 1	ND	N-1-1	0	0	2	1	1
Audubon - Lake Park 230kV Ckt 1	ND	N-1-1	Base Case	1,890	14	0	2,961
Wilton - Winger 230kV Ckt 1	ND	N-1-1	4	0	14	0	18
Bison - Maple River 345kV Ckt 1	ND	N-1-1	25	0	0	0	25
Maple River - Winger 230kV Ckt 1	ND	N-1-1	1	0	0	0	1
Audubon - Erie Junction 230kV Ckt 1	ND	N-1-1	26	0	0	0	26

The major reliability benefits of the Project can be seen on the 230 kV system in North Dakota, as well as the parallel 345 kV system in North Dakota. For example, the 230 kV system from Shyenne – Lake Park – Audubon has a large number of thermal issues mitigated with the addition of the Project. There are also areas on the parallel 345 kV system that see reliability benefits, such as the areas around the Bison and Maple River substations The Project will also increase the transmission capacity of the system, allowing for greater transfer capacity and renewable energy outlet from North Dakota into Minnesota.

4.3.2 Applicants' Economic Need Analysis

As discussed in Section 4.2.7.3, under the Future 2A scenario, the MISO LRTP Tranche 2.1 Portfolio will provide net economic savings estimated at $23.1 billion to $72.4 billion over the first 20 years of service.[81] MISO estimates these projected savings will offset the capital cost of the MISO LRTP Tranche 2.1 Portfolio by a ratio of 1.8 to 3.5, meaning net savings are expected relative to what would be needed without the MISO LRTP Tranche 2.1 Portfolio under the Future 2A scenario. On behalf of the Applicants, Xcel Energy conducted economic analyses using PROduction MODeling (PROMOD) software, which is used to support economic transmission planning. The PROMOD software simulates the electric market on an hourly constrained-dispatch basis using models containing generation unit locations and operating characteristics, transmission grid topology, and market system operations. The PROMOD software can calculate the future cost of producing electricity, market congestion, and energy losses based on these assumptions.

The economic analysis was performed in a manner consistent with MISO's analysis of the entire LRTP Tranche 2.1 Portfolio but focused on identifying the economic benefits specifically for the Project. Xcel Energy, on behalf of the Applicants, conducted economic analyses, each comparing PROMOD results under various scenarios to show the incremental benefit of Project to the entire MISO footprint.

The first analysis evaluated the adjusted production cost (APC) savings[82] benefit of the Project to the MISO footprint. The second analysis evaluated the carbon reduction benefits of the Project for the MISO footprint. Each of these analyses is described in detail in the separate subsections below. Both analyses were conducted under MISO Future 2A.

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[81] **Appendix E-1** at 144 (MTEP24 Report).

[82] APC savings are utilized to measure the economic benefits of proposed transmission projects. These savings are calculated as the difference in total production costs of energy for a generation fleet adjusted for import costs and export revenues with and without the proposed transmission project.

As detailed in Section 4.2.8.3, the MISO LRTP Tranche 2.1 Portfolio, which includes the Project, is expected to provide $$23.1 billion to $72.4 billion in net economic savings over the first 20 years of service. MISO quantified nine different economic savings metrics. The Applicants quantified two of MISO's nine metrics for the Project because they can most reasonably be calculated on a Project-specific basis. The omission of the other metrics in the Project's economic benefits should not imply that those metrics are not provided by the Project, only that they were not quantified.

4.3.2.1 Adjusted Production Cost Savings of the Project

Xcel Energy used the PROMOD software to calculate the APC savings benefit of the Project using the MTEP24 Future 2A. **Table 4-7** shows the APC savings benefit on a present value basis over 20 years of the Project using these models. As shown in these tables, the APC savings benefit of the Project to the MISO footprint is up to $76.3 million over the first 20 years of the Project being in-service. Further, the analysis produced a 20-year present value APC savings of $57.51 million for the five Applicants impacted by this Project.

Table 4-7
APC Savings Benefits of the Project under MTEP24 Future 2A Model

Timeline	APC Benefits	MISO	Applicants
20 Year Present Value	APC Benefits ($Millions)	$76.3	$57.51

4.3.3 Applicants' Carbon Reduction Analysis

As discussed in Section 4.2.7.2, one of the benefits of the LRTP Tranche 2.1 Portfolio is a reduction in carbon emissions across the MISO footprint. MISO's PROMOD analysis demonstrated the implementation of the LRTP Tranche 2.1 Portfolio is estimated to reduce carbon emissions by 127 million metric tons over the first 20 years of the LRTP Tranche 2.1 Portfolio being in-service and 199 million metric tons over the first 40 years that the LRTP Tranche 2.1 Portfolio is in service.[83]

MISO also calculated the economic benefit of the carbon reduction or decarbonization enabled by LRTP Tranche 2.1 Portfolio. MISO used two different CO_2 emission prices,

[83] **Appendix E-1** at 161 (MTEP24 Report).

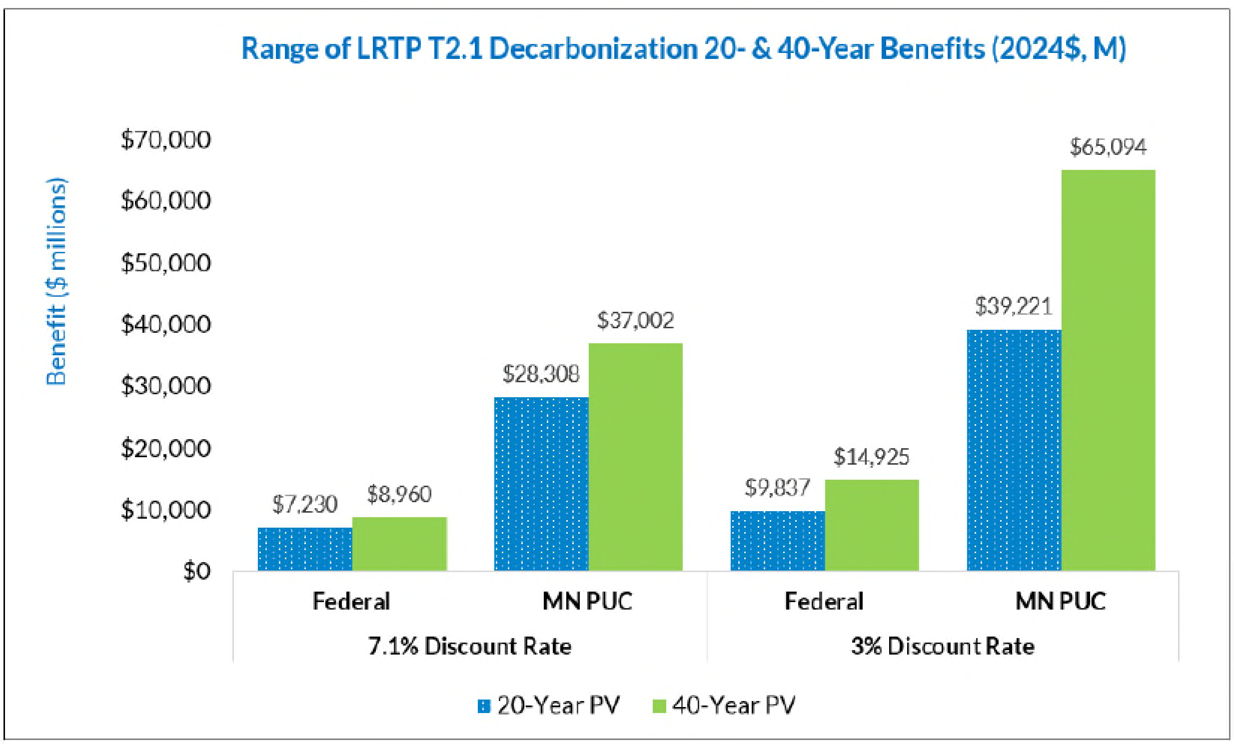
the federal price and the Minnesota Public Utilities Commission price, to estimate a benefit value of decarbonization as shown in **Table 4-8**.

Table 4-8
MISO's Carbon Costs Used for Monetization of Decarbonization Benefits

	Federal	MN PUC
2024$/metric ton	$85	$248.67

This resulted in MISO's decarbonization benefit values of $7.2 billion to $9.0 billion over a 20-to-40-year period as shown on the first set of bars in **Figure 4-19**. Using the Commission's carbon costs, the decarbonization benefits from the Tranche 2.1 Portfolio are higher, ranging from $28.3 million to $37.0 million over the first 20 to 40 years that these projects are in service, as shown on the second set of bars in **Figure 4-19**.

Figure 4-19
MISO's Analysis of LRTP Tranche 2.1 Decarbonization Benefits[84]



[84] **Appendix E-1** at 162, Figure 2.154 (MTEP24 Report).

Xcel Energy, on behalf of the Applicants, also evaluated the carbon reduction benefits of the Project using PROMOD. Xcel Energy's analysis estimated the Project will reduce CO_2 emissions within MISO by approximately 50,000 metric tons over the first 20 years that the Project is in service.

While there is no cost of carbon that is applicable to the entire MISO footprint currently, Xcel Energy used two different carbon costs to determine a range of potential carbon reduction benefits of the Project. Xcel Energy used the same two prices used by MISO (i.e., the Minnesota Public Utilities Commission approved CO_2 costs of $248.67/metric tons [$2024] and a federal cost of carbon of $85/metric ton [$2024]).[85]

Based on these two carbon prices, Xcel Energy found that the Project provides decarbonization benefits ranging from $4.3 million to $12.4 million over the first 20 years that the Project is in service as shown in **Table 4-9**.

Table 4-9
Carbon Reduction PV[86] Benefits of the Project under MTEP24 Future 2A Model

MISO	MN PUC	Federal
2024 $/metric ton	*$248.67*	*$85*
20-Year Benefit ($Millions)	$12.4	$4.3

4.3.4 Congestion and Curtailment Analysis

The LRTP Tranche 2.1 portfolio helps relieve transmission constraints and reduce congestion, enabling more efficient dispatch of lower-cost resources. This improvement translates into significant economic benefits, including congestion and fuel savings estimated at $8.1 billion to $11.3 billion over a 20-year to 40-year horizon as shown in the first set of bars on **Figure 4-20** below.[87]

[85] **Appendix E-1** at 161 (MTEP24 Report).

[86] Present value.

[87]

Figure 4-20
MISO's Analysis of LRTP Tranche 2.1 Congestion and Fuel Savings Benefits[88]

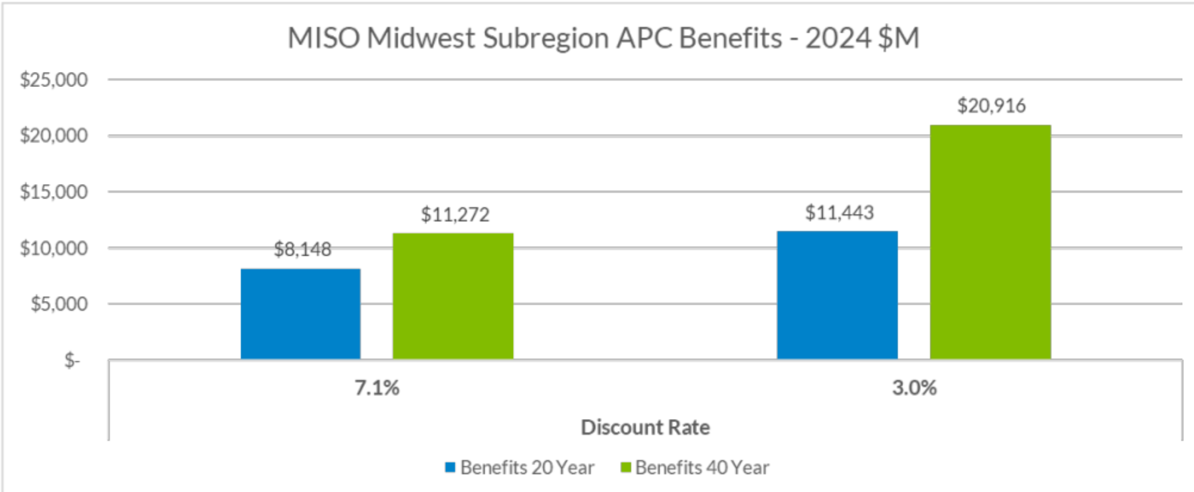


Figure 2.149: Congestion and Fuel Savings Benefit Value

4.4 Estimated System Losses

Energy losses on the transmission system can result in increased costs for utilities and ratepayers due to the need to generate enough energy to adequately serve loads while also accounting for the losses incurred during the transmission of this energy. Each new transmission line that is added to the electric system affects the losses of the system. If a new transmission line reduces transmission losses, utilities will not have to generate as much energy to meet customer demands. Thus, if a new transmission line reduces system losses, then the costs to end-use consumers to provide that energy will also be reduced.

Lower voltage lines tend to have higher losses than higher voltage lines. This is because when the voltage of a line is lowered, the current must be increased to achieve similar power flow. This increases losses because of the correlation between the physical requirements of the transmission line conductor and the amount of current flowing on that conductor.

[88] **Appendix E-1** at 157, Figure 2.149 (MTEP24 Report).

Applicants compared the loss savings achieved by the Project across LRZ1 using the Light cases for the Future 2A, Year 20 (F2Y20) Tranche 2.1 dispatch model and the Shoulder High Wind MTEP25 model set. These cases were used to compare line losses because these cases feature the highest losses due to high wind transfers. Line loss data was pulled for transmission lines within the LRZ1 area (Xcel Energy, Minnesota Power, Southern Minnesota Municipal Power Agency, Great River Energy, Otter Tail, Montana-Dakota Utilities, and Dairyland Power Cooperative). To determine the amount of line losses, the base model with no changes to today's transmission system was compared to the model with the Project added to see the benefits that the Project alone has on line losses. A similar comparison was made with the full LRTP Tranche 2.1 model and the Tranche 2.1 without LRTP19 model. These comparisons were done for both the F2Y20 Tranche 2.1 dispatch and MTEP25 model sets and the results are provided in **Table 4-10**. In conclusion, the Project reduces line losses by an average of 5.45 MW and 25.39 MegaVolt Ampere of reactive power as shown in **Table 4-11**

Table 4-10
Estimated Line Losses

Estimated Line Losses						
Model	**Base Model**	**LRTP 19**	**Delta**	**Tranche 2.1 Without LRTP 19**	**Tranche 2.1**	**Delta**
MTEP25 2030 Shoulder High Wind Line Losses for LRZ 1						
MW Losses	958.44	954.65	3.79	862.51	861.92	0.59
MVAR Losses	9,369.55	9,347.99	21.56	8,956.89	8,952.08	4.81
Future 2 Year 20 LRTP Light Load Dispatch Models						
MW Losses	1,509.39	1,498.56	10.83	1,177.34	1,170.75	6.59
MVAR Losses	11,779.98	11,727.54	52.44	11,465.55	11,442.82	22.73

Table 4-11
Average Line Losses

	Average Losses
MW Losses	5.45
MVAR Losses	25.385

4.5 Effect of Promotional Practices

The Applicants have not conducted any promotional activities or events that have triggered the need for the Project. As discussed above, the Project is needed to address regional reliability issues across MISO's Midwest subregion.

4.6 Effect of Inducing Future Development

The Project is not necessarily intended to induce future development, but it will support future economic development (for example, additional renewable generation).

4.7 Socially Beneficial Uses of Facility Output

The Project is needed to maintain reliability of the transmission system for the Applicants' customers and the MISO Midwest subregion as aging coal-fired generation resources are retired and replaced with renewable generation. As discussed in Sections 4.2.7.2 and 4.3.3, by enabling greater renewable generation, the LRTP Tranche 2.1 Portfolio will provide societal benefits, such as a reduction in carbon emissions. MISO estimated that the LRTP Tranche 1 Portfolio will reduce carbon emissions by 127 million metric tons over the first 20 years that these projects are in service and 199 million metric tons over the first 40 years.[89] Using the Minnesota Public Utilities Commission's valuation of carbon emission reduction of $248.67/metric ton,[90] the LRTP Tranche 2.1 Portfolio is expected to result in $39.2 million to $65.1 million in carbon reduction benefits across the MISO footprint over the first 20 to 40 years these projects are in service.[91] Using this same cost of carbon ($248.67/metric ton), the Applicants estimate the carbon reduction benefits of the Project alone to the MISO footprint will be $12.4 million over the first 20 years the Project is in service. In addition, the Project will relieve transmission congestion, increase market access to lower cost renewable generation, and provide economic benefits in the form of reduced wholesale energy costs.

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[89] **Appendix E-1** at 161 (MTEP24 Report).

[90] **Appendix E-1** at 161 (MTEP24 Report).

[91] **Appendix E-1** at 161 (MTEP24 Report).

5 ALTERNATIVE ANALYSIS

The Applicants analyzed a number of different alternatives considered to solve the need identified in the previous chapter. Minnesota Certificate of Need statutes and rules require analysis of transmission and non-transmission alternatives. This includes examining size alternatives (different transmission line voltages), type alternatives (including different transmission line configurations, as well as generation and non-wires alternatives), demand-side management, and a "no build" alternative to solve the identified need. As discussed in more detail below, the Applicants' analysis of these alternatives determined that none of these alternatives alone or in combination with other alternatives is a more reasonable and prudent alternative to the proposed Project.

5.1 Size Alternatives

5.1.1 Different Voltages

The Applicants evaluated the feasibility of different line voltages (both higher and lower) to relieve current capacity issues and to improve electric system reliability throughout the region as more renewable energy resources are added to the transmission system in and around the region. As additional renewable generation is constructed in the region, the existing congestion problem will only worsen if there is not sufficient capacity available to transmit this generation to load centers such as the Twin Cities. As of September 2025, for the West MISO DPP cycle 23, there is approximately 19,500 MW of generation in the MISO queue that has requested to be placed in-service.[92]

In examining transmission alternatives to relieve congestion, the capacity of a single transmission line is an important consideration, as the amount of congestion present on the transmission system is, in part, a function of the amount of available transmission capacity on a single transmission line. Generally speaking, the higher the voltage of a transmission line, the higher capacity the line has to carry power, assuming the same

[92] MISO, *DPP Study Cycle Update, Interconnection Process Working Group* (Sept. 3, 2025), available at: https://cdn.misoenergy.org/20250903%20IPWG%20Item%2003b%20DPP%20Study%20Cycle%20Update715446.pdf

current. The correlation between voltage level and the capacity of a transmission line is shown by the following equation:

Three Phase AC Power (MVA, capacity) = Volts (V) x Amperes (I) x $\sqrt{3}$

Table 5-1 provides a general comparison of the capacity of transmission lines operated at different voltages assuming the same current of 3000 amps.

Table 5-1
Comparison of Capacity by Voltage Level

Voltage Level	Capacity (MVA)
69 kV	358.5
115 kV	597.6
230 kV	1,195.1
345 kV	1,792.7
Double-Circuit 345/345 kV	3,585.4
500 kV	2,598.1

Given the increasing amounts of renewable generation in Minnesota and the surrounding states, it is important that sufficient transmission capacity be in place to deliver this renewable generation reliably, efficiently, and economically to load centers.

5.1.1.1 Higher Voltage

The Applicants considered higher voltage 765 kV and 500 kV transmission lines as alternatives to the proposed 345 kV transmission lines. While several new 765 kV lines are proposed for southern Minnesota as part of Tranche 2.1, there are currently no 765 kV transmission lines in northern Minnesota and the closest LRTP Tranche 2.1 proposed 765 kV projects connect at either the North Rochester Substation in southeastern Minnesota or the Big Stone Substation in eastern South Dakota. In addition, although there are two 500 kV transmission lines in Minnesota, neither 500 kV line is located in the vicinity of the Project. As a result, constructing a new 765 kV or 500 kV transmission line in this part of the state would require additional substation transformers to accommodate these higher voltage transmission lines. Specifically, connecting higher voltage lines to the existing electric system, mainly comprised of 345 kV, 230 kV, 115 kV, 69 kV, and 41.6 kV lines in the Project area, would require installation of additional transformers at the existing Alexandria and Bison substations.

Further, the Project involves stringing an additional 345 kV circuit on the existing CapX2020 Fargo to St. Cloud 345 kV Transmission Project transmission line infrastructure, which was constructed as 345/345 kV double-circuit capable as part of the Fargo to St. Cloud 345 kV Transmission Project (Docket No. E002, ET/TL-09-1056). The existing double-circuit infrastructure was not built to accommodate a 500 kV or 765 kV circuit and would need to be removed and replaced if a 500 kV of 765 kV circuit were to be installed, resulting in significant additional costs and environmental impacts compared to the currently proposed 345 kV Project.

A 500 kV or 765 kV transmission line would also require a wider ROW than the proposed 345 kV transmission line. A 500 kV or a 765 kV transmission line would require at least 200 feet of ROW, while a 345 kV transmission line only requires 150 feet of ROW. In addition, the typical construction for a 500 kV or 765 kV transmission line would likely be a two-pole structure or a four-legged latticed type structure that would result in greater environmental impacts along the route, with two or four foundations per structure as opposed to one foundation for a double-circuit 345 kV monopole.

Based on Applicants' analysis, higher voltage transmission lines above 345 kV are not a more reasonable or prudent alternative to the proposed Project.

5.1.1.2 Lower Voltage

The Applicants also analyzed lower voltage alternatives to the Project. Transmission line voltages lower than 345 kV include: 230 kV, 161 kV, 138 kV, 115 kV, 69 kV, and 41.6 kV. As there are existing 230 kV, 115 kV, 69 kV, and 41.6 kV transmission lines in the vicinity of the Project, the Applicants examined these lower voltages as alternatives to the proposed 345 kV Project.

The Project is designed to address issues on the heavily constrained 230 kV system in northwestern and central Minnesota and neighboring states. The existing 230 kV system is congested during periods of high renewable generation, which results in higher energy prices for Minnesota customers. This is because lower cost renewable energy is unable to reach customers. Because of congestion, higher cost resources must be dispatched and renewable generation is curtailed. Given the lower capacity of 115 kV, 69 kV, and 41.6 kV transmission lines, the Applicants eliminated these lower voltage alternatives from further study as these voltages would not have sufficient capacity to address the congestion issues on the existing 230 kV system and would not offer the capacity needed to support future renewable generation. As a result, installing these lower voltage alternatives would require more transmission facilities to be constructed in the future to provide additional capacity to support this future generation. The existing 230 kV system in the Project area is currently heavily congested, so it is beneficial to install transmission facilities with voltages greater than 230 kV to unload the existing 230 kV system. In addition, the cost of a 345 kV is similar to 230 kV but allows for significantly greater capacity to support future generation in the Project area.

Another consideration in determining the appropriate voltage for a new transmission line is whether the voltage of the new line is present on the existing system in the Project area. The majority of the transmission system in the Project area is at the 345 kV voltage level such that integrating a new line at the 345 kV voltage fits into the existing system without requiring the need to construct additional substation facilities. For instance, a lower voltage line would require additional costs associated with substation upgrades to accommodate the introduction of new voltage to the system. The existing Bison and Alexandria substations already have 345 kV infrastructure such that additional transformation is not required. If a lower voltage alternative such as 230 kV or 115 kV is selected, additional transformers might be needed at these substations, resulting in increased costs.

Another drawback of lower voltage alternatives is that lower voltage lines tend to have higher losses than higher voltage lines. This is because when the voltage of a line is lowered, the line rating must be increased to achieve similar levels of power transfer. To achieve a comparable line rating on a lower voltage line, larger conductor and thus more robust structures, foundations, and associated hardware would also be required, leading to higher costs.

Based on the analysis discussed above, the Applicants determined that lower voltages are not a more reasonable or prudent alternative to the Project.

5.1.2 Common Tower

The Project involves stringing a second single-circuit 345 kV circuit on existing double-circuit capable infrastructure from the Bison Substation to the Alexandria Substation. The Applicants evaluated triple-circuiting the Project, which would require removal of the existing double-circuit capable infrastructure that was installed between 2012 and 2014 and replacing that infrastructure with new triple-circuit infrastructure. Transmission structures like these generally have useful lives of approximately 60 years, thus replacing these structures that are far from the end of their useful lives would add significant costs to the Project. In addition, while triple-circuiting a line may be technically feasible, there are operational and maintenance concerns with this design. Generally, all three lines must be taken out of service to work on a single line.

Moreover, triple-circuit structures are taller than double-circuit structures and would likely require two poles rather than one, as well as a wider ROW of 175 feet to 200 feet as compared to the typical 150-foot ROW for a single-circuit and double-circuit 345 kV transmission line. Importantly, the existing 150-foot ROW is already owned by the Applicants, so expanding the ROW for a triple-circuit structure would necessitate the purchase of new land rights along the route.

5.2 Type Alternatives

5.2.1 Transmission with Different Terminals/Substations

The Applicants requested, and the Commission granted, an exemption from Minn. R. 7849.0260(B)(4) that requires a discussion of "transmission lines with different terminals or substations."[93] This exemption was granted because Minn. Stat. 216B.243, subd. 3(6) states that the Commission "must not require evaluation of alternative end points for a high-voltage transmission line qualifying as a large energy facility unless the alternative end points are (i) consistent with end points identified in a federally registered planning authority transmission plan, or (ii) otherwise agreed to for further evaluation by the applicant." The only end points identified in the MISO MTEP24

[93] *In the Matter of the Application for a Certificate of Need for the Bison to Alexandria Second Circuit 345 kV Transmission Line Project,* Docket No. E002, ET2, E017, ET6135/CN-25-116, Order (Nov. 18, 2025).

definition for the Project are those proposed by the Applicants, and the Applicants have not agreed to an evaluation of any alternative end points.

5.2.2 Upgrading Existing Transmission Lines

The Applicants considered upgrading existing transmission facilities as an alternative to the Project. The Project as proposed involves upgrading an existing 345 kV transmission circuit on double-circuit capable infrastructure to add an additional 345 kV transmission circuit.

5.2.3 Double Circuiting of Existing Transmission Lines

Double circuiting is the construction of two separate circuits on the same structures to reduce the overall amount of ROW required. In general, double-circuiting transmission lines minimizes the need for new ROW and expansion of the overall footprint of the transmission system.

The Project is proposed to be double circuited with an existing 345 kV transmission line, and as proposed will eliminate the need for additional ROW.

5.2.4 Direct Current Line

Applicants considered a High Voltage Direct Current (HVDC) line in place of the proposed alternating current (AC) facilities. An HVDC transmission system consists primarily of a converter station, in which the AC voltage of the conventional electric grid is converted to HVDC voltage, a transmission line, and another converter station at the other end, where the voltage is converted back into AC.

In certain applications, the Applicants believe that HVDC transmission can offer cost advantages over its AC counterpart because fewer conductors are needed, less ROW is needed for the transmission line, and line losses are reduced. However, considering the Project length (101 miles), HVDC would not be expected to present a cost advantage because the "break even distance" at which the cost of the additional AC conductors exceeds the cost of AC/DC converter stations for HVDC is typically in the range of approximately 370 to 500 miles. An HVDC transmission line is generally employed to deliver generation over a considerable distance, more than 300 miles, to a load center. HVDC systems typically do not allow for cost-effective interconnections along the line.

While line losses and conductor costs associated with HVDC lines are generally less than those associated with high voltage AC lines, HVDC lines also require expensive converter stations at each end point of the line to convert power from AC to DC and DC to AC. It should be noted that HVDC converter stations do not eliminate the need for AC substation facilities that would be required after the power is converted back to AC. There are also extended lead times (6 years or more) for HVDC systems.

Converter stations for 500 kV to 600 kV HVDC lines can range from approximately $670 million to $811 million.[94] Given the substantial additional cost imposed by the required HVDC converter stations, the costs associated with a HVDC design would exceed the benefits and therefore HVDC is not a more prudent or reasonable alternative to the proposed Project.

5.2.5 Underground Transmission Lines

Applicants evaluated underground transmission, both AC and DC, and concluded that an underground design would not be a feasible or reasonable alternative to the proposed overhead design due to the significantly higher cost of undergrounding a line of this length and voltage.

High voltage AC underground cable systems at 345 kV are generally limited in length to approximately 50 miles or less because of its impact on reactive power. While longer installations can be constructed with the addition of shunt reactors along the line, this is an atypical design and practical applications of underground high voltage AC lines for more than 50 miles are cost prohibitive due to the technical requirements required for a line of this length. As the proposed Project is over 100 miles in length, an underground high voltage AC design was deemed to be cost prohibitive.

[94] MISO, Transmission Cost Estimate Workbook for MTEP25 at Table 4.3-1 (May 2024), available at: https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimate%20Workbook%20for%20MTEP25547535.xlsx.

High voltage DC cable systems are used for underground lines of approximately 100 miles or more. High voltage DC systems do not have the same reactive power limitations and line losses as high voltage AC underground cable systems. High voltage DC cable systems require converter stations on each end of the line to convert the voltage from DC to AC and AC to DC. Because of the need for conversion from overhead to underground and conversion of voltage through converter stations, high voltage DC lines do not readily accommodate interconnections at midpoints along the lines.

Both underground AC and DC designs are infeasible due to costs. Indicative estimates for underground high voltage DC over 100 miles are $25 million or more per mile, depending on the ultimate design.

Construction costs for AC underground transmission are anticipated to be similar to underground high voltage DC but would not require converter stations. Specifically, Applicants developed a cost estimate to underground two miles of a 345 kV line using an open trench construction method. Applicants determined that this open trench underground installation would cost at least $20 million per mile (2025$). This compares to an indicative cost estimate of $3.8 million per mile for the Applicants' overhead designs.[95] If underground is considered the specific location must be studied, as certain installations, for example a deep burial under a river, would result in additional costs. In addition, all underground cable installations behave differently, electrically, then overhead lines and therefore a study would be required to determine if reactive compensation is required. If reactive compensation is required, this would add several million dollars to the underground costs stated above. Based on this cost analysis, the Applicants determined that the underground design is not a reasonable alternative.

The Project involves stringing a second 345 kV transmission line circuit on existing transmission infrastructure that was initially constructed as double-circuit capable. An underground design would mean that the cost savings associated with using the existing

[95] This is a cost for a new 345 kV single-circuit line and does not reflect the cost for the Project which involves stringing a second circuit on existing structures. MISO, *Transmission Cost Estimate Workbook for MTEP25* at Table 4.1-1 (May 2024), available at: https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimate%20Workbook%20for%20MTEP25547535.xlsx.

double-circuit infrastructure would not be realized and reconstruction for an underground alternative would result in significantly more environmental impacts.

5.2.6 Alternative Conductors

The conductor for the Project will be determined during the final design of the Project based on the results of a conductor optimization study. This conductor optimization study will identify the optimal conductor configuration or configurations for the Project based on a technical and economic analysis of different conductor sizes and configurations.

The Applicants currently anticipate using a double bundled 2x397.5 kcmil 26/7 ZTACSR "Ibis" conductor for the new 345 kV transmission circuit.

5.2.7 Generation and Non-Wires Alternatives

5.2.7.1 Generation Alternatives

In evaluating alternatives to the proposed Project, the Applicants considered the addition of new generation resources rather than the proposed transmission line facilities to resolve the congestion currently present. Fundamentally, however, adding new generation resources to resolve congestion is not a reasonable alternative given that generation alternatives will not add transmission capacity. Transmission congestion occurs when there is not enough transmission capacity to support all generation output at a particular time. Thus, regardless of the type of generation facility evaluated, construction of additional generation facilities is not a feasible and prudent alternative to the Project because such generation would (1) further exacerbate the congestion already present on the system; (2) result in underutilization of existing generation resources; and (3) likely be more costly than the proposed Project. In addition, the LRTP Tranche 2.1 Portfolio was designed to address the needs of the MISO Midwest subregion and it is not likely or cost effective that a generation alternative would be able to provide the regional benefits needed in the MISO Midwest subregion.

5.2.7.1.1 Peaking Generation

The Applicants considered peaking generation as an alternative to the Project. Peaking generation refers to flexible generation resources—typically natural gas or diesel generators—that can be quickly dispatched to supplement other generation resources. One of the purposes of this Project and the entire LRTP Tranche 2.1 Portfolio is to enable greater generation deliverability across the MISO Midwest subregion. Construction of additional peaking generation will not create the needed transmission capacity across the MISO Midwest subregion but rather worsen the existing congestion and curtailment issues and increase customer costs.

5.2.7.1.2 Distributed Generation

The Applicants considered distributed generation as an alternative to the Project. Distributed generation refers to generation that is located near load centers, is connected to the local distribution system, and can run continuously when called upon, typically on natural gas or other fossil fuels. Renewable distributed generation and battery energy storage were also considered as alternatives and are discussed below. Fossil-fueled distributed generation has the same drawbacks as peaking generation. The Project is needed to provide additional transmission capacity to provide greater generation deliverability across the MISO Midwest subregion. As a result, adding additional distributed generation will not provide this additional transmission capacity and instead will only worsen the existing congestion and curtailment issues on the system. Construction of new distributed generation resources will also result in the underutilization of existing generation resources due to the congestion and curtailment issues.

5.2.7.1.3 Renewable Generation

The Applicants considered renewable generation as an alternative to the Project. Renewable generation refers to energy that is produced from the sun or the wind and that is either connected to the transmission system at a single transmission interconnection point or at multiple locations on the transmission and distribution system. Western Minnesota, North Dakota, and South Dakota have abundant wind resources and, as a result, a number of large-scale wind facilities have already been constructed in these areas. The Project is needed to provide additional transmission capacity to provide greater generation deliverability for these existing renewable generation resources. The addition of new renewable generation resources in lieu of adding transmission capacity would only worsen the existing congestion and curtailment issues on the system and require further build-out of the transmission system.

5.2.7.2 Energy Storage

The Applicants considered energy storage as an alternative to the Project. Energy storage refers to the ability to capture energy produced at one point in time for use at a later time. Current energy storage technologies include battery storage systems and pumped hydro facilities.

To be a viable alternative to the Project, an energy storage alternative must address the needs addressed by the Project. As part of the LRTP Tranche 2.1 Portfolio, the Project relieves thermal constraints, reduces transmission congestion on some of the most-constrained flowgates in the region, and increases the deliverability of generation resources in the Dakotas and Minnesota. While an energy storage solution may address some of the needs addressed by the Project, it cannot provide all of the same benefits as the proposed transmission Project. For example, an appropriately sized battery energy storage system located in the right area may relieve some thermal and voltage constraints and improve transmission congestion on a short-term basis, its effectiveness will be limited by its duration limitations. A battery energy storage system will also not be able to increase the capacity of regional transfer interfaces or enable the delivery of other types of generation like the proposed Project. As a result, an energy storage alternative is not a reasonable alternative to the proposed Project.

5.2.7.3 Reactive Power Additions

The Applicants considered reactive power additions as an alternative to the Project. Reactive power additions refer to capacitor or reactor banks for voltage control. These devices generally maintain local voltage stability on the system. These devices are not effective at enabling large power transfers across a broad region, such as those needed to relieve the existing congestion on the system. As a result, reactive power additions are not a reasonable alternative to the proposed Project. While reactive power additions are not by themselves able to accommodate large scale power transfers, these reactive power additions will likely be needed for ancillary support.

5.2.7.4 Flow Control Devices

The Applicants evaluated flow control devices as an alternative to the Project. Flow control devices refers to devices that divert power flows from constrained areas, but do not provide system stability or additional transmission capacity. Flow control devices are generally used to address more localized overloads where there is already sufficient capacity on the system. As discussed, the primary purpose of this Project is to provide additional transmission capacity across the MISO Midwest subregion. As flow control devices would not provide any additional transmission capacity to support generation outlet, these devices are not a viable alternative to the proposed Project.

5.2.7.5 Conservation and Demand-Side Management

The Applicants analyzed conservation and demand-side management as an alternative to the Project. Specifically, the Applicants analyzed conservation and demand-side management tools that reduce overall demand as well as tools that reduce peak demand. This included interruptible load programs and energy efficiency programs. Since the need for the Project is driven in part by the need for additional transmission capacity to deliver increasing amounts of renewable generation on the system across the MISO Midwest subregion rather than a localized increase in demand, conservation and demand-side management are not effective alternatives to meet the identified need. The Applicants provide information on their conservation and energy efficiency programs in **Appendix F**. **Appendix F** also provides discussion on how conservation and energy efficiency was considered by MISO in its evaluation and approval of the Project.

5.3 Any Reasonable Combination of Alternatives

As the only feasible alternative to meet the identified need is a transmission alternative and the proposed Project is the best performing alternative, there is no reasonable combination of alternatives that would be a more reasonable and prudent alternative to the Project.

5.4 No Build Alternative/Consequences of Delay

Applicants also considered a no build alternative (i.e., no new transmission facilities constructed to meet the identified need). If the Project is not constructed, customers will be denied the reliability and economic benefits of this Project.

As discussed in **Chapter 4**, this Project, along with the other Northern Minnesota projects, resolves more than 50 percent of the constraint violations on transmission elements both above and below 200 kV. The Northern Minnesota projects also provide outlets for North Dakota generation and resolve constraint violations in this area. Providing generation outlet for this generation is important to enabling the state's ability to achieve its goal of 100 percent carbon-free generation by 2040. As discussed in **Chapter 3**, additional carbon-free generation will need to be added to the system to achieve this 2040 goal.

In addition, as discussed in **Chapter 4**, this Project is a key part of MISO's LRTP Tranche 2.1 portfolio. Overall, the Tranche 2.1 Portfolio of projects is expected to deliver benefits in excess of costs, totaling $23.1 billion to $72.4 billion over the first 20 years that they are in service with an overall benefit-to-cost ration ranging from 1.8 to 3.5.[96]

[96] **Appendix E-1** at 144, Figure 2.137 (MTEP24 Report).

6 TRANSMISSION LINE OPERATING CHARACTERISTICS

6.1 Transmission Line Operating Characteristics Overview

The major components of an overhead transmission line include (1) an above-ground structure typically made from wood or steel, often referred to as a pole or tower; (2) the wires attached to the structure and carrying the electricity, called conductors; (3) insulators connecting the conductors to the structures to provide electrical insulation; (4) shield wires which protect the line from direct lightning strikes, along with providing a fiber optic communications path between substations; and (5) ground rods located below ground and connected at each structure.

During operation, transmission lines are, for the most part, passive elements of the environment, as they are stationary in nature with few, if any, moving parts. Their primary impact is aesthetic (i.e., a man-made structure in the landscape). Due to the physics of how electricity works, some chemical reactions occur around conductors in the air due to the electrical and magnetic fields created around the conductors. As a result, noise can occur in some circumstances, as well as the potential for interference with electromagnetic signals. All of these operating characteristics are considered when designing the transmission line to prevent any significant impact on its operation and the overall environment.

6.2 Ozone and Nitrogen Oxide Emissions

Corona consists of the breakdown or ionization of air within a few centimeters of energized conductors. Usually some imperfection, such as a scratch on the conductor or a water droplet, is necessary to induce corona because transmission lines are designed to be corona free under typical operating conditions. Corona can produce ozone and oxides of nitrogen in the air surrounding the conductor. Ozone also forms in the lower atmosphere from lightning discharges and from reactions between solar ultraviolet radiation and air pollutants, such as hydrocarbons from auto emissions. The natural production rate of ozone is directly proportional to temperature and sunlight, and inversely proportional to humidity. Thus, humidity or moisture, the same factor that increases corona discharges from transmission lines, inhibits the production of ozone. Ozone is a very reactive form of an oxygen molecule and combines readily with other elements and compounds in the atmosphere. Because of its reactivity, it is relatively short-lived.

Currently, both state and federal governments have regulations regarding permissible concentrations of ozone and oxides of nitrogen. The state and national ambient air quality standards for ozone are similarly restrictive. The National Ambient Air Quality Standard for ozone is 0.070 parts per million (ppm) on an 8-hour averaging period. The state standard is 0.070 ppm based on the fourth highest 8-hour daily maximum average in one year.[97] The ozone created by the Project will be below these standards.

The national standard for nitrogen dioxide (NO_2), one of several oxides of nitrogen, is 100 parts per billion (ppb) and the annual standard is 53 ppb. The State of Minnesota is currently in compliance with the national standards for NO_2. The operation of the proposed Project will not create any potential for the concentration of these pollutants to exceed the nearby (ambient) air standards.

Sulfur hexafluoride will be used in equipment that is installed at the substations. Small releases will occur as part of regular breaker operation and maintenance. Applicants will minimize sulfur hexafluoride emissions through operational best management practices (BMPs) and will monitor equipment for leaks. Applicants will comply with Environmental Protection Agency reporting requirements in the event a leak is detected.

6.3 Audible Noise

Noise is defined as unwanted sound. Noise may include a variety of sounds of different intensities across the entire frequency spectrum. Noise is measured in units of decibels (dB) on a logarithmic scale. Because human hearing is not equally sensitive to all frequencies of sound, certain frequencies are given more "weight." The A-weighted decibel (dBA) scale corresponds to the sensitivity range for human hearing. Noise levels capable of being heard by humans are measured in dBA. A noise level change of three dBA is barely perceptible to average human hearing. A five dBA change in noise level, however, is clearly noticeable. A 10 dBA change in noise levels is perceived as a

[97] Minn. R. 7009.0080.

doubling or halving of noise loudness, while a 20 dBA change is considered a dramatic change in loudness.

6.3.1 Noise Related to Construction of the Project

Construction activities are expected to generate noise that will be short-term and intermittent, confined to daytime hours. Consequently, the Project is anticipated to produce temporary and localized noise impacts during the construction period but is not expected to result in significant long-term noise effects in the surrounding area. Residents located near the construction zones may experience temporary noise disturbances as construction progresses along the Project's route over an estimated two-year period; however, noise at individual locations will dissipate as crews move forward.

Installation of the transmission line will create intermittent noise due to various construction activities, leading to brief increases in ambient sound levels at adjacent residences until work shifts to other sections of the corridor. Typical equipment utilized during construction will include man lifts, cranes, dozers, forklifts, loaders, drill rigs, pickup trucks, dump trucks, and flatbed trucks. A helicopter will also be employed during transmission line stringing to transport personnel and equipment to elevated structures, hovering near each site intermittently.

The most sustained noise levels during construction are likely to occur during foundation excavation activities, employing equipment such as drill rigs and concrete trucks where new structures are to be built. The Federal Highway Administration Roadway Construction Noise Model was used to estimate indicative noise levels associated with this phase, based on the simultaneous operation of a drill rig truck, dump truck, front end loader, concrete pump truck, and concrete mixer truck. Projected noise measurements at various distances from the construction activity for this scenario are presented in **Table 6-1**.

Table 6-1
Estimated Construction Noise during Foundation Excavation

Activity	Estimated L_{eq} Sound Level (dBA) at Distance from Construction Activity			
	50 feet	100 feet	200 feet	400 feet
Foundation excavation	81	75	69	63

Construction noise effects are expected to be localized to where construction is occurring at that time and temporary in nature. Construction activity will also primarily occur during daytime hours, and nearby residents will be advised of the construction activity and schedule.

6.3.2 Transmission Line Noise

Generally, activity-related noise levels during the operation and maintenance of transmission lines are minimal. Transmission conductors can produce noise under certain conditions. The level of noise depends on conductor conditions, voltage level, and weather conditions. In foggy, damp, or rainy weather, power lines can create a crackling sound due to the small amount of electricity ionizing the moist air near the conductors. During heavy rain, the background noise level of the rain is usually greater than the noise from the transmission line. As a result, people do not normally hear noise from a transmission line during heavy rain. During light rain, dense fog, snow, and other times when there is moisture in the air, transmission lines will produce audible noise equal to approximately household background levels. During dry weather, audible noise from transmission lines is barely perceptible by humans.

The Minnesota Pollution Control Agency (MPCA) has established standards for the regulation of noise levels. The land use activities associated with residential, commercial, and industrial land have been grouped together into Noise Area Classifications (NACs).[98] Each NAC is then assigned both daytime (7 a.m. to 10 p.m.) and nighttime (10 p.m. to 7 a.m.) limits for land use activities within the NAC.[99] **Table 6-2** shows the MPCA daytime and nighttime limits in dBA for each NAC. The limits are expressed as

[98] Minn. R. 7030.0050.

[99] Minn. R. 7030.0040.

a range of permissible dBA within a 1-hour period; L_{50} is the dBA that may be exceeded 50 percent (30 minutes) of the time within an hour, while L_{10} is the dBA that may be exceeded 10 percent (6 minutes) of the time within an hour. Residences, which are typically considered sensitive to noise, are classified as NAC-1.

Table 6-2
Minnesota Pollution Control Agency Noise Limits by Noise Area Classification (dBA)

Noise Area Classification (NAC)	Land Use Activities	Daytime		Nighttime	
		L50	L10	L50	L10
1	residential housing, religious activities, camping and picnicking areas, health services, hotels, educational services	60	65	50	**55**
2	retail, business and government services, recreational activities, transit passenger terminals	65	70	65	**70**
3	highways, utilities, manufacturing, fairgrounds and amusement parks, agricultural and forestry activities	75	80	75	**80**

There are residences adjacent to the Preferred Route which would fall under NAC-1. Because corona noise may occur during daytime or nighttime periods, the 50 dBA L_{50} nighttime noise limit at NAC-1 (i.e., residences) is the most restrictive noise limit that needs to be met by the Project.

Audible noise generated by the transmission line was estimated using the Bonneville Power Administration Corona and Field Effects model. Typical audible noise was estimated for the existing and new 345 kV circuits with 5% overvoltage installed on the dominant type of structure in the corridor.

The estimated transmission line L_{50} sound levels at several distances from the transmission line structure at 5 feet above ground are shown in **Table 6-3**.

Table 6-3 Estimated Typical Transmission Line Corona Noise

Structure Type	Estimated L_{50} Sound Level (dBA) at Distance from Structure			
	0 feet	**50 feet**	**150 feet**	**300 feet**
345 / 345 kV Double-Circuit Monopole	52	49	45	42

The noise estimates in **Table 6-3** demonstrate that typical transmission line corona noise is expected to be below the 50 dBA L_{50} nighttime noise limit at distances of approximately 50 feet or greater from the structure. Because the transmission line ROW is 150 feet wide, it is anticipated that transmission line sound levels would remain below 50 dBA at the edges of the ROW. Transmission line noise may vary to some degree along the corridor, but it is expected to be below the State standards at nearby residences.

6.4 Radio, Television, and GPS Interference

The Project is expected to have no adverse effects on communications (i.e., television, radio) during construction or operation. The Applicants will comply with applicable sections of the latest version of the NESC related to appropriate spacing between power and communication cables. Conversely, the transmitted signals from fiber optic cables will not be distorted by any form of outside electronic, magnetic, or radio frequency interference.

Radio noise is a complex function of conductor size, surface conditions, spacing, operating voltage, and meteorological conditions. Weather effects, such as variations in humidity, air density, wind, and rain, affect radio noise levels. For example, during a rain event there may be an increase in radio noise over that experienced during sunny days. Also, as the conductor ages, surface imperfections tend to be smoothed out by weathering over time, resulting in a reduction of a few decibels in noise as compared to the levels when the line is new. The Project is not expected to result in any interference with radio or TV reception because the proposed facilities are similar to the existing facilities and will use existing ROW where no such interference has been reported.

If radio interference from transmission line corona does occur, satisfactory reception from AM radio stations previously providing good reception can be restored by the appropriate modification of (or addition to) the receiving antenna system.

A two-way mobile radio located immediately adjacent to and behind a large metallic structure (such as a steel tower) may experience interference because of signal-blocking effects. Movement of either mobile unit so that the metallic structure is not immediately between the two units should restore communications. This would generally require a movement of less than 50 feet by the mobile unit adjacent to a metallic tower.

Television interference is rare but may occur when a large transmission structure is aligned very close to the receiver and between the receiver and a weak distant signal, creating a shadow effect. If television or radio interference is caused by or from the operation of the proposed facilities in areas where good reception is presently obtained, Applicants will take necessary action to restore reception to the present level, including the appropriate modification of receiving antenna systems if deemed necessary.

Transmission lines typically do not cause interference with Global Positioning Systems (GPS). Utilities regularly use GPS-based surveying methods under and around transmission lines and have not experienced interference.

6.5 Safety

The Project will be designed in compliance with local, state, and NESC standards regarding clearance to ground, clearance to crossing utilities, clearance to buildings, strength of materials, and ROW widths. Appropriate standards will be met for construction and installation, and all applicable safety procedures will be followed during and after installation of the Project.

The proposed transmission lines will be equipped with protective devices to safeguard the public from the transmission lines if an accident occurs, such as a structure or conductor falling to the ground. The protective devices include breakers and relays located where the line connects to the substations. The protective equipment will de-energize the line should such an event occur.

6.6 Electric and Magnetic Fields

Electro-magnetic fields (EMFs) are found wherever there is electricity, whether it be within wiring, appliances, computers, or power lines. Transmission lines create EMF because they carry electric currents at relatively high voltages. EMFs decrease in size as the distance from the source increases, so EMFs are highest closest to the lines (typically near the center of the transmission line ROW) and decrease as the distance from the transmission corridor increases. For the lower frequencies associated with power lines (referred to as Extremely Low Frequency), EMF should be considered separately – electric fields and magnetic fields, measured in kilovolt per meter (kV/m) and milliGauss (mG), respectively. Electric fields are dependent on the voltage of a transmission line, and magnetic fields are dependent on the current carried by a transmission line. Electric fields are also attenuated by objects, such as trees and the walls of structures, and are completely shielded by materials, such as metal and the earth.

6.6.1 Electric Fields

There is no federal standard for transmission line electric fields. The Commission, however, has imposed a maximum electric field limit of 8 kV/m, measured at 1 meter above the ground.[100] The standard was designed to prevent serious hazards from shocks when touching large objects parked under AC transmission lines of 500 kV or greater. Maximum conductor voltage is defined as the nominal voltage plus 5 to 10 percent depending on the facility owner.

The maximum electric field generated by the Project, estimated near or at the centerline of the overhead lines, was calculated at 1 meter (3.28 feet) above ground, as well as 75 feet from the centerline. In each scenario calculated, the electric field was calculated to be below 4.0 kV/m. The strength of electric fields diminish rapidly as the distance from the conductor increases. The electric field values of all of the design configurations are presented in **Appendix I**.

6.6.2 Magnetic Fields

There are presently no Minnesota regulations pertaining to magnetic field exposure. Applicants provide information to the public, interested customers, and employees so they can make informed decisions about magnetic fields. Such information includes the availability for measurements upon request.

Considerable research has been conducted since the 1970s to determine whether exposure to power-frequency (60 hertz) magnetic fields causes biological responses and health effects. Public health professionals have also investigated the possible impact of

[100] *In the Matter of the Route Permit Application for a 345 kV Transmission Line from Brookings County, S.D. to Hampton, Minn.*, Docket No. ET2/TL-08-1474, ORDER GRANTING ROUTE PERMIT (Sept. 14, 2010) (adopting the Administrative Law Judge's Findings of Fact, Conclusions, and Recommendation at Finding 194).

exposure to EMF on human health for the past several decades. While the general consensus is that electric fields pose no risk to humans, the question of whether exposure to magnetic fields can cause biological responses or health effects continues to be debated.

Since the 1970s, a large amount of scientific research has been conducted on EMF and health. This large body of research has been reviewed by many leading public health agencies, such as the U.S. National Cancer Institute, the U.S. National Institute of Environmental Health Sciences, and the World Health Organization (WHO), among others. These reviews show that exposure to electric power EMF neither causes nor contributes to adverse health effects.

For example, in 2016, the U.S. National Cancer Institute summarized the research as follows:

> Numerous epidemiologic studies and comprehensive reviews of the scientific literature have evaluated possible associations between exposure to non-ionizing EMFs and risk of cancer in children (13–15). (Magnetic fields are the component of non-ionizing EMFs that are usually studied in relation to their possible health effects.) Most of the research has focused on leukemia and brain tumors, the two most common cancers in children. Studies have examined associations of these cancers with living near power lines, with magnetic fields in the home, and with exposure of parents to high levels of magnetic fields in the workplace. No consistent evidence for an association between any source of non-ionizing EMF and cancer has been found.[101]

Wisconsin, Minnesota, and California have all conducted literature reviews or research to examine this issue. In 2002, Minnesota formed an Interagency Working Group (Working Group) to evaluate the body of research and develop policy recommendations to protect the public from any potential problems resulting from high voltage transmission line EMF effects. The Working Group consisted of staff

[101] NAT'L CANCER INSTITUTE, *Electromagnetic Fields and Cancer* (updated May 27, 2016), available at: https://www.cancer.gov/about-cancer/causes-prevention/risk/radiation/electromagnetic-fields-fact-sheet.

from various state agencies and published its findings in a White Paper on EMF Policy and Mitigation Options in September 2002. The report summarizes the findings of the Working Group as follows:

> Research on the health effects of EMF has been carried out since the 1970s. Epidemiological studies have mixed results – some have shown no statistically significant association between exposure to EMF and health effects, some have shown a weak association. More recently, laboratory studies have failed to show such an association, or to establish a biological mechanism for how magnetic fields may cause cancer. A number of scientific panels convened by national and international health agencies and the United States Congress have reviewed the research carried out to date. Most researchers concluded that there is insufficient evidence to prove an association between EMF and health effects; however, many of them also concluded that there is insufficient evidence to prove that EMF exposure is safe. (*Id.* at p. 1.)[102]

The Commission, based on the Working Group and WHO findings, has repeatedly found that "there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects."[103]

The maximum electric field generated by the Project, estimated near or at the centerline of the overhead lines was calculated at 1 meter (3.28 feet) above ground, as well as 75 feet from the centerline. In each scenario calculated, the magnetic field was calculated to be below 98 mG. The strength of magnetic fields diminish rapidly as the

[102] THE MINNESOTA STATE INTRAGENCY WORKING GROUP ON EMF ISSUES, *A White Paper on Electric and Magnetic Fields Policy and Mitigation Options* (Sept. 2002).

[103] *In the Matter of the Application of Xcel Energy for a Route Permit for the Lake Yankton to Marshall Transmission Line Project in Lyon County*, Docket No. E002/TL-07-1407, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER ISSUING A ROUTE PERMIT TO XCEL ENERGY FOR THE LAKE YANKTON TO MARSHALL TRANSMISSION PROJECT at 7-8 (Aug. 29, 2008); *see also In the Matter of the Application for a HVTL Route Permit for the Tower Transmission Line Project*, Docket No. ET2, E015/TL-06-1624, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER ISSUING A ROUTE PERMIT TO MINNESOTA POWER AND GREAT RIVER ENERGY FOR THE TOWER TRANSMISSION LINE PROJECT AND ASSOCIATED FACILITIES at 23 (Aug. 1, 2007) ("Currently, there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects.").

distance from the conductor increases. The magnetic field values of all of the design configurations are presented in **Appendix I**.

6.7 Stray Voltage and Induced Voltage

"Stray voltage" is a condition that can potentially occur on a property or on the electric service entrances to buildings from distribution lines serving these buildings—not transmission lines, as proposed here. The term generally describes a voltage between two objects where no voltage difference should exist. More precisely, stray voltage is a voltage that exists between the neutral wire of either the service entrance or of premise wiring and grounded objects in buildings, such as barns and milking parlors. The source of stray voltage is a voltage that is developed on the grounded neutral wiring network of a building and/or the electric power distribution system.

Transmission lines do not, by themselves, create stray voltage because they do not connect directly to businesses or residences. Transmission lines, however, can induce voltage on a distribution circuit that is parallel and immediately under the transmission line. If the proposed transmission lines run parallel to or cross distribution lines, appropriate mitigation measures can be taken to address any induced voltages.

6.8 Farming Operations, Vehicle Use, and Metal Buildings Near Power Lines

The Project will be designed to meet or exceed minimum clearance requirements with respect to electric fencing as specified by the NESC. Nonetheless, insulated electric fences used in livestock operations can be instantly charged with an induced voltage from transmission lines. The induced charge may continuously drain to ground when the charger unit is connected to the fence. When the charger is disconnected either for maintenance or when the fence is being built, shocks may result. The local electrical utility can provide site-specific information to landowners about how to prevent possible shocks when the charger is disconnected if requested.

Farm equipment, passenger vehicles, and trucks may be safely used under and near power lines. The power lines will be designed to meet or exceed minimum clearance requirements with respect to roads, driveways, cultivated fields, and grazing lands as specified by the NESC. Recommended clearances within the NESC are designed to accommodate a relative vehicle height of 14 feet.

Vehicles, or any conductive body, located under energized high voltage transmission lines will be immediately charged with an electric charge. Without a continuous grounding path, this charge can provide a nuisance shock. Such nuisance shocks are a rare event because generally vehicles are effectively grounded through tires. Modern tires provide an electrical path to the ground because carbon black, a good conductor of electricity, is added to tires when they are produced. Metal parts of farming equipment are frequently in contact with the ground when tilling or engaging in various other activities. Therefore, the induced charge on vehicles will normally be continually flowing to ground unless they have unusually old tires or are parked on dry rock, plastic, or other surfaces that insulate them from the ground. Applicants can provide additional vehicle-specific methods for reducing the risk of nuisance shocks in vehicles to landowners if requested.

Buildings are permitted near transmission lines but are generally discouraged within the ROW itself because a structure under a line may interfere with safe operation of the transmission facilities. For example, a fire in a building within the ROW could damage a transmission line. The NESC establishes minimum electrical clearance zones from power lines for the safety of the general public and utilities often acquire easement rights that require clear areas in excess of these established zones. Utilities may permit encroachment into that easement for buildings and other activities when they can be deemed safe and still meet the NESC minimum requirements. Metal buildings may have unique issues due to induction concerns. For example, conductive buildings near power lines of 200 kV or greater must be properly grounded. Any person with questions about a new or existing metal structure can contact the Applicants for further information about proper grounding requirements.

7 TRANSMISSION LINE CONSTRUCTION AND MAINTENANCE

7.1 Right-of-Way Acquisition

The Applicants have conducted a review of existing land rights along the Project corridor and do not anticipate requiring additional land rights. As such, the current scope does not anticipate the need for further easement acquisition or negotiations with property owners.

The Applicants' ROW agents will work with the landowner to address any short-term construction needs, impacts, or restoration.

If new or expanded ROW are determined to be necessary, the Applicants' ROW agents will identify all persons and entities that may have a legal interest in the identified real estate. The Applicants' ROW agents contact each property owner to describe the need for the transmission facilities and how the Project may affect each parcel. The Applicants' ROW agents also seek information from the property owner about any specific concerns that they may have with the Project.

To aid in the design of the Project, Applicants may request permission to enter the property to conduct preliminary surveys and geotechnical work. During this process, the location of the proposed facility may be staked with permission of the property owner.

The agent will discuss the construction schedule and construction requirements with the property owner. Special consideration may be needed for fences, crops, or livestock. Fences and livestock may need to be moved, temporary or permanent gates may need to be installed, and crops may need to be harvested early. In each case, the ROW agent and construction personnel coordinate these processes with the property owner.

Land value data will be collected to assist in determining the fair market value of the easement needed for the land parcels to be crossed by the Project, as well as the impact the easement may have on the market value of those parcels. A fair market value offer will be developed that recognizes the impact of the easement to each parcel. Sometimes, a negotiated easement agreement cannot be reached. In those cases, the Applicants may exercise eminent domain pursuant to Minnesota law. The process of exercising the right of eminent domain is called condemnation.

Before commencing a condemnation proceeding, typically, the Applicants must obtain at least one appraisal and provide a copy to the property owner. The property owner may also obtain another property appraisal, and the Applicants must reimburse the property owner for the cost of the appraisal according to the requirements and limits set forth in Minn. Stat. §117.036. To start the formal condemnation process, the Applicants file a petition in the district court where the property is located and serves that petition on all owners with an interest in each of the land parcels identified in the petition.

If the district court grants the petition, the court then appoints a three-person condemnation commission that will determine a just compensation amount for the easement. The three people appointed to the condemnation commission must be knowledgeable of applicable real estate matters. The commissioners schedule a viewing of the property and then schedule a valuation hearing where the utilities and property owners offer their evidence, such as testimony by appraisers, as to the fair market value of the property interests required for the Project. The condemnation commission then makes an award as to the value of the property acquired for the easement and that award is filed with the court. Each party has the right to appeal the award to the district court for a jury trial. A jury trial typically occurs in the event of an appeal in which the jury considers the parties' evidence and renders a verdict. At any point in this process, the case can be dismissed if the parties reach a settlement.

There may be instances where a property owner elects to require the Applicants to purchase their entire property rather than acquiring only an easement for the transmission line. The property owner is granted this right under Minn. Stat. § 216E.12, subd. 4, which is sometimes referred to as the "Buy-the-Farm Statute." The Buy-the-Farm Statute applies only to transmission lines that are 200 kV or more; thus, the Buy-the-Farm Statute may apply to parcels crossed by the proposed 345 kV transmission lines.

7.2 Construction Procedures

Construction is estimated to last up to 24 months. It is anticipated that construction will employ approximately 100 to 150 construction workers.

Construction will begin after necessary federal, state, and local approvals are obtained and any necessary additional property rights are acquired. Construction in areas where new easements are not needed or have already been obtained may proceed while ROW acquisition for other areas is still in process. The precise timing of construction will consider various requirements of permit conditions, environmental restrictions, availability of outages for existing transmission lines (if required), available workforce, and materials.

Construction activities will adhere to the Applicants' established best practices for both construction and mitigation, with the objective of minimizing temporary and permanent effects on land and the environment. The construction process is anticipated to proceed as follows:

Site Preparation

1) During the site preparation phase of the work some of the sediment and erosion control measures will be installed in accordance with the Stormwater Pollution Prevention Plan (SWPPP). Those measures that are not installed at this time will be installed before or concurrent with the start of the earth-disturbing activities associated with the installation of access roads, work pads, and stringing sites. All control measures will be regularly monitored and maintained or repaired as necessary throughout construction through final stabilization. Supplemental controls will also be added where necessary to account for changing site conditions and seasonal variations in weather.

Limited Vegetation Clearing

2) Most of the ROW has been previously cleared in connection with the construction and vegetation management of the existing transmission line. Limited clearing will be needed along the edges of the ROW in certain areas to meet the vegetation clearing requirements in accordance with good utility best

practice and the long-term vegetation maintenance requirements. Additionally, in limited locations, limited tree clearing and vegetation removal may be needed for access to construction areas.

Impacts to environmentally sensitive areas (i.e., water resources, listed species habitat) will be minimized to the extent practicable. Where possible, this work will be completed by hand. Mechanical work will be necessary in some locations to cut the vegetation and/or remove it from the site for proper disposal. When work with equipment is necessary, it will be done from construction mats to minimize impacts to soils and other non-target vegetation.

Access Road Development

3) The Applicants will, when possible, identify construction access opportunities by reviewing existing transmission line easements, roads, or trails in proximity to the existing transmission line corridor. Where practicable, construction activities will be limited to existing easement areas; however, temporary off-easement access may sometimes be necessary. In such instances, permission from property owners will be obtained before utilizing off-easement access. Most access roads will be located within the existing transmission line corridor. Selection and use of access roads will aim to reduce impacts on water resources, agricultural lands, habitats for listed species, and residential properties. Access roads will also be chosen to avoid steep slopes and other physical barriers.

   Existing roads may occasionally be improved for construction purposes, which may involve gravel amendments or minor grading.

Temporary Matting Installation

4) When possible, construction will be scheduled during frozen ground conditions. When construction during winter is not possible and conditions require, temporary construction matting will be used for access roads and work pads within sensitive areas (e.g., wetlands, agricultural lands, areas with unstable soils) or in upland areas at landowner request. Within agricultural fields, the use of matted access roads could also involve soil segregation practices or other protective measures.

Foundation Installation

5) Drilled pier foundations are typically between eight to ten feet in diameter and are typically 20 to 60 feet deep, depending on soil conditions. The actual diameter and depth of the hole (and foundation) depend on structure design and soil conditions that are determined during the initial survey and soil testing phases. Concrete is brought to the site by concrete trucks from a local concrete batch plant and filled around a steel rebar support cage and anchor bolts. Once the foundation is cured, the structure is bolted to the foundation.

   The new monopoles needed for the Project will be set on drilled shaft foundations. Installing the drilled shaft foundations will involve drilling a hole to the design depth, installing anchor bolt cages, filling the hole with concrete, finishing the surface, and curing the concrete. Temporary or permanent steel casings or drilling aids, such as slurries, borehole sealants, or other additives, may be necessary to stabilize holes until they are filled with concrete. Excess excavated non-hazardous soil material will be spread in adjacent upland areas and stabilized in accordance with the requirements of the SWPPP or will be hauled off site to an appropriate disposal facility if spreading in an upland area (i.e., agricultural sites) is not possible. During foundation excavations in wetlands, temporary spoil stockpiles will be placed on construction matting in accordance with the SWPPP.

Structure Hauling and Assembly

6) New monopoles will be moved from staging areas and delivered to the site of each foundation where they are assembled. Using a crane, the monopole is lifted and placed into position. Insulators and other hardware are attached to the monopole prior to placing it on the foundation.

Conductor Stringing

7) Conductor stringing is the last major step of transmission line construction, and the Applicants anticipate utilizing helicopters for this activity. Stringing pulling pads are typically located at 2-mile intervals within the ROW, when possible, or

within temporary construction easements. Helicopter landing zones will be determined by the construction Contractor.

Helicopters start the process of conductor stringing by pulling a "sock-line" or high strength rope through pulleys attached to the insulators on each structure that is attached to the conductor, which are pulled into place and sagged to meet design requirements that are compliant with good utility practice and minimum code clearances. This process requires brief access to each structure to secure the conductor wire to the insulator hardware and to fasten the shield wire on each structure. After conductor installation is complete, conductor marking devices will be installed if required. These marking devices may include bird flight diverters or air navigational markers. The Applicants will work with the appropriate agencies to identify locations where marking devices need to be installed.

Where the transmission line crosses streets, roads, highways, or other energized conductors or obstructions, temporary guard or clearance poles may be installed before conductor stringing. The temporary guard or clearance poles ensure conductors will not obstruct traffic or contact existing energized conductors or other cables during stringing operations.

Construction will require the use of many different types of construction equipment, including tree removal equipment, mowers, cranes, backhoes, digger-derrick line trucks, drill rigs, dump trucks, front-end loaders, bucket trucks, bulldozers, flatbed tractor-trailers, flatbed trucks, pickup trucks, concrete trucks, helicopters, and various trailers or other hauling equipment. Excavation equipment is often on wheeled or track-driven vehicles. Construction crews will attempt to use equipment and favorable weather conditions, when opportunities are available, that minimizes impacts to land.

Staging areas, or laydown yards, are set up for transmission projects to store equipment and materials needed for new transmission lines. Typically, two or more staging yards are identified before construction begins, with approvals handled by the contractor. Structures, conductors, matting, and other materials are delivered to these areas and stored until required for transmission construction.

7.3 Restoration and Clean-Up Procedures

Crews will attempt to minimize ground disturbance whenever feasible, but areas will be disturbed during the normal course of work. Once construction is completed in an area, disturbed areas will be restored to their original condition to the maximum extent feasible. Temporary restoration before the completion of construction in some areas along the ROW may be required per National Pollution Discharge Elimination System and MPCA construction permit requirements.

After construction activities have been completed, a utility representative will contact the property owner to discuss any damage that has occurred as a result of the Project. This contact may not occur until after the Applicants have started restoration activities. If fences, drain tile, or other property have been damaged, the Applicants will repair damages or reimburse the landowner to repair the damages.

Farmers will be compensated for crop losses caused by Project construction. The compensation will be based upon the area(s) affected, the typical yield for the crops lost, and the market rates for those crops. A utility representative will measure the area(s) in which planted crops were damaged or destroyed or not planted at the Applicant's request. The lost yields will be determined in coordination with the property owner. The market rate will also be determined in coordination with the property owner and local elevator and/or other evidence to determine the appropriate rate of payment. The Applicants will also make a payment for future year crop loss due to soil compaction. In addition, property owners will be compensated for their expense to deep rip compacted areas. If an individual does not have access to deep ripping equipment, Applicants will provide this service or access to such equipment.

Ground-level vegetation disturbed or removed from the ROW during construction of the Project will naturally reestablish to pre-construction conditions. Areas where significant soil compaction or other disturbance from construction activities occur will require additional assistance in reestablishing the vegetation stratum and controlling soil erosion. In these areas, the Applicants will use seed that is noxious weed free to reestablish vegetation.

Another aspect of restoration relates to the roads used to access staging areas or construction sites. After construction activities are complete, the Applicants will ensure township, city, and county roads used for purposes of access during construction will be restored to their prior condition. The Applicants will meet with township road supervisors, city road personnel, or county highway departments to address any issues that arise during construction with roadways to ensure roads are adequately restored, if necessary, after construction is complete.

7.4 Maintenance Practices

Transmission lines and substations are designed to operate for decades and require only moderate maintenance, particularly in the first few years of operation. Great River Energy is expected to be responsible for the maintenance of the 345 kV transmission circuit, including aerial and ground inspections, every four years. Typically, one to two workers are required to perform aerial inspections and three workers are required to perform the ground inspections. Any defects identified during these inspections will be assessed and corrected. Great River Energy will also perform the necessary vegetation management for the line. Vegetation maintenance generally also occurs every four years.

Line inspections are the principal operating and maintenance cost for transmission facilities. The aerial inspections cost approximately $75 to $100 per mile and the ground inspections cost approximately $200 to $400 per mile. These cost estimates are based on historical costs for these types of inspections. Actual line-specific maintenance costs depend on the setting, the amount of vegetation management necessary, storm damage occurrences, structure types, materials used, and the age of the line.

The estimated service life of the proposed transmission lines for accounting purposes varies among utilities. The Applicants use an approximately 60-year service life for their transmission assets. However, practically speaking, high voltage transmission lines are seldom completely retired.

7.5 Storm and Emergency Response and Restoration

Transmission infrastructure has very few mechanical elements and is built to withstand weather extremes that are normally encountered. With the exception of outages due to severe weather, such as tornadoes and heavy ice storms, transmission lines rarely fail.

Transmission lines are automatically taken out of service by the operation of protective relaying equipment when a fault is sensed on the line. Such interruptions are usually only momentary. Scheduled maintenance outages are also infrequent. As a result, the average annual availability of transmission infrastructure is very high, in excess of 99%.

However, unplanned outages of transmission facilities can happen for a variety of reasons. Unplanned outages can occur due to mechanical failures or severe weather, like heavy ice, wind, and lightning. In the event an unplanned outage of any facility along the proposed Project occurs, Applicants have the necessary infrastructure and crews in place to respond quickly and safely to return these facilities to service.

8 ENVIRONMENTAL INFORMATION

This section provides a general description of the environmental setting, land use and human settlement, land-based economies, archeological and historical resources, hydrological features, vegetation and wildlife, and rare and unique natural resources that are known to occur or may potentially occur in the Project Study Area, shown in **Map 8-1**. Maps 8-1 through 8-15 are included in **Appendix J**. This section also identifies potential impacts to existing resources and identifies measures that can be implemented to avoid, minimize, or mitigate impacts. The environmental information for the Project is described generally across the Project Study Area.

8.1 Project Study Area

The Project Study Area includes a 0.5-mile buffer area from the existing transmission line alignment.[104]

The Project Study Area measures approximately 64,526 acres and includes portions of Clay, Wilkin, Otter Tail, Grant, and Douglas counties (**Map 8-1**). **Map 8-2** through **Map 8-5** show additional details of the Project Study Area.

The Project extends from the Minnesota-North Dakota border in Holy Cross Township in Clay County, crossing Clay, Wilkin, Otter Tail, Grant, and Douglas counties, before terminating at Alexandria Substation in Alexandria, Minnesota, in Douglas County. The Project involves stringing a second 345 kV transmission circuit onto existing transmission line infrastructure. When the existing infrastructure was originally installed, space was left for this future second circuit, allowing electrical capacity to be increased by leveraging the existing infrastructure. As part of the Project, up to 107 steel monopoles and 94 foundations will be installed at certain locations to accommodate the new 345 kV transmission line circuit. Eighty-six of these steel monopoles and 82 foundations are within Minnesota.

These locations are where the original line was designed for two-structure angles but only one structure was erected during construction of the Fargo – St. Cloud

[104] The Project Notice Plan used the same buffer to develop the landowner mailing list.

transmission project. These new monopoles will be installed within the existing transmission line ROW.

As discussed further in Section 8.1.2, the landscape within the Project Study Area varies. This is a result of past glacial activity and other ecological factors that affected the landscape over time. These changes are apparent in hydrology, vegetation, topography, land use, and human settlement patterns within the Project Study Area.

8.1.1 Description of Environmental Setting

The landscape of the Project Study Area consists of generally level to slightly undulating landforms that were once tallgrass prairie. (**Map 8-6**). Agricultural fields now dominate this portion of the Project Study Area.

Within the Project Study Area, the landscape consists of broad, gently rolling terrain historically covered in tallgrass prairie, much of which has transitioned to agricultural use, as well as upland forests and mixed woodlands interspersed among open fields and lakes. Major rivers in the Project Study Area include the Red River, Pelican River, and Otter Tail River. Larger cities in the Project Study Area include Alexandria, Fergus Falls, Rothsay, and Barnesville.

8.1.2 Geomorphology and Physiography

The Minnesota Department of Natural Resources (MDNR) and the U.S. Forest Service developed an Ecological Classification System (ECS) for ecological mapping and landscape classification in Minnesota that is used to identify, describe, and map progressively smaller areas of land with increasingly uniform ecological features (reference (1)). Within the ECS, the State of Minnesota is split into ecological provinces, sections, and subsections. Under this classification system, the majority of the Project Study Area lies within the Red River Valley and North Central Glaciated Plains Sections of the Prairie Parkland Province. The remaining portion falls within the Minnesota and NE Iowa Morainal Section of the Eastern Broadleaf Forest Province. The Project Study Area includes the Red River Prairie, Hardwood Hills, and Minnesota River ecological subsections.

Table 8-1 provides the acreage and percentage of the Project Study Area within each ECS subsection. **Map 8-7** depicts the ECS subsections in relation to the Project Study Area. General physiography and geomorphology for each subsection is outlined below.

Table 8-1
ECS Subsections in the Project Study Area

ECS Subsection[1]	Counties	Total	
		Acres	Percentage
Red River Prairie	Clay, Otter Tail, Wilkin	39,830	62
Hardwood Hills	Douglas, Otter Tail, Grant	8,623	13
Minnesota River Prairie	Douglas, Otter Tail, Grant	16,076	25
Total		64,529	100

[1] ECS boundaries do not conform to county boundaries. As such, portions of each county listed are within the ECS and some counties are within multiple ECSs. Source: https://www.dnr.state.mn.us/ecs/index.html

8.1.2.1 Red River Prairie Subsection

The Red River Prairie subsection is a broad, flat landscape defined by the ancient glacial Lake Agassiz (reference (1)). The terrain is mostly level, with subtle relief from till plains, beach ridges, sand dunes, and river valleys. The topography is flat to gently rolling, with steeper slopes occurring along drainages and adjacent to Lake Traverse. Glacial drift generally ranges between 200 feet and 400 feet. The subsection is characterized by moderately well-drained to poorly drained soils composed of clays, silts, and sands. The subsection is primarily drained by the Red River, which forms its western boundary and flows north into Canada. Due to the region's flat topography, the drainage network is poorly developed, and rivers and streams meander extensively. Seasonal flooding is common, especially in early spring, when frozen conditions to the north can cause water to back up and inundate large areas. Lakes are scarce, with most found in the southeastern till plain; these are typically shallow and perched. Historically the subsection was dominated by tallgrass and wet prairie ecosystems, with limited forest cover along waterways, but has since been mostly converted to agriculture with some remnant prairie ecosystems remaining intact.

8.1.2.2 Minnesota River Prairie

The Minnesota River Prairie subsection is characterized by large till plains that are bisected by the broad valley of the Minnesota River (reference (1)). The Minnesota River was formed by Glacial River Warren, which drained Glacial Lake Agassiz. Topography is steepest along the Minnesota River and the Big Stone Moraine, which has steep kames and broad slopes, while topography outside of the river valley consists of level to gently rolling ground moraine. Glacial drift generally ranges between 100 feet and 400 feet throughout this subsection. Soils are predominantly well- to moderately well-drained loams formed in gray calcareous till of the Des Moines lobe with some localized inclusions of clayey, sandy, and gravelly soils. Streams and small rivers drain into the Minnesota River or the Upper Iowa River, though drainage networks are poorly developed due to landscape characteristics. There are 150 lakes greater than 160 acres in size throughout this subsection, though many are shallow. Wetlands were common within this subsection prior to Euro-American settlement, and most have been drained to establish cropland.

8.1.2.3 Hardwood Hills Subsection

The Hardwood Hills subsection is characterized by steep slopes, high hills, and lakes formed in glacial end moraines and outwash plains (reference (1)). During the Wisconsin age glaciation, ice stagnation moraines, end moraines, ground moraines, and outwash plains were formed in this subsection. Kettle lakes are abundant within the moraines and outwash deposits and there are over 400 lakes greater than 160 acres in size within this subsection. Most of this subsection is covered in 100 feet to 500 feet of glacial drift over diverse bedrock. Loamy soils are dominant, with loamy sands and sandy loams on outwash plains to loams and clay loams on moraines. The high ridge of the Alexandria Moraine is the headwaters region for many rivers and streams that flow east and west; the Chippewa, Long Prairie, Sauk, and Crow Wing are the major rivers in this subsection and the Mississippi River forms part of the eastern boundary. The Hardwood Hills subsection is split by the Continental Divide and waters north of the divide eventually flow toward Hudson Bay and waters south of the divide flow into the Mississippi River system (**Map 8-7**).

8.1.2.4 Topography

Topography within the Red River Prairie subsection is flat landscape shaped by ancient glacial Lake Agassiz with subtle relief from beach ridges and meandering river valleys. The elevation ranges between 800 feet to 1,000 feet above sea level. The Hardwood Hills subsection topography is characterized by steep slopes and rolling hills formed by glacial moraines and outwash plains and contains abundant kettle lakes and wetlands. Elevations range between 1,200 feet to 1,500 feet above sea level. The Minnesota River Prairie subsection is gently rolling ground moraines with steeper slopes along the Minnesota River Valley and Big Stone Moraine. Elevations range between 900 feet to 1,200 feet above sea level (**Map 8-6**).

8.1.3 Human Settlement

The following sections describe elements related to human settlement and land uses within the Project Study Area.

8.1.3.1 Land Use and Land Cover

According to the 2023 National Landcover Database – Land Use-Land Cover dataset, cultivated cropland is the dominant land cover, making up 65 percent of the Project Study Area (**Map 1-1, Map 8-8**) and, therefore, agriculture is the primary land use. Pasture/Hay is the second most dominant land cover type, accounting for 9 percent of the Project Study Area, followed by emergent herbaceous wetlands and low intensity developed areas at approximately 5 percent each. The remaining land cover classifications make up approximately 16 percent of the Project Study Area.

The Project is not expected to significantly change current land use or cover in the Project Study Area. New monopoles will have minimal additional impact, and adding a second circuit on existing transmission infrastructure will not alter land cover within the established ROW.

Table 8-2
Land Cover in the Project Study Area

Land Use Category	Total Project Study Area Acres	Total Project Study Area Percentage
Barren Land	62	0.10
Cultivated Crops	42,009	65.10
Deciduous Forest	1,901	2.95
Developed, High Intensity	109	0.17
Developed, Low Intensity	3,652	5.66
Developed, Medium Intensity	1,275	1.98
Developed, Open Space	2351	3.64
Emergent Herbaceous Wetlands	3,328	5.16
Evergreen Forest	3	0.00
Pasture/Hay	5,844	9.06
Herbaceous	552	0.86
Mixed Forest	10	0.02
Open Water	3,085	4.78
Shrub/Scrub	1	0.00
Woody Wetlands	347	0.54
Total	**64,529**	**100**

8.1.3.2 Commercial, Industrial, Residential Land Use

Human settlement within the Project Study Area includes municipalities, farmsteads, rural residences, utility infrastructure, roadways, and commercial and industrial areas. Publicly available information was reviewed to characterize commercial, industrial, and residential land use patterns throughout the Project Study Area.

Larger cities and towns within or adjacent to the Project Study Area are concentrated along Interstate 94 (**Map 8-1**). Larger cities and towns include Barnesville, Rothsay, Fergus Falls, and Alexandria.

Residential areas in the Project Study Area are located within large and small cities and towns, as well as scattered rural residences and farmsteads located in more rural areas. Outside of the larger municipalities, communities are generally small and rural in nature, with farmsteads and residences located along roadways, away from population centers. Commercial and industrial areas in the Project Study Area are generally located within or adjacent to these larger municipalities.

There are no federally recognized reservations or other tribal lands located within the Project Study Areas.

8.1.3.3 Displacement

The development and construction of the Project is not anticipated to displace any residential homes or businesses. NESC and the Applicants' standards require minimum clearances between transmission line facilities and buildings to safeguard safe operation of transmission line facilities. To maintain these clearances, the Applicants plan to remain within the existing 150-foot-wide transmission ROW for the existing 345 kV transmission line. The Project involves stringing a second 345 kV circuit on existing transmission line infrastructure. Additionally, an estimated 107 new monopoles (86 structures within Minnesota) are proposed in specific areas along the current transmission line to address alignment changes (such as directional turns) and certain highway crossings. These new monopoles will also be installed within the existing transmission line ROW.

8.1.3.4 Aesthetics

Overhead electric transmission and distribution lines and other linear infrastructure (e.g., roads, pipelines) are present throughout the Project Study Area. The 345 kV transmission line circuit will be located within an existing transmission line ROW for the entire route. New monopoles will be located within the existing ROW and sited adjacent to existing transmission infrastructure and would therefore have a negligible impact on the surrounding aesthetics.

8.1.3.5 Socioeconomics

8.1.3.5.1 Population and Economic Profile

The existing socioeconomic conditions are based on data reviewed from the 2019–2023 American Community Survey (ACS) 5-Year Estimates (reference (2)). The Project Study Area is located wholly or partially within the five counties identified in **Table 8-3**; these counties form the basis of establishing socioeconomic conditions described herein.

Population and socioeconomic data for counties within the Project Study Area and the State of Minnesota are provided in **Table 8-3**. Counties in the Project Study Area are generally rural in nature. The cities of Fergus Falls, Otter Tail County, and Alexandria in Douglas County are the largest cities within the Project Study Area. The northwestern terminus of the Project Study Area is west of the City of Barnesville in Clay County. The five counties within the Project Study Area combined comprise approximately 3 percent of the State's total population over the age of 16 years.

Table 8-3
Population and Socioeconomic Data

Location	Population 16 Years and Over	Unemployment Rate (Percent)	Per Capita Income (Dollars)	Top employment by Industry
State of Minnesota	4,549,661	2.7	$46,957	E, M, R
Clay County	50,898	2.7	$38,791	E, R, P
Douglas County	31,755	1.7	$43,543	E, M, R
Grant County	4,878	1.9	$38,893	E, R, W
Otter Tail County	48,652	3.1	$38,723	E, M, R
Wilkin County	5,092	3.0	$36,057	E, A, M

U.S. Census Bureau, 2019-2023 5-Year American Community Survey Estimates. Industries are defined under the 2022 North American Industry Classification System.
Classification System and abbreviated as follows: Ag = Agriculture, Forestry, Fishing, and Hunting, and Mining; E = Educational, Health Care and Social Assistance; M = Manufacturing; P= Professional, Scientific, and Management, and Administrative and Waste Management Services; R = Retail Trade; W = Wholesale Trade
Source: reference (2)

The unemployment rate within the Project Study Area ranges from a low of 1.7 percent in Douglas County to a high of 3.1 percent in Otter Tail County. Per capita annual income averages, within the five counties that the Project Study Area crosses, are below the state average of $46,957 and range from a low of $36,057 to a high of $43,543. Education, health care, and social assistance is the primary labor category in all the five counties that the Project Study Area crosses, as well as in the State of Minnesota.

8.1.3.5.2 Local Economy and Labor Force

The Minnesota Department of Employment and Economic Development (DEED) 2022 Regional Profile for Northwest Region 4 (West Central) provides a summary of key labor market, employment, and industry trends and projections. Northwest Region 4 encompasses Becker, Clay, Douglas, Grant, Otter Tail, Pope, Stevens, Traverse, and Wilkin counties. Five of nine counties that comprise Region 4 are within the Project Study Area, including Clay, Wilkin, Otter Tail, Grant, and Douglas counties.

Based on the DEED Northwest Region 4 profile summary, Region 4 contains 7,088 business establishments that provided 88,630 jobs in 2021, representing 3.2 percent of total employment in the State of Minnesota. Otter Tail, Douglas, and Clay counties ranked highest in number of jobs, consisting of 22,114, 181,767, and 18,984 jobs in 2021, respectively. Health Care and Social Assistance (16,445 jobs), manufacturing (12,966 jobs), retail trade (10,840 jobs), and education services (9,052) are the largest industry sectors in the region. Construction jobs represented the highest job increase, adding over 300 jobs and growing 6.4 percent between 2019 and 2021.

Region 4 is within the greater Northwest Planning Area, which encompasses 26 counties in northwestern Minnesota. The Northwest Planning Area is anticipated to grow 5.1 percent from 2020 to 2030, an increase in 12,719 jobs. Health Care and Social Assistance is expected to contribute the most jobs to the regional economy.

The Project would not require new ROW acquisitions or relocations. Project impacts are anticipated to be temporary in nature and limited to the existing transmission line corridor and access roads. Potential impacts to local economies would primarily consist of construction-related impacts, such as short-term roadway closures and diversions that may temporarily affect access to local businesses. The Applicants would be required to maintain access to any affected businesses and residences throughout construction.

Transmission line projects have the potential to benefit the socioeconomic conditions of an area in the short term through an influx of labor personnel, creation of construction jobs, purchases of construction material and other goods from local businesses, and expenditures on temporary housing, food, fuel, etc. for non-local personnel. In the long term, transmission line projects may beneficially impact the local tax base in the form of revenues generated from utility property taxes. The benefits apply to the local community regardless of economic status, race, and personal identification.

The Applicants will work with local communities to identify opportunities for further enhancing the socioeconomic benefits of the Project.

8.1.3.6 Environmental Justice

8.1.3.6.1 MPCA Environmental Justice Areas

Pursuant to Minn. Stat. § 216B.1691, subd. 1(e), environmental justice (EJ) areas are defined as area that meet the following criteria based on the most recent data published by the U.S. Census Bureau:

- 40 percent or more of the area's total population is nonwhite;
- 35 percent or more of households in the area have an income that is at or below 200 percent of the federal poverty level;
- 40 percent or more of the area's residents over the age of five have limited English proficiency; or
- The area is located within Indian Country, which is defined as federally recognized reservations and other Indigenous land per United State Code, Title 18, Section 1151.

The MPCA has created the "Understanding Environmental Justice" mapping tool as a resource to identify EJ communities throughout the state and provide guidance for integrating EJ principles such as fair treatment and meaningful involvement of EJ communities. The tool identifies EJ areas as defined by Minn. Stat. § 216B.1981, subd. 1(e) based on U.S. Census 2018-2022 ACS 5-Year Estimates data at the Census Tract (CT) level.

The MPCA mapping tool was reviewed to identify EJ areas located within the Project Study Area (reference (3)). The Project Study Area is located within portions of 15 CTs. The MPCA mapping tool identified four EJ communities within these 15 CTs that meet the criteria for low income, defined as 35 percent of households in the CT have an income at or below 200 percent of the federal poverty level (**Map 8-9**). These EJ areas encompass portions of the City of Fergus Falls in Otter Tail County, City of Alexandria in Douglas County, and Pelican Lake Township in Grant County, and include the following CTs:

- Census Tract 9609, Otter Tail County
- Census Tract 9610, Otter Tail County
- Census Tract 4507.04, Douglas County
- Census Tract 701, Grant County

No CTs within the Project Study Area met the EJ criteria pertaining to limited English proficiency and people of color, and no federally recognized reservations or other tribal lands are located within the Project Study Area.

8.1.3.6.2 County and Census Tract EJ Analysis

An EJ analysis was completed utilizing data obtained from the 2019-2023 ACS 5-Year Estimates at the CT level. To assess if an EJ community is present within the Project Study Area, the percentage of the minority and low-income populations for each CT within the Project Study Area was compared to a larger geographical area, consisting of the five counties intersected by the Project Study Area and the State of Minnesota. Generally, it is assumed that an EJ community is present if the percentage of the minority or low-income populations are the CT level is 10 percent or greater than that of the counties, or the EJ population represents 50 percent or greater of the total CT population.

Race and ethnicity data for the Project Study Area was obtained from the 2019–2023 ACS 5-Year Estimates at the CT level. **Table 8-4** presents race and ethnicity data for the Project Study Area. The majority of the population is White, ranging from 85.8 percent (CT 9609, Otter Tail County) to 98.2 percent (CT 4501, Douglas County).

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Table 8-4
Race and Ethnicity Demographics of the Project Study Area

Location	White (%)	Black or African American (%)	American Indian and Alaskan Native (%)	Asian (%)	Native Hawaiian and other Pacific Islander (%)	Some Other Race Alone (%)	Two or More Races (%)	Hispanic* (%)	Total Minority (%)
State of Minnesota	4,476,710 (78.4%)	388,789 (6.8%)	50,883 (0.9%)	289,148 (5.1%)	2,376 (0.04%)	151,560 (2.7%)	354,300 (6.2%)	353,608 (6.2%)	1,237,006 (21.6%)
Clay County	56,650 (86.3%)	3,174 (4.8%)	566 (0.9%)	1,125 (1.7%)	176 (0.3%)	419 (0.6%)	3,518 (5.4%)	3,186 (4.9%)	8,978 (13.7%)
Douglas County	37,462 (95.2%)	186 (0.5%)	97 (0.2%)	168 (0.4%)	69 (0.2%)	453 (1.2%)	919 (2.3%)	848 (2.2%)	1,892 (4.8%)
Grant County	5,749 (94.1%)	31 (0.5%)	27 (0.4%)	4 (0.1%)	2 (0.03%)	70 (1.1%)	225 (3.7%)	158 (2.6%)	359 (5.9%)
Otter Tail County	55,320 (91.8%)	608 (1.0%)	118 (0.2%)	393 (0.7%)	19 (0.03%)	1,200 (2.0%)	2,623 (4.4%)	2,260 (3.7%)	4,961 (8.2%)
Wilkin County	5,938 (92.6%)	14 (0.2%)	48 (0.7%)	4 (0.1%)	0 (0.0%)	179 (2.8%)	230 (3.6%)	238 (3.7%)	475 (7.4%)
CT 9617, Otter Tail	3,036 (96.3%)	20 (0.6%)	0 (0.0%)	8 (0.3%)	0 (0.0%)	5 (0.2%)	83 (2.6%)	14 (0.4%)	116 (3.7%)
CT 9616, Otter Tail	2,225 (97.9%)	2 (0.1%)	4 (0.2%)	5 (0.2%)	0 (0.0%)	2 (0.1%)	34 (1.5%)	27 (1.3%)	47 (2.1%)
CT 9610, Otter Tail	4,796 (93.2%)	6 (0.1%)	29 (0.6%)	13 (0.3%)	0 (0.0%)	0 (0.0%)	300 (5.8%)	108 (2.1%)	348 (6.8%)
CT 9609, Otter Tail	4,676 (85.8%)	141 (2.6%)	10 (0.2%)	256 (4.7%)	19 (0.3%)	0 (0.0%)	350 (6.4%)	28 (0.5%)	776 (14.2%)
CT 9608, Otter Tail	3,508 (93.3%)	17 (0.5%)	3 (0.1%)	10 (0.3%)	0 (0.0%)	53 (1.6%)	136 (4.2%)	98 (3.0%)	219 (6.7%)

Location	White (%)	Black or African American (%)	American Indian and Alaskan Native (%)	Asian (%)	Native Hawaiian and other Pacific Islander (%)	Some Other Race Alone (%)	Two or More Races (%)	Hispanic* (%)	Total Minority (%)
CT 9607, Otter Tail	2,614 (95.8%)	12 (0.4%)	2 (0.1%)	4 (0.1%)	0 (0.0%)	6 (0.2%)	91 (3.3%)	103 (3.8%)	115 (4.2%)
CT 9501, Wilkin	2,878 (93.8%)	9 (0.3%)	25 (0.8%)	4 (0.1%)	0 (0.0%)	57 (1.9%)	94 (3.1%)	136 (4.4%)	189 (6.2%)
CT 4510, Douglas	4,517 (96.3%)	0 (0.0%)	3 (0.1%)	41 (0.9%)	0 (0.0%)	16 (0.3%)	113 (2.4%)	41 (0.9%)	173 (3.7%)
CT 4509, Douglas	3,543 (97.5%)	11 (0.3%)	0 (0.0%)	1 (0.03%)	0 (0.0%)	9 (0.2%)	70 (1.9%)	4 (0.1%)	91 (2.5%)
CT 4507.04, Douglas	3,012 (93.2%)	76 (2.4%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	145 (4.5%)	61 (1.9%)	221 (6.8%)
CT 4502, Douglas	3,781 (97.9%)	1 (0.03%)	4 (0.1%)	6 (0.2%)	0 (0.0%)	7 (0.2%)	64 (1.7%)	23 (0.6%)	82 (2.1%)
CT 4501, Douglas	3,324 (98.2%)	4 (0.1%)	14 (0.4%)	10 (0.3%)	0 (0.0%)	4 (0.1%)	29 (0.9%)	14 (0.4%)	61 (1.8%)
CT 701, Grant	3,166 (97.9%)	20 (0.6%)	17 (0.5%)	2 (0.1%)	0 (0.0%)	46 (1.4)	79 (2.4%)	91 (2.7%)	164 (7.9%)
CT 302.02, Clay	4,875 (95.5%)	8 (0.2%)	2 (0.04%)	71 (1.4%)	10 (0.2%)	41 (0.8%)	98 (1.9%)	54 (1.1%)	230 (4.5%)
CT 301.10, Clay	5,598 (93.9%)	130 (2.2%)	61 (1.0%)	6 (0.1%)	0 (0.0%)	2 (0.3%)	162 (2.7%)	70 (1.2%)	361 (6.1%)

Source: reference (2), Table B02001 and B03003
CT denotes Census Tract
*Hispanic refers to ethnicity and is not classified as a separate race.

Minority populations are defined as any person who identifies as any race other than white. The minority population within the CTs crossed by the Project Study Area range from approximately 1.8 percent (CT 4501, Douglas County) to 14.2 percent (CT 9609, Otter Tail County) of the total population within the CT. The minority populations of the CTs within the Project Study Area are similar to that of the counties within the Project Study Area, ranging from 4.8 percent (Douglas County) to 13.7 percent (Clay County), and less than the minority population of the State of Minnesota, 21.6 percent.

The Hispanic or Latino populations of the CTs within the Project Study Area range from approximately 0.1 percent (CT 4509, Douglas County) to 4.4 percent (CT 9501, Wilkin County). These percentages are similar to or less than the proportion of the Hispanic or Latino populations at the counties, ranging from 2.2 percent (Douglas County) to 4.9 percent (Clay County) and State of Minnesota, 6.2 percent. Low-income data for the Project Study Area was obtained from the 2019–2023 ACS 5-Year Estimates at the CT level. The U.S. Census Bureau utilizes U.S. Department of Health and Human Services (HHS) poverty guidelines to determine poverty thresholds. The year 2023 HHS weighted average poverty threshold for a four-person family was $31,200. **Table 8-5** provides a comparison of the total households, percentage of households below poverty thresholds, and median household income for CTs within the Project Study Area, counties, and State of Minnesota.

The percentage of households below poverty ranges between 4.0 percent (CT 9617, Otter Tail County) to 25.7 percent (CT 4507.04, Douglas County). In comparison, the percentage of households below poverty of counties within the Project Study Area ranges between 9.7 percent (Douglas County) and 14.8 percent (Clay County), and is 9.4 percent at the state level. The percentage of the low-income population within CT 4507.04 is meaningfully greater than the low-income population of Douglas County (9.7 percent) and the State of Minnesota (9.4 percent). Therefore, it is assumed that a low-income population is present within CT 4507.04.

Table 8-5
Low-Income Demographics of the Project Study Area

Location	Total Households	Households Below Poverty Thresholds (%)	Median Household Income
State of Minnesota	2,282,967	215,597 (9.4%)	$87,556
Clay County	25,939	3,847 (14.8%)	$77,664
Douglas County	17,416	1,691 (9.7%)	$77,264
Grant County	2,521	274 (10.9%)	$72,957
Otter Tail County	25,181	2,655 (10.5%)	$70,912
Wilkin County	2,691	393 (14.6%)	$69,635
CT 9617, Otter Tail	1,285	51 (4.0%)	$100,060
CT 9616, Otter Tail	971	69 (7.1%)	$81,513
CT 9610, Otter Tail	2,248	331 (14.7%)	$41,078
CT 9609, Otter Tail	2,580	392 (15.2%)	$45,076
CT 9608, Otter Tail	1,273	117 (9.2%)	$95,824
CT 9607, Otter Tail	1,144	123 (10.8%)	$73,676
CT 9501, Wilkin	1,196	66 (5.5%)	$86,842
CT 4510, Douglas	1,986	95 (4.8%)	$107,653
CT 4509, Douglas	1,409	53 (3.8%)	$104,659
CT 4507.04, Douglas	1,831	471 (25.7)	$47,438
CT 4502, Douglas	1,685	150 (8.9%)	$85,388
CT 4501, Douglas	1,387	144 (10.4%)	$85,551
CT 701, Grant	1,336	137 (10.3%)	$71,250
CT 302.02, Clay	1,855	89 (4.8%)	$94,460
CT 301.10, Clay	2,198	269 (12.2%)	$106,250

Source: U.S. Census Bureau 2019-2023 ACS Five-Year Estimates, Table B17017, B19013
Shading denotes CTs in which a low-income population is present.

8.1.3.6.3 EJ Findings

The Project involves the installation of a new 345 kV transmission circuit between the existing Bison Substation and the existing Alexandria Substation that will utilize existing double-circuit capable infrastructure. Construction activities will be limited to the existing 150-foot transmission line corridor and access roads. Up to 107 additional foundations (86 within Minnesota) and steel monopoles will be installed at select locations within the existing transmission line ROW. No new ROW acquisitions or relocations will be required to construct the Project. Given that Project impacts are minimal in nature and limited to the existing transmission line corridor, impacts are anticipated to primarily consist of temporary construction-related impacts, such as temporary roadway closures and diversions, construction noise and odors, and other short-term impacts. Temporary construction impacts would be experienced by all populations adjacent to the transmission line corridor and would not disproportionately affect EJ populations.

8.1.3.7 Recreation

Recreational opportunities in the Project Study Area include outdoor recreational trails, use of public lands and parks, snowmobiling, hunting, and fishing, boating, camping, and participation in local area events. There are several types of formally managed and regulated lands across the Project Study Area, including federal easements and managed lands, National Wildlife Refuges (NWRs), Waterfowl Production Areas (WPAs), Wildlife Management Areas (WMAs), Scientific and Natural Areas (SNAs), state trails, state parks, and municipal and county parks and trails (**Map 8-10** and **Map 8-11**).

The Northern Tallgrass Prairie NWR is the only NWR located within the Project Study Area. The refuge includes 16.3 acres in Otter Tail County, near Fergus Falls, Minnesota (**Map 8-11**). The NWR provides a variety of recreational activities such as hiking, fishing, hunting, education programs, wildlife viewing, and boating.

WPAs are lands that were established to conserve migratory bird habitat. There are 26 WPAs (consisting of approximately 6,876 acres) located throughout the Project Study Area (**Map 8-11**). Some WPAs are available for hunting during state-designated hunting seasons.

WMAs are part of Minnesota's outdoor recreation system and are established to protect those lands and waters that have a high potential for wildlife production, public hunting, trapping, fishing, and other compatible recreational uses. There are five WMAs located throughout the Project Study Area (**Map 8-11**).

SNA lands are natural areas where native plants and animals flourish and are managed by MDNR. Most SNAs do not have designated hiking trails, restrooms, or drinking water; however, they are available for bird and wildlife watching, hiking, photography, snowshoeing, and cross-country skiing. There are no SNAs located within the Project Study Area (**Map 8-11**).

The MDNR manages 35 state water trails covering over 4,500 miles throughout Minnesota. These trails provide opportunities for canoeing, kayaking, paddleboarding, and camping. There are approximately 4.6 miles of designated state water trails throughout the Project Study Area (**Map 8-10**). These state water trails are located along the Otter Tail River and the Red River of the North.

No state trails are located within the Project Study Area.

Additional hiking trails are located within state, local and county parks. No state or county parks are located within the Project Study Area. There is one municipal park found within the Project Study Area. (**Map 8-10**).

Snowmobile trails are found throughout the Project Study Area and generally follow existing county and township roads, though many state parks and hiking trails also allow snowmobiling during the winter months. In total, there are approximately 26.1 miles of snowmobile trails within the Project Study Area (**Map 8-10**).

The Applicants will work with applicable federal, state, county, and local agencies to develop appropriate mitigation measures to minimize impacts on public recreational use of these areas. Mitigation measures could include avoiding construction during seasons of peak use, signage, and ensuring public access to recreation areas is not restricted, as well as obtaining relevant permits/approvals from applicable agencies.

8.1.3.8 Conservation Easements

Conservation lands are areas designated by a legal instrument (i.e., contract, easement, regulation) that limits or conditions certain uses of the land to fulfill the respective conservation purpose. Conservation lands in the Project Study Area include the following:

- Conservation Reserve Enhancement Program (CREP)
- Reinvest in Minnesota (RIM)
- Wetland Reserve Program (WRP)

There are approximately 687.7 acres of conservation easements located in the Project Study Area (**Map 8-10; Table 8-6**).

Table 8-6
Conservation Easements in Project Study Area

Conservation Easement	Project Study Area (Acres)
Conservation Reserve Enhancement Program	358.4
Reinvest in Minnesota	245.3
Wetland Reserve Program	84
Total	**687.7**

The CREP program is the largest conservation program in the Project Study Area. CREP is a land conservation program established to pay farmers a yearly rental fee for agreeing to take environmentally sensitive land out of agricultural production with the intent of improving environmental health and quality (reference (4)). There are 358.4 acres of CREP land located in the Project Study Area (**Map 8-10; Table 8-6**).

Similar, the RIM program was implemented by the Minnesota Board of Water and Soil Resources to conserve environmentally sensitive property to improve water quality by reducing soil erosion, phosphorus and nitrogen loading, and improving wildlife habitat and flood attenuation on private lands (reference (5)). There are approximately 245.3 acres of land in the RIM program located in the Project Study Area (**Map 8-10; Table 8-6**).

The WRP properties are established by the United States Department of Agriculture (USDA) and Natural Resource Conservation Service to provide habitat for migratory waterfowl and other wetland dependent wildlife, including threatened and endangered species; improves water quality by filtering sediments and chemicals; reduces flooding; recharge groundwater; protect biological diversity; provide resilience to climate change; and provide opportunities for educational, scientific, and limited recreational activities (**Map 8-10**, reference (6)). There are approximately 84 acres of WRP land within the Project Study Area (**Table 8-6**).

The Permanent Wetland Easement Program (PWP) is a state program that establishes permanent conservation easements to protect at-risk wetlands. No PWP land was identified within the Project Study Area (**Map 8-10; table 8-6**).

Similarly, wetland banking easements are conservation easements that protect wetlands from future disturbances. No wetland banking easements were identified within the Project Study Area (**Map 8-10; Table 8-6**).

Depending on the governing conservation program, specific restrictions may be applied that would limit or restrict development of a transmission line. As the Project utilizes the existing 345 kV transmission line ROW, impacts to conservation lands will primarily be temporary in nature. However, two structures are located within existing RIM easements. The Applicants will work with the owners and managing agency to develop appropriate mitigation measures to minimize effects at these locations.

8.1.3.9 Public Services and Transportation

The Project Study Area is primarily located in a rural setting in northwestern Minnesota (**Map 8-13**). In rural areas, residents often rely on privately owned domestic water wells and on-site septic systems for their water supply and wastewater treatment. Larger populations centers provide municipal water and sewer treatment via buried public infrastructure.

Existing road infrastructure within the Project Study Area is a mix of state, county highways and roads, and township roads. The Project Study Area generally follows Interstate 94 (I-94). Major transportation networks located in the Project Study Area include I-94, U.S. Highways 59 and 75, and Minnesota State Highways 9, 17, 27, 29, 34, 54, 78, 79, 108, 114, and 210 (**Map 8-13**). In addition, two railroads intersect the Project Study Area. A railroad owned by Otter Tail Valley Railroad Company generally follows the I-94 corridor and a segment of Burlington Northern Santa Fe Railroad extends along US Highway 75, within the Project Study Area.

Numerous electric transmission lines exist throughout the Project Study Area, as depicted on **Map 8-13**. Electrical substations that support the network of transmission lines are scattered throughout the Project Study Area; these facilities are generally sited on the outer edges of municipalities or away from population centers in rural areas.

Hazardous liquid pipelines are present within the Project Study Area (**Map 8-13**). Generally, these pipelines are sited away from population centers, while the distribution lines typically supply population centers. The location of pipelines will be identified with more specificity during final design of the Project. The Project is within the existing ROW corridor, which is intersected by public infrastructure, roads, railroads, and pipelines. Any required crossing permissions or agreements will be obtained from the applicable owners/operators.

No airports are located within the Project Study Area (**Map 8-13**) Several airports are located outside of the Project Study Area, including the Fergus Falls Municipal Airport – Einar Mickelson Field and Alexandria Municipal Airport – Chandler Field. A private field and Barnesville municipal airport, a grass airstrip, are located slightly outside the Project Study Area near the City of Barnesville. The Project Study Area is within the Minnesota Department of Transportation (MnDOT) Airport Influence Areas associated with these municipal airports. Private airports located outside the Project Study Area consist of a mixture of hospital/medical center airstrips or landing pads, and privately owned landing strips.

Pursuant to 14 CFR Part 77 (Part 77), the Federal Aviation Administration (FAA) is committed to maintaining the safe and efficient use of navigable airspace for both public and military airports and heliports. To achieve this goal, the FAA conducts aeronautical studies of proposed and existing structures submitted via Form 7460-1, "Notice of Proposed Construction or Alteration" (Notice). The requirements for submitting such notifications are outlined in § 77.9. The FAA mandates notification for any transmission line constructed near an airport where the structure's height exceeds a slope of 100:1 within 20,000 feet (3.8 miles) or 50:1 within 10,000 feet (1.9 miles) from the airport. Typically, to comply with local regulations under 14 CFR Part 77, transmission lines should be located approximately one mile from municipal airports. The Project will adhere to all applicable rules regarding airport safety zones. Additionally, as the Project utilizes existing transmission line infrastructure, it is already in compliance with airport setback requirements.

Hospitals, fire stations, and police departments are located throughout the Project Study Area. Generally, these public services are located within municipalities identified in Section 8.1. Some rural hospitals, fire stations, and police departments located outside of municipal boundaries provide services to rural residences.

Impacts on public services and transportation can be addressed through measures such as design, permitting, and construction, including paralleling existing utility corridors and other linear infrastructure. The current circuit runs parallel to I-94 for a significant portion of its route. The Project plans to limit additional effects on public services and transportation while constructing the second circuit. The Applicants are coordinating with applicable federal, state, and county agencies, including MnDOT, to minimize impacts on public services and transportation. During early coordination discussions with MnDOT, it was noted that MnDOT plans to construct structural and living snow fence installations along portions of I-94 corridor between the Cities of Moorhead and Osakis, beginning in 2027. The Applicants will continue to coordinate with MnDOT on this Project. Mitigation measures could include avoiding construction during hours of peak use, detours, signage, and ensuring access to public service infrastructure is not restricted.

8.1.4 Land-Based Economies

8.1.4.1 Agriculture

The agricultural production industry is a significant part of local economies throughout Minnesota. Information from the USDA's 2022 Census of Agriculture was obtained to evaluate the agricultural setting of at the county-level. Table 8-7 summarizes agriculture statistics for counties within the Project Study Area.

The percentage of land used for farmland by county within the Project Study Area represents a greater proportion of the total county area compared to the State of Minnesota. Grant County has the greatest percentage of county land used for farmland

(96.6 percent). Otter Tail County has the largest market value for agricultural products sold ($551 million). Corn for grain and soybeans is the predominant crop based on acreage in each county and the State of Minnesota. The dominant livestock based on number of farms is cattle for counties in the Project Study Area, followed by hogs, sheep, and chickens (**Table 8-7**).

Table 8-7
Agriculture Statistics by County

Location	Total Farmland (acres)	Top 3 Harvested Crops by Acres	Top 3 Livestock by No. of Farms	Market Value of Agricultural Products Sold (dollars)
State of Minnesota	25,442,525 (49.9% of state)	Corn for grain, soybeans, forage	Cattle, hogs, sheep	$28,482,097,000
Clay County	556,161 (83.1% of county)	Soybeans, corn for grain, wheat	Cattle, sheep, hogs	$466,030,000
Douglas County	268,096 (65.8% of county)	Soybeans, corn for grain, forage	Cattle, sheep, chickens	$168,616,000
Grant County	338,754 (96.6% of county)	Corn for grain, soybeans, sugar beets	Cattle, chickens, sheep	$313,725,000
Otter Tail County	770,922 (61.1% of county)	Corn for grain, soybeans, forage	Cattle, sheep, hogs	$551,279,000
Wilkin County	401,044 (83.4% of county)	Soybeans, corn for grain, sugar beets	Cattle, hogs, sheep	$254,790,000

Source: reference (7)

Given that the Project proposes to string the new 345 kV transmission line on existing transmission line infrastructure, impacts to agricultural production will be largely avoided. However, minimal permanent impacts on agricultural land may occur due to new pole placement. Temporary impacts to agricultural lands during construction may include soil compaction, disruption of agricultural practices, and crop damages within the existing ROW at proposed structure locations, access locations, and other work areas. In areas where impacts on normal farming operations are unavoidable, the Applicants will consult with the agricultural operators to make all reasonable efforts to minimize impact. The Applicants will consult with farmers to designate site-specific techniques to be implemented, including determining the appropriate locations for temporary fencing and gate locations, the moving of livestock as needed, and optimal locations for access to the transmission line corridor.

8.1.4.2 Forestry

The Project Study Area is dominated by agricultural lands with minimal forested land. No commercial forestry operations have been identified in the Project Study Area, based upon review of publicly available data. The MDNR evaluates potential timber harvest or other forest management activity on a 10-year basis and prepares an Annual Stand Exam List, which identifies potential timber harvest areas. A review of the MDNR 10-year Stand Exam List (2021 – 2030) determined that no forest stands are present within the Project Study Area (reference (8)). Therefore, no impacts to commercial forestry operations are anticipated during construction or operation of the Project.

8.1.4.3 Tourism

Tourism in the Project Study Area centers around outdoor recreational opportunities, such as snowmobiling, hunting and fishing, boating, camping, and other activities. As described in Section 8.1.3.7, several federal- and state-managed lands are present within the Project Study Area, including one NWR, WPAs, WMAs, and SNA lands that provide outdoor recreational opportunities. **Table 8-8** summarizes annual tourism revenue for counties within the Project Study Area.

Table 8-8
Visitor Spending by County (2023)

Location	Visitor Spending ($ millions)						
	Lodging	Food & Beverage	Recreation	Retail	Transportation	Second Home	Total
State of Minnesota	$4,274.7	$3,299.6	$1,934.8	$2,137.5	$2,474.2	N/A	$14,120.8
Clay County	$13.1	$18.3	$7.3	$15.5	$10.8	$5.9	$71.0
Douglas County	$39.3	$25.7	$12.5	$23.6	$17.0	$14.7	$132.8
Grant County	$0.6	$0.6	$0.5	$0.3	$2.1	$1.6	$5.7

Location	Visitor Spending ($ millions)						
	Lodging	Food & Beverage	Recreation	Retail	Transportation	Second Home	Total
Otter Tail County	$25.6	$23.8	$10.5	$16.6	$15.2	$30.7	$122.5
Wilkin County	$0.4	$0.9	$0.3	$0.3	$2.1	$0.8	$4.8

Source: reference (9)

The Project would not result in direct impacts to tourist destinations and work is anticipated to be limited to the existing 150-foot transmission line corridor and access roads. Therefore, impacts on tourism in the Project Study Area would be minimal and limited to temporary construction impacts.

8.1.4.4 Mining

Mining does not comprise a major industry in the Project Study Area. According to the MDNR map of minerals mined in Minnesota, one horticultural peat mining operation is located within Otter Tail County (reference (10)). Smaller sand, gravel, and stone quarry operations are found within the Project Study Area. The mined sand and gravel material are primarily used for making concrete for highways, roads, bridges, and buildings. The Project is anticipated to avoid these mining resources, and no impacts to mining are anticipated.

8.1.5 Archaeological and Historical Resources

Previously identified archaeological sites (e.g., artifact scatters, structural ruins, and cemeteries) are present in the Project Study Area. The Project Study Area also contains above-ground historic resources, including railroads, bridges, and churches. Rural farmsteads and homesteads have also been documented throughout the Project Study Area.

Available cultural resources data retrieved from the Minnesota State Historic Preservation Office on August 12, 2025, indicate that 37 archaeological sites, 75 above ground historic resources, and 37 burial sites and cemeteries have been documented within the Project Study Area as summarized in **Table 8-9**. Several of the identified cultural resources are eligible for listing in the National Register of Historic Places (NRHP).

Table 8-9
Summary of Cultural Resources Identified in Literature Review

County	Archaeological Sites			Above Ground Historic Resources			Burial Sites and Cemeteries		
	Resource Number Total	Considered Eligible	Intersect Project Area	Resource Number Total	Considered Eligible	Intersect Project Area	Resource Number Total	Considered Eligible	Intersect Project Area
Clay	11	1	2	6	1	1	4	--	--
Wilkin	--	--	--	5	--	1	--	--	--
Otter Tail	8	1	1	28	1	4	15	--	3
Grant	4	1	2	3	--	--	6	--	1
Douglas	14	1	3	12	--	1	7	--	4
Multiple	--	--	--	21	2	16	5	--	2
Totals	**37**	**4**	**8**	**75**	**4**	**23**	**37**	**--**	**10**

The Applicants completed a Phase Ia literature review to characterize the prehistoric and historic context along the route and further examine the previously recorded archaeological sites and historic architectural resources to determine recommendations regarding avoidance for any sites determined eligible for or listed in the NRHP. A summary of the Phase Ia literature review findings will be presented in the Route Permit Amendment Application.

The Project is aligned with an existing transmission line along the existing route, thereby reducing the potential impact on cultural resources. As most of the area was previously disturbed during the initial construction, the likelihood of affecting cultural resources during new construction activities is minimized.

If impacts to a specific cultural resource cannot be avoided by the Project, that cultural resource would require a formal significance evaluation to determine if it meets the eligibility requirements for listing on the NRHP, if its eligibility has not been previously determined. If found significant, mitigation strategies may be undertaken to reduce impacts. If cultural resources are listed in the NRHP, or if they are considered eligible for listing, they may be afforded protection under federal and state regulations.

The Applicants provided notice to all Minnesota tribal governments and federally recognized tribes with ancestral ties to Minnesota per the Notice Plan, and these tribes were invited to the open houses held in September. The Applicants will work with the appropriate state, federal, and tribal agencies to avoid known cultural resources as much as possible.

8.1.6 Hydrologic Features

There are eight major watershed basins (hydrologic unit code [HUC]-04) and 81 major surface water watersheds (HUC-08) covering Minnesota. The Project Study Area is predominantly located within the Minnesota River Watershed (HUC-4) and Red River Watershed (HUC-4). A small portion of the Project Study Area also crosses the Mississippi Headwaters Watershed (HUC-4). There are seven HUC-8 Watersheds located within the Project Study Area (**Map 8-14** and **Map 8-15**); though a watershed may cross the Project Study Area, it does not necessarily mean the major river associated with the watershed is located within the Project Study Area.

According to the MDNR Public Water Inventory (PWI) dataset, there are 62 PWI basins and 46 PWI wetlands located within the Project Study Area (**Map 8-15**). Pelican Lake is the only waterbody in the Project Study Area that is greater than 1,000 acres in size.

The Project Study Area is located primarily within the Midwest wetland delineation region. The Midwest region is characterized by its generally flat to rolling topography, fertile soils, and moderate to abundant rainfall (reference (11)). Wetlands in the region are generally characterized as prairie wetlands or riverine wetlands.

A smaller portion of the Project Study Area also intersects the Great Plains and Northcentral and Northeast wetland delineation regions. While the Great Plains region is like the Midwest region in terms of topography, it has a generally more semi-arid climate (reference (11)). Wetlands in this region occupy only a small percentage of the landscape but are highly diverse and include freshwater marshes, sloughs, wet meadows, floodplain and riparian wetlands, seeps, springs, slope, and pothole wetlands, among others.

Unlike the previous two regions, the terrain of the Northcentral and Northeast region goes from being nearly flat to mountainous, with precipitation increasing in general from west to east. The region is defined by its recent history of glaciation and ample precipitation, which has resulted in a diversity of wetlands that can broadly be categorized as either freshwater or saltwater wetlands (reference (12)).

According to the United States Fish and Wildlife Service (USFWS) National Wetland Inventory database, the Project Study Area contains approximately 9,137 acres of wetlands, comprising approximately 14 percent of the Project Study Area (**Map 8-15**). The majority of the wetlands are classified as riverine, shallow open water wetlands, or shallow marshes (**T**Table 8-10**able 8-10**).

Table 8-10
National Wetland Inventory Wetlands Within the Project Study Area

Cowardin Class[1]	Circular 39 Class[2]	Wetland Type	Acres in Project Study Area
PEMA, PFOA	1	Seasonally Flooded Wetlands	2,215
PEMD	2	Wet Meadows	300
PEMC and F; PUSC	3	Shallow Marshes	2,663
PABF and PUBF	4	Deep Marshes	227
L1UBH, L2ABH, L2UBH, L2USC, PABH, PUBH	5	Shallow Open Water	3,359
PSS1A, C, and D	6	Shrub Swamp	103
PFO1, 1C, and 1D	7	Wooded Swamp	146
PSS3D	8	Bogs	20
PUBK	80	Lake	14
R2UBH and R2USC	90	Rivers	121
TOTAL			**9,137**

[1] reference (13)
[2] reference (14)

The Project corridor has previously been impacted by the construction of the existing transmission line, and minimal effects on surface waters are expected during the installation of the second circuit.

Calcareous fens are rare distinctive peat-accumulating wetlands that depend on a constant supply of calcium and other mineral rich groundwater. This unique microenvironment can support highly diverse and unique rare plant communities. According to the MDNR's Identification List of Known Calcareous Fens (reference (15)), there are no known calcareous fens located within the Project Study Area. (**Map 8-12**).

8.1.6.1 Floodplains

The major floodplains in the Project Study Area occur adjacent to large waterbodies and watercourses. Most of the Project Study Area is mapped as areas with minimal flood hazard (Zone X). The Federal Emergency Management Agency has mapped regulated floodways located along the Chippewa River, Whisky Creek, Pomme de Terre River, and Red River of the North. Outside the 100-year floodplain, some areas along these rivers are mapped as 500-year floodplains that reach beyond the adjacent riverine areas into agricultural areas and the edges of communities. Additional floodplains are found adjacent to larger perennial streams and areas with shallow banks and low terraces.

It is anticipated that the Project would have no effect on the flood elevations within the Project Study Area because the Project involves use of an existing transmission line corridor and construction of the second circuit is not expected to result in flood elevations to rise.

8.1.6.2 Groundwater

Groundwater in Minnesota is divided into six aquifer provinces based on glacial geology and bedrock (reference (16)). The Project Study Area is located within the Central (Province 4) and Western (Province 5) groundwater provinces. The majority of the Project Study Area (69 percent) is located within the Central groundwater province.

The Central groundwater province is characterized by buried sand aquifers and relatively extensive surficial sand plains, part of a thick layer of sediment deposited by glaciers overlaying the bedrock. This province has thick glacial sediment, and sand and gravel aquifers are common (reference (16)). The Western groundwater province is primarily comprised of glacial sediments that may contain only limited extents of surficial and buried sand aquifers. Fractured bedrock buried deeply beneath the glacial sediment is of limited use as an aquifer (reference (16)). The Project is not anticipated to adversely impact groundwater resources within either province.

8.1.6.3 Karst

A karst feature is characterized as a landscape underlain by limestone that has been eroded by dissolution, producing caves, fissures, or sinkholes. According to the MDNR Karst Feature Inventory, there are no karst features located within or near the Project Study Area. (reference (17)).

8.1.7 Vegetation

More than half of the Project Study Area falls within the Red River Prairie subsection, followed by the Minnesota River Prairie and Hardwood Hills subsections (**Map 8-7**). Descriptions of each subsection are provided in Section 8.1.2.

Pre-settlement vegetation in the Red River Prairie subsection and Minnesota River Prairie subsection consisted primarily of tallgrass prairie and wet prairie islands. Floodplain forests were present within the riparian areas along watercourses and waterbodies (reference (1)).

In the Hardwood Hills subsection, irregular topography and presence of numerous lakes and wetlands provided a partial barrier to fire, resulting in more woodland or forest compared to the Minnesota River Prairie and Red River Prairie subsections. At pre-settlement, mixed hardwood forests were found in the eastern portion of the subsection, while tallgrass prairie was found on flatter terrain in the west (reference (1)).

Currently, the Project Study Area is dominated by agricultural land, with corn and soybeans representing the most common crops. Natural vegetation is present in wetlands and the forested areas near waterbodies and watercourses (**Map 8-8**). In addition, areas of native vegetation are found scattered throughout the Project Study Area in lands mapped or managed by the MDNR; these include potential native prairie remnants and native plant communities, and Sites of Biodiversity Significance (**Map 8-12**).

Potential impacts to existing vegetation in the Project Study Area would occur where matting placement and routine tree trimming is necessary for Project construction and maintenance. Construction and maintenance activities also have the potential to result in the introduction or spread of noxious weeds. Because the Project follows the existing transmission line corridor, no new clearing outside of the existing 150-foot ROW is proposed or anticipated. Where routine maintenance is required, the Applicants will follow the appropriate BMPs and mitigation measures to minimize potential impacts on vegetation resources.

8.1.8 Wildlife

Several lands that are preserved or managed for wildlife and associated habitat are scattered throughout the Project Study Area, including: Aquatic Management Areas, WMAs, and USFWS NWRs and WPAs (**Map 8-11**).

The Project Study Area's agricultural landscape, combined with the preserved or managed wildlife lands, provides habitat for a diversity of resident and migratory wildlife species. These species include large and small mammals, songbirds, waterfowl, raptors, fish, reptiles, mussels, and insects. These species use the Project Study Area for forage, shelter, breeding, or as stopover during migration.

Temporary impacts to wildlife may occur during construction from increased noise and human activity, which could cause some species to temporarily abandon their habitat. Permanent habitat loss, conversion, or fragmentation will not occur since the Project follows existing transmission line infrastructure.

Once the Project is operational, there is potential for increased avian and transmission line interactions in the form of collisions and potential electrocution. However, this potential impact is already present along the existing transmission line infrastructure in the Project Study Area.

The Applicants will work with applicable resource agencies to develop the appropriate BMPs and mitigation measures to minimize the potential for Project activities to impact these sensitive wildlife resources. The Applicants would also incorporate BMPs, as well as implement design and engineering measures where necessary that are consistent with the Avian Power Line Interaction Committee's guidelines to minimize the potential for avian collisions (reference (18)).

8.1.9 Protected Species

Data on federal and state-protected species were reviewed for the Project using the USFWS Information for Planning and Consultation (IPaC) online tool and the MDNR Natural Heritage Inventory System (NHIS) database (License Agreement #2024-057). Although this review does not represent a comprehensive survey, it provides information on the potential for the presence of protected species within the Project Study Area.

8.1.9.1 Federally Protected Species

The USFWS IPaC online tool was queried on September 2, 2025, for a list of federally threatened and endangered species, proposed species, candidate species, and designated critical habitat that may be present within the Project Study Area. The IPaC query identified five species as potentially occurring in the Project Study Area (**Table 8-11**). No designated critical habitat was identified within the Project Study Area.

Table 8-11
Federally Protected Species and Designated Critical Habitat Within the Project Study Area

Common Name	Scientific Name	Federal Status[1]
Northern long-eared bat	*Myotis septentrionalis*	END
Monarch butterfly	*Danaus plexippus*	Proposed THR
Western regal fritillary	*Argynnis idalia occidentalis*	Proposed THR
Western prairie fringed orchid	*Platanthera praeclara*	THR
Suckey's cuckoo bumble bee	*Bombus suckleyi*	Proposed END

[1] THR = threatened; END = endangered.

8.1.9.1.1 Northern Long-Eared Bat

The federally endangered northern long-eared bat roosts in living and dead trees greater than 3 inches in diameter that have loose or peeling bark, cavities, or crevices during the active season (reference (19)). During winter, they hibernate in caves and mines. No northern long-eared bat hibernacula or maternity root trees have been identified in the

Project Study Area (reference (20)). A review of the MDNR NHIS licensed data did not indicate northern long-eared bat species occurrences within the Project Study Area. However, potentially suitable roosting and foraging habitat is present in the Project Study Area.

Potential impacts to individual northern long-eared bats may occur if removal of woody vegetation occurs during the active season, April 1 to October 31. Tree clearing activities conducted when the species is in hibernation are not anticipated to result in direct impacts to individual bats since they do not hibernate in trees, but it could result in indirect impacts due to removal of suitable foraging and roosting habitat.

As tree clearing is not proposed for this Project, no impacts to the northern long-eared bat are anticipated. Should the scope of the Project be modified, the Applicants would consult with USFWS to develop necessary avoidance and minimization measures for this species and will comply with any applicable USFWS requirements.

8.1.9.1.2 Monarch Butterfly

Monarch butterflies, a federally proposed threatened species, are found in areas with a high number of flowering plants, which provide sources of nectar. Monarch butterflies rely exclusively on the presence of milkweed (*Asclepias* spp.) to complete the caterpillar life stage (reference (21)).

On December 12, 2024, the USFWS published a proposed rule to the Federal Register proposing to list the monarch butterfly as a threatened species under the Endangered Species Act (ESA) (reference (22)). The USFWS is proposing this species for listing due to its decline in population across its range. The main threats to the monarch butterfly are the impacts of habitat loss and degradation, exposure to insecticides, and the effects of climate change. A decision on the final rule listing the species as threatened is anticipated in late 2025 and may occur prior to the start of the Project.

Suitable habitat for monarch butterflies is present in the Project Study Area, and construction may impact monarch butterfly individuals. If the USFWS determines the monarch butterfly should be listed and protections for the species coincides with Project planning, permitting, and/or construction, the Applicants would review Project activities for potential impacts on the species, develop appropriate avoidance and minimization measures, and consult with USFWS as appropriate.

8.1.9.1.3 Western Regal Fritillary

The western regal fritillary is a federally proposed threatened species. This species is strongly associated with native prairie habitat in Minnesota that contains violets (*Viola* spp.), especially bird's-foot violet (*V. pedata*) (reference (23)). A review of the MDNR NHIS licensed data did not indicate western regal fritillary species occurrences within the Project Study Area.

Suitable habitat for western regal fritillary is present in the Project Study Area, and construction activities may impact western regal fritillary individuals. The Applicants will consult with the USFWS to determine if any measures are required to minimize potential impacts to the western regal fritillary.

8.1.9.1.4 Western Prairie Fringed Orchid

The federally threatened and state endangered western prairie fringed orchid inhabits moist tallgrass prairie. The species occurs most often in mesic to wet unplowed tallgrass prairies and meadows (native prairie areas and prairie remnants) in full sun on sandy or calcareous till soils (reference (24)).

While the MDNR NHIS database does not document any occurrences of the western prairie fringed orchid in the Project Study Area, potential suitable habitat for the species may be present in MDNR remnant prairie communities (**Map 8-12**). Impacts to suitable prairie habitat could impact western prairie fringed orchid individuals should they be present. If suitable habitat for the western prairie fringed orchid cannot be avoided, the Applicants would consult with the USFWS and MDNR to determine next steps and develop appropriate avoidance and minimization measures.

8.1.9.1.5 Suckley's Cuckoo Bumble Bee

Suckley's Cuckoo Bumble Bee (*Bombus suckleyi*) is a federally proposed endangered species. This species is known as a social parasite and depends on host bumble bee colonies for their survival. They are usually observed in low abundance at the margins of their host species' range in habitat types that include prairies, grasslands, meadows, urban and agricultural areas, and woodlands (reference (25)). Suitable habitat for host bumble bee species is present in the Project Study Area where abundant flowering plants are present.

On December 17, 2024, the USFWS published a proposed rule to the Federal Register proposing to list Suckley's cuckoo bumble bee as an endangered species under the ESA (reference (25)). The USFWS is proposing this species for listing due to its decline in population across its range. The main threats to Suckley's cuckoo bumble bee include impacts from declining host species populations, commercial use of managed bees, pathogens, pesticides, habitat loss and degradation, and the effects of climate change. A decision on the final rule listing the species as threatened is anticipated in late 2025 and may occur prior to the start of the Project.

Project construction could impact Suckley's cuckoo bumble bees or associated habitat. However, the Project would utilize the transmission line corridor, and disturbance to the existing 150-foot transmission line corridor and access roads. These impacts would be temporary in nature and are not anticipated to adversely impact the integrity of bumble bee habitat. The Applicants would consult with the USFWS to determine if any measures are required to minimize potential impacts to Suckley's cuckoo bumble bees or its host species.

8.1.9.1.6 Bald Eagles

Although no longer federally listed under the ESA, bald eagles (*Haliaeetus leucocephalus*) are protected by both the *Migratory Bird Treaty Act* and the *Bald and Golden Eagle Protection Act* (BGEPA). The BGEPA prohibits the take of bald or golden eagle adults, juveniles, or chicks including their parts, nests, or eggs without a permit. The BGEPA also addresses impacts resulting from human-induced alterations occurring around previously used nesting sites. Work conducted within 660 feet of an active eagle nest during the nesting season may disturb nesting eagles to such a degree that adults abandon the nest, resulting in take of eggs and/or chicks; an active nest is one where eggs or chicks are present (reference (26)).

Bald eagles are primarily found near rivers, lakes, marshes, and other waterbodies and habitat suitable for bald eagles is present within the Project Study Area. If construction activities will take place in suitable eagle nesting habitat during the species nesting season, surveys to identify active nests within 660 feet of work areas will be conducted in early spring (i.e., early March/early April) of the year of construction. If active nests are identified within the disturbance buffer, the Applicants would consult with the USFWS to determine next steps and develop appropriate avoidance and minimization measures.

8.1.9.2 State Protected Species

The MDNR NHIS database was queried on September 3, 2025, to identify known occurrences of state protected threatened and endangered species within the Project Study Area. The NHIS query identified a total of four threatened and endangered species that have been documented within the Project Study Area (**Table 8-12**)Table 8-12.

Table 8-12
State Protected Species Within the Project Study Area

Common Name	Scientific Name	State Status[1]	Federal Status[1]
Birds			
Henslow's Sparrow	*Ammodramus henslowii*	END	SOC
Mollusks			
Fluted-shell	*Lasmigona costata*	THR	---
Insects			
A Caddisfly	*Limnephilus secludens*	END	---
Fish			
Pugnose Shiner	*Miniellus anogenus*	THR	---

[1] THR = threatened; END = endangered; SOC = species of concern.

Habitat suitable for several state-protected species is potentially present in the vicinity of the Project Study Area. The Applicants will conduct a Natural Heritage Review utilizing the Minnesota Conservation Explorer online tool and would consult with the MDNR to minimize the potential for adverse impacts to state-protected species and associated habitat from construction and operation of the Project.

8.1.10 Other Permits and Approvals

In addition to a Certificate of Need, a Route Permit Amendment from the Commission is required prior to construction, and the Applicants may also need to obtain other local, state, and federal approvals. Permits and approvals that may be required for the Project are listed in Table 8-13. Typical municipal permit categories are listed, but specific permits may vary from city to city and are limited. Once the Commission issues a Route Permit, local zoning, building, and land use regulations and rules are preempted per Minn. Stat. § 216E.10, subd. 1.

Table 8-13
Potential Permits and Compliance Approvals

Permit/Approval	Administering Agency
Local	
Road Crossing/Right-of-Way Permits	County, Township, City
Public Lands Permits - Local	County, Township, City
Utility Permits	County, Township, City
Oversize / Overweight Permits	County, Township, City
Driveway/Access Permits	County, Township, City
Municipal Stormwater Permits	County, Township, City
North Dakota	
Amended CPCN	NDPSC
Amended Certificate of Corridor Compatibility	NDPSC
Amended Route Permit	NDPSC
Minnesota	
Certificate of Need	MNPUC
Route Permit Amendment	MNPUC
Threatened & Endangered Species Consultation	MDNR
License to Cross Public Waters and State Lands	MDNR
Water Appropriation – Temporary Construction Dewatering Permit	MDNR
Utility Permit	MnDOT
Driveway/Access Permits	MnDOT
Oversize/Overweight Permits	MnDOT
Wetland Conservation Act Exemption Concurrence	Minnesota Board of Water and Soil Resources
Section 401 Water Quality Certification	MPCA

Permit/Approval	Administering Agency
National Pollutant Discharge Elimination System Permit – Construction Stormwater Permit	MPCA
Cultural Resources Consultation	Minnesota State Historic Preservation Office
Federal	
Section 7 Consultation	USFWS
Section 10 Permit	USACE
Section 404 Permit	USACE
Notice of Proposed Construction and Actual Construction or Alteration (7460)	FAA
Spill Prevention, Control, and Countermeasure Plan	EPA
Farmland Protection Policy Act/Farmland Conversion Impact Rating	United States Department of Agriculture and Natural Resource Conservation Service

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IN THE MATTER OF THE APPLICATION FOR A CERTIFICATE OF NEED FOR THE BISON TO ALEXANDRIA SECOND CIRCUIT 345 KV TRANSMISSION LINE PROJECT

DOCKET NO. E002, ET2, E015, E017, ET6135/CN-25-116

CERTIFICATE OF SERVICE

Gustav Gerhardson certifies that on the 15th day of January, 2026, on behalf of Northern States Power Company, doing business as Xcel Energy, Great River Energy, Minnesota Power, Otter Tail Power Company, and Missouri River Energy Services on behalf of Western Minnesota Municipal Power Agency, he efiled a true and correct copy of the **CERTIFICATE OF NEED APPLICATION** by posting the same on eDockets. Said filing is also served as designated on the attached Service List on file with the Minnesota Public Utilities Commission in the above-referenced docket number.

/s/ Gustav Gerhardson
Gustav Gerhardson

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