Joint Application to the Minnesota Public Utilities Commission for a Certificate of Need for the Gopher to Badger Link Project

MPUC Docket No. ET3, E002/CN-25-121

SUBMITTED BY:

Northern States Power Company d/b/a DBA Xcel Energy
Dairyland Power Cooperative

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DEFINED TERMS

$	U.S. dollar
AAR	Ambient Adjusted Line Ratings
AC	alternating current
ACSR	aluminum conductor steel reinforced
AECC	Aluminum Encapsulated Carbon Core
AMAs	Aquatic Management Areas
amps	amperes
Applicants	Northern States Power Company, dba Xcel Energy and Dairyland Power Cooperative
Application	Joint Certificate of Need Application
APLIC	Avian Power Line Interaction Committee
BGEPA	Bald and Golden Eagle Protection Act
BMPs	best management practices
BWSR	Board of Soil and Water Resources
C.F.R.	Code of Federal Regulations
CAGR	compound annual growth rate
CapX2020	Capacity Expansion Needed by 2020
CN	Certificate of Need
CO_2	carbon dioxide
Commission or MPUC	Minnesota Public Utilities Commission
CPLANET	Controlled Planning Expansion Tool
CREP	Conservation Reserve Enhancement Program
CRP	Conservation Reserve Program
Dairyland	Dairyland Power Cooperative
dB	decibels
dBA	A-weighted decibels
DC	direct current
Department	Minnesota Department of Commerce
DFAX	distribution factor
DLRs	Dynamic Line Ratings
DM&E	Dakota, Minnesota and Eastern Railroad
ECS	Ecological Classification System
EIA	U.S. Energy Information Administration
EMF	electric and magnetic fields
EPRI	Electric Power Research Institute
EWP Program	Emergency Watershed Protection Program
FAA	Federal Aviation Administration
FEMA	Federal Emergency Management Administration
FERC	Federal Energy Regulatory Commission

FSA	Farm Service Agency
GI	Generator Interconnection
GLH	GridLiance Heartland, LLC
GW	gigawatt
HUCs	Hydrologic Unit Codes
HVDC	high voltage direct current
IBA	Important Bird Area
IPaC	Information for Planning and Conservation
IRP	Integrated Resource Plan
JTIQ	Joint-Targeted Interconnection Queue
kcmil	thousand circular mil
kV	kilovolt
kV/m	kilovolts per meter
LCOE	levelized cost of energy
LRTP	Long-Range Transmission Planning
LRTP Tranche 1	The MISO-approved first phase of the LRTP
LRTP Tranche 2.1	The MISO-approved next phase of the LRTP
mA	milliAmperes
MBTA	Migratory Bird Treaty Act
MBS	Minnesota Biological Survey
MDNR	Minnesota Department of Natural Resources
mG	milliGauss
Minn. R. Ch.	Minnesota Rules Chapter
Minn. Stat. §	Minnesota Statutes Section
MISO	Midcontinent Independent System Operator, Inc.
MnDOT	Minnesota Department of Transportation
MPCA	Minnesota Pollution Control Agency
MRO	Midwest Reliability Organization
MTEP	MISO Transmission Expansion Plan
MTEP24	MISO’s 2024 Transmission Expansion Plan
MVP	Multi-Value Project
MW	megawatt
MWh	megawatt hour
N-1	single contingency condition
N-1-1	double contingency condition
NAC	noise area classifications
NDEX	A long-standing interface system operators use to measure total flows between Minnesota and North Dakota.
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code

NLEB	northern long-eared bat
NO_2	nitrogen dioxide
Notice Area or Study Area	The area provided notice under the approved Notice Plan, as shown on **Figure 1.8-1.**
NPCs	Native Plant Communities
NPV	net present value
NRCS	Natural Resources Conservation Service
NRHP	National Register of Historic Places
NSP	Northern States Power Company
NSP Companies	Xcel Energy and NSPW
NSPW	Northern States Power Company, a Wisconsin corporation
OPGW	optical ground wire
OSHA	Occupational Safety and Health Administration
ppm	parts per million
Project	The Gopher to Badger Link Transmission Line Project
PROMOD	Hitachi Energy's production cost model
PWI	Public Waters Inventory
PWP	Permanent Wetlands Preserves
Refuge	Upper Mississippi River National Wildlife and Fish Refuge
RIIA	Renewable Integration Impact Assessment
RIM	Reinvest in Minnesota
RJD	Richard J. Dorer
RTO	regional transmission organization
Segment 1	Approximately 34 miles of a single-circuit 765 kV high voltage transmission line between the North Rochester Substation and a point near Marion, Minnesota.
Segment 2	Approximately 105 miles of 765 kV/161 kV double-circuit high voltage transmission line between Marion, Minnesota, to the Minnesota/Wisconsin state line.
SF_6	sulfur hexafluoride
SIL	surge impedance loading
SMRs	small modular nuclear reactors
SNAs	Scientific and Natural Areas
SOBS	Sites of Biodiversity Significance
SPP	Southwest Power Pool
STATCOMs	static synchronous compensators
TOs	Transmission Owners
U.S.C. §	United States Code Section
USACE	U.S. Army Corps of Engineers
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey

V	volts
VOLL	value of load lost
WDNR	Wisconsin Department of Natural Resources
WMAs	Wildlife Management Areas
WQCs	water quality certifications
WRE	Wetland Reserve Easements
Xcel Energy	Northern States Power Company doing business as Xcel Energy

1 EXECUTIVE SUMMARY

1.1 INTRODUCTION

Northern States Power Company, a Minnesota corporation, d/b/a Xcel Energy (Xcel Energy) and Dairyland Power Cooperative (Dairyland) (together, Applicants) submit this joint application to the Minnesota Public Utilities Commission (Commission) for a Certificate of Need (CN) (Application) for the Gopher to Badger Link Transmission Line Project (Project).

The Project will be part of a 765 kilovolt (kV) path connecting Minnesota, South Dakota, Iowa, and Wisconsin, and consists of two segments:

- Segment 1: A single-circuit 765 kV high voltage transmission line between the existing North Rochester Substation[1] and a point near Marion, Minnesota;

- Segment 2: A 765 kV/161 kV double-circuit high voltage transmission line from near Marion, Minnesota, to the Wisconsin border. Segment 2 also includes a new three-circuit breaker 161 kV switching station at a location to be identified in Houston County, Minnesota, as well as minor upgrades at existing 161 kV substations to support operation of the new Project facilities.

All Project facilities are expected to be in service by the end of 2034 and are estimated to cost $979 million (low-range) to $1.273 billion (high-range) ($2024).

The Project was studied, reviewed, and approved as part of the Midcontinent Independent System Operator, Inc. (MISO) Long-Range Transmission Planning (LRTP) Tranche 2.1 Portfolio. MISO is a federally registered regional planning authority and regional transmission organization (RTO). MISO is responsible for planning and operating the transmission system and energy market in parts of 15 states, including Minnesota, and the Canadian province of Manitoba. MISO is an independent not-for-profit entity that has a responsibility, established by the Federal Energy Regulatory Commission (FERC), to identify needed transmission and mandate transmission owners (TOs) to develop necessary transmission projects to address reliability issues.

The Project is needed to maintain system reliability amid fundamental changes in demand for electricity as well as the type and amount of generation that is interconnected to the grid within the MISO Midwest subregion.[2] In the late 2000s, the level of new generation connected to MISO to meet system needs and renewable portfolio standards was 25 gigawatts (GW). Accelerated by electrification, economics, consumer and business preferences, and policies and laws like Minnesota's Carbon Free by 2040,[3] the amount of generation has increased four-fold. Today, 116 GW of new generation must be connected. Energy demand is trending up, and the type and location of generation resources to serve this electric load demand have fundamentally transformed over the past two decades. The amount of renewable generation interconnecting to the system has dramatically increased while the amount of fossil-fueled generation on the grid

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1 The North Rochester Substation will be expanded to accommodate 765 kV facilities and is being reviewed as part of PowerOn Midwest in Docket No. E002, ET2, ET6675/CN-25-117.

2 The MISO Midwest subregion includes MISO transmission customers in Minnesota, Montana, North Dakota, South Dakota, Iowa, Wisconsin, Missouri, Illinois, Indiana, Michigan, and Kentucky.

3 Minn. Stat. § 216B.1691, subd. 2(g).

has dramatically decreased. A summary of the factors driving the need for the Project is shown in **Table 1.1-1**.

TABLE 1.1-1
Comparison of Transmission System Needs in 2000s Versus 2024

Transmission System Need	2000s	Current
MISO demand needs [a]	1 percent annual growth (trending down)	1 percent annual growth (trending up)
Amount of new MISO generation necessary to be enabled [b]	25 GW (Total MISO GI Queue Size: ~60 GW)	116 GW (Total MISO GI Queue Size: ~270 GW)
MISO fossil-fuel generation retirements [c]	0.4 GW	84 GW
MISO generation mix [d]	Fossil fuels: 83 percent Nuclear: 13 percent Renewable: 0 percent	Fossil fuels: 66 percent Nuclear: 14 percent Renewable: 19 percent
Minnesota policy	25% renewable by 2025	100% carbon free by 2040
Needed transmission transfer capability [e]	1 - 3 GW	10+ GW
Primary High Voltage Class	345 kV	765 kV

Note: GI = Generator Interconnection

[a] 2000s: MISO Transmission Expansion Plan (MTEP) 11 Low BAU Future (primary future used to analyze MTEP11 Multi-Value Project Portfolio). Available at: https://cdn.misoenergy.org/MTEP14%20MVP%20Triennial%20Review%20Report117061.pdf. Page 16.
Current: See **Appendix E.2**. Page 31.
Current demand forecasts do not account for potential data centers and other industrial demands, which MISO predicts could increase growth rates by upwards of three-times the current forecasts. MISO. December 2024 Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.

[b] 2000s: MISO. Multi Value Project Portfolio Results and Analyses January 10, 2012.
Current: See **Appendix E.1**. Page 75.
MISO GI Queue. Current values as of November 2025. Available at: https://www.misoenergy.org/planning/resource-utilization/GI_Queue/gi-interactive-queue/.

[c] 2000s: MTEP11 Low BAU Future (primary future used to analyze MTEP11 Multi-Value Project Portfolio). Available at: https://cdn.misoenergy.org/MTEP14%20MVP%20Triennial%20Review%20Report117061.pdf. Page 16.
Current: See **Appendix E.2**. Page 88.

[d] 2000s: MISO. MISO'S Response to the Reliability Imperative. Available at: https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216. Page 7.
Current: MISO Fact Sheet – September 2025. Available at: https://www.misoenergy.org/about/media-center/corporate-fact-sheet/. Totals do not sum to 100 percent due to omission of "other" fuel types.

[e] 2000s: MISO Regional Generator Outlet Study Report – November 2010. Available at: https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf.
Current: See **Chapter 6**

As generation types and demands for electricity evolve, so too must the transmission grid (or, electric grid), which moves electricity from its point of generation to where it is consumed. The Project is necessary to continue to serve customer demand every minute of every day and to ensure the resiliency of the grid, particularly given the rapid pace of retiring baseload generation.

The Applicants and MISO identified that Minnesota requires upwards of 10,000 megawatts (MW) of additional electrical transmission capacity. The Project and the MISO LRTP Tranche 2.1

Portfolio of 24 projects[4] will create a large-scale backbone network throughout the Midwest that will ultimately be interconnected with an existing 2,400-mile 765 kV network in the eastern United States. This new transmission backbone network will make Minnesota's connection to the broader Midwest and eastern United States more robust and resilient, enabling Minnesota and the region to meet its electrical demands in a more reliable and cost-effective manner. Additional details on the current and future electricity demand supported by the Project are included in **Chapter 4**.

The Project will enhance the ability of the transmission system to move energy into and out of Minnesota and surrounding areas.[5] This geographic diversity and "reach" to access generation across multiple states (e.g., where the wind is blowing and/or sun shining) will allow for a steady flow of electricity to serve communities, so long as the transmission system can efficiently move the energy from where it is produced to where it is consumed.

In addition, these new transmission connections will help ensure reliability 24 hours a day, 7 days a week, and 365 days a year during ever-increasing extreme weather events. During these times, Minnesota may have to rely on neighboring states to provide power to maintain operations of the grid. For example, in February 2021 during Winter Storm Uri, it was necessary for MISO to import an unprecedented level of power from the eastern United States to maintain reliability for the MISO region, including Minnesota, and states to the west.[6] The Project will enable utilities to reliably serve existing and additional future demand for electricity.

The Applicants are submitting this Application pursuant to Minnesota Statutes Section (Minn. Stat. §) 216B.243 and Minnesota Rules Chapter (Minn. R. Ch.) 7849. To facilitate review, a completeness checklist is included as **Appendix A**, which identifies where in this Application information required by Minnesota statutes and rules can be found. The Applicants intend to file a Route Permit Application in Fall 2026.

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[4] The MISO Board of Directors approved the LRTP 2.1. Portfolio on Dec. 12, 2024. MISO identified the components of the Project as LRTP 26 (MISO. MISO Board Approves Historic Transmission Plan to Strengthen Grid Reliability. Available at: https://www.misoenergy.org/meet-miso/media-center/2024/miso-board-approves-historic-transmission-plan-to-strengthen-grid-reliability/).

[5] As described further in **Section 6.1**, for the purposes of the need analysis in this Application, the entirety of LRTP numbers 22 through 26 (including the portions of those projects outside Minnesota) were studied.

[6] See **Section 6.6.1** for additional details on resilience and Winter Storm Uri.

1.2 PROJECT DESCRIPTION

The following sections describe the proposed Project facilities, including transmission lines and substations.

1.2.1 Project Facilities

1.2.1.1 Segment 1

Segment 1 of the Project consists of approximately 34 miles of a single-circuit 765 kV high voltage transmission line between the North Rochester Substation and a point near Marion, Minnesota. For Segment 1, multiple 765 kV structure designs were analyzed – including H-frame and monopole designs – for engineering, regulatory, land-use, and cost considerations. Xcel Energy proposes to construct Segment 1 using four-legged self-supporting lattice structures. The lattice structure design best balances engineering, land-use, and cost considerations, as detailed in **Section 2.2**. The structures will be placed 1,100 to 1,300 feet apart, on average, and will typically be 150 to 175 feet tall. Segment 1 will generally require up to an approximately 250-foot-wide right-of-way.

1.2.1.2 Segment 2

Segment 2 of the Project consists of approximately 105 miles of 765 kV/161 kV double-circuit high voltage transmission line between Marion, Minnesota, to the Minnesota/Wisconsin state line. Multiple structure designs were also analyzed for Segment 2, and the Applicants propose to construct Segment 2 using four-legged self-supporting lattice structures. The lattice structure design was selected for Segment 2 for similar reasons as Segment 1, as detailed in **Section 2.2**. The structures will be placed 1,200 to 1,500 feet apart, on average, and will typically be 150 to 199 feet tall. Segment 2 will generally require up to an approximately 250-foot-wide right-of-way.

1.2.1.3 Substations

The Project includes a new three-circuit breaker 161 kV switching station in Houston County, Minnesota (Segment 2). A specific location has not yet been identified. The 161 kV switching station will connect to two existing 161 kV transmission lines from Harmony, Minnesota, and Lansing, Iowa, and an existing single-circuit 161 kV line between the new switching station and the existing Genoa Substation in Wisconsin. This will allow for reducing the number of 161 kV lines connecting to Wisconsin to accommodate the new 765 kV circuit.

In addition, upgrades at existing 161 kV substations within Segment 2 are expected to support operation and coordination between the new 765 kV facilities and the existing 161 kV network, as further detailed in **Section 2.4**.

1.3 PROJECT OWNERSHIP

The Applicants are Xcel Energy and Dairyland.

Xcel Energy is a public utility that generates electrical power, and transmits, distributes, and sells it to residential and business customers within service territories assigned by state regulators in parts of Minnesota, Wisconsin, South Dakota, North Dakota, and the upper peninsula of Michigan. The Xcel Energy and Northern States Power Company (NSP), a Wisconsin corporation (NSPW), collectively the NSP Companies, own and operate the five-state integrated NSP system pursuant to the terms of the Federal Energy Regulatory Commission approved Interchange Agreement. The NSP Companies have about 1.8 million electricity customers in the upper Midwest.

Dairyland is a not-for-profit generation and transmission electric cooperative formed in December 1941 and based in La Crosse, Wisconsin. Dairyland provides the wholesale electrical requirements to more than 700,000 people through its 24 distribution cooperatives and 27 municipal utilities in a four-state area including Wisconsin, Minnesota, Iowa, and Illinois. Dairyland owns over 3,300 miles of transmission line (34.5 kV and higher) and 232 substations in Minnesota, Wisconsin, Iowa, and Illinois.

Xcel Energy will solely own Segment 1, and it is anticipated that both Applicants will have an ownership interest in Segment 2.

In addition to the Applicants, GridLiance Heartland (GLH) will have an ownership interest in and support project development and construction of Segment 2. GLH is an affiliate of GridLiance, a NextEra Energy Transmission subsidiary that collaborates with rural electric cooperatives and municipal utilities to invest in electric infrastructure and improve the reliability of regional electric grids. GLH owns and operates transmission assets in the Midwest and focuses on modernizing the grid, replacing aging infrastructure and improving reliability in America's heartland.

The rebuilt 161 kV facilities in Segment 2, including the new switching station, will be wholly owned by Dairyland.

1.4 PROJECT NEED

The Project is needed to 1) mitigate system overloads to maintain system reliability to meet existing and future energy needs; 2) meet growing electrical demand in a cost-effective manner; and 3) support the energy transition. As described further in **Section 6.1**, for the purposes of the need analysis in this Application, the Applicants studied the entirety of LRTP numbers 22 through 26 (including the portions of those lines outside of Minnesota). This group of projects is referred to as the "Studied Projects."

The following sections provide a summary of the regional and local Minnesota drivers for the Studied Projects, considering MISO's LRTP efforts and Minnesota-specific factors. Additional details on the need for the Studied Projects are provided in **Chapters 5 and 6**.

1.4.1 Regional Drivers

The MISO region is facing fundamental shifts in how electricity is produced and consumed. The grid must respond to reliably move electricity from the point of generation to where it is consumed. The Project, as part of the overall MISO LRTP Tranche 2.1 Portfolio, is needed to maintain reliability as Minnesota and the Midwest region evolves its energy industry landscape, including new generation resources, consumer demand for low-carbon resources, decentralization of generation, and changing and growing demands for electricity.

Recognizing the complex challenges to electric reliability in the region - from the transformational changes in the generation fleet, extreme weather events, and other factors - MISO initiated the LRTP in 2019. The LRTP is a multi-year, multi-phase effort to identify necessary regional transmission grid improvements required to cost-effectively maintain system reliability in the face of greater uncertainty and variability in supply (e.g., greater reliance on wind and solar generation). In short, the LRTP is designed to enable the transmission grid to move more cost-effective electricity, farther distances, and from different generation sources to continue to serve electrical needs 24 hours a day, 7 days a week, 365 days a year.

In 2022, MISO approved the first phase, or “tranche,” of the LRTP (LRTP Tranche 1) as the initial step to address Minnesota and the broader Midwest region’s evolving reliability needs. The MISO LRTP Tranche 1 consists of 18 transmission projects which will result in approximately 2,000 miles of new and upgraded high voltage transmission lines across nine states. The LRTP Tranche 1 includes three projects in Minnesota:

- Big Stone South to Alexandria to Big Oaks Transmission Projects: Commission Docket Numbers CN/22-538, TL-23-159, and TL-23-160;

- Northland Reliability Project: Commission Docket Numbers CN-416 and TL-22-415; and

- Mankato to Mississippi River Project: Commission Docket Numbers CN-22-532 and TL-23-157.

In 2024, MISO approved the next phase of the LRTP (LRTP Tranche 2.1) to establish a new 765 kV “backbone” across the Midwest. The LRTP Tranche 2.1 includes 24 projects totaling approximately 3,600 miles of new and upgraded transmission in MISO’s Midwest subregion (Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, and Wisconsin). The LRTP Tranche 2.1 builds upon, and is enabled by, the LRTP Tranche 1 and the existing transmission grid, which serves as entry and exit ramps for the new LRTP Tranche 2.1 765 kV transmission backbone network. Combined, the existing 765 kV and 345 kV networks work together to move electricity across multiple states to each local community where it is consumed.

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. MISO concluded that the LRTP Tranche 2.1 Portfolio is needed for:

- **Reliability:** Addresses reliability issues (i.e., points on the transmission grid which require solutions to meet North American Electric Reliability Corporation (NERC) national reliability standards) across the MISO region.[7] The LRTP Tranche 2.1 Portfolio supports energy adequacy so that energy can be delivered where it is needed 24 hours a day, 7 days a week, 365 days a year. The LRTP Tranche 2.1 Portfolio will also maintain system reliability through enabled demand and system stability.

- **Cost Effectiveness/ Economic Benefits:** The $21.8 billion LRTP Tranche 2.1 Portfolio has a benefit-to-cost ratio of 1.8 to 3.5 (based on MISO’s 2024 analysis). This means that $1.00 invested in transmission will result in economic benefits of $1.80 to $3.50 dollars.[8] For an average electrical consumer, MISO estimates that the LRTP Tranche 2.1 Portfolio

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7 The Applicants and MISO are required to ensure the transmission grid meets NERC national reliability standards (i.e., prevent a “violation” of reliability standards). To ensure the transmission grid meets reliability standards, MISO and the Applicants model how changes in both the production and use of electricity will impact the transmission grid and identify any inadequacies of the existing transmission grid. The Applicants and MISO must identify mitigation plans (“fixes”) to each reliability issue as required by NERC. The reliability issues addressed by the MISO Tranche 2.1 Portfolio are summarized in pages 63 to 69 and detailed in pages 77 through 123 of **Appendix E.1**. The NERC reliability standards are available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL001-5.pdf.

8 Net savings are 20-year net present value (NPV) in $-2024 (Id., Page 125, Figure 2.137).

is estimated to cost about $5 per 1,000 kWh of energy used while providing $10 to $18 of value over that same amount of usage per month in value.[9]

- **Enabling Generation Transition:** The LRTP Tranche 2.1 Portfolio alleviates congestion and enables interconnection of approximately 116,000 GW of new generation resources. These resources will include carbon-free resources[10] to reduce Midwest carbon dioxide (CO_2) emissions by 127 million to 199 million metric tons over 20 to 40 years and help states like Minnesota to comply with decarbonization laws.[11]

The Project, together with LRTP Project Nos. 22-25, serves a key role in the MISO LRTP Tranche 2.1 by addressing reliability issues specific to southern Minnesota, eastern North Dakota, eastern South Dakota, northern and central Iowa, and western Wisconsin.[12] Additional information on the MISO LRTP Tranche 2.1 Portfolio and process is in **Section 4.6.**

1.4.2 Local Minnesota Drivers

Minnesota's transmission grid has evolved since the Rural Electrification Act of the 1930s that initially brought electricity to most of the state. Several key inflection points - step-changes, or significant buildouts driven by fundamental changes in how electricity was generated and/or consumed – have shaped Minnesota's grid to its present state. The last inflection point in the late 2000s was driven by several transformational factors:

- FERC established RTOs, including MISO, with orders to operate and plan the transmission grid on a multi-state regional basis to improve reliability and cost-efficiency, transforming how the transmission system is used.
- Minnesota passed the Next Generation Energy Act of 2007, which included a Renewable Energy Standard requiring most utilities to generate 25 percent of their electricity (30 percent for Xcel Energy) from renewable sources by 2025. This created the need to interconnect a significant amount of new generating sources.
- Demand for electricity reached new peaks and was forecasted to grow at upwards of 2.49 percentage points annually.[13] Even absent the need to interconnect new generation, the transmission grid began to exceed the limit to which Minnesota transmission owners could make incremental improvements to the lower voltage system to accommodate new and/or shifts in energy usage.

The Capacity Expansion Needed by 2020 (CapX2020) coalition of 11 Minnesota utilities addressed those fundamental changes by proposing and constructing more than 800 miles of high voltage transmission lines in Minnesota that are currently in-service.

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9 MISO. Fact Sheet - Long Range Transmission Planning Tranche 2.1. Available at: https://cdn.misoenergy.org/LRTP%20Tranche%202.1666573.pdf

10 See **Appendix E.1** Page 75.

11 Id., Page 142.

12 Id., Pages 84 and 92.

13 CapX2020 Vision Study, 2005.

1.4.2.1 Generation Changes

In 2011, 53 percent of the electricity generated in Minnesota was from coal-fired generation. In 2024, electricity from coal was approximately 20 percent and renewables provided approximately 33 percent of electricity generation in Minnesota.[14] As of January 2025, approximately 7,000 MW of new renewable generation has been installed in Minnesota.[15]

In 2023, the Minnesota Legislature increased the amount of renewable energy that electric utilities were required to acquire. Legislation mandating "100 Percent Carbon-Free by 2040" was signed into law, which requires electric utilities to transition to meet the needs of Minnesota customers with 100 percent carbon-free electricity by the end of 2040. Driven by a combination of economics, consumer preferences, age of existing generation, and regulatory policies, 72,000 MW of new generation is expected to be added, and 16,000 MW of existing generation is expected to be retired over the next 20 years in Minnesota and the surrounding area (within MISO's Local Resource Zone 1).[16] These are baseload generators that have provided round-the-clock energy production for many decades. The retired baseload generators provide more than just energy production, they also provide essential reliability services, which keep electricity safe and stable. As these generators are retired, both the "baseload" nature and essential reliability services of these sources must be replaced.

1.4.2.2 Increasing Demand

Since 2007, demand growth in the Midwest has remained relatively flat, initially due to the Great Recession from 2007 to 2009 and then from demand efficiency programs absorbing growth. Current forecasts, however, indicate a 1.14 percent annual growth rate for Minnesota and the surrounding area, adding approximately 5,000 MW over the next 20 years.[17] Demand forecasts do not include the potential for growth attributed to data centers and other industrial demands beyond what is currently firmly committed, which MISO predicts could increase growth rates by upwards of three times the current forecasts.[18]

1.4.2.3 Transmission Grid Localized Improvement Option Exhausted

The Applicants have a responsibility to implement the right transmission at the right time to maintain reliability. New transmission lines are proposed only after all other options to upgrade existing transmission lines have been exhausted. The Applicants and Minnesota's transmission owners have been at the forefront of "squeezing every drop" of capacity out of the existing transmission grid through uses of new technology to allow transmission line ratings to be adjusted in real-time based on actual weather conditions and upgrading transmission and substation equipment to the latest designs. These incremental changes are insufficient to address the identified transmission system needs.

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14 U.S. Energy Information Administration (EIA). Electricity Data Browser. Available at: https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vvg&geo=000004&sec=g&freq=A&start=2001&end=2024&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=.

15 EIA. Electric Power Monthly. Table 6.2.B. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_02_b

16 See **Appendix E.2.** Pages 87 and 88.

17 MISO. Futures Report, Series 1A. See **Appendix E.2**. Page 32 - MISO Local Resource Zone 1.

18 MISO. December 2024 Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf

1.5 HOW PROJECT ADDRESSES MULTIPLE NEEDS

1.5.1 Reliability

The Project will maintain system reliability for current and future demands. How the Project supports reliability is measured by NERC compliance, energy adequacy, enabled demand, and system stability.

- NERC compliance means the regional transmission system will meet the planning requirements NERC has established.
- Energy adequacy[19] means the transmission system will be able to move energy to where it is needed to avoid interruption in service.
- Enabled demand measures how much additional customer demand can be served.
- System stability measures how well the transmission system can transfer large amounts of power between geographic areas.

1.5.1.1 NERC Criteria

NERC defines the reliability standards for which the electrical grid is planned. The Studied Projects eliminate expected reliability overloads of 102 different facilities, 27 of which are 200 kV or higher, addressing 1,313 reliability issues as defined by NERC.[20]

1.5.1.2 Energy Adequacy

The Studied Projects provide the ability to transfer bulk energy to, through, and out of Minnesota to continue to serve load 24 hours a day, 7 days a week, 365 days a year. The Studied Projects help enable the transmission grid to take on the role currently served by baseload generation, essentially allowing the transmission grid to function as a super-sized battery, as illustrated on **Figure 1.5-1**. This figure shows projected available resources and general power flows across the system in the year 2042. **Figure 1.5-1** displays three different hours of expected generation output and electrical demands under typical and actual weather patterns in winter. The figure shows how, as the weather front moves from east to west, the Studied Projects facilitate moving energy from where it is produced to where it is needed, which changes by the hour. Without the Studied Projects, during these hours, over 2,000 MW of load would not be served, and a similar magnitude of energy generation would be wasted (curtailed) because there is inadequate transmission to move it where it is needed. On an annual basis, approximately 1,300,000 megawatt hours (MWh) of load from Minnesota and the surrounding area is at expected risk of not being served without the Studied Projects by 2042. Risk levels are highest during times when

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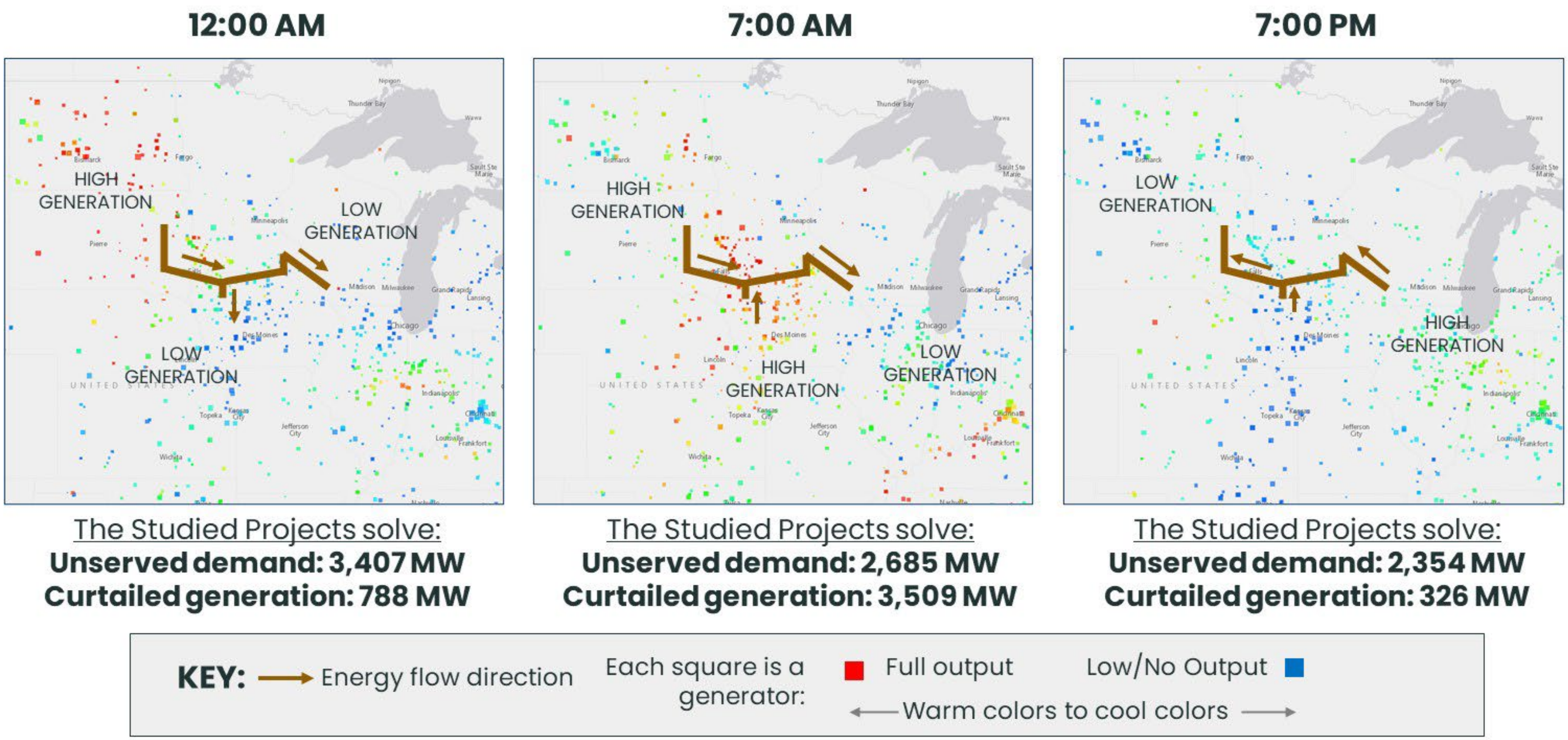
[19] Energy adequacy is distinct from resource adequacy which measures the supply of energy available to meet demand.

[20] MISO. Details in **Appendix E.4**. **Appendix E.4** contains the full reliability results for Table 2.13 (page 85) and Table 2.102 (page 95) in **Appendix E.1**. In accordance with Minnesota Rules, part 7829.0500, and Minnesota Statutes Chapter 13, Applicants have designated portions of **Appendix E.4** as NONPUBLIC DATA– NOT FOR PUBLIC DISCLOSURE because it contains confidential security information, as defined by Minn. Stat. § 13.37(1)(a). The public disclosure or use of this information creates an unacceptable risk of disruption to the electrical grid. Thus, Applicants maintain this information as nonpublic pursuant to Minn. Rule 7829.0500, subp. 3. Given the need to include nonpublic information, Applicants have prepared and are electronically filing both nonpublic and public versions of **Appendix E.4**.

electricity demand is highest and during atypical weather conditions (e.g., extreme weather events).

Figure 1.5-1: Energy Adequacy Provided by the Studied Projects: Typical Winter Day (2042)



1.5.1.3 Enabled Demand

The Studied Projects are needed to serve forecasted demands for electricity. The Studied Projects are also sized appropriately to reliably serve future increases in residential, commercial, and industrial energy demands totaling approximately 6,000 MW over the next 20 years. In addition, the Studied Projects make accommodating an additional approximately 1,600 MW of load growth less expensive.

1.5.1.4 System Stability

The Studied Projects will improve system transfer capability and address system instability issues. As the power plants historically relied upon for system stability are retired and are increasingly replaced with inverter-based resources (e.g., wind and solar generators) and demands for electricity become more dynamic, backbone transmission upgrades, like the Studied Projects, are critical to networking the grid to maintain stability.

1.5.2 Cost Effectiveness/ Economic Benefits

The Studied Projects are expected to provide $7.7 billion to $25.3 billion in economic benefits to customers and members over the first 20 years of service by reducing congestion and providing access to lower cost generation resources. The Studied Projects are the most cost-effective alternative to meet Minnesota's growing electrical needs. MISO estimates that the Studied Projects, when coupled with the broader LRTP Tranche 2.1 Portfolio, are expected to provide economic savings of over two times the costs for Minnesota. The Studied Projects reduce congestion in Minnesota by upwards of 11 percent, allowing energy needs to be served with lower cost energy.

1.5.3 Enabling Generation Transition

The Studied Projects enable aging and/or cost-inefficient generation to retire and be replaced by new generation – including carbon-free generation – which helps meet state policy objectives and satisfy customer demand. The Studied Projects also contribute to more efficient use of existing generation resources. The Studied Projects help enable approximately 24,000 MW of new generation (10,000 MW in Minnesota) to be reliably connected to the transmission grid. While generation is typically interconnected at the 345 kV and lower voltage, the Studied Projects enable new generation to interconnect by pulling electricity off the existing lower voltage transmission lines to create transmission capacity to add new generation.

The Studied Projects will enable better/full utilization of carbon-free resources, reducing curtailment by 5.6 to 7.2 million MWh on an annual basis. Curtailment refers to a condition where a generator can, and economically should, provide power to the grid, but there is insufficient transmission capacity to move the energy generation from the generator to where it is needed to serve demand, or where there is not enough demand or storage resources to use all available generation. While not limited to renewable generation, curtailment occurs primarily at renewable resources which are economically the lowest cost generators from an operating perspective. CO_2 emissions will also be reduced, in support of Minnesota's Carbon Free by 2040 law. Combined, the Studied Projects will reduce annual CO_2 emissions by 5.4 to 7.5 million tons.

1.6 ALTERNATIVES

The Applicants evaluated multiple system alternatives to the Studied Projects, including alternative voltages, generation and non-wires alternatives, transmission alternatives, combinations of alternatives, and a no-build alternative. The Applicants also evaluated alternative conductor and structure design. None of the alternatives is a more reasonable and prudent alternative to the Studied Projects, as summarized in **Table 1.6-1**.

TABLE 1.6-1

Alternatives Evaluation Summary

Alternative	Reason for Rejection
Alternative Voltages	
Lower voltage	**Cost:** Less cost-effective than the Studied Projects. **Impact:** More land-impacts than the Studied Projects.
Higher voltage	**Viability:** No voltages higher than 765 kV alternating current (AC) are operating in the United States.
Generation And Non-Wires Alternatives	
Peaking generation	**Need:** Does not provide transfer capability needed for reliability and efficiency.
Renewable generation	**Need:** Does not address reliability-energy adequacy needs.
Battery energy storage	**Need:** Does not provide transfer capability needed for reliability and efficiency.
Distributed generation	**Need:** Does not address reliability-energy adequacy needs.
Nuclear generation	**Viability:** Does not comply with Minnesota law.
Demand side management/Conservation	**Viability:** Magnitude of necessary load reduction infeasible.
Reactive power additions	**Need:** Does not address NERC reliability needs.
Transmission Alternatives	
Upgrade existing transmission lines	**Cost:** Less cost-effective than the Studied Projects **Impacts:** Number and scale of upgrades infeasible (at least 1,394 miles of transmission lines and 10 substation upgrades required) **Optionality**: Does not allow for any future growth or expansion beyond the amount studied.
Alternative endpoints	**Need:** Project endpoints identified and optimized by MISO.[21]
Double circuiting (765 kV/765 kV) and other engineering considerations	**Need:** Single circuit meets current forecasts' needs and proactively accommodates a reasonable level of potential future needs
High voltage direct current	**Cost:** Less cost-effective than Studied Projects
Underground	**Viability:** Underground 765 kV technology presently not available
Reasonable Combination Of Alternatives	
Lower voltage and upgrading existing lines	**Cost**: Less cost-effective than the Studied Projects. **Optionality**: Does not allow for any future growth or expansion beyond the amount studied.
Lower voltage and peaking generation/storage	**Cost**: Less cost-effective than the Studied Projects. **Optionality**: Does not allow for any future growth or expansion beyond the amount studied.

21 See Minnesota Department of Commerce, Division of Energy Resources Comments on Exemption Requests, at 6 (Oct. 21, 2025) ("The Department agrees with the Applicants that Minnesota Statutes limit the consideration of alternative end points in this matter….").

TABLE 1.6-1 Alternatives Evaluation Summary	
Alternative	**Reason for Rejection**
Alternative Transmission Line Engineering	
Alternative conductor design	Segment One: 17 conductors were studied for the Project. Based on cost, performance and the Project requirements, Xcel Energy proposes the 1192.5 45/7 ACSR Bunting conductor or a similar performing conductor. Segment Two: Seven ACSR conductors and six composite-core conductors were evaluated for the Project. Based on cost, performance, and project requirements, Dairyland selected the 795 30/19 ACSR (GA2) Mallard conductor for typical spans and the 1037 York Aluminum Encapsulated Carbon Core (AECC) conductor for the Mississippi River crossing.
Alternative structure design	Applicants considered multiple structure designs, including tubular H-Frame and monopole designs. Based on cost, resiliency and constructability considerations, Applicants determined that the lattice design was the best performing design for the Project.
No Build Alternative	
No build alternative	**Need:** Without the Studied Projects, there are consequences to: 1) system reliability (unserved demand, NERC reliability violations, energy adequacy, and system instability); 2) generation plans (increased risk of not complying with Minnesota's Carbon Free by 2040 law); and 3) economics (less efficient and more expensive piecemeal solution required absent the Project's coordinated regional approach).

The Project does not preclude other technologies but rather enables these technologies to work together with the Project to optimally maintain reliability. Given the complex challenges to regional reliability from the changing generation fleet and electrical demands, an “all of the above” approach is needed. Although the Project is defined by the 765 kV backbone, the Project is part of a larger system which also includes and/or assumes:

- lower voltage transmission line additions (e.g., 345 kV);
- upgrades of existing transmission lines;
- expansion of demand side management;
- additional distributed generation;
- utility-scale generation additions of multiple fuel-types, and
- expansion in energy storage.[22]

All these technologies, including the Project, are necessary to support future grid reliability. Additional details are provided in **Chapter 7**.

1.6.1 Transmission Line Voltage Alternatives

The Applicants and MISO identified the need to transfer upwards of 10,000 MW more electrical capacity to, through, and out of Minnesota to meet customer demands. The expansion of the transmission system could potentially be accomplished through multiple 345 kV facilities[23] or a combination of 345 kV and 765 kV facilities. Given the magnitude of the capacity required, MISO

[22] MISO LRTP Tranche 2.1 assumes approximately 3,500 MW of new energy storage will be added in Minnesota and the surrounding area over the next 20 years (See **Appendix E.2**. Page 87, MISO Local Resource Zone 1).

[23] Minnesota’s high voltage network is largely 345 kV with a few 500 kV lines primarily connecting to Manitoba.

concluded that 765 kV facilities along a west-east corridor through the Midwest with additional 345 kV transmission line facilities should be constructed.

The 765 kV voltage minimizes costs and the amount of right-of-way needed, reducing environmental impacts. In other words, it would require more right-of-way for a 345 kV west-east corridor to create the same capabilities as a single 765 kV right-of-way. The general capacity differences of 765 kV and 345 kV voltages as identified by MISO, are shown in **Table 1.6-2** and **Figure 1.6-1**.

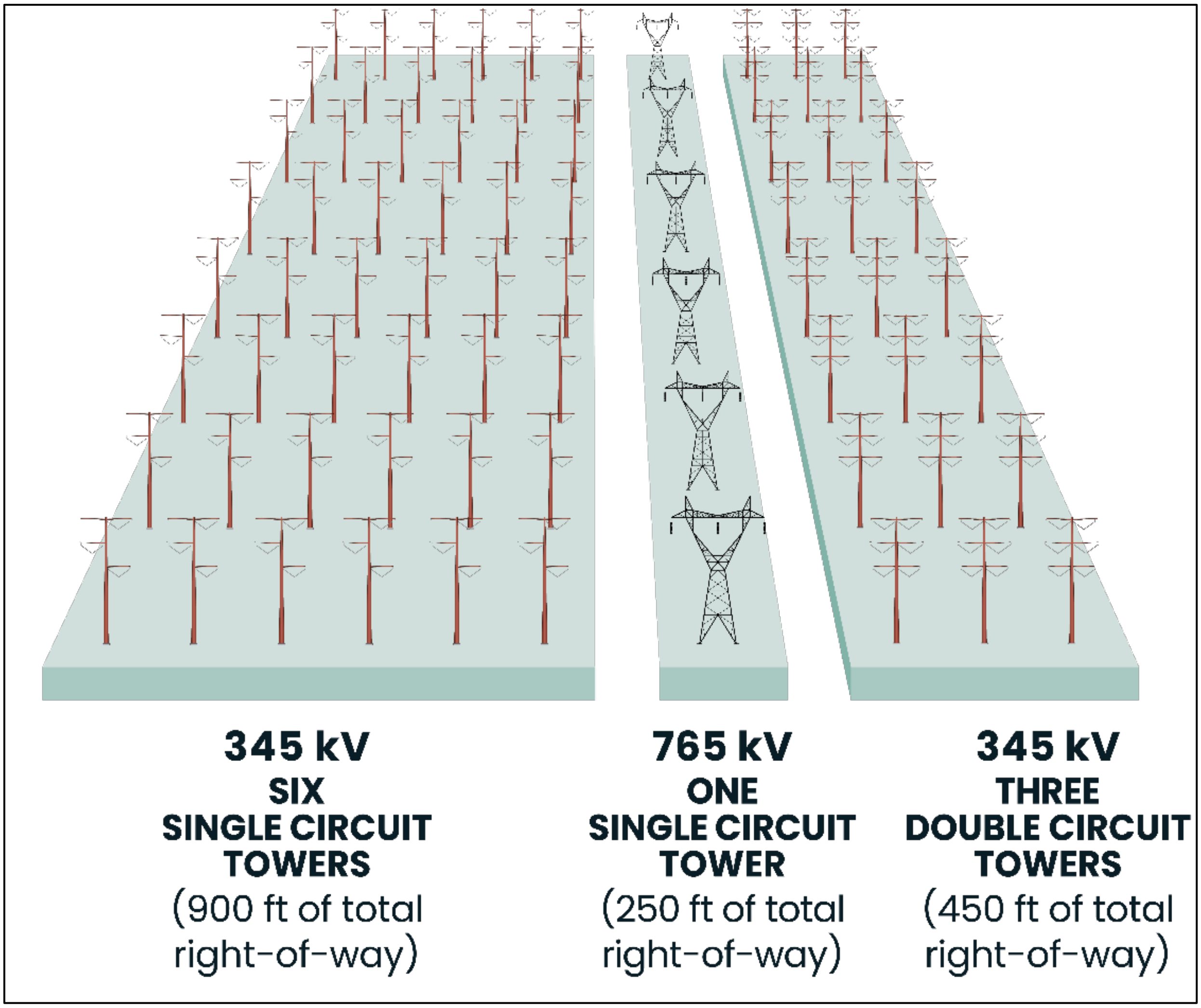
The Applicants independently considered 765 kV, 500 kV, and 345 kV. Like MISO, the Applicants concluded that the 765 kV voltage is best suited to address system reliability needs in a manner which is less costly and less impactful than other alternatives.

TABLE 1.6-2
Comparison of Land Impacts to Meet Reliability Needs by Voltage Class

Voltage Class	Number of Lines Needed to Provide Equivalent Capability as one 765 kV Line [a]	Approximate ROW Needs for Each Line (feet)	Total ROW Width (feet)	Total Impacted Acreage for 410 Miles [b]
345 kV single-circuit	6	150	900	44,727
345 kV double-circuit	3	150	450	22,364
765 kV (the Studied Projects)	1	250	250	12,424

[a] Source: MISO. See **Appendix E.1.** Page 35.
[b] Mileage for Minnesota portion of the Studied Projects (MISO LRTP numbers 22 through 26).

Figure 1.6-1: Comparison of Total Right-of-Way Width Based on General Capacities of Each Voltage Class (Not to Scale)[24]



The 765 kV voltage is also the least-costly option to transfer the necessary level of energy. As shown in **Table 1.6-3**, 765 kV transmission costs are less than 345 kV options.

24 **Figure 1.6-1** illustrates total right-of-way width to meet needs for each voltage class. For 345 kV and double-circuit 345 kV, lines may not be located in a single-common right-of-way, as shown for illustrative purposes; however, the total width of all rights-of-way would equal values displayed on **Figure 1.6-1.**

TABLE 1.6-3 Comparison of Costs to Meet Reliability Needs by Voltage Class			
Voltage Class	Approximate Cost for Each Line ($million - 2024/mile) [a]	Number of Lines Needed to Provide Equivalent Transfer Capability of One 765 kV	Approximate Total Cost ($2024)
345 kV single-circuit	3.6	6	$21.6 million/mile
345 kV double-circuit	6.0	3	$18 million/mile
765 kV single-circuit	5.7	1	$5.7 million/mile
[a] 345 kV line costs - MISO. MTEP25 Cost Estimation Guide. Available at: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fcdn.misoenergy.org%2FMISO%2520Transmission%2520Cost%2520Estimate%2520Workbook%2520for%2520MTEP25547535.xlsx&wdOrigin=BROWSELINK. Table 4.1-1 and 4.1-2. 765 kV line costs – see **Section 2.4**.			

1.6.2 Non-Transmission Alternatives

The Applicants evaluated generation and non-wires alternatives, including new peaking generation, renewable generation, battery energy storage, distributed generation, nuclear generation, demand-side management and conservation measures, and reactive power additions.

The Studied Projects are needed to maintain NERC reliability standards by addressing system overloads. The Studied Projects increase transfer capability to move electricity from new and existing generation to serve new and existing electrical demands. The ability to transfer more energy is not only needed for reliability but also to efficiently and fully utilize available generating resources (i.e., avoids curtailment of wasted generation). By its nature, transfer capability is created by transmission solutions, not generation. Adding additional generation does not address the core issues addressed by the Studied Projects of:

- Increasing transmission capacity to allow for the interconnection of new generation;
- Maintaining local reliability and resource adequacy by being able to transfer energy into an area when local generation is not available; and
- Efficiently and fully utilizing generation capacity.

Conversely, in most cases, adding additional generation exacerbates system issues that the Studied Projects seek to address.

Nonetheless, the Applicants evaluated adding local generation as a direct alternative to the Studied Projects. Adding additional local capacity does not increase the ability to reliably interconnect new generation or transfer capability – rather it supports energy adequacy issues by adding additional local generation where existing local generation is insufficient to meet demand and/or the existing grid is not capable of transferring enough energy to meet demand energy.

No generation alternative is a more reasonable and prudent alternative to the Studied Projects.

1.7 PROJECT SCHEDULE AND COSTS

The Applicants anticipate starting construction on the Project as early as 2030. The target energization for the Project is 2034. **Table 1.7-1** summarizes the permitting schedule; more detail on the schedule is provided in **Section 2.7**.

TABLE 1.7-1
Anticipated Project Schedule

Project Component	Segment One	Segment Two
Start CN Proceeding	Q1 2026	Q1 2026
Start Route Permit Proceeding	Q3 2026	Q3 2026
Begin Land Acquisition	2027	2027
Obtain Permits to Construct	2030	2030
Start of Construction	2030	2031
Project Operation	2034	2034

The schedule is based on the information currently available and is dependent on the anticipated timing of the CN proceeding, Route Permit proceeding, and post-permit requirements that must be completed prior to the start of construction. The schedule is also dependent on the Applicants advancing design work in parallel with the Commission permitting processes. For instance, the Applicants assumed early design work, up to 30 percent completion of the transmission line design, to coincide with the issuance of the Route Permit. In addition, the schedule may be adversely impacted by labor and materials availability at the time of construction.

Estimated costs for the Project are approximately $979 million (low-range) to $1.273 billion (high-range), based on the best available information at the time of filing. More detail on costs is provided in **Section 2.5**.

1.8 POTENTIAL ENVIRONMENTAL IMPACTS

Chapter 10 of this Application provides a discussion of the natural environment and land use features in the area reviewed for the Project Study Area, which is equivalent to the Project Notice Area as shown on **Figure 1.8-1**.

As discussed in further detail in **Chapter 10,** environmental and land use features vary moving from the western to eastern portion of the Project Study Area. These variations are reflected in the changing patterns of hydrology, vegetation, wildlife, land use, and human settlement. The primary land use within the Project Study Area is agriculture, with municipalities and rural homesteads scattered throughout. Utility infrastructure, such as transmission and distribution lines and wind and solar generating facilities, are common within the Project Study Area. At the Minnesota/Wisconsin border, the Project requires a crossing of the Mississippi River.

Overall, many Project impacts can be avoided and minimized through thoughtful routing, consistent with the Commission's routing criteria. The Applicants will coordinate with federal, state, and local permitting agencies, Tribal governments, and other stakeholders to avoid, minimize, and mitigate potential human and environmental impacts during future routing processes.

1.9 PUBLIC INPUT AND INVOLVEMENT

Each of the Applicants has a long history of working with landowners and in partnership with local communities to develop energy infrastructure projects in Minnesota. Prior to filing this Application, the Applicants engaged thoughtfully with communities and stakeholders through mailings, meetings, Open Houses, and other methods to ensure that stakeholders were informed of the Project and had an opportunity to provide comments. Additional information on public input and involvement is included in **Chapter 11**.

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/. Click on the eDockets link near the top right-hand side, then "Go to eDockets" and then enter the docket number "25-121" in the "Docket #s" section. Click "search" (not "lookup"). A copy of the Application will also be available on the Project website at http://www.gophertobadgerlink.com/.

The public can subscribe to the Project's CN docket and receive email notifications when information is filed in that docket. Subscribing to the docket may result in a large number of emails. To subscribe:

- Visit the website: https://www.edockets.state.mn.us/subscriptions/verify
- Enter your email address
- Follow the prompts sent via email

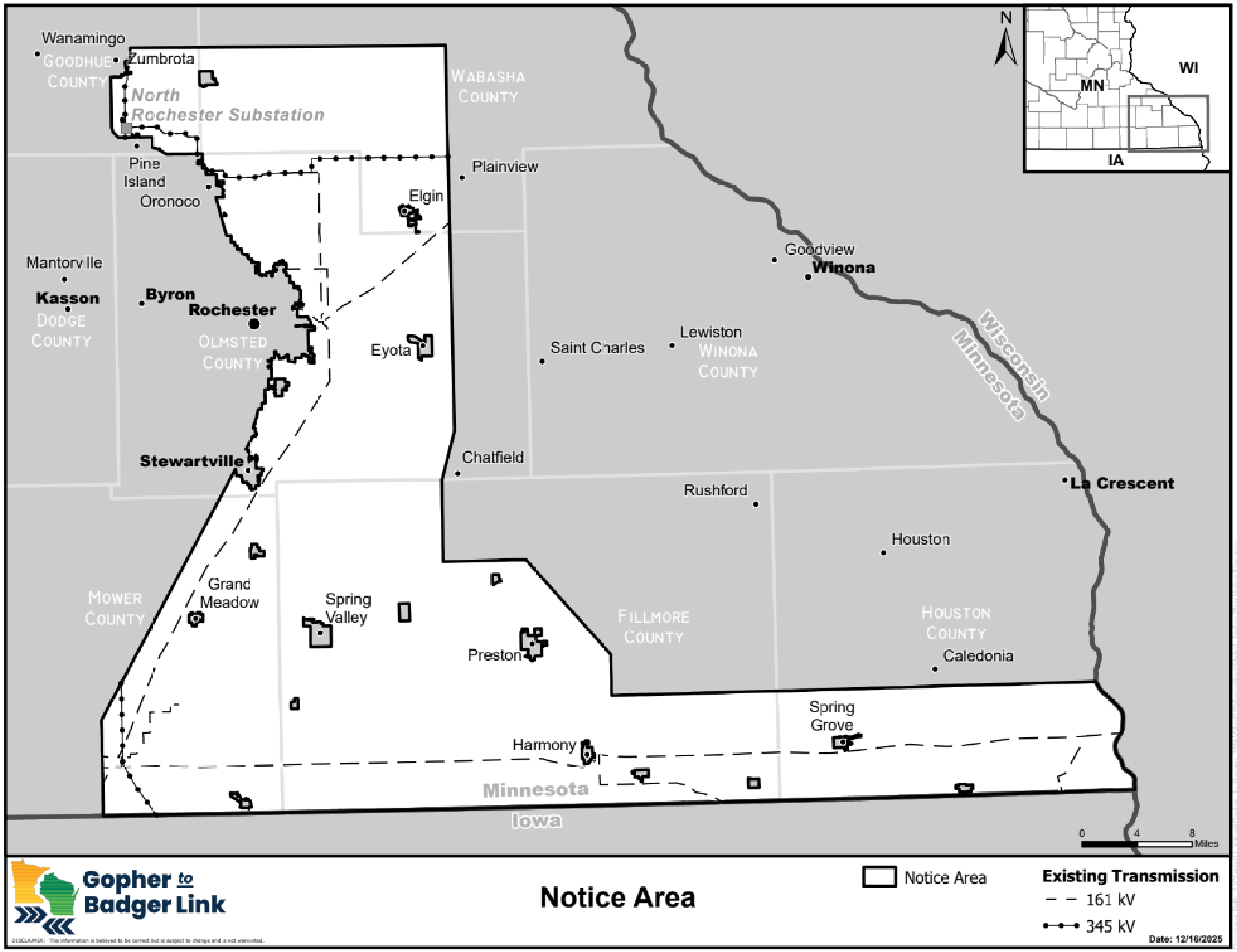
If you would like to have your name added to the CN mailing list, send an email to eservice.admin@state.mn.us or call 651-201-2246. If you send an email or leave a phone message, please include: the docket number (CN-25-121), your name, and your complete mailing address and email address.

If you have questions about the state regulatory process, you may contact Commission staff: Sam Lobby at sam.lobby@state.mn.us or 651-201-2205.

Minn. R. 7829.2550, subp. 1, requires an applicant to file a proposed Notice Plan with the Commission at least three months before filing an application for a CN. This Notice Plan is prepared as an initial step in the CN regulatory process. Preparation of a Notice Plan, and its review and approval by the Commission, ensures that interested persons are aware of the proceeding and have the opportunity to participate. The Applicants filed their proposed Notice Plan on October 8, 2025. The Commission approved the Notice Plan on December 23, 2025. The Commission Order on the Notice Plan is included in **Appendix B**.

The area provided notice under the approved Notice Plan (the Notice Area) is depicted on **Figure 1.8-1.** Landowners and other stakeholders within the Project Notice Area were provided notice about the Project in January 2026. The Project Notice Area includes portions of the following counties: Goodhue, Wabasha, Olmsted, Mower, Fillmore, and Houston. The Applicants designed the Project Notice Area to be broad enough to encompass potential future routing corridors, but exclude areas where future routing is unlikely, either because of the presence of routing constraints, and/or because of the Project's geographic requirements.

Figure 1.8-1: Gopher to Badger Link Project Notice Area



The Project Notice Area also represents the Project Study Area further considered in this Application in **Chapter 10**. The Project Notice Area was developed to ensure that those stakeholders "reasonably likely to be affected by the proposed transmission line"[25] received notice and would have the opportunity to participate in the proceedings.

1.10 PROJECT MEETS CERTIFICATE OF NEED CRITERIA

Minnesota rules and statutes specify the criteria the Commission should apply in determining whether to grant a CN. Subdivision 3 of Minn. Stat. § 216B.243 identifies the criteria the Commission must evaluate when assessing need. Minn. R. Ch. 7849.0120 further provides that the Commission grant a CN 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.

Applicants' proposal as summarized in this Chapter and detailed throughout the Application 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 Applicants' customers.

B. A more reasonable and prudent alternative to the Project has not been demonstrated by a preponderance of the evidence.

C. The proposed Project will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments.

D. The proposed Project will comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

The Applicants will secure all necessary permits and authorizations prior to commencing construction on the portions of the Project that require such approvals.

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25 Minn. R. 7829.2550, subp. 1.

1.11 APPLICATION ORGANIZATION

The remaining ten chapters of the Application are organized as follows:

- **Chapter 2**: Project Description
- **Chapter 3**: Coordinated Transmission Development
- **Chapter 4**: Need for Comprehensive Expansion Consistent with Regulatory Authority
- **Chapter 5**: Need Drivers
- **Chapter 6**: How Project Addresses Multiple Defined Needs
- **Chapter 7**: Alternatives to the Project
- **Chapter 8**: Transmission Line Operating Characteristics
- **Chapter 9**: Transmission Line Construction and Maintenance
- **Chapter 10**: Environmental Information
- **Chapter 11**: Agency, Tribal, and Public Outreach

1.12 APPLICANTS' REQUEST AND CONTACT INFORMATION

For the reasons discussed above and in the remainder of this Application and Appendices, Applicants respectfully request that the Commission find this Application complete and, upon completion of its review, grant a CN for the Project. All correspondence relating to this Application should be directed to:

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2 PROJECT DESCRIPTION

2.1 PROJECT COMPONENTS

The Project is proposed to include:

- **Segment 1**: A single-circuit 765 kV high voltage transmission line between the expanded North Rochester Substation[26] and a point near Marion, Minnesota;
- **Segment 2**:
  - A primarily 765 kV/161 kV double-circuit high voltage transmission line from near Marion, Minnesota, to the Wisconsin border;
  - Upgrades at existing 161 kV substations, contained within Segment 2, to support operations and coordination between the new 765 kV facilities and the existing 161 kV network;
  - A new three-circuit breaker 161 kV switching station in Houston County, Minnesota; a specific location has not yet been identified. The 161 kV switching station will connect to two existing 161 kV transmission lines from Harmony, Minnesota, and Lansing, Iowa, and an existing single-circuit 161 kV line that will extend between the new switching station and the existing Genoa Substation in Wisconsin.

2.2 TRANSMISSION LINE AND STRUCTURES

2.2.1 Structure Analysis & Selection

The Applicants propose to use four-legged self-supporting lattice structures for the Project. The Applicants may use other specialty structures depending on site-specific needs and/or conditions. The Applicants selected a self-supporting lattice tower design from among several structure types considered for the Project. The self-supporting lattice tower design best meets the Project requirements based on considerations of cost, engineering, resiliency, and land-use impacts. Additional information on structure selection for both Segment 1 and Segment 2 is presented in **Section 7.6.2**.

2.2.2 Structure Descriptions

Segment 1: Proposed structure heights will typically range in height from approximately 150 to 175 feet tall. However, where existing transmission lines are crossed, or where topography, environmental constraints, or design needs necessitate, structure heights could be up to 200 feet tall, or greater. In cases where structure heights exceed 200 feet, the Applicants anticipate the Federal Aviation Administration (FAA) would issue determinations of no hazard with the expectation that structures be marked and lit. The typical spans between structures will be approximately 1,100 to 1,300 feet, with shorter or longer spans used as needed. The Applicants will generally install structures on drilled pier concrete foundations. The typical foundations will range in size from approximately 5 to 7 feet in diameter and 25 to 65 feet in depth. Specialty

26 The North Rochester Substation will be expanded to accommodate 765 kV facilities and is being reviewed as part of PowerOn Midwest in Docket No. 25-117.

foundations may be required due to geotechnical (or soil) conditions. Foundation depth will be based on site-specific conditions and detailed engineering design.

Segment 2: Proposed structure heights will typically range in height from approximately 150 to 199 feet tall. However, where existing transmission lines are crossed or terrain factors require, structure heights could be up to 210 feet tall. The typical spans between structures will range from 1,200 – 1,500 feet. The structures will typically be installed on drilled pier concrete foundations ranging from 4 to 8 feet in diameter and depths that are expected to range from 15 to 50 feet. Specialty foundations may be required due to geotechnical (or soil) conditions. Foundation depth will be based on site-specific conditions and detailed engineering design.

Table 2.2-1 summarizes the typical structure designs for both Segment 1 and Segment 2.

TABLE 2.2-1
765 kV and 765 kV/161 kV Transmission Line Characteristics

Line Type	Structure Type	Structure Material	Typical Right-of-Way Width (feet)	Typical Structure Height (feet)	Typical Foundation Diameter (feet)	Average Span between Structures (feet)
765 kV	Lattice	Galvanized Steel	Up to 250	150-175	5-7	1,100 – 1,300
765 kV / 161 kV	Lattice	Galvanized Steel	Up to 250	150-199	4-8	1,200 – 1,500

* Structure sizes may change based on site conditions and analysis of proposed routes.

2.2.3 Conductor

A single-circuit transmission line carries three phases (conductors) and separate shield wire(s). A double-circuit transmission line carries six phases (conductors) and two separate shield wires. Each phase can consist of one wire or multiple “bundled” wires.

On Segment 1, a six-conductor bundle of 1192.5 thousand circular mil (kcmil) 45/7 aluminum conductor steel reinforced (ACSR) Bunting conductor with 15-inch sub-conductor spacing and a total capacity equal or greater than 4,000 amperes (amps) is proposed. Xcel Energy identified this conductor as the most appropriate for Segment 1 and selected this conductor among 17 conductors studied. Xcel Energy identified the 1192.5 45/7 Bunting as appropriate for the Project based on a study of 17 conductors. The conductor provides the requisite capacity for the Project, including meeting MISO’s ampacity and surge impedance loading (SIL) requirements of 4,000 amps and of 2,400 MW, respectively.

On Segment 2, the Project will utilize a six-conductor bundle of 795 kcmil 30/19 ACSR Mallard conductors with 18-inch sub-conductor spacing for the 765 kV circuit and a two-conductor bundle of 795 kcmil 30/19 ACSR Mallard conductors with 18-inch subconductor spacing for the 161 kV circuit. 1037 AECC York conductor will be utilized at the Mississippi River crossing. Conductor selection for Segment 2 was based on a comprehensive conductor selection study that evaluated multiple conductor sizes, types, and bundle configurations through a rigorous multi-criteria analysis encompassing electrical performance, mechanical performance, and economic considerations. The analysis factored in the criticality of each criterion for the proposed double-circuit configuration. Audible noise compliance and reduced conductor sags and conductor blowout were most impactful to the selection to help minimize structure heights and maximize use of the proposed right-of-way. The proposed conductors provide superior sag and blowout performance due to the relatively high mechanical strength of the conductor cores. Like the conductor selected for Segment 1, the conductors selected for Segment 2 meet all Project and regulatory requirements.

The Project will be designed to meet or surpass relevant local and state codes including the 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.

Additional information on conductor selection is presented in **Section 7.6.1**.[27]

2.3 SHIELD WIRE/OPTICAL GROUND WIRE

The Project will utilize two shield wires to provide adequate shielding from lightning strikes, thereby providing electrical protection for the lines. The Applicants intend to install optical ground wire (OPGW) as the shield wire type for the Project. The OPGW will not only provide shielding protection, but it will also provide telecommunications capacity for the Applicants. The OPGW will be installed above the phase conductors, near the top of the structures.

2.4 SUBSTATIONS

Segment 2 includes the construction of a new 161 kV three-circuit breaker switching station in Houston County, Minnesota, and minor upgrades at existing 161 kV substations to accommodate the operation of the new 765 kV facilities in shared right-of-way with the 161 kV transmission facilities. The new switching station will connect existing 161 kV transmission lines from Harmony, Minnesota, and Lansing, Iowa, and will include a rebuilt 161 kV line extending east to the Genoa Substation in Wisconsin. The specific location for the switching station has not yet been identified.

Upgrades at existing substations are expected to include modifications to bus configurations, protection and control systems, grounding and communication equipment, and installation or replacement of surge arresters and insulation components as needed. Substation design and site requirements will be refined through ongoing system studies and detailed substation engineering.

2.5 PROJECT COSTS

2.5.1 Construction Costs

Project costs are broken down by component in **Table 2.5-1**. Applicants have provided low-range and high-range cost estimates. All costs are presented in 2024 dollars and include permitting, engineering, materials, land rights and right-of-way, and construction costs. Estimated costs for the proposed Project are approximately $979 million (low-range) to $1.273 billion (high-range) based on the best available information at the time of filing.

Table 2.5-1
Project Cost Estimate Ranges by Project Component ($2024)

Project Component	Low-Range	High-Range
Segment 1	$215 million	$280 million
Segment 2	$764 million	$993 million
Project Total	$979 million	$1.273 billion

27 Applicants request authorization to use the conductors identified in this section or conductors of equivalent capacity.

These estimates were developed by the Applicants based upon the scope of the Project presented in this Application. The cost estimates are based on design, analysis, and bids from contractors, engineering firms, and independent consultants. The final cost of the Project will be impacted by materials and labor costs that may increase due to multiple factors, including but not limited to shortages, steel pricing, and tariffs.

The Applicants will comply with Minn. Stat. § 216I.05, subd. 12(d), which directs the Commission to require the recipient of a route permit to construct an energy infrastructure facility, including contractors and subcontractors, to “pay no less than the prevailing wage rate,” as defined in Minn. Stat. § 177.42. These cost estimates assume that the Applicants will pay prevailing wages for applicable positions for the construction of the Project.

2.5.2 Operation and Maintenance Costs

Once constructed, O&M costs will be initially driven by controlling regrowth vegetation within the right-of-way. The Applicants anticipate post-construction annual maintenance cost of approximately $3,200 - $4,500 per mile. The majority of this cost is related to vegetation management. The Applicants also perform other general maintenance, such as conducting regular right-of-way patrols and repairing storm-damaged, aged, or worn equipment or facilities. The specific O&M costs for an individual transmission line vary based on the location of the line, the number of trees located along the right-of-way, the age and condition of the line, the voltage of the line, and other factors.

Over the life of the new switching station, inspections will be performed regularly to maintain equipment and make necessary repairs. Circuit breakers, batteries, protective relays, and other equipment need to be serviced periodically in accordance with the manufacturer’s recommendation. Routine compliance inspections will be performed, and the site must also be kept free of vegetation and drainage maintained.

2.6 RATE IMPACT

The Commission’s rules require an applicant to provide the annual revenue requirements to recover the costs of a proposed project. Applicants requested an exemption from this rule requirement for Dairyland. Because the Project’s costs will be allocated across the MISO footprint, Applicants instead proposed to provide information regarding the expected Project cost, MISO’s cost allocation methodology, and the share that will be allocated to Minnesota utilities’ load. As discussed in **Section 2.6.3** below, Xcel Energy provides its relevant data related to the Project’s effects on its rates systemwide and in Minnesota.

2.6.1 MISO Cost Allocation

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) according to the MISO tariff. Therefore, the Project, along with all other projects in the LRTP Tranche 2.1 Portfolio, qualifies for regional cost allocation. MISO has determined that the LRTP Tranche 2.1 portfolio will be allocated to transmission customers in the MISO Midwest Subregion, where the portfolio is located and provides proximate benefits. 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 pursuant to the formula rate in

Attachment MM-MVP Charge in the MISO tariff. Withdrawing Transmission Owners[28] in the MISO Midwest Subregion pay the annual revenue requirement through Schedule 26-A charges, which are assessed based on actual monthly energy consumption by customers.

The allocated share of the annual revenue requirement for Minnesota customers is determined by the percent of total MISO energy used by Minnesota utilities, which has been estimated at approximately 18 to 24 percent based on MISO's posted 2023 energy withdrawal data.

Table 2.5-1 summarizes the estimated cost allocation for the Project to each local balancing authority area in the MISO Midwest Subregion.

Table 2.5-1
Estimated Cost Allocations Based on Attachment MM of the MISO Tariff[a]

Local Balancing Authority Area	Cost Allocation Zone	Local Balancing Authority Area Allocation
Alliant East	2	2.8%
Alliant West	3	3.8%
Ameren Illinois	4	8.6%
Ameren Missouri	5	7.1%
Big Rivers Electric Corporation	6	1.4%
Cinergy	6	7.6%
Consumers	7	9.3%
Columbia Water and Light Department	5	0.3%
City Water Light and Power	4	0.3%
Detroit Edison	7	9.8%
Dairyland Power Cooperative	1	1.3%
GridLiance Heartland, LLC	4	0.0%
Great River Energy	1	2.9%
Hoosier Energy	6	0.7%
City of Henderson, Kentucky (d/b/a Henderson Municipal Power & Light)	6	0.1%
Indianapolis Power and Light	6	2.7%
Montana Dakota Utilities	1	0.9%
MidAmerican Energy Company	3	6.7%
Madison Gas and Electric	2	0.7%
Michigan Upper Peninsula	2	0.6%
Minnesota Power	1	2.3%
Muscatine Power and Water	3	0.2%
Northern Indiana Public Service Company LLC	6	3.6%
Northern States Power	1	9.3%
Otter Tail Power	1	3.3%
Southern Indiana Gas and Electric	6	1.1%
Southern Illinois Power Cooperative	4	0.3%
Southern Minnesota Municipal Power Agency	1	0.3%
Upper Peninsula Power Company	2	0.2%
Wisconsin Electric Power Company	2	5.9%
Wisconsin Public Service Company	2	2.7%
Exports and Wheel-Throughs	N/A	3.0%

[28] Defined in the MISO Tariff.

Table 2.5-1 Estimated Cost Allocations Based on Attachment MM of the MISO Tariff[a]		
Local Balancing Authority Area	Cost Allocation Zone	Local Balancing Authority Area Allocation
[a] MISO. Schedule 26A Indicative Annual Charges. Available at: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fcdn.misoenergy.org%2FSchedule%252026A%2520Indicative%2520Annual%2520Charges106365.xlsx&wdOrigin=BROWSELINK.		

Xcel Energy has load in multiple local balancing authorities: Great River Energy and Xcel Energy. Dairyland likewise has load in multiple local balancing authorities: Dairyland. Xcel Energy, Alliant West, Alliant East, and Southern Minnesota Municipal Power Agency. The Applicants calculated the costs allocated to each individual Applicant by multiplying each local balancing authority allocation by each utility's load ratio share.

Xcel Energy's allocated cost will be approximately 8.5 percent. Dairyland's allocated cost will be approximately 1.3 percent.

2.6.2 Rate Impact – Dairyland

MISO estimates Dairyland's local balancing authority will be allocated approximately 1.3 percent of the total costs for the Project with the rest of the costs being allocated to load in the remaining MISO Midwest Subregion. As a not-for-profit transmission and generation cooperative, Dairyland's costs are allocated to its member-owner distribution cooperatives based on a board approved formula rate methodology. This formula rate methodology allocates power supply and transmission costs by agreed upon applicable billing determinants. Each Dairyland member-owner distribution cooperative develops their own rates based on individual costs, including allocated costs from Dairyland, for their member-consumers via applicable customer rate class.

2.6.3 Rate Impact – Xcel Energy

Instead of the data identified in Minn. R. 7849.0260(C)(5) and Minn. R. 7849.0270, subp. 2(E), Xcel Energy requested an exemption and proposed to provide an annual revenue requirement impact for the capital costs of the Project for a 20-year period. The Commission approved the requested exemption. Accordingly, **Appendix D** provides revenue requirement calculations for the NSP system (both Xcel Energy and NSPW), and are then adjusted to a Minnesota jurisdictional basis for Xcel Energy. These revenue requirement calculations do not account for any future operation and maintenance costs for the Project or fuel impacts. These revenue requirement calculations also assume that the Project is individually or jointly owned with the other co-owners as discussed in **Section 1.3**.

2.7 PROJECT SCHEDULE

The anticipated permitting and construction schedule for each segment of the Project is provided in **Table 2.6-1** and **Table 2.6-2**. This schedule is based on information known as of the date of the filing of this Application and may be subject to change.

TABLE 2-6.1 Segment 1 Anticipated Schedule	
Activity	Estimated Date
Minnesota Certificate of Need Proceeding	February 2026

TABLE 2-6.1 Segment 1 Anticipated Schedule	
Activity	**Estimated Date**
Route Permit Proceeding Commenced	Fall 2026
Land Acquisition Begins	2027
Required Federal, State, and Local Permits Obtained	2030
Start Project Construction	2030
Project Operation	2034

TABLE 2-6.2 Segment 2 Anticipated Schedule	
Activity	**Estimated Date**
Minnesota Certificate of Need Proceeding	February 2026
Route Permit Proceeding Commenced	Fall 2026
Land Acquisition Begins	2027
Required Federal, State, and Local Permits Obtained	2030
Start Project Construction	2031
Project Operation	2034

The Applicants developed the overall Project schedule based on the anticipated timing of the CN and Route Permit proceedings, while also considering the subsequent activities that must be completed prior to the commencement of construction of the Project. Although the Applicants are commencing this permitting process years before the in-service dates identified by MISO, the Applicants anticipate that the entirety of this time will be needed to accomplish necessary processes and tasks prior to commencement of construction, and then complete construction.

For example, following the issuance of the Route Permit, the Applicants considered the anticipated time and resources needed for such things as land acquisition, survey, environmental permits, detailed design, procurement of materials, lead time of materials, tree clearing, and above and below grade construction.

Material lead times are largely based on current lead times. However, lead times are likely to increase by the time material orders are placed for the Project, due in large part to the likely increase in demand for materials across the industry during this timeframe. In addition, the material needs for the Project will be sizable, which will likely contribute to increased material lead times. Adding to some of the lead time uncertainty is the likelihood that some materials may need to be sourced internationally, whether for technical reasons, qualified supplier availability, or other reasons.

Similar to material availability, the Applicants believe that labor resources will be in high demand during the anticipated construction timeframe for the Project. Based on early analysis, the Applicants assume that more than 800 personnel may be needed for construction of the Project, and 11 to 17 part-time personnel may be needed for operation.

For these reasons, meeting the target in-service date for the Project will depend on the timely receipt of necessary approvals and permits, the timely execution of tasks that must be completed prior to the start of construction, material availability, and resource availability. There is little flexibility in the schedule to meet the target in-service date for the Project.

3 COORDINATED TRANSMISSION DEVELOPMENT

The Project resulted from coordinated transmission development across the MISO region, which consists of 15 states and the Canadian province of Manitoba. FERC approved MISO as the first RTO on December 20, 2001. Since that time, MISO has overseen comprehensive annual planning processes involving broad stakeholder engagement. To put this Project in the context of the broader coordinated transmission system, this chapter provides a discussion of the workings of the electric system, the reliability requirements that affect the way the system is developed, and obligations that require utilities, including the Applicants, to provide adequate electric service to all customers. **Chapter 4** describes historical precedents for the present MISO LRTP Tranche 2.1 initiative, the long-range goals and policies supported by a coordinated build-out of the transmission system, and the scope of MISO LRTP Tranche 2.1, which includes the Project.

3.1 ELECTRICAL SYSTEM OVERVIEW

Electric transmission is the process of delivering generated electricity over long distances to the distribution grid. It involves the use of high-voltage transmission lines, transformers, and the electrical grid to ensure efficient and reliable energy delivery.

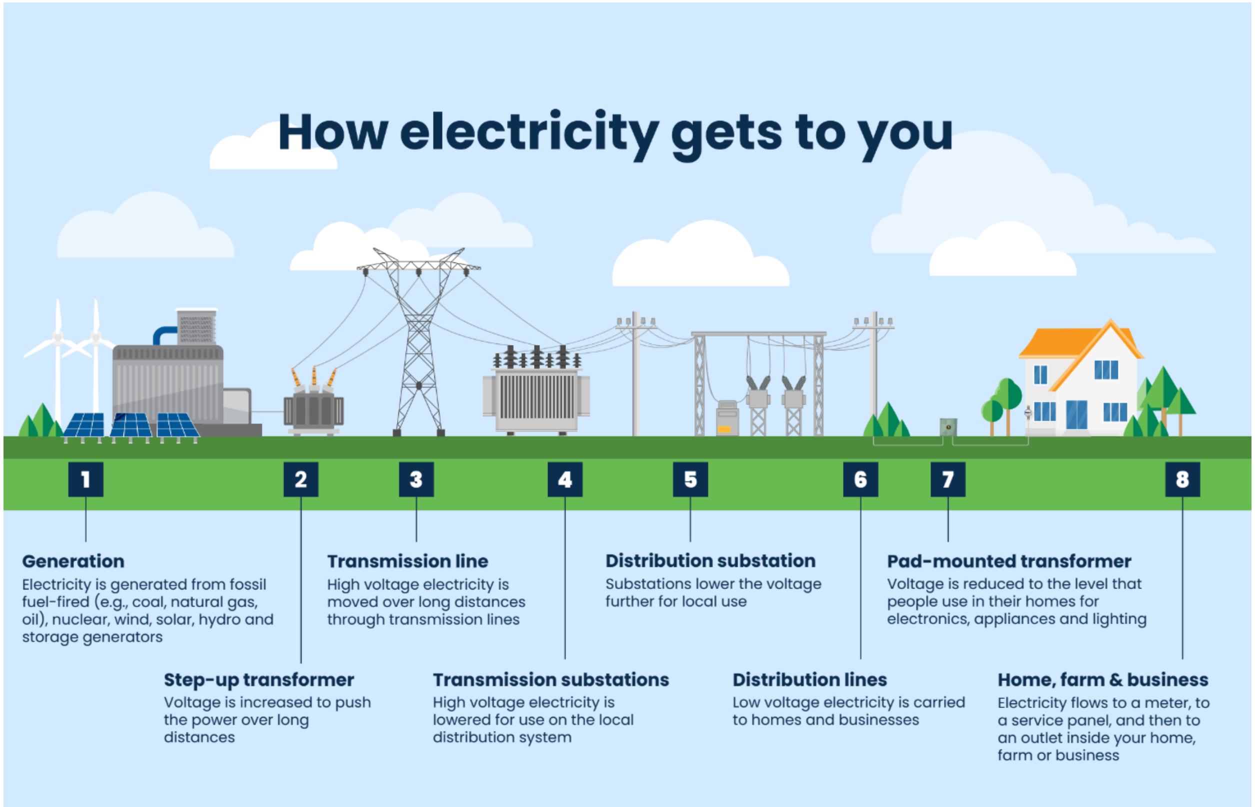
By turning on a light switch, a circuit is completed that connects the light bulb with the wires that serve the building. The building wires are connected to a transformer and distribution line outside of the building. Distribution lines, in turn, are connected to substations and larger transmission lines, which comprise the bulk power system that carries electricity from electric generating plants to the areas where the electricity is needed. The bulk power system, or bulk electric system, is a term for the electric generation resources, transmission lines, and interconnections generally operated above 100 kV.

The network of transmission lines which work together to connect places where energy is generated to where it is used is commonly referred to as the electric grid or the transmission grid. Over time, the grid has become smarter, more dynamic, and increasingly interconnected due to rising reliability expectations and advancements in technology, along with additional wind, solar, and storage energy resources.

Electricity is produced at generating stations using a variety of sources or fuels, including natural gas, coal, oil, nuclear, and renewable sources (e.g., solar, wind, hydro, biomass, biofuels). Electricity from generating stations along high voltage transmission lines is pushed along high voltage transmission lines often at voltages in excess of 100,000 volts (V) (e.g., 115 kV, 230 kV, 345 kV, 500 kV, 765 kV). One kV equals 1,000 V. Voltage on transmission lines is higher than what is used by the consumer because transmitting electricity over long distances at higher voltages reduces electrical losses on the system. Once the electricity reaches the community in which it will be used, the electricity is “stepped down” to lower, more usable levels at a substation. Then, the electricity is sent along smaller distribution lines to be delivered to neighborhoods and businesses.

A diagram showing the transfer of electricity from generator to consumer is shown in **Figure 3.1-1.**

Figure 3.1-1: How Electricity Gets to You



3.2 TRANSMISSION NETWORK

The electric transmission system in the United States is composed of a highly decentralized interconnected network of generating plants, high voltage transmission lines, and distribution facilities. Electricity uses all available paths as it flows from generation to consumer. Since electricity from all sources is commingled in the transmission system, it is not possible to know exactly where the electric power came from that lights the room of a home.

More specifically, the bulk electric system is composed of high voltage transmission lines which can carry electricity long distances and deliver power to distribution systems to meet customer needs in specific locations, and bulk transformers at 100 kV and above. Transmission lines are made up of conductors, which complete a three-phase circuit and are usually accompanied by a shield wire on top that provides protection from lightning strikes. The shield wire can also include fiber optic cable which provides a communication path between substations for transmission line protection equipment. The shield wire can also include fiber optic cable which provides a communication path between substations for transmission line protection equipment. These conductors are groups of wires, usually made from aluminum, and are most commonly held up by poles or towers (commonly referred to as transmission structures) that are made from wood or steel. Transmission lines carry electricity from the generation source to the area where the power is needed. The rate at which electric charge moves through a wire is called current and is measured in amps. The wire carrying the current resists its movement. This resistance is measured in a unit called ohms. Aluminum wires carry electricity with relatively little resistance.

Substations are a part of the electric generation, transmission, and distribution system and contain high-voltage electric equipment to monitor, regulate, and distribute electricity. Substations allow transmission lines to connect with other substations and allow power to be transformed from a higher transmission voltage to a lower voltage for distribution, typically below 69 kV. Substation property dimensions depend on the size of the project; anticipated future needs based on the 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 fenced area and the required surrounding areas, including stormwater ponds, grading, parking, access roads, and the transmission line rights-of-way that will enter and exit the substation. The configuration of a substation may change over time to accommodate future load growth or electric system needs.

Designing the transmission system and the proper implementation of new transmission facilities requires complex analysis including modeling of the power system's steady-state and dynamic performance.

3.2.1 Nationwide

Today, there are more than 153,000 miles of high voltage transmission lines in the United States that transmit electricity at voltages in excess of 200 kV.[29] There are also many thousands of miles of transmission lines between 100 and 200 kV. These facilities include AC lines and direct current (DC) lines. **Table 3.2-1** provides a perspective of the miles of in-service high voltage transmission lines operating at over 200 kV in the United States.

TABLE 3.2-1

Miles of In-Service AC and DC High-Voltage Transmission Lines in the United States [a]

	200-287 kV	345 kV	450 -500 kV	765 kV
Miles	65,800	55,600	28,400	2,400

[a] ESRI. U.S. Electric Power Transmission Lines, Homeland Infrastructure Foundation-Level Data. Data Accurate as of September 30, 2024. Archived as of September 10, 2025. Available at: https://www.arcgis.com/home/item.html?id=d4090758322c4d32a4cd002ffaa0aa12.

The MISO LRTP Tranche 2.1 projects will be the first 765 kV transmission facilities in Minnesota. However, as shown in **Table 3.2-1**, approximately 2,400 miles of 765 kV transmission lines are safely and reliably operating in the United States and have been since the first 765 kV transmission lines were installed in the 1970s. A map of the existing 765 kV lines currently operating in the United States is shown on **Figure 3.2-1**. The 765 kV voltage level is also in use internationally.

Minnesota is not alone in developing new 765 kV transmission lines. Facing similar grid reliability needs, new 765 kV transmission lines are proposed and/or under development in Iowa[30], Illinois[31],

29 ESRI. U.S. Electric Power Transmission Lines, Homeland Infrastructure Foundation-Level Data. Data Accurate as of September 30, 2024. Archived as of September 10, 2025. Available at: https://www.arcgis.com/home/item.html?id=d4090758322c4d32a4cd002ffaa0aa12

30 See **Appendix E.1**. Page 144.

31 Id.

Indiana[32], Michigan[33], New Mexico[34], South Dakota[35], Texas[36], Virginia[37], West Virginia[38], and Wisconsin[39]. In 2025 the Southwest Power Pool (SPP) began planning efforts to develop a 765 kV overlay designed to interconnect with MISO's LRTP Tranche 2.1 Portfolio.[40]

32 Id.
33 Id.
34 SPP Engineering. 2024 Integrated Transmission Planning Assessment Report. Page 147. Available at: https://www.spp.org/media/2229/2024-itp-assessment-report-v10.pdf
35 See **Appendix E.1**. Page 144.
36 SPP Engineering. 2024 Integrated Transmission Planning Assessment Report. Page 147. Available at: https://www.spp.org/media/2229/2024-itp-assessment-report-v10.pdf
37 PJM. 2024 Regional Transmission Expansion Plan. Page 270. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/2024-rtep/2024-rtep-report.pdf
38 Id. Page 295
39 See **Appendix E.1**. Page 144.
40 Southwest Power Pool's 2025 ITP. Available at: https://spp.org/documents/74831/mopc%20education%20session_2025%20itp_20250923.pdf

Figure 3.2-1: Existing 765 kV Transmission Lines in the United States

3.2.2 Eastern Interconnection

The electric transmission grid in the United States (excluding Alaska and Hawaii) is divided into three major subsystems, called interconnections: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas Interconnection. While very little power is exchanged across the interconnections, power is readily transferred within an interconnection.

Minnesota is a part of the largest subsystem, the Eastern Interconnection. This means that Minnesota's electric system is not only interconnected with neighboring states North Dakota, South Dakota, Iowa, and Wisconsin, but also with virtually all the states and Canadian provinces in the eastern two-thirds of North America. The entire electric system in the Eastern Interconnection operates as a single integrated electrical machine. The dynamics of the electrical system are complicated and require the moment-by-moment matching of generation resources and load requirements at the proper voltage across the interconnection. If the load balance or voltage is disturbed by a sudden change in generation output, transmission line availability, or customer usage, the bulk power system provides capacity within the Eastern Interconnection for other connected generation sources to adjust and keep the system in balance. This means that the operation of electrical generators and transmission facilities in Ohio or Nebraska can potentially impact the reliability of electric service to customers in Minnesota, and vice versa.

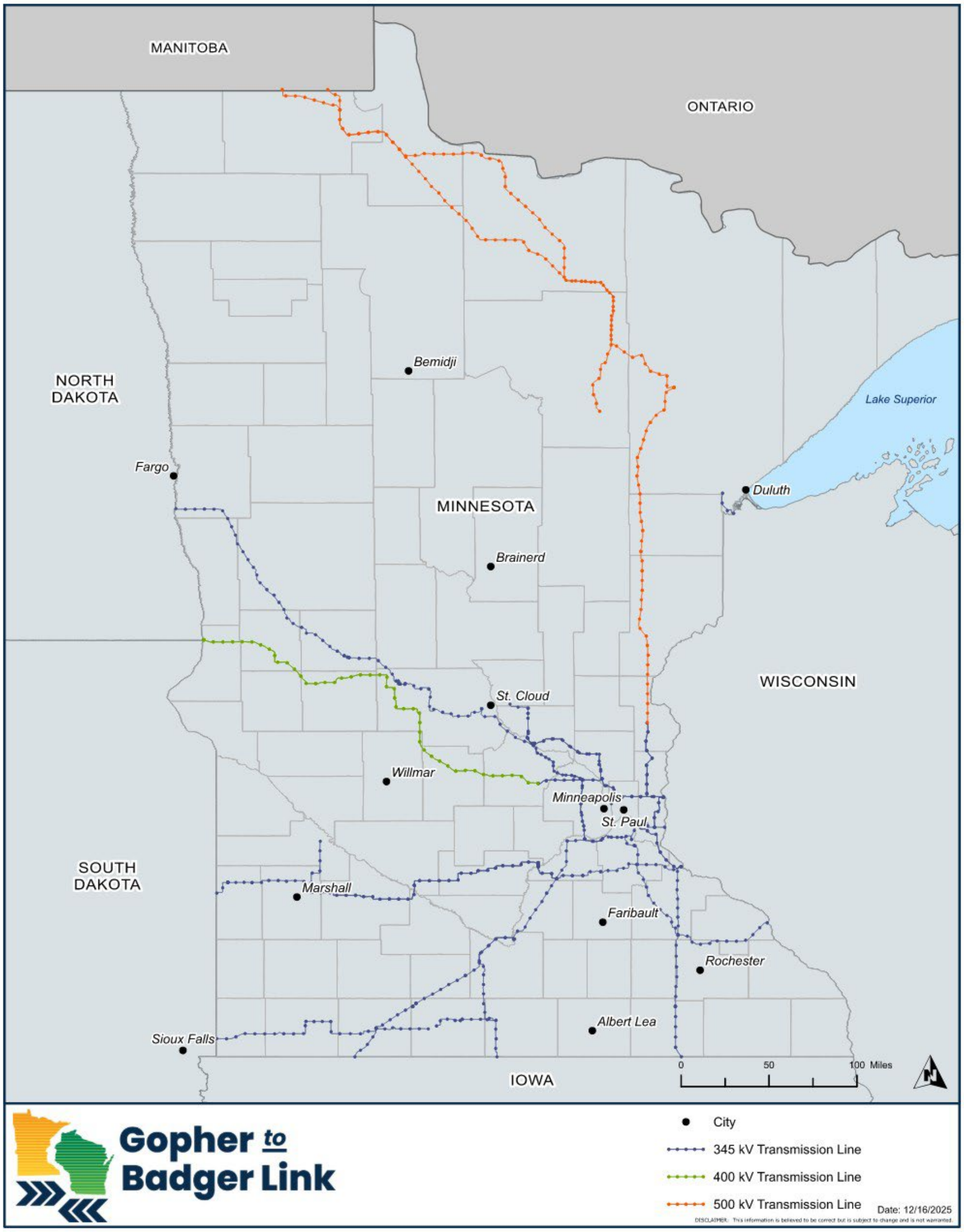
3.2.3 Minnesota

According to the 2025 Minnesota Transmission Owners Biennial Report, [41] there are more than 19,000 miles of AC transmission lines of 69 kV and higher voltages in Minnesota, including more than 8,500 miles of 69 kV lines, nearly 5,400 miles of 115 kV, 138 kV, and 161 kV lines, approximately 2,100 miles of 230 kV lines, and 3,000 miles of 345 kV and 500 kV lines. In addition, there are almost 230 miles of DC transmission lines in Minnesota.

The Minnesota transmission system connects over a hundred electric generating plants, sized from less than 1 MW to more than 1,700 MW, including fossil fuel-fired (e.g., coal, natural gas, oil), nuclear, wind, solar, hydro, and storage, located both inside and outside the state, to serve the state's more than five million residents and businesses. The Minnesota transmission system is also connected to utilities in surrounding states and in Canada. **Figure 3.2-2** shows the transmission system in Minnesota for voltages of 345 kV and greater.

[41] 2025 Minnesota Biennial Transmission Report. Section 7.1. Available at: https://www.minnelectrans.com/report-2025.html

Figure 3.2-2: Minnesota AC Transmission Grid



3.3 REGULATORY STRUCTURE

Load serving utilities in Minnesota have a legal obligation under Minnesota statutes to serve retail customers, whether residential, commercial, or industrial, located in their assigned retail service territory within the state. In addition, TOs have a legal obligation under federal law to provide reliable transmission services to wholesale customers, such as municipal utilities, connected to their transmission systems. This means that the system must be developed to reliably serve wholesale and retail customers throughout MISO. Fulfilling this important obligation, both now and into the future, requires electric utilities to engage in transmission planning to assess projected growth in customer requirements so as to have adequate lead time to construct new facilities (i.e., generation, transmission, distribution) necessary to serve growing customer demands.

Because of the importance of providing safe, adequate, and reliable service to customers, and the important role electric transmission plays in that service, electric transmission is highly regulated. Regulatory oversight of transmission in Minnesota occurs at several levels and by several different regulatory bodies; the Commission, Minnesota Department of Commerce (Department), FERC, MISO, Midwest Reliability Organization (MRO), and NERC.

3.3.1 <u>Minnesota Public Utilities Commission Authority</u>

The Commission provides plenary oversight over many aspects of the electric service system and construction of new facilities pursuant to state law. For investor-owned public utilities such as Xcel Energy, the Commission has regulatory control over all aspects of the provision of retail electric service to customers. The Commission reviews and approves the rates, charges, and service provisions of public utilities, as well as matters pertaining to the quality of service, integrated resource plans, affiliated interest transactions, and a variety of other types of transactions.

The Commission also has regulatory authority over some aspects of the provision of electric service by other types of electric utilities (such as co-Applicant Dairyland). For example, the Commission has the authority to review and consider Certificates of Need, such as the present Application, and Route Permits even if the applicant is not a public utility. In addition, the Commission has the authority to review and accept utility resource plans for non-public utilities and to adjudicate disputes over the retail service area boundaries of the various categories of utilities within Minnesota, regardless of their business form.

3.3.2 <u>Minnesota Department of Commerce</u>

The Department is the leading energy policy agency in the State of Minnesota. The Department plays several roles that are important to the implementation of the State's energy policy, including the development and implementation of new infrastructure. The Department has primary responsibility for the enforcement, investigation, and advocacy of utility matters in Minnesota (Minn. Stat § 216A.07 subds. 2 and 4). The Department takes a leading role in analyzing and evaluating utility proposals, including Certificate of Need applications.

The Department provides recommendations to the Commission on behalf of customers and ratepayers. As part of its analysis, the Department assesses the needs identified by Applicants. The Department also directly regulates the conservation and demand-side management programs of investor-owned public utilities (e.g., Xcel Energy), which can affect system reliability and the need for new transmission facilities.

3.3.3 Federal Energy Regulatory Commission

Under the Federal Power Act (16 United States Code Section (U.S.C. §) 824 et seq.), FERC has jurisdiction over the transmission of electricity in interstate commerce.

In 1992, Congress enacted the Energy Policy Act of 1992, which authorized expanded competition in the wholesale electric power supply industry, making generation a competitive market subject to FERC's regulatory authority. In addition, under the Federal Power Act, FERC has plenary authority to regulate the interstate electric transmission grid as the nation's electric highway system. Subsequent initiatives by FERC provided further changes to industry structure. In essence, over time, mechanisms were put in place that treat the transmission system like a regulated common carrier that is required to provide "comparable and non-discriminatory" open access to all eligible users of the transmission system.

Over the past 25 to 30 years, Congress and FERC have implemented a series of policies designed to provide open access to the transmission grid.

In 2000, FERC released Order 2000 which encouraged the formation of RTOs, like MISO. In 2001, FERC approved MISO as the RTO for the Midwest. MISO’s tariff, which is essentially a rule book for MISO and its members, is regulated by FERC. When FERC issues a new order, MISO’s tariff and corresponding practices adjust accordingly to comply. Since MISO’s formation, there have been several key orders which have shaped how the transmission grid is planned and operated.

- **FERC Order 693:**[42] FERC establishes Mandatory Reliability Standards for the Bulk-Power System.
- **FERC Order 890:**[43] Mandated a coordinated, open, and transparent transmission planning process, both on a sub-regional and regional level.
- **FERC Order 1000:**[44] Bolsters open and transparent regional planning requirements in FERC Order 890 and added an explicit requirement to plan for public policy (e.g., Minnesota Carbon Free by 2040 standard).
- **FERC Order 1920:**[45] Establishes a minimum 20-year planning horizon for regional transmission planning and defines metrics to measure the economic effectiveness of transmission projects.

While the Commission retains state-law jurisdiction over the construction of new transmission facilities and generation, access to and operation of the transmission system is regulated by

42 FERC. Order No. 693, Mandatory Reliability Standards for the Bulk-Power System. 18 Code of Federal Regulations (C.F.R.) Part 40 (March 16, 2007). Available at: https://www.ferc.gov/sites/default/files/2020-05/E-13_11.pdf

43 FERC. Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service, 18 C.F.R. Parts 35 and 37 (Feb. 16, 2007). Available at: https://ferc.gov/sites/default/files/2020-06/OrderNo.890.pdf.

44 FERC. Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 18 C.F.R. Part 35 (July 21, 2011). Available at: https://www.ferc.gov/sites/default/files/2020-04/OrderNo.1000.pdf.

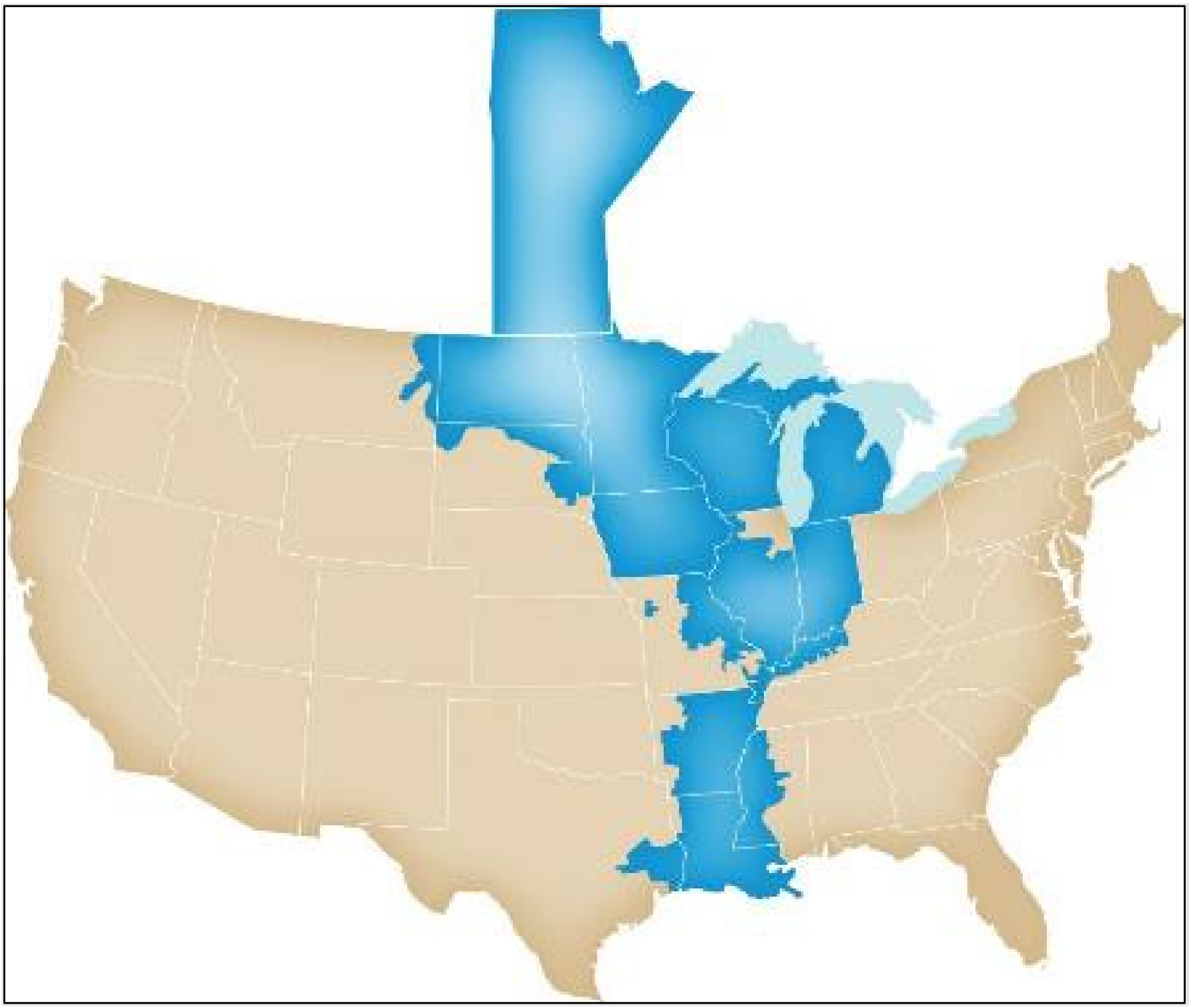
45 FERC. Order 1920-A and 1920-B, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, 18 C.F.R. Part 35 (November 21, 2024, and April 11, 2025). Available at: https://cms.ferc.gov/media/e-1-rm-21-17-001 and https://cms.ferc.gov/media/order-1920-b.

FERC. Jurisdictional utilities who own and operate transmission facilities are required to provide comparable access to all qualifying entities requesting access to the system and comply with mandatory NERC reliability standards.

3.3.4 Midcontinent Independent System Operator

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. **Figure 3.3-1** presents a map of MISO's reliability footprint.

Figure 3.3-1: MISO Reliability Footprint



As a federally registered planning authority and 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. MISO has 56 member-TOs, including Xcel Energy and Dairyland, with more than 79,000 miles of transmission lines under its functional control.[46]

[46] See **Appendix E.5**.

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.

MISO has a responsibility, established by the FERC, to study the transmission system within its footprint to identify necessary transmission projects to address reliability issues. This study includes the development of the 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. MISO adheres to the planning principles outlined in FERC Order Nos. 890, 1000, and 1920 in developing the MTEP. These FERC Orders require an open 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 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.

3.3.5 North American Electric Reliability Corporation

Reliability standards for electric transmission planning are established and enforced by the NERC.[47] NERC is a not-for-profit corporation, whose members include the Regional Entities across the United States, Canada, and the northern part of Mexico.

Overseen by FERC, NERC is the Electric Reliability Organization for the United States. NERC has the legal authority to enforce reliability standards on all owners, operators, and users of the bulk electric system. NERC has the power to impose a financial penalty up to $1 million per day for any violation of approved NERC reliability standards.[48] To fulfill its mission to ensure the reliability of the bulk electric system in North America, NERC:

- sets standards for the reliable operation and planning of the bulk electric system;
- monitors, assesses, and enforces compliance with reliability standards;
- audits bulk electric system operators to ensure that they are prepared to meet their reliability responsibilities;
- supports excellence in electric system operations through the accreditation of operator training programs and certification of system operators and operating organizations;
- provides education and training resources to promote reliability;
- assesses, analyzes, and reports on bulk electric system adequacy and performance; and
- coordinates reliability standards and procedures with the regional entities (such as MRO) and other organizations (such as MISO).

47 NERC. Homepage. Available at: https://www.nerc.com/Pages/default.aspx.

48 NERC. Sanction Guidelines of the North American Electric Reliability Corporation. Available at: https://www.nerc.com/pa/Stand/Resources/Documents/Appendix_4B_of_the_Rules_of_Procedure_Sanction_Guidelines.pdf.

The MRO is the RE that implements the NERC standards for Minnesota and the surrounding region. The MRO is designed to develop standards, monitor compliance, enforce standards, and assess reliability' of the bulk electric system. The MRO operates independently of the entities subject to its jurisdiction, thus ensuring that the reliability standards developed and enforced by the MRO are fair. The REs' members include the Applicants and all segments of the electric industry including rural electric cooperatives; investor-owned utilities; state, municipal and provincial utilities; federal power agencies; independent power producers; power marketers; and end-use customers.

3.3.6 National Electrical Safety Code

Transmission construction and operation must also comply with the NESC, a national standard that contains rules to safeguard employees and the general public during the operation and maintenance of electric supply lines and substations. The Commission requires utilities to comply with the NESC standards when constructing new facilities.[49]

The NESC was well defined by the 1920s and is currently revised every five years following extensive research and review per procedures established by the American National Standards Institute.[50] Among other requirements, the NESC specifies the physical clearances, and the mechanical strength of structures and equipment required to ensure safe operation of high-voltage electrical facilities such as transmission lines and substations. Consideration of the NESC's line-ground and line-to-line clearances, coupled with the NESC's mechanical strength requirements, determine whether existing transmission lines can be reconductored or converted to higher voltages. The NESC's provisions establish the minimum clearances required from adjacent objects, such as buildings.

The facilities proposed in this Application will comply with all applicable NESC standards.

3.4 DEFINING TRANSMISSION NEEDS

Electricity is a critical service and, thus, the transmission grid is planned to stay reliable, affordable and affordable all while enabling public policy. Reliability in the most basic sense means "keeping the lights on" 24 hours a day, 365 days a year. To accomplish that task, the transmission system is designed to transport energy from generation to where it is needed, not only during "normal" operating conditions (e.g., a typical day), but also during times when the demand for electricity is highest, such as the hottest summer day when air conditioners are running or conversely the coldest winter day when electric heating is at its maximum. In addition, the transmission system is designed to withstand the outage of a generator, transmission line, transformer, or other transmission system element without major disruption to the overall power supply. Reliability is measured and assessed to federal standards which are set by NERC (see **Section 3.3.5**).

As a critical service, it is also important that electricity remains cost effective. Due to the magnitude of the investment costs associated with the infrastructure needed to generate and transport electricity (a new transmission line or power plant is often hundreds of millions of dollars), an intensive planning process is undertaken to ensure that any needed addition to the power grid is the best option. The best option not only considers the up-front cost of the project (lower is better)

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49 Minn. R. 7826.0300.

50 IEEE Standards Association. The National Electric Safety Code. Available at: https://standards.ieee.org/products-programs/nesc/.

but also the value provided (higher is better). “Value provided” includes the ability to save money on monthly bills by having access to less expensive generators (also known as reducing system congestion), less public or environmental impacts, carbon reduction, lower risk of needing repair, and/or better flexibility to meet potential future power needs.

Although the transmission grid is extremely reliable, in recent years, low-probability but high-impact events, like extreme weather and sabotage, have had an increasing impact on the power grid across the United States. As a result, owners and operators of transmission facilities, including the Applicants, are seeking new ways to increase the resilience of the transmission grid to better prevent, withstand, and recover from low-probability but high-impact events. Resilience efforts include the use of stronger transmission structures, new conductors which minimize icing, enhanced security measures, and other physical and non-physical improvements.

3.4.1 What is “Reliability?”

Reliability is commonly defined as “keeping the lights on.” Because it often requires over a decade to identify and construct infrastructure necessary to ensure reliability, reliability is assessed on a forward basis – commonly ten to twenty years in the future. A common misconception is assuming that, because the grid is reliable today, improvements are not needed to ensure the grid will be reliable tomorrow. Similarly, the system is reliable today because the correct actions were taken in the previous decade(s).

Reliability is measured by multiple metrics. The reliability need for the Project, as detailed in **Section 6.3**, is measured in eleven different metrics, and each is a reliability driver. NERC defines the reliability of the interconnected bulk electric system in two ways: adequacy and security. "Adequacy" is the ability of the electric system to always supply the aggregate electrical demand and energy requirements of customers, considering scheduled and reasonably expected unscheduled outages of system elements (e.g., generators, transmission lines). "Security" is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Most traditionally, reliability is measured against NERC reliability standards (see **Section 3.3.5**). NERC standards establish a minimum level of reliability which must be met by the Applicants and MISO.

NERC’s reliability standards apply primarily to the components within the bulk electric system. The bulk electric system must be capable of performing under a variety of expected system conditions and must be planned to withstand forced and maintenance outages and other service interruptions known as contingencies. The standards are designed to keep the interconnected system planned, designed, and operating to withstand a number of contingencies caused by the loss of a generation unit or transmission line, or other system failures.

The NERC reliability standards require that the system be designed so that under system intact conditions or single contingency (N-1) condition (e.g., when a single transmission line, generator, or transformer is out of service) operators can reliably operate the system and serve all connected loads without any ongoing overloads or voltage problems. An overload exists when a transmission line, transformer, or other piece of equipment is subjected to loadings that exceed its applicable rating. Transmission lines and transformers typically have continuous (“normal”) and short-term (“emergency”) ratings. For transmission lines, nominal seasonal ratings are computed for at least each season’s conditions. Determination of line ratings involves consideration of the increased conductor sag that occurs at higher current loadings impacting line to ground distances required by NESC as well as the potential for irreversible metallurgical damage to the conductor. Transformer ratings are based on heat dissipation capability and consideration of insulation degradation that is accelerated at the higher internal temperatures resulting from high loadings.

Each transmission owner establishes loading criteria (a facility rating methodology) to avoid operation of transmission facilities at excessively high temperatures which can lead to transmission system damage. Normal ratings are available for continuous operation of the facilities; emergency ratings allow higher flows for a shorter duration of time.

For example, a utility may operate a transmission transformer at the emergency rating level for a short duration (typically less than 30 minutes) to complete transmission circuit breaker switching operations to manage a temporary system condition rather than interrupting service to customers. Designing and operating the system according to prudent loading practices ensures that the transmission system is operated safely and reliably.

The system must also be designed so that if there is a double contingency (or N-1-1) condition, where any two lines, generators, transformers, breakers, or combination thereof, are out of service, the power system will remain in a secure state. However, NERC reliability standards permit interruption of service to customers under double contingency conditions to maintain the safe operation of the electrical system. The NERC reliability standards also require that plans be in place to mitigate the effects of an extreme contingency, where an entire substation, several lines, or an entire generation plant becomes unavailable.

The technical analyses provided and summarized in **Section 6.3** of this Application comply with the NERC reliability standards. Performance of the system with the proposed Project was reviewed and determined to be acceptable for system-intact and outage conditions (i.e., the Project is needed to maintain NERC reliability standards and does not create new reliability violations due to an outage of the Project).

This **Section 3.4** provides additional detail below regarding the reliability needs, which is measured by “Energy Adequacy” and two other key reliability concepts, “Transfer Capability” and “System Stability.” This section also discusses the other needs of enabling policy, cost effectiveness, and resiliency.

3.4.1.1 Energy Adequacy

Energy adequacy is the ability to have energy to serve demand every hour of every day. Historically, with consistently cyclical load patterns and a primarily fossil fuel generation fleet, the system was planned to meet peak demand conditions. The notion was, if generation and transmission capacity were adequate to reliably serve demand during the most stressed conditions (typically summer peak), then there would be adequate generation capacity to meet demand during the other less stressful times of the year.

As demands for electricity become more dynamic, generation output becomes more dependent on weather patterns, and atypical weather becomes more common, it is no longer adequate to plan the grid to only meet peak demand conditions. Rather, “all hours matter.” In fact, forecasts detailed in **Chapter 6** of this Application show that the most stressed conditions from a reliability perspective in the next 20 years are not during peak conditions, but, rather, during hours of high (atypical) east-to-west (e.g., from Minnesota to South Dakota and North Dakota) or south-to-north flows (e.g., from Iowa and Minnesota to Manitoba). To maintain reliability every hour of every day, the transmission grid must be planned to have the capability and flexibility to move power from where it is produced to where it is needed regardless of the conditions.

Ensuring energy adequacy requires additional analysis and scenarios to ensure the grid can meet all likely future system conditions and demands. While in previous years, the system was planned under a few different scenarios using traditional transmission planning models, now the system is planned considering different scenarios, conditions, generation dispatches, transfers, and loading levels. Multiple tools are used to assess system needs from different perspectives. For example, in this Application, the reliability/energy adequacy need for the Project is assessed using four different loading levels, two different years, and four different transfer scenarios with MISO models (see **Section 6.2.2**). The Applicants and further assessed energy adequacy needs under four additional historical but reliability-stressed conditions in **Section 6.3.4**. Finally, MISO and the Applicants assessed 8,760 hourly energy needs under multiple scenarios using Hitachi Energy's production cost model, PROMOD (see **Section 6.3.2**).

In recent years, MISO and FERC have recognized the importance of energy adequacy, as opposed to traditional peak reliability, and have implemented additional precision into how the system is both planned and operated. In 2022, MISO implemented a seasonal resource adequacy construct. MISO's seasonal resource adequacy construct replaces its single annual capacity requirement based on a summer peak with separate requirements and resource accreditations (credit for how well a generator performs in a specific season) for summer, fall, winter, and spring to better ensure reliability across the entire year. Furthermore, in the same year, FERC implemented Order 881, which requires all TOs, including the Applicants, to implement ambient adjusted transmission line ratings. Historically, transmission line ratings were commonly fixed (i.e., constant) for each season to ensure the line operates within its engineered parameters. Ambient adjusted ratings provide additional precision to adjust the rating based on real-time temperatures to allow the system to be operated more reliably.

3.4.1.2 Transfer Capability

Transfer capability refers to the maximum amount of electric power that can be moved or transferred between different regions or areas of the grid. This capability is crucial for maintaining reliable electricity flow and ensuring that power can be delivered from where it is generated to where it is needed.

Transfer capability is typically measured across an interface (e.g., a state line or electrical region). While transfer capability is measured differently depending on the specific application. Traditionally, transfer capability is measured by proportionally scaling up generation on one side of the interface and load on the other side of the interface until a reliability overload is identified. The amount scaled immediately before a reliability overload is identified is the transfer capability.

Transfer capability is one of multiple ways to measure grid reliability and an increasingly key reliability metric as the generation fleet evolves. As wind and solar generation output is dependent on weather, there will be times when wind and solar generation within a community or even within much of Minnesota will be unavailable. Conversely, there will be times when there will be more wind and solar generation than can be used within Minnesota or a local area. Transfer capability allows the grid to reliably move power from where it is being produced to where it is needed to serve load every hour of every day. Thus, the ability to transfer energy to follow weather patterns is one part of the answer to the question of "how is reliability maintained when the wind isn't blowing, or the sun isn't shining?" Transfer capability allows the electric grid to perform akin to a super-sized battery.

The Project, and the broader MISO LRTP Tranche 2.1 Portfolio, are specifically designed to increase the ability to transfer bulk power across the MISO region to reliably serve load as discussed in **Sections 4.6**, **6.2, and 6.4** of this Application.

3.4.1.3 System Stability

Stability is a reliability attribute of the power grid. A stable system operates normally under all reasonably expected conditions and can quickly return to a normal state if there is a disturbance to the system. Unanticipated disturbances on the system may be caused by many things, such as a lightning strike on a transmission line, a transmission line structure failing, or a generator tripping offline because of a problem. Without a stable system, otherwise isolated events may lead to cascading and potentially widespread and catastrophic impacts, up to and including blackouts. NERC reliability standards require that the transmission grid be designed to withstand the loss of any single element without disruption. Utilities like the Applicants also typically evaluate the impacts of events involving multiple system elements and planned maintenance outages to prevent or minimize disruptions. As the generation changes where, how, and what kind of energy is produced and transmitted to customers, the stability of the grid must continually be assessed to ensure that the power grid remains reliable.

There are several aspects to stability that must be considered when planning the power grid, including voltage stability and transient stability. Voltage stability simply refers to the ability of the system to recover from an event and rapidly restore voltage within the normal operating range. A voltage collapse occurs when the voltage in some part of the system cannot recover following an event, resulting in extremely low voltages, and possibly causing damage to electrical devices and blackouts. Historically, centralized fossil-fueled baseload generating stations inherently have provided voltage support to the power system to maintain acceptable operating voltages and prevent voltage collapses. As the power system evolves to include a greater variety of generators, new solutions are necessary to ensure that system voltages remain robust, predictable, and stable under all reasonably expected conditions.

Transient stability refers to the short-term response of the grid during the first few seconds after a disturbance (i.e., the transient period). Typical areas of interest in the transient period are voltage and frequency response. Transient stability performance is typically measured by how severe the impact is immediately after the disturbance and how quickly the system voltage and/or frequency recovers from the disturbance. If the system voltage and/or frequency fails to recover to normal operating voltage or frequency, the system is unstable and transmission system elements are likely to begin tripping offline to try to stabilize the system by isolating the disturbance. Depending on the severity of the impacts, this can lead to cascading outages and blackouts.

3.4.2 <u>What is “Enabling Policy?”</u>

Public policy refers to state and/or federal law. As such, the Applicants and MISO must comply with applicable state or federal policy and thus must develop a transmission plan which enables policy. As the transmission grid must also be planned to comply with NERC national reliability standards, the following objective function is used to plan the transmission grid:

> *identify a transmission plan which enables a public policy in compliance with national reliability standards in the most cost-effective and least-impactful manner.*

In February 2023, Governor Tim Walz signed the "100 Percent by 2040" legislation into law, which, at a high level, directs electric utilities to transition to meet the needs of Minnesota customers with 100 percent carbon-free electricity by the end of 2040.[51] To comply with this legislation, additional sources of emission-free electric energy, like wind and solar, will be added to serve Minnesota's electrical needs. All generation scenarios and conditions used to assess Minnesota's transmission needs in this Application comply with Minnesota's "100 Percent by 2040" legislation. Likewise, all alternatives evaluated in this Application are measured for compliance with current Minnesota law.

Wind and solar resources are more commonly located in geographically dispersed and remote locations and provide electricity based on weather conditions. Thus, the transmission grid must be expanded to not only provide space to interconnect new carbon-free generators but also to be able to ship power across multiple states to follow weather patterns to ensure a steady-flow of electricity to when and where it's needed by each community (see **Section 5.3**).

In addition, to meet Minnesota law, the grid must be bolstered to maintain reliability after existing fossil-fuel generation retires. As detailed in **Section 3.4.1.3**, fossil-fuel generation not only provides power to the grid, but also key reliability attributes which keep power safe and stable. As those generators retire, the transmission grid must be expanded to take on roles currently served by the current fossil-fuel generation fleet.

As detailed in **Section 6.5** of this application, the Project is a significant step to enabling Minnesota's Carbon Free by 2040 law.

3.4.3 <u>What is "Cost Effectiveness?"</u>

Electricity is critical to everyday life and, thus, it must be accessible and affordable. Energy infrastructure including power plants, transmission lines, and substations are substantial long-term investments. The proposed Project is expected to have a useful lifespan of at least 50 years. Cost effectiveness refers to the ability of a proposed solution to meet the identified need as compared to the <u>total</u> costs over the life of a project.[52] Total cost considers not only the upfront capital and annual operations and maintenance costs of a transmission line but also cost impacts (typically savings) from greater access to less expensive generation, reduced system losses and lowered generation planning reserve margin.[53]

Cost effectiveness for transmission lines is measured in terms of total cost impacts (typically upfront costs, less economic benefits/savings) or a benefit-to-cost ratio (i.e., savings divided by upfront costs). Both measures are designed to provide an "out the door" estimate of total costs.

For projects which are primarily reliability-driven and are needed to comply with national reliability standards, such as the Project, cost-effectiveness is primarily measured as a comparison between alternative solutions to address reliability issues. The most cost-effective solution will address reliability issues for the least total cost.

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51 Minn. H.F. 7, sec. 8 (2023); amending Minn. Stat. § 216B.1691, subd. 8(g).

52 Given the time-value of money and depreciation, cost-effectiveness is typically measured over the first 20 years of a project's service.

53 Planning reserve margin is the amount of generation capacity a utility must possess to reliably serve load. As additional transmission is added, there is potential to decrease the amount each utility must hold as there is more efficient sharing of generation reserves between utilities in the region.

FERC and MISO have defined and approved consistent metrics to measure societal "out-the-door" economic impacts of transmission lines. MISO and utilities use these metrics to determine the impacts to not only the transmission portion of a monthly electric bill but also the generation portion to determine the total impacts to consumers.

3.4.4 What is "Resiliency?"

Resiliency refers to the ability of the grid to withstand and recover from disruptions, including extreme weather events, equipment failures, and acts of sabotage. It encompasses the capacity to anticipate, adapt to, and quickly recover from disturbances, ensuring a reliable electricity supply even under low-probability, high-impact conditions.

While closely related, resilience differs from reliability. Reliability focuses on the consistent and dependable delivery of electricity under normal and emergency operating conditions and is measured against the NERC reliability standards. Resilience, on the other hand, specifically addresses the ability to withstand and recover from extreme and unusual events. As atypical events become more typical, reliability standards are shifting to encompass more actions which were previously defined as resilience.

Resiliency is considered and weighed in all aspects of planning a power grid. For example, in determining the transfer capability necessary to maintain reliability by the Project, the Applicants considered not only "normal" operating conditions but also lower-probability, historically experienced, increased conditions of grid stress (see **Section 6.3.4**).

The Project's transmission facilities will be designed and constructed to meet or exceed all applicable federal, state, and industry standards, including the NESC, applicable NERC reliability standards, and relevant industry guidance for overhead transmission line design. These standards establish minimum requirements to ensure safe, reliable, and resilient operation under a wide range of environmental and operating conditions.

Resiliency is addressed through the application of baseline design criteria together with project-specific engineering evaluations. The Project accounts for historically observed and extreme weather conditions, site-specific environmental factors, and abnormal loading scenarios in the structural and electrical design. Engineering judgment, informed by applicable standards and supporting analyses where appropriate, is used to ensure the transmission facilities can withstand and recover from low-probability, high-impact events.

The Project also incorporates design features intended to limit the extent of damage and support efficient restoration following disturbance events. These include consideration of abnormal load cases, enhanced structural capacity at selected critical locations, and system-level measures to reduce the potential for cascading failures.

Together, these design and operational considerations provide a resilient transmission system that supports reliable service during normal operations and facilitates timely restoration following extreme or unusual events. Storm response and emergency restoration practices are described further in **Section 9.6**.

4 NEED FOR COMPREHENSIVE EXPANSION CONSISTENT WITH REGULATORY AUTHORITY

This chapter describes historical precedents for MISO LRTP Tranche 2.1, the long-range goals and policies supported by a coordinated build-out of the transmission system, and the scope of the MISO LRTP Tranche 2.1 Portfolio, which includes the Project.

The Applicants, along with all other Minnesota utilities, are obligated to develop, propose, and construct transmission facilities that satisfy all regulatory, policy, and mandatory reliability requirements. These rules and requirements work together to require that Minnesota's electric transmission system be planned, constructed, operated, and maintained in a way that will allow it to operate reliably and in coordination with other interconnected transmission systems throughout the Upper Midwest and the entire Eastern Interconnection. This Application should be reviewed in light of these regulatory requirements.

Among other reasons, and as discussed in more detail in **Chapter 5,** the Project is needed to enable Minnesota to serve electricity demands from new generation sources. In Minnesota, all state-regulated electric utilities, such as Xcel Energy, are required to file an Integrated Resource Plan (IRP) with the Commission every two years. Similar to the objective function used to plan the transmission grid, in each IRP, utilities must identify the generation needs to serve forecasted demand plus a required reserve margin while complying with state laws (e.g., the Minnesota Carbon Free by 2040 law) for the least total costs. The Commission reviews and ultimately rules on each IRP. The IRP becomes the state-approved plan for generation, and the transmission grid is developed to enable the generation plan in a reliable and least cost manner. The Project and MISO LRTP Tranche 2.1 Portfolio are designed to enable the approved IRPs for Minnesota and the broader Midwest region. Additional information on the Applicants' most recent IRP and generation changes is in **Section 5.3**.

What sets the Project (and broader 765 kV backbone in the MISO LRTP Tranche 2.1 Portfolio) apart is the long-term view to provide a steady supply of reliable electricity for the upcoming decades. The Project is an inflection point in Minnesota's grid. The Project is similar to the long-term view that resulted in the large regional interconnections in the 1970s and the CapX2020 development in the 2000s. While utilities must continue to develop facilities that meet the immediate needs of customers as well as facilitate annual changes and generation and demand, each can be met more reliably and cost-effectively with the Project in place. The Project will benefit the overall system and Minnesota customers and businesses for years and decades to come.

4.1 MINNESOTA TRANSMISSION GRID HISTORY, PRE-2001

Minnesota's transmission grid has come a long way since the Rural Electrification Act of 1936 initially brought electricity to most of the state. There have been several key inflection points, step-changes, or significant buildouts driven by fundamental changes in how electricity was produced and/or consumed, which have shaped Minnesota's grid to where it is today.

- **1930s:** The Rural Electrification Act provides low-cost federal loans to help rural communities form cooperatives to bring electricity to lower populated areas. Most communities are powered by local diesel generators. Transmission initially extends outward from the Twin Cities area to connect more communities to hydro generation. By the 1940s, local cooperatives are formed, and the start of a grid is established in Northwest Minnesota.

- **1950s:** The 230 kV network is developed across the state to provide an outlet for small coal power plants and to facilitate the initial transfers of energy between utilities.

- **1970s:** The significant development of large centrally located power plants drives a major expansion of the high-voltage transmission grid across the upper Midwest. Grid enhancements in the 1980s and 1990s are comparatively incremental in nature.

The last significant build-out of the grid occurred in the late 2000s and the build out was driven by several transformational factors:

- RTOs (e.g., MISO) were formed under orders from the FERC, empowered by the Federal Power Act, to operate and plan the transmission grid on a multi-state regional basis to improve reliability and cost-efficiency, transforming how the transmission system is used and managed.

- Minnesota passed the Next Generation Energy Act of 2007, which included a Renewable Energy Standard requiring most utilities to generate 25 percent of their electricity (30 percent for Xcel Energy), from renewable sources by 2025. [54] This created the need to interconnect a significant amount of new generating sources.

- Demand for electricity was growing at an historical rate of a few percentage points annually, and even absent the need to interconnect new generation, the transmission grid was reaching the limit of what Minnesota transmission owners could continue to incrementally expand to accommodate new and/or shifts in energy usage.

To meet these combined needs, an approximately 800-mile 345 kV network was ultimately developed in Minnesota (see **Section 4.3)**.

While the needs of the late 2000s, which drove the last significant expansion of Minnesota grid, were the largest to date, they pale in comparison to the magnitude of today's transmission needs (as described in **Chapter 5)**. To meet modern transmission needs in a reliable and cost-effective manner, a different and longer-term approach was needed. Thus, in 2019, MISO launched the LRTP, a multi-year multi-phase process to identify the transmission expansion necessary to optimally meet the needs of the transmission grid for the next 20 years. Additional information on the LRTP process is found in **Sections 4.4 through 4.7.**

4.2 MISO TRANSMISSION EXPANSION PLAN PROCESS, POST-2001

MISO has a responsibility to study the transmission system within its footprint to identify necessary transmission projects to maintain the NERC reliability standards. MISO's planning process, also known as the MTEP process, is an open and transparent process, and per FERC requirements, considers feedback from all stakeholders including end-use customers, regulatory authorities, environmental advocates, independent power producers, transmission owners, and others.

The MTEP process is performed annually in 18-month overlapping cycles. The results are contained within an MTEP report. Thus MTEP, depending on the context, refers to MISO's planning process or the report and data series used to develop the report and MISO's analysis

54 State of Minnesota. Next Generation Energy Act of 2007. Available at: https://www.revisor.mn.gov/laws/2007/0/Session+Law/Chapter/136/2014-06-28%2012:17:06+00:00/pdf.

that identified the need for the Project is the MTEP year 2024 (MTEP24) report. The MTEP process is a top-down, bottom-up process which simultaneously considers both regional needs (top-down) and local needs (bottom-up) and to identify the optimal plan to meet all the MISO region's reliability needs.

Each year as part of the MTEP process, MISO assesses changes in transmission system needs based on changes in demand, generation, and state and federal policy, amongst other factors. Should a change in any one factor result in the grid no longer meeting national reliability standards or policy, MISO, through its stakeholder process, will identify mitigation to ensure the system stays in compliance.

The first MTEP report was released in 2003. Since then, there have been over 20 annual MTEP cycles. In the last 3 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 for age and condition purposes. However, in response to fundamental shifts in electricity usage and production, MISO has also identified three regional transmission overlays (portfolios of higher-voltage transmission projects which, when combined, span the footprint): the MVP Portfolio (**Section 4.3**), MISO LRTP Tranche 1 Portfolio (**Section 4.5**), and MISO LRTP Tranche 2.1 Portfolio (**Section 4.6**).

4.3 MVP 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 described in **Section 5.3**. In 2004, CapX2020, now known as Grid North Partners, formed to develop a long-term vision for the Minnesota 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 and South Dakota. CapX2020's vision for Minnesota was optimized for the entire Midwest via MISO's first regional MVP portfolio, a portfolio of 17 projects, primarily at 345 kV, totaling approximately 2,200 miles across nine Midwest states.[55] All CapX2020 lines were in service as of 2017.

To optimally meet immediate needs with longer-term goals in mind, at the recommendation of the Department[56] and approval of the Commission,[57] the 345 kV CapX2020 projects were upsized and built as single-circuit but double-circuit capable. Today, the second circuit has been or is planned to be added to nearly all the CapX2020 projects, which has allowed Minnesota to double the transmission capacity of each corridor with minimal physical impacts and significantly less costs than would be required for a new stand-alone option.

The scope of the Project in this Application includes the addition of a second circuit of the existing CapX2020 transmission line between North Rochester and Hampton. Despite recent and planned

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55 MISO. Regionally Cost Allocated Project Reporting Analysis. 2011 MVP Portfolio Analysis Report. Available at: https://cdn.misoenergy.org/MVP%20Dashboard117055.pdf.

56 Surrebuttal Testimony of Dr. Steve Rakow on Behalf of the Minnesota Office of Energy Security. Available at: https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7b3330DBFF-01B4-407D-B195-30774E30DD2A%7d&documentTitle=5320643. Page 21.

57 CapX 2020 Transmission Expansion Initiative. Order Granting Certificates of Need with Conditions. https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7b54C51FAE-B774-4EED-A93C-CAF6ECC5EB52%7d&documentTitle=20095-37752-01. Page 43.

doubling of transmission capacity in the CapX2020 circuits,[58] additional transmission capacity is still needed to meet the needs for the next 20 years.

4.4 MISO LONG RANGE TRANSMISSION PLAN

In the 2010s and 2020s, more states, like Minnesota, passed mandates to reduce and/or eliminate carbon-emitting generation, additional details in **Section 5.3**. Seeing a fundamental shift in the generation mix towards more renewable (i.e., wind, solar, hydro) generation sources, MISO released a study in 2021 called the Renewable Integration Impact Assessment (RIIA) to understand the implications of an increase in renewable generation entering the system, or renewable penetrations. The RIIA found that up to 30 percent renewable penetration is manageable with incremental transmission; however, managing the system beyond 30 percent of system-wide renewable penetrations will require transformational change in planning, markets, and operations, as shown on **Figure 4.4-1**.

Within the next 20 years, Minnesota's generation mix is expected to be primarily renewable, and MISO is expected to be 83 percent renewable.[59]

In 2024, the MISO system achieved a 19 percent renewable penetration MISO-wide.[60] Minnesota achieved a 33 percent renewable penetration.[61] While incremental transmission expansion has and continues to be developed, the increased stress to efficiently maintain reliability is evident in the increased congestion levels and more frequent use of MISO emergency operating procedures.

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 MISO future needs.

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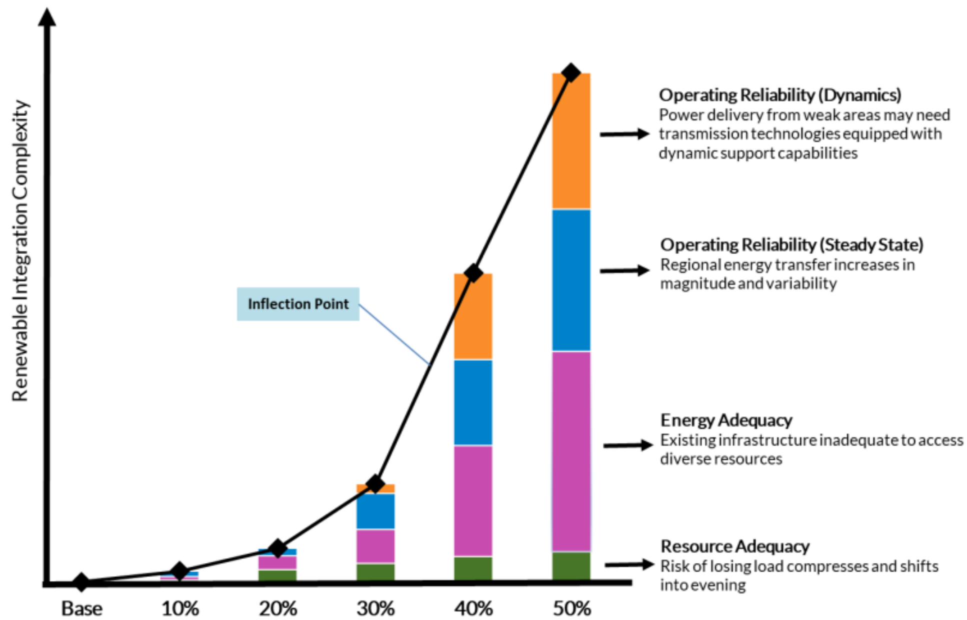
58 Recent completed second-circuit projects include Brookings County to Lyon County and Helena to Hampton. The second-circuit between Alexandria and Monticello (Big Oaks) is expected to be completed in 2026. The second-circuit between Fargo and Alexandria is a project in the MISO LRTP Tranche 2.1 Portfolio. The second circuit between Hampton and North Rochester is proposed in Docket No. 25-117.

59 See **Appendix E.2**. Page 77.

60 **Appendix E.5**.

61 EIA. Electricity. Available at: https://www.eia.gov/electricity/data/browser/" \l "/topic/0?agg=2,0,1&fuel=vvg&geo=000004&sec=g&freq=A&start=2001&end=2024&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=. Referenced November 2025.

Figure 4.4-1: Reliability Implications of Increasing Renewable Penetrations[62]



The LRTP is one component of MISO's Reliability Imperative,[63] 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 Effective** – 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. In MISO's LRTP, MISO and stakeholders worked to identify a transmission plan that simultaneously

62 MISO's Renewable Integration Impact Assessment (RIIA). Available at: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf?_t_id=HAcY9Glq5QpaFZ2DUyt_JA%3d%3d&_t_uuid=Ls_331WCSMiJH1i_VSQ81w&_t_q=riia&_t_tags=language%3aen%2csiteid%3a11c11b3a-39b8-4096-a233-c7daca09d9bf%2candquerymatch&_t_hit.id=Optics_Models_Find_RemoteHostedContentItem/520051&_t_hit.pos=3.

63 MISO. Reliability Imperative Report. Available at: https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/.

addresses multiple regional needs, which under the MISO tariff is defined as an MVP. For a project to be deemed needed by MISO as an MVP it must:

- Reliably and economically enable regional public policy needs;
- Provide multiple types of regional economic value; and/or
- Provide a combination of regional reliability and economic value.

4.5 LRTP TRANCHE 1

In July 2022, MISO approved the first tranche, or phase, of the LRTP (LRTP Tranche 1). The 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 4.5-1** depicts the projects in the LRTP Tranche 1 Portfolio.

The LRTP Tranche 1 Portfolio includes three 345 kV projects in Minnesota include:

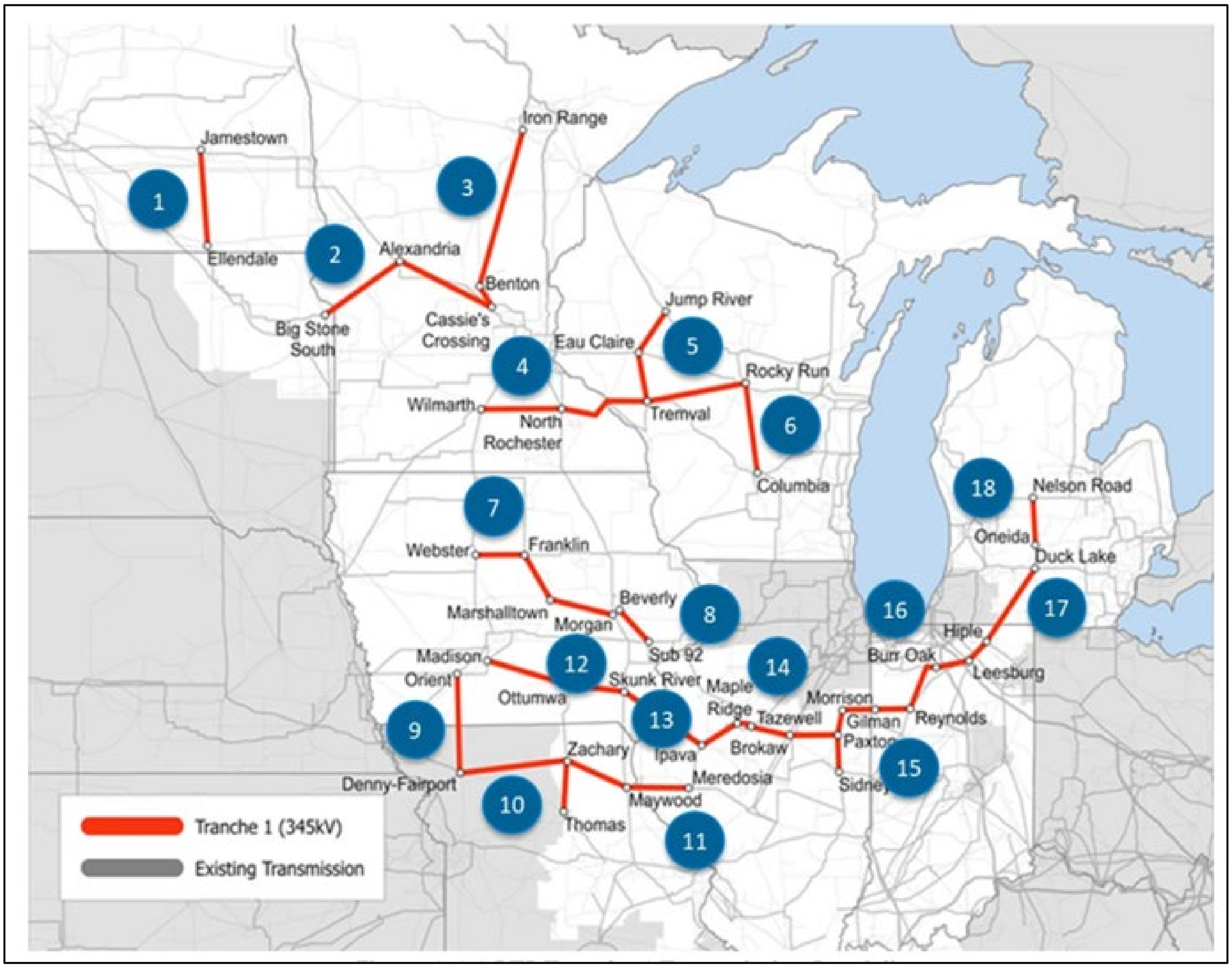
- the Big Stone South to Alexandria to Big Oaks Transmission Project;[64]
- the Northland Reliability Project;[65] and
- the Mankato to Mississippi River Project.[66]

64 Commission Docket Numbers CN/22-538, TL-23-159, and TL-23-160

65 Commission Docket Numbers CN-416 and TL-22-415.

66 Commission Docket Numbers CN-22-532 and TL-23-157.

Figure 4.5-1: MISO LRTP Tranche 1 Portfolio



LRTP Tranche 1 was intentionally designed as a first step to address immediate reliability needs driven by retiring fossil fuel plants and to increase primarily 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.[67]

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67 Values as of July 2022. Market forces have driven Project costs to increase since 2022 and the same forces will also cause benefits to increase.

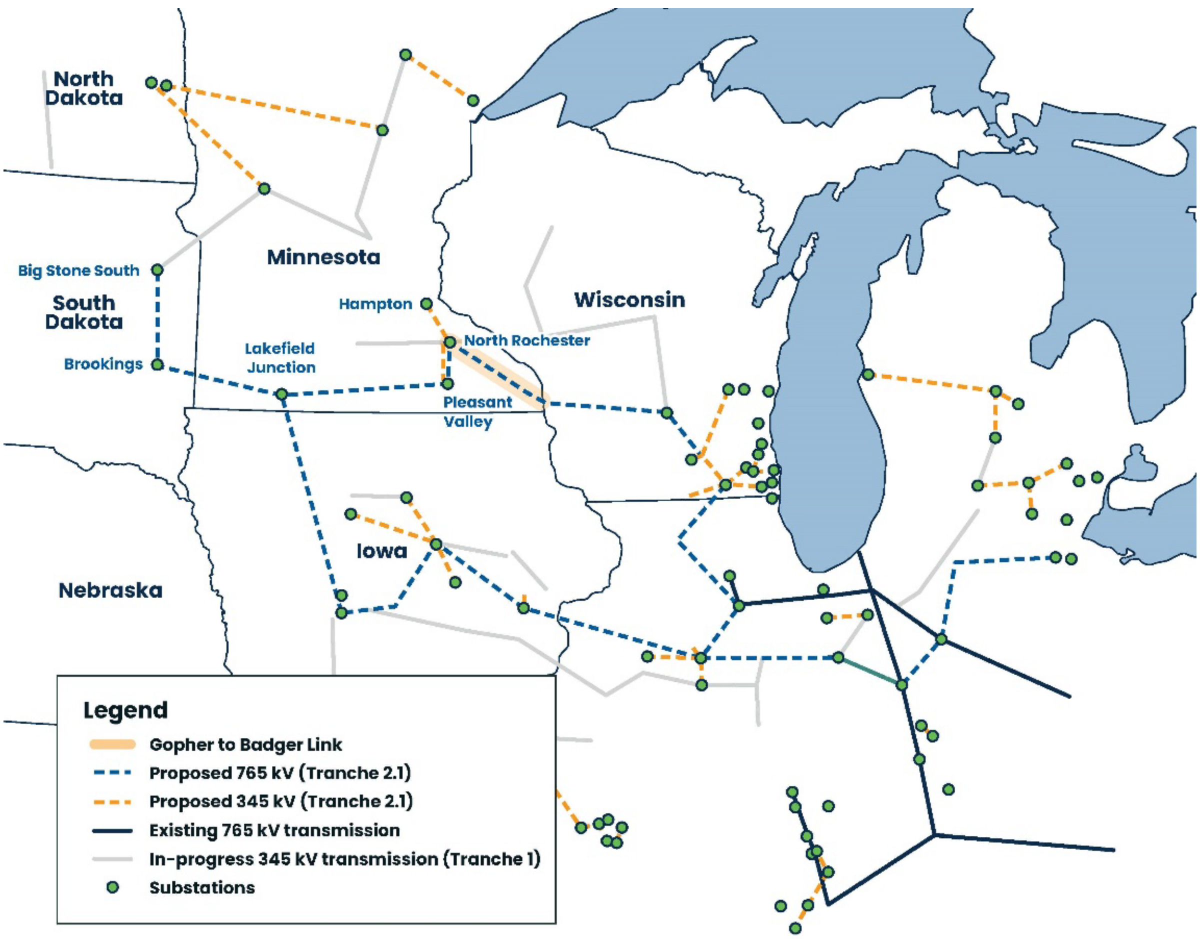
- Supports the reliable interconnection of approximately 43,431 MW in new, primarily renewable, generation capacity across the MISO Midwest subregion, 8,339 MW of which is in Minnesota and the surrounding region.

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

4.6 LRTP TRANCHE 2.1

In 2024, MISO approved the next phase of the LRTP (LRTP Tranche 2.1) which establishes a new 765 kV "backbone" across the Midwest, as shown on **Figure 4.6-1**.

Figure 4.6-1: MISO LRTP Tranche 2.1 Portfolio[68]



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 portfolio builds upon and is enabled by the LRTP Tranche 1 and the existing transmission grid, which serves as "on and exit ramps" for the new LRTP Tranche 2.1 765 kV transmission "super network", as well as contingency backup to meet NERC reliability standards. Combined, the existing 765 kV and

68 MTEP24 Chapter 2. **Appendix E1**. Page 144

345 kV networks 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, as further described in **Section 7.4**. The complete Chapter 2 from the MTEP24 Report ("Regional/Long-Range Transmission Planning") is included as **Appendix E.1**. 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.[69] The LRTP Tranche 2.1 Portfolio meets the following MVP criteria:

- **Reliability** – Addresses 961 reliability violations across the Midwest.[70]
- **Economic Efficiency/Net Benefits** – The $21.8 billion portfolio has a benefit-to-cost ratio of 1.8 to 3.5. This means that every $1.00 invested in transmission will result in economic benefits of $1.80 to $3.50. 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.[71]
- **Policy** – Alleviates congestion and enables interconnection of approximately 116,000 MW of primarily carbon-free resources[72] to reduce Midwest CO_2 emissions by 127 million to 199 million metric tons over 20 to 40 years to help states like Minnesota comply with decarbonization laws.[73] In addition to Minnesota, Illinois[74] and Michigan[75] have enforceable decarbonization standards, and Wisconsin[76] has a decarbonization goal. In addition, many Midwest utilities have decarbonization goals.

The Studied Projects serve a key role in the execution of MISO LRTP Tranche 2.1 by addressing reliability needs specific to southern Minnesota, eastern North Dakota, eastern South Dakota, northern and central Iowa, and western Wisconsin.[77]

4.6.1 Reliability Need

MISO identified the need for the LRTP Tranche 2.1 Portfolio to prevent numerous thermal and voltage reliability issues as summarized on **Figure 4.6-2.** 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 (see **Section 5.1** for additional details) in the 10-year and 20-year time horizons.

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69 Id. Page 6.

70 Id. Page 63 through 69 and 77 through 124.

71 Id. Page 125, Figure 2.13. Net savings are 20-year Net Present Value (NPV) in $2024.

72 Id. Page 75.

73 Id. Page 142.

74 Illinois Climate and Equitable Jobs Act mandates 100% carbon-free power by 2045. Illinois Department of Commerce. Available at: https://dceo.illinois.gov/ceja.html.

75 Michigan Senate Bill 271 mandates 100 percent carbon-free power by 2040. State of Michigan. Michigan Becomes National Leader in Climate Action with New Legislation. Available at: https://www.michigan.gov/whitmer/news/press-releases/2023/11/28/governor-whitmer-signs-historic-clean-energy-climate-action-package.

76 Wisconsin Governor Evers Executive Order #38 established a state goal to reach 100 percent carbon-free electricity by 2050. Available at: https://docs.legis.wisconsin.gov/code/executive_orders/2019_tony_evers/2019-38.pdf.

77 Pages 84 and 92.

Figure 4.6-2: MISO Summary of Reliability Issues[78]

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

4.6.2 Generation Transition and Public Policy

MISO's analysis shows that the LRTP Tranche 2.1 Portfolio supports the reliable interconnection of approximately 115.7 GW of new generation.[79] Of the capacity supported by the LRTP Tranche 2.1 Portfolio, 32.1 GW is in Minnesota and the surrounding region (MISO Local Resource Zone 1).[80] 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.[81] Using the Commission's valuation of CO_2 emission reduction,[82] the LRTP Tranche 2.1 Portfolio is expected result in approximately $28 to $39 billion in carbon reduction benefits over the first 20 years across the MISO footprint.[83]

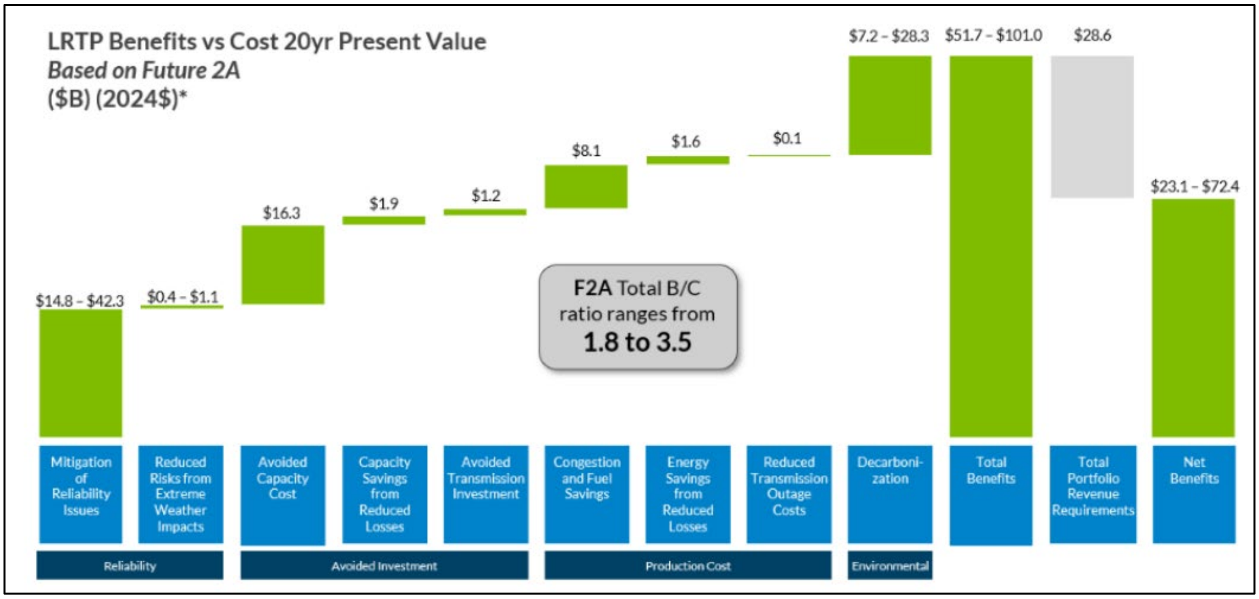
78 Id. Page 29. Central, East, and West refer to MISO regions. Minnesota is in the MISO West Region.
79 Id. Page 75.
80 Id. Page 76.
81 Id. Page 142.
82 In re Establishing an Updated 2020 Estimate of the Costs of Future Carbon Dioxide Regulation on Elec. Generation under Minn. Stat. § 216H.06, Docket No. E999/DI-19-406, Order Establishing 2020 and 2021 Estimate Of Future Carbon Dioxide Regulation (September 30, 2020).
83 See **Appendix E.1**. Page 143.

4.6.3 Cost Effectiveness / Net Benefits

MISO's analysis shows that 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 on **Figure 4.6-3**.[84] 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 that net savings are expected relative to what would be needed without the MISO LRTP Tranche 2.1 Portfolio.[85] For an average electrical consumer, MISO estimates that the LRTP Tranche 2.1 Portfolio is estimated to cost about $5 per 1,000 kWh of energy used while providing $10 to $18 of value over that same amount of usage per month in value.[86]

As shown on **Figure 4.6-3**, MISO quantified the economic savings of the MISO 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.[87]

Figure 4.6-3: Economic Savings from the MISO LRTP Tranche 2.1 Portfolio[88]



4.6.4 Other Qualitative Benefits

The LRTP Tranche 2.1 Portfolio also provides multiple other qualitative benefits. MISO expects that 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

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84 Id. Page 125.

85 Id. Values based on MISO Future 2A.

86 MISO. Fact Sheet - Long Range Transmission Planning Tranche 2.1. Available at: https://cdn.misoenergy.org/LRTP%20Tranche%202.1666573.pdf.

87 FERC. Order 1920-A and 1920-B, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, 18 C.F.R. Part 35 (November 21, 2024, and April 11, 2025). Available at: https://cms.ferc.gov/media/e-1-rm-21-17-001 and https://cms.ferc.gov/media/order-1920-b.

88 MTEP24 Chapter 2. **Appendix E1**. Page 125.

economic impacts of natural gas price changes by providing access to a broader pool of generation resources.[89]

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.

4.6.5 Studied Projects as Part of MISO LRTP Tranche 2.1

MISO LRTP Tranche 2.1 was developed as a portfolio of projects designed to work together; however, each project group in the portfolio was also justified by MISO based on regional and local needs. MISO identified that the Project is a critical component of the LRTP Tranche 2.1 Portfolio and the best option to meet Minnesota and the Midwest's electrical needs. To identify the optimal LRTP Tranche 2.1 Portfolio, MISO evaluated 97 different alternatives,[90] including multiple alternatives to the Studied Projects.[91] MISO's justification for the Studied Projects is summarized as follows:

> *The 765 kV project in northeastern South Dakota, Southwestern Minnesota and Western Iowa provides an outlet for generation in South Dakota and also connects both west-to-east 765 kV paths developed in the initial portfolio to provide contingency support.[92] The Minnesota – Wisconsin West – Wisconsin East project adds power transfer capability into load centers in Minnesota and Wisconsin….[93] The portfolio resolves most constraints in Southern Minnesota and Western Wisconsin, especially on 200 kV and above facilities.[94] The Minnesota – Wisconsin West – Wisconsin East project assists transfer of power into load centers in Minnesota and Wisconsin…. Projects in Southern Minnesota and Wisconsin enable substantially more renewable delivery, particularly from the Eastern Dakotas, Southwestern Minnesota, and Northern Iowa – locations with some of the strongest wind resources.[95] This is aided through the loop configuration of the other Tranche 2.1 765 kV west-to-east path which increases the amount of power that can reliably flow over 765 kV facilities.[96]*

Details on MISO and the Applicants' need analysis are presented in **Chapter 6**.

4.7 MINNESOTA TRANSMISSION OWNERS' EFFORTS TO EXPAND EXISTING GRID CAPACITY

The Applicants have a responsibility to ensure the right transmission upgrades are developed at the right time to maintain reliability. New transmission lines are proposed only after all other options to upgrade existing facilities have been exhausted. The Applicants and Minnesota's

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89 Id. Page 148.
90 Id. Page 42.
91 Id. Pages 45 and 52.
92 Id. Page 93.
93 Id. Page 84.
94 Id. Page 84.
95 Id. Page 86.
96 Id. Page 86.

transmission owners have been on the forefront of using technology to “squeeze every drop” of capacity out of the existing transmission grid through such recent initiatives as:

- **Ambient Adjusted Line Ratings (AAR):** The Applicants and all MISO transmission owners are implementing ratings on all facilities which are adjusted based on actual temperatures. Temperature is a primary factor in transmission line capacity; generally, the cooler the temperature the more power can safely flow on a transmission line. Previously, line ratings were established on a seasonal basis. This extra precision allows additional capacity when conditions warrant.

- **Dynamic Line Ratings (DLRs):** Several Minnesota utilities, including Xcel Energy, have implemented DLRs at the most impactful sites. DLRs build on the AAR concept by adding additional real-time meteorological data such as wind speed and irradiance to add further precision to enable additional transmission capacity when conditions warrant.

- **Near-Term Congestion Projects:** In 2023, Grid North Partners, an evolution of CapX2020, announced plans to construct 19 projects to help decrease congestion levels over the next several years. The congestion projects are primarily upgrades of existing infrastructure which require little to no new right-of-way. Solutions identified as part of the Grid North Partners study were incremental quick-implementation solutions which help reduce congestion to bridge to longer-term holistic solutions, like the Project and MISO LRTP Tranche 2.1 Portfolio, and help reduce impacts of outages necessary to construct LRTP projects.

- **Grid Enhancing Technologies:** In 2025, as part of the Minnesota Biennial Transmission Plan, the Minnesota Transmission Owners, including Xcel Energy, conducted a second iteration of the near-term congestion study focusing on grid enhancing technologies.[97] Gride enhancing technologies are hardware or software that increases the capacity or flexibility of a high voltage transmission line, effectively optimizing power flow to reduce congestion and improve the integration of renewable energy. These technologies include, but are not limited to, dynamic line rating, advanced power flow controllers, and topology optimization.[98] The 2025 study addresses 30 additional solutions which will be implemented in the near-term to incrementally expand the capacity of the existing transmission grid.

Due to the collective actions taken, the Minnesota transmission grid today is reliable, has enabled Minnesota to meet mandates ahead of schedule (e.g., the renewable portfolio standard)[99], and helps provide electricity costs that are less than the national average.[100] While each effort has resulted in expanded grid capacity, the amount of additional capacity which has been added is a fraction of what is needed to meet Minnesota’s projected electrical needs as described in **Chapters 5 and 6**. Minnesota utilities have a history of working collaboratively and proactively to identify long-term transmission solutions, but it often takes over a decade to identify and construct infrastructure necessary to ensure future system reliability. These actions have also helped bridge

97 2025 Minnesota Biennial Transmission Report. Section 9.3. Available at: https://www.minnelectrans.com/report-2025.html.

98 Grid Enhancing Technologies definition from Minnesota Statute Section 216B.2425.

99 EIA. Electricity Data Browser, Net generation for all sectors, Minnesota, Annual, 2001-23. Available at: https://www.eia.gov/state/analysis.php?sid=MN#29.

100 EIA. Electric Power Annual, Table 2.10: Average Price of Electricity to Ultimate Customers by End-Use Sector. Available at: https://www.eia.gov/electricity/annual/table.php?t=epa_02_10.html.

the long-term solutions, such as the Project, that are needed to maintain reliability, meet new policy mandates, and remain cost competitive.

5 NEED DRIVERS

As the way that our region generates and uses electricity changes, the electric transmission grid must evolve with it. The Project is needed to maintain system reliability amid fundamental changes in how energy is produced and used. This chapter details the generation and demand forecasts which are driving the need for the Project.

- **Section 5.1 – Need Scenarios:** MISO and the Applicants used a scenario-based approach to analyze the need for the Project to consider a range of potential generation and demand forecasts. MISO's Future 2A, based on approved state integrated resource plans and state and utility goals, is the primary scenario used in this Application.

- **Section 5.2 – Generation Fleet Transformation:** Driven by a combination of economics, consumer preferences, age of existing generation, and regulatory policies, 72 GW of new generation is expected to be added and 16 GW of existing generation is expected to be retired over the next 20 years in Minnesota and the surrounding area (within MISO's Local Resource Zone 1).[101]

  For the broader MISO region, MISO forecasts that by 2042, fossil fuel generation will provide approximately 2 percent of annual energy, compared to 66 percent in 2024. Variable wind and solar generation will provide approximately 73 percent of annual energy, compared to 17 percent in 2024.[102]

- **Section 5.3 – Evolving Electrical Demands:** Peak demand and electrical consumption in Minnesota and within the MISO region is forecasted to increase over the next two decades as a result of new and expanded manufacturing, electrification (e.g., heating and cooling, appliances, agriculture, transportation, etc.), and emerging industries like data centers. Demand forecasts used in this Application do not consider data center and other industry growth potential. However, MISO predicts that these inputs could increase demand growth by as much as three-fold.

5.1 NEED SCENARIOS

Forecasts of the future generation mix and energy usage are necessary to plan the grid, as transmission grid expansions are long-term decisions. As part of each MTEP cycle, MISO and its stakeholders 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 range of generation and demand forecasts considering potential future economic and policy outcomes, ensuring that the actual future is within the range of the Futures. These Futures, which envision system conditions 20 years ahead, are then used to assess and identify the transmission needed to deliver the necessary energy reliably and efficiently from generation resources to customers. Futures are developed through an iterative and robust stakeholder process which includes representatives from MISO utilities, state regulatory authorities, public consumer advocates, environmental representatives, and independent power producers.

In MTEP24, three Futures were used in MISO's grid planning initiatives: Future 1A, Future 2A, and Future 3A. As of February 2026, the MTEP24 futures, referred to as "Series 1A," published on November 1, 2023, are the latest available. MISO developed these scenarios between 2022

[101] See **Appendix E.2.** Pages 87 and 88.

[102] See **Appendix E.2.** Page 7 (2042 values). See Appendix E.**5** (2024 values).

and 2023 and incorporated numerous rounds of stakeholder feedback, policy assessments, and industry trends. MISO's three Futures incorporate varying assumptions about utility and state goals, retirements, distributed energy resource adoption, and electrification, among other factors. All MTEP24 Futures assume that the changes announced through October 2022 in utility IRPs (resource plans for upwards of 10-15 years into the future) are realized.[103] A summary of the key assumptions for each MTEP24 Future is shown on **Figure 5.1-1.**

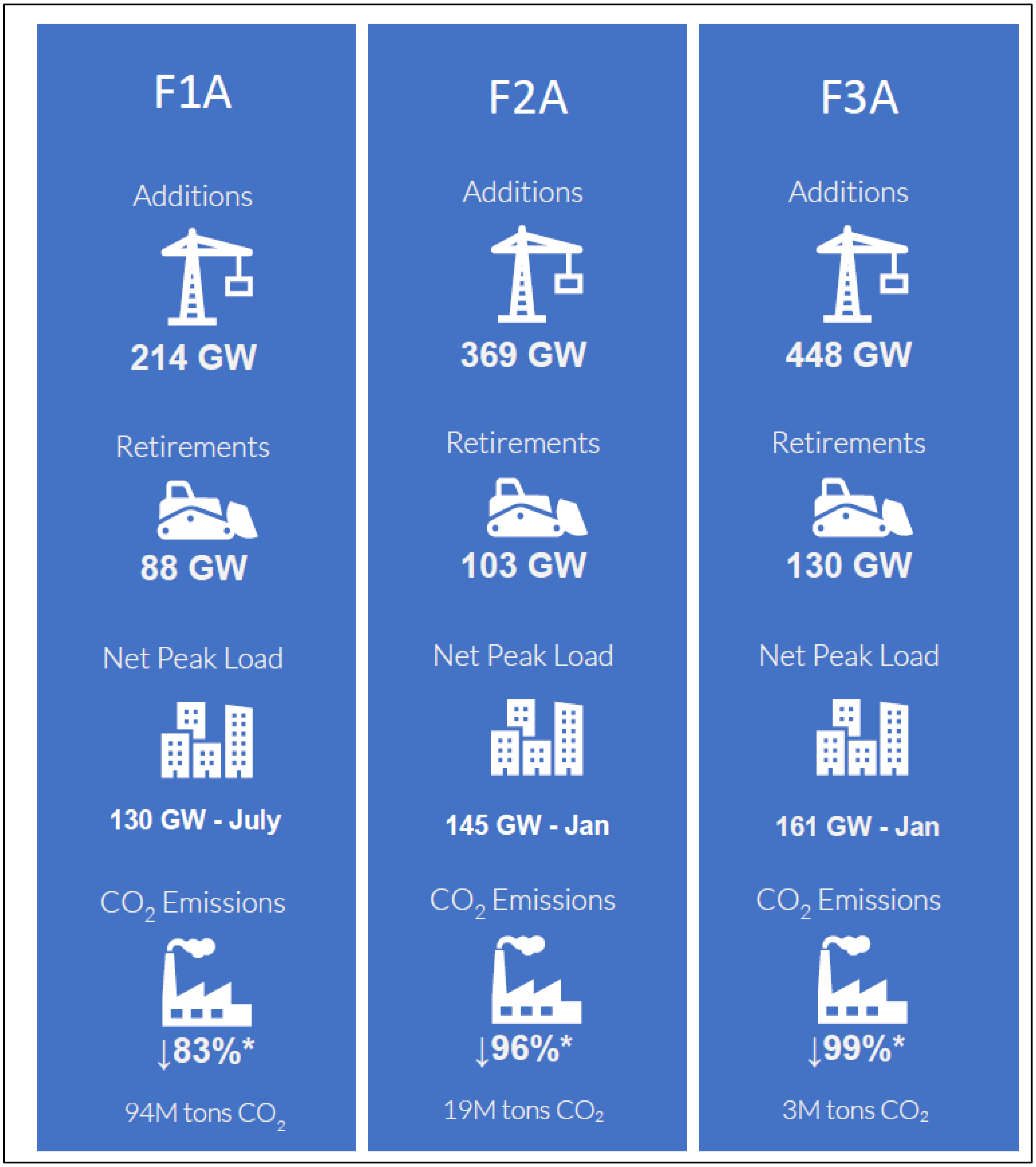
The magnitude of change considered in MTEP24 Futures is transformational. Future 1A alone, the "least transformational" of the MTEP24 Futures as it assumes only 85 percent of state decarbonization goals as of 2022 are met, anticipates 88 GW of generation retirements and 214 GW of resource additions.[104] For perspective, MISO's current installed capacity is approximately 203 GW.[105]

Future 2A is MISO's LRTP Tranche 2.1 base scenario. Unless noted otherwise, the Applicants' analysis in this Application is performed using Future 2A. Per MISO, "Future 2A is most aligned with an optimized, least-cost expansion that meets member goals."[106] Future 2A incorporates 100 percent of utility IRPs and announced state and 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. [107]

Additional details on MISO's MTEP24 Futures can be found in **Appendix E.2**, the MISO Series 1A Futures Report.

103 Id. Page 4.
104 Id. Page 6.
105 **Appendix E.5**.
106 See **Appendix E.1.** Page 10
107 Id. Page 143.

Figure 5.1-1: MISO Futures Generation Assumptions – Cumulative Change Through 2042[108]



5.2 GENERATION FLEET TRANSFORMATION

The Project and the MISO LRTP Tranche 2.1 Portfolio enable the interconnection and reliable transfer of more generation across the system, exceeding the capabilities of the existing grid. While the current approved IRPs in Minnesota rely primarily on additional renewable

108 See **Appendix E.2**. Page 4.

generation,[109] the Project is agnostic to the type of generation which it enables. The Project can move electrons generated by natural gas, coal, hydrogen, energy storage, nuclear, renewables, etc. – providing flexibility for utilities to adjust generation plans as technology, regulatory and company policies, and economics evolve.[110]

The Project and the MISO LRTP Tranche 2.1 Portfolio support reliability for every hour of every day by facilitating the movement of energy to, through, and out of Minnesota, depending on electrical demand and generator availability. The following sections provide details on the generation forecast for Minnesota and the broader MISO region, as the Project's need is not only driven by Minnesota's generation requirements but by those of the broader MISO region.

5.2.1 MISO Energy Landscape Transformation

The MISO footprint (see **Figure 3.3-1**) is experiencing a fundamental change in the energy industry landscape due to shifts in generation resources and decentralization of generation.

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. In By 2024, coal generation had shrunk to approximately 25 percent of MISO's annual energy production, and annual energy from wind and solar generation rose to 17 percent.[111] Since 2001, over 50 GW of renewable resources have been installed across the MISO region.[112] Since 2010, over 30 GW of fossil fuel generation has retired in the MISO region.[113]

The MISO generation evolution is being driven by several factors, including but not limited to economics, age of existing generation, customer and business preferences, state policies, and state and utility goals.

As shown on **Figure 5.2-1**, many states and utilities in MISO have carbon-free and decarbonization targets. **Figure 5.2-2** displays the levelized cost of energy (LCOE), a measure of the lifetime cost to deliver an equivalent amount of energy by generation type. As shown on **Figure 5.2-2,** the LCOE for utility scale wind without federal tax subsidies is $37 to $86 per MWh, utility scale solar without federal tax subsidies is $38 to $78 per MWh, natural gas combustion turbine is $149 to $251 per MWh, and natural gas combined cycle is $48 to $109 per MWh, as of June 2025.

MISO forecasts generation trends, including the retirement of legacy fossil-fuel generation and replacement with wind, solar, and other new technologies, to continue and potentially accelerate over the next 20 years. This is based primarily on state-approved IRPs (MISO Future 2A). MISO forecasts that nameplate generation capacity will roughly double by 2042 as shown on **Figure 5.2-3**.

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109 See Section 5.3.2.

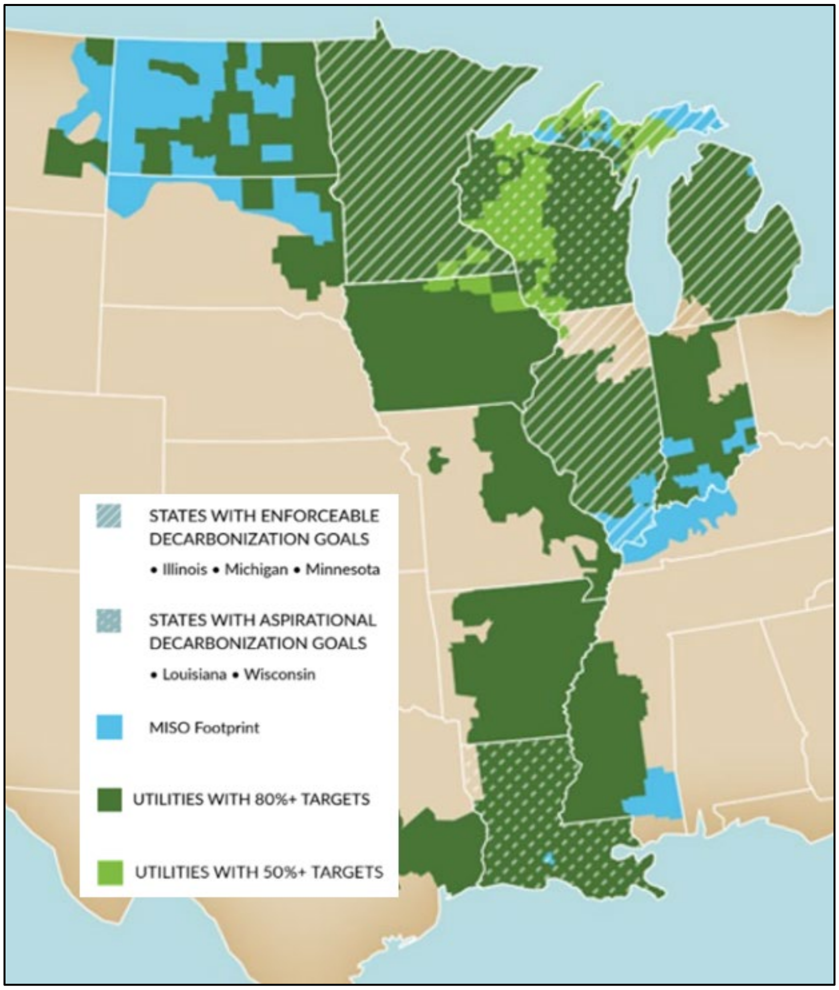
110 FERC Order 888 mandates all public utilities to provide open non-discriminatory access to transmission facilities to any generator regardless of owner, fuel-type, etc. FERC. Available at: https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform/order-no-888.

111 **Appendix E.5**.

112 Id. Installed wind and solar capacity.

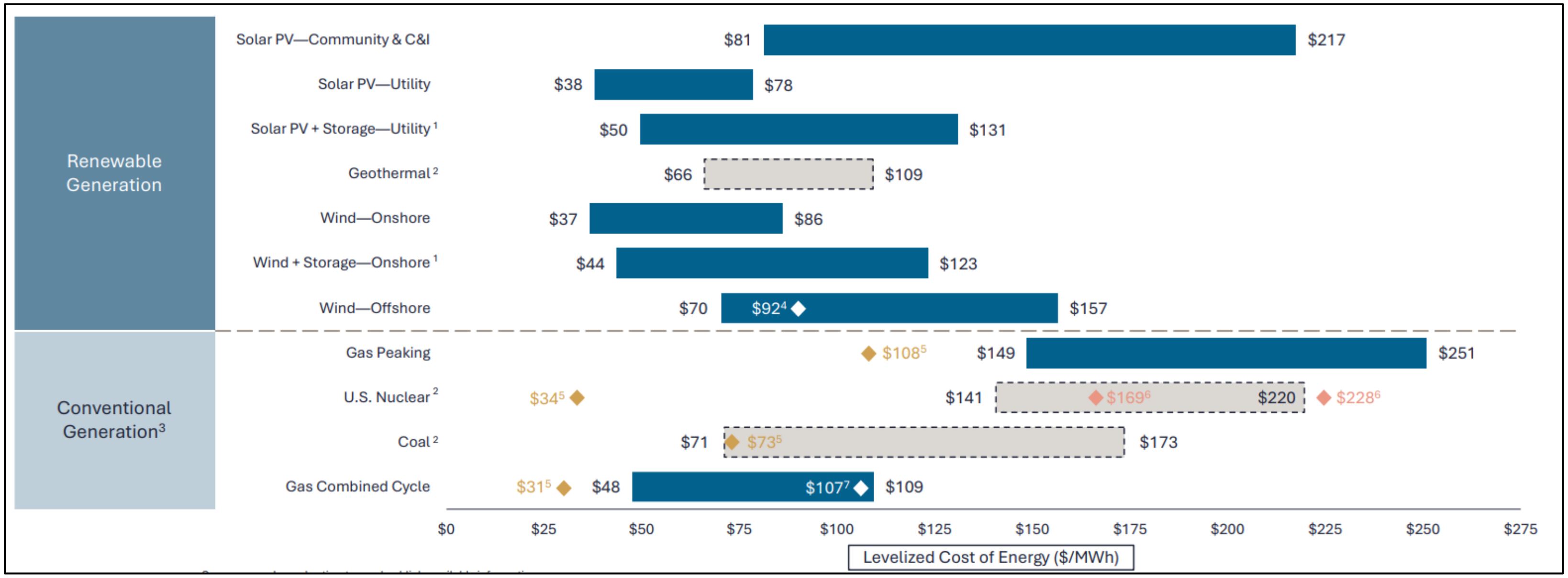
113 MISO. MTEP 23, Chapter 2: Portfolio Evolution. Available at: https://cdn.misoenergy.org/Recommended%20MTEP23%20Chapter%202%20-%20Portfolio%20Evolution630591.pdf. Page 5.

Figure 5.2-1: Decarbonization or Clean Energy Goals Across the MISO Footprint as of September 2025[114]



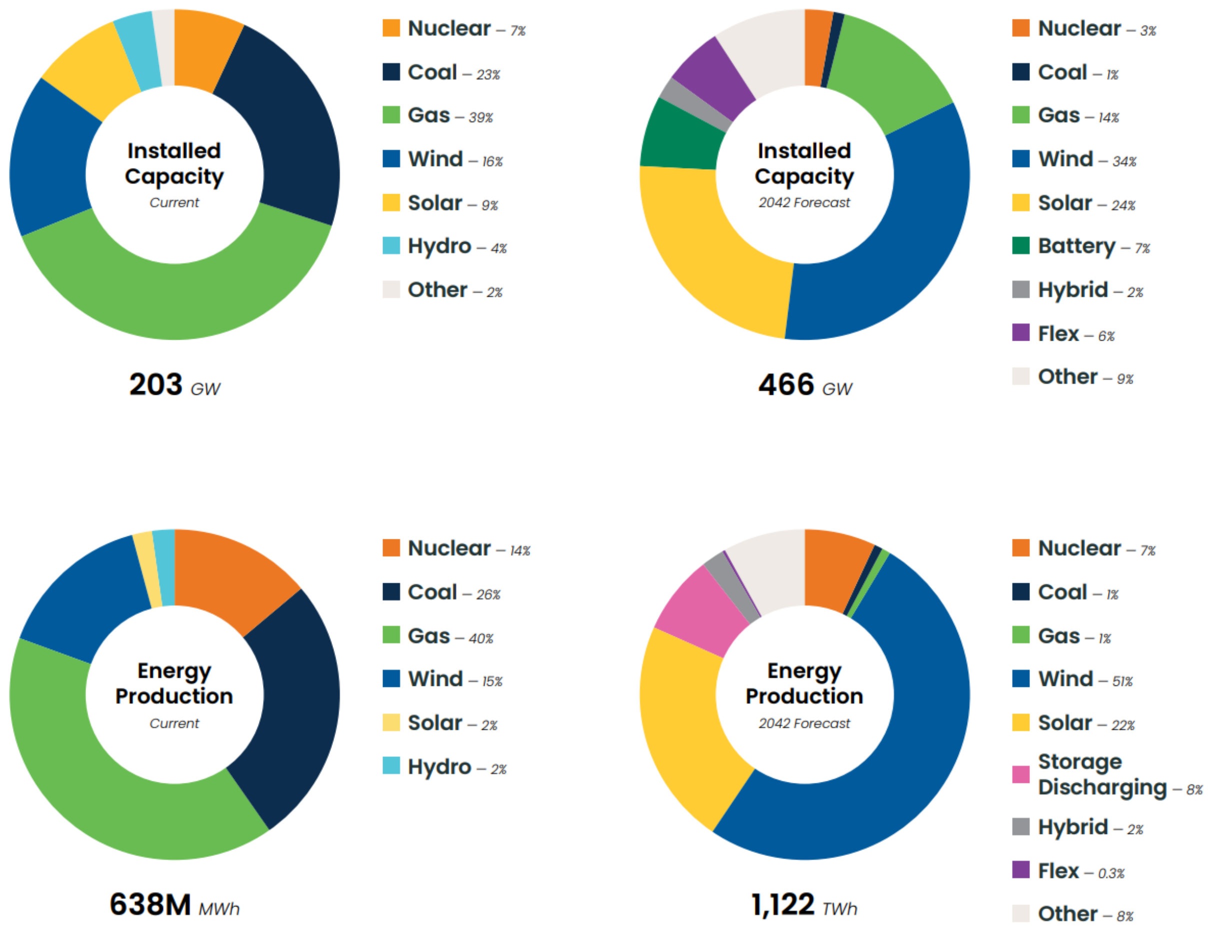
114 MISO. MISO's Response to the Reliability Imperative – Updated February 2024. Available at: https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

Figure 5.2-2: Levelized Cost of Energy by Generation Type – Wind and Solar Photovoltaic, Excluding Federal Tax Subsidies[115]



115 Lazard. Levelized Cost of Energy. Available at: https://www.lazard.com/media/eijnqja3/lazards-lcoeplus-june-2025.pdf.

Figure 5.2-3: MISO Region Forecasted 2042 Generation Energy and Capacity[116]



116 See **Appendix E.2.** Page 7 (2042 values). **Appendix E.5**.

5.2.2 Minnesota Energy Landscape Transformation

Minnesota's generation transition is consistent, but accelerated, relative to the overall generation transition occurring within the MISO footprint. This accelerated transition is due to a combination of economics, consumer and commercial preferences, age of existing generators, and Minnesota's Carbon-Free by 2040 law.[117] The Project and the MISO LRTP Tranche 2.1 Portfolio is needed to enable the generation transition in a reliable manner by providing transmission capacity to interconnect additional generation (see **Section 6.5.1**), transfer generation from where it is available to where it is needed (see **Section 6.3.2**), and efficiently use all available generation capacity (see **Sections 6.4.2 and 6.5.2**).

In 2011, over half of the electricity generated in Minnesota came from coal-fired generation. In 2024, electricity from coal was reduced to approximately 20 percent and renewables provided over 33 percent of electricity generation statewide.[118] As of June 2025, approximately 7,000 MW of new renewable generation has been installed in Minnesota to meet electrical needs.[119] Meanwhile, many of the traditional baseload generators that have provided round-the-clock energy production for decades are retiring. Based on the information contained within IRPs, Minnesota's active remaining baseload fossil-fuel generators are planned to retire and/or cease coal-fired operations as follows:

- Sherburne County Generating Station Unit 1 - 2026[120]
- Sherburne County Generating Station Unit 3 – 2030[121]
- Allen S. King – 2028[122]
- Clay Boswell Energy Center – 2035[123]

MISO forecasts the generation mix trends in Minnesota and the surrounding area (MISO Local Resource Zone 1)[124] to continue over the next 20 years, based on the information primarily contained within IRPs. MISO forecasts that by 2042, over 50,000 MW of wind and solar generation will be added in Local Resource Zone 1, providing much of the annual energy, with other technologies including natural gas, battery storage, and demand response[125] providing the remainder, as shown on **Figure 5.2-4.**

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117 Minn. Stat. § 216B.1691, subd. 2g.

118 EIA. Electricity. Available at: https://www.eia.gov/electricity/data/browser/" \l "/topic/0?agg=2,0,1&fuel=vvg&geo=000004&sec=g&freq=A&start=2001&end=2024&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=. Referenced November 2025.

119 EIA. Electric Power Monthly. Table 6.2.B. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_02_b. Referenced November 2025.

120 Xcel Energy. 2024-2040 Integrated Resource Plan. Available at: https://xcelnew.my.salesforce.com/sfc/p/#1U0000011ttV/a/8b000002YCQL/2EQNYnEG7hBohut31h0nHs5yppYhY.lwg_GbUZK8t6w.

121 Id.

122 Id.

123 Minnesota Power. 2025 Integrated Resource Plan. Available at: https://www.mnpower.com/IRP2025.

124 MISO Local Resource Zone 1 includes the MISO footprint in most of Minnesota, North Dakota, South Dakota, Montana, and western Wisconsin.

125 Demand response encompasses multiple forms of peak shaving and load reduction programs, such as interruptible loads, load management (e.g., residential air conditioner saver switch) and dual fuel programs.

Figure 5.2-4: Minnesota and Surrounding Area (Local Resource Zone 1) Current to Future 2A Generation Forecast – Resource Additions and Retirements[126]

Zone	Milestone	Battery	CC	CT Gas	Demand Response	DGPV	IC Gas	Solar	Hybrid	ST Coal	ST Gas	Wind	Flex	EE	UDG	Totals
LRZ 1	2027	20	100	981	1,446	375	0	4,867	0	163	0	4,651	2,123	804	18	15,548
	2032	540	100	2,103	1,533	925	0	7,200	70	163	0	23,444	2,123	1,579	42	39,822
	2037	1,616	100	3,225	1,807	1,675	0	10,264	219	163	595	34,388	2,123	2,128	115	58,418
	2042	3,493	100	4,029	1,919	2,675	0	13,654	219	163	595	40,125	2,123	2,559	376	72,030

Future 2A Resource Retirements (MW) - *Cumulative*									
Zone	Milestone	Coal	Gas	Nuclear	Oil	Wind	Solar	Other	Totals
LRZ 1	2027	3,612	1,604	0	325	123	0	962	6,625
	2032	5,355	2,141	0	570	1,772	0	996	10,834
	2037	5,844	2,362	0	584	3,178	24	1,014	13,005
	2042	5,844	2,988	0	678	5,274	470	1,014	16,268

126 See **Appendix E.2**. Pages 87 and 88. Report published November 1, 2023. As of January 2026, this is the latest information available.

5.2.2.1 Applicants' Minnesota Integrated Resource Plans

In Minnesota, all state-regulated electric utilities, such as Xcel Energy, are required to file IRPs with the Commission every two years. In addition, though not state-regulated, Dairyland files an optional IRP which is similarly reviewed by the Commission every two years. In each IRP, utilities must identify the generation needs to serve forecasted demand plus a required reserve margin while complying with state laws for the least total costs.

For investor-owned utilities, the Commission reviews and ultimately rules on each IRP. The IRP becomes the state-approved plan for generation, and the transmission grid is developed to enable the generation plan in a reliable and least cost effective manner. The Project and MISO LRTP Tranche 2.1 Portfolio are designed to enable the approved IRPs for Minnesota and the broader Midwest region.

Xcel Energy's most recent 2024-2040 IRP was approved by the Commission on February 20, 2025.[127] The Commission's approved plan includes:

- Extending the use of the Prairie Island and Monticello nuclear plants into the 2050s and retiring all coal facilities by 2030.
- Adding new renewable resources by 2030, including 3,200 MW of wind and 400 MW of solar.
- Adding 600 MW of battery storage by 2030.
- Adding approximately 2,100 MW of peaking and dispatchable resources by 2029, roughly half of which will come from wind, solar, and battery resources, and half from a new gas peaking plant (Lyon County) and two existing gas power purchase agreements. Xcel Energy's proposed Lyon County plant is being reviewed in a CN proceeding is being reviewed in a CN proceeding.[128]
- Integrating over 1,800 MW of additional distributed energy resources (e.g., distributed solar, energy efficiency, and demand response) by 2030.

Dairyland filed its most-recent optional IRP compliance report on June 26, 2025.[129] As described in the compliance report, Dairyland is using a balanced approach to add natural gas generation and renewable generation to meet the future load obligations and continue to diversify the Dairyland generation portfolio. Dairyland intends to use short-term capacity contracts to purchase or sell any short-term capacity deficit or surplus while it continues to evaluate its existing plants and new generation. Dairyland is currently meeting the MISO Resource Adequacy requirements and all the renewable energy obligations and plans to do so in the future.

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127 *In the Matter of Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan*, Docket No. E-002/RP-24-67, Order Approving Settlement Agreement with Modifications (Apr. 21, 2025).

128 Northern States Power Company, a Minnesota corporation doing business as Xcel Energy, has submitted a Combined Application to the Minnesota Public Utilities Commission (Commission) for the proposed Lyon County Generating Station Project. This application seeks multiple approvals, including a Certificate of Need, Site Permit, Transmission Line Route Permit, and Pipeline Routing Permit, as well as a Partial Exemption for routing the pipeline. Docket No. 25-145.

129 Dairyland Power Cooperative's 2025 Optional-IRP Compliance Report Pursuant to Minn. Stat. § 216B.2422, subd. 2b, MPUC Docket No. ET-3/RP-25-271 (June 26, 2025).

5.2.3 Impact of Federal Policies on Midwest Generation Trends

Utilities consider many factors when determining generation plans to meet demand needs. These factors include costs, performance, and state and federal policies over a planning horizon of 15 or more years. As described in **Section 3.4.2**, utilities such as the Applicants must comply with all enacted policies. In addition, because generation plans are long-term decisions, utilities must consider the potential for future policy changes.

In 2025, the U.S. Congress enacted the One Big Beautiful Bill Act, and the U.S. Secretary of Energy issued several orders. The One Big Beautiful Bill sunsets federal tax credits for wind and solar generations,[130] prevented certain power plants in Michigan[131] and Pennsylvania[132] from closing, and exempted compliance with the Mercury and Air Toxics Standards for two years for specific coal power plants in Ohio, Illinois, and Colorado[133], amongst others.

Each presidential administration enacts policies to reflect its priorities and energy policies. **Figure 5.2-5** displays some of the key policies and priorities impacting generation plans during the past four presidential administrations. As shown on **Figure 5.2-5**, despite changes in parties, policies and orders, generation trends across the Midwest have been generally consistent over the past four federal administrations. Key policy changes are highlighted on bottom timeline.

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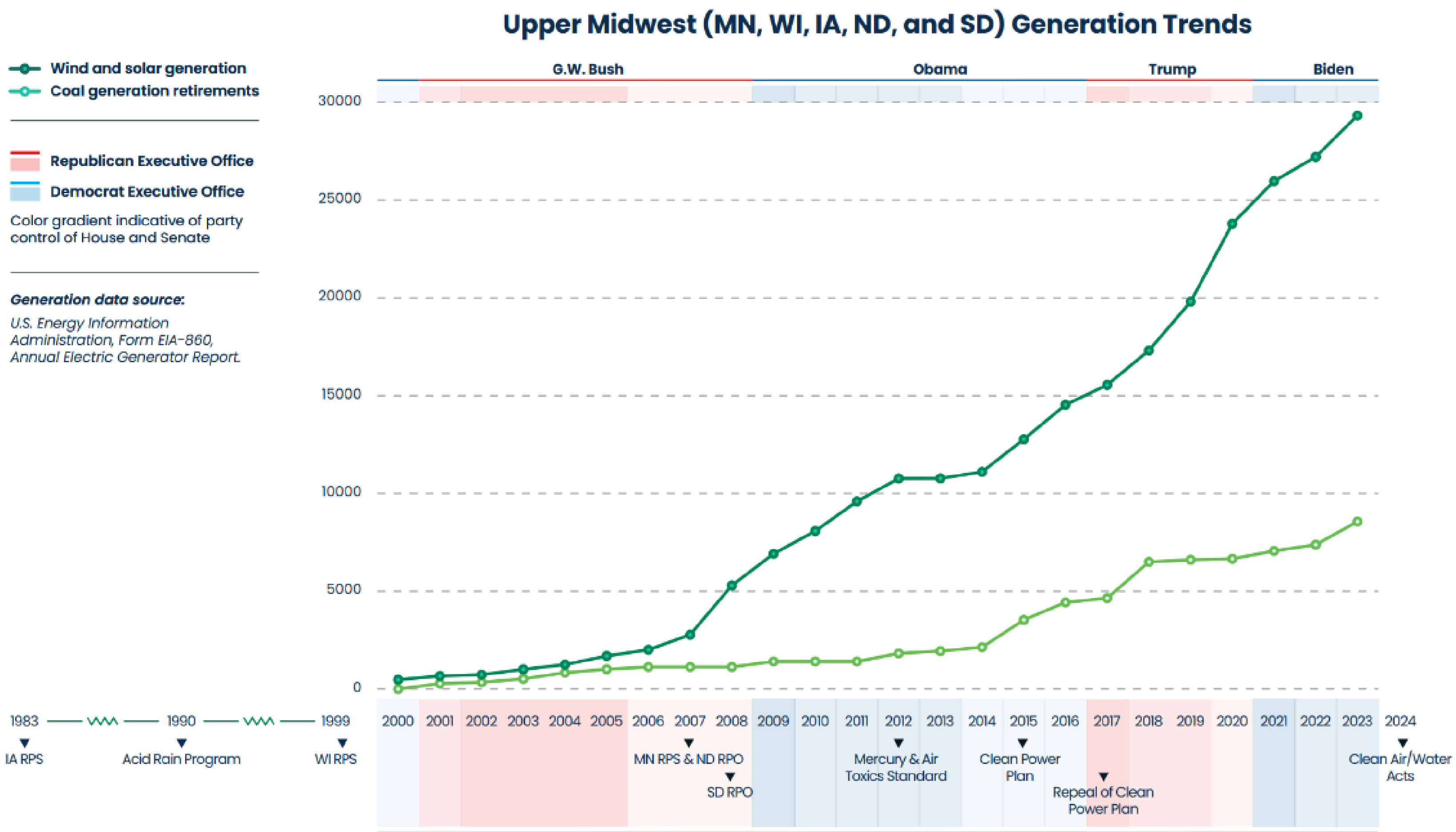
130 H.R. 1, Public Law No. 119-21.

131 United States Department of Energy. Order No. 202-25-3. Available online at: https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf.

132 United States Department of Energy. Order No. 202-25-4. Available online at: https://www.energy.gov/sites/default/files/2025-05/Federal%20Power%20Act%20Section%20202%28c%29%20PJM%20Interconnection.pdf.

133 The White House. July 17, 2025, Proclamation: Regulatory Relief for Certain Stationary Sources to Further Promote American Energy. Available online at: https://www.whitehouse.gov/presidential-actions/2025/07/regulatory-relief-for-certain-stationary-sources-to-further-promote-american-energy/.

Figure 5.2-5: Upper Midwest Generation Historical Trends by Federal Administration



The generation forecasts used in this Application are primarily based on state-approved IRPs and comply with Minnesota and other states' enacted policies and announced state and utility goals (see **Section 5.1** for additional details on MISO Future 2A). Nonetheless, MISO evaluated need under a scenario which considers a deceleration of generation evolution trends,[134] and found the MISO LRTP Tranche 2.1 Portfolio, which includes the Project, provides benefits in excess of costs.[135]

5.3 EVOLVING ELECTRICAL DEMANDS

The Project is driven by the need to reliably serve existing, expanding, and new electrical demands from the changing generation fleet. As need for the Project is not only driven by Minnesota's demand forecast but the broader MISO region, the following sections provide details on generation forecast for Minnesota and the MISO region.

5.3.1 <u>Base MISO Region Peak Demand and Energy Forecast</u>

Since the late 2000s, demand growth in the Midwest has in aggregate remained relatively flat. This was initially due to the Great Recession from 2007 to 2009, then from energy efficiency programs absorbing growth, and finally, due to the COVID-19 pandemic, as shown on **Figure 5.3-1**.

MISO load forecasting prior to 2019 relied heavily on econometric-based evaluations of gross load, using standard economic indicators such as gross domestic product, population, and employment rates. These methods, while useful, rest on the premise that historical trends and relationships between economic variables and electricity demand will persist into the future. During times of economic instability or periods of rapid industry transformation, these relationships no longer hold, requiring the development of new load forecast methodologies. In 2019, MISO developed a new set of forward-looking future scenarios to guide the LRTP and other planning studies. This effort considered a range of possible economic, political, and technological outcomes to project load growth over a 20-year study period.[136]

Current MISO forecasts (published in November 2023) indicate a 1 to 2 percent compound annual growth rate (CAGR) for the next 20 years. MISO-wide base peak gross demand and annual energy forecasts used for analysis in this Application assume a 1.14 percent and 1.25 percent CAGR, respectively, growing MISO gross coincident peak demand by approximately 25 percent of current levels and gross annual energy by 28 percent over the next 20 years.[137]

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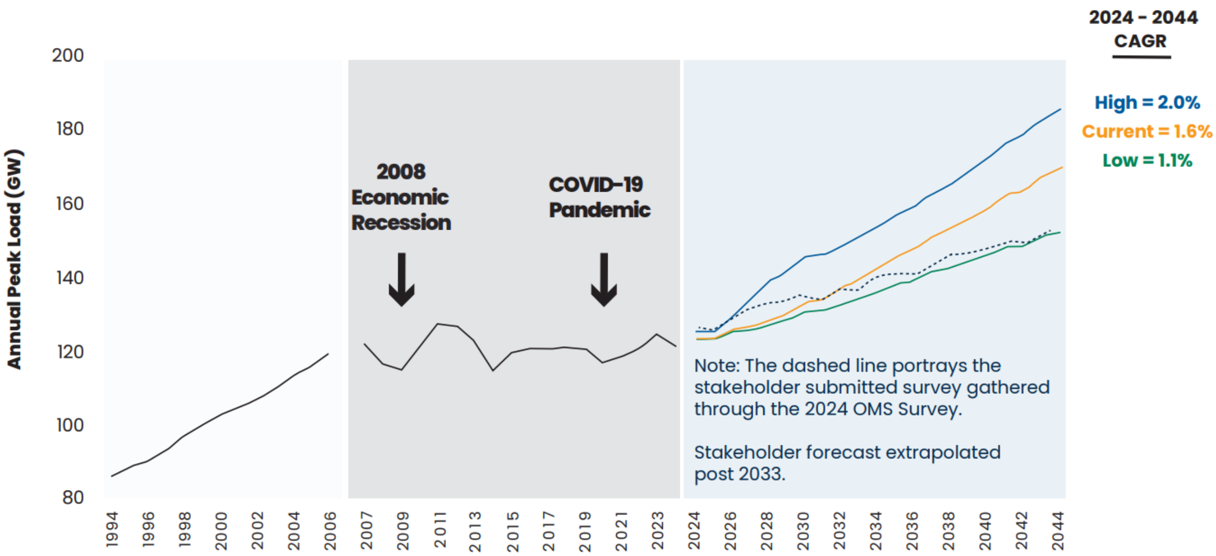
134 Details on MISO's Future 1A can be found in **Appendix E.2.**

135 The MISO LRTP Tranche 2.1 Portfolio has a benefit to cost ratio of 1.2 to 2.2 under MISO Future 1A. See **Appendix E.1**. Page 143.

136 MISO. December 2024 Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf. Page 8.

137 See **Appendix E.2**. Page 31, Figures 25 and 26.

Figure 5.3-1: MISO Region Net Peak Load Expectations Over Time (1994 to 2044)[138]



For Minnesota and the surrounding region (Local Resource Zone 1), MISO forecasts total load to peak at approximately 24 GW in 20 years; compared to a 2023 peak load of approximately 19.4 GW.[139] The load growth rate is consistent with the Organization of MISO States Survey as shown on **Figure 5.3-1**.

Demand forecasts do not include the potential for growth attributed to data centers and other industrial demands beyond what was firmly committed in 2023. MISO predicts that the addition of these inputs could increase demand by as much as three-fold.[140] Base forecast demand growth is driven by multiple factors including:

- Growth and expansion of existing residential, commercial, agriculture, and industrial electricity use;
- New and expanded manufacturing;
- The electrification of heating and cooling, appliances, transportation and additional devices in homes and businesses; and
- The initial start of emerging industries like data centers and artificial intelligence applications.

The development of data centers is substantially impacting the transmission system. In 2025, multiple data center projects were publicly announced in the vicinity of the Project including but

138 Id. Page 4.

139 Id. Page 32. MISO Local Resource Zone 1. 2023 peak demand from MISO production cost models.

140 MISO. December 2024 Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.

not limited to Meta's UMore Park,[141] Project Skyway,[142] and the Nobles County Powered Data Park.[143] The Applicants and other Minnesota transmission owners continue to process these and additional requests from large commercial loads, ranging from tens of MWs to over 1,000 MW each. While not all will come to fruition, for perspective, if even one large load (e.g., 1,000 MW) is interconnected, it would increase state demand levels by more than 5 percent. These potential large load additions are not included in the MISO base demand forecast used to justify the need for the Project but are examples of the type and scale of potential future load additions.

MISO's base demand forecast starting point is developed by aggregating each MISO member's forecasts. Xcel Energy's most recent peak demand and annual forecast may be found in Xcel Energy's 2024 Annual Electric Utility Forecast Report filed on July 1, 2024, which is provided in **Appendix F.1**. Dairyland's most recent peak demand and annual forecast may be found in Dairyland's 2025 Annual Electric Utility Forecast Report filed submitted on June 16, 2025, which is provided in **Appendix F.2**.

5.3.2 MISO Demand and Energy Forecast Ranges

To consider a broader range of potential outcomes to bookend uncertainty, MISO creates multiple demand and energy forecasts from the base forecast in the Futures (see **Section 5.1** for details on MISO's Futures). The load forecasts used in MISO's Futures consider different adaptation rates for demand response, energy efficiency, and distributed generation (e.g., behind-the-meter generation) and differing impacts of electrification. MISO's demand and energy forecasts are developed for each of MISO's ten Local Resource Zones to consider regional differences. MISO's ten Local Resource Zone forecasts are then aggregated to a MISO-wide forecast.

The MTEP24 Futures' gross peak demand and annual energy forecast for the MISO Market Footprint are provided on **Figure 5.3-2** and **Figure 5.3-3**, respectively.

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[141] Minnesota Employment and Economic Development. Governor Walz Announces Meta Will Build New Data Center in Rosemount. Available online at: https://mn.gov/deed/newscenter/press-releases/?id=1045-614051#:~:text=PAUL%2C%20MN%5D%20%E2%80%93%20Governor%20Tim%20Walz%20today,million%2C%20715%2C000%2Dsquare%2Dfoot%20data%20center%20in%20Rosemount%2C%20supporting.

[142] Project Skyway. Available online at: https://pineislandskyway.com/.

[143] Geronimo Power. Nobles County Powered Data Park. Available online at: https://geronimopower.com/in-development/nobles-county-powered-data-park/.

Figure 5.3-2: MISO Market Footprint MTEP24 Futures Gross Coincident Peak Load Forecast[144]

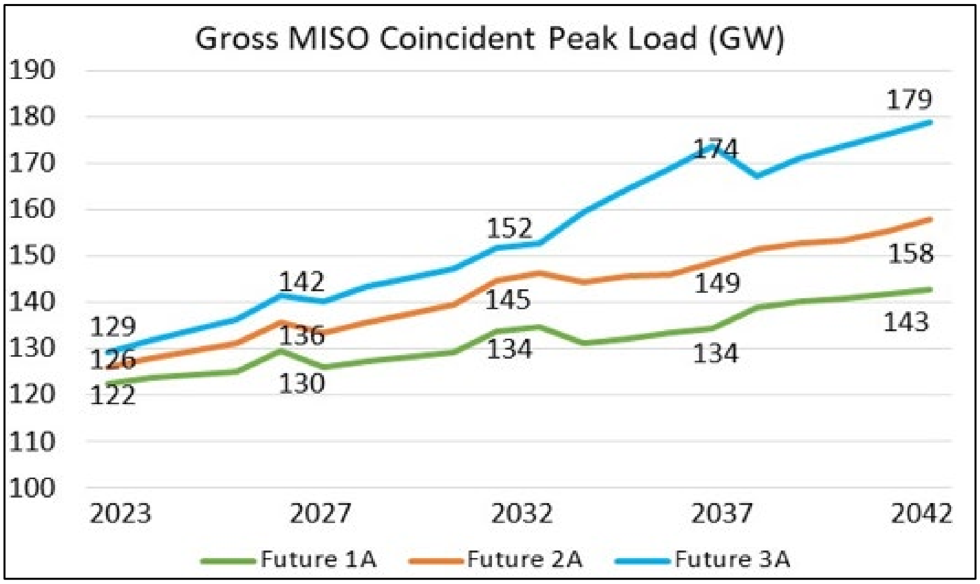
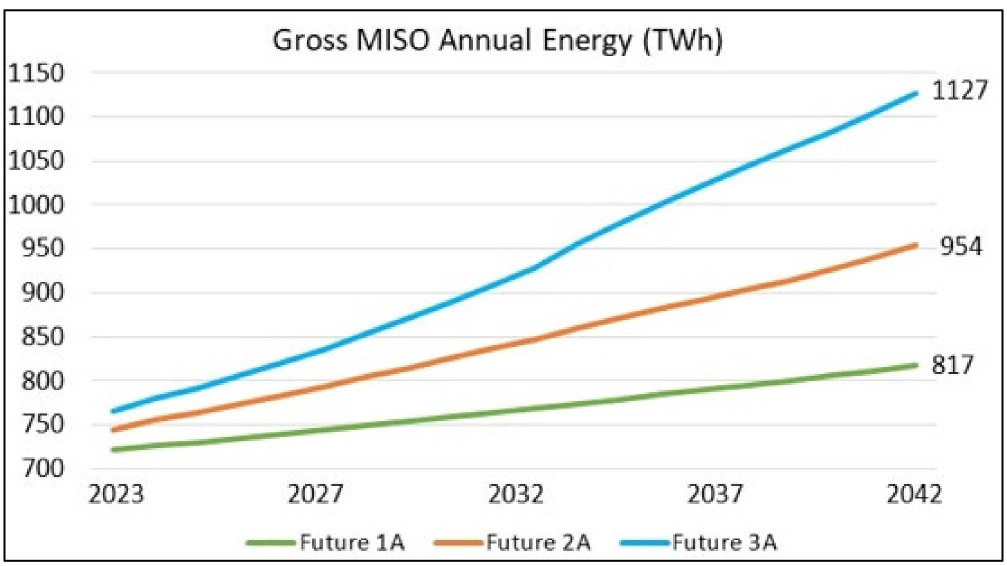


Figure 5.3-3: MTEP24 Futures MISO Market Footprint Annual Energy Forecast[145]



144 See: **Appendix E.2.** Page 31.

145 Id.

The associated peak demand and annual energy CAGR are provided in **Table 5.3-1**.

TABLE 5.3-1

MTEP24 Futures 20-Year CAGR[146]

MTEP24 Future	Annual Gross MISO Coincident Demand 20-Year CAGR (percent)	MTEP24 Future
Future 1A	0.77	0.63
Future 2A	1.14	1.25
Future 3A	1.63	1.95

MISO's demand forecast used in planning modeling is a gross forecast, which does not include the net reductions from demand response or distributed generation as is provided in the Applicants' Annual Forecast Reports. MISO's planning process explicitly models demand response and distributed generation as a supply-side resource. MISO estimates that the Future 2A demand and energy CAGR, net of demand response and distributed generation (i.e., indicative of load that will be realized at the meter), is approximately 0.8 percent.[147]

Details on how conservation and energy efficiency was considered by MISO in the evaluation of the Project can be found in **Appendix G**. Additional details on MISO's MTEP24 load forecast can be found in **Appendix E.2**, the MISO Series 1A Future Report.

[146] Id. Page 27

[147] Id. Page 27.

6 HOW PROJECT ADDRESSES MULTIPLE DEFINED NEEDS

The Studied Projects[148] enable the transmission grid to move more energy farther distances and to-and-from more locations than the existing transmission grid's capabilities. As described in this chapter, the Studied Projects reliably increase the capacity of the grid in a cost-effective manner while, at the same time, supporting the generation transition driven in part by state policy. This chapter discusses the engineering and analyses undertaken to demonstrate how the Studied Projects meet these three needs.

- **Section 6.3 - Reliability Need:** The Studied Projects mitigate projected reliability overloads of the existing transmission grid to satisfy national electric standards to enable the regional transfer of the energy needed today, and in the future, to serve customer and member electricity demands every hour of every day.

- **Section 6.4 - Cost-Effectiveness/Net Economic Benefits:** The Studied Projects provide economic benefits to customers and members by reducing transmission congestion and providing access to lower cost generators.

- **Section 6.5 - Enabling Generation Transition:** The Studied Projects enable aging generation to retire and be replaced by new generation, including carbon-free generation which helps meet state policy objectives. The Studied Projects also contribute to more efficient use of existing generation resources.

Table 6.0-1 summarizes the metrics demonstrating how the Studied Projects enhance reliability, provide economic benefits, and support state policy.

TABLE 6.0-1

How the Studied Projects[a] Meet Reliability, Economic, and Public Policy Needs

Category	Measure	Description
Reliability Need (**Section 6.3**)	Solves reliability issues of 102 different facilities, addressing 1.313 NERC reliability violations	Ability to maintain NERC reliability standards b and reliably transfer energy across the region to serve load.
	1,300 GWh mitigated unserved demand	Demand over a year no longer at high risk of not being served.
	3,010 MW load enabled	Load included in "base" forecast which would not be reliably served without the Studied Projects.
	Addresses multiple dynamic stability instability issues	Ability of the system to reliably transfer energy and recover after an unexpected event.
Cost Effectiveness/ Economic Benefits (**Section 6.4**)	$7.7 billion to $25.3 billion economic savings over first 20 years of service	Savings from decreasing congestion, providing access to lower cost generation, carbon reductions, and avoided reliability needs.
	2 to 11 percent system congestion relief	Reduction in transmission system "bottlenecks" which improves system reliability and access to lower cost generating resources.
Enabling Generation Transition	5.6 TWh to 7.2 TWh reduced curtailment (annual)	Reduction in "wasted" energy from generators which safeguards system reliability, improves system efficiency, and reduces emissions.

148 As discussed in **Section 1.4**, the Applicants studied the entirety of LRTP numbers 22 through 26 (including the portions of those lines outside of Minnesota). This group of projects is referred to as the Studied Projects.

TABLE 6.0-1 How the Studied Projects[a] Meet Reliability, Economic, and Public Policy Needs		
Category	**Measure**	**Description**
(**Section 6.5**)	Enabled generation: 24 GW	New carbon free generation which with the Studied Projects can be reliably interconnected to the grid.
	Reduction in CO2 emissions = 3.6 million tons (annual)	Studied Projects-enabled generation interconnections and reduced curtailment helps utilities to meet Minnesota's Carbon Free by 2040 law.
[a] The Studied Projects definition used for the need analysis is LRTP Numbers 22 through 26, see **Section 6.1** for additional information. [b] NERC. Reliability Standards. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL001-5.pdf .		

The Studied Projects are a "step-change" in the transmission grid that is warranted given the magnitude of the reliability needs of the regional grid and Minnesota's energy demand and generation resources. For context, the Studied Projects:

- mitigate reliability overloads of 102 different transmission facilities – even one overload is not acceptable per NERC standards and would require mitigation;[149]

- enable approximately 3,010 MW of forecasted load to be reliably interconnected and served in Minnesota and the surrounding region[150] over the next 20 years – Minnesota's peak demand in 2024 was approximately 10,790 MW and is expected to grow to 12,455 MW by 2042;[151] and

- support the reliable interconnection of approximately 24 GW of new nameplate generation in Minnesota and the surrounding region; approximately 18 GW of nameplate generation is installed in Minnesota as of 2023 and is expected to increase to 34.5 GW by 2042.[152]

The Studied Projects provide the ability to transfer bulk energy to, through, and out of Minnesota to continue to serve load every hour of every day. As Minnesota and other states increasingly rely on weather-dependent generation resources and load becomes more variable, the ability to transfer energy to follow weather patterns is critical to system reliability. To meet projected reliability needs with the expected generation fleet, Minnesota needs to transfer upwards of 10 GW more energy, as shown on **Figure 6.0-1** and **Figure 6.0-2**.

As detailed in **Section 4.6**, the Studied Projects, in conjunction with the MISO LRTP Tranche 2.1 Portfolio, help provide the necessary transfer capability needs to support reliability. The Project and the MISO LRTP Tranche 2.1 Portfolio will create a network of backbone connections throughout the Midwest that will ultimately be interconnected with the existing 765 kV network (see **Figure 3.2-1**), allowing Minnesota to meet our electrical needs. Additionally, the Project's 765 kV technology provides the transfer capability needed in a manner which is more cost-effective and less impactful in terms of land-use than other alternatives (see **Section 7.2**).

149 See **Section 6.3.1** for additional details.
150 The Studied Projects enabled demand to be reliably served in Minnesota, Iowa, South Dakota, North Dakota, and Wisconsin.
151 MISO Future 2A models – Load growth assumptions included in **Appendix E.2**.
152 Current generation level source: EIA. State Electricity Profiles – Minnesota. Available at: https://www.eia.gov/electricity/state/minnesota/
Future generation level source: MISO Future 2A, see: **Appendix E.2.**

Figure 6.0-1: Map of Maximum Transfer Needed

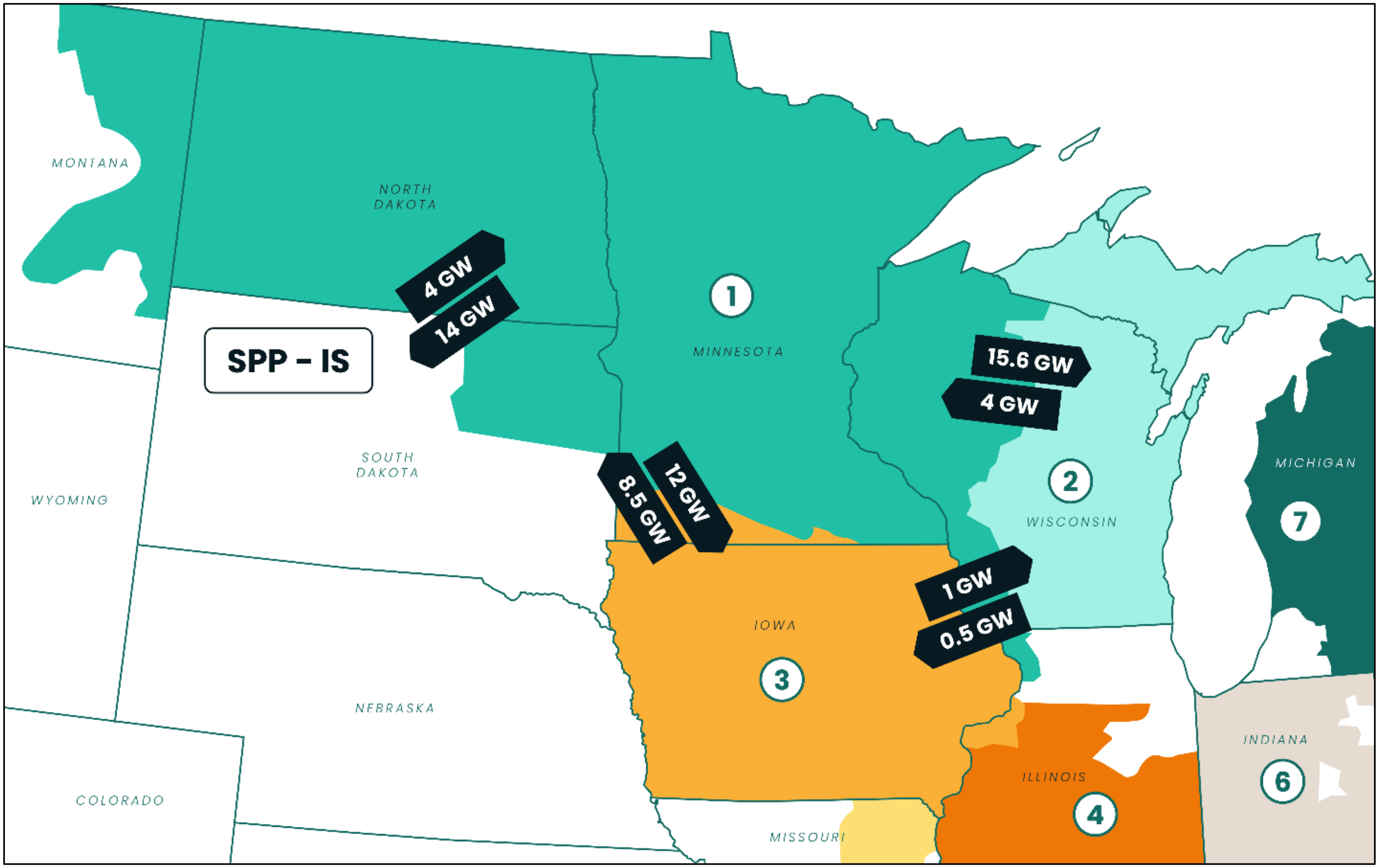
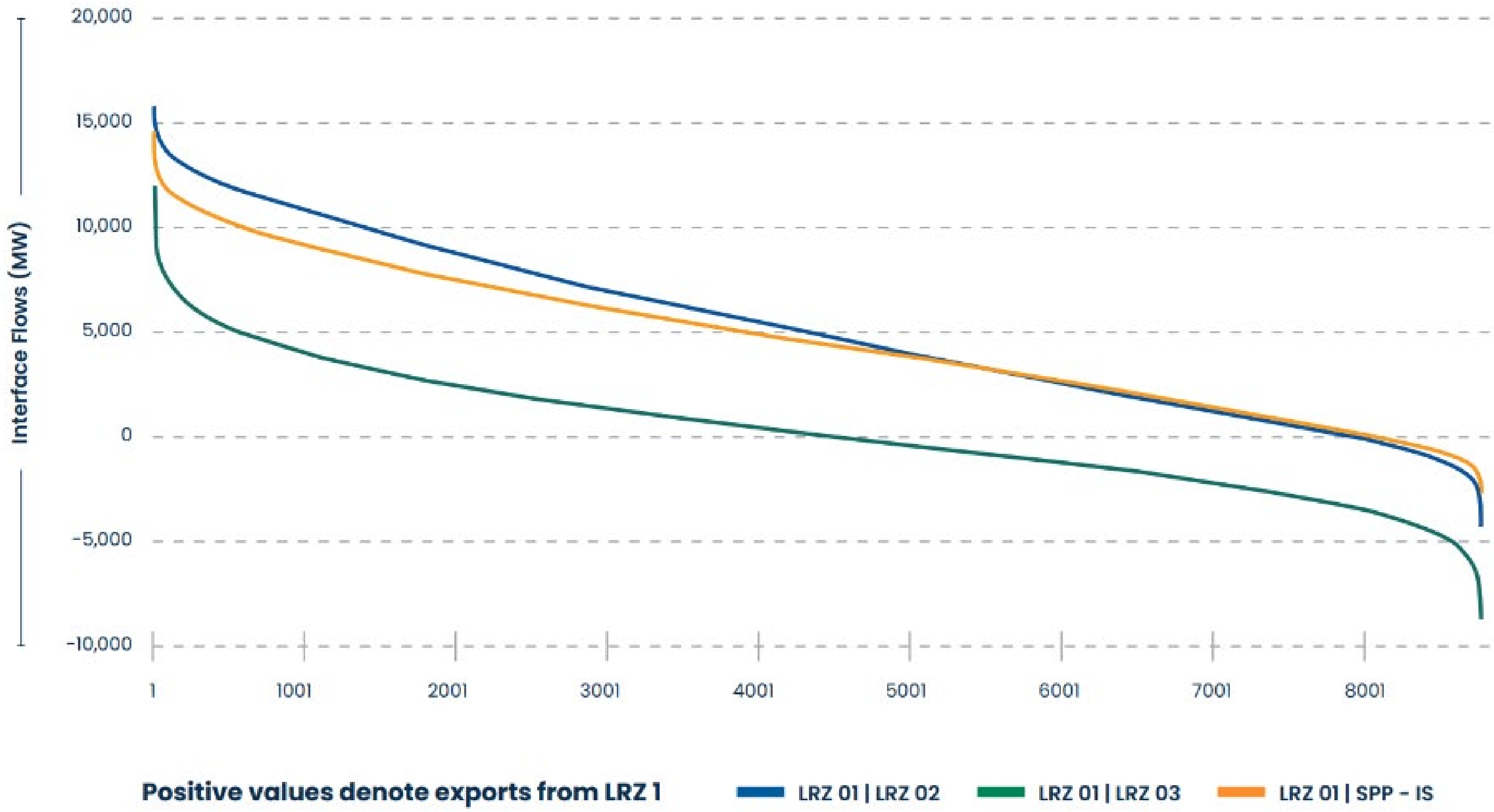


Figure 6.0-2: Annual Duration Curve of Transfer Needed



6.1 SCOPE OF ANALYSIS

This Application seeks a CN for the Minnesota portion of MISO LRTP Tranche 2.1 project number 26.[153] Electricity flows freely across state lines, and one of the primary drivers for the Project is to be able to move energy across multiple states, including but not limited to Minnesota, Iowa, South Dakota, and Wisconsin. Thus, to quantify the reliability benefits of the Project, it is necessary to study the Project and its practical extensions into neighboring states. For the purposes of the need analysis in this Application, Applicants studied the entirety of LRTP numbers 22 through 26 (including the portions of those transmission lines outside of Minnesota). As noted, this group of projects is referred to as the Studied Projects.

The Studied Projects create a contiguous transmission path with on and off ramps at existing 345 kV high-voltage hubs in Minnesota. Combined with the rest of the LRTP Tranche 2.1 Portfolio, this provides connections between generation and load. Eliminating any portion would create a break in the high capacity 765 kV paths between these 345 kV hubs.

Each Studied Projects line is needed and is necessary because the LRTP projects work together to address system needs.

- **LRTP 26:** This Project works with LRTP 22 through 25 to move energy between high-renewable areas in Minnesota, South Dakota, and Iowa to eastern demand centers. Conversely, LRTP 26 enables power to move from Wisconsin and eastern generation sources to Minnesota and South Dakota when local generation is not available.

- **LRTP 25:** The double-circuit 345 kV line between Pleasant Valley and North Rochester is needed to meet NERC reliability standards contingency backup when the parallel 765 kV section is out of service. The North Rochester to Hampton double-circuit 345 kV line connects the 765 kV grid to the greater Twin Cities electrical network.

- **LRTP 24:** The east-west line across southern Minnesota is the primary “artery” for the Studied Projects, connecting Minnesota’s high-voltage hubs to both generation sources and load sinks.

- **LRTP 23:** The connection from Minnesota to Iowa provides connections to high-potential generation areas. Additionally, this line creates a loop across central Iowa, which serves as contingency backup for the Studied Projects as required by NERC reliability standards. Likewise, the Studied Projects serve as a backup in the event of an outage of one of the MISO LRTP Tranche 2.1 765 kV projects in central Iowa to central Illinois.

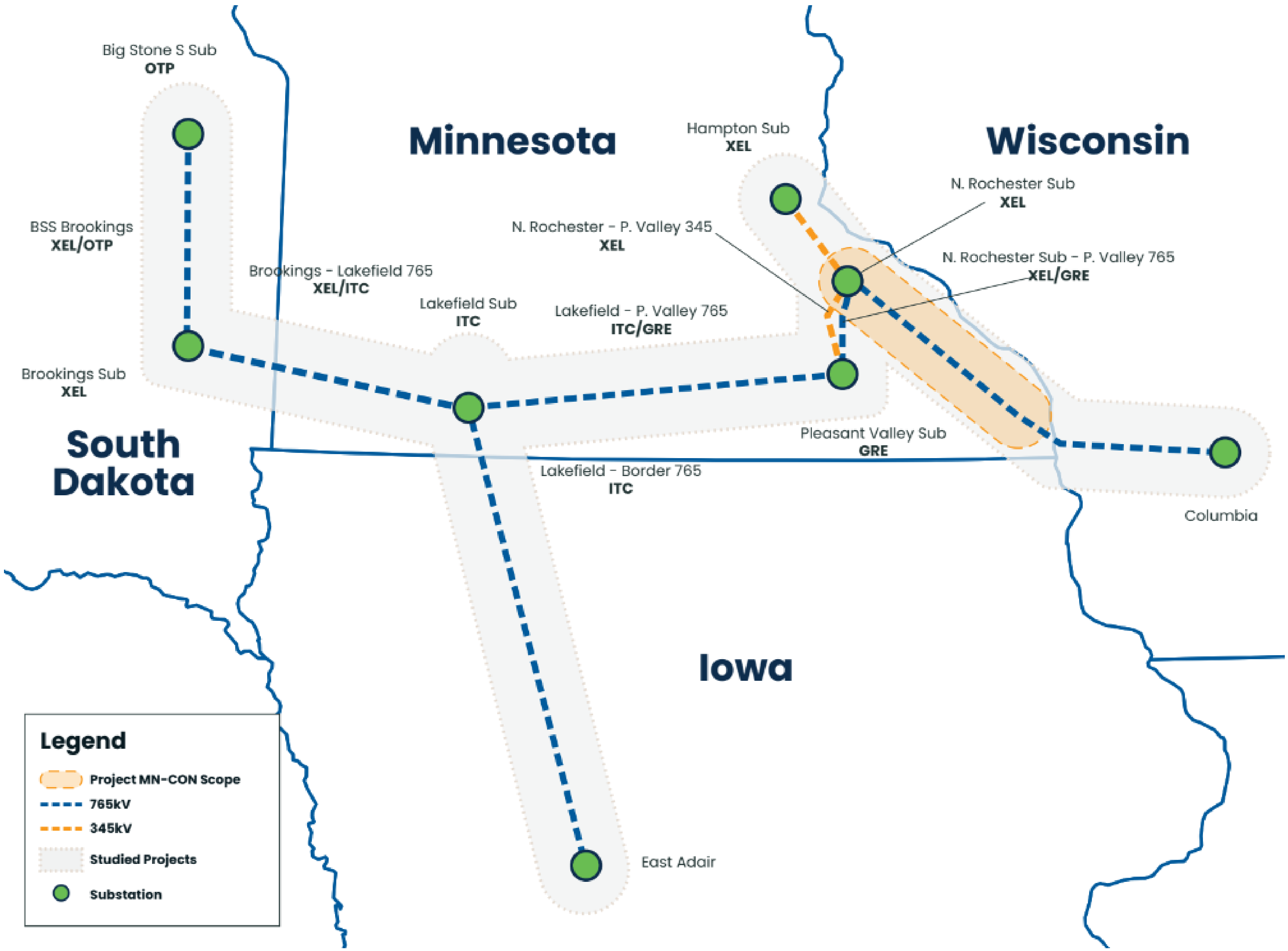
- **LRTP 22:** The westernmost line from South Dakota to Lakefield Junction in Minnesota is needed to tap into high-potential generation areas in southwest Minnesota, South Dakota, and North Dakota, and to transfer excess generation to load areas to the east. Conversely, this line enables energy to flow to South Dakota and North Dakota from Minnesota from other points east when local generation is not available to serve the local load.

[153] See **Appendix E.1.** Page 84.

MISO studied LRTP 22 through 26 together. Consistent with MISO's analysis, need analysis performed by the Applicants in support of this Application includes LRTP 22 through 26, the Studied Projects, as shown in the grey buffered lines on **Figure 6.1-1**.[154]

[154] See **Appendix E.2**. Page 144.

Figure 6.1-1 : Studied Projects Definition for Need Analysis



6.2 STUDY METHODOLOGY

The Applicants performed the need analysis for the Studied Projects based on industry-standard practices that are consistent with MISO's federally approved tariff.[155] The following sections detail the study processes, key assumptions, and methodology used to both identify and quantify the need for the Studied Projects.

6.2.1 Study Assumptions

The analysis used to determine and quantify the need for the Studied Projects was performed comparing two different cases:

- **Project case:** All MISO-approved projects (including the MISO LRTP Tranche 2.1 Portfolio).

- **Pre-Project case:** All MISO-approved projects, less the Studied Projects.

Because the only difference between each case is the addition of the Studied Projects, all resulting changes in system performance are directly attributed to the Studied Projects.

The underlying transmission topology used for the Applicants' analyses includes all transmission projects approved by MISO as January 1, 2025, including the MISO LRTP Tranche 2.1 Portfolio and Joint-Targeted Interconnection Queue (JTIQ) projects.[156] The JTIQ Portfolio includes:

- Bison – Hankinson – Big Stone South 345 kV
- Lyon Country – Lakefield 345 kV
- Raun – S3452 345 kV
- Auburn – Hoyt 345 kV
- Sibley 345 kV Bus Reconfiguration

MISO's analysis of the MISO LRTP Tranche 2.1 Portfolio and Project was performed prior to MISO's approval of the MTEP24 projects, including the JTIQ projects and, therefore, MISO's analysis did not include the JTIQ projects in the Project and Pre-Project case. MISO performed a sensitivity analysis including the JTIQ projects and found that the MISO LRTP Tranche 2.1 Portfolio's need is independent of the JTIQ projects (i.e., needed regardless of the JTIQ portfolio's status) and that the JTIQ projects complement the MISO LRTP Tranche 2.1 Portfolio.[157]

Unless otherwise noted, all analysis is performed using MISO's Future 2A scenario assumptions, as detailed in **Section 5.1**. Future 2A assumptions are based on known and state-approved policies and integrated resource plans. Load forecasts are based on a mid-level growth rate, which includes only known firm load additions from data centers. No speculative data center additions are included in the demand forecast. Mid-level demand forecasts are based on the utility demand and conservation forecasts, which for the Applicants are described in **Section 5.3**.

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155 MISO Tariff Attachment FF. Available at: https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

156 MISO. Joint Targeted Interconnection Queue Study. Available at: https://cdn.misoenergy.org/JTIQ%20Report623262.pdf.

157 Appendix E.1. Page 39.

MISO's Future 2A assumptions were developed through an open and transparent stakeholder process, as prescribed in MISO's federally approved tariff and FERC Orders 890 and 1000.

6.2.2 Studies Undertaken to Demonstrate How Project Meets Reliability Needs

Applicants used multiple models and processes each designed to assess different necessary system attributes. Models and processes are generally grouped into three primary categories, the details of each are further described in the subsequent sections:

- **Steady-State Reliability -** Assesses potential overloads of the transmission grid (i.e., line flows or voltage levels outside physical capabilities). Analysis is detailed but is limited to a single snapshot in time (e.g., 1 hour of the year). Multiple cases (e.g., hours), each looking at a different "worst case" scenario, are used to provide a representative sample of system conditions, helping ensure reliability is maintained for the entire year.

- **Production Cost** – Simulates an 8,760 hourly dispatch of load and generation over a year to determine both reliability implications (e.g., inability to fully serve a load at a specific time) and market economics (e.g., costs to serve load). Production cost models assess system needs for all hours of a year but not to the same level of detail as steady-state models.

- **System Stability** – Assesses sub-minute and sub-second reliability implications of the system. Models determine the ability of the system to come back to a state of equilibrium in terms of frequency and voltage following an event (e.g., loss of the generator or a transmission line). Models are extremely detailed but are limited in what can be monitored (i.e., assessed) and are a single snapshot in time. Similar to steady-state reliability models, stability analysis is performed using multiple cases, each looking at a different "worst case" scenario, to provide a representative sample of system conditions, helping ensure reliability is maintained for the rest of the year.

As each model is designed to analyze different system reliability attributes, the combination of results not only most accurately quantifies the need for the Project but is the best indication of system performance that will be experienced by the operators of the grid.

Models used by the Applicants are consistent with MISO's base models, tools, and assumptions. Unless otherwise noted, the only primary difference between the Applicants' analysis and MISO's is the Applicants' analysis is Project-specific versus MISO's that is based on the combined MISO LRTP Tranche 2.1 Portfolio.

6.2.2.1 Steady-State Reliability Analysis Methodology

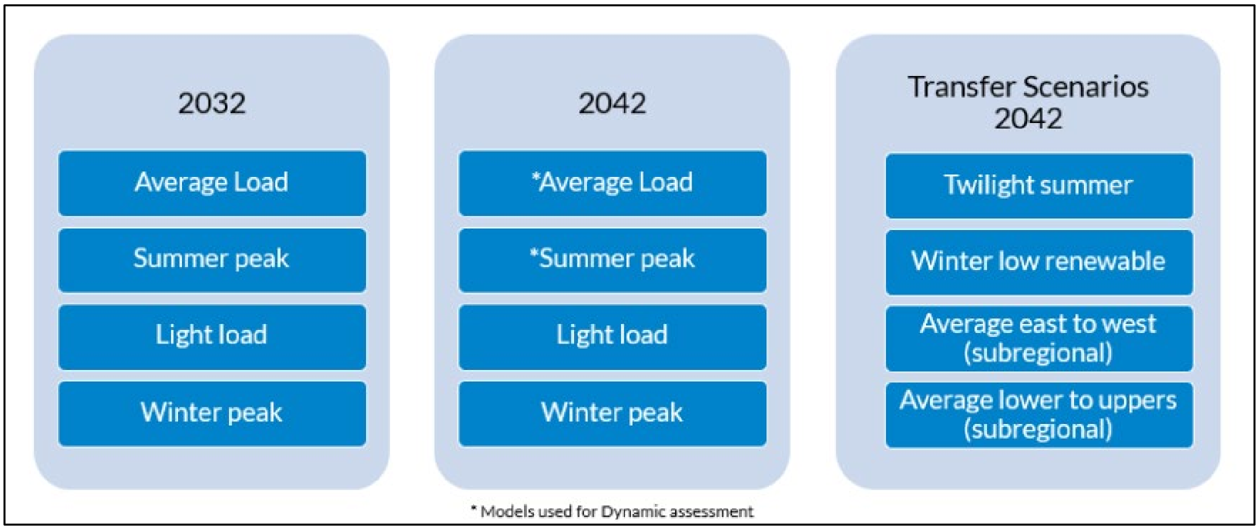
MISO and the Applicants conducted the steady-state reliability analysis in this Application for forecast years 2032 and 2042, under four different load levels and generation levels and four different transfer scenarios, as shown on **Figure 6.2-1**. Per MISO: "these broad base models encompassed multiple uncertainties around variable renewable energy output, load profiles, and seasons, thus providing the platform to perform a wide range of reliability studies."[158] Unless otherwise noted, reported mitigated reliability issues are the sum total of unique issues mitigated under all scenarios.

[158] **Appendix E.1**. Page 14.

Steady-state reliability modeling is conducted using Power System Simulator for Engineering and Transmission Adequacy and Reliability Assessment – both industry standard reliability software packages.

To develop non-wire alternative solutions to steady-state reliability issues, the Applicants used the Electric Power Research Institute's (EPRI) Controlled Planning Expansion Tool (CPLANET). EPRI is an independent, nonprofit organization that conducts research and development related to the generation, delivery, and use of electricity. CPLANET is a reliability optimization tool which inputs a reliability case and determines optimal (e.g., minimum) generation additions or load reductions necessary to mitigate reliability issues.

Figure 6.2-1: MISO Reliability Model Scenarios[159]



A steady-state reliability analysis was used to quantify the following for the Studied Projects:

- Mitigated NERC reliability violations (MISO performed): **Section 6.3.1.**
- Load enabled (Applicant-performed): **Sections 6.3.3** and **6.6.1.**
- Reduced reliability impacts due to lower-probability high-impact events (Applicant-performed): **Section 6.3.4.**
- Enabled generation (MISO- and Applicant-performed): **Section 6.5.1.**
- Reduced system losses (Applicant-performed): **Section 6.6.3.**

6.2.2.2 Production Cost Analysis Methodology

Production cost analysis in this Application was conducted by MISO and the Applicants using PROMOD for forecast years 2037 and 2042 using MISO's Future 2A. PROMOD, an industry standard production cost model which uses a security constrained economic commitment and

159 Id. Page 14 Figure 2.8.

dispatch algorithm, similar to the MISO market operations, to project 8,760 hourly generation outputs and line flows in compliance with NERC single contingency (or, N-1) standards.

All post-processing of PROMOD data (e.g., calculation of adjusted production costs savings) is consistent with MISO's defined processes and industry standards.

Federal tax incentives for renewable generation (e.g., production tax credits) are excluded from MISO and the Applicants' economic benefit calculations.[160] Production cost analysis was used in this Application to quantify the following for the Studied Projects:

- Reduction in unserved demand (Applicant-performed): **Section 6.3.2.**
- Congestion and fuel savings (Applicant-performed): **Section 6.4.2.**
- Reduction in generation curtailment (Applicant-performed): **Section 6.5.2.**
- Carbon emissions reduction (Applicant-performed): **Section 6.5.3.**

6.2.2.3 Stability Analysis Methodology

Stability analysis in this Application was conducted by the Applicants' consultant and included both voltage and dynamic stability analysis. As further detailed in **Appendix E.3**, the stability analysis used four different planning scenarios for the planning year 2042. These planning scenarios considered different system load conditions, generation portfolio mix, and transmission interface levels:

- The Light Load scenario represents off-peak system conditions, characterized by a high proportion of renewable energy serving the MISO load.

- The Peak Summer Load scenario represents a scenario with the highest load and highly stressed conditions expected to occur during summer months.

- The Peak Winter Load scenario represents a scenario with the highest load and highly stressed conditions expected to occur during winter months.

- The Average Load scenario represents a highly stressed scenario characterized by the highest angular separation across the system, lowest inertia (because of lowest conventional generation, both in absolute terms and by percentage), lowest short circuit current contribution, and highest renewable penetration, meaning that renewables are serving most of MISO load and is the most severe case due to the required transfers of generation across long distances to serve load.

A sensitivity scenario has been created for each of the planning scenarios above, with the generation portfolio shifted from renewable resources to conventional synchronous generation-based resources.

The starting point for the cases used in this analysis was the Average, Light Load, Summer, and Winter 2042 cases that MISO created for LRTP Tranche 2.1 analysis. The Voltage Security Assessment Tool 24.0 was used to analyze voltage stability, an industry standard tool. Transient Security Assessment Tool was used to analyze dynamic stability, also an industry standard.

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[160] See **Appendix E.1**. Page 136.

Stability analysis was used in this Application to quantify the following for the Studied Projects:

- Improvement in stability margin energy (Applicants' consultant performed): **Section 6.3.5**.

6.3 RELIABILITY NEED

The Studied Projects are needed to mitigate overloads of the transmission grid to comply with NERC's TPL-001 reliability standards and to continue to serve customer and member demands every hour of everyday. The following sections detail and quantify how the Studied Projects are needed to support system reliability by:

- **NERC Reliability:** Mitigates transmission system overloads of 102 different system facilities as defined by NERC reliability standards **(Section 6.3.1)** and overloads of 24 additional transmission system facilities under lower-probability high-impact events **(Section 6.3.4)**;

- **Energy Adequacy:** Allows approximately 1,305,000 MWh of Minnesota load to no longer be at expected risk of being unserved in the future **(Section 6.3.2)**;

- **Enabled Demand:** Enables approximately 3,010 MW of forecasted demand to be reliably served **(Section 6.3.3)**; and

- **System Stability:** Improves transfer capability and address system instability issues **(Section 6.3.5)**.

6.3.1 <u>NERC Reliability Analysis</u>

The electrical grid is planned to meet NERC reliability standards. The Studied Projects eliminate expected reliability overloads of 102 different facilities, 27 of which are 200 kV or higher – addressing 1,313 reliability issues as defined by NERC.[161] The most significant NERC steady-state reliability overloads addressed by the Studied Projects are shown in **Figure 6.3-1**.

NERC national reliability standards require appropriate mitigation for each reliability issue, also referred to as a violation. Transmission reliability is most stressed when there are large geographic differences in generation output (e.g., high generation output in South Dakota and Western Minnesota, but low generation output in Wisconsin and to the east – and vice versa) leading to high transfers in summer average load and winter conditions. Under those conditions, the existing transmission grid is incapable of moving the necessary amounts of energy, resulting in overloads of the existing east-west transmission paths in the Studied Projects area, for contingencies of transmission lines in the same area.

The Studied Projects mitigate these reliability issues by creating a new high-capacity path to move power to, through, and out of Minnesota and into the broader Midwest region. Without the Studied Projects, the existing 345 kV grid is simultaneously facilitating both intra- and inter-state transfers. The Studied Projects create a new low impedance path which pulls power from the 345 kV and lower voltage grid, avoiding overloads, and allows the existing grid to collect, move, and distribute

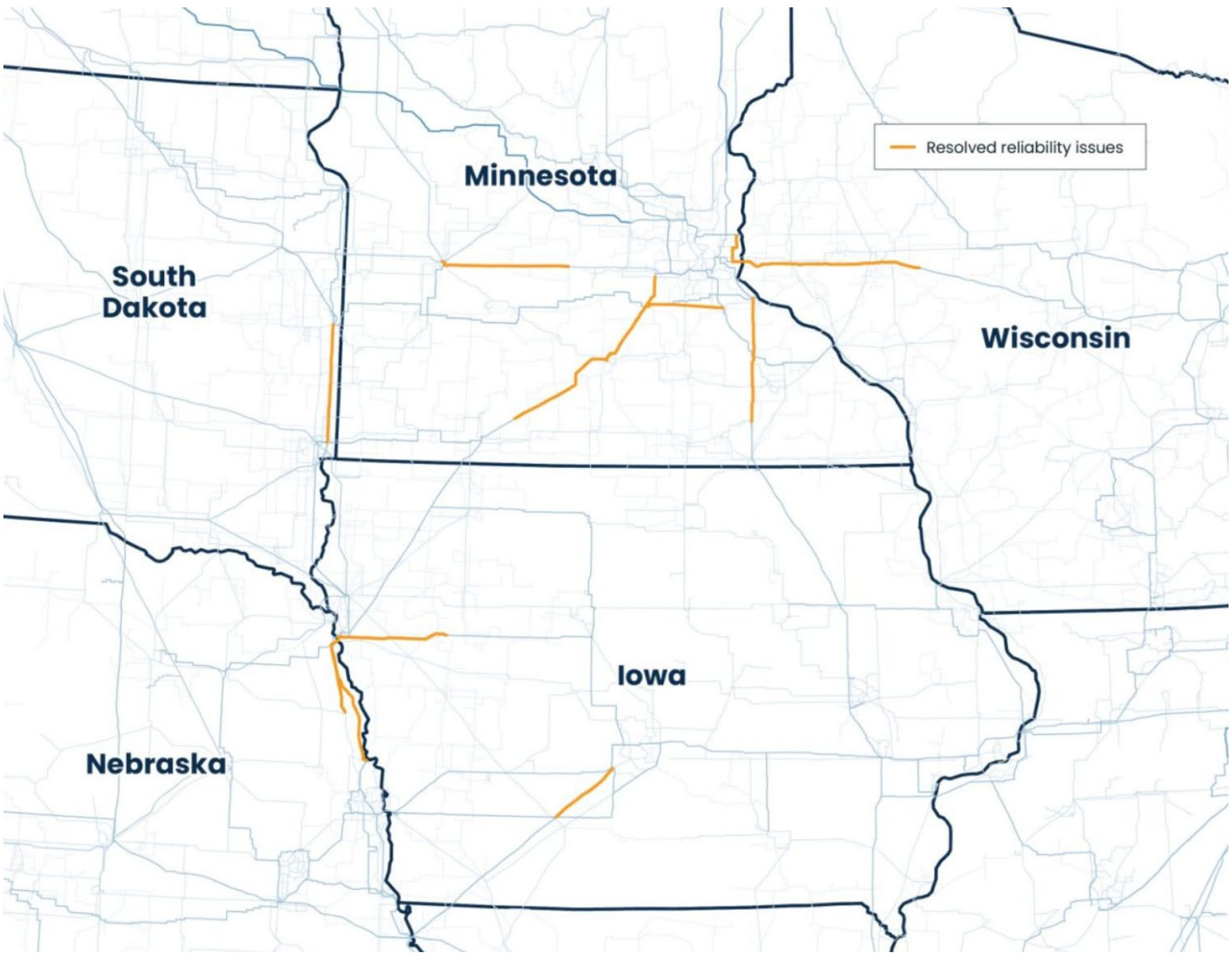
[161] MISO. Details in **Appendix E.4**. **Appendix E.4** contains the full reliability results for Table 2.13 (page 85) and Table 2.102 (page 95) in **Appendix E.1** (MTEP24 Chapter 2: Regional/Long Range Transmission Planning). **Figure 6.3-1** combines Figure 2.89 (Page 86) and Figure 2.103 (Page 96) in **Appendix E.1**.

power primarily intra-state, while the 765 kV lines facilitate long-distance bulk power transfers to adjacent states and beyond.

In addition, the Studied Projects play a key role in the broader MISO LRTP Tranche 2.1 Portfolio, which eliminates NERC reliability issues across the Midwest as discussed in **Section 4.6.1**.

While the Project is designed the Project to be in-service at all times, NERC reliability standards require that the transmission grid be able withstand a loss (e.g., outage) of any transmission line, including the Studied Projects. When a 765 kV line from the Studied Projects is out of service, the existing and planned 345 kV grid (to include the 345 kV circuit between the Pleasant Valley Substation, North Rochester Substation, and Hampton Substation) serves as a required contingency backup to maintain system reliability standards.

Figure 6.3-1: Map of Top Steady-State Reliability Issues Mitigated by the Studied Projects



6.3.1.1 Supporting Local Reliability in Southern Minnesota

The Project supports reliability for the Midwest region and southern Minnesota alike. The Studied Projects are needed to address the reliability issues of the grid detailed in **Section 6.3.1** – to move generation from where it is being produced to where it is needed – including southern Minnesota. The Studied Projects establish a new transmission backbone connection at three substations spread across southern Minnesota and connecting to Wisconsin. MISO optimally selected those substations because each is a hub – meaning each substation has strong connections to the 345 kV, 230 kV, and lower voltage transmission lines which directly serve the communities in the vicinity of these substations. Each Project substation serves as a collection point for sending generation to other areas and serving local demand. Whether a substation is importing (i.e., serving local load) or exporting (i.e., sending excess generation) can change by the moment based on system conditions.

Many of the communities where the Studied Projects are located have vast generation resources, including wind, solar, and natural gas peaking plants. Wind and solar generation are variable in nature, meaning output is dependent on weather patterns – on average these plants are outputting roughly half of the time (typical capacity factors range from 35 percent to 55 percent). Natural gas peaking plants are dispatchable resources that can be called upon to serve demand but are typically the highest-cost resource in the MISO market. By design and economics, these generators typically produce electricity less than 10 percent of the year. When these local generators are not producing energy, power is being shipped into southern Minnesota from different areas – increasingly from many states away. This shared pool of generation helps ensure a steady flow of electricity in a cost-efficient manner.

Electricity demands in southern Minnesota are also evolving. Southern Minnesota has a diverse array of industries including agriculture, manufacturing and industrial, commercial, and medical, many of which are increasingly electrifying (i.e., increasing electrical usage). Other emerging industries such as data centers have potential to further increase electrical demands.

In the next decade, as the Midwest generation fleet continues to evolve and demands for electricity grow, the existing grid is not capable of moving the necessary amounts of power into southern Minnesota when local generation is not available. The system overloads impacting area reliability are shown on **Figure 6.3-1**. It should be noted that system overloads impacting an area's reliability are commonly not located in that area as the grid is a network in which the "weakest link" can prevent generation from being imported from another area.

Likewise, when southern Minnesota has generation output in excess of what is needed locally, the existing grid is incapable of fully exporting that energy so it can be sold to other areas. The result is this excess energy is currently curtailed (wasted) at times.[162] The inability to fully export excess energy has economic consequences for southern Minnesota through the inability to sell a product and potential reliability consequences for other areas who need power to serve their load.

As described in **Section 6.4.2** and **Section 6.5.2**, the Studied Projects address both congestion and curtailment issues (respectively). The Studied Projects expand the grid capacity to continue to provide reliable service to southern Minnesota for today and tomorrow's electrical needs.

6.3.2 Energy Adequacy – 8,760 Reliability

The Studied Projects provide the ability to transfer bulk energy to, through, and out of Minnesota to continue to serve load 24 hours a day, 7 days a week, 365 days a year. The Studied Projects' transfer capability[163] helps enable the transmission grid to take on the role currently served by baseload generation, essentially allowing the transmission grid to function as a super-sized

[162] The Commission examined generation curtailment and transmission congestion in southern Minnesota (Nobles County). Docket No. E999/CI-24-316.

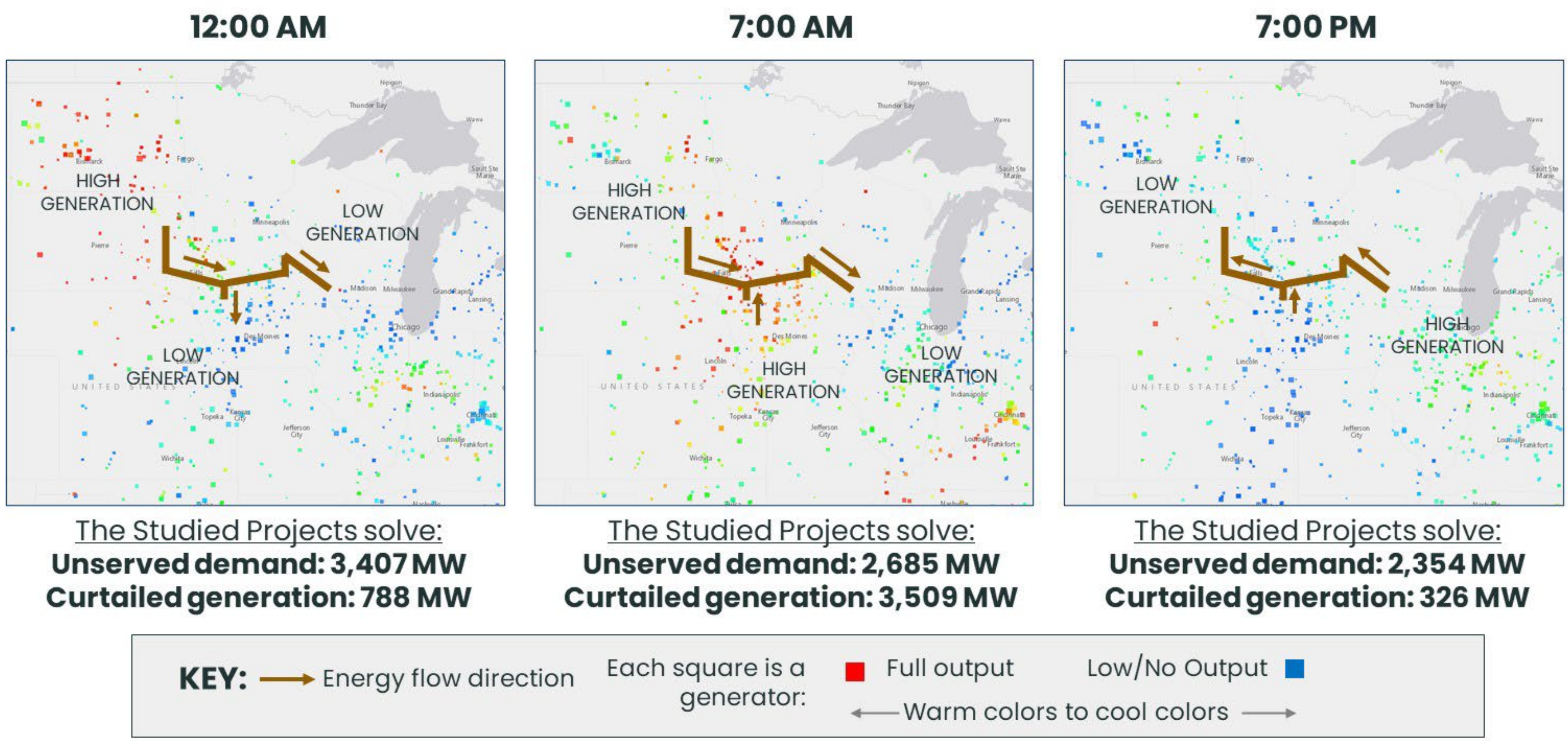
[163] See **Section 3.4.1.2** for additional details on how transfer capability is defined.

battery. **Figure 6.3-2** displays three different hours of expected generation output and electrical demands in 2042 under a typical, and actual, weather pattern in winter. The figure shows how, as the weather front moves from west to east, the Studied Projects facilitate moving energy from where it is produced to where it is needed, which changes by the hour.

Without the Studied Projects, during these three hours, over 2,000 MW of load is not being served, and a similar magnitude of generation is being wasted (i.e., curtailed) because there is inadequate transmission to move (i.e., transfer) energy from where it is being produced to where it is needed. On an annual basis, approximately 1,300,000 MWh of Minnesota load is at expected risk of not being served without the Studied Projects by 2042. Risk levels are highest during times when electricity is needed most and during atypical weather conditions.

As illustrated on **Figure 6.3-2**, the transfer capability enabled by the Studied Projects is multi-directional. This means that the Studied Projects enable a west to east transfer (e.g., from South Dakota into Minnesota) and at other times an east to west transfer (e.g., from Wisconsin to Minnesota). Similarly, the Studied Projects enable north to south and south to north transfers, depending on generation availability and electrical demands.

Figure 6.3-2: Energy Adequacy Need for Studied Projects –Typical Winter Day (2042)



The multi-directional nature grid needs are not new but have been increasing in magnitude and volatility in terms of frequency of flow direction changes. For example, historically, transfer between the Dakotas and Minnesota was nearly always transferring power energy from west to east (measured using “NDEX,” a long-standing interface system operators use to measure total flows between Minnesota and North Dakota). Since 2022, NDEX transfers have been nearly equally split between west to east and east to west.[164]

Applicants have completed an analysis of transfer capability and the resulting unserved demand (see **Section 6.2.2** for additional details on methodology). The Applicants’ analysis looked at every hour of the year and determined if the grid can transfer the needed energy from where it is being produced to where it is needed to serve load at that hour. **Figure 6.3-2** shows three representative hours of the 8,760 hours evaluated by the Applicants.

Unserved demand means there is inadequate power available to completely serve a specific load at a specific time. To prevent a voltage-drop (i.e., collapse), which could damage equipment, consumer appliances, etc., the grid operator will systematically shed load (i.e., “turn off the lights”) to maintain a safe and adequate voltage for the rest of the system. Unserved demand is caused by either a lack of generation available or inadequate transmission capacity to move generation to a specific demand site. The Applicants’ analysis quantifies the amount of demand that would be at risk of being unserved without the Studied Projects, or demand that would need to be served by a future-new dispatchable generation technology at that site. MISO models quantify unserved demand as the sum of “emergency energy” and “flex output.”[165]

The Applicants’ quantification of load at risk of being unserved is likely conservative because, unlike actual operations, planning models have perfect foresight of load levels, generation availability, and weather patterns, and, thus, can perfectly plan and optimize to minimize risk.

6.3.3 Enabled Demand Analysis

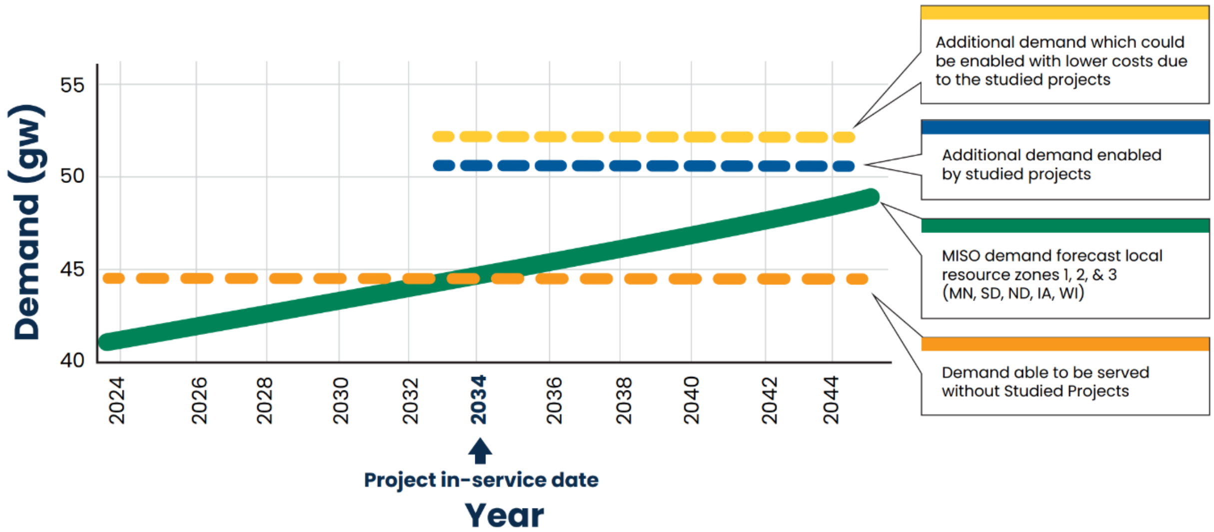
Without the Studied Projects, the grid will be unable to reliably serve the base demand forecast. The Studied Projects help enable 3,010 MW of the base forecast demand growth to be reliably served over the next 20 years as shown on **Figure 6.3-3**. As reported in **Section 5.3**, the base demand forecast only includes firm large-load additions and does not include potential/speculative large spot-load (e.g., data center) additions.

The Studied Projects are needed to serve the current forecasted demands for electricity; however, the Studied Projects also leave capacity to reliably serve potential future increases in residential, commercial, and industrial energy demands totaling an additional approximately 3,000 MW over the next 20 years, as shown in **Figure 6.3-3** and further detailed in **Section 6.6.1.**

164 From August 2022 to April 2025, NDEX transfers were 50.4 percent from Minnesota to North Dakota and 49.6 percent from North Dakota to Minnesota.

165 MISO “flex” output is defined in **Appendix E.2**. Page 20.

Figure 6.3-3: Demand Growth Enabled by the Studied Projects



To interconnect new load to the transmission grid, utilities (like the Applicants) and MISO perform analysis to ensure that the new load will not harm the reliability of the grid (i.e., that both the new and existing load can be reliably served). Should adding the new load result in violating a NERC reliability standard, an upgrade or expansion of the transmission grid is required for that new load to be interconnected.[166]

The Applicants' analysis captures load in the base forecast that could not be reliably interconnected but for the Studied Projects using EPRI's CPLANET tool (see **Section 6.2.2.1** for details on methodology). The load enabled by the Studied Projects is the minimum amount of load additions over the next 20 years that had to be reduced to eliminate the reliability issues mitigated by the Studied Projects.

6.3.4 Sensitivity Analysis for Serving Load in Lower-Probability High-Impact Events

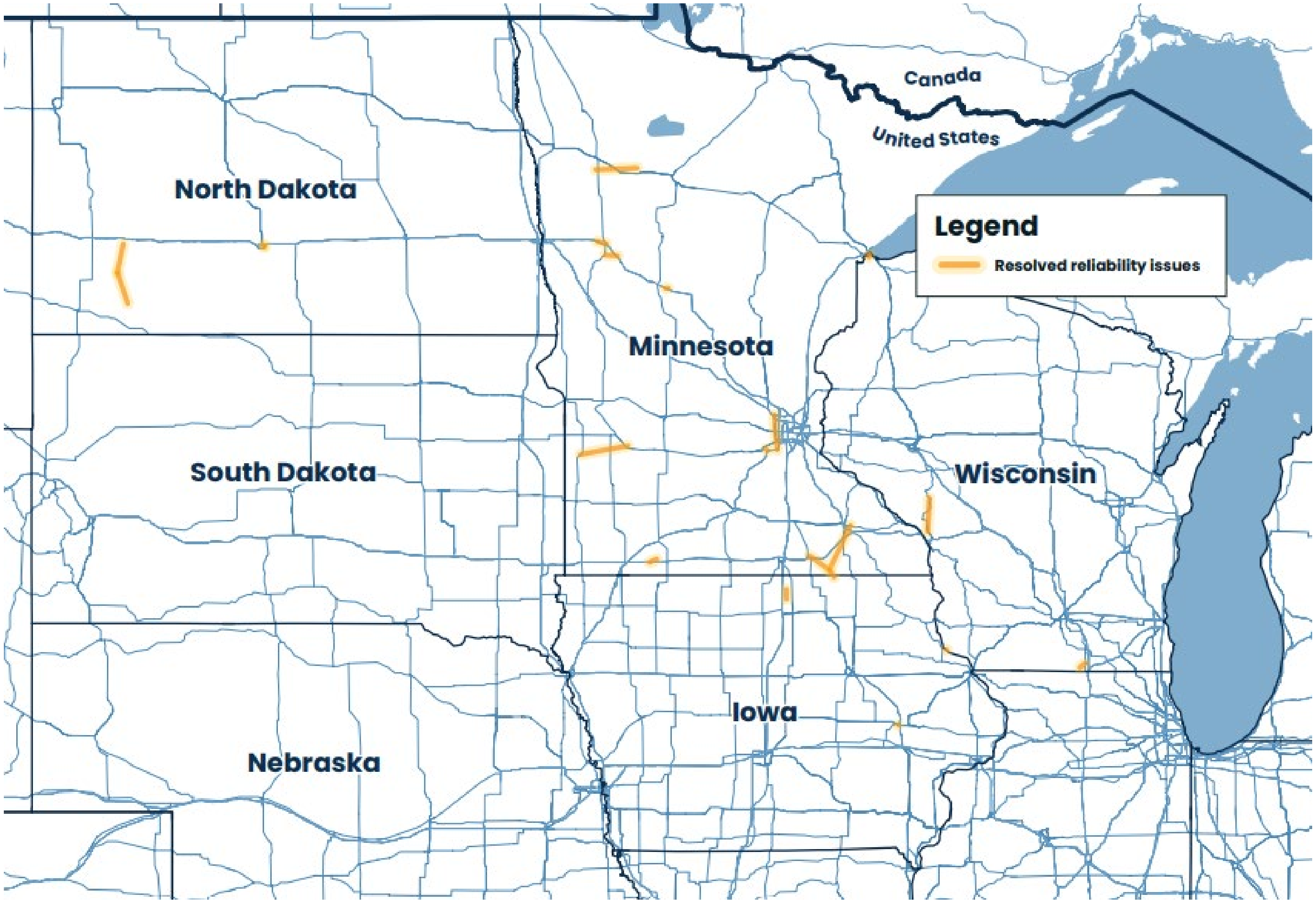
The Studied Projects also help maintain reliability under lower-probability, high-impact events such as extreme weather and multiple system outages. As the scenarios used in **Section 6.3.1** modeled only typical stress conditions (e.g., summer and winter peak) to understand the reliability impacts during additional conditions of higher grid stress, the Applicants modeled four additional scenarios, each based on an hour of actual historical weather in 2018. Under the additional modeled stressed conditions, the Studied Projects eliminate 50 additional reliability issues (13 above 200 kV) at 24 different sites, shown on **Figure 6.3-4**. Only those reliability issues mitigated by the Studied Projects that are not already captured under **Section 6.3.1** are included on **Figure 6.3-4**.

Over the last decade, the number of extreme events has been on the rise. Since its founding in 2001 to 2016, MISO did not declare a single grid emergency; between 2019 and August 2025, MISO declared 56 grid emergencies, many during non-traditional times of grid stress. MISO declares grid emergencies when there is an elevated risk of the system not being able to serve the demand.

166 MISO's planning procedures detailed in MISO Tariff Attachment FF.

While historically the most stressed conditions have been extreme cold (e.g., Winter Storm Uri) or extreme heat, with increased reliance on variable and weather-dependent generating resources, the most stressed conditions in the future could be widespread wind and solar droughts, atypical wind and/or solar patterns, multiple outages, and/or dramatic changes in demand.

Figure 6.3-4: Additional Reliability Issues Mitigated under Lower-Probability High-Impact Events



Reliability impacts of lower-probability, high-impact events were identified by the Applicants using the following load and generation scenarios:

- **Highest west to east flow:** Conditions experienced on February 23, 2018, at 22:00.
- **Highest 24-hour flow change:** Conditions experienced on February 24, 2018, at 13:00.
- **High load and low resource availability:** Conditions experienced on July 13, 2018, at 20:00.
- **Highest east to west flow:** Conditions experienced on February 28, 2018, at 13:00.

Each additional scenario is based on actual experienced load and weather patterns. Simply put, the scenarios capture the reliability impacts if tomorrow's generation fleet and electricity demands occurred with yesterday's weather patterns. Apart from the generation dispatch and load-level, all other assumptions, modeling and analysis are consistent with MISO models and analysis used in **Section 6.3.1.**

Under current NERC reliability standards, these additional scenarios are deemed extreme and, thus, the same mitigation requirements do not apply. While these additional reliability issues mitigated by the Studied Projects could be defined as resiliency needs, as opposed to reliability needs, given each scenario is based on actual experienced conditions, the Applicants have included these as a component of the reliability need.

6.3.5 System Stability Analysis

The Studied Projects add a significant component to the overall transmission grid resulting in improvements to the stability of the grid, both from a voltage and transient aspect as well as lowering probability of a cascading event. System stability is an increasingly important attribute for the grid due to the changing generation mix and more dynamic load patterns. Historically, system stability was maintained by large centrally located power plants. The large rotating mass of those power plants helped the grid remain stable during a system event (e.g., unexpected outage of a transmission line or power plant). As the power plants historically relied upon for system stability are retired and are increasingly replaced with inverter-based resources (e.g., wind and solar generator) and demands for electricity become more dynamic, backbone transmission upgrades, like the Studied Projects, are critical to networking the grid to maintain stability.

When comparing analysis with and without the Studied Projects, the performance of the grid is significantly enhanced in transferring power through Minnesota. Transfer capability is measured using both steady-state and stability studies. As transfer capability is determined by the most limiting measure, which can be different depending on specific conditions, the Applicants have evaluated each measure (steady-state and stability). In summary, under each metric, the Studied Projects enable a significant increase in the ability to reliably transfer energy from generation to load.

The voltage stability results show that the Studied Projects provide a significant increase in transfer capability of generation within Minnesota and neighboring states to load centers. As detailed in **Appendix E.3**, the Studied Projects increase the transfer capability from a voltage stability perspective by upwards of 4 GW. The Studied Projects' backbone-nature enables the needed increases in system stability and allows the potential for further increases in system stability through incremental system reactive power devices.

More significantly, stability analysis shows that without the Studied Projects, an outage of select parallel or downstream 765 kV or 345 kV paths can create system instability. Specifically:

- Without the Studied Projects, the loss of (i.e., outage of) the parallel MISO LRTP Tranche 2.1 Portfolio east-west line from central Iowa to Illinois (Sub T to Woodford County – LRTP project numbers 38 and 40) triggered major voltage oscillations in the Average Load scenario with high wind generation conditions.

- Similarly, without the Studied Projects, the loss of the 765 kV transmission between Twinkle and Sub T in Iowa triggered significant angle instability conditions in the Light Load scenario with high wind generation conditions.

- The loss of the 345 kV line between Alexandria and Big Oaks in Minnesota (MISO LRTP Tranche 1) or the loss of the 345 kV line between Iron Range and St. Louis in Minnesota triggered voltage oscillations and generator angle instability conditions without the Studied Projects for the Average Load scenarios.

A full copy of the stability analysis report is included in **Appendix E.3**.

6.4 COST-EFFECTIVENESS/ECONOMIC BENEFITS

While primarily driven by reliability, the Project provides economic benefits to customers and members which allows Minnesota to meet its reliability needs in a cost-effective manner. As discussed in **Chapter 7**, the Studied Projects are the most cost-effective alternative to meet reliability needs. The Studied Projects reduce system-wide congestion in Minnesota by upwards of 11 percent, allowing energy needs to be served with lower cost energy resulting in economic savings to consumers and members. As detailed in the following sections, the Studied Projects are expected to provide economic savings totaling $7.7 billion to $25.3 billion over the first 20 years of service based on four metrics. MISO in their evaluation of the LRTP Tranche 2.1 Portfolio, quantified nine benefit metrics. The Applicants quantified three MISO benefit metrics - the omission of the other metrics should not imply that those metrics are not provided by the Studied Projects, only that they were not quantified. The Applicants quantified a fourth benefit metric (avoided asset renewal).

6.4.1 <u>Economic Savings</u>

The Studied Projects are expected to provide $7.7 billion to $25.3 billion in economic benefits over the first 20 years of service as shown on **Figure 6.4-1**.[167]

As shown on **Figure 6.4-1**, the Studied Projects' economic benefits are the total of four economic savings metrics: mitigation of reliability issues,[168] reducing carbon emissions,[169] congestion and fuel savings,[170] and avoided asset renewals. These metrics are approved in MISO's federally approved tariff and further recognized in FERC Order 1920.[171] The Applicants' valuation method

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[167] Net savings consider financing fees and the time value of money.

[168] See **Appendix E.1.** Page 127.

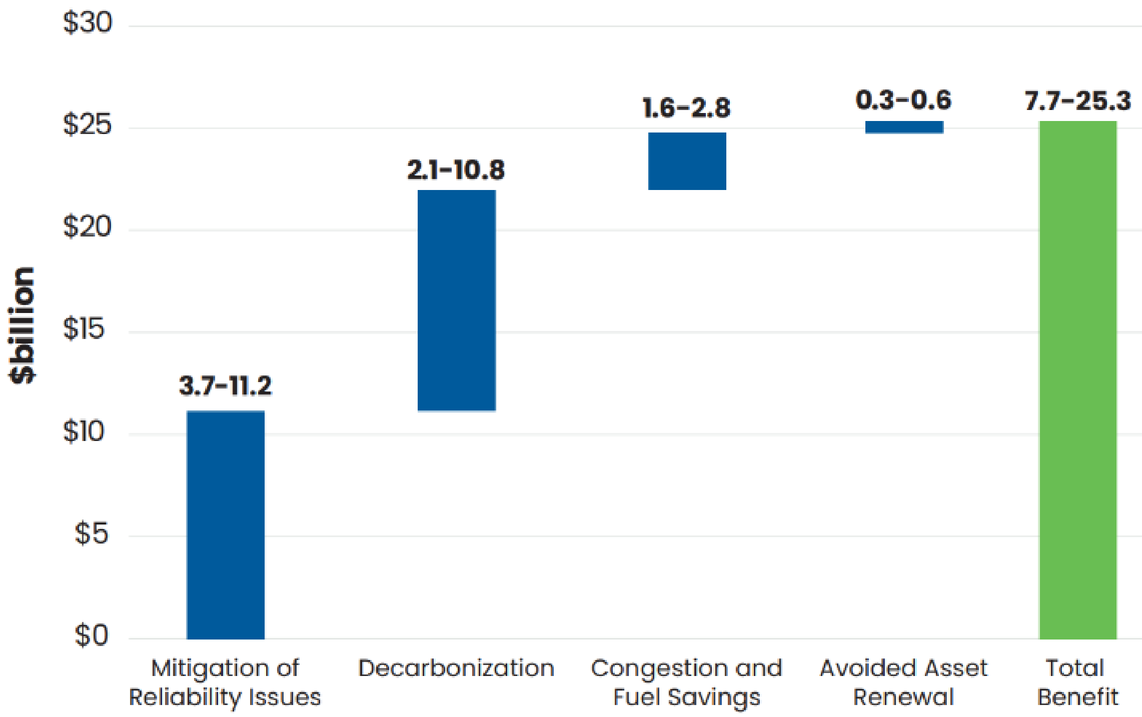
[169] See **Appendix E.1**. Page 142. The reduction of carbon emissions due to the Studied Projects is detailed in **Section 6.5.3.**

[170] See Section 6.4.2.

[171] FERC. Order 1920-A and 1920-B, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, 18 C.F.R. Part 35 (November 21, 2024, and April 11, 2025). Available at: https://cms.ferc.gov/media/e-1-rm-21-17-001 and https://cms.ferc.gov/media/order-1920-b.

for each metric is consistent with MISO's tariff defined methodology and models. Consistent with MISO's assumptions, the value of reducing carbon emissions is quantified using a range which considers the 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of carbon emissions.[172]

Figure 6.4-1: Project Economic Savings



Avoided asset renewal benefits are associated with the upgrade of 137 miles of 161 kV transmission lines in LRTP Project number 26 – included in the scope of the Studied Projects. The existing 161 kV transmission lines are on wooden H-frame structures that are reaching the end of their useful lives. Replacement of these lines in conjunction with the Studied Projects avoids the otherwise necessary asset renewal costs.

As detailed in **Section 4.6.3**, the MISO LRTP Tranche 2.1 Portfolio, which includes the Studied Projects, is expected to provide $23 billion to $72 billion in net economic savings over the first 20 years of service. MISO quantified nine different benefit metrics. The Applicants quantified three of MISO's nine benefit metrics for the Studied Projects because they can most reasonably be calculated on a Project-specific basis. The Applicants quantified a fourth benefit metric (avoided asset renewal). The omission of the other benefit metrics in the Studied Projects' economic benefits should not imply that those metrics are not provided by the Studied Projects, only that they were not quantified.

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172 MISO. LRTP Tranche 2 Business Case Metrics Methodology Whitepaper. Available at: https://cdn.misoenergy.org/LRTP%20Tranche%202%20Business%20Case%20Metrics%20Methodology%20Whitepaper633738.pdf. Page 31.

It should be noted that the models and assumptions used to quantify the economic benefits for the Studied Projects were developed in 2022 and early 2023.[173] Since 2023, costs for materials, labor, production, etc. have continued to rise. As economic benefits reflect the value of avoided costs (e.g., fuel cost savings, avoided transmission and generation investment, etc.) it is expected that benefits will likewise increase with costs. Thus, the Studied Projects' benefits estimated in **Figure 6.4-1** are likely lower than expected.

6.4.2 Congestion and Fuel Savings

One of the key measures of economic savings is congestion reduction. Congestion has been a focus in recent years in Minnesota[174] and is one of four benefit metrics quantified for the Studied Projects on **Figure 6.4-1**. Congestion is a limitation, or bottleneck, on the transmission grid, which prevents the lowest cost-generation from serving load. The Studied Projects are expected to reduce system congestion in Minnesota and the surrounding area, providing access to lower cost generation and resulting in $321 million to $660 million in cost savings over the first 20 years of the Studied Projects' service, as shown in **Table 6.4-1**. The reduction in congestion not only provides greater flexibility to efficiently serve load, but the resulting economic savings help offset the capital cost of the Studied Projects.

TABLE 6.4-1

Congestion and Fuel Savings from the Studied Projects

Period	20-year NPV ($M)		40-year NPV ($M)	
Discount Rate	7.1 percent	3.0 percent	7.1 percent	3.0 percent
MISO Midwest	$1,558	$2,814	$2,013	$4,603
Minnesota and surrounding region (Local Resource Zone 1)	$321	$660	$601	$1,802

The Studied Projects reduce total system congestion in Minnesota and surrounding states by approximately 2 percent to 11 percent, with the range dictated by system conditions in a given year. More importantly, the Studied Projects address congestion on the most difficult (i.e., expensive, largest-scale, and longest to construct) transmission elements in southern Minnesota, shown on **Figure 6.4-2**. With the largest elements mitigated, enabling additional congestion reduction with smaller scale and quicker implementation solutions, such as what has been done through Grid North Partners' recent efforts (see **Section 4.7**), can more easily be done in the future.

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173 See **Appendix E.2**. At the time of filing this Application, the MISO Series 1A futures are the latest models available.

174 Recent proceedings in Minnesota involving congestion include Nobles County congestion analysis, 2025 grid enhancing technologies study, and the 2022 Grid North Partners near-term congestion study detailed in the 2025 2025 Minnesota Biennial Transmission Report. *See, e.g., In the Matter of the Investigation into Transmission-Curtailment Matters, Drivers, and Potential Solutions to Limitations Resulting from the Nobles County Substation,* Docket No. E-999/CI-24-316; Minn. Laws 2024, Ch. 127, H.F. 5247; *2025 Biennial Transmission Projects Report,* Docket No. E999/M-25-99, 2025 Biennial Transmission Projects Report, Ch. 9 (Oct. 31, 2025).

Figure 6.4-2: Map of Top Congested Elements Mitigated by the Studied Projects

6.5 ENABLING GENERATION TRANSITION

As described in **Section 5.2**, driven by a combination of economics, age and condition, consumer preferences, utilities goals, and policies, the generation fleet in Minnesota and the broader Midwest region is evolving. Within the next 10 to 15 years, most fossil fuel generators will be retired and replaced primarily with wind and solar generation. The existing fossil fuel resources not only support reliability by providing energy (i.e., MWs), but also key reliability attributes that keep the grid stable and ensure reliability every hour of every day (i.e., energy adequacy). While wind and solar technologies continue to advance, by nature, their output is dependent on weather conditions. At the same time, demand usage is also evolving in magnitude, location, and profile. System changes are needed to allow the new variable generation fleet to serve the evolving demand; specifically, to provide a consistent flow of electricity every hour of every day (i.e., energy adequacy), interconnect new generation capacity at different locations, and to replace retiring reliability attributes. While technologies such as energy storage[175] are part of the solution, transmission infrastructure like the Studied Projects address the bulk of the needs. The Studied Projects help enable the energy transition by:

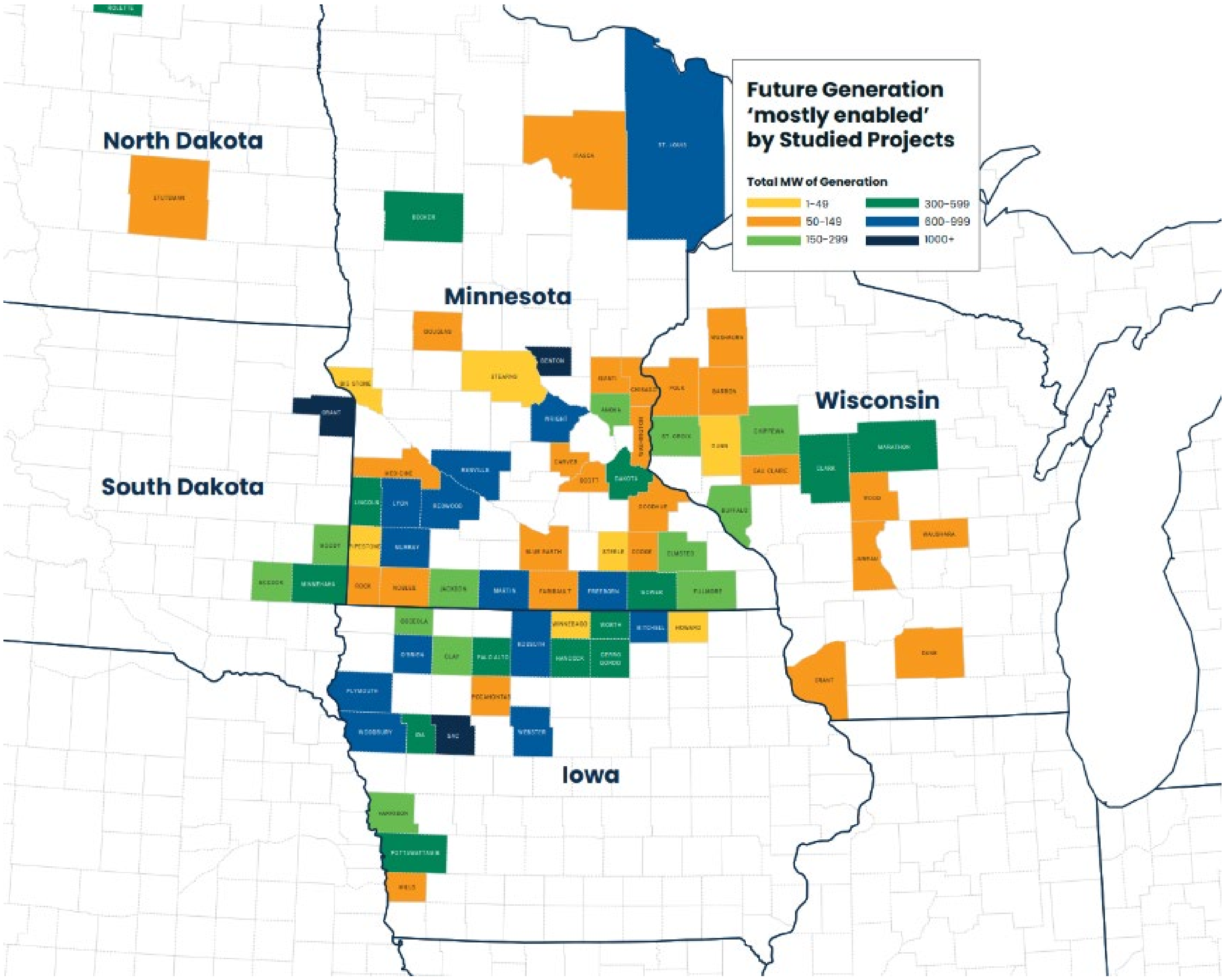
- **Enabling generation:** The Studied Projects help enable approximately 24GW of new generation (10GW in Minnesota) to be reliably interconnected to the transmission grid to replace retiring generation capacity and to serve load (**Section 6.5.1**).
- **Reducing curtailment:** The additional transmission capacity provided by the Studied Projects allows better and fuller utilization of existing generation resources, reducing curtailment (i.e., wasted energy) by upwards of 7.2 million MWh on an annual basis (**Section 6.5.2**).
- **Reducing carbon emissions:** The reduced curtailment, enabled generation, and reduced congestion provided by the Studied Projects decreases carbon dioxide emissions by 3.6 million to 4.5 million tons annually to help comply with Minnesota's Carbon Free by 2040 law (**Section 6.5.3**).

6.5.1 Enabled Generation

The Studied Projects help enable approximately 24 GW of generation to be reliably interconnected to the transmission grid as shown on **Figure 6.5-1.** While generation is typically interconnected at the 345 kV and lower voltages, the Studied Projects pull power off the existing lower voltage transmission lines to create transmission capacity to add new generation.

[175] See **Section 7.1** for additional details on how the Project is one technology of many that are needed to enable the energy transition.

Figure 6.5-1: Generation Enabled by the Studied Projects



To interconnect a new generator to the transmission grid, a generation developer must go through the MISO Generator Interconnection Queue. MISO performs a study to ensure that the connecting generator(s) does not cause a reliability issue to the transmission grid. If the generation addition causes a reliability issue or overload, the transmission grid must be upgraded to mitigate the reliability issue(s) to interconnect the new generator.[176]

MISO's federally approved tariff requires that if a new generator causes a five percent or more reliability issue impact (referred to as a distribution factor, or DFAX), that generator cannot fully interconnect until there is a plan in place to mitigate that reliability violation.[177]

As detailed in **Section 4.6.2**, the MISO LRTP Tranche 2.1 Portfolio, which includes the Studied Projects, helps enable approximately 116 GW of new generation to be interconnected across the Midwest.[178] Without the MISO LRTP Tranche 2.1 Portfolio, the 116 GW of generation has more

176 MISO's generator interconnection procedures detailed in MISO Tariff Attachment X.

177 MISO Tariff Attachment X Section 3.7.1 and 3.8.

178 See **Appendix E.1.** Page 75.

than a five percent DFAX on a reliability constraint and, thus, would not be able to interconnect without alternative mitigation.[179]

To isolate the generation enabled by the Studied Projects, the Applicants filtered MISO's data to generators which have a five percent or more DFAX on reliability constraints mitigated specifically by the Studied Projects. Because the Studied Projects are part of a broader portfolio, which intentionally provides overlapping reliability needs (i.e., the Studied Projects and another project in the MISO LRTP Tranche 2.1 Portfolio may both contribute to addressing a single reliability constraint), the Applicants calculated the generation enabled in multiple definitions:

- **10.2 GW**: Generators which are exclusively enabled by the Studied Projects (i.e., no other project in the LRTP Tranche 2.1 Portfolio addresses the necessary reliability mitigations).
- **45.0 GW**: Generators which are enabled by the Studied Projects in combination with other LRTP Tranche 2.1 Portfolio projects (i.e., multiple projects work together to mitigate the reliability issue to enable the generation addition).
- **24.5 GW**: Generators which are mostly enabled by the Studied Projects. Includes generators which are exclusively enabled by the Studied Projects and those which the most significant reliability constraint(s) is addressed by the Studied Projects.

The Studied Projects can enable generation nameplate totals greater than the line's rated physical capacity due to the network nature of the grid (i.e., creating new capacity and unlocking capacity in the existing grid).

6.5.2 Curtailment Analysis

Curtailment refers to a condition where a generator can, and economically should, provide power to the grid, but there is either insufficient transmission capacity to move the energy generation from the generator to where it is needed to serve demand (i.e., there is congestion), or there is not enough demand or storage resources to use all available generation. While not limited to renewable generation, curtailment occurs primarily at renewable resources which are economically the lowest cost generators from an operating perspective.

Curtailment is a reliability, economic, and policy issue. Curtailment results in an inability to access the least-cost generation, which is needed to serve load. Curtailment also often results in higher costs as the energy is wasted and must be replaced by another generator, often more expensive and potentially carbon emitting generation. The curtailed renewable generation therefore would not contribute to carbon-free goals. The Studied Projects and the MISO LRTP Tranche 2.1 Portfolio reduce curtailment by directly mitigating insufficient transmission capacity, but also by enabling generation by providing connections to reach loads across MISO (and, even beyond MISO).

The Studied Projects reduce renewable generation curtailment (i.e., generation which is wasted and cannot used to serve electrical needs) by 5.6 to 7.2 million MWh on an annual basis. Much of the reduced curtailment is in Southern Minnesota. However, given the regional nature of the Studied Projects, the Studied Projects reduce generation curtailment across a five-state Upper Midwest region (see **Figure 6.5-2**).

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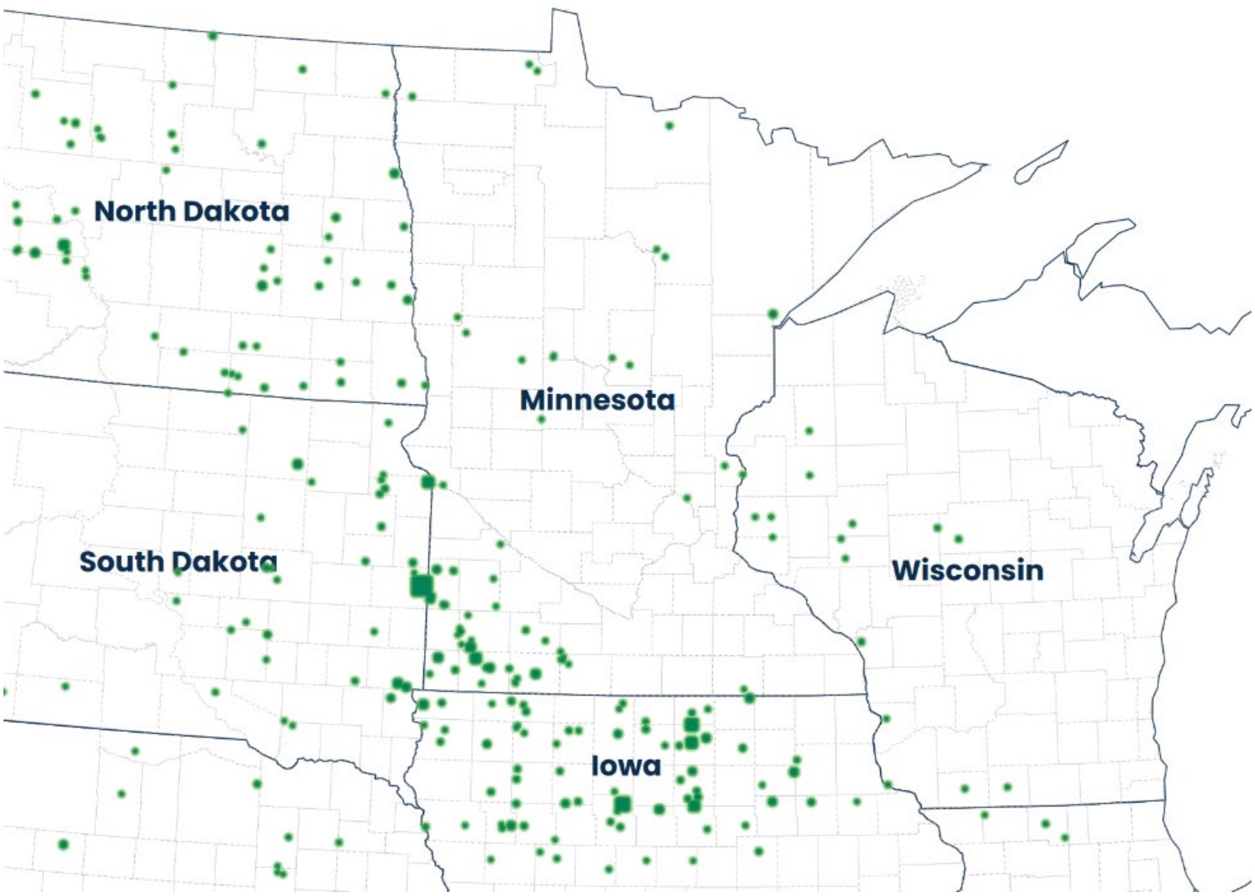
179 Id. Page 27.

Figure 6.5-2: Reduction in Generation Curtailment from the Studied Projects
(Dot size indicative of magnitude of curtailment reduction)



6.5.3 Carbon Reduction – Socially Beneficial Uses of Facility Output

The Studied Projects are needed to maintain transmission reliability for the state and the broader MISO region as the region undergoes a transition from fossil fuel generation resources to cleaner energy resources. The Studied Projects reduce annual carbon emissions by 5.4 to 7.5 million tons, as shown in **Table 6.5-1**, supporting public policy goals such as Minnesota's carbon-free by 2040 standard and its interim targets.

TABLE 6.5-1 Carbon Emission Reduction from Reduced Congestion and Curtailment	
Year	**Carbon Emission Reduced by Studied Projects (tons)**
2032	4,556,816
2037	4,362,798
2042	3,609,815

The Studied Projects reduce annual CO_2 emissions by reducing renewable curtailments (see **Section 6.5.2**) and decreasing congestion (see **Section 6.4.2**).

As detailed in **Section 4.6.2,** MISO estimates that the addition of the broader MISO LRTP Tranche 2.1 Portfolio, including the Studied Projects, is projected to result in a reduction of 127 million to 199 million metric tons of CO_2 emissions.

In addition, as discussed in **Section 6.5.1**, the Studied Projects directly support the reliable interconnection of approximately 24 GW of new carbon-free generation, which also decreases carbon emissions by offsetting more expensive carbon emitting resources in the dispatch. The carbon reductions from the additional generation enabled by the Studied Projects are not captured in **Table 6.5-1** and, thus, carbon reduction totals are conservative.

6.6 ADDITIONAL PROJECT BENEFITS

The Project provides additional benefits to Minnesota and the broader region. This section provides an overview of the analysis of the Project's beneficial impacts on the ability to serve load beyond the base load forecast, flexibility and resiliency, and reduced system losses.

6.6.1 Enabled Demand Growth Beyond the Base Load Forecast

Given the critical nature of electricity and length of time needed to develop infrastructure, it is necessary to consistently be a step ahead of needs. While the Studied Projects are needed to meet today's forecasted demand needs as detailed in **Section 6.3.3**, the Studied Projects also help enable upwards of approximately 3,000 MW of additional load growth beyond the base forecast to be reliably interconnected. The additional load enabled is agnostic to type, industry, and timing and could be used to accommodate residential, commercial, and/or industrial growth. As detailed in **Section 5.3**, the current demand forecasts do not include potential for load growth from data center development, which MISO predicts could increase demand by as much as three-fold.[180]

Reliability impacts for new load interconnections are dependent on multiple factors, the largest being the location of new load, co-location with generation (i.e., is load "offset" by on-site generation), and the hourly profile. As a conservative measure, the Applicants assumed that new load has a 100 percent load factor (i.e., it is "always on") and is not co-located with new generation. To consider a range of potential locations for the future load, the Applicants analyzed two different scenarios:

- **Spread across the State of Minnesota:** Where all existing load is scaled-up on a pro-rata basis; and
- **Directly located on the Studied Projects:** Where new load is spread equally at the Lakefield Junction Substation, Pleasant Valley Substation, and North Rochester Substation.

In the future, with the generation mix primarily composed of wind, solar, and storage, the most stressed reliability conditions (i.e., limiting case) for the grid to serve the state's load are the times when all local wind and solar is offline and storage is depleted. Under this situation, reliability is dependent on the grid's transfer capability. To determine the amount of additional load which could be interconnected with the Studied Projects, the Applicants analyzed this limiting case, where

180 MISO. December 2024 Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf).

serving existing, forecasted, and potential additional load is done by transferring energy from outside of Minnesota. Additional load enabled by the Studied Projects is calculated as the difference in transfer capability needed to serve the base demand and the total transfer capability provided by the Studied Projects.

To determine the total transfer capability provided by the Studied Projects, the Applicants incrementally increased the transfer levels until a system overload was identified. While the Studied Projects enable the bulk of the increased transfer, as transfer is increased there are lower-voltage facilities (i.e., underlying facilities) which overload. Upgrading lower-voltage/underlying facilities is typical and identified in the annual MTEP planning process. As such, these violations were cataloged, but the Applicants continued to increase the transfer until there was a violation of a higher-voltage, more-significant facility which would require more than a typical annual MTEP system upgrade to mitigate. The transfer level immediately before the higher-voltage violation is the total transfer enabled by the Studied Projects.

The cost to mitigate each reliability violation is calculated using MISO's Cost Estimation Guide by assuming the monitored element is upgraded.[181] As shown on **Figure 6.6-1**, the Studied Projects enable 3,140 MW of additional load beyond the base forecast. **Figure 6.6-1** details the additional load enabled by the Studied Projects assuming new load is spread across the entire state. Should new load be located directly at 765 kV substations, the Studied Projects enable additional load. As shown on **Figure 6.6-1**, approximately $500 million in transmission system upgrades, spread across multiple transmission facilities, are required to meet this load level in addition to the Studied Projects; however, each of these upgrades is small scale and in the range of a "typical" (i.e., non-LRTP) annual load serving project.

As detailed in **Section 6.3.3**, without the Studied Projects the base demand forecast is not reliably served. Thus, without the Studied Projects, there is no additional enabled load. To isolate the additional load enabled by the Studied Projects versus the additional lower-voltage mitigation, similar analysis was performed on a non-Project case with the same lower-voltage mitigation. As shown on **Figure 6.6-1**, the difference between these cases is the amount specifically enabled by the Studied Projects.

Additional load of 3,140 MW is the equivalent of increasing the annual net growth rate for MISO load in Minnesota, South Dakota, North Dakota, Iowa, and Wisconsin (MISO Local Resource Zones 1, 2, and 3) from 0.8 percent to 1.2 percent over the next 20 years.

Additionally, as shown on **Figure 6.6-1**, the Studied Projects decrease the costs to enable additional load growth beyond the level enabled by the Studied Projects by approximately $500 million to $900 million. To interconnect load growth beyond the load growth enabled by the Studied Projects, approximately 1,600 MW, larger-scale reliability overloads on the 345 kV grid must be addressed, in addition to the overloads on the lower voltage system. The Studied Projects proactively address some of the 345 kV overloads that need to be resolved, thereby reducing the costs to expand the system beyond 1,600 MW.

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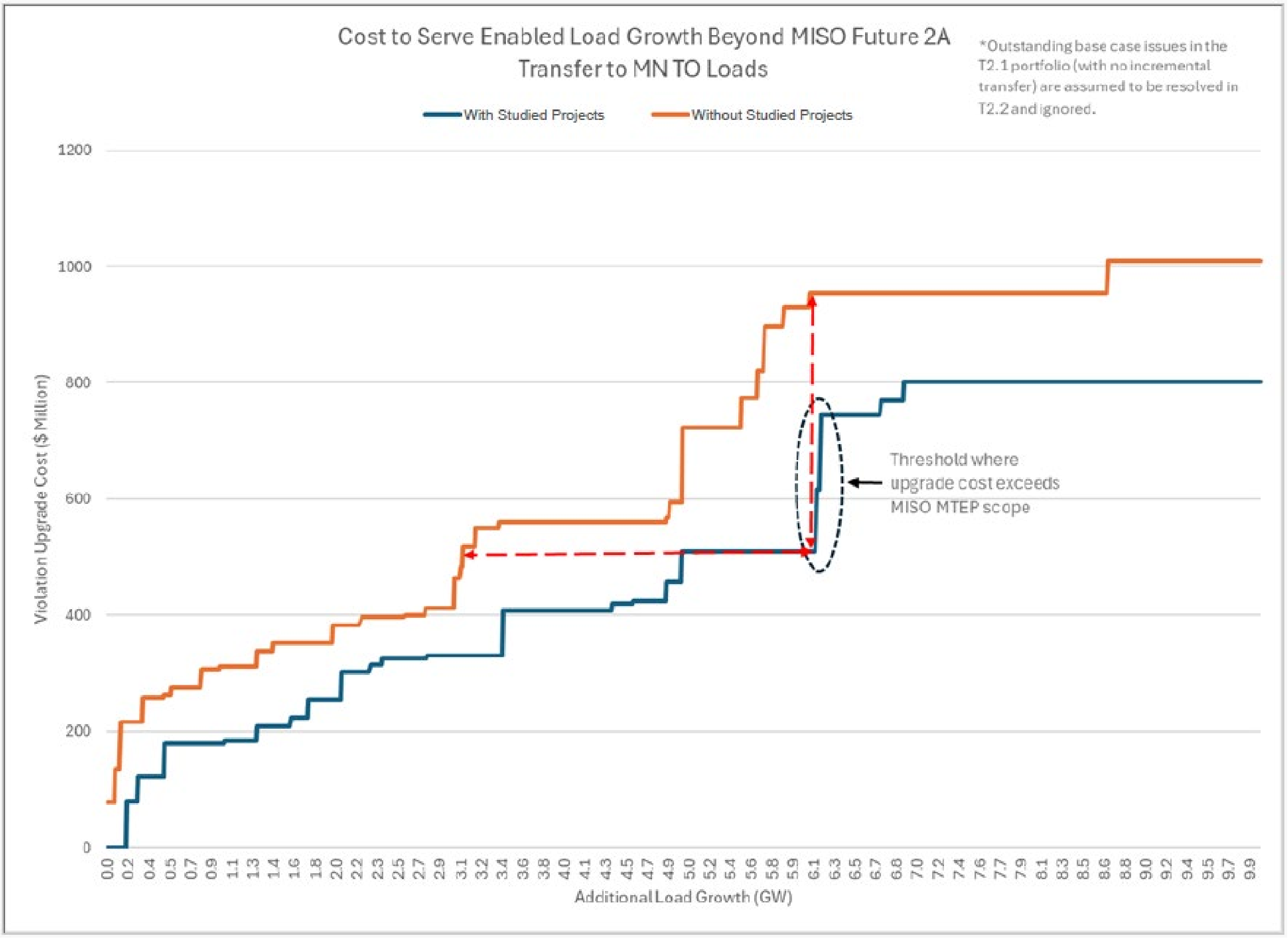
181 MISO. Cost Estimation Guide / Workbook for MTEP 24. Available at: https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680

Figure 6.6-1: Additional Load Enabled by the Studied Projects

(Assumes new load is geographically spread across Minnesota)



6.6.2 Flexibility and Resiliency

The Studied Projects establish a strong, low-impedance, and high-capacity path which not only facilitates bulk transfers between Minnesota, South Dakota, Iowa, and Wisconsin, but also with much of the Eastern Interconnection, in the eastern part of the United States. When combined, the projects within the MISO LRTP Tranche 2.1 Portfolio create a super network, allowing Minnesota to meet its electrical needs in a more reliable and cost-effective manner. In addition to directly supporting daily reliability, the transmission backbone network provides flexibility to respond to extreme weather and other low-probability high-impact events.

In **Section 6.3.4**, the Applicants showed that the Studied Projects enable the system to be reliable even under stressed conditions. The modeled stress conditions were based on actual experienced weather conditions from 2018; however, there is potential for different and/or more extreme weather conditions in the future. Transmission enhancements, like the MISO LRTP Tranche 2.1 Portfolio and the Project, provide flexibility to be able to respond to these types of events.

Winter Storm Uri in February 2021 was an example of the regional transmission expansion providing flexibility beyond modeled scenarios. Winter Storm Uri was a widespread rare Category 3 “Major” winter storm in which Midwest temperatures dropped as low as -30 degrees Fahrenheit. There was an unprecedented need to transfer high amounts of power from the east to the west to maintain reliability during the storm. At that time, most of the MISO MVP Portfolio, the first regional (i.e., LRTP) transmission portfolio approved by MISO, had been recently constructed. The MVP Portfolio was primarily designed to facilitate power transfers from west to east. However, during Winter Storm Uri, to support reliability, PJM — the MISO-equivalent organization in the eastern United States — at one point exported approximately 13,000 MW of energy to MISO, which was used to support SPP; the MISO-equivalent organization to the west of MISO.[182] This level of transfer to maintain reliability would not have been possible without the MVP Portfolio, and was well beyond the scenarios/conditions for which the MVP Portfolio was specifically planned and analyzed. Similarly, the Project and MISO LRTP Tranche 2.1 Portfolio provide significantly more grid flexibility than currently available to be able to respond to the next unprecedented event.

6.6.3 Reduced System Losses

Losses are a measure of the energy flow across the system that is converted into heat due to impedance within the elements of the transmission system. More simply, losses are wasted energy. It is necessary for utilities to provide enough generation to serve their respective system demands (plus reserves), considering the loss of energy before it can be usefully consumed. When system losses are reduced or minimized, electrical energy is delivered to end users more efficiently, helping to defer the need to add more generation resources to a utility’s portfolio. Therefore, system loss reduction results in monetary savings in the form of less fuel required to meet the system demand plus potentially delayed capital investment in generation plant construction.

Generally, the higher the voltage, the lower the transmission system losses. Diminishing losses at higher voltages is one of the primary reasons the transmission grid is operated at voltages higher than what is both generated and consumed. The Studied Projects reduce system losses

182 MISO: The February Arctic Event Report. Available at: https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf.

by pulling system flows off lower voltage facilities which have higher losses, and onto the higher-voltage Studied Projects, which have lower losses.

Each new transmission line that is added to the electric system affects the losses of the system. In determining the losses associated with a particular transmission project, it is not reasonable to consider only the Studied Projects' transmission facilities and calculate losses directly from operation of those new transmission facilities. Rather, it is necessary to look at the total losses of the system that result with and without the Studied Projects. The losses were therefore studied using the larger MISO system. In its Exemption Order, the Commission authorized the Applicants to provide line loss data for the system as a whole, rather than line loss data specific to an individual transmission line.[183]

The Applicants used power flow software to calculate the losses using MISO's eight defined scenarios. In each case, system line losses due to the Studied Projects were compared between a case with the Studied Projects and a case without the Studied Projects (see **Section 6.2** for additional detail). Annual losses were calculated by weighing each of the scenarios shown in **Table 6.6-1** based on the approximate percentage of the year the scenario best represents. For example, the average loading as compared to the other scenarios best represents the hourly conditions for approximately 22 percent of the year. Similar weights were calculated for all scenarios. Weights were determined by comparing each's scenario assumptions to 8,760 hourly load and generation levels.[184]

As shown in **Table 6.6-1**, the Studied Projects are expected to reduce transmission system losses by approximately 450 MW during conditions of highest losses. Over a year, the Studied Projects are expected to reduce system losses by approximately 1.6 million MWh.

TABLE 6.6-1

Change in System Transmission Line Losses from the Studied Projects

Scenario[a] (Approximate Percentage of Year Scenario Represents)	Reduction in System Line Losses from the Studied Projects
Average Loading (22 percent)	452.6 MW
Average East to West (10 percent)	36.9 MW
Average Lowers to Uppers (12.5 percent)	385 MW
Light Load (5 percent)	372.5 MW
Summer Peak (2 percent)	170.8 MW
Twilight Summer (1 percent)	101.7 MW
Winter Peak (2.5 percent)	352.8 MW
Winter Low Renewables (45 percent)	8.7 MW
Annual Sum (100 percent)	1,634,001 MWh

[a] Scenario definitions based on MISO MTEP24 reliability models – see **Section 6.2.2** for additional information.

6.7 IMPACT OF DELAY

If the Project were delayed, there will be both regional and local reliability consequences. The MISO LRTP Tranche 2.1 Portfolio assumes the Project will be in service in 2034. Delay of the Project would degrade the performance of the broader portfolio, which was optimized to work

183 See Order on Initial Filings.

184 MISO. LRTP Tranche 2 Business Case Metrics Methodology Whitepaper. Available at: https://cdn.misoenergy.org/LRTP%20Tranche%202%20Business%20Case%20Metrics%20Methodology%20Whitepaper633738.pdf.

together to maintain reliability across the Midwest. The loss in performance would increase the risk of reliability events and unserved demand and could jeopardize Minnesota and other MISO states in meeting clean energy policy objectives. In addition, as the national reliability standards require MISO and the Applicants to plan and implement solutions to meet reliability standards, temporary solutions would be required until the Project is in-service. Given the volume and magnitude and reliability needs addressed by this Project as detailed in **Section 6.3**, depending on the length of the delay, a temporary solution would be expensive at best and infeasible at worst (see **Section 7.4.1**).

In addition to the regional impacts, a delay in the Project will also have local impacts. The Project is needed to support reliability in Minnesota as aging power plants transition or retire. The transition of these aging plants and replacement with new generation sources is a key component of Minnesota utilities' IRPs, the Commission has reviewed and approved. In addition, a delay will also delay the curtailment reductions discussed in **Section 6.5.2** above.

6.8 EFFECT OF PROMOTIONAL PRACTICES

The Applicants have not conducted any promotional activities or events that have triggered the need for the Project. Rather, the Project is driven by regional reliability issues related to the clean energy transition and meeting public policy objectives.

6.9 EFFECT OF INDUCING FUTURE DEVELOPMENT

The Project is not intended to induce future development, but it is needed to serve demand arising from future economic development that otherwise would not be possible if the Project and the MISO LRTP Tranche 2.1 Portfolio were not constructed as discussed in **Sections 6.3.3** and **6.6.2**.

7 ALTERNATIVES TO THE PROJECT

An applicant is required to consider various alternatives to the Project in any Certificate of Need proceeding for a proposed transmission line project. Minn. Stat. § 216B.243, subd. 3(6) states that, in assessing need, the Commission shall evaluate "possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation." The Commission's rules likewise require an application to discuss the following alternatives:

(1) New generation of various technologies, sizes, and fuel types;

(2) Upgrading of existing transmission lines or existing generating facilities;

(3) Transmission lines with different design voltages or with different numbers, sizes, and types of conductors;

(4) Double-circuiting of existing transmission lines;

(5) If the proposed facility is for DC (AC) transmission, an AC (DC) transmission line;

(6) If the proposed facility is for overhead (underground) transmission, an underground (overhead) transmission line; and

(7) Any reasonable combinations of the alternatives listed in subitems (1) to (6).[185]

Minn. R. 7849.0340 further requires an applicant to analyze not building the proposed facility.

This Chapter discusses the Applicants' evaluation of multiple system alternatives to the Studied Projects, including alternative voltages; generation and non-wires alternatives; transmission alternatives; combinations of alternatives; and a no-build alternative. None of the alternatives is a more reasonable and prudent alternative to the Studied Projects, as summarized in **Table 7.0-1**. This Chapter also discusses the Applicants' evaluation of alternative conductor and structure design, as summarized in **Table 7.0-1**.

TABLE 7.0-1

Alternatives Evaluation Summary

Alternative	Reason for Rejection
Alternative Voltages	
Lower voltage	**Cost:** Less cost-effective than the Studied Projects. **Impact:** More land-impacts than the Studied Projects.
Higher voltage	**Viability:** No voltages higher than 765 kV AC are operating in the United States.
Generation And Non-Wires Alternatives	
Peaking generation	**Need:** Does not provide transfer capability needed for reliability and efficiency.
Renewable generation	**Need:** Does not address reliability-energy adequacy needs.
Battery energy storage	**Need:** Does not provide transfer capability needed for reliability and efficiency.
Distributed generation	**Need:** Does not address reliability-energy adequacy needs.
Nuclear generation	**Viability:** Does not comply with Minnesota law.

185 Minn. R. 7849.0260.

TABLE 7.0-1 Alternatives Evaluation Summary	
Alternative	**Reason for Rejection**
Demand side management/Conservation	**Viability:** Magnitude of necessary load reduction infeasible.
Reactive power additions	**Need:** Does not address NERC reliability needs.
Transmission Alternatives	
Upgrade existing transmission lines	**Cost:** Less cost-effective than the Studied Projects **Impacts:** Number and scale of upgrades infeasible (at least 1,394 miles of transmission lines and 10 substation upgrades required) **Optionality**: Does not allow for any future growth or expansion beyond the amount studied.
Alternative endpoints	**Need:** Project endpoints identified and optimized by MISO.[186]
Double circuiting (765 kV/765 kV) and other engineering considerations	**Need:** Single circuit meets current forecasts' needs and proactively accommodates a reasonable level of potential future needs
High voltage direct current	**Cost:** Less cost-effective than Studied Projects
Underground	**Viability:** Underground 765 kV technology presently not available
Reasonable Combination Of Alternatives	
Lower voltage and upgrading existing lines	**Cost**: Less cost-effective than the Studied Projects. **Optionality**: Does not allow for any future growth or expansion beyond the amount studied.
Lower voltage and peaking generation/storage	**Cost**: Less cost-effective than the Studied Projects. **Optionality**: Does not allow for any future growth or expansion beyond the amount studied.
Alternative Transmission Line Engineering	
Alternative conductor design	Segment One: 17 conductors were studied for the Project. Based on cost, performance and the Project requirements, Xcel Energy proposes the 1192.5 45/7 ACSR Bunting conductor or a similar performing conductor. Segment Two: Seven ACSR conductors and six composite-core conductors were evaluated for the Project. Based on cost, performance, and project requirements, Dairyland selected the 795 30/19 ACSR (GA2) Mallard conductor for typical spans and the 1037 York AECC conductor for the Mississippi River crossing.
Alternative structure design	Applicants considered multiple structure designs, including tubular H-Frame and monopole designs. Based on cost, resiliency and constructability considerations, Applicants determined that the lattice design was the best performing design for the Project.
No Build Alternative	
No build alternative	**Need:** Without the Studied Projects, there are consequences to: 1) system reliability (unserved demand, NERC reliability violations, energy adequacy, and system instability); 2) generation plans (increased risk of not complying with Minnesota's Carbon Free by 2040 law); and 3) economics (less efficient and more expensive piecemeal solution required absent the Project's coordinated regional approach).

7.1 ANALYSIS OF ALTERNATIVES

The evaluation of alternatives implies substitution or an "OR" – transmission <u>or</u> generation – 345 kV <u>or</u> 765 kV. In practice, all technologies are needed to work together to optimally maintain reliability. The Studied Projects do not preclude other technologies evaluated but rather enable these technologies to work synergistically with the Studied Projects. Given the complex challenges to regional reliability from the changing generation fleet and electrical demands, an

186 See Minnesota Department of Commerce, Division of Energy Resources Comments on Exemption Requests, at 6 (Oct. 21, 2025) ("The Department agrees with the Applicants that Minnesota Statutes limit the consideration of alternative end points in this matter….").

"all of the above" approach is needed. The Studied Projects work as part of a larger system which also includes and/or assumes:

- lower-voltage transmission line additions (e.g., 345 kV);
- upgrades of existing transmission lines;
- expansion of demand side management;
- additional distributed generation;
- utility-scale generation additions of multiple fuel-types; and
- expansion in energy storage.[187]

All these technologies, including the Studied Projects, are necessary to support future grid reliability.

7.1.1 Alternative Evaluation Criteria

To be an alternative to the Studied Projects, an alternative (or combination of alternatives) must, at a minimum, address the primary needs for the Studied Projects detailed in **Chapter 6**. Because there are multiple needs, needs were prioritized and alternatives screened based on the following criteria.

A viable alternative must:

- Address the NERC reliability violations mitigated by the Studied Projects (see **Section 6.3.1**);

- Maintain energy adequacy (serve load at all hours, every day) by eliminating an equivalent level of unserved demand as the Studied Projects (see **Section 6.3.2**);

- Comply with state law (see **Section 3.4.2**); and

- Have similar cost-impacts as the Studied Projects – considering both upfront capital costs and economic impacts e.g., congestion and fuel savings (see **Section 2.4** and **Section 6.4**).

Alternatives that met these criteria were further evaluated on additional factors: flexibility to meet future needs, curtailment reduction, carbon emission reductions, resiliency, and land and community impacts.

7.1.2 Alternative Evaluation Methodology and Cost Assumptions

The Applicants compared the electrical performance of the alternative to the Studied Projects based on practices which are industry standard and consistent with MISO's federally approved tariff. All analysis and assumptions are consistent with need methodology detailed in **Section 6.2.**

To evaluate generation non-wire alternatives, the Applicants used EPRI's CPLANET tool (see discussion in **Section 6.2.2**).

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[187] MISO LRTP Tranche 2.1 assumes approximately 3,500 MW of new energy storage will be added in Minnesota and the surrounding area over the next 20 years. See **Appendix E.2.** Page 87 for MISO Local Resource Zone 1.

To evaluation transmission alternatives, the Applicants directly replaced the Studied Projects with other potential transmission solutions. The Applicants also studied combinations of alternatives.

Because the Project as evaluated (i.e. the Studied Projects) extends beyond Minnesota into South Dakota, Iowa, and Wisconsin,[188] the Applicants did not limit the geographic scope of alternatives to Minnesota.

The Applicants used consistent "planning-level" scope and cost assumptions to have "apples to apples" costs to compare against alternatives. **Section 2.4.1** of the Application includes an engineering level estimate of the Project based on over a year of detailed engineering analysis and cost estimates acquired from current and actual bids, an equivalent level is not available for each alternative. For consistency, the Studied Projects and alternatives are each compared using planning-level scopes and MISO's MTEP24 cost-estimation guide or equivalent for non-wire alternatives. When comparing costs between alternatives, the focus is the relative relationship between the Studied Projects and alternatives (e.g. higher or lower cost) using a common set of cost assumptions rather than the absolute magnitude of each cost. The Studied Projects' estimated cost of $6.008 billion ($2024) for comparison with alternatives is provided in **Table 7.1-1**.

TABLE 7.1-1

Studied Projects Cost Estimate for Comparison with Alternatives[189]

Project	Estimated Cost ($2024)
Minnesota Portions of LRTP 22 – 25	$2.244 billion
South Dakota portion of LRTP 22	$724 million
Iowa 765 kV portions of LRTP 23	$1.116 billion
Minnesota portion of LRTP 26	$821 million
Wisconsin portion of LRTP 26	$1.103 billion
TOTAL [a]	**$6.008 billion**
[a] The Studied Projects 20-year NPV cost using a 7 percent discount rate is $5.919 billion.	

7.2 ALTERNATIVE VOLTAGES - WHY 765 KV? WHY NOW?

The Applicants and MISO identified the need to transfer more than 10,000 MW more electrical capacity to, through, and out of Minnesota to meet future demands (see **Figure 6.0-1** and **Figure 6.0-2)**. The expansion of the transmission system technically could be accomplished through 345 kV facilities[190] or a combination of 345 kV and 765 kV facilities. However, given the magnitude of the capacity required, MISO concluded that 765 kV facilities along a west-east corridor with additional 345 kV transmission line facilities should be constructed.

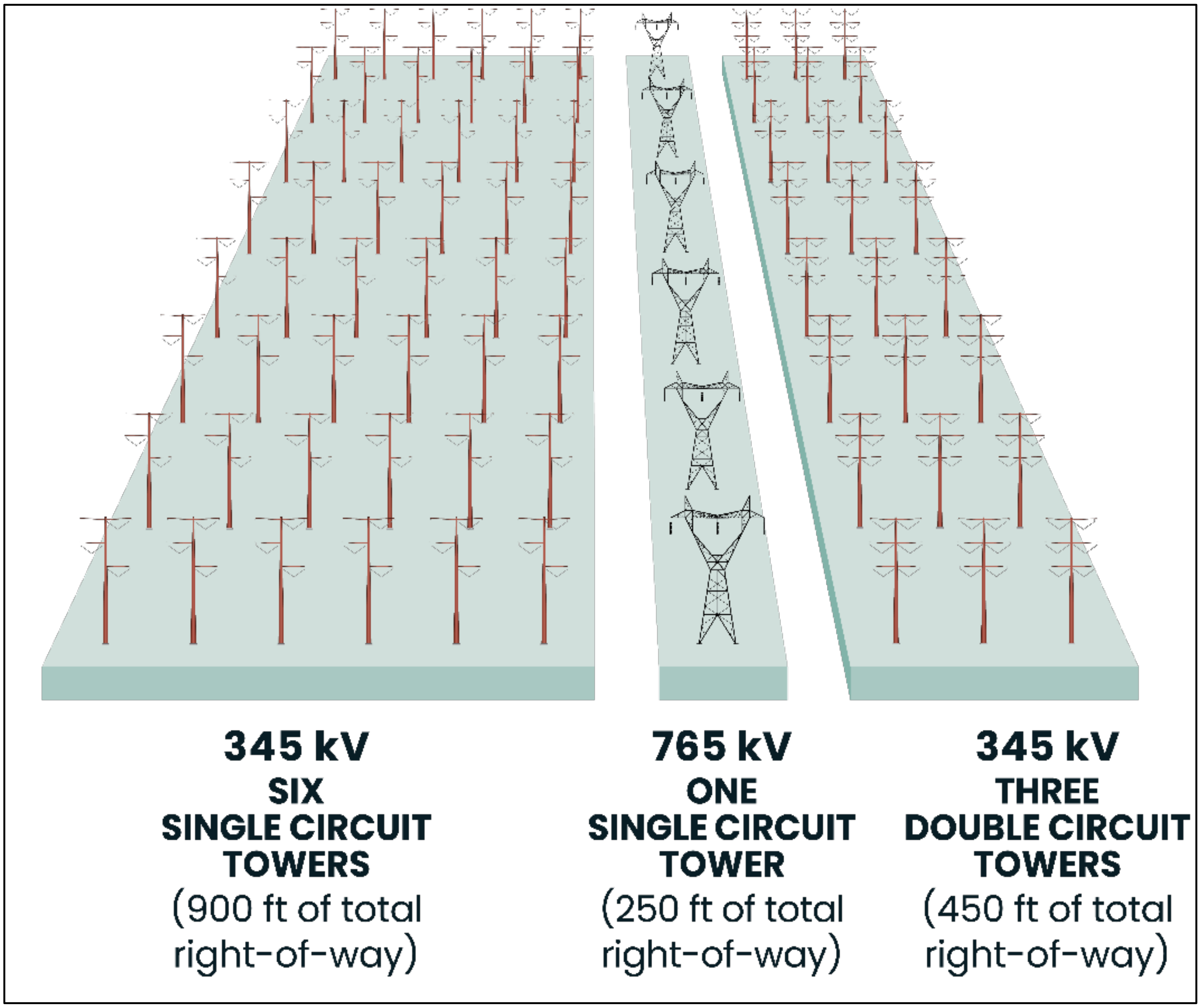
The 765 kV voltage minimizes costs and the amount of right-of-way needed, which minimizes environmental impacts. It would require multiple 345 kV corridors resulting in more right-of-way to create the same capabilities as a single 765 kV right-of-way, as shown in **MISO Figure 7.2-1** and **Table 7.2-1.**

188 See Section 6.1.

189 Cost estimates based on MISO MTEP24 approved scope and costs. See **Appendix E.1**. Page 145.

190 Minnesota's high-voltage network is largely 345 kV with a few 500 kV lines primarily connecting to Manitoba.

Figure 7.2-1: Comparison of Total Right-of-Way Width Based on General Capacities of Each Voltage Class (Not to Scale) [191]



191 **Figure 7.2-1** illustrates total right-of-way width to meet needs for each voltage class. 345 kV and double-circuit 345 kV lines may not be located in a single-common right-of-way, as shown for illustrative purposes; however, the total width of all rights-of-way would equal values displayed on **Figure 7.2-1**. See **Table 7.2-1** for additional details.

TABLE 7.2-1 Comparison of Land Impacts to Meet Reliability Needs by Voltage Class				
Voltage Class	**Number of Lines Needed to Provide Equivalent Capability as one 765 kV Line [a]**	**Approximate ROW Needs for Each Line (feet)**	**Total ROW Width (feet)**	**Total Impacted Acreage for 410 Miles [b]**
345 kV Single-Circuit	6	150	900	44,727
345 kV Double-Circuit	3	150	450	22,364
765 kV (Studied Projects)	1	250	250	12,424

[a] MISO. See **Appendix E.1.** Page 35.
[b] Mileage for Minnesota portion of the Studied Projects (MISO LRTP numbers 22 through 26).

The 765 kV voltage is also the least-cost option to transfer the necessary level of energy. As shown in **Table 7.2-2**, 765 kV transmission costs are half the costs of single- or double-circuit 345 kV options that have the equivalent capability.

TABLE 7.2-2 Comparison of Costs to Meet Reliability Needs by Voltage Class			
Voltage Class	**Approximate Cost for each line [a] (million/mile, $2024)**	**Number of Lines Needed to Provide Equivalent Capability as one 765 kV Line [b]**	**Approximate Total Costs (million/mile, $2024)**
345 kV Single-Circuit	3.6	6	$21.6
345 kV Double-Circuit	6.0	3	$18.0
765 kV (the Project)	5.7	1	$5.7

[a] MISO. MTEP24 Cost Estimation Guide. Available at: https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf. Table 4.1-1 and 4.1-2.
[b] MISO. See **Appendix E.1.** Page 35

While the Project is the first 765 kV line in the Upper Midwest, approximately 2,400 miles of 765 kV lines have been safely and reliably operating in the United States for decades (see **Section 3.2.1**). 765 kV transmission technology has been included in long-term plans for the Upper Midwest since 2009. Previous evaluations of 765 kV in the Upper Midwest include:

- Green Power Express: Approximately 3,000 miles of 765 kV across 7 states proposed by ITC in 2009 to enable the interconnection of approximately 60 GW of generation. The Green Power Express did not move forward due to an insufficient underlying system and lack of cost allocation mechanism.

- MISO MVP & Precursor Studies: In the 2000s, MISO conducted multiple studies considering 345 kV, 765 kV, and high voltage direct current (HVDC) overlays. MISO selected a primarily 345 kV overlay, with some 765 kV, as it met system needs at the time for the least costs.[192]

[192] MISO Regional Generator Outlet Study. Available at: https://cleangridalliance.org/_uploads/_media_uploads/_source/RGOS_Overview.pdf.

- MISO LRTP Tranche 1: MISO's long-term view consistently included transmission greater than 345 kV including 765 kV.[193] MISO LRTP Tranche 1 did not include 765 kV because the underlying system at that time could not support the higher voltage, and the 345 kV voltage could meet the system needs.

Today, each of the conditions necessary for 765 kV is present, including:

- **Need:** Best option considering technical performance, cost, impacts, etc.
- **Sufficiently robust underlying system to:**
  - Meet NERC reliability criteria: National standards require that the system be capable of maintaining reliability should there be an outage of a transmission line.
  - Fully utilize the Project: Underlying system has capacity to move power to and from the 765 kV network.
- **Mechanisms to share costs:** Regional buildouts require significant capital and sign-off from all utilities to pay their share. The Project and MISO LRTP Tranche 2.1 Portfolio are a coordinated buildout which allows each state to maintain reliability more cost-effectively.

7.2.1 Lower Voltage Alternative

The Applicants evaluated a lower-voltage double-circuit 345 kV transmission line with the same endpoints to determine if it could meet the need for the Studied Projects (the Lower-Voltage Alternative).[194] The Lower-Voltage Alternative replaced the 765 kV facilities in the Studied Projects with double-circuit 345 kV facilities and included the 345 kV circuit between the Pleasant Valley Substation, North Rochester Substation, and Hampton Substation that is part of the Project. The Applicants' evaluation of the Lower-Voltage Alternative tested MISO's conclusion that multiple 345 kV transmission lines would be required to provide the same capabilities as a 765 kV transmission line proposed as part of the Project.

The Applicants estimate that the cost of the Lower-Voltage Alternative is $5,022 million ($2024).[195] The Applicants evaluated the electrical performance of the Lower-Voltage Alternative using steady-state, production cost, and stability analysis. Unless noted, all analyses and assumptions for the Lower-Voltage Alternative are consistent with the Project's analysis detailed in **Section 6.2**.

As detailed in the following sections**,** the Applicants' analysis concluded that a single double-circuit 345 kV line was inadequate to meet the needs identified in **Section 7.1.1**. This means that multiple double-circuit 345 kV facilities would be required to provide transmission capacity equivalent to the Studied Projects' single 765 kV circuit facilities. Even two double-circuit 345 kV circuits are more costly and more land-impactful than the single 765 kV circuit Studied Projects' facilities as shown in **Tables 7.1-1 and 7.1-2**. Consequently, an alternative of multiple double-circuit 345 kV facilities was considered but rejected.

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193 MISO. MTEP 21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary. https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf. Page 17.

194 The Applicants also considered but did not evaluate in detail a 500 kV alternative, as 500 kV has similar electrical capacity and similar costs as a double-circuit 345 kV.

195 Cost per mile shown in **Table 7.2-2.**

Section 7.5 describes the Applicants' evaluation of pairing the Lower-Voltage Alternative with existing system upgrades and non-wire alternatives.

7.2.1.1 Lower-Voltage Alternative Reliability Analysis

As shown in Table 7.2-3, the Lower-Voltage Alternative does not fully address the NERC steady-state reliability violations mitigated by the Studied Projects.[196] The Lower-Voltage Alternative does not adequately "pull" power flows off the underlying system during high transfer conditions and thus violations remain at each of the "weakest" points across Minnesota and the surrounding area.

TABLE 7.2-3

Steady-State Reliability Analysis: Lower-Voltage Alternative Comparison

Solution	All	>200 kV
Studied Projects (765 kV)	80	25
Lower-Voltage Alternative (double-circuit 345 kV)	67	23

The Applicants also compared the ability to maintain energy adequacy (ability to serve load every hour of every day) between the Lower-Voltage Alternative and the Studied Projects. As shown in **Table 7.2-4**, the Lower-Voltage Alternative does not mitigate the same level of load at risk of being unserved as the Studied Projects.

TABLE 7.2-4

Unserved Demand Analysis: Lower-Voltage Alternative Comparison – Year 2042 Future 2a

Solution	Mitigated Unserved Demand (MWh)	Difference in Mitigated Unserved Demand Compared to Studied Projects (MWh)
Studied Projects (765 kV)	1,305,782	-
Lower-Voltage Alternative (double-circuit 345 kV)	552,233	753,549

[a] Unserved demand is caused by either a lack of generation available or inadequate transmission capacity to move generation to a specific demand site. The Applicants' analysis quantifies the amount of demand that would be at risk of being unserved without the Project, or demand that would need to be served by a future-new dispatchable generation technology at that site. MISO models quantify unserved demand as the sum of "emergency energy" and "flex" output.

The Lower-Voltage Alternative also does not mitigate generation curtailment (wasted energy) to the same level as the Studied Projects as shown in **Table 7.2-5**.

[196] The count of reliability issues mitigated by the Studied Projects shown in **Table 7.2-3**, differs from the count in **Section 6.3.1** due to the treatment of the JTIQ projects. In **Table 7.2-3**, the JTIQ projects are included in both the pre- and post-case in the Applicants' analysis of the Studied Projects and the Lower-Voltage Alternative. The JTIQ projects are included in the Applicants' analysis because they were approved by MISO in 2024. The count in **Section 6.3.1**, provided by MISO, excludes the JTIQ projects in both the pre- and post-case as when MISO performed their analysis the JTIQ projects were not MISO approved. In both cases, the only difference between the pre- and post-case is the Studied Projects or alternative. Both counts consistently highlight the need for the Studied Projects to mitigate NERC reliability issues.

TABLE 7.2-5 Wind and Solar Generation Curtailment Analysis: Lower-Voltage Alternative Comparison – Year 2042 Future 2a		
Solution	**Reduction in Curtailed Generation from Solution (MWh)**	**Difference in Curtailed Generation Compared to Studied Projects (MWh)**
Studied Projects (765 kV)	7,207,981	-
Lower-Voltage Alternative (double-circuit 345 kV)	4,605,138	2,602,843

7.2.1.2 Lower-Voltage Alternative Stability Analysis

As summarized in **Table 7.2-6**, the Lower-Voltage Alternative does not fully address instability issues addressed by the Studied Projects.

TABLE 7.2-6 Dynamic Stability Analysis Comparison: Lower-Voltage Alternative		
System Stability Maintained with Outage of:	**Studied Projects (765 kV)**	**Lower-Voltage Alternative (double-circuit 345 kV)**
Parallel path 765 kV lines in Iowa and Illinois (Twinkle to Sub T or Sub T to Woodford County 765 kV)	Yes	No
King to Eau Claire 345 kV line	Yes	No
One Alexandria to Bison 345 kV line	Yes	No

The projects in the MISO LRTP Tranche 2.1 Portfolio were designed and optimized to work together to meet the needs of the region. The Studied Projects serve as a “contingency back-up” to maintain system stability when other projects in the MISO LRTP Tranche 2.1 Portfolio are out of service, namely the parallel east-west paths in Iowa to Illinois and the path from Fargo to the Twin Cities. As shown in **Table 7.2-6**, the Lower-Voltage Alternative is not capable of addressing dynamic stability issues during outages of these transmission lines.

Additional details on the stability comparative analysis are included in **Appendix E.3**.

7.2.1.3 Lower-Voltage Alternative Economic Analysis

The Applicants compared the Lower-Voltage Alternative and the Studied Projects’ ability to reduce system congestion. As shown in **Table 7.2-7**, the Lower-Voltage Alternative does not provide the same magnitude of congestion and fuel savings as the Studied Projects.

TABLE 7.2-7 Congestion and Fuel Savings Comparison: Lower-Voltage Alternative, MISO Region 20-Year Net Present Value Future 2A – 7 Percent Discount Rate		
Solution	**Congestion and Fuel Savings – MISO Midwest Footprint ($2024)**	**Difference in Savings (millions)**
Studied Projects (765 kV)	$1.600 billion	-
Lower-Voltage Alternative (double-circuit 345 kV)	$966 million	$-634 (less savings)

7.2.2 Higher-Voltage Alternatives

765 kV is currently the highest AC voltage class in production and operating in the United States. Thus, higher-voltage AC alternatives are not a viable alternative to the Project.

7.3 GENERATION AND NON-WIRES ALTERNATIVES

The Applicants evaluated generation and non-wires alternatives, including new peaking generation, renewable generation, battery energy storage, distributed generation, nuclear generation, demand-side management and conservation measures, and reactive power additions.

As detailed in **Chapter 6**, the Studied Projects are needed to maintain NERC reliability standards by addressing system overloads. The Studied Projects increase transfer capability to move electricity from new and existing generation to serve new and existing electrical demands. The ability to transfer more energy is not only needed for reliability but also to efficiently and fully utilize available generating resources (i.e., avoids curtailment or wasted generation). By its nature, transfer capability is created by transmission solutions, not generation. Adding additional generation does not address the core issues addressed by the Studied Projects of:

- Increasing transmission capacity to interconnect with new generation;
- Maintaining local reliability by being able to transfer energy into an area when local generation is not available; and
- Efficiently and fully utilizing generation capacity.

Conversely, in many cases adding additional generation without adding transmission grid capacity to fully interconnect new generation ("generation outlet") exacerbates system issues such as curtailment.

Nonetheless, in the following sections, the Applicants evaluated adding local generation as a direct alternative to the Studied Projects. Adding additional local capacity does not increase generation outlet or transfer capability – rather it addresses energy adequacy issues by adding additional local generation to address times where existing local generation is insufficient to meet demand and/or the existing grid is not capable of transferring enough energy to meet demand; and/or it provides a counter-flow to push back on new generation to avoid a reliability overload.

While the Applicants only evaluated and quantified generation alternatives for Minnesota, and the areas bordering Minnesota this generation alternative approach would also require MISO to adopt a similar strategy, as other states, would be unable to rely on Minnesota generation when their local generation is not available to serve their load.

As detailed in the following sections, no generation alternatives are a more reasonable and prudent alternative to the Studied Projects.

7.3.1 Peaking Generation

The Applicants considered peaking generation as an alternative to the Studied Projects. Peaking generation, in this context, means local dispatchable generation that is interconnected to the transmission system and can run continuously and whenever called upon. The Applicants considered both natural gas and hydrogen as peaking generation fuel sources. The Applicants considered three general configurations for peaking generation: reciprocating internal combustion engine, combustion turbines, and combined cycle generation. The Applicants assumed that each peaking generation addition could be sized exactly to meet system needs.

As discussed in **Section 7.1.2**, the Applicants used the EPRI CPLANET tool to identify the peaking generation additions necessary to address the NERC steady-state reliability needs. Analysis identified that peaking generation additions alone were incapable of addressing all the NERC steady-state reliability needs addressed by the Studied Projects. Peaking generation additions totaling 5,172 MW spread amongst 12 locations were able to solve approximately one third of the steady-state reliability needs of the Studied Projects (or, 23 of 80 facilities addressed by the Studied Projects). The estimated cost for those peaking units based on available technology is as follows:

- **Reciprocating Internal Combustion Engine:** Total estimated capital cost: $6.455 billion ($2024),[197]
- **Combustion Turbines (natural gas):** Total estimated capital cost: $4.282 billion ($2024),[198]
- **Combustion Turbines (hydrogen):** Total estimated capital cost: $4.458 billion ($-024),[199] or
- **Combined Cycle Generation:** Total estimated capital cost: $4.401 billion ($2024).[200]

In addition to the generation additions, it would be necessary to upgrade 56 different transmission elements, estimated to cost approximately $1,649 million, summarized in **Table 7.3-1**, to address the NERC steady-state reliability issues not resolved through the peaking generation additions.

TABLE 7.3-1

System Upgrades in Addition to Peaking Generation Needed to Address NERC Reliability Needs

Scope	Number (unique locations)	Total Miles	Estimated Cost ($2024)
Peaking generation alternative (natural gas CT)	12	-	$4.282 billion
345 kV line upgrade	7	203	$869 million
230 kV line upgrade	3	59	$111 million
161 kV line upgrade	7	106	$190 million
138 kV line upgrade	9	82	$146 million
115 kV line upgrade	23	156	$268 million
Transformer upgrade	6	-	$63 million
Additional transformer	2	-	$19 million
TOTAL	**69**	**604**	**$5.947 billion** [a]

[a] Twenty-year NPV cost using a 7 percent discount rate is $6.255 billion.

[197] EIA. Construction Cost Data for Electric Generators Installed in 2023. Available at: https://www.eia.gov/electricity/generatorcosts/.

[198] EIA. Annual Energy Outlook 2025 at Table 4 (“MISW” region). Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf.

[199] Id.

[200] Id.

Each peaking generation solution, combined with necessary transmission upgrades, may be designed to mitigate the identified NERC reliability issues and for a similar construction cost as the Studied Projects. However, when considering total costs including fuel, congestion, generation curtailment (wasted energy), and emissions, the peaking generation alternative is significantly more costly than the Studied Projects, as shown in **Table 7.3-2**.

It should be noted that to provide the necessary reactive power support, the peaking plants would have to be built and operated to provide reactive power when not outputting real power (MWs) and/or additional reactive power equipment (e.g., capacitors, reactors, and Static Synchronous Compensators [STATCOMs]) would be necessary. As the total cost for the peaking generation alternative already exceeded the cost of the Studied Projects the Applicants did not further evaluate the necessary reactive additions.

TABLE 7.3-2

Total Cost Effectiveness of The Studied Projects Versus Peaking Generation Alternative: 20-Year Net Present Value – 7 Percent Discount Rate ($2024)

		Savings Relative to "Do Nothing" [b] ***Positive value denotes a cost savings***				
	Capital Cost [a]	**Congestion and Fuel**	**Avoided Reliability**	**Asset Renewal**	**Decarbonization**	**Total Costs**
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion – $6.222 billion	($5.927 billion) - ($1.832 billion) [c]
Peaking generation alternative (natural gas combustion turbines)	$6.255 billion	$47 million	$3.705 billion	-	($440 million) – ($1.265 billion)	$2.944 billion - $3.768 billion

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO's planning-level scopes and MISO's MTEP24 cost-estimation guide or equivalent for non-wire alternatives.

[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 value of lost load (VOLL). Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of CO_2 emissions.

[c] Negative values denote a total cost reduction (savings exceed upfront costs)

In addition to a higher total cost, the peaking generation alternative does not allow for future growth or expansion beyond the amount studied – as detailed in **Section 6.6.1** the Studied Projects proactively enable load growth beyond the base forecast. In addition, peaking generation alternatives do not provide similar regional flexibility and resiliency benefits as the Studied Projects as discussed in **Section 6.6.2.** Peaking generation alternatives which utilize fossil fuels also do not help meet the state's Carbon Free by 2040 law. In addition, timing and permitting uncertainty is a concern as each of the 12 generators would need to go through the MISO generator interconnection queue processes and state and local permitting (as appropriate). Most importantly, as discussed in **Section 7.3.1**, peaking generation does not address the core issues of generation outlet and transfer capability, which are addressed by the Studied Projects.

The addition of new peaking generation is not a more reasonable and prudent alternative to the Studied Projects.

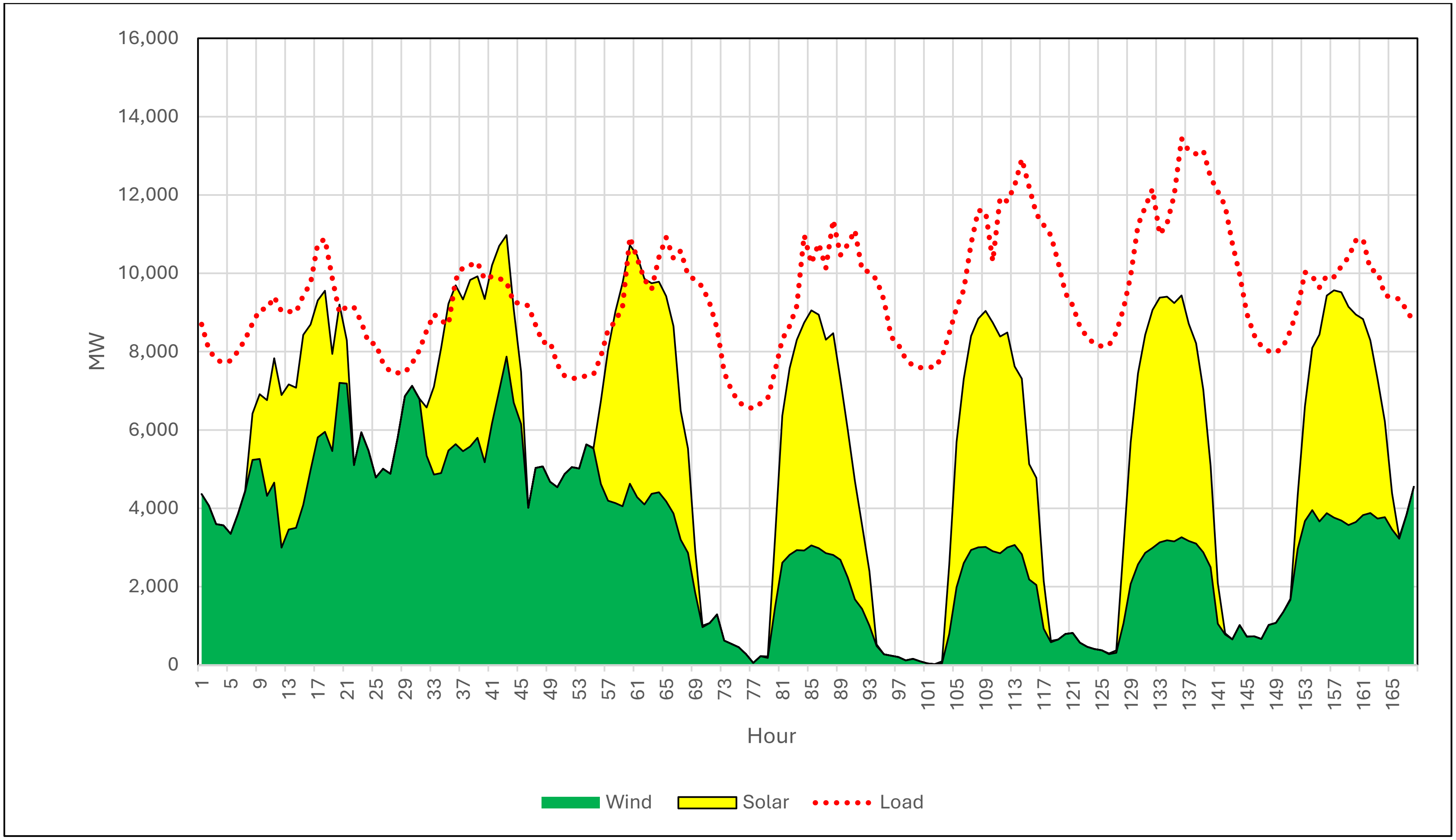
7.3.2 Renewable Generation

The Applicants considered renewable generation (i.e., solar and wind generation) as an alternative to the Studied Projects. The renewable generation may be interconnected at a single location on the transmission system or at multiple locations on the transmission or distribution system.

The Studied Projects help maintain system reliability every hour of every day (energy adequacy) by providing the ability to transfer (import) regional and diverse energy when local generation is not available. As such, a viable generation alternative to the Studied Projects must always be available locally to meet reliability needs. Because renewable generation is dependent on natural events, such as sunlight or wind speed, and cannot be dispatched if those natural conditions are not present, neither wind nor solar generation alone is a viable alternative to the Studied Projects.

As shown on **Figure 7.3-1**, without the multi-state geographic diversity enabled by the Studied Projects and MISO LRTP Tranche 2.1 Portfolio there are hours where there is practically no in-state wind or solar output, and thus no reasonable amount of additional renewable generation will meet the reliability need of the Studied Projects.

Figure 7.3-1: Minnesota Hourly Total Renewable Output During Last Week of July 2018



The Studied Projects are needed to reliably serve load in Minnesota, when local wind and solar levels are at their lowest. During these hours, the Studied Projects facilitate importing generation to Minnesota from other parts of the MISO footprint. Replacing the Studied Projects with additional local renewable generation, subject to the same weather patterns versus geographically diverse renewables, is not viable as it does not address the issue of local generation being unavailable.

The addition of new renewable generation is not a viable alternative to the Studied Projects. The combination of renewable generation with energy storage is discussed in **Section 7.3.3**.

7.3.3 Battery Energy Storage

Energy storage, in this context, means a local battery or some other energy storage technology capable of being charged and discharged when called upon. The Applicants considered and evaluated both 4- and 8-hour energy storage options. Each energy storage option assumes lithium-ion battery technology per the U.S. Department of Energy's National Renewable Electric Laboratory. Any longer-duration storage solutions will be significantly more costly to implement.

Battery storage locations were optimized to meet reliability needs with the minimum amount of storage additions (i.e., lowest capital costs). As such, battery storage locations considered co-location with renewables including wind and solar, demand sources (representative of either utility-scale at load or a collection of distributed storage units), and other strategic places on the transmission system. If storage additions were limited to only one of these locations, the amount of storage necessary to meet reliability needs of the Studied Projects would at-best be more expensive or at-worst be non-viable, as the alternative would address less of the reliability needs of the Studied Projects. The Applicants also considered adding both additional generation and storage (together). The option was rejected, because even with the storage alternative and no additional generation, there is generation curtailment (excess energy which is wasted). Adding additional generation would increase curtailment and capital costs.

As discussed in **Section 7.1.2**, the Applicants used the EPRI CPLANET tool to identify energy storage additions necessary to address the NERC steady-state reliability needs. Analysis identified that energy storage additions alone were incapable of addressing all the NERC steady-state reliability needs addressed by the Studied Projects. Energy storage additions totaling 7,527 MW spread amongst 30 locations were able to solve approximately half of the steady-state reliability needs of the Studied Projects (or, 42 of 80 facilities addressed by the Studied Projects). The estimated cost based on available technology is as follows:

- **Energy Storage:** 7,527 MW total at 30 locations. Total estimated capital cost: \$12.879 billion (\$2024) for 4-hour batteries or \$25.691 billion (\$2024) for 8-hour batteries.[201]

In addition to the storage additions, it is necessary to upgrade 38 different transmission elements estimated to cost approximately \$1.227 billion to address reliability issues which could not be efficiently resolved through storage additions, as shown in **Table 7.3-3**. It should be noted that to provide the necessary reactive power support, the battery additions would have to be built and operated to provide reactive power.

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201 U.S. Department of Energy's National Renewable Electric Laboratory. 2024 Annual Technology Baseline (4-hour and 8-hour battery – moderate maturity curve). Available at: https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.

TABLE 7.3-3 System Upgrades in Addition to Storage Additions to Address NERC Reliability Needs			
Scope	Number (Unique Locations)	Total Miles	Estimated Cost ($2024)
Energy Storage Alternative • 4-Hour Batteries • 8-Hour Batteries	30	-	$12.879 billion $25.691 billion (respectively)
345 kV Transmission Line Upgrade	5	143	$651 million
230 kV Transmission Line Upgrade	3	59	$111 million
161 kV Transmission Line Upgrade	4	78	$141 million
138 kV Transmission Line Upgrade	6	57	$80 million
115 kV Transmission Line Upgrade	15	98	$172 million
Transformer Upgrade	4	-	$44 million
Additional Transformer	1	-	$11 million
TOTAL – 4-Hour Batteries	**68**	**435**	**$14.106 billion** [a]
TOTAL – 8-Hour Batteries	**68**	**435**	**$2626.918 billion** [b]

[a] Twenty-year NPV cost using a 7 percent discount rate is $15.089 billion.
[b] Twenty-year NPV cost using a 7 percent discount rate is $26.918 billion.

Both 4-hour battery and 8-hour battery energy storage options, combined with necessary transmission upgrades, may be designed to mitigate the NERC steady-state reliability issues but each technology offers tradeoffs between upfront costs and economic savings (e.g. congestion and fuel savings); thus, each were further evaluated using production cost models in **Table 7.3-4**. As shown in **Table 7.3-4**, each energy storage alternative has a significantly higher total cost than the Studied Projects.

TABLE 7.3-4 Total Cost Effectiveness of the Studied Projects Versus Battery Energy Storage Alternative: 20-Year Net Present Value – 7 Percent Discount Rate (Millions)						
		Savings Relative to “Do Nothing” [b] *Positive value denotes a cost savings*				
	Capital Cost[a]	Congestion and Fuel	Avoided Reliability	Asset Renewal	Decarbonization	Total Costs
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion – $6.222 billion	(-$5.927 billion) - (-$1.832 billion) [c]
4-Hour Batteries Alternative	$15.089 billion	$383 million	$3.705 billion	-	$231 million - $495 million	$10.506 billion - $10.770 billion
8-Hour Batteries Alternative	$28.896 billion	$461 million	$3.705 billion	-	$364 million - $591 million	$24.139 billion - $24.366 billion

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO’s planning-level scopes and MISO’s MTEP24 cost-estimation guide or equivalent for non-wire alternatives.
[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 VOLL. Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of CO_2 emissions.
[c] Negative values denote a total cost reduction (savings exceed upfront costs).

In addition to a higher total cost, the energy storage generation alternative does not allow for any future growth or expansion beyond the amount studied – as detailed in **Section 6.6.1** the Studied Projects proactively enable load growth beyond the base forecast. In addition, peaking generation alternatives do not provide similar regional flexibility and resiliency benefits as the Studied

Projects as discussed in **Section 6.6.2.** In addition, timing and permitting uncertainty are a concern as each of the 30 batteries would need to go through the appropriate MISO processes as well as state and local permitting (as appropriate). Most importantly, as discussed in **Section 7.3**, energy storage does not address the core issues of generation outlet and transfer capability, which are addressed by the Studied Projects.

The addition of energy storage is not a more reasonable and prudent alternative to the Studied Projects.

7.3.4 Distributed Generation

Distributed generation is typically smaller-scale generation that is connected to the local distribution system. Distributed generation can be dispatchable generation, which is able to run continuously when called upon, most likely on diesel, natural gas, or other fossil fuels. Distributed generation can also be renewable and/or battery energy storage.

Dispatchable distributed and renewable generation have the same fundamental limitations as transmission-connected peaking, renewable generation, and battery energy storage, as discussed in **Sections 7.3.1, 7.3.2, and 7.3.3,** but at a greater cost.[202] Therefore, the addition of new dispatchable or renewable distributed generators is not a more reasonable and prudent alternative to the Studied Projects.

7.3.5 Nuclear Generation

Minnesota currently has a nuclear power moratorium in place, preventing the construction of new nuclear power facilities.[203] Thus nuclear is not a viable alternative to the Project. Nonetheless, given public interest in potential new nuclear technologies, the Applicants evaluated nuclear options.

Nuclear generation, in this context, is a thermal power station in which the power source is a nuclear reactor. The Applicants considered two general configurations for nuclear generation: utility-scale nuclear plants and small modular nuclear reactors (SMRs). SMRs are an emerging technology. In the United States, SMRs are in the research and prototype phase and not in wide commercial deployment.[204] For analysis purposes, the Applicants assumed each SMR can be sized exactly to meet reliability needs. The Applicants assumed that each large-scale nuclear plant was 1,000 MW. Each nuclear generator (utility-scale or SMR) was assumed to have a minimum generation dispatch of 25 percent of nameplate capacity.

As discussed in **Section 7.1.2**, the Applicants used the EPRI CPLANET tool to identify nuclear generation additions necessary to address the NERC steady-state reliability needs. The following SMR nuclear generation additions were able to solve approximately one-third of the steady-state reliability needs of the Studied Projects (or, 23 of 80 facilities addressed by the Studied Projects). The estimated cost based on available technology is as follows:

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[202] A distributed peaking generation has an overnight construction cost of $1,929/kW ($-2024) compared to $828/kw for a utility-scale combustion turbine. Source: US Energy Information Administration, Annual Energy Outlook 2025 at Table 4 ("MISW" region). EIA. Assumptions to the Annual Energy Outlook

[203] Minn. Stat. § 216B.243, subdivision 3b.

[204] U.S. Department of Energy. Advanced Small Modular Reactors. Available at: https://www.energy.gov/ne/advanced-small-modular-reactors-smrs.

- **SMR:** 5,172 MW total at 12 locations. Total estimated capital cost: $49.284. billion ($2024).[205]

The Applicants considered but rejected a utility-scale nuclear option as to address reliability. As each utility-scale nuclear plant is assumed to have a minimum capacity size of 1,000 MW, adding 12,000 MW of nuclear generation (one unit per site) is not a reasonable or prudent alternative

In addition to the SMR nuclear additions, it would be necessary to upgrade 57 different transmission elements, estimated to cost approximately $1.655 million, summarized in **Table 7.3-5**, to address the NERC steady-state reliability issues not resolved through nuclear generation additions.

TABLE 7.3-5

System Upgrades in Addition to Nuclear Generation Needed to Address NERC Reliability Needs

Scope	Number (Unique Locations)	Total Miles	Estimated Cost ($2024)
SMR Nuclear Alternative	12	-	$49.289 billion
345 kV Transmission Line Upgrade	7	203	$869 million
230 kV Transmission Line Upgrade	3	59	$111 million
161 kV Transmission Line Upgrade	7	106	$190 million
138 kV Transmission Line Upgrade	9	82	$146 million
115 kV Transmission Line Upgrade	23	156	$268 million
Transformer Upgrade	6	-	$63 million
Additional Transformer	2	-	$19 million
TOTAL	**69**	**604**	**$50.949 billion** [a]

[a] Twenty-year NPV cost using a 7 percent discount rate is $54.754 billion.

Nuclear generation additions, combined with necessary transmission upgrades, may be designed to mitigate the identified NERC reliability issues and further reduce carbon dioxide emissions; however, at a significantly higher cost than the Studied Projects, as shown in **Table 7.3-6**.

[205] EIA. Annual Energy Outlook 2025 at Table 4 (“MISW” region). Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf.

TABLE 7.3-6

Total Cost Effectiveness of the Studied Projects Versus SMR Nuclear Generation Alternative: 20-Year Net Present Value – 7 Percent Discount Rate (Millions)

	Capital Cost [a]	Savings Relative to "Do Nothing" [b] *Positive value denotes a cost savings*				Total Costs
		Congestion and Fuel	Avoided Reliability	Asset Renewal	Decarbonization	
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion – $6.222 billion	($5.927 billion) - ($1.832 billion) [c]
SMR nuclear alternative	$54.754 billion	$854 million	$3.705 billion	-	$2.868 billion - $8.385 billion	$41.810 billion-$47.327 billion

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO's planning-level scopes and MISO's MTEP24 cost-estimation guide or equivalent for non-wire alternatives.

[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 VOLL. Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of CO_2emissions.

[c] Negative values denote a total cost reduction (savings exceed upfront costs).

In addition to a higher total cost, the nuclear generation alternative does not allow for any future growth or expansion beyond the amount studied – as detailed in **Section 6.6.1** the Studied Projects proactively enable load growth beyond the base forecast. In addition, nuclear generation alternatives do not provide similar regional flexibility and resiliency benefits as the Studied Projects, as discussed in **Section 6.6.2**. Even if Minnesota's nuclear moratorium where lifted, timing and permitting uncertainty is a concern as each of the 12 generators would need to go through the MISO queue processes and state and local permitting (as appropriate). Most importantly, as discussed in **Section 7.3.5**, nuclear generation does not address the core issue addressed by the Studied Projects – generation outlet and transfer capability.

The addition of new nuclear generation is not a more reasonable and prudent alternative to the Studied Projects.

7.3.6 Demand Side Management/Conservation

The Applicants considered demand-side management/conservation as an alternative to the Studied Projects. In this context, demand side management/conservation is assumed to encompass all forms of peak shaving and load reduction programs, such as interruptible loads and dual fuel programs, as well as more general energy conservation programs, such as energy-efficiency rebates. It should be noted that MISO's models assume implementation of current demand side management and conservation plans and an expected forecast for program growth as detailed in **Appendix G**. This alternative considers adding additional demand side management and conservation beyond the base forecast to attempt to address NERC reliability needs. The demand side management/conservation alternative is sized as the minimal amount of load which would have to be reduced to avoid NERC reliability issues without the Studied Projects.

As discussed in **Section 7.1.2**, the Applicants used the EPRI CPLANET tool to identify demand side management/conservation programs necessary to address the NERC steady-state reliability needs. Analysis identified that demand side management/conservation alone was incapable of addressing all the NERC steady-state reliability needs addressed by the Studied Projects. Demand side management/conservation program additions totaling 5,122 MW were able to solve approximately one third of the steady-state reliability needs of the Studied Projects (or, 28 of 80 facilities addressed by the Studied Projects). In addition to the demand side management/conservation additions, at a minimum, it would be necessary to upgrade the transmission grid to address each of the outstanding NERC reliability issues.

Although conservation programs will continue to be implemented in the area of the Studied Projects area to encourage efficient use of electricity, it is unrealistic for these programs to reach the significant levels of load reduction required to maintain grid reliability. For these reasons, solutions involving demand-side management/conservation are not a more reasonable and prudent alternative to the Studied Projects.

7.3.7 Reactive Power Additions

The Applicants considered implementing additional reactive power additions to support reliability. Reactive power additions, in this context, mean transmission technology capable of providing reactive power and voltage support to the system through the use of traditional electromechanical devices such as switched capacitor banks and reactors, flexible AC transmission system devices such as static volt-amperes reactive compensators or STATCOMs, or synchronous condensers. Unlike generation or energy storage solutions, reactive power additions do not produce any active or real power (i.e., MWs) for consumption by end-use customers, meaning this alternative is not capable of providing real power support when local generation is not available, as discussed for previous generation and non-wires alternatives. Instead, reactive power solutions enable increased interface transfer capability by providing voltage support where needed to prevent voltage collapse.

While a reactive power addition may contribute to resolving or reducing the severity of the reliability issues, reactive power additions alone cannot satisfy all the needs of the Studied Projects. This is because existing transmission lines become overloaded when transferring power to, through, or out of Minnesota. Reactive power additions alone cannot mitigate these steady-state overloads on the transmission line, meaning that the additional existing system upgrades described in **Sections 7.3 and 7.4** would also be required. For these reasons, solutions involving only reactive power additions are not a more reasonable and prudent alternative to the Studied Projects.

7.4 TRANSMISSION ALTERNATIVES

7.4.1 Existing System Upgrades

The Applicants considered upgrading existing transmission facilities as an alternative to the Studied Projects (the Existing System Upgrades Alternative). For this analysis, existing system upgrades consisted of rebuilding overloaded transmission lines and facilities to a higher capacity and adding capacitor banks. Upgrading of existing transmission implies the installation of new conductors and/or equipment on existing transmission structures; however, as this definition did not meet reliability needs provided by the Studied Projects, the Applicants also considered a rebuild of existing transmission lines (including structures) to higher capacity and voltage levels.

The Existing System Upgrades Alternative was developed in an iterative fashion to resolve the NERC steady-state reliability violations and energy adequacy issues described in **Sections 6.3.1, 6.3.2, and 6.3.5**. Where transmission line overloads were identified, the existing transmission lines were upgraded to higher capacity. If the higher-capacity line was not sufficient to mitigate the reliability issue, the line was rebuilt as a double-circuit, and then at the next higher voltage level. Reactive power additions (e.g., capacitors, reactors, and STATCOMs) were added to provide the equivalent level of reactive power support as the Studied Projects. Analysis continued iteratively until all steady-state reliability issues mitigated by the Studied Projects were resolved. The resulting Existing System Upgrades Alternative is detailed in **Table 7.4-1**.

TABLE 7.4-1

Existing System Upgrades Alternative Scope

Scope	Number (Unique Locations)	Total Miles	Estimated Cost ($2024)
345 kV Transmission Line Upgrade	15	735	$2.800 billion
230 kV Transmission Line Upgrade	3	47	$89 million
161 kV Transmission Line Upgrade	17	230	$458 million
138 kV Transmission Line Upgrade	10	87	$154 million
115 kV Transmission Line Upgrade	42	294	$504 million
Transformer Upgrade	6	-	$63 million
Additional Transformer	4	-	$45 million
Reactive Support (Capacitors, STATCOMs)	-	-	$1,261 billion
TOTAL	**97**	**1,394**	**5.376 billion** [a]

[a] Twenty-year NPV cost using a 7 percent discount rate is $5.297 billion.

Based on MISO's Transmission Cost Estimate Guide for MTEP24,[206] the Applicants estimate the cost for these upgrades to be at least $5.376 billion. Timing and constructability are a concern for the existing system upgrades alternative, as it would require extended, coordinated outages on 87 individual transmission lines as well as shorter bus outages at multiple substations which can result in extended market congestion and marginal system reliability. In addition, prior to construction each upgrade would need to go through MISO's planning process and then be engineered and permitted by federal, state, and local agencies (as applicable).

If constructability and timing concerns could be managed, existing system upgrades may be designed to mitigate the identified NERC reliability issues. However, when considering total costs including congestion, generation curtailment (wasted energy), and generation dispatch costs, the existing system upgrade alternative costs more than the Studied Projects, as shown in **Table 7.4-2**.

[206] MISO. Cost Estimation Guide / Workbook for MTEP 24. Available at: https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf.

TABLE 7.4-2

Total Cost Effectiveness of the Studied Projects Versus Existing System Upgrade Alternative: 20-year Net Present Value – 7 percent discount rate ($2024)

	Capital Cost [a]	Savings Relative to "Do Nothing" [b] *Positive value denotes a cost savings*				Total Costs
		Congestion and Fuel	Avoided Reliability	Asset Renewal	Decarbonization	
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion – $6.222 billion	($5.927 billion) - ($1.832 billion) [c]
Existing System Upgrades Alternative	$5.297 billion	$178 million	$3.705 billion	-	$326 million - $952 million	$463 million - $1.088 billion

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO's planning-level scopes and MISO's MTEP24 cost-estimation guide.

[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 VOLL. Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of carbon emissions.

[c] Negative values denote a total cost reduction (savings exceed upfront costs)

It should be emphasized that while the Existing System Upgrades Alternative addresses the minimum NERC reliability requirements, it does not provide the same level of operational reliability. As detailed in **Section 6.3.4**, in addition to the core steady-state overloads, the Studied Projects address overloads of 24 additional facilities under lower-probability higher-impact events. As the total costs of the Existing System Upgrades Alternative already exceeded the cost of the Studied Projects, the Applicants did not quantify the incremental upgrades necessary to provide an equivalent level of operational reliability as the Studied Projects.

In addition, the Existing System Upgrades Alternative does not provide the same level of future flexibility or optionality. The MISO LRTP Tranche 2.1 Portfolio, including the Studied Projects, was intentionally designed as the "foundation" to not only meet today's system needs, but to be built upon to more efficiently meet potential future needs. In simple terms the Existing System Upgrades Alternative would be "full" on day 1 whereas the Studied Projects would still have space to accommodate future changes and options for further expansion. More specifically:

- The Existing System Upgrades Alternative does not allow for future growth or expansion beyond the amount studied – as detailed in **Section 6.6.1** the Studied Projects proactively enable load growth beyond the base forecast. Future load growth or additional changes on the system would continue to drive additional incremental upgrade needs for the foreseeable future.

- In addition, the Existing System Upgrade Alternative does not provide similar regional flexibility and resiliency benefits as the Studied Projects as discussed in **Section 6.6.2**.

For all these reasons, upgrading of existing facilities is not a more reasonable or prudent alternative to the Studied Projects.

7.4.2 Alternative Endpoints

The Applicants did not consider alternative transmission line endpoints for the Studied Projects. Pursuant to Minn. Stat. § 216B.243, subd. 3(6),[207] the Applicants are not required to evaluate 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 (i.e., MISO) transmission plan, or (ii) otherwise agreed to for further evaluation by the applicant.

MISO, in its identification of the Studied Projects and the LRTP Tranche 2.1 Portfolio considered multiple configurations and endpoints. After multiple rounds of analysis, MISO selected the Studied Projects and LRTP Tranche 2.1 Portfolio as the optimal configuration to meet regional system needs. Additional information on MISO's evaluation of alternative system endpoints can be found in **Appendix E.1**.[208]

7.4.3 Double Circuiting Considerations

Double-circuiting is the construction of two separate transmission circuits (three phases per circuit) on the same structure. Placing two transmission circuits on common structures generally reduces right-of-way requirements, which potentially reduces human and environmental impacts.

The 765 kV portions of the Project are proposed as a single 765 kV circuit to meet MISO's identified needs. As discussed in **Section 6.6.2**, the Project is proactively designed to support a reasonable amount of future system needs. Unlike other voltage classes (e.g., 345 kV) where double-circuit transmission structures of the same voltage are common, all existing 765 kV structures in the United States carry a single 765 kV circuit. Double-circuiting 765 kV transmission lines presents reliability, maintenance, and practical challenges.

- **Reliability challenges:** Reliability standards established by NERC require that the transmission system is planned to be able to withstand potential contingencies, including the loss of all circuits on a common structure. For a double-circuit 765 kV line, the remaining transmission system would need to be planned to maintain reliability during the simultaneous outage of two 765 kV lines. As two 765 kV lines carry the equivalent as twelve 345 kV lines, the underlying system would need to be significantly developed to provide adequate contingency back-up.

- **Maintenance considerations:** When multiple circuits share common structures, performing maintenance on one circuit may require the use of specialized live-line procedures and additional safety controls to keep adjacent circuits energized. If live-line work is not feasible for the task, then all circuits on the shared structure must be de-energized to ensure worker safety. As MISO coordinates outages to ensure ongoing system reliability, trying to schedule simultaneous outages involving multiple 765 kV circuits on a common tower is more difficult than if each circuit could be maintained separately without taking the others out of service at the same time. The backbone nature of 765 kV increases the difficulty and

207 "[T]he 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."

208 See **Appendix E.1**. Page 42.

criticality of trying to schedule outages. In addition, taller or more specialized structures required for the double-circuit may require specialized equipment and maintenance practices.

- **Practical siting challenges:** The Project's single-circuit 765 kV is configured with the phases horizontally aligned to minimize structure heights and comply with all applicable state and federal safety and engineering standards. Double-circuit structures require lines to have the phases either be configured vertically or multiple horizontal elevations. Regardless of design, given the necessary clearances, double-circuit structure heights would likely exceed 200 feet and require lighting in accordance with FAA guidance. In addition to taller heights, the additional conductor and arms weight will result in more robust (i.e., more steel) and costly structures.

While a double-circuit 765/765 kV presents the reliability and siting challenges discussed above, MISO identified Segment 2 as a double-circuit 765/161 kV line based in part on utilizing an existing transmission line crossing of the Mississippi River. The existing 161 kV transmission crossing corridor near Genoa, Wisconsin presents a unique opportunity to double-circuit with a lower voltage (i.e., 161 kV) line while also reducing the reliability concerns presented by double-circuiting higher voltage lines. The existing 161 kV circuits being double-circuited consist of multiple segments connecting to existing substations throughout the corridor, meaning loss of a portion of the double-circuit line will not result in complete loss of the 161 kV circuits—power can be backfed from adjacent stations, and each 161 kV station has an alternate source available. This contrasts with a 765 kV/765 kV configuration where both circuits typically serve the same terminal substations, eliminating redundancy over the entire segment. In addition, Dairyland's existing 161 kV line is aging, creating additional economic benefits to rebuilding the lines as part of this Project.

As part of the Segment 2 design, the Applicants completed rigorous vetting of the 765/161 kV configuration. This included thorough analysis of the following: electrical induction of the 765 kV circuit on the 161 kV circuit under normal operations, maintenance, and transient conditions; electric and magnetic fields; audible noise; right-of-way width evaluation; induction on vehicles and other objects in compliance with the NESC 5mA rule; NESC clearance requirements; lightning protection and grounding; insulation coordination; structure configuration development; live line maintenance, climbing space, and work space; and all other preliminary design calculations and modeling. The comprehensive vetting process confirmed the viability, safety, and efficiency of the design to support both the proposed 765 kV and existing 161 kV circuits. The configuration leverages and expands the existing 161 kV right-of-way to accommodate the proposed 765 kV / 161 kV double-circuit to minimize corridor expansion and associated impacts.

7.4.4 High Voltage Direct Current

HVDC lines are typically proposed for transmitting large amounts of electricity over long distances because line losses are less than an AC line. HVDC lines require converter stations at each delivery point because the DC power must be converted to AC power before customers can use it. A single 600 kV or 640 kV HVDC converter station can be upwards of $750 million to $900 million, respectively.[209] The converter station costs do not include nor obviate the need for line

[209] MISO. Cost Estimation Guide / Workbook for MTEP 2024. Available at: https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf Table 4.3

construction and AC substation upgrades. Such converter stations would add significantly to the cost of the Project as the Project has three 765 kV delivery points (i.e., substations) in Minnesota and three additional delivery points outside of Minnesota.

HVDC lines are typically proposed for large regional transmission projects that involve hundreds of miles of new transmission line between two delivery points. As a general rule, HVDC becomes a cost-effective alternative to AC transmission when the line length is greater than 260 miles and high transfer capability is needed.[210] As detailed in **Section 1.2.1**, the Studied Projects is made up of a series of individual facilities, each providing delivery points between generation and demand. The Studied Project's longest line, between the Lakefield Junction Substation and the Pleasant Valley Substation, is 130 miles, which is much shorter than the threshold for which HVDC is cost effective.

HVDC is not a more reasonable and prudent alternative for the Project.

7.4.5 <u>Underground</u>

Undergrounding has not been used for 765 kV transmission lines. Underground 765 kV cable is not currently available from cable manufacturers. Development of a new voltage class of cable system takes several years through design, prototypes, and qualification testing.

Even if an underground design were feasible, the construction cost of placing the entire length of the Project's proposed transmission line underground is currently unknown, as this would involve the engineering and construction of an unprecedented voltage level that has never been developed or placed underground before. However, based on existing cost comparisons for 345 kV and 500 kV lines, underground installation is expected to be more than five times as expensive per mile as compared to the proposed overhead construction.

The largest AC voltage underground transmission lines that are in service today are 500 kV. In the United States, the most comparable project is the Tehachapi Renewable Transmission Project in Chino Hills, California.[211] The Tehachapi Renewable Transmission Project undergrounded an approximately 3.5-mile segment of a 500 kV line. The cost for the undergrounding the 3.5-mile 500 kV segment was estimated at $247 million, or approximately $70 million per mile in 2014.[212] For reference, the Project's 765 kV overhead transmission lines are estimated to cost approximately $7.4 million per mile.[213] It should be emphasized that the Tehachapi Renewable Transmission Project is also at a lower voltage level than the Project.

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210 MISO. Discussion of Legacy, 765 kV, and HVDC Bulk Transmission. Available at: https://cdn.misoenergy.org/20230308%20PAC%20Item%2007%20Discussion%20of%20765%20kV%20and%20HVDC628088.pdf. Slide 6.

211 T&D World. Engineering a 500 kV Underground System. Available at: https://www.tdworld.com/intelligent-undergrounding/article/20969593/engineering-a-500-kv-underground-system.

212 See In the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Tehachapi Renewable Transmission Project (Segments 4 through 11), Docket No. A0706031, Decision Granting the City of Chino Hill's Petition for Modification of Decision 09-12-044 and Requiring Undergrounding of Segment 8A of the Tehachapi Renewable Transmission Project, at 2-3, 22, 47 (July 11, 2013); Decision Granting, in part, the Petition of SCE for Modification of Decision 13-07-018, at 10 (Jan. 16, 2014).

213 Escalation range based on Handy-Whitman Index of Public Utility Construction Costs for 2014 (Pacific Region) to 2025 (Central Region). Range indicative of escalation of total transmission plan (low end) and underground conductor, conduit, and devices (high end). The Handy-Whitman Index of Public Utility

The installation of an underground 765 kV transmission line is not a feasible, reasonable, or prudent alternative for any portion of the Project.

7.5 ANY REASONABLE COMBINATION OF ALTERNATIVES

The Applicants also considered combinations of generation/non-wire and transmission alternatives to the Studied Projects. The Applicants analyzed two combinations of alternatives:

- Lower-Voltage Alternative with existing system upgrades; and
- Lower-Voltage Alternative with peaking generation or storage.

The Applicants analyzed these two combinations to represent the optimized combinations of the Lower-Voltage Alternative and transmission and generation alternatives (respectively). It should be noted that in the evaluation of generation and non-wire alternatives in **Section 7.3** the Applicants considered the combination of generation alternatives and existing system upgrades.

As detailed in the following sections, none of the combined alternatives is a more reasonable and prudent alternative to the Studied Projects.

7.5.1 Combination of Lower-Voltage Alternative and Existing System Upgrades

The Applicants evaluated combining the Lower-Voltage Alternative and existing system upgrades. The scope of the combined alternative was developed by starting with the Lower-Voltage Alternative described in **Section 7.2.1** and then adding existing system upgrades to mitigate the remaining NERC reliability violations using the iterative process described in **Section 7.4.1.** The scope of the resulting combined alternative is shown in **Table 7.5-1**.

TABLE 7.5-1

Combined Lower-Voltage Alternative and Existing System Upgrades Alternative Scope

Scope	Count (unique locations)	Total Miles	Estimated Cost ($2024)
Lower-Voltage Alternative (*see* **Section 7.2.1**)	-	840	$5.022 billion
230 kV Transmission Line Upgrade	2	31	$59 million
161 kV Transmission Line Upgrade	1	17	$30 million
138 kV Transmission Line Upgrade	2	17	$44 million
115 kV Transmission Line Upgrade	6	53	$80 million
Transformer Upgrade	1	-	$8 million
Additional Transformer	2	-	$21 million
Reactive Support (Capacitors, STATCOMs)	-	-	$1.106 billion
TOTAL	**14 + Lower-Voltage Alt**	**957**	**$6.370 billion**

[a] Twenty-year NPV cost using a 7 percent discount rate is $6.276 billion.

This alternative may be designed to mitigate the identified NERC reliability issues and provide equivalent reactive support as the Studied Projects; however, at a higher total cost than the Studied Projects, as shown in **Table 7.5-2**.

Construction Costs, a semi-annual publication by Whitman, Requardt and Associates that tracks and quantifies the escalation of costs for construction, materials, and equipment in the public utility industry.

TABLE 7.5-2

Total Cost Effectiveness of the Studied Projects Versus Combined Lower-Voltage Alternative and Existing System Upgrades Alternative: 20-Year Net Present Value – 7 Percent Discount Rate ($2024)

		Savings Relative to "Do Nothing" [b] *Positive value denotes a cost savings*				
	Capital Cost [a]	Congestion and Fuel	Avoided Reliability	Asset Renewal	Decarbonization	Total Costs [c]
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion – $6.222 billion	($5.927 billion) - ($1.832 billion)
Combined Lower-Voltage Alternative and Existing System Upgrades Alternative	$6.266 billion	$904 million	$3.705 billion	-	$1.399 billion – 4.088 billion	($2.421 billion) - $268 million

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO's planning-level scopes and MISO's MTEP24 cost-estimation guide.

[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 VOLL. Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of carbon emissions.

[c] Negative values denote a total cost reduction (savings exceed upfront costs)

It should be emphasized that while the combined alternative addresses the minimum NERC reliability requirements in the current forecast, it provides no future flexibility or optionality. The MISO LRTP Tranche 2.1 Portfolio, including the Studied Projects, was intentionally designed as the "foundation" to not only meet today's system needs, but to be built upon to more efficiently meet potential future needs. In simple terms the alternative would be "full" on "Day 1" whereas the Studied Projects would still have space to accommodate future changes and options for further expansion. More specifically:

- The alternative does not allow for future growth or expansion beyond the amount studied. As detailed in **Section 6.6.1,** the Studied Projects proactively enable load growth beyond the base forecast. Future load growth or additional changes on the system would continue to drive additional incremental upgrade needs for the foreseeable future.

- In addition, the alternative does not provide similar regional flexibility and resiliency benefits as the Studied Projects, as discussed in **Section 6.6.2**.

For all these reasons, the combined alternative is not a more reasonable or prudent alternative to the Studied Projects.

7.5.2 Combination of Lower-Voltage Alternative and Peaking Generation/Storage

The Applicants evaluated combining the Lower-Voltage Alternative and peaking generation/storage. Natural gas peaking generation (**Section 7.3.1**) and battery energy storage (**Section 7.3.3**) were the lowest cost, non-wire alternatives. As discussed in these sections, adding additional local capacity does not increase generation outlet or transfer capability; rather, it addresses energy adequacy issues by adding generation to address times where local generation is not available and energy cannot be transferred from outside a local area to meet demand by the existing grid; and/or provides a counter-flow to "push back" on new generation to avoid a reliability overload.

The Applicants developed the scope of the combined alternatives by starting with the Lower-Voltage Alternative described in **Section 7.2.1** and then adding peaking generation or battery energy storage to mitigate the remaining NERC reliability violations issues using the process described in **Section 7.3.1** and **Section 7.3.3**, respectively. The scope of the resulting combined alternatives is as follows:

- **Lower-Voltage Alternative and Natural Gas Peaking Generation Alternative:** $6.431 billion ($2024)
    - **Lower-Voltage Alternative**: $5.022 billion ($2024)
    - **Natural Gas Peaking Generation**: 1,540 MW total at seven locations: $1.275 billion ($2024). [214]
    - **Existing System Upgrades**: Upgrades totaling $134 million were necessary to solve the remaining steady-state reliability issues.
- **Lower-Voltage Alternative and Battery Energy Storage Alternative:** $6.209 billion ($2024) for 4-hour batteries and $7.257 billion for 8-hour batteries ($2024).
    - **Lower-Voltage Alternative**: $5.022 billion ($2024)
    - **Battery Energy Storage**: 615 MW total at nine locations: $1.053 billion ($2024) for 4-hour batteries and $2.100 billion ($2024) for 8-hour batteries ($2024). [215]
    - **Existing System Upgrades**: Upgrades totaling $134 million were necessary to solve the remaining steady-state reliability issues ($2024).

Peaking or storage additions alone were incapable of addressing each reliability issue even when combined with the Lower-Voltage Alternative; thus, additional existing system upgrades were also required as detailed in **Table 7.5-3.**

TABLE 7.5-3

Combined Lower-Voltage Alternative and Existing System Upgrades Alternative Scope

Scope	Number (Unique Locations)	Total Miles	Estimated Cost ($2024)
Non-Wire Alternatives: • Natural Gas CT, • Energy Storage (4-Hour Batteries), or • Energy Storage (8-Hour Batteries).	7 9 9 (respectively)	-	$1.275 billion $1.053 billion $2.100 billion (respectively)
Lower-Voltage Alternative (*see* **Section 7.2.1**)	-	840	$5.022 billion
230 kV Transmission Line Upgrade	1	28	$54 million
161 kV Transmission Line Upgrade	1	17	$30 million
138 kV Transmission Line Upgrade	1	9	$16 million
115 kV Transmission Line Upgrade	2	23	$34 million

214 EIA. Annual Energy Outlook 2025 at Table 4 ("MISW" region). Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf.

215 U.S. Department of Energy's National Renewable Electric Laboratory. 2024 Annual Technology Baseline (4 and 8-hour battery – moderate maturity curve). Available at: https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.

Scope	Number (Unique Locations)	Total Miles	Estimated Cost ($2024)
TOTAL- Natural Gas CT	12 + Lower-Voltage Alt.	917	$6.431 billion [a]
TOTAL- Energy Storage (4-Hour Battery)	14 + Lower-Voltage Alt.	917	$6.209 billion [b]
TOTAL- Energy Storage (8-Hour Battery)	14 + Lower-Voltage Alt.	917	$7.257 billion [c]

[a] Twenty-year NPV cost using a 7 percent discount rate is $6.454 billion.
[b] Twenty-year NPV cost using a 7 percent discount rate is $6.215 billion.
[c] Twenty-year NPV cost using a 7 percent discount rate is $7.343 billion.

These alternatives may be designed to mitigate the identified NERC reliability issues; however, at a higher total cost than the Studied Projects, as shown in **Table 7.5-4**.

TABLE 7.5-4

Total Cost Effectiveness of the Studied Projects Versus Combined Lower-Voltage Alternative and Generation Additions: 20-Year Net Present Value – 7 Percent Discount Rate ($2024)

	Capital Cost [a]	Savings Relative to "Do Nothing" [b] *Positive value denotes a cost savings*				Total Costs [c]
		Congestion and Fuel	Avoided Reliability	Asset Renewal	Decarbonization	
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion – $6.222 billion	($5.927 billion) - ($1.832 billion)
Combined Lower-Voltage Alternative and Natural Gas Peaking Generation	$6.454 billion	$1.270 billion	$3.705 billion	-	$966 million - $2.826 billion	($1.347 billion) - $513 million
Combined Lower-Voltage Alternative and Battery Energy Storage: 4-Hour Batteries	$6.215 billion	$1.251 billion	$3.705 billion	-	$1.192 billion - $3.488 billion	($2.229 billion)- $67 million
Combined Lower-Voltage Alternative and Battery Energy Storage: 8-Hour Batteries	$7.343 billion	$1.283 billion	$3.705 billion	-	$1.219 billion - $3.564 billion	($1.209 billion)- $1.136 billion

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO's planning-level scopes and MISO's MTEP24 cost-estimation guide or equivalent for non-wire alternatives.
[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 VOLL. Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of CO_2 emissions.
[c] Negative values denote a total cost reduction (savings exceed upfront costs).

The peaking plants and battery additions would have to be built and operated to provide reactive power and/or additional reactive power equipment (e.g., capacitors, reactors, and STATCOMs) to provide the necessary reactive power support. As the total cost for the alternative already exceeded the cost of the Studied Projects the Applicants did not further evaluate the necessary reactive additions.

Finally, it should be emphasized that while the combined alternative addresses the minimum NERC reliability requirements in the current forecast, it provides no future flexibility or optionality. The MISO LRTP Tranche 2.1 Portfolio, including the Studied Projects, was intentionally designed as the “foundation” to not only meet today’s system needs, but to be built upon to more efficiently meet potential future needs. In simple terms the alternative would be “full” on “Day 1” whereas the Studied Projects would still have space to accommodate future changes and options for further expansion. More specifically:

- The alternative does not allow for any future growth or expansion beyond the amount studied. As detailed in **Section 6.6.1,** the Studied Projects proactively enable load growth beyond the base forecast. Future load growth or additional changes on the system would continue to drive additional incremental upgrade needs for the foreseeable future.

- In addition, the alternative does not provide similar regional flexibility and resiliency benefits as the Studied Projects as discussed in **Section 6.6.2**.

For all these reasons, this alternative is not a more reasonable or prudent alternative to the Studied Projects.

7.6 ALTERNATIVE TRANSMISSION LINE ENGINEERING

As the Project is the first 765 kV transmission line in Minnesota, significant engineering went into developing a 765 kV transmission voltage class standard which enables MISO’s determined electrical performance requirements, meets all applicable state and federal standards for noise and safety, is resilient to Minnesota’s weather conditions, and minimizes cost, human, and environmental impacts. The final proposed Project configuration detailed in **Section 2.2**, is the result of over a year of engineering evaluation. The following sections detail alternative conductor and structure configurations considered for the Project.

7.6.1 Alternative Conductor Design

7.6.1.1 Segment 1

Segment 1 of the Project proposes to utilize a six-conductor bundle of 1192.5 kcmil 45/7 ACSR Bunting conductor with 15-inch sub-conductor spacing, or a conductor with similar performance. The Applicants initially studied both four-conductor bundle and six-conductor bundle conductor configurations. However, the four-conductor bundle configuration was immediately determined to not to be an acceptable option due to its higher noise profile. After evaluating more than a dozen conductors, Xcel Energy determined that the 1192.5 45/7 ACSR Bunting would provide the requisite capacity for the Project, including meeting or exceeding MISO’s requirements of 4,000 amps and 2,400 MW SIL.

Amongst other items, the study considered structure configuration, line losses, noise performance, electric field performance, and economic performance. Based on the results of the study, two consistent conductor candidates were identified, 1192.5 kcmil 45/7 ACSR Bunting and 1272 kcmil 45/7 ACSR Bittern, as best suited for Segment 1 of the Project. Both met all relevant Project requirements, including Minnesota’s noise standards, and were identified as being the most economical conductors. Xcel Energy selected the 1192.5 45/7 ACSR Bunting conductor, which has a slightly smaller diameter.

7.6.1.2 Segment 2

Segment 2 of the Project will utilize a six-conductor bundle of 795 kcmil 30/19 ACSR Mallard with 18-inch subconductor spacing for the 765 kV line, providing a total capacity equal to or greater than 4,000 amps and meeting or exceeding MISO's requirements of 4,000 amps and 2,400 MW SIL. Of the conductors evaluated, the 795 kcmil 30/19 ACSR Mallard was among the lowest-cost options while delivering the requisite electrical performance for the Project.

Conductor selection for Segment 2 was driven by the needs of the 765/161 kV double-circuit configuration. A comprehensive study evaluated multiple sizes, types, and bundle configurations using a rigorous multi-criteria analysis of electrical performance, mechanical performance, and economics. Consistent with these findings, Mallard ACSR and York AECC meet all applicable requirements and provide superior mechanical performance for double-circuit structures, including reduced sag (critical for minimizing structure heights) and reduced right-of-way width.

Accordingly, Segment 2 will use a six-conductor bundle of 795 kcmil 30/19 ACSR Mallard with 18-inch spacing for the 765 kV circuit and a two-conductor bundle of the same Mallard conductor with 18-inch spacing for the 161 kV circuit. The 1037 kcmil York AECC conductor will be used in the same configuration for the Mississippi River crossing.

7.6.2 Alternative Structure Design

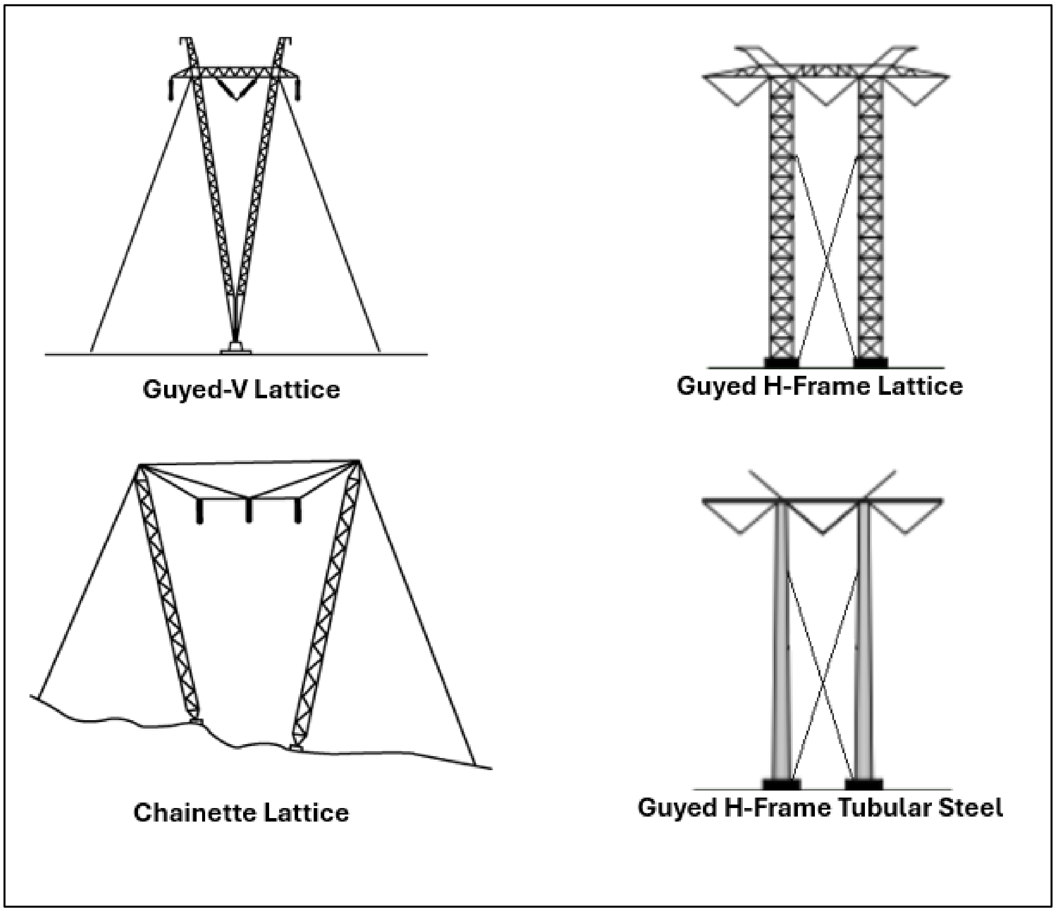
7.6.2.1 Segment 1

The structures proposed for Segment 1 of the Project' are a self-supporting lattice design that will typically range in height from approximately 150 to 175 feet tall. Lattice structures are the most common structure type for existing 765 kV transmission lines across the United States. The structures will typically be installed on drilled pier concrete foundations, with the foundations for tangent structures ranging in size from approximately 5 to 7 feet in diameter and 25 to 65 feet in depth. Actual foundation size will be based on site-specific conditions and detailed engineering design. Typical span lengths, meanwhile, will range from 1,110 to 1,300 feet. **Appendix C.1** contains a typical 765 kV structure drawing. The Applicants selected a self-supporting lattice tower design from among several structure types considered for the Project. The self-supporting lattice tower design was determined to best meet the Project needs based on considerations of cost, engineering, resiliency, and land-use impacts.

Xcel Energy considered several different structure types for the Project. Several were immediately rejected as acceptable options. For instance, based on land-use types within the Project's Notice Area, which are primarily agricultural areas, Xcel Energy determined that any structures requiring the use of guy wires and anchors would not be feasible for the Project. As such, structure types such as guyed-v lattice, Chainette lattice, guyed H-frame lattice, and guyed H-frame tubular steel were removed from consideration. Images of these structure types are presented in **Figure 7.6-1**.[216]

[216] Guyed-v lattice and chainette lattice (see guyed cross-rope suspension tower) from: Hydro Quebec. Power Transmission Towers. Available at: https://www.hydroquebec.com/learning/transport/types-pylones.html.
Guyed h-frame lattice and guyed h-frame tubular steel (as modified) from: SaVRee. Electrical Transmission Towers Explained. Available at: https://www.savree.com/en/encyclopedia/electrical-transmission-towers.

Figure 7.6-1: Alternative Structure Designs



Xcel Energy determined that the structure footprint of such structure types, along with the risk associated with third party damage to guyed structures, was unacceptable.

In addition to self-supporting lattice, Xcel Energy evaluated tubular steel H-frame and tubular steel monopole structure types as being potential options to consider for the Project. The Applicants first identified the general structure geometry and line characteristics for each structure type. The design of the tubular H-frame structure was based on similar line characteristics as the self-supporting lattice tower, including overall structure height, phase spacing, and span length, amongst other items. In addition, the design of the tubular H-frame structure type was based on the structure being mounted to drilled pier concrete foundations. In comparison, the tubular steel monopole structure was based on the conductors being arranged in a delta configuration, putting the conductor in a stacked vertical alignment. Given this configuration, and an assumed ruling span of 1,100 feet, Xcel Energy determined the typical height of a tubular steel monopole structure would be approximately 200 feet. As with the self-supporting lattice and tubular H-frame, Xcel Energy based the design of the tubular steel monopole on the use of a drilled pier concrete foundation.

To compare the three structure types, Xcel Energy performed a comprehensive structure selection analysis and comparison of each.

Based on the analysis, Xcel Energy determined that the tubular steel H-frame structure type could potentially be a technically feasible 765 kV structure option, but screened it from further consideration based on costs, constructability, and technical considerations. The weight of the tubular H-frame structure required to meet the engineering needs of the Project was determined to be significantly greater than the weight of the self-supporting lattice structure, thereby contributing to additional material handling challenges during construction. Further, Xcel Energy determined that the tubular steel H-frame structures were approximately 20 percent more costly per mile as compared to self-supporting lattice structures.

Based on the results of the structure selection analysis, Xcel Energy determined that tubular steel monopole structures were an unreasonable alternative for the Project. Although Xcel Energy determined that tubular steel monopoles could likely support 1,100-foot span lengths, Xcel Energy found that the structure heights and weights needed to support such spans would be excessive. Xcel Energy further determined that if span lengths were reduced to 800 feet, structure heights could be maintained below 200 feet, the height at which FAA lighting and marking would be recommended, the quantity of structures required on a given Project segment would increase by up to 40 to 50 percent as compared to using self-supporting lattice structures. For these reasons, tubular steel monopole structures were also found to be approximately 40 percent more costly per mile than self-supporting lattice structures. A summary of the alternative structure types considered, and the associated conclusion is presented in **Table 7.6-1**.

TABLE 7.6-1

Alternative 765 kV Structure Types Considered for Segment 1 of the Project

Structure	Spans	Heights	Cost (Material plus Labor)	Analysis
Guyed-V lattice, Chainette lattice, Guyed H-frame lattice, and guyed H-frame tubular steel	1,100 to 1,300 feet	150 to 175 feet	Not evaluated	Screened from detailed analysis because footprints of such structure types would cause greater impacts to existing land use than self-supporting structures. Guyed structures also have a greater risk of third-party damage.
Tubular steel monopole	800 feet	Under 200 feet	Approximately 40 to 50 percent more per mile than self-supporting lattice	Not selected because of costs, quantity of structures required, and live-line maintenance considerations caused by delta configuration with two phases stacked on one side of the structure. Constructability was also a consideration.
Tubular steel H-frame	1,100 to 1,300 feet	150 to 175 feet	Approximately 20 percent more per than self-supporting lattice	Not selected because less resilient compared to the self-supporting lattice structure. Significantly greater steel weights than self-supporting lattice structure. Design would also have a higher cost and present constructability challenges.

7.6.2.2 Segment 2

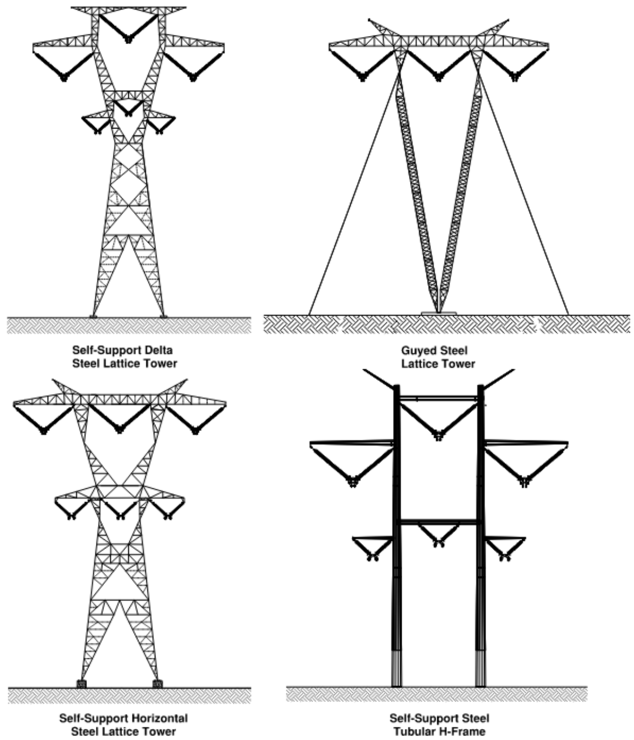
The structures proposed for Segment Two of the Project consist primarily of self-supporting delta steel lattice towers designed to support a double-circuit configuration with a 765 kV circuit and an underbuilt 161 kV circuit on a single structure. The structures will typically range in height from approximately 150 to 200 feet, with taller structures utilized at select locations such as major roadway, river, and environmental crossings. Foundations will generally consist of drilled pier concrete foundations, with actual foundation dimensions determined based on site-specific geotechnical conditions and detailed engineering design. Typical span lengths will range from approximately 1,200 to 1,500 feet, with longer spans employed at select locations where appropriate to minimize environmental and land-use impacts. **Appendix C.2** contains a typical structure drawing, and **Figure 7.6-2** provides a conceptual rendering of the proposed tangent tower configuration.

The structure configuration proposed for Segment Two reflects the design approach developed for this segment of the Project and is presented independently of the structure design used for other Project segments.

Figure 7.6-2: Proposed Structure Design

Several alternative structure types were considered for Segment Two as part of the Project's evaluation of feasible structure configurations. These alternatives included guyed lattice structures, self-supporting horizontal lattice towers, steel tubular H-frame structures, and steel tubular monopole structures. These structure types were evaluated with respect to engineering feasibility, constructability, right-of-way requirements, cost considerations, operational factors, and consistency with the Project's design objectives. Images of representative alternative structure types are presented in **Figure 7.6-3**.

Figure 7.6-3: Segment 2 – Sample Alternative Structure Designs



Guyed structure alternatives were considered during the Project's evaluation of feasible structure types. These configurations were not advanced for Segment Two because the required guy anchor footprints would increase right-of-way width and land-use impacts relative to self-supporting structures. In addition, long-term access and maintenance considerations, as well as exposure to third-party activities, present challenges for application to a double-circuit 765/161 kV transmission line.

Steel tubular monopole and tubular H-frame structures were also evaluated for potential application on Segment Two. While these structure types can be engineered for extra-high-voltage service, their use on a long-distance double-circuit 765/161 kV transmission line introduces design tradeoffs. For comparison purposes, these structure configurations were evaluated using span lengths and conductor arrangements representative of a double-circuit 765/161 kV application. In particular, shorter achievable span lengths would increase the total number of structures required, resulting in higher foundation quantities, longer construction duration, and increased overall project cost, as well as reduced efficiency for long-distance construction and operation. Based on these considerations, tubular structure types were not advanced for widespread use along Segment Two.

Self-supporting horizontal lattice towers were evaluated and determined to be technically feasible. However, relative to delta-configured lattice structures, horizontal configurations were found to be less efficient in right-of-way utilization and to produce less favorable audible noise and electric and magnetic field performance at the edge of the right-of-way. As a result, horizontal lattice structures were not advanced as the preferred structure type for Segment Two.

For Segment Two, the Project proposes the use of self-supporting delta steel lattice towers to support the 765/161 kV double-circuit configuration. This structure type provides the structural capacity necessary to support large conductor bundles and longer spans while efficiently utilizing the available right-of-way. The delta configuration allows for optimized conductor spacing, which helps minimize audible noise and electric and magnetic field levels at the edge of the right-of-way. In addition, lattice structures offer proven reliability, construction flexibility in varied terrain, and support effective failure-containment strategies that enhance long-term system performance under extreme loading conditions and reduce operational and maintenance impacts.

Based on these considerations, the self-supporting delta steel lattice tower design was determined to best meet the Project's needs for Segment Two with respect to engineering performance, constructability, reliability, cost considerations, and land-use impacts. A summary of the structure types considered and the associated conclusions is presented in **Table 7.6-2**.

TABLE 7.6-2

Summary of the Structure Types Considered for Segment Two and Associated Conclusions

Structure	Typical Spans	Typical Heights	Cost (Material plus Labor)	Key Considerations
Guyed structures and lattice mast variants (guyed mast, cross-rope, chainette, self-supporting delta lattice mast, guyed steel lattice tower)	Variable to limited	Typically >150 feet	Not evaluated	These structure types were evaluated but not advanced for Segment Two due to larger structure footprints and associated right-of-way requirements. In addition, span limitations, foundation demands, and increased design and construction complexity limit their suitability for a long-distance double-circuit 765/161 kV application.
Tubular monopole and specialty tubular structures (self-supporting delta steel tubular monopole, steel tubular Pyramax)	Limited	Often >200 feet	Not evaluated	These tubular structure options were evaluated but were not advanced due to span length limitations, foundation requirements, and material and fabrication considerations associated with double-circuit 765/161 kV loading.
Self-supporting delta steel lattice tower	~1,200–1,500+ feet	~150–200 feet	Proposed structure type	This four-leg lattice tower with delta-configured phases provides the structural capacity required for a double-circuit 765/161 kV transmission line while supporting longer spans and efficient use of the available right-of-way.
Self-supporting horizontal steel lattice tower	~1,200–1,500+ feet	~150–200 feet	Comparable to Proposed structure type	This structure type was evaluated but not advanced because the horizontal phase arrangement results in less efficient right-of-way utilization and less favorable audible noise and electric and magnetic field performance at the edge of the right-of-way compared to delta configurations.
Self-supporting steel tubular H-frame	~900–1,200 feet	<200 feet	Higher due to increased structure count	This structure type was evaluated but not advanced because shorter achievable span lengths would increase the number of structures required, resulting in higher foundation quantities, longer construction duration, and increased overall project cost for a long-distance double-circuit 765/161 kV transmission line.

7.7 NO BUILD AND CONSEQUENCES OF DELAY

As required by Minn. R. 7849.0340, the Applicants also considered the no build alternative, i.e., no new transmission constructed to meet the identified reliability needs. As detailed in **Section**

7.2 through **Section 7.5**, no alternative is more prudent and/or reasonable than the Studied Projects. Should the Studied Projects be delayed and/or not constructed, there would be local and regional reliability, policy, and economic consequences.

As detailed in **Section 6.3.1**, the Studied Projects address 1,313 reliability issues on 102 different facilities. Per NERC, each of these issues requires a corrective action plan– i.e., doing nothing is not a reasonable option. Should the Studied Projects (the regional coordinated solution) not move forward, utilities would need to develop smaller-piecemeal solutions which as detailed in **Section 7.4.1** will at best be more expensive and at worst would be infeasible to develop in a reasonably timely manner. These smaller piecemeal solutions also do not allow for future growth or expansion and thus addressing potential future needs would also likely be more expensive and inefficient. The MISO LRTP Tranche 2.1 Portfolio, including the Studied Projects, was intentionally designed as a new "foundation" to not only meet today's system needs, but to be built upon to more efficiently meet potential future needs.

As detailed in **Section 6.5.1**, the Studied Projects and MISO LRTP Tranche 2.1 portfolio are needed to enable generation in state approved IRPs. Planned generation in Minnesota's IRPs is currently in various stages of the MISO Generator Interconnection Queue, MISO Expedited Resource Addition Study, and/or planning – all of which assume the MISO approved LRTP Tranche 2.1 Portfolio will move forward as scheduled. Should the Project not move forward as planned, there would be a cascading impact which would likely delay and/or alter generation additions needed to serve new, expanding, and existing demands for electricity. Additionally, the generation in the state-approved IRPs will further Minnesota's Carbon Free by 2040 law. Should the Project not move forward or be delayed, there are state law compliance risks.

Other states would also be adversely impacted. This Project is a key component of a broader regional portfolio. The coordinated and regional approach enabled through the portfolio helps each MISO Midwest state meet reliability needs and goals in a more efficient and effective manner. The portfolio has been designed and optimized by MISO to work together - meaning the Project supports other states' needs and likewise other projects in the MISO LRTP Tranche 2.1 Portfolio support Minnesota's needs. A delay or cancellation of the Project not only increases risks of not meeting Minnesota's needs but also other states' needs.

8 TRANSMISSION LINE OPERATING CHARACTERISTICS

8.1 OVERVIEW

The major components of the proposed Project will include (1) above ground steel structures referred to as towers; (2) below ground concrete drilled piers referred to as foundations (3) the wires attached to the structure and carrying the electricity, called conductors; (4) insulators and associated hardware connecting the conductors to the structures to provide structural support and electrical insulation; (5) shield wires, including optical ground wires, which protect the line from direct lightning strikes; and (6) 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 human-made structure in the landscape. Due to the physics of how electricity functions, noise may be generated in some circumstances; interference with electromagnetic signals can occur; and electrical and magnetic fields are created around the conductors. Each of these operating characteristics is considered when designing the transmission line to prevent any significant impacts to its operation and to the overall environment.

8.2 CORONA

Corona discharges occur on transmission line conductors when the electric field intensity at the conductor's surface is above a certain critical value. High levels of electric field give rise to a chain of ionization events in the surrounding air that culminates in the formation of corona discharges. The corona on conductors can produce a number of effects, such as power loss, electromagnetic interference, audible noise, gaseous effluents, and light. Some of these corona effects have important implications for the electrical design of transmission lines, particularly in the choice of conductor size. [217]

Oxidants such as ozone and various oxides of nitrogen (collectively known as NOX) contribute to atmospheric air pollution. Ozone is also formed in the lower atmosphere from lightning discharges and from reactions between solar ultraviolet radiation and air pollutants. 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 natural production of ozone. The formation of ozone at ground level is mainly due to the action of ultraviolet radiation on the gaseous emissions of combustion processes. For example, photochemical reactions taking place in automobile exhaust gases are known to generate ozone and contribute to increased pollution in urban areas. Ozone is a very reactive form of oxygen molecules and combines readily with other elements and compounds in the atmosphere. Because of its reactivity, it is relatively short-lived.

The rapid growth of high voltage transmission lines in the early 1970s raised some concerns of the possibility of ozone generation by corona discharges on transmission line conductors and the impact on ambient air quality. Laboratory studies and measurements near transmission lines have

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[217] P. Sarma Maruvada (EPRI). EPRI AC Transmission Line Reference Book, 200 kV and Above, Third Edition, 2005. Sections 8.1 and 11.9.

clearly shown, however, that transmission lines do not make any significant contribution to ambient atmospheric ozone levels.[218]

Both the state and federal governments currently have regulations regarding permissible concentrations of ozone and oxides of nitrogen. The National Ambient Air Quality Standard for ozone is 0.070 parts per million (ppm) on an 8-hour averaging period.[219] The state standard for ozone is also 0.070 ppm on an 8-hour averaging period. The national and state standard for nitrogen dioxide (NO_2), one of several oxides of nitrogen, is 100 parts per billion on a 1-hour average and 53 parts per billion annual mean. The State of Minnesota is currently in compliance with the national standards for ozone and NO_2. The operation of the proposed transmission lines would not create any potential for the concentration of these pollutants to exceed ambient air standards.

The most significant contributor to greenhouse gases is CO_2, followed by methane, nitrous oxide, and fluorinated gases (hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride (SF_6), and nitrogen trifluoride). Other greenhouse gases include nitrogen oxides, volatile organic compounds, and other gases produced through human activities. In Minnesota, CO_2 is the primary greenhouse gas emitted by human activities. CO_2 is most frequently produced through the combustion of hydrocarbon fuels to operate vehicles and equipment, generate electricity, and provide heat for homes and industrial processes.[220]

Construction of the Project will produce greenhouse gas emissions during pre-construction, construction, and restoration activities through the use of cranes, bulldozers, bucket loaders, personal employee vehicles, and other heavy equipment associated with Project construction and maintenance. During operations, some negligible operational greenhouse emissions are anticipated as a result of the use of maintenance vehicles (e.g., cars, trucks, helicopters) or substation equipment (i.e., SF_6 production). The emission of SF_6, when it occurs, would originate from substations as releases occur due to cracks in seals in certain substation equipment. The Applicants would track SF_6 and would maintain their equipment to minimize unanticipated releases.

8.3 NOISE

Noise is defined as unwanted sound. It may be composed of 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, the most noticeable frequencies of sound are given more "weight" in most measurement schemes. The A-weighted decibel (dBA) scale corresponds to the sensitivity range for human hearing by applying more "weight" to frequencies a person hears clearly and less "weight" to frequencies a person doesn't hear as well. A noise level change of 3 dB is barely perceptible to a person with healthy hearing organs in an ideal listening environment (i.e., an audiology booth). A 5 dB change in noise level is clearly noticeable for that same person in the same listening environment. For reference, **Table 8.3-1** shows noise levels associated with common, everyday

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218 Id.

219 EPA National Ambient Air Quality Standards Table. Available online at: https://www.epa.gov/criteria-air-pollutants/naaqs-table.

220 MPCA. January 2025 Report to the Legislature. Greenhouse Gas Emissions in Minnesota, 2005-2022. Available online at: https://www.pca.state.mn.us/sites/default/files/lraq-3sy25.pdf .

sources, providing context for the transmission line and substation noise levels discussed later in this section.

TABLE 8.3-1 Common Noise Sources and Levels	
Sounds Pressure Levels (dBA)	**Common Indoor and Outdoor Noises**
110	Rock band at 5 meters
100	Jet flyover at 300 meters
90	Chainsaw at 1 meter
85	Typical construction activities
80	Food blender at 1 meter
70	Vacuum cleaner at 3 meters
60	Normal speech at 1 meter
50	Dishwasher in the next room
40	Library
30	Bedroom
20	Quiet rural nighttime
Source: MPCA, 2015	

Table 8.3-2 provides the Minnesota Pollution Control Agency (MPCA) daytime and nighttime noise standards organized by Noise Area Classifications (NAC) (Minn. R. Ch. 7030.0400 and 7030.0500). MPCA noise standards are expressed using the L50 and L10 statistical descriptors. The L50 noise level represents the level exceeded 50 percent of the time, or for 30 minutes in an hour. The L10 noise level represents the level exceeded 10 percent of the time, or for six minutes in an hour.

Audible noise will occur as part of the construction and operation phases of the Project. Noise-sensitive land uses in the vicinity of the Project primarily include residences and neighborhoods, recreational areas, cemeteries, churches, office and retail buildings, restaurants, and parks. NACs are categorized by the type of land use activities at a location and the sensitivity of those activities to noise. Residential-type land use activities including residences, churches, camping and picnicking areas, and hotels are included in NAC-1. Commercial-type land use activities such as transit terminals, retail, and business services are included in NAC-2. Industrial-type land use activities are included in NAC-3.

TABLE 8.3-2 MPCA Noise Limits by Noise Area Classification					
Noise Area Classification	**Description**	**Daytime (dBA)**		**Nighttime (dBA)**	
		L10	**L50**	**L10**	**L50**
1	Residential-type Land Use Activities	65	60	55	50
2	Retail-type Land Use Activities	70	65	70	65
3	Manufacturing-type Land Use Activities	80	75	80	75
Source: MPCA, 2015					

Construction is anticipated to occur primarily during daytime hours. The main sources of noise will be the operation of heavy equipment, tree clearing, and vehicle traffic.

Corona, as discussed in **Section 8.2**, occurs when the electric field intensity on the conductor exceeds the breakdown strength of air and the air within a few centimeters of the conductor becomes ionized. This ionization produces a “crackling” sound. Typically, corona discharge levels on transmission lines, and therefore noise levels, are higher in wet or humid conditions. During heavy rain, the background noise level of the rain is usually greater than the corona 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, and sometimes snow and other high-humidity conditions, it is easier to hear corona noise because it is not being masked by the sound of rain. Several other factors, including voltage, conductor shape and diameter, and surface irregularities such as scratches, nicks, dust, or water drops can affect a conductor’s electrical surface gradient and, therefore, its corona noise discharge level. The way conductors are arranged also affects corona noise production.

At substations, transformers, reactors, and switchgear are among the primary noise sources. Noise emissions from this equipment have a tonal character that sometimes sounds like a hum or a buzz, which corresponds to the frequency of the alternating current. Transformers are among the largest noise sources, and the core of a transformer will expand and contract as it is magnetized and demagnetized at a rate that is based on the frequency of the alternating current. This type of noise does not have much low frequency content and, therefore, blends into background noise levels with increasing distance away from the source without being too intrusive off-site.

The Project Notice Area is composed of multiple types of land uses, predominantly, agricultural use which has a NAC 3 classification and a daytime and nighttime L50 limit of 75 dBA. However, the Project has been designed to meet the more stringent NAC 1 daytime L50 limit of 60 dBA and nighttime L50 limit of 50 dBA.

Construction noise will be temporary and primarily limited to daytime hours. Instances such as outages, operational limitations, customer schedules, or other factors may cause construction to occur outside of daytime hours or on weekends. Heavy equipment will also be equipped with sound attenuation devices such as mufflers to minimize the daytime noise levels. Mitigation may be proposed for activities that occur during nighttime hours.

The Applicants calculated Corona noise levels were calculated using the Bonneville Power Administration Corona and Field Effects Program audible noise module, a corona noise model created by the Bonneville Power Administration. The program calculates audible noise levels due to corona at different distances from the transmission line centerline, expressed as L50 noise levels in A-weighted decibels. Calculated audible noise levels associated with the proposed 765 kV segment and 765/161 kV segment, measured at various distances from the edge of the right-of-way, are shown in **Table 8.3-3.**

TABLE 8.3-3

Transmission Line Noise Levels

Segment	**Nominal Voltage**	***L50 Noise Level Range at Distance from Centerline***		
		100'	**125'**	**150’**
Segment 1	765 kV	49.8	48.9	48.1
Segment 2	765 / 161 kV	49.48	48.98	48.46

[a] Calculations assume a 1.05pu overvoltage from nominal (803.25 kV & 169.1 kV).

Because audible noise is primarily related to the electric field, and electric fields are particularly dependent on the voltage of the transmission line, the values were calculated at the lines' maximum continuous operating voltage. Maximum continuous operating voltage is generally defined for the Project as the nominal voltage plus 5 percent (or, a 1.05 overvoltage). In this case, the model used a maximum continuous operating voltage of 803.3 kV for 765 kV lines.

Audible noise levels under L50 foul weather conditions (rain, snow, or fog) are reported at a height of 1.5 meters above ground for multiple right-of-way width alternatives. As indicated in **Table 8.3-2**, the most stringent MPCA noise standard is the nighttime L50 limit for the land use category that includes residential areas (NAC-1). The NAC-1 nighttime limit is 50 dBA. Modeling results in **Table 8.3-3** indicate that Project-related audible noise from the transmission lines is expected to not exceed the most stringent MPCA noise standards.

8.4 RADIO, TELEVISION, AND GPS INTERFERENCE

Generally, transmission lines do not cause interference with radio, television, or other communication signals and reception. While it is rare in everyday operations, four potential sources for interference do exist, including gap discharges, corona discharges, and shadowing and reflection effects.

Gap discharge interference is the most commonly noticed form of interference with radio and television signals, and also typically the most easily fixed. Gap discharges are usually caused by hardware defects or abnormalities on a transmission or distribution line causing small gaps to develop between mechanically connected metal parts. As sparks discharge across a gap, they create the potential for electrical noise, which can cause interference with radio and television signals in addition to audible noise. The degree of interference depends on the quality and strength of the transmitted communication signal, the quality of the receiving antenna system, and the distance between the receiver and the transmission line. Gap discharges are usually a maintenance issue, since they tend to occur in areas where gaps have formed due to broken or ill-fitting hardware (e.g., clamps, insulators, brackets). Because gap discharges are a hardware issue, they can be repaired relatively quickly once the issue has been identified.

In the rare occurrence where interference does occur, it is the responsibility of the transmission owner/operator to mitigate the issue. Corona from transmission line conductors can also generate electromagnetic noise at the same frequencies that radio and television signals are transmitted. The air ionization caused by corona generates audible noise, radio noise, light, heat, and small amounts of ozone as noted previously in this section. The potential for radio and television signal interference due to corona discharge relates to the magnitude of the transmission line-induced radio frequency noise compared to the strength of the broadcast signals. Because radio frequency noise, like electric and magnetic fields, becomes significantly weaker with distance from the transmission line conductors, very few practical interference problems related to corona-induced radio noise occur with transmission lines. In most cases, the strength of the radio or television broadcast signal within a broadcaster's primary coverage area is great enough to prevent interference.

If interference from transmission line corona associated with the Project does occur for an AM radio station within a station's primary coverage area where good reception existed before the Project was built, satisfactory reception can be obtained by appropriate modification of, or addition to, the receiving antenna system. The situation is unlikely, however, because AM radio frequency interference typically occurs immediately under a transmission line and dissipates rapidly with increasing distance from the line.

FM radio receivers are not affected by transmission lines because corona-generated radio frequency noise currents decrease in magnitude with increasing frequency and are quite small in the FM broadcast band (88-108 megahertz), and the interference rejection properties inherent in FM radio systems make them virtually immune to amplitude type disturbances.

The potential for television interference due to radio frequency noise caused by transmission lines is now substantially reduced because the United States has completed the transition from analog to digital broadcasting. Digital reception is in most cases considerably more tolerant of noise than analog broadcasts. Due to the higher frequencies of television broadcast signals (i.e., 54 megahertz and above) a transmission line seldom causes reception problems within a station's primary coverage area.

Shadowing and reflection effects are typically associated with large structures, such as tall buildings, and may cause reception problems by disturbing broadcast signals and leading to poor radio and television reception. Although the occurrence is rare, a transmission structure or the conductor can create a shadow on adjoining properties that obstructs or reduces the transmitted signal. Structures may also cause a reflection or scattering of the signal. Reflected signals from a structure result in the original signal breaking into two or more signals. Multipath reflection or scattering interference can be caused by the combination of a signal that travels directly to the receiver and a signal reflected by the structure that travels a slightly longer distance and is received slightly later by the receiver. If one signal arrives with significant delay relative to the other, the picture quality of digital television broadcast signals may be impacted. With digital broadcasts, the picture can become pixelated or freeze and become unstable. The most significant factors affecting the potential for signal shadow and multipath reflection are structure height above the surrounding landscape and the presence of large flat metallic facades. Television interference due to shadowing and reflection effects is rare but may occur when a large transmission structure is aligned between the receiver and a weak distant signal, creating a shadow effect.

In the rare situation where the Project may cause interference within a station's primary coverage area, the problem can usually be corrected with the addition of an outside antenna. If television or radio interference is caused by or from the operation of the proposed facilities in those areas where good reception was available prior to construction of the Project, Applicants will evaluate the circumstances contributing to the impacts and determine the necessary actions to restore reception to the prior level, including the appropriate modification of receiving antenna systems if necessary.

8.5 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 right-of-way widths. Appropriate standards will be met for construction and installation, and all applicable safety procedures will be followed during and after installation.

The Project will be equipped with protective devices (e.g., circuit breakers and relays located in substations where transmission lines terminate) to safeguard the public in the event of an accident, or if a structure or conductor falls to the ground. The protective equipment will de-energize the transmission line should such an event occur.

8.6 ELECTRIC AND MAGNETIC FIELDS

Electric and magnetic fields (EMF) are forces that are present anywhere electricity is produced or used, including around electric appliances and any wire that is conducting electricity. The term EMF typically refers to electric and magnetic fields that are coupled together. However, for lower frequencies associated with distribution or transmission lines, electric and magnetic fields are relatively decoupled and should be described separately. Electric fields are the result of electric charge, or voltage, on a conductor. The intensity of an electric field is related to the magnitude of the voltage on the conductor and is typically described in terms of kV per meter (kV/m). Magnetic fields are the result of the flow of electricity, or current, traveling through a conductor. The intensity of a magnetic field is related to the magnitude of the current flow through the conductor and is typically described in units of magnetic flux density expressed as Gauss or milliGauss (mG).

8.6.1 Electric Fields

The voltage on any wire produces an electric field in the area surrounding the wire. The conductors of a transmission line produces an electric field extending from the energized conductors to other nearby objects, such as the ground, structures, vegetation, buildings, and vehicles. The intensity of transmission line electric fields is proportional to the voltage of the line and rapidly decreases with distance from the transmission line conductors. The presence of trees, buildings, or other solid structures nearby can also significantly reduce the magnitude of the electric field. Because the magnitude of the voltage on a transmission line is near-constant, the magnitude of the electric field will be near-constant for each of the proposed configurations, regardless of the power flowing on the line.

When an electric field reaches a nearby conductive object, such as a vehicle or metal fence, it induces a voltage on the object. The magnitude of the induced voltage is dependent on many factors, including, but not limited to, the object's capacitance, shape, size, orientation, location, resistance with respect to ground, and the weather conditions. If the object is insulated or semi-insulated from the ground and a person touches it, a small current would pass through the person's body to the ground. This might be accompanied by a discharge and mild shock, similar to what can occur when a person walks across a carpet and touches a grounded object, like a doorknob, or another person.

The main concern with induced voltage is not the magnitude of the voltage induced, but the current that would flow through a person to the ground should the person touch the object. To ensure that any such spark discharge associated with transmission line induced voltage does not reach unsafe levels, the NESC requires that any discharge be less than 5 milliamperes (mA). The Project will be designed consistent with this NESC requirement.

There is no federal standard for transmission line electric fields. The Commission, however, has historically imposed a maximum electric field limit of 8 kV/m measured at one meter above ground for new transmission projects.[221] As demonstrated in **Table 8.6-1**, the electric fields associated with the Project will be within the Commission's 8 kV/m limit.

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221 *In the Matter of the Route Permit Application for a 345 kV Transmission Line from Brookings County, S.D. to Hampton*, 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).

TABLE 8.6-1 Electric Field Calculation Summary[a]												
		Distance to Proposed Centerline (feet) kV/m										
Segment	**Voltage**	**-125**	**-100**	**-75**	**-50**	**-25**	**0**	**25**	**50**	**75**	**100**	**125**
Segment 1	765 kV	2.93	4.73	6.98	7.47	5.24	4.96	5.24	7.47	6.98	4.73	2.93
Segment 2	765 / 161 kV	2.61	3.52	4.31	4.33	2.89	0.82	2.89	4.33	4.31	3.52	2.61
[a] Electric Field values calculated at 1.05pu overvoltage from nominal (803.3 kV and 169.1 kV).												

8.6.2 Magnetic Fields

Current passing through any conductive material, including a wire, produces a magnetic field in the area around the material. The current flowing through the conductors of a transmission line produces a magnetic field that extends from the energized conductors to other nearby objects. The intensity of the magnetic field associated with a transmission line is proportional to the amount of current flowing through the line's conductors and rapidly decreases with the distance from the conductors. Unlike electric fields, magnetic fields are not significantly impacted by the presence of trees, buildings, or other solid, non-ferromagnetic structures nearby. However, they are impacted by structures made of ferromagnetic materials. Because the actual power flow on a transmission line could potentially vary widely throughout the day depending on electrical system conditions, the actual magnetic field level in the vicinity of the transmission line could also vary widely from hour to hour.

There are currently no Minnesota regulations pertaining to magnetic field exposure. The Commission has acknowledged that Florida, Massachusetts, and New York have established standards for magnetic field exposure.[222] Average Magnetic fields calculated for the Project are presented in **Table 8.6-2**.

TABLE 8.6-2 Magnetic Field Calculation Summary[a]													
765 kV													
Structure Type	System Condition	Current (Amps)	*Distance to Proposed Centerline (feet) mG*										
			-125	-100	-75	-50	-25	0	25	50	75	100	125
765 kV	Highest Loading – System Intact	2,264	75.7	108.6	155.8	203.9	225.3	225.0	225.3	203.9	155.8	108.6	75.7
765 / 161 kV													
Structure Type	System Condition	Current (Amps)	*Distance to Proposed Centerline (feet)*										
			-125	-100	-75	-50	-25	0	25	50	75	100	125
765/161 kV	Highest Loading – System Intact	2264/168	57.8	74.9	95.7	117.7	135.1	141.2	135.1	117.7	95.7	74.9	57.8
[a] Magnetic field levels shown reflect typical operating conditions for the transmission line, based on expected power flow and average structure height.													

222 In the Matter of the Route Permit Application for the North Rochester to Chester 161 kV Transmission Line Project, Docket No. E-002/TL-11-800, ORDER at 20 (Sept. 12, 2012).

Magnetic fields associated with some common household electric appliances[223] are provided in **Table 8.6-3** to provide context for the calculated magnetic field levels associated with the Project.

TABLE 8.6-3

Table of Magnetic Fields of Common Electric Appliances

Appliance	6 Inches from Source	1 Foot from Source	2 Feet from Source
Hair Dryer	300 mG	1 mG	-
Electric Shaver	100 mG	20 mG	-
Can Opener	600 mG	150 mG	20 mG
Electric Stove	30 mG	8 mG	2 mG
Television	N/A	7 mG	2 mG
Portable Heater	100 mG	20 mG	4 mG
Vacuum Cleaner	300 mG	60 mG	10 mG
Copy Machine	90 mG	20 mG	7 mG
Computer	14 mG	5 mG	2 mG

EMF from transmission lines, and their effects on health, have been studied for more than 40 years by governmental bodies, public health organizations and government appointed scientific panels from all over the world. Initially, there were concerns of a possible association between childhood leukemia and magnetic fields of transmission lines. Subsequent research failed to demonstrate a causal relationship between transmission lines and any health risk. The World Health Organization and other health agencies have concluded that, at levels of EMF exposure found near transmission lines, there are no known health consequences.

8.7 STRAY VOLTAGE AND INDUCED VOLTAGE

Stray voltage is typically caused by a lower voltage service system serving a customer, usually a farm, but it can also be caused by customer equipment. Questions concerning stray voltage are usually best addressed by the electric distribution utility that serves the farm directly. Transmission lines can, however, induce voltage on objects parallel to and immediately under the transmission line. Appropriate measures will be taken to prevent induced voltage problems when the Project parallels or crosses objects.

8.8 FARMING OPERATIONS, VEHICLE USE, AND METAL BUILDINGS NEAR TRANSMISSION LINES

The Applicants will comply with the NESC with respect to grounding objects and fences within the right-of-way and will work with landowners to resolve issues that arise because of the Project. Farm equipment, passenger vehicles, and trucks may be safely used under and near transmission lines. The Project will be designed to meet or exceed minimum clearance requirements with respect to roads, driveways, cultivated fields, and grazing lands.

Vehicles or other conductive equipment under high voltage transmission lines may become electrically charged due to induced voltage from the transmission lines. Without a continuous grounding path, this charge can provide a nuisance shock. Such nuisance shocks, however, are

223 Source: USEPA. EMF in Your Environment. Magnetic Field Measurements of Everyday Electrical Devices. Available at: https://nepis.epa.gov/Exe/tiff2png.cgi/000005EP.PNG?-r+75+-g+7+D%3A%5CZYFILES%5CINDEX%20DATA%5C91THRU94%5CTIFF%5C00000191%5C000005EP.TIF.

typically rare, as vehicles are generally effectively grounded through tires or other means. Modern tires are produced using carbon black, a good conductor of electricity, thus providing an electrical path to ground. Additionally, metal components of farming equipment are often in contact with the ground when in operation. Therefore, unless vehicles or equipment have unusually old tires or are parked on dry rock, plastic, or other surfaces that insulate them from the ground, any induced charge on vehicles or equipment will normally flow continuously to ground.

Buildings are permitted near transmission lines but are generally not permitted within the right-of-way, as a structure under a transmission line may interfere with the safe operation of the transmission facilities. In addition, the NESC establishes minimum electrical clearance zones from transmission lines to various objects, including buildings, for the safety of the general public. The Applicants will acquire easement rights that provide the necessary area to operate and maintain the Project. The Applicants may permit encroachment into these easements for specific activities when they can be deemed safe and still meet the NESC minimum requirements.

Metal buildings near the right-of-way may have unique concerns due to induction. For example, per NESC requirements, conductive buildings near transmission lines of 170 kV or greater must be properly grounded. Any person with questions about new or existing metal buildings or structures may contact the Applicants for further information about proper grounding requirements.

9 TRANSMISSION LINE CONSTRUCTION AND MAINTENANCE

9.1 ENGINEERING DESIGN AND REGULATORY APPROVALS

Detailed transmission line and substation engineering design work generally begins after the Commission designates a route and issues a route permit. The design of a transmission line is refined as more site-specific information is gathered for properties along the approved route. Throughout the process, Applicants work with landowners and ensure that all permit conditions are satisfied. After a route permit is issued, Applicants will prepare plan and profile documents which provide a detailed description of the facilities, including structure placement, spans, and wire heights.

9.2 LAND RIGHTS ACQUISITION

The Applicants will work with landowners to acquire easements for an up to approximately 250-foot right-of-way. In some areas, the width may vary depending on span length and other design requirements. The Applicants will review and make these modifications on a case-by-case basis.

The Applicants will address land rights and related matters with landowners and other stakeholders throughout the permitting proceedings. The Applicants intend to contact landowners to obtain rights-of-entry agreements to support the Applicants' survey efforts. It is anticipated that the more detailed land rights acquisition discussions with landowners will occur in conjunction with the Applicants' survey efforts and will continue throughout the permitting and post-permitting periods. In those discussions, the Applicants will describe the Applicants' survey, construction, and access plans, as well as potential impacts on the land, mitigation opportunities, and restoration. The land rights evaluation and acquisition process will include title search, contact with the landowner, survey, real estate document preparation, discussion and negotiation, and completion of land rights agreements, including permanent easements, temporary easements, and/or other agreements as necessary to support the initial survey needs of the project and construction, operation, and maintenance of the Project.

The Applicants may discuss special considerations such as temporary or permanent gates, fencing, and access accommodations. The Applicants' experience with easement discussions is that, in most cases, they are able to work with landowners to address their concerns and reach an agreement for the purchase of the necessary land rights. In all cases, the Applicants will use fair market value data to try in good faith to reach agreements with landowners on a voluntary basis. In some cases, agreements cannot be reached. In those cases, the Applicants may be required to obtain the necessary rights for the Project by exercising their right of eminent domain under Minnesota law. The process of exercising the right of eminent domain is called condemnation. Minnesota law establishes a common process – through Minn. Stat. Ch. 117 – for condemnation actions and has a well-developed body of law for determining valuation issues to ensure that landowners receive just compensation.

Typically, before commencing a condemnation proceeding, a condemning authority obtains an appraisal and provides it to the property owner, along with the condemning authority's offer of compensation. To start the formal condemnation process, a utility (or other condemning authority) files a petition in the district court where the property is located and serves that petition on all owners of interests in each of the properties identified in the petition. At or around the date the petition is filed, the utility also issues a notice to the owners that identifies the date on which the utility is asking the district court to grant the utility title to and possession of the land rights pursuant to Minnesota's "quick take" process.

If the court grants the petition, the court appoints a three-person condemnation commission that will determine the just compensation for the easement. The three people must be knowledgeable of applicable real estate issues. The commissioners schedule a viewing of the property and then schedule a valuation hearing where the utility and landowners can testify as to the fair market value of the easement or fee. As part of the valuation process, the landowner typically also obtains an appraisal and has certain rights of reimbursement in connection with the costs of obtaining an appraisal. At the commissioners' hearing on valuation, the parties offer their evidence, such as testimony by appraisers or the landowners, about the fair market value impacts the acquisition has on the property's value. The condemnation commission then makes an award in an amount representing just compensation and that award is filed with the court. Each party has the right to appeal the award to the district court for a trial. In the event of an appeal, the jury or judge 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.

In addition, the Project is subject to Minnesota's "Buy the Farm" law (Minn. Stat. § 216I.21, subd. 4). Under the Buy the Farm law, when a utility files condemnation to obtain the easement rights necessary to support the Project, certain landowners of certain classes of land have the right to elect that the utility acquire the owners' fee interest in the property instead of the easement sought by the utility. The eligible classes of property include agricultural and non-agricultural homestead, non-homestead agricultural land, rental residential property, and commercial and non-commercial seasonal residential recreational property. Owners who make Buy the Farm elections may also be entitled to relocation assistance. The Applicants intend to communicate with landowners early in the acquisition process to make clear the options that are available if a landowner wants to further explore or pursue a Buy the Farm transaction. As part of the discussions, the Applicants will also provide landowners resources regarding the relocation assistance that may be available to them.

9.3 CONSTRUCTION PROCEDURES

Work on each construction spread[224] will begin after all required federal, state and local approvals are obtained, property and all necessary land rights are acquired, and final design is completed. The precise timing of construction will consider various requirements that may be in place due to permit conditions, system loading issues and available workforce.

The Applicants will notify landowners prior to the start of the construction phase of the Project, including an update on the Project schedule and other related construction activities.

The first phase of construction activities for the new structures will involve survey staking of the transmission line centerline, easement boundaries, potential off right-of-way access routes, and/or structure locations, then removal of all trees and other vegetation from the full width of the easement area.[225] As a general practice, low-growing brush will be allowed to reestablish at the outer limits of the easement area after all vegetation has initially been cleared. Tree species that endanger safe and reliable operation of the transmission line will be removed.

The NESC states that "vegetation that may damage ungrounded supply conductors should be pruned or removed." Trees beyond the easement area that are in danger of falling into the

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224 Construction spreads refer to a specific area under construction. Construction spreads are determined by the utility based on multiple factors, such as engineering, labor, materials, and permitting needs.

225 Right-of-way located within environmentally sensitive areas and where conductor clearance heights dictate may not be cleared edge to edge.

energized transmission line (danger trees) will be removed or trimmed to eliminate the hazard, as allowed by the terms in the given acquired easement. Danger trees generally are those that are dead, weak or leaning towards the energized conductors. While clearing typically occurs immediately prior to the installation of structures and their associated foundations, there are instances where clearing must occur before the overall line design and structure placements are finalized. This is often the result of calendar restrictions to avoid vulnerable timeframes in the life cycle of particular flora or fauna species. In those situations, the Applicants would proceed with clearing in parallel with final design efforts.

All material resulting from the clearing operations will either be chipped on site and spread on the easement area outside of sensitive environmental areas, stacked in the easement area for use by the property owner, or removed and disposed of as otherwise agreed to with the property owner during easement negotiations.

The Applicants will design the transmission line structures for installation at the existing ground elevations. Where terrain requires (typically on slopes exceeding 10 percent), working areas may be graded or leveled with fill. If acceptable to the landowner, the Applicants will leave the graded/leveled areas after construction to allow for access during future maintenance activities. If not acceptable to the landowner, the Applicants will, to the extent practicable, return the grade of the site back to its original condition.

Construction will require the use of many different types of construction equipment, including, amongst other things, 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, stringing equipment, helicopters, and various trailers or other hauling equipment. To the extent practicable, construction crews will attempt to use equipment and matting that minimizes impacts to lands.

The Applicants will use construction staging areas/laydown yards for the staging of personnel and equipment and the storage of materials necessary to construct the new transmission line facilities. The Applicants estimate that construction of the Project will likely include 1-2 staging areas on Segment 1 and 6-8 staging areas on Segment 2, ranging from 20 to 60 acres in size.

The Applicants will evaluate construction access opportunities by identifying existing transmission line easements, roads, or trails that run near the approved route. When feasible, the Applicants will limit construction activities to the easement area. In certain circumstances, additional off-easement access or workspace may be required.

New access roads, or improvements to existing access roads and bridges, may be required to accommodate construction equipment. The Applicants will obtain permits for new access from local road authorities when needed.

Structure and foundation installation will begin after right-of-way clearing and access preparation are complete. **Section 2.2.2** describes the types of foundations proposed for Project structures. The actual diameter and depth of the foundation and associated excavation will depend on structure and foundation design and the soil conditions that are determined during geotechnical exploration. Once the excavation is prepared, the Applicants will place a steel rebar cage in the excavation, along with an anchor bolt cage or stub angle, depending on the design of the structures. Concrete is then brought to the site from a local concrete batch plant or portable, onsite batch plant and is placed in the excavation.

Structure components will then be transported from staging areas and delivered to the appropriate foundation locations once the concrete has properly cured. The Applicants will assemble and erect the structures in sections. The structure base will be bolted to the foundation via the anchor bolts or stub angles, and then insulators and associated hardware will be attached to the structure.

Conductor and shield wire stringing is the last major component of transmission line construction. Where the Project crosses streets, roads, highways, or other energized conductors or obstructions, the Applicants may install temporary guard structures before conductor stringing. The temporary guard structures ensure that conductors will not obstruct traffic or contact existing energized conductors or other cables during stringing operations and also protect the conductors from damage. Depending on the type of crossing, traffic control may be applicable based on local permitting requirements.

Stringing setup areas are dependent on the line design and configuration. However, it is anticipated that stringing sites will typically be located at approximately 3- to 4-mile intervals. These sites are located within the right-of-way when possible. When necessary, the Applicants will acquire temporary construction easements. Stringing operations require access to each structure to secure the conductor and shield wire to the insulators and clamps, respectively, once final conductor sag, compliant with the Applicants' procedures and minimum code clearances, is established. This access can be conducted via crane, aerial lift, or helicopter.

Conductor accessories will be installed as required after conductor installation is complete. These accessories may include vibration dampers, spacer-dampers, bird flight diverters, or aerial navigation markers. The Applicants will work with the appropriate agencies to identify locations where marking devices will be installed.

Certain soil conditions and environmentally-sensitive areas may require special construction techniques. To the extent possible, the Applicants will attempt to place structures outside of such areas, so as to minimize any environmental impacts. When it is not feasible to avoid traversing sensitive areas, one or more of the following options will be used to minimize impacts, in consultation with the appropriate agencies:

- When practicable, construction will be scheduled during frozen ground conditions.
- When construction during frozen conditions is not practicable, construction mats will be used where wetlands and other sensitive areas would be impacted. Mats may also be used across upland terrain, access routes, and structure pads where ground disturbance, equipment stability, or access limitations require additional support.
- Equipment fueling and other maintenance will occur away from environmentally-sensitive areas and waterways. These construction practices help prevent soil erosion and ensure that fuel and lubricants do not enter waterways or impact environmentally-sensitive areas.
- Various best management practices (BMPs) will be identified in the Project's Stormwater Pollution Prevention Plan, including the use of silt fences, bio logs, erosion control blankets with embedded seeds, hydromulch, and other sound water and soil conservation practices to protect topsoil and adjacent water resources and to minimize soil erosion.

These techniques are also used to reduce impacts to private property including driveways, yards, and agricultural drain tile.

9.4 RESTORATION AND CLEAN-UP PROCEDURES

Construction crews will attempt to minimize ground disturbance, but areas will be disturbed during the normal course of work. Once construction is completed in an area, governed by seasonal constraints, applicants will restore disturbed areas to their original condition to the maximum extent feasible. Temporary restoration before the completion of construction in some areas along the right-of-way may be required per National Pollutant Discharge Elimination System and MPCA construction permit requirements.

After construction activities have been completed, a 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 crops damaged during construction. The damaged area will be measured, yield determined in consultation with the farmer, and crop losses paid at current market rates. The Applicants will also make a payment for future year crop loss due to soil compaction. In addition, farmers will be compensated for their expense to deep rip compacted areas. If an individual does not have access to deep ripping equipment, the Applicants will provide this service.

Ground-level vegetation disturbed or removed from the right-of-way during construction of the Project will naturally reestablish to pre-construction conditions. Vegetation that is consistent with substation/switchyard site operation outside the fenced area will be allowed to reestablish naturally at substation sites. Areas where significant soil compaction or other disturbances 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.

Further, after construction activities are complete, the Applicants will ensure that 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 the roads are adequately restored, if necessary, after construction is complete.

9.5 MAINTENANCE PRACTICES

Applicants will design and maintain the transmission lines in accordance with the NESC and the Applicants' standards. In general, transmission lines are highly reliable and unplanned outages have been limited. The average annual availability of transmission infrastructure is very high, in excess of 99 percent. Transmission facilities have decades-long estimated service lives but, practically speaking, high voltage transmission lines are seldom retired. Regular maintenance and asset renewal of transmission line components is necessary for longer term reliable operation.

The Applicants will require access to the transmission line right-of-way to periodically conduct inspections, perform maintenance, and repair damage that may occur. Generally, the Applicants will inspect the Project at least once by air and once by ground annually. These inspections will be limited to the defined easement areas and through other access easement areas where obstructions or terrain dictate. If maintenance concerns are identified during inspection, repairs will be performed as necessary. Should any damage occur to the right-of-way, the right-of-way will be restored to its original condition, or the landowner will be provided with reasonable compensation for any damage to the property. The annual inspections are the principal operating and maintenance cost for transmission facilities. The aerial inspections cost approximately $150 per mile, and the ground inspections cost approximately $500 per mile. 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 Applicants will manage the right-of-way to control any encroachments that may interfere with the operation of the transmission line, including removal of vegetation that interferes with the operation and maintenance of the transmission line. Native shrubs that will not interfere with the safe operation and maintenance of the transmission line will be allowed to reestablish in the outer edge the right-of-way. Right-of-way clearing practices include a combination of mechanical and hand clearing, with herbicide application where allowed, to remove or control vegetation growth.

9.6 STORM AND EMERGENCY RESPONSE AND RESTORATION

Transmission infrastructure has 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.

In the event of a fault on the transmission system, protective relaying equipment is designed to immediately detect the fault and automatically remove the transmission line from service. Such interruptions are usually only momentary. Scheduled maintenance outages are also infrequent.

However, unplanned outages of transmission facilities can happen for a variety of reasons. Unplanned outages can occur due to such things as mechanical failures or severe weather such as heavy ice, wind, or a combination of ice and wind. In the event that an unplanned outage was to occur, the Applicants have the necessary infrastructure and crews in place in central and southern Minnesota to respond quickly and safely to return the line to service.

If there is a storm or emergency outage, the Applicants have distributed service centers in the region that will initiate a tactical response by deploying on call first responders to the lines as quickly as possible to patrol the line and immediately assess the damage. Once the damage has been assessed the first responder will immediately relay the following information back to the service center:

- magnitude of damage;
- isolation requirements for switching;
- material required for restoration;
- number of line crew needed; and
- equipment needed.

Based on the assessment of the first responder, the utility owner will develop a plan to restore the damaged facilities. The goal of the repair is to place the transmission system back into service as quickly as possible to minimize the impact to the transmission system. The Applicants have the benefit of both internal and contract crews distributed across central and southern Minnesota and the Twin Cities that will enable a rapid response to outage events on the transmission line. These crews can typically be mobilized and on-site within two hours of an event to begin restoration activities.

In addition to line crews, the Applicants maintain a stock of essential transmission line materials to ensure timely and efficient repairs. These materials are strategically stocked to address common repair needs and meet quantity requirements. For specialized or major repairs, additional materials may be procured as needed to return the line to service as quickly as possible.

The Applicants also have experienced internal engineering departments that can assist in the event of unplanned outages. If a storm or emergency outage were to occur, on-call engineers can be notified to assist in identifying an appropriate repair. The engineer will assess the situation based on feedback from onsite personnel and design an appropriate solution for any damaged infrastructure. Based on the scale of the damage, additional engineering resources can be requested as needed.

10 ENVIRONMENTAL INFORMATION

10.1 PROJECT STUDY AREA

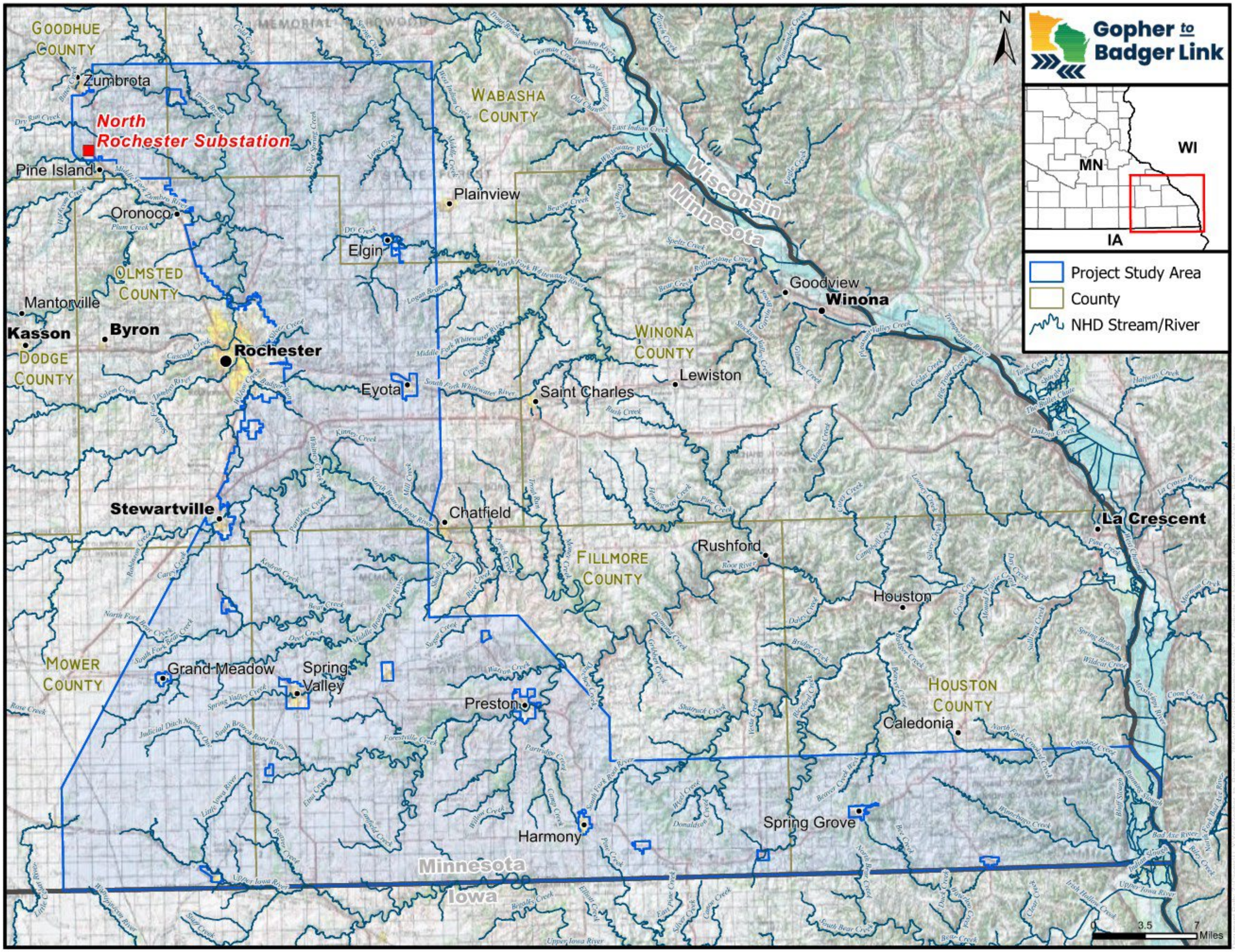
The Applicants gathered environmental information to characterize conditions within the Project Study Area. The Project Study Area is equivalent to the Project Notice Area as described in **Chapter 1** and as shown on **Figure 1.8.1**. The Project Study Area occurs in portions of Goodhue, Wabasha, Olmsted, Mower, Fillmore, and Houston counties. The intent of this Chapter is to describe the major features present within the Project Study Area. Throughout this Chapter, information about existing resources is presented from the western portion to the eastern portion of the Project Study Area, as appropriate.

Larger cities (greater than 2,000 people) in or immediately adjacent to the Project Study Area from northwest to southeast include Zumbrota, Pine Island, Plainview, Rochester, Eyota, Stewartville, Chatfield, Spring Valley, and Caledonia. Major rivers in the Project Study Area include the Zumbro, Root, Whitewater, Cannon, and Mississippi Rivers.

The landscape of the western portion of the Project Study Area consists of level to gently rolling older till plains. Agricultural fields now dominate this portion of the Project Study Area. The eastern portion of the Project Study Area, characteristic of the Driftless Area, consists of an old plateau covered by loess (windblown silt) that has been extensively eroded along rivers and streams. It is characterized by highly dissected landscapes associated with major rivers in southeastern Minnesota. Bluffs and deep stream valleys (500 to 600 feet deep) are common. The Driftless Area[226] is characterized by its geological features and ecological diversity. It is a region that was not glaciated during the last Ice Age, resulting in a landscape with cold, clear streams and abundant wildlife. River bottom forests grew along major streams and rivers (**Figure 10.1-1**).

[226] MDNR. 2025. Driftless Odyssey. Available online at: https://files.dnr.state.mn.us/eco/nongame/projects/driftless-odyssey-story.pdf Accessed December 2025.

Figure 10.1-1: Topography in the Project Study Area Map



10.2 PHYSIOGRAPHIC REGIONS

The Minnesota Department of Natural Resources (MDNR) and the U.S. Forest Service developed an Ecological Classification System (ECS)[227] 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. Within the ECS, the State of Minnesota is split into ecological provinces, sections, and subsections. Under this classification system, the Project Study Area is in the Eastern Broadleaf Forest Province (**Figure 10.2-1**). The majority of the Project Study Area is located in the Paleozoic Plateau Section of the Eastern Broadleaf Forest Province. The very western portion of the Project Study Area overlaps a small portion of the Minnesota and Northeast Iowa Morainal Section.

Ecological sections are further broken down into subsections. The Project Study area includes three ECS subsections: the Rochester Plateau on the west, the Oak Savanna subsection in the southwest portion of the Project Study Area and The Blufflands subsection on the east.

Table 10.2-1 provides the acreage and percentage of the Project Study Area within each ECS subsection. **Figure 10.2-1** depicts the ECS subsections in relation to the Project Study Area. General physiography and geomorphology for each subsection is outlined below.

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227 MDNR. 2025. Ecological Classification System. Available online at: https://www.dnr.state.mn.us/ecs/index.html. Accessed October 2025.

Figure 10.2-1: Ecological Classification System Subsections Map

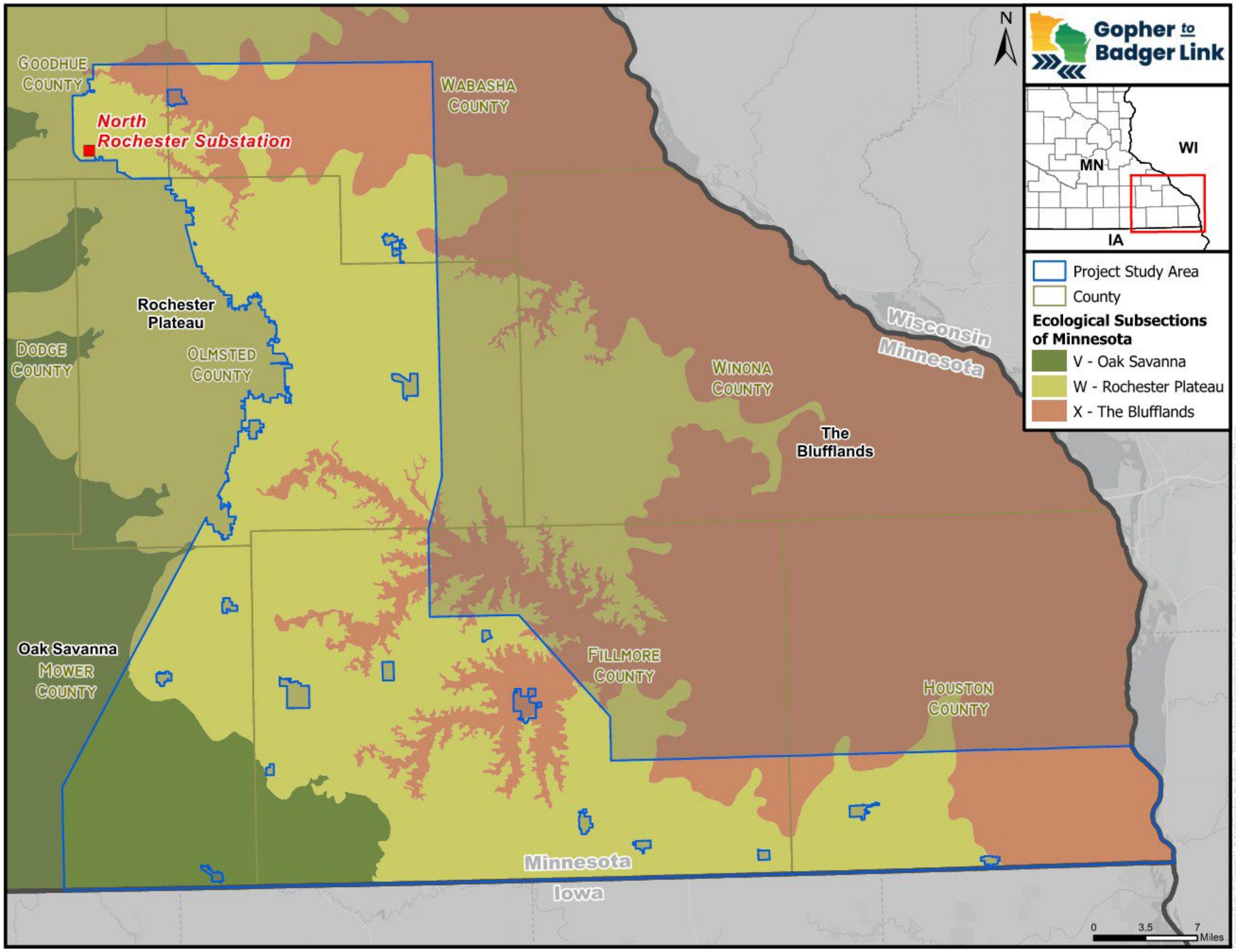

TABLE 10.2-1 Ecological Classification System Subsections in the Project Study Area			
ECS Subsection[a]	Counties	Acres in Project Study Area	Percentage of Project Study Area
Rochester Plateau	Goodhue, Wabasha, Olmsted, Mower, Fillmore, Houston	600,607	62.4%
The Blufflands	Wabasha, Olmsted, Fillmore, Houston	232,146	24.1%
Oak Savanna	Mower, Fillmore	129,856	13.5%
[a] 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.			

10.2.1 Rochester Plateau Subsection[228]

This unit consists of an old plateau covered by loess (windblown silt) along the eastern border and pre-Wisconsin age glacial till in the central and western parts. The western portion is a gently rolling glacial till plain that is covered by loess in places.

This subsection consists of level to gently rolling older till plains. Topography is controlled by underlying glacial till along the western edge of the subsection, where loess is several feet thick. As glacial drift thins to the east, topography is largely bedrock controlled. Sinkholes are common in the southwestern portion of the subsection.

Soil thickness is variable; loess deposits range from 30 feet thick on broad ridgetops, to less than a foot on valley walls. There are few lakes in this subsection. The drainage network is well developed and dendritic in nature. Major rivers include the headwaters of the Zumbro, Root, Whitewater, and Cannon. Several coldwater trout streams are present in the eastern part of this subsection.

10.2.2 The Blufflands Subsection[229]

The Blufflands Subsection in the eastern portion of the Study Area is associated with the Driftless Area characteristics. The western boundary of the subsection is complex, following major river valleys. The northern boundary marks the northern extent of loess deposits. There is also a small outwash plain that marks the northern boundary. The eastern boundary is the Mississippi River.

This subsection consists of an old plateau covered by loess (windblown silt) that has been extensively eroded along rivers and streams. It is characterized by highly dissected landscapes associated with major rivers in southeastern Minnesota. Bluffs and deep stream valleys (500 to 600 feet deep) are common. River bottom forests grew along major streams and rivers.

The area is a loess-capped plateau, deeply dissected by river valleys. The greatest relief occurs along the Mississippi River (see **Section 10.3**), where relief is up to 600 feet. In the east, loess lies directly on bedrock. Sinkholes are common in the southwestern portion of the subsection.

228 MDNR. 2025. Rochester Plateau Subsection. Available online at: https://www.dnr.state.mn.us/ecs/222Lf/index.html. Accessed September 2025.

229 MN DNR. 2025. The Blufflands Subsection. Available online at: https://www.dnr.state.mn.us/ecs/222Lc/index.html. Accessed October 2025.

There are no lakes in this subsection. The drainage network is well developed and dendritic in nature. Major rivers include the Cannon, Zumbro, Root, Whitewater, and Mississippi (which forms the eastern boundary). There are coldwater trout streams throughout the subsection.

10.2.3 Oak Savanna Subsection[230]

Much of this subsection is a rolling plain of loess-mantled ridges over sandstone and carbonate bedrock and till. As a result, fires from the surrounding prairies to the south, west, and east burned the landscape frequently enough to maintain oak opening rather than forest (Albert 1993). At the southwestern edge of the subsection are moraine ridges which led to woodlands protected from prairie fires by the rugged relief. Presently, most of the subsection is farmed. Most of this subsection has a fairly well developed drainage network. This is due to the nature of landforms within the unit. There are few lakes; but they are present in the moraines that form the western edge of the subsection.

10.3 HYDROLOGIC FEATURES

10.3.1 Major Basins

Hydrologic Unit Codes (HUCs) are used nationwide to differentiate drainage areas with a series of numbers. There are eight major watershed basins (HUC-04) and 81 major surface water watersheds (HUC-08) covering Minnesota. The Project Study Area includes three HUC-04 watersheds: the Upper Mississippi–Black–Root (0704), the Upper Mississippi-Maquoketa-Plum (0706), and the Upper Mississippi–Iowa–Skunk–Wapsipinicon (0708) along the Minnesota and Iowa border. There are seven HUC-08 Watersheds located within the Project Study Area (**Figure 10.3-1; Table 10.3.1)**; 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.

230 MDNR. 2025. Oak Savanna Subsection. Available online at: https://www.dnr.state.mn.us/ecs/222Me/index.html. Accessed September 2025.

Figure 10.3-1: Watersheds in the Project Study Area.

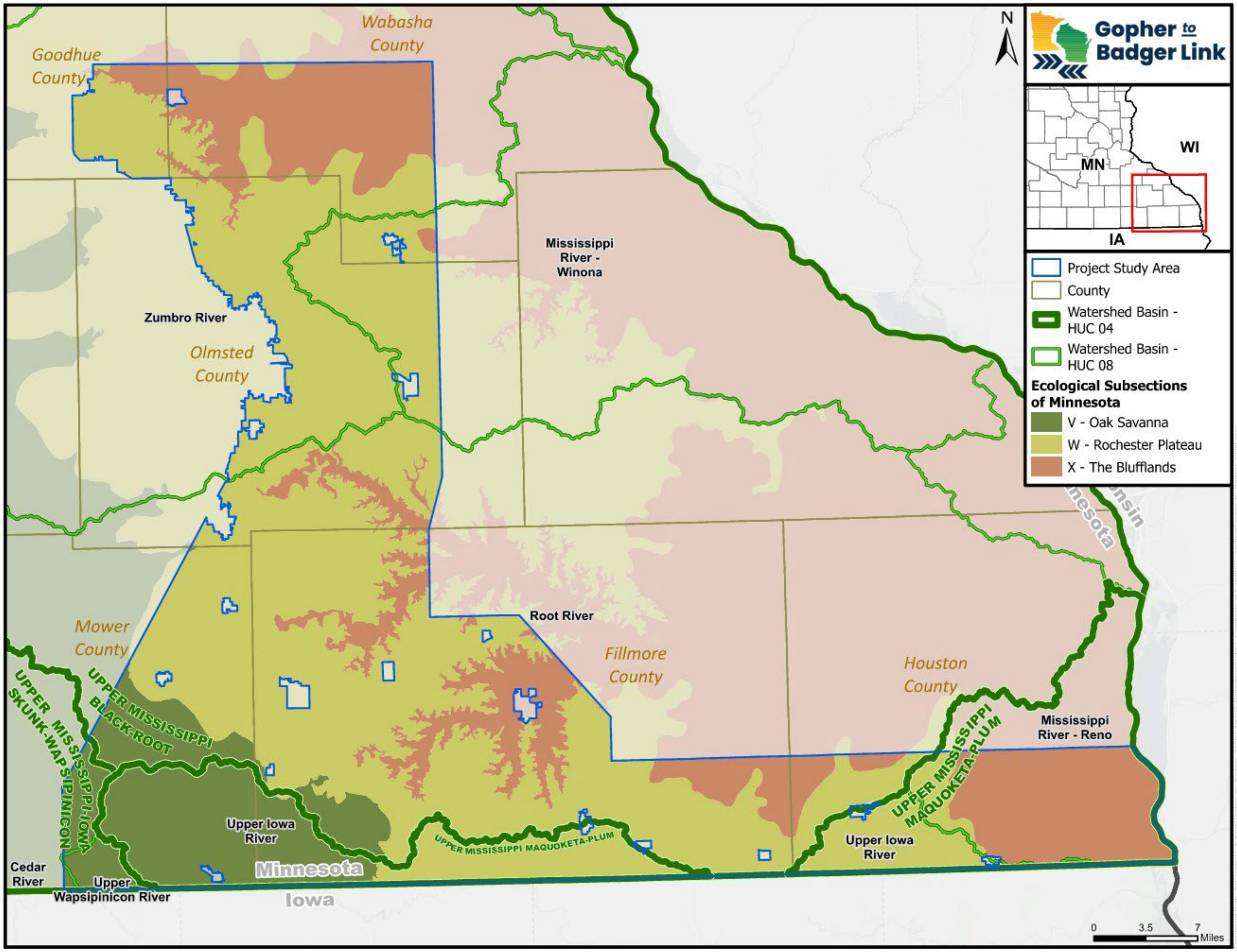

TABLE 10.3-1 Major Watersheds (HUC-08) in the Project Study Area by ECS			
Major Watershed (HUC-08)	**Rochester Plateau**	**The Blufflands**	**Oak Savanna**
Zumbro River	137,334	80,324	0
Mississippi River - Winona	51,850	1,110	0
Root River	337,900	84,695	38,586
Mississippi River – Reno	8,937	65,297	0
Upper Iowa River	64,586	719	72,029
Upper Wapsipinicon River	0	0	8,231
Cedar River	0	0	11,011

10.3.2 Surface Water

According to the MDNR Public Waters Inventory (PWI) dataset and MDNR Hydrography Dataset, there are 7,892 acres of surface water located within the Project Study Area, of which 45 percent are considered Public Waters (**Table 10.3-2**, **Figure 10.3-2**). All basins and wetlands are less than 600 acres in size, excluding the Mississippi River floodplains and the Lock and Dam basins.

Figure 10.3-2: Public Waters Inventory and Wetlands in the Project Study Area.

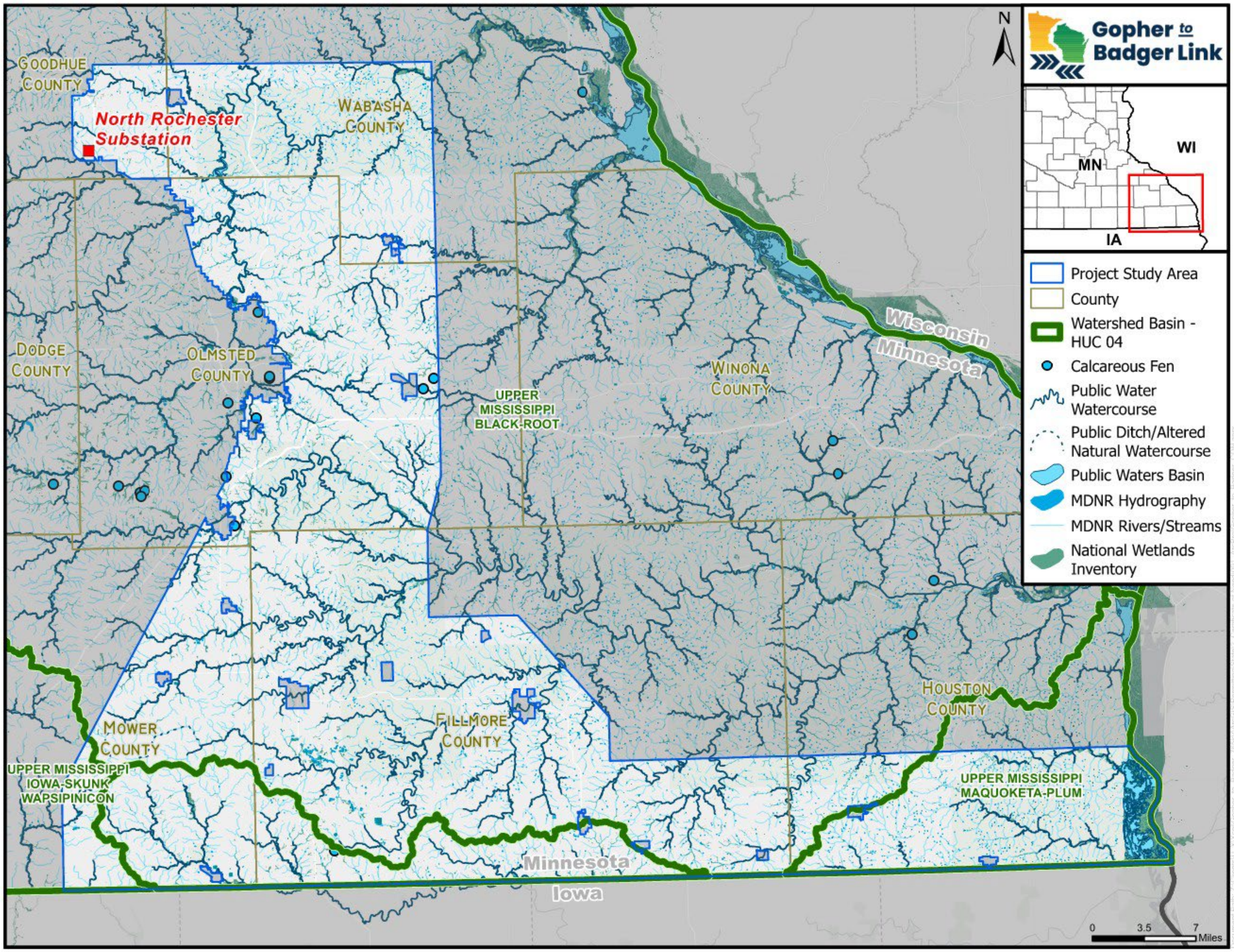

TABLE 10.3-2 Surface Water Types by Subsection within the Project Study Area				
Surface Water Feature Type	**Oak Savanna (acres)**	**Rochester Plateau (acres)**	**The Blufflands (acres)**	**Total Acres**
Non-Public Waters	272	1,040	3,050	4,362
Artificial basin	25	40	1	67
Lake or Pond	204	926	336	1,466
Riverine polygon	27	60	2,702	2,788
Wetland	16	14	11	41
Public Waters	15	114	3,400	3,530
Lake or Pond	15	49	697	762
Riverine polygon	0	0	2,666	2,666
Wetland	0	65	36	102
TOTAL	**287**	**1,155**	**6,450**	**7,892**

10.3.3 Rivers and Streams

According to the MDNR PWI dataset and MDNR Rivers and Streams Dataset, there are 3,225 miles of watercourses located within the Project Study Area, of which 33 percent are considered Public Waters (**Table 10.3-3**, **Figure 10.3-2**).

TABLE 10.3-3 Watercourses by Subsection within the Project Study Area				
Watercourse Type	**Oak Savanna (miles)**	**Rochester Plateau (miles)**	**The Blufflands (miles)**	**Total miles**
Non-Public Waters	248	1,256	644	2,148
Public Waters	126	507	444	1,077
TOTAL	374	1,763	1,088	3,225

The Mississippi River is the southeastern edge of the Project Study Area in Houston County. The Mississippi River forms the eastern border of Houston County, MN, creating a landscape of bluffs, backwaters, and wetlands. Other major tributaries like Root River, Crooked Creek, and Winnebago Creek also flow into the Mississippi River within or near this county. Apart from being a public water, the Mississippi River is also a navigable water as defined under Section 10 of the Rivers and Harbors Act. The Project would cross the Mississippi River.

The Project Study Area also includes the U.S. Fish and Wildlife Service (USFWS) Upper Mississippi River National Wildlife and Fish Refuge (the Refuge) (see **Section 10.5.1**) and the Reno Bottoms area. In addition, the MDNR has mapped a portion of the Mississippi River located within the Project Study Area as a Minnesota wild rice water.[231]

The Reno Bottoms Area is a 14,000-acre backwater area on the western side of Pool 9 of the Mississippi River. The U.S. Army Corps of Engineers (USACE), in partnership with the USFWS,

[231] MDNR. 2020. Wild Rice Lakes Identified by DNR Wildlife. Available online at: https://mnatlas.org/resources/wild-rice-mn-dnr/ Accessed December 2025.

MDNR, Wisconsin Department of Natural Resources (WDNR), Iowa Department of Natural Resources and U.S. Geological Survey, is currently studying the feasibility of restoring habitat within this area, which has experienced increased water levels and degradation of historic vegetation and habitat. The restoration project has been divided into two phases, with Phase 1 extending from Millstone Landing on the Minnesota side of the river and from Lock & Dam 9 on the Wisconsin side of the river, south across the Iowa border. Phase 2 extends north from Millstone Landing and Lock & Dam 9 to Reno, Minnesota. The Project Study Area crosses portions of both Phase 1 and Phase 2. The USACE anticipates initiating construction of Phase 1 of the Project in 2028.[232]

Impacts to waterbodies from a transmission line are typically avoided by siting structures outside of the bed and banks and spanning the feature where feasible; however, temporary bridges may be required across some features during construction. The Project will cross waterbodies regulated by the USACE St. Paul District under Section 10 and 404 of the Clean Water Act. The MDNR regulates PWI watercourses under Minn. Stat. Ch. 103G and Minn. R. Ch. 6115 and 6135, which require permits for work below the ordinary high water mark, and licenses for overwater crossings. In addition, local permits from watershed districts may be required. Further, as discussed above, the Mississippi River crossing is regulated by the USACE, MDNR, the WDNR, and will require coordination with the USFWS. The Applicants will submit permit applications for the Project later in the routing and permitting process. Permit applications will contain information on how the Applicants will construct and operate the Project to minimize impacts.

10.3.4 Wetlands

The Project Study Area is located within the Midwest Regional Supplement to the USACE wetland delineation manual. The Midwest region is characterized by its generally flat to rolling topography, fertile soils, and moderate to abundant rainfall.[233] Wetlands in the Midwest region are generally characterized as prairie wetlands or riverine wetlands.

Wetlands are important resources for flood abatement, wildlife habitat, and water quality. According to the National Wetlands Inventory database[234], the Project Study Area contains approximately 48,608 acres of wetlands, comprising roughly 5 percent of the Project Study Area (**Figure 10.3-2**). Most of the wetlands are classified as freshwater emergent wetlands and freshwater forested wetlands (**Table 10.3-4)**.

TABLE 10.3-4

Wetland Acreage within the Project Study Area

Wetland Type	Oak Savanna	Rochester Plateau	The Blufflands	Total Acres in Project Study Area	% Wetland Type in Project Study Area
Freshwater Emergent Wetland	2,647	11,076	9,010	22,733	2.4%

232 USACE. Undated. Upper Mississippi River Restoration: Reno Bottoms Habitat Rehabilitation & Enhancement Project. Available online at: https://www.mvr.usace.army.mil/Missions/Environmental-Stewardship/Upper-Mississippi-River-Restoration/Habitat-Restoration/St-Paul-District/Reno-Bottoms/. Accessed December 2025.

233 USACE. 2010. Regional Supplement to the Corps of Engineers Wetland Delineation Manual (Version 2.0). Available online at: https://www.mvp.usace.army.mil/Portals/57/docs/regulatory/Website%20Organization/Midwest%20Regional%20Supplement%20(Version%202).pdf. Accessed October 2025.

234 USFWS. 2025. National Wetlands Inventory. Available online at: https://www.fws.gov/program/national-wetlands-inventory/wetlands-data. Accessed October 2025.

TABLE 10.3-4 Wetland Acreage within the Project Study Area					
Wetland Type	**Oak Savanna**	**Rochester Plateau**	**The Blufflands**	**Total Acres in Project Study Area**	**% Wetland Type in Project Study Area**
Freshwater Forested Wetland	553	4,486	10,329	15,368	1.6%
Freshwater Forested/Emergent Wetland	16	103	259	377	0.0%
Freshwater Forested/Shrub Wetland	0	20	14	35	0.0%
Freshwater Pond	185	736	793	1,714	0.2%
Freshwater Shrub Wetland	207	666	692	1,565	0.2%
Freshwater Shrub/Emergent Wetland	17	79	20	116	0.0%
Lake	69	267	909	1,245	0.1%
Riverine	173	868	4,414	5,456	0.6%
Total Acres by Subsection	**3,866**	**18,303**	**26,439**	**48,608**	**5.0%**

The Upper Mississippi River wetland area from Wabasha, Minnesota, to north of Rock Island, Illinois is designated as a Ramsar Site by the Ramsar Convention. This designation does not affect jurisdiction or current uses of the wetland area, but is intended to provide additional funding for outreach, research and grants with the intent of heightening public awareness and appreciation for the ecosystem.[235]

Similar to waterbodies, impacts to wetlands associated with a transmission line are typically avoided by siting structures outside of the wetland boundaries and spanning the feature where feasible; seasonal restrictions, construction mat installation, and removal of woody vegetation may be required across some features. Several agencies regulate impacts to wetlands in Minnesota. The USACE St. Paul District regulates wetlands that are hydrologically connected to the nation's navigable rivers under Section 404 of the Clean Water Act. The MDNR regulates PWI basins and wetlands under Minn. Stat. Ch. 103G and Minn. R. Ch. 6115 and 6135, which similar to PWI watercourses, require permits for work below the ordinary high water mark and/or licenses for overwater crossings. Section 401 of the Clean Water Act requires that water quality certifications (WQCs) be issued to protect the surface water features from water quality degradation. The MPCA is responsible for issuing the Section 401 WQC in Minnesota for surface waters of the state, which include waterbodies and wetlands. The Section 401 WQC is issued as part of the USACE Section 404 permit. Finally, the Minnesota Board of Water and Soil Resources (BWSR) coordinates the state Wetland Conservation Act.

The Applicants will design the Project to avoid and minimize potential temporary and permanent impacts to wetlands and will work with regulatory agencies to obtain necessary permits and approvals prior to construction of the Project.

235 USFWS. Undated. Fact Sheet: Wetland of International Importance (Ramsar): Upper Mississippi River Floodplain Wetlands – Minnesota, Wisconsin, Iowa and Illinois. Available at: https://www.fws.gov/sites/default/files/documents/news-attached-files/RamarUppermiss.pdf. Accessed December 2025.

10.3.5 Calcareous Fens

Calcareous fens[236] 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. MDNR regulates potential impacts to calcareous fens under Minn. Stat. § 103G.223 and Minn. R. 8420.0935.[237] A review of MDNR data identified several fens within the Project Survey Area (**Figure 10.3-2**). Applicants will carefully consider the location of these features when routing the Project to avoid and minimize impacts and will coordinate with the MDNR during the permitting process.

10.3.6 Floodplains

Federal Emergency Management Agency (FEMA) floodplain digital data is available within Olmsted, Mower, Fillmore, Goodhue, and Houston counties within the Project Study Area. The major floodplains in the Project Study Area occur adjacent to large waterbodies and watercourses. Regulatory floodways are mapped along the Root, Whitewater, Zumbro (and tributaries), Upper Iowa River, Deer Creek, Spring Valley Creek, tributary to the Little Cedar River, and Mississippi River. In most locations, 100-year and 500-year floodplain areas exist beyond the regulatory floodways. Additional 100-year and 500-year floodplain areas exist along larger perennial streams, ponds, and lakes. Most of the Project Study Area is mapped as areas with minimal flood hazard (Zone X).[238]

10.3.7 Groundwater

Groundwater in Minnesota is divided into six aquifer provinces based on glacial geology and bedrock.[239] The Project Study Area is located within three groundwater provinces. The Western portion is located within the South-central Groundwater Province, the far eastern portion is within the East-central Groundwater Province, and the Eastern portion is located within the Karst Groundwater Province. The majority of the Project Study Area (91 percent) is located within the Karst Groundwater Province.

The Karst Groundwater Province is characterized by thin (less than 50 feet) glacial sediment overlying thick and extensive bedrock (carbonate and sandstone).

The South-central Province is characterized by thick loam and clay loam glacial sediment, with limited extents of surficial and buried sand aquifers, overlying thick and extensive Paleozoic aquifers.

The East-central Province is characterized by buried sand aquifers and relatively extensive surficial sand plains, part of a thick layer of sediment deposited by glaciers overlying the bedrock. It is underlain by sedimentary bedrock with good aquifer properties.

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236 DNR. 2025. Calcareous Fens. Available online at: https://www.dnr.state.mn.us/wetlands/calcareous-fens.html. Accessed October 2025.

237 Minn. R. 8420.0935, subp. 2.

238 FEMA. 2025. Flood Map Service Center. Available online at: https://msc.fema.gov/portal/search?AddressQuery=fillmore%20county%20MN. Accessed October 2025.

239 MPCA. 2025. The Condition of Minnesota's Groundwater Quality 2018 – 2023. Available online at: https://www.pca.state.mn.us/sites/default/files/wq-am1-11.pdf. Accessed October 2025.

The Applicants will conduct geotechnical evaluations prior to construction of the Project; these evaluations will include identification of locations with shallow depth to groundwater resources.

10.3.8 Karst and Springs

Southeastern Minnesota is a region composed of rolling hills, bluffs, and valleys, where shallow levels of sediment cover Paleozoic carbonate and sandstone bedrock. This region, also known as the Driftless Area, was not glaciated during the last ice age and covers portions of Dakota, Goodhue, Wabasha, Olmsted, Winona, Fillmore and Houston counties, Minnesota, and extends into southwestern Wisconsin, northeastern Iowa, and the extreme northwestern corner of Illinois. Karst landscapes can develop where these types of bedrock are at or near the surface. Over time, the carbonate minerals in the rock are dissolved by rain and groundwater, creating karst. Karst is characterized by sinkholes, caves, springs, and underground drainage dominated by rapid conduit flow.[240] The MDNR maintains the Karst Features Inventory, which contains both reported and verified karst features like sinkholes, caves, stream sinks, and karst springs.[241] The location of springs is also maintained by the MDNR as the Minnesota Spring Inventory.[242] Karsts and springs as mapped by the MDNR are known to occur throughout the Project Study Area.

Future Project activities will use BMPs for all construction activities in these areas to prevent surface runoff and sedimentation in these areas. In addition, the Applicants will conduct geotechnical analyses where appropriate to evaluate whether karst is present at structure locations and structure foundation design will account for the presence of karst, as needed.

10.4 NATURAL VEGETATION AND ASSOCIATED WILDLIFE

The pre-settlement and current natural vegetation, and associated wildlife species, vary across the Project Study Area due to the characteristics of each ECS. A general description of each subsection can be found in **Section 10.2**, and **Figure 10.2-1** depicts the subsections within the Project Study Area.

10.4.1 Vegetation

The western portion of the Study Project Area is located in the Rochester Plateau ECS subsection. The eastern portion crosses The Blufflands ECS subsection. The southwest corner of the Project Study Area is located in the Oak Savanna ECS subsection. Thorough descriptions of each subsection are provided in **Section 10.2**.

Tallgrass prairie and bur oak savanna were the dominant vegetation before settlement in the Rochester Plateau ECS subsection.[243] Fire was important in upland prairie and oak savanna dominated communities.

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240 MDNR. 2025. Springs, Springsheds, and Karst. Available online at: https://www.dnr.state.mn.us/waters/groundwater_section/mapping/springs.html. Accessed October 2025.

241 MDNR. 2025. Karst Feature Inventory Points. Available online at: https://gisdata.mn.gov/dataset/geos-karst-feature-inventory-pts. Accessed October 2025.

242 MDNR. 2025. Minnesota Spring Inventory. Available online at: https://arcgis.dnr.state.mn.us/portal/apps/webappviewer/index.html?id=560f4d3aaf2a41aa928a38237de291bc. Accessed October 2025.

243 MN DNR. 2025. Rochester Plateau Subsection. Available online at: https://www.dnr.state.mn.us/ecs/222Lf/index.html. Accessed October 2025.

In The Blufflands subsection[244], tallgrass prairie and bur oak savanna were major vegetation types on ridge tops and dry upper slopes. Red oak-white oak-shagbark hickory-basswood forests were present on moister slopes, and red oak-basswood-black walnut forests in protected valleys. Prairie was restricted primarily to broader ridge tops, where fires could spread, but also occurred on steep slopes with south or southwest aspect.

Bur oak savanna was the primary vegetation in the Oak Savanna subsection[245], but areas of tallgrass prairie and maple-basswood forest were common. Tallgrass prairie was concentrated on level to gently rolling portions of the landscape, in the center of the subsection. Bur oak savanna developed on rolling moraine ridges at the western edge of the subsection and in dissected ravines at the eastern edge. Maple-basswood forest was restricted to the portions of the landscape with the greatest fire protection, either in steep, dissected ravines or where stream orientation reduced fire frequency or severity

Currently, the Project Study Area is dominated by agricultural land, with the highest concentrations in the western half, with corn and soybeans representing the most common crops. Forests are scattered throughout the Project Study Area and are generally tied to stream and river corridors. See **Section 10.5** for a breakdown of current land use. In addition, areas of native vegetation are found scattered throughout the Project Study Area in lands mapped or managed by the MDNR; these include native prairie remnants, numerous conservation easements, Native Plant Communities (NPCs), Scientific and Natural Areas (SNAs), and Sites of Biodiversity Significance (SOBS) (**Figure 10.4-1**). The largest block of forest is contained in Forestville Mystery Cave State Park and in the southeast portion of the Project Study Area near the Mississippi River.

Potential impacts to vegetation in the Project Study Area would occur where clearing of trees and other vegetation is necessary for Project construction and maintenance. Construction and maintenance activities also have the potential to result in the introduction or spread of invasive and noxious species.

As routing for the Project is developed and refined, the Applicants would strive to avoid large, forested areas and other sensitive native vegetation resources to the extent practicable and would work with agencies to develop the appropriate BMPs and mitigation measures where avoidance is not possible.

10.4.1.1 Native Plant Communities and Sites of Biodiversity Significance

The MDNR classifies native vegetation in Minnesota by considering a variety of features, including hydrology, vegetation, soils, topography, and natural disturbance regimes (e.g., fire, floods, drought). This classification system is meant to "provide a framework and common language for improving our ability to manage vegetation, survey natural areas for biodiversity conservation, identify research needs, and promote study and appreciation of native vegetation in Minnesota."[246] NPCs are classified into classes, types, and subtypes. A variety of NPCs are found within the Project Study Area (**Figure 10.4-1**, **Table 10.4-1**), primarily mesic hardwood and

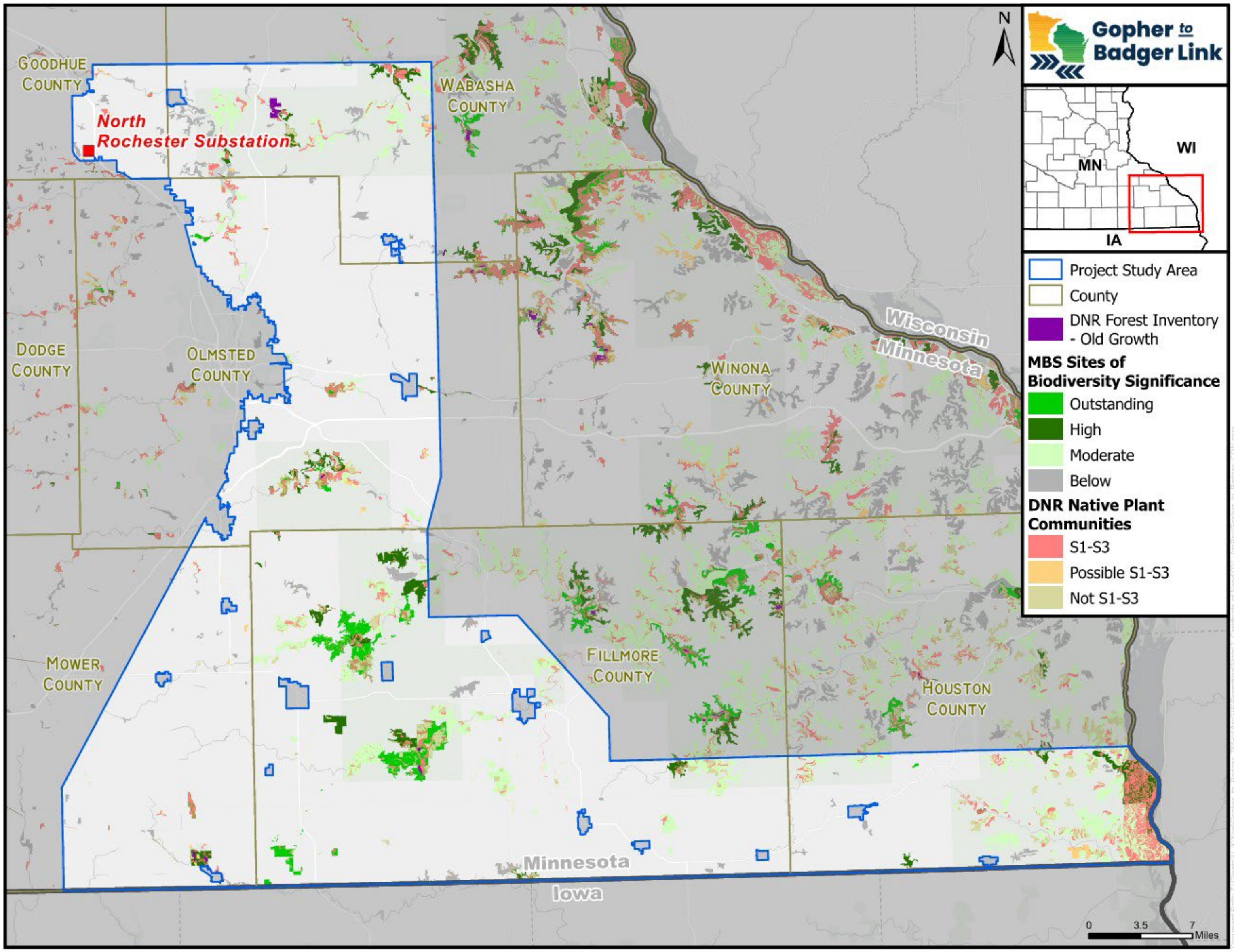
[244] MDNR. 2025. The Bluffland Subsection. Available online at: https://www.dnr.state.mn.us/ecs/222Lc/index.html. Accessed October 2025.

[245] MDNR. 2025. Oak Savanna Subsection. Available online at: https://www.dnr.state.mn.us/ecs/222Me/index.html. Accessed September 2025.

[246] MDNR. 2025. Minnesota's Native Plant Communities. Available online at: https://www.dnr.state.mn.us/npc/index.html. Accessed October 2025.

floodplain forest communities. There are 68 individual NPC classifications in the Project Study Area that are classified in eleven NPC Systems.

Figure 10.4-1: Minnesota DNR Native Plant Communities and Sites of Biodiversity Significance in the Project Study Area.



The MDNR ranks[247] SOBS based on the relative significance of biodiversity of the site at a statewide level. This system ranks sites at four levels: outstanding, high, moderate, or below based on the presence of rare species populations, the size and condition of native plant communities within the site, and the landscape context of the site. Within the Project Study Area, there are 41 sites (13 percent of sites) ranked as high and 28 (9 percent of sites) ranked as outstanding (**Figure 10.4-1, Table 10.4-2**). The Blufflands (73 percent of SOBS acreage in the Project Study Area) and Rochester Plateau subsections (24 percent of SOBS acreage in the Project Study Area) have the highest percentage of acres in Outstanding SOBS in the Project Study Area.

TABLE 10.4-1

NPC Breakdown by System Code and Subsection

NPC System Code	NPC Acres	Percentage
Oak Savanna	1,056	
Fire-Dependent Forest/Woodland System	150	14.2%
Floodplain Forest System	141	13.4%
Mesic Hardwood Forest System	191	18.1%
Open Rich Peatland System	12	1.1%
River Shore System	1	0.0%
Upland Prairie System	148	14.1%
Wet Forest System	3	0.3%
Wet Meadow/Carr System	259	24.5%
Wetland Prairie System	151	14.3%
Rochester Plateau	5,483	
Cliff/Talus System	307	5.6%
Fire-Dependent Forest/Woodland System	455	8.3%
Floodplain Forest System	211	3.9%
Marsh System	4	0.1%
Mesic Hardwood Forest System	4,072	74.3%
Open Rich Peatland System	9	0.2%
River Shore System	3	0.1%
Upland Prairie System	209	3.8%
Wet Forest System	1	0.0%
Wet Meadow/Carr System	186	3.4%
Wetland Prairie System	26	0.5%
The Blufflands	21,950	
Cliff/Talus System	1,160	5.3%
Fire-Dependent Forest/Woodland System	1,610	7.3%
Floodplain Forest System	4,761	21.7%
Marsh System	1,380	6.3%
Mesic Hardwood Forest System	12,185	55.5%
River Shore System	56	0.3%
Upland Prairie System	495	2.3%
Wet Forest System	22	0.1%
Wet Meadow/Carr System	281	1.3%
Total Mapped Acres in Project Study Area	**28,489**	

247 MDNR. 2025. Minnesota Biological Survey (MBS) Site Biodiversity Ranks. Available online at: https://www.dnr.state.mn.us/eco/mbs/biodiversity_guidelines.html. Accessed October 2025.

TABLE 10.4-2 MDNR Sites of Biodiversity Significance by Subsections					
ECS Subsection	**Below Number of sites (acres)**	**Moderate Number of sites (acres)**	**High Number of sites (acres)**	**Outstanding Number of sites (acres)**	**Total Number of sites (acres)**
Oak Savanna	12 (507)	5 (180)	2 (828)	4 (1,530)	23 (3,044)
Rochester Plateau	53 (4,440)	54 (9,000)	19 (2,877)	14 (4,186)	140 (20,504)
The Blufflands	36 (5,806)	85 (36,242)	20 (12,504)	10 (8,060)	151 (62,613)
TOTAL SITES (Acres)	**101 (10,754)**	**144 (45,421)**	**41 (16,209)**	**28 (13,776)**	**314 (86,161)**

As routing for the Project is refined, the Applicant will avoid NPCs and SOBS where practicable and will work with the appropriate agencies to develop the appropriate BMPs and mitigation measures where avoidance is not possible.

10.4.1.2 Native Prairie

The MDNR has developed the Minnesota Prairie Conservation Plan[248] to preserve existing prairie habitats, identify areas in need of conservation, and build cooperation between federal and state agencies and conservation organizations. A primary strategy for protecting existing prairie resources is to maintain habitat through conservation easements (see **Section 10.5.1.4** Conservation Easements) on public and private lands. Roughly 65 percent of land in the Project Study Area is categorized as cultivated cropland (refer to **Section 10.5**). Native prairie is present within these ECSs, but is generally found in small, scattered pockets along the margins of waterbodies where native vegetation has not been disturbed by agricultural production.

As routing for the Project is refined, the Applicant will avoid native prairie locations, where practicable, and will work with agencies to develop the appropriate BMPs and mitigation measures where avoidance is not possible.

10.4.2 Federally Listed Species

The USFWS Information for Planning and Conservation (IPaC) online tool was queried on October 15, 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 eleven species and one designated critical habitat that may be present within the Project Study Area (see **Table 10.4-3**). The Applicants will coordinate with the USFWS to avoid and minimize Project impacts on federally listed species as the Project design progresses.

248 MDNR. 2025. Minnesota Prairie Conservation Plan. Available online at: https://www.dnr.state.mn.us/prairieplan/index.html. Accessed October 2025.

TABLE 10.4-3 Federally Listed Species and Designated Critical Habitat within the Project Study Area		
Common Name	Scientific Name	Federal Status
Northern Long-eared Bat	*Myotis septentrionalis*	Endangered
Tricolored Bat	*Perimyotis subflavus*	Proposed Endangered
Higgins Eye (pearlymussel)	*Lampsilis higginsii*	Endangered
Salamander Mussel	*Simpsonaias ambigua*	Proposed Endangered
Sheepnose Mussel	*Plethobasus cyphyus*	Endangered
Monarch Butterfly	*Danaus plexippus*	Proposed Threatened
Rusty Patched Bumble Bee[a]	*Bombus affinis*	Endangered
Western Regal Fritillary	*Argynnis idalia occidentalis*	Proposed Threatened
Leedy's Roseroot	*Rhodolia integrifolia ssp. Leedyi*	Threatened
Prairie Bush-clover	*Lespedeza leptostachya*	Threatened
Western Prairie Fringed Orchid	*Platanthera praeclara*	Threatened
[a] Species also has designated critical habitat within Project boundary.		

Northern Long-eared Bat

The northern long-eared bat (NLEB) (*Myotis septentrionalis*) is a federally endangered bat that is found across much of the eastern and north central United States and all Canadian provinces from the Atlantic coast west to the southern Northwest Territories and eastern British Columbia. During summer, NLEBs roost singly or in colonies underneath bark, in cavities, or in crevices of both live and dead trees. Males and non-reproductive females may also roost in cooler places, like caves and mines. This bat seems opportunistic in selecting roosts, using tree species based on suitability to retain bark or provide cavities or crevices. It has also been found, rarely, roosting in structures like barns and sheds. NLEBs spend winter hibernating in caves and mines, called hibernacula. They typically use large caves or mines with large passages and entrances; constant temperatures; and high humidity with no air currents.[249]

Tricolored Bat

The range of this once common species includes the eastern and central United States and portions of southern Canada, Mexico, and Central America. During the winter, tricolored bats are often found in caves and abandoned mines, although in the southern United States where caves are sparse, tricolored bats are often found roosting in road-associated culverts where they exhibit shorter torpor bouts and forage during warm nights. During the spring, summer, and fall, tricolored bats are found in forested habitats where they roost in trees, primarily among leaves of live or recently dead deciduous hardwood trees, but may also be found in Spanish moss, pine trees, and occasionally human structures.[250]

Higgins Eye (pearlymussel)

The Higgins eye is a freshwater mussel of larger rivers where it is usually found in areas with deep water and moderate currents. Its range includes the upper Mississippi River, the St. Croix River between Minnesota and Wisconsin, the Wisconsin River in Wisconsin, and the lower Rock

249 USFWS. 2025. ECOS Species Profile. Available online at: https://ecos.fws.gov/ecp/species/9045. Accessed October 2025.

250 USFWS. 2025. ECOS Species Profile. Available online at: https://ecos.fws.gov/ecp/species/10515. Accessed October 2025.

River between Illinois and Iowa. The animals bury themselves in the sand and gravel river bottoms with just the edge of their partially-opened shells exposed. The river's currents flow over the mussels as they siphon water for microorganisms such as algae and bacteria.[251]

Salamander Mussel

The species historical range included Arkansas, Illinois, Indiana, Iowa, Kentucky, Michigan, Missouri, New York, Ohio, Pennsylvania, Tennessee, West Virginia, and Wisconsin. There is proposed critical habitat for this species (published in the Federal Register on August 22, 2023) but it occurs outside the Project Study Area. Salamander Mussel inhabits rivers, streams, and in some cases lakes with natural flow regimes. Salamander Mussel has an obligate parasitic relationship with its host the mudpuppy (*Necturus maculosus*). Mudpuppy is the only host of Salamander Mussel and is the only non-fish host used in North America. For Salamander Mussel to complete reproduction, mudpuppy must be present during glochidia release in the summer. [252]

Sheepnose Mussel

The species historical range included Alabama, Illinois, Indiana, Iowa, Kansas, Kentucky, Minnesota, Mississippi, Missouri, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin. There is proposed critical habitat for this species (published in the Federal Register on December 13, 2024) but it occurs outside the Project Study Area. Sheepnose depend on mimic shiner (*Notropis volucellus*) and sauger (*Sander canadensis*) as host fish; of these, only mimic shiner has been observed to be naturally infested and successfully facilitate transformation of juveniles in the lab and is most likely the primary host species.[253]

Monarch Butterfly

The monarch butterfly is a large butterfly with an approximate 3- to 4-inch wingspan and characterized by bright orange coloring on the wings with distinctive black borders and veining, serving as a warning sign to predators of their toxicity. In North America, the species is split into two populations (eastern and western), both well known for their long-distance migration. During the fall, both populations begin migrating to their overwintering locations, where they require a specific microclimate with a temperature that prevents excessive lipid depletion but also prevents freezing. At overwintering sites, monarchs undergo reproductive diapause until the spring when males and females begin mating before dispersing north again. The eastern population migrates from Mexico to Canada, reproducing two to three generations while migrating. The western population migrates north and east from coastal California toward the Rockies and Pacific Northwest, also reproducing into multiple generations.

Throughout the migration corridor and during the breeding cycles, monarchs can be found in a wide variety of habitats including prairies, grasslands, urban gardens, road ditches, and agricultural fields if there is a healthy and abundant supply of nectar resources for foraging that are diverse and of sufficient quality. The patch size and location of this type of habitat is important

251 USFWS. 2025. ECOS Species Profile. Available online at: https://ecos.fws.gov/ecp/species/5428. Accessed October 2025.

252 USFWS. 2025. ECOS Species Profile. Available online at: https://ecos.fws.gov/ecp/species/6208#lifeHistory. Accessed October 2025.

253 USFWS. 2025. ECOS Species Profile. Available online at: https://ecos.fws.gov/ecp/species/6903#lifeHistory. Accessed October 2025.

for monarchs as well. Milkweed must also be of sufficient quality and quantity as it is the sole host plant for oviposition and for the larvae to feed on until the larvae pupates into a butterfly.[254]

Rusty Patched Bumble Bee

Historically, the rusty patched bumble bee was broadly distributed across the eastern United States, Upper Midwest, and southern Quebec and Ontario in Canada. Since 2000, this bumble bee has been reported from only 13 states and 1 Canadian province: Illinois, Indiana, Iowa, Maine, Maryland, Massachusetts, Minnesota, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, Wisconsin and Ontario, Canada. Rusty patched bumble bees once occupied grasslands and tallgrass prairies of the Upper Midwest and Northeast, but most grasslands and prairies have been lost, degraded, or fragmented by conversion to other uses. Bumble bees need areas that provide nectar and pollen from flowers, nesting sites (underground and abandoned rodent cavities or clumps of grasses), and overwintering sites for hibernating queens (undisturbed soil). [255]

Critical habitat has been designated for the rusty patched bumble bee, and is present in Olmsted County. Natural or semi-natural vegetation typifies rusty patched bumble bee habitats. It is assumed that the rusty patched bumble bee nests in upland grasslands and shrublands that contain forage during the summer and fall and also as far as 30 meters into the edges of forest. It is also assumed that the species winters exclusively beneath trees in upland forests.[256]

Western Regal Fritillary

The western regal fritillary is found in large, intact, contiguous native tallgrass prairie habitats in portions of Arkansas, Colorado, Illinois, Indiana, Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota, Wisconsin, and Wyoming. Regal fritillaries can range widely with females potentially traveling up to 100 miles searching for three main habitat components: violet hostplants for larvae, nectar plants for adults, and native grasses to provide protection throughout the life cycle. Adults can be found foraging in both upland and wet prairie habitats; however, habitat can only be considered suitable for all life stages if violet species are present to provide shelter and forage for larvae. The density of violets seems to correlate positively to number of butterflies within a given area. Habitat alteration has reduced the species' range and abundance.[257]

Leedy's Roseroot

Leedy's roseroot is a cliffside wildflower, found today in only seven locations in three states. Four populations are found in Fillmore and Olmsted Counties, Minnesota. The primary limiting factor is its specialized cliffside habitat on cool, moderate cliffs. The major threats are its low numbers and

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254 USFWS. 2024. *Monarch Butterfly (Danaus plexippus) Species Status Assessment Report, Version 2.3* (December 2024). Available online at: https://www.fws.gov/sites/default/files/documents/2025-01/ssa_monarch-butterfly_2024.pdf. Accessed October 2025.

255 USFWS. 2025. ECOS Species Profile. Available online at: https://ecos.fws.gov/ecp/species/9383. Accessed October 2025.

256 USFWS. 2025. *Rusty Patched Bumble Bee Voluntary Section 7 Consultation Technical Assistance* (April 2025). Available online at: https://www.fws.gov/sites/default/files/documents/2025-01/ssa_monarch-butterfly_2024.pdf. Accessed October 2025.

257 USFWS. 2024. Endangered and Threatened Wildlife and Plants; Endangered Status for the Eastern Regal Fritillary and Threatened Status with Section 4(d) Rule for the Western Regal Fritillary, Proposed Rule, USFWS. Available online at: https://www.govinfo.gov/content/pkg/FR-2024-08-06/pdf/2024-16982.pdf. Accessed October 2025.

few populations, its disjunct occurrences, on-site disturbances, and groundwater contamination.[258]

Prairie Bush-clover

The prairie bush-clover is a hardy Midwestern prairie plant species with naturally low genetic diversity that is capable of self-fertilization. The species both historically and currently occurs in Illinois, Iowa, Minnesota, and Wisconsin. Primary threats to the species include land conversion and the encroachment of dominant vegetation and non-native, invasive plant species. Prairie bush-clover is endemic to Midwestern prairies in Illinois, Iowa, Minnesota, and Wisconsin. The majority of populations at the time of listing were found on gentle, north-facing slopes of 10-15 degrees. Prairie bush-clover also occurs at bedrock outcrop sites interspersed with upland prairie.[259]

Western Prairie Fringed Orchid

Western prairie fringed orchid is a perennial orchid of the North American tall grass prairie and is found most often on unplowed, calcareous prairies and sedge meadows. Soil moisture is a critical determinant of growth, flowering, and distribution. Pollination is required for seed production, and the species is pollinated by only a few species of sphinx moths. Seeds are wind-dispersed and may also be adapted for dissemination through the soil profile by water. This species is dependent on mycorrhizal fungi for seed germination and nutritional support before plants are capable of photosynthesis. The persistence of western prairie fringed orchid is dependent on periodic disturbance by fire, mowing, or grazing, but these practices may also cause adverse effects and must be carefully implemented. [260]

10.4.3 Migratory Birds

Migratory Birds are protected under the Migratory Bird Treaty Act (MBTA) of 1918, as amended (16 U.S.C. §§ 703–7121). The MBTA prohibits the take (including killing, capturing, selling, trading, and transport) of protected migratory bird species without prior authorization by the USFWS. Specifically, the MBTA makes it unlawful to take, possess, buy, sell, purchase, or barter any listed migratory bird (50 C.F.R. § 10), including feathers or other parts, nests, eggs, or products, except as allowed by implementing regulations (50 C.F.R. § 21).

The Project Study Area intersects sensitive areas for migratory birds, including the Blufflands-Root River Important Bird Area (IBA) and the Refuge, discussed further in **Section 10.5.1**. The Blufflands-Root River is located primarily in Houston and Fillmore Counties, and also extends into Winona and Olmstead Counties. This area provides a mix of wooded valleys, or coulees, and flat, agricultural areas connecting to floodplains that support a number of breeding and migratory bird

258 USFWS. 1998. *Leedy's Roseroot Recovery Plan* (September 1998). Available online at: https://ecos.fws.gov/docs/recovery_plan/980925.pdf. Accessed October 2025.

259 USFWS. 2021. *Prairie Bush-Clover (Lespedeza leptostachya) Species Status Assessment Report, Version 1.0* (August 2021). Available online at: https://www.fws.gov/sites/default/files/documents/SSA%20Prairie%20BushClover_082021.pdf . Accessed October 2025.

260 USFWS. 2025. Western Prairie Fringed Orchid. Available online at: https://www.fws.gov/species/western-prairie-fringed-orchid-platanthera-praeclara. Accessed October 2025.

species.[261] The Refuge is a continental flyway for migrating birds in the fall and spring. The Refuge is used by waterfowl and landbirds annually as a migratory corridor and stopover site.[262] Routing considerations for minimizing potential effects will be discussed further in the forthcoming route permit proceeding.

The Applicants will follow Avian Power Line Interaction Committee (APLIC) guidance[263] to the extent practicable in order to avoid and minimize impacts upon migratory birds, including to reduce the potential risk of avian collision and electrocution and loss of habitat during the nesting season. The Applicants will work with the USFWS and other applicable agencies as the Project design progresses.

10.4.4 Bald and Golden Eagles

Bald eagles (*Haliaeetus leucocephalus*) are protected by both the MBTA and the Bald and Golden Eagle Protection Act (BGEPA). The BGEPA prohibits the take of a bald or golden eagle adults, juveniles, or chicks including their parts, nests, or eggs without a permit. Take is defined by the BGEPA as to pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest, or disturb. The BGEPA also addresses impacts resulting from human-induced alterations occurring around previously used nesting sites. In Minnesota, the bald eagle nesting season is generally January 15 – July 31. Bald eagles have adapted well to suburban environments, nesting at popular lakes; they also nest at more traditional sites along northern lakes and the St. Croix and Mississippi Rivers. Bald eagles move south for the winter to areas with open water that attract large numbers of waterfowl or fish species, including the Mississippi River in southeast Minnesota. The species is primarily found near rivers, lakes, marshes, and other waterbodies where opportunities to fish are plentiful. Bald eagles nest in tall trees with clear lines of sight and large sturdy branches for perching and nest building.

Potentially suitable nesting habitat for bald eagles is present in all ECS subsections, especially along the Mississippi River. 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., late March/early April) of the year of construction. If active nests are identified within the disturbance buffer, the Applicants will determine next steps and develop appropriate avoidance and minimization measures.

10.4.5 State Listed Species

The Minnesota Natural Heritage Inventory System database was also reviewed for state-listed threatened and endangered species that have the potential to occur within the Project Study Area (**Table 10.4-3**). The Applicants will conduct a Natural Heritage Review utilizing the Minnesota Conservation Explorer online tool once the Project design progresses and will further coordinate with the MDNR as needed.

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[261] Audubon Society. 2024. Blufflands-Root River. Available online at: https://gis.audubon.org/portal/apps/dashboards/ab402cba1acc461d924783cf0f5e181c#site=3973. Accessed December 2025.

[262] Audubon Society. 2024. Upper Mississippi/Trempealeau NF&W Refuges. Available online at: https://gis.audubon.org/portal/apps/dashboards/ab402cba1acc461d924783cf0f5e181c#site=3629. Accessed December 2025.

[263] Avian Power Line Interaction Committee (APLIC). Available online at: https://www.aplic.org/. Accessed December 2025.

Several state-listed endangered and threatened species have been documented within the vicinity of the Project Study Area (**Table 10.4-3**).

TABLE 10.4-3

Minnesota State Listed Species

Common Name	Scientific Name	State Status
Birds		
Henslow's Sparrow	*Centronyx henslowii*	Endangered
Loggerhead Shrike	*Lanius ludovicianus*	Endangered
Reptiles		
Blanding's Turtle	*Emydoidea blandingii*	Threatened
Wood Turtle	*Glyptemys insculpta*	Threatened
Timber Rattlesnake	*Crotalus horridus*	Threatened
Western Ratsnake	*Pantherophis obsoletus*	Threatened
Amphibians		
Blanchard's Cricket Frog	*Acris blanchardi*	Endangered
Mussels		
Higgins Eye	*Lampsilis higginsii*	Endangered
Rock Pocketbook	*Arcidens confragosus*	Endangered
Washboard	*Megalonaias nervosa*	Endangered
Yellow Sandshell	*Lampsilis teres*	Endangered
Butterfly	*Ellipsaria lineolata*	Threatened
Elktoe	*Alasmidonta marginata*	Threatened
Ellipse	*Venustaconcha ellipsiformis*	Threatened
Fawnsfoot	*Truncilla donaciformis*	Threatened
Fluted-shell	*Lasmigona costata*	Threatened
Monkeyface	*Theliderma metanevra*	Threatened
Mucket	*Actinonaias ligamentina*	Threatened
Spike	*Eurynia dilatata*	Threatened
Wartyback	*Pustulosa nodulata*	Threatened
Fish		
Crystal Darter	*Crystallaria asprella*	Endangered
Pallid Shiner	*Hybopsis amnis*	Endangered
Skipjack Herring	*Alosa chrysochloris*	Endangered
Gravel Chub	*Erimystax x-punctatus*	Threatened
Paddlefish	*Polyodon spathula*	Threatened
Invertebrates		
Ottoe Skipper	*Hesperia ottoe*	Endangered
Plants		
Butternut	*Juglans cinerea*	Endangered
Canada Forked Chickweed	*Paronychia canadensis*	Endangered
Carey's Sedge	*Carex careyana*	Endangered
Christmas Fern	*Polystichum acrostichoides*	Endangered
Goldenseal	*Hydrastis canadensis*	Endangered
Iowa Golden Saxifrage	*Chrysosplenium iowense*	Endangered
Leedy's Roseroot	*Rhodiola integrifolia ssp. leedyi*	Endangered
Obovate Beakgrain	*Diarrhena obovata*	Endangered
Plantain-leaved Sedge	*Carex plantaginea*	Endangered
Prairie Shooting Star	*Dodecatheon meadia*	Endangered
Purple Rocket	*Iodanthus pinnatifidus*	Endangered

TABLE 10.4-3 Minnesota State Listed Species		
Common Name	**Scientific Name**	**State Status**
Sweet-smelling Indian Plantain	*Hasteola suaveolens*	Endangered
Western Prairie Fringed Orchid	*Platanthera praeclara*	Endangered
Wild Quinine	*Parthenium integrifolium*	Endangered
Big Tick Trefoil	*Desmodium cuspidatum*	Threatened
Black Buffalo	*Ictiobus niger*	Threatened
Catchfly Grass	*Leersia lenticularis*	Threatened
Clasping Milkweed	*Asclepias amplexicaulis*	Threatened
Clinton's Bulrush	*Trichophorum clintonii*	Threatened
Clustered Broomrape	*Orobanche fasciculata*	Threatened
Davis' Sedge	*Carex davisii*	Threatened
Edible Valerian	*Valeriana edulis var. ciliata*	Threatened
False Mermaid	*Floerkea proserpinacoides*	Threatened
Glade Mallow	*Napaea dioica*	Threatened
Great Indian Plantain	*Arnoglossum reniforme*	Threatened
Hair-pointed Feather Moss	*Cirriphyllum piliferum*	Threatened
James' Sedge	*Carex jamesii*	Threatened
Narrow-leaved Glade Fern	*Homalosorus pycnocarpos*	Threatened
One-flowered Broomrape	*Orobanche uniflora*	Threatened
Ovate-leaved Skullcap	*Scutellaria ovata var. versicolor*	Threatened
Prairie Bush Clover	*Lespedeza leptostachya*	Threatened
Prairie Milkweed	*Asclepias hirtella*	Threatened
Reniform Sullivantia	*Sullivantia sullivantii*	Threatened
Rock Sandwort	*Minuartia dawsonensis*	Threatened
Smooth-sheathed Sedge	*Carex laevivaginata*	Threatened
Snowy Campion	*Silene nivea*	Threatened
Spreading Sedge	*Carex laxiculmis var. copulata*	Threatened
Stemless Tick Trefoil	*Hylodesmum nudiflorum*	Threatened
Sterile Sedge	*Carex sterilis*	Threatened
Stream Parsnip	*Berula erecta*	Threatened
Sullivant's Milkweed	*Asclepias sullivantii*	Threatened
Three-leaved Coneflower	*Rudbeckia triloba var. triloba*	Threatened
Tubercled Rein Orchid	*Platanthera flava var. herbiola*	Threatened
Tuberous Indian Plantain	*Arnoglossum plantagineum*	Threatened
Upland Boneset	*Eupatorium sessilifolium*	Threatened
Witch-hazel	*Hamamelis virginiana*	Threatened

10.4.6 General Wildlife

The Project Study Area’s agricultural landscape and abundant deciduous forest, combined with the preserved or managed wildlife lands, provide 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 may occur in areas that are permanently cleared for construction and maintenance of the Project.

10.5 LAND USE

Topography within the Rochester Plateau subsection consists of level to gently rolling older till plains. The eastern boundary with The Blufflands subsection is an area of transition between a level to rolling plateau and dissected landscapes. The Blufflands subsection is characterized by highly dissected landscapes associated with major rivers in southeastern Minnesota. Bluffs and deep stream valleys (500 to 600 feet deep) are common. Elevation ranges from 623 to 1,444 feet above sea level within the Project Study Area.

According to the 2024 National Landcover Database dataset, cultivated cropland is the dominant land cover making up 65 percent of the Project Study Area (**Table 10.5-1, Figure 10.5-1**). Deciduous forest and pasture/hay are the second and third most dominant land cover types, accounting for 27 percent of the Project Study Area each. The remaining land cover classifications make up approximately eight percent of the Project Study Area. There is a clear pattern of agriculture in the western portion of the Project Study Area changing into more forested areas to the east.

Figure 10.5-1: Land Cover in the Project Study Area Map

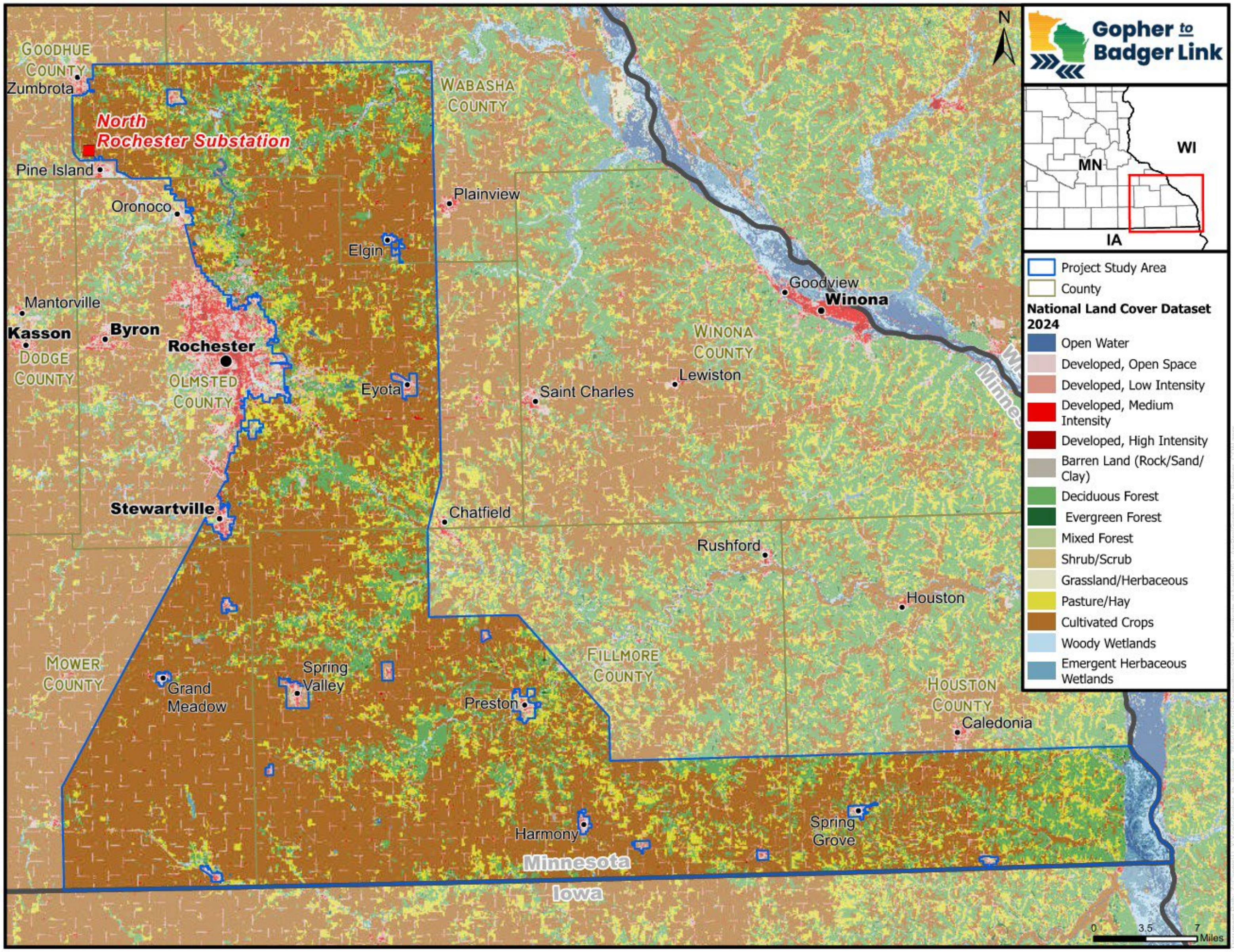

TABLE 10.5-1 Land Cover in the Project Study Area		
Land Use Category	**Acres**	**Percentage**
Cultivated Crops	620,620	64.5%
Deciduous Forest	135,510	14.1%
Pasture/Hay	120,375	12.5%
Developed, Low Intensity	30,690	3.2%
Developed, Open Space	24,836	2.6%
Emergent Herbaceous Wetlands	8,364	0.9%
Woody Wetlands	7,255	0.8%
Open Water	5,144	0.5%
Developed, Medium Intensity	3,573	0.4%
Barren Land	1,938	0.2%
Mixed Forest	1,760	0.2%
Evergreen Forest	1,250	0.1%
Grassland/Herbaceous	785	0.1%
Shrub/Scrub	324	0.0%
Developed, High Intensity	233	0.0%

10.5.1 Recreation and Managed Lands

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, Wildlife Management Areas (WMAs), SNAs, state trails, state parks, and municipal and county parks and trails (**Table 10.5-2**, **Figure 10.5-2**).

Figure 10.5-2: Managed Land and Recreation in the Project Study Area.

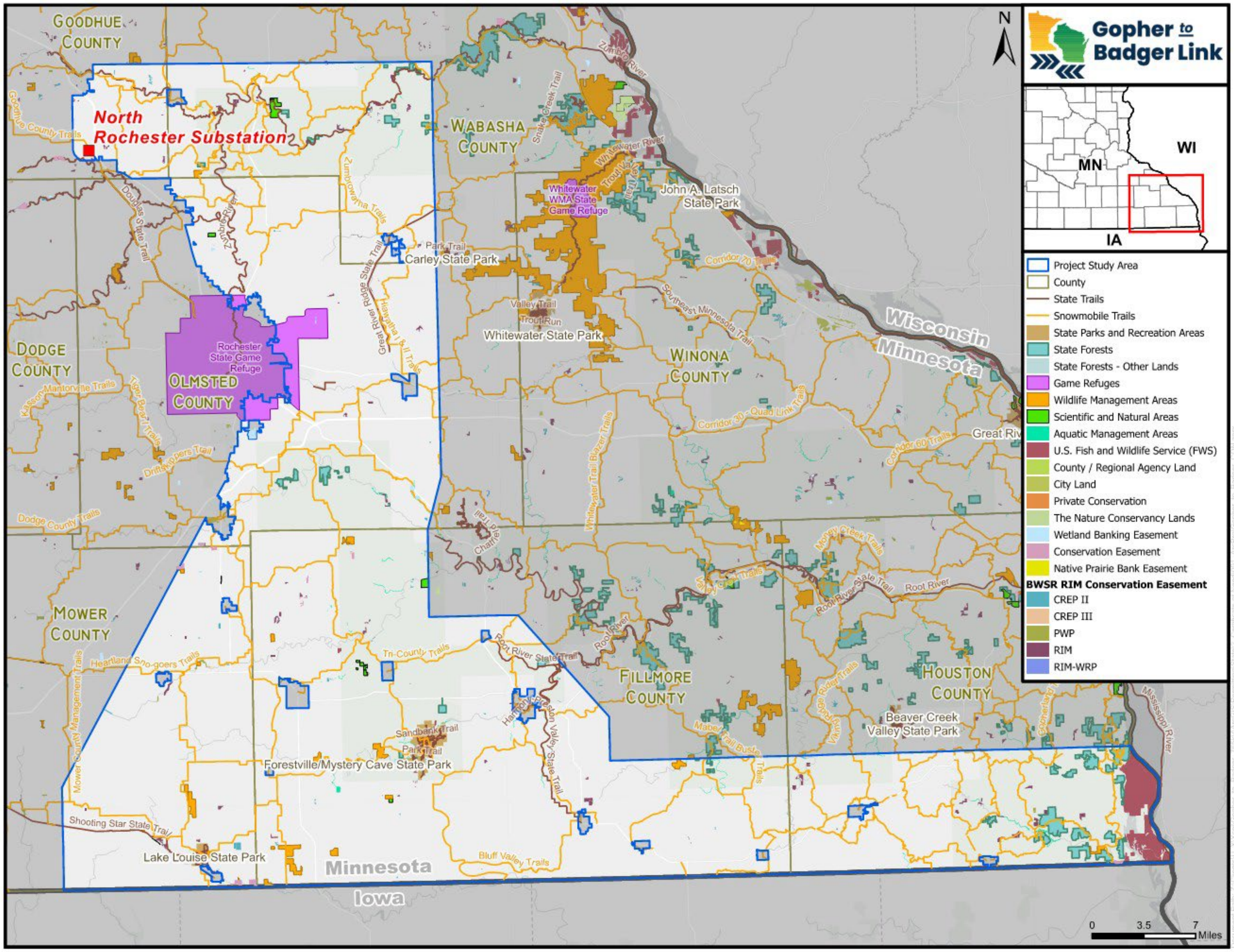

TABLE 10.5-2 Managed Lands in the Project Study Area	
Agency	**Acres**
Federal	**14,476**
National Wildlife Refuge	14,476
State	**17,798**
State Forest	8,218
State Park	4,177
State Wildlife Management Area	3,290
Aquatic Management Area	998
State Research Natural Area	912
Other Forest Land	**203**
TOTAL	**32,274**

In general, public recreation areas and managed lands may be avoided through the routing and siting process. If these areas cannot be avoided, the Applicants will work with applicable federal, state, county, and local agencies regarding minimizing potential Project impacts.

10.5.1.1 Federal Lands

The Refuge[264] is the only federal property located within the Project Study Area and is located at the southeast corner of the Project Study Area in Houston County. The Refuge stretches 261 river miles from Wabasha, Minnesota to Rock Island, Illinois, and protects more than 240,000 acres of Mississippi River floodplain. The Refuge hosts more than 3.7 million annual visits for hunting, fishing, wildlife observations, and other recreation. The Refuge is a Ramsar Site (see **Section 10.3.4**) and a Globally Important Bird Area (see **Section 10.4.3**).

Federal conservation easements are discussed in **Section 10.5.1.4** below.

10.5.1.2 State Administered Lands

WMAs are part of Minnesota's outdoor recreation system and are established to protect those lands and waters that have high potential for wildlife production, public hunting, trapping, fishing, and other compatible recreational uses. There are 18 WMAs located throughout the Project Study Area.

Portions of the one million-acre Richard J. Dorer (RJD) Memorial Hardwood State Forest[265] overlap the Project Study Area in Olmsted, Fillmore and Houston Counties. The RJD Memorial Hardwood State Forest was created in 1961 with specific conservation goals to improve wildlife habitat, prevent erosion, stabilize streams, and produce timber. The RJD Memorial Hardwood Forest is unique in that the state does not own most of the land. In fact, the state only owns 45,000 acres out of the one million acres covered by the forest.

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264 USFWS. 2025. Upper Mississippi River National Wildlife and Fish Refuge. Available online at: https://www.fws.gov/refuge/upper-mississippi-river. Accessed October 2025.

265 MDNR. 2025. Richard J. Dorer Memorial Hardwood State Forest. Available online at: https://www.dnr.state.mn.us/state_forests/forest.html?id=sft00033#information. Accessed October 2025.

Aquatic Management Areas (AMAs)[266] are managed by the MDNR and provide angler and management access, protect critical shore land habitat and provide areas for education and research. Trout stream easements, a special type of AMA are concentrated in the cold-water rich counties such as Fillmore, Wabasha, and Houston. There are 27 AMAs (998 acres) located throughout the Project Study Area with many located along trout streams.

SNAs 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 seven SNAs located within the Project Study Area: Zumbro Falls, Wykoff Balsam Fir, Oronoco Prairie, Shooting Star Prairie, Racine Prairie, Pin Oak Prairie, and Cherry Grove Blind Valley.

There are two state parks located within the Project Study Area: Forestville Mystery Cave State Park and Lake Louise State Park.

TABLE 10.5-3

Miles of Recreation Trails within the Project Study Area

Trail Type	Number of Trails	Miles
Hiking Trail	17	44
State Trail	5	48
State Water Trail	3	80
Snowmobile Trail	12	606
TOTAL	**37**	**778**

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 80 miles throughout the Project Study Area. These state water trails are located along the Zumbro, Root, and Mississippi Rivers. These state water trails extend outside of the Project Study Area.

Five state trails with 48 miles of hiking opportunity are all or partially located within the Project Study Area: the Great River State Trail (Wabasha and Olmsted Counties), Chester Woods State Trail (Olmsted County), Shooting Star State Trail (Mower County), Root River State Trail (Fillmore County), and Harmony-Preston Valley State Trail (Fillmore County).

There are twelve grant-in-aid snowmobile trails found throughout the Project Study Area that 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 606 miles of snowmobile trails within the Project Study Area.

State conservation easements are discussed in **Section 10.5.1.4** below.

To the extent the Project ultimately crosses State lands, the Applicants will coordinate with the appropriate agency regarding applicable permits and avoidance and minimization measures.

266 MDNR. 2025. Aquatic Management Areas. Available online at: https://www.dnr.state.mn.us/amas/index.html. Accessed October 2025.

10.5.1.3 Locally Administered Lands

Additional hiking trails are located within local and county parks throughout the Project Study Area. County and municipal parks are also found throughout the Project Study Area.

10.5.1.4 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 are shown in **Table 10.5-4** and described further below.

TABLE 10.5-4

Conservation Easements In The Project Study Area

Conservation Easement Ownership/Management	Acres
Federal	706
Natural Resources Conservation Service (NRCS)	611
Wetland Reserve Program	369
Grassland Reserve Program	122
Emergency Watershed Protection Program (EWP Program)	120
USFWS	95
Wildlife Habitat Easements	95
State	1,899
Conservation Reserve Enhancement Program (CREP) Reinvest in Minnesota (RIM)	1,292
Permanent Wetlands Preserves (PWP) Program	127
Conservation Reserve Program (CRP)	253
Wetland Banking Easement	227
TOTAL	**2,605**

There are approximately 2,605 acres of conservation easements located in the Project Study Area (**Figure 10.5-2**; **Table 10.5-1**). The Wetland Reserve Easements (WRE) properties are established by the United States Department of Agriculture (USDA) and the NRCS 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; recharges groundwater; protects biological diversity; provides resilience to climate change; and provides opportunities for educational, scientific and limited recreational activities.[267]

The Grassland Reserve Programs are land conservation programs administered by the Farm Service Agency (FSA). In exchange for a yearly rental payment, farmers enrolled in the program agree to remove environmentally sensitive land from agricultural production and plant species that will improve environmental health and quality. The EWP Program offers technical and financial assistance to help local communities relieve imminent threats to life and property caused by floods, fires, windstorms and other natural disasters that impair a watershed.

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267 2025. Wetland Reserve Easements (WRE). Available online at: https://www.nrcs.usda.gov/programs-initiatives/wetland-reserve-easements. Accessed October 2025.

USFWS Wildlife Habitat Easements are "working lands" under permanent federal conservation easements that allow delayed haying and/or grazing while protecting restored wetlands and prairie grasslands for nesting ducks, pheasants, and other wildlife

The 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.[268] There are 242 acres of CREP land located within the Project Study Area.

The RIM Reserve Partnership Easement program was implemented by BWSR 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. There are approximately 1,062 acres of land in the RIM program located in the Project Study Area.

The PWP Program, a state conservation easement program that aims to permanently protect at-risk wetlands on private land. PWP enrolls eligible wetlands (types 1, 2, 3, and 6) in a permanent conservation easement, providing landowners with rental payments based on a percentage of the land's assessed value.

The CRP, administered by the FSA, protects more than 20 million of acres of American topsoil from erosion and is designed to safeguard the nation’s natural resources. In Minesota, BWSR helps administer this program, in coordination with the RIM program, through partnerships with local Soil and Water Conservation Districts. By reducing water runoff and sedimentation, CRP protects groundwater; helps improve the condition of lakes, rivers, ponds, and streams; and is a major contributor to increased wildlife populations in many parts of the country.

Depending on the governing conservation program, specific restrictions may be applied that could limit or restrict development of a transmission line. As Project routing progresses, the Applicants will work with federal, state, and county agencies and landowners to identify conservation easements that may be affected by the Project. If a conservation easement cannot be avoided through modifications in Project routing and siting, the Applicants will work with the owner and managing agency to develop mitigation measures.

10.5.2 Agricultural Production

The agricultural production industry is a significant part of the local economy throughout Minnesota. Information from the USDA’s 2022 Census of Agriculture for each of the counties in the Project Study Area is provided in **Table 10.5-5**.

The percentage of land used for farmland varies by county within the Project Study Area. Goodhue County has the greatest percentage of county land used for farmland (87 percent). Fillmore County has the most farmland (470,312 acres). Corn is the predominant crop produced in each county, typically followed by soybeans and forage. Cattle and hogs are the dominant livestock produced in the Project Study Area.

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268 BWSR. 2025. MN CREP for Landowners. Available online at: https://bwsr.state.mn.us/mn-crep-landowners. Accessed October 2025.

TABLE 10.5-5 Agricultural Statistics (2022) for the Project Study Area			
County	**Land in Farms (acres)**	**Top 3 Crops by Acreage**	**Top 3 Livestock Inventories by Farms**
Goodhue County	421,698 (87% of county)	Corn, soybeans, forage	Hogs and pigs, cattle, poultry, sheep and lambs
Wabasha County	235,417 (70% of county)	Corn, soybeans, forage	Cattle, hogs and pigs, poultry
Olmsted County	308,004 (74% of county)	Corn, soybeans, forage	Cattle, hogs and pigs, poultry
Mower County	380,070 (68% of county)	Corn, soybeans, vegetables	Hogs and pigs, cattle, poultry
Fillmore County	470,312 (85% of county)	Corn, soybeans, forage	Hogs and pigs, cattle, poultry
Houston County	223,021 (63% of county)	Corn, forage, soybeans	Cattle, hogs and pigs, poultry
Source: https://www.nass.usda.gov/Publications/AgCensus/2022/Online_Resources/County_Profiles/Minnesota/.			

The Applicants will maintain landowner access to agricultural fields, storage areas, structures, and other agricultural facilities and will work with landowners to address their concerns during construction to the extent practicable. The Applicants will work with landowners to address concerns with irrigation systems and drain tile. Crop production on some portions of agricultural lands may be temporarily interrupted while transmission line facilities are constructed, and there will be permanent loss of areas currently under agricultural production where transmission structures are placed. The Applicants will compensate landowners for impacts on crops resulting from the construction, operation, and maintenance of the Project.

10.5.3 Forestry Production

According to the 2024 National Landcover Database and the Minnesota Forest Resource Council, approximately 15 percent of the Project Study Area is forested (**Table 10.5-1, Figure 10.5-1**). The Project Study Area occurs within the MDNR's Paleozoic Plateau forestry management section, which includes approximately 65,000 acres of state-forest managed lands consisting of high-quality hardwoods and riparian hardwoods.[269] The MDNR-managed Richard J. Dorer Memorial Hardwood State Forest occurs within this forestry management section, and is crossed by the Project Study Area. The Richard J. Dorer Memorial Hardwood State Forest encompasses over a million acres of non-contiguous parcels in Dakota, Goodhue, Wabasha, Winona, Olmsted, Houston, and Fillmore Counties. The MDNR only owns approximately 45,000 out of the 1 million acres of the State Forest, and not all of the land is currently forested.[270] Forestry in the region supports recreation, biodiversity, and wildlife, and requires management to maintain.

10.5.4 Mineral Extraction

Mineral extraction in southeastern Minnesota primarily focuses on industrial minerals, including the significant mining of silica sand for fracking and glassmaking, and limestone and dolostone for construction. The region also has extensive deposits of sand and gravel used for aggregate.

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269 MDNR. Undated. Paleozoic Plateau Section Forest Resource Management Plan (PP SFRMP). Available online at: https://www.dnr.state.mn.us/forestry/section/pps.html. Accessed December 2025.

270 MDNR. Undated. Richard J. Dorer Memorial Hardwood State Forest: Forest Information. Available online at: https://www.dnr.state.mn.us/state_forests/forest.html?id=sft00033#information. Accessed December 2025.

While the state's metallic mineral reserves are mainly in the northeastern part of the state, there is ongoing exploration for copper and nickel in the southern region on private land.

Smaller sand and gravel operations are found within the Project Study Area (**Table 10.5-6**). The mined sand and gravel material are primarily used for making concrete for highways, roads, bridges, and buildings. Mining operations can generally be avoided through route design. The Applicants will work with private owners and Minnesota Department of Transportation to identify mining operations and design the Project to avoid these areas to the extent practicable.

TABLE 10.5-6

Number of Mineral Extraction Sites by County within the Project Study Area

County	Gravel Pit	Quarry	Sand Pit	Strip Mine	Total
Fillmore	22	39	5	1	67
Goodhue	5	2			7
Houston	2	22			24
Mower	28	15	2		45
Olmsted	43	22	3		68
Wabasha	16	4			20
TOTAL	**114**	**102**	**10**	**1**	**231**

Source: U.S. Geological Survey (USGS). 2023. Prospect- and mine-related features on USGS topographic maps in Minnesota [Data set]. U.S. Department of the Interior. Available online at: https://mrdata.usgs.gov/usmin/

10.6 HUMAN SETTLEMENT

Human settlement within the Project Study Area includes municipalities, farmsteads, utility infrastructure, roadways, and commercial and industrial areas. The Applicants reviewed publicly available information to characterize human settlement patterns throughout the Project Study Area.

Municipalities in the Project Study Area are concentrated along roadways such as U.S. Highways 52 and 63. Larger cities (greater than 2,000 people) in or immediately adjacent to the Project Study Area from northwest to southeast include Zumbrota, Pine Island, Plainview, Rochester, Eyota, Stewartville, Chatfield, Spring Valley, and Caledonia. (**Figure 10.1-1**). 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 larger municipalities.

Residential areas in the Project Study Area are located within large and small municipalities, as well as scattered farmsteads located in more rural areas. NESC and the Applicants' standards require minimum clearances between transmission line facilities and buildings to ensure safe operation.

The primary method of mitigation for minimizing effects on human settlements and related infrastructure is to route transmission lines away from municipalities, and residential, commercial, and industrial areas.

The Project will be designed in compliance with State, NESC, and Applicants' standards for clearance to ground, crossing other utilities, buildings, strength of materials, vegetation, and other obstructions. Furthermore, the Applicants will comply with construction standards, which include requirements of NESC and Occupational Safety and Health Administration (OSHA). Adherence to NESC, the Applicants, and OSHA standards will limit the effects of the Project on areas of human settlement and related infrastructure.

10.6.1 Demographics and Socioeconomics

Demographic information for the Project Study Area is based on the U.S. Census Bureau 2020: American Community Survey 5-year Estimates Data Profiles, available on Explore Census Data and QuickFacts websites. U.S. Census information is available at the state and county levels; for a listing of counties within each ECS, refer to **Table 10.2-1**.

The Project Study Area encompasses portions of six counties with populations that vary in size from 144,248 persons in Olmsted County to 21,228 persons in Fillmore County (see **Table 10.6-1**). Rochester, in Olmsted County, is the largest city in southeastern Minnesota, serving as the region's economic and cultural hub.

Five out of six counties in the Project Study Area have a median household income below the state average, but only Mower County has a poverty percentage higher than the state average. Two counties, Olmsted and Mower Counties, have a minority population percentage higher than the state average.

TABLE 10.6-1 Demographic and Socioeconomic Information within the Project Study Area						
Location	**Population 2010**[a]	**Population 2020**[b]	**Percent Change 2010-2020**	**Unemployment Rate (%)**[c]	**Median Household Income**[d]	**Population below poverty level (%)**[e]
State of Minnesota	5,303,925	5,706,494	7.6%	4.2%	$87,556	9.3%
Goodhue County	46,183	47,582	3.0%	4.1%	$83,979	9.3%
Wabasha County	21,676	21,387	-1.3%	3.2%	$81,349	8.4%
Olmsted County	144,248	162,847	12.9%	3.2%	$89,431	7.9%
Mower County	39,163	40,029	2.2%	3.8%	$66,578	12.1%
Fillmore County	20,866	21,228	1.7%	3.2%	$69,157	8.9%
Houston County	19,027	18,843	-1.0%	3.2%	$77,043	6.5%
a & b	U.S. Census Bureau. 2021. Decennial Census of Population and Housing, 2010 & 2020. Available online at: https://www.census.gov. Accessed October 2025 .					
c	County Unemployment Rates. 2025. Available online at: https://mn.gov/deed/data/current-econ-highlights/county-unemployment.jsp. Accessed October 2025.					
d	Source: U.S. Census Bureau. 2024. Small Area Income and Poverty Estimates (SAIPE): 2023 Median Household Income by County and State. Available online at: https://www.census.gov. Accessed October 2025.					
e	U.S. Census Bureau. (2024). American Community Survey, 2023 ACS 5-Year Estimates, Table S1701: Poverty Status in the Past 12 Months. U.S. Department of Commerce. Retrieved from https://data.census.gov/					

TABLE 10.6-2 Race and Ethnicity of the Population in the Project Study Area									
County	**White Alone (%)**	**Black or African American (%)**	**American Indian or Alaska Native (%)**	**Asian Alone (%)**	**Native Hawaiian/ Pacific Islander Alone (%)**	**Hispanic or Latino (%)**	**Other (%)**	**Total Minority (%)[a]**	**Language Other Than English Spoken at Home (2017-2021)[b]**
Minnesota	78.8%	6.4%	0.3%	4.8%	0.1%	5.6%	4.0%	21.1%	
Goodhue County	89.6%	1.6%	0.9%	0.8%	0.0%	3.9%	3.2%	10.4%	7.1%
Wabasha County	93.6%	0.3%	0.2%	0.6%	0.1%	3.3%	1.8%	6.4%	5.6%
Olmsted County	76.3%	7.2%	0.1%	6.3%	0.1%	5.8%	4.2%	23.7%	17.3%
Mower County	74.0%	3.5%	0.0%	5.7%	0.4%	13.0%	3.3%	26.0%	13.9%
Fillmore County	94.6%	0.6%	0.1%	0.6%	0.0%	1.9%	2.3%	5.4%	6.2%
Houston County	93.8%	0.4%	0.2%	1.0%	0.0%	1.5%	3.2%	6.2%	3.9%

[a] Total minority percentage equals the total population minus the percentage of white alone, not Hispanic or Latino.

[b] U.S. Census Bureau. (2023). American Community Survey, 2017–2021 ACS 5-Year Estimates, Tables B03002, B17020, and B16004: Demographic and Housing Characteristics. U.S. Department of Commerce. Available at: https://data.census.gov/ Accessed October 2025.

Transmission line projects have the potential to benefit the socioeconomic conditions of an area in the short term through an influx of non-local personnel, creation of construction jobs, purchases of construction material and other goods from local businesses, and expenditures on temporary housing 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. Additionally, permanent job creation or relocation of personnel to the area for the operation of a transmission line project could affect area demographics. Potential mitigation measures that may enhance the socioeconomic benefits experienced by local communities include use of local personnel and construction material retailers during construction of the Project. The Applicants will work with local communities to identify opportunities for further enhancing the socioeconomic benefits of the Project.

10.6.2 Environmental Justice

The Commission defines an environmental justice area – consistent with Minn. Stat. § 216B.1691, subd. 1(e) – as an area that meets one or more of the following criteria:

(1) 40 percent or more of the area's total population is nonwhite;

(2) 35 percent or more of households in the area have an income that is at or below 200 percent of the federal poverty level;

(3) 40 percent or more of the area's residents over the age of five have limited English proficiency; or

(4) the area is located within Indian country, as defined in United State Code, title 18, section 1151.[271]

Although the statute quoted above applies to the establishment of Minnesota's renewable energy objectives, the Applicants apply this statutory definition because it is the only statutory definition of environmental justice applicable to any Commission proceedings.

The MPCA website "Understanding Environmental Justice" provides tools to help identify environmental justice communities throughout the state and provide guidance for integrating environmental justice principles such as fair treatment and meaningful involvement of environmental justice communities.

The Applicants used the MPCA mapping tool[272] to identify environmental justice communities located near the Project.

The MPCA mapping tool did not identify any environmental justice areas within the Project Study Area. There is one environmental justice area (low-income community) within one mile of the Project Study Area on the east side of Rochester. There are no federally recognized Tribal Areas located within the Project Study Area.

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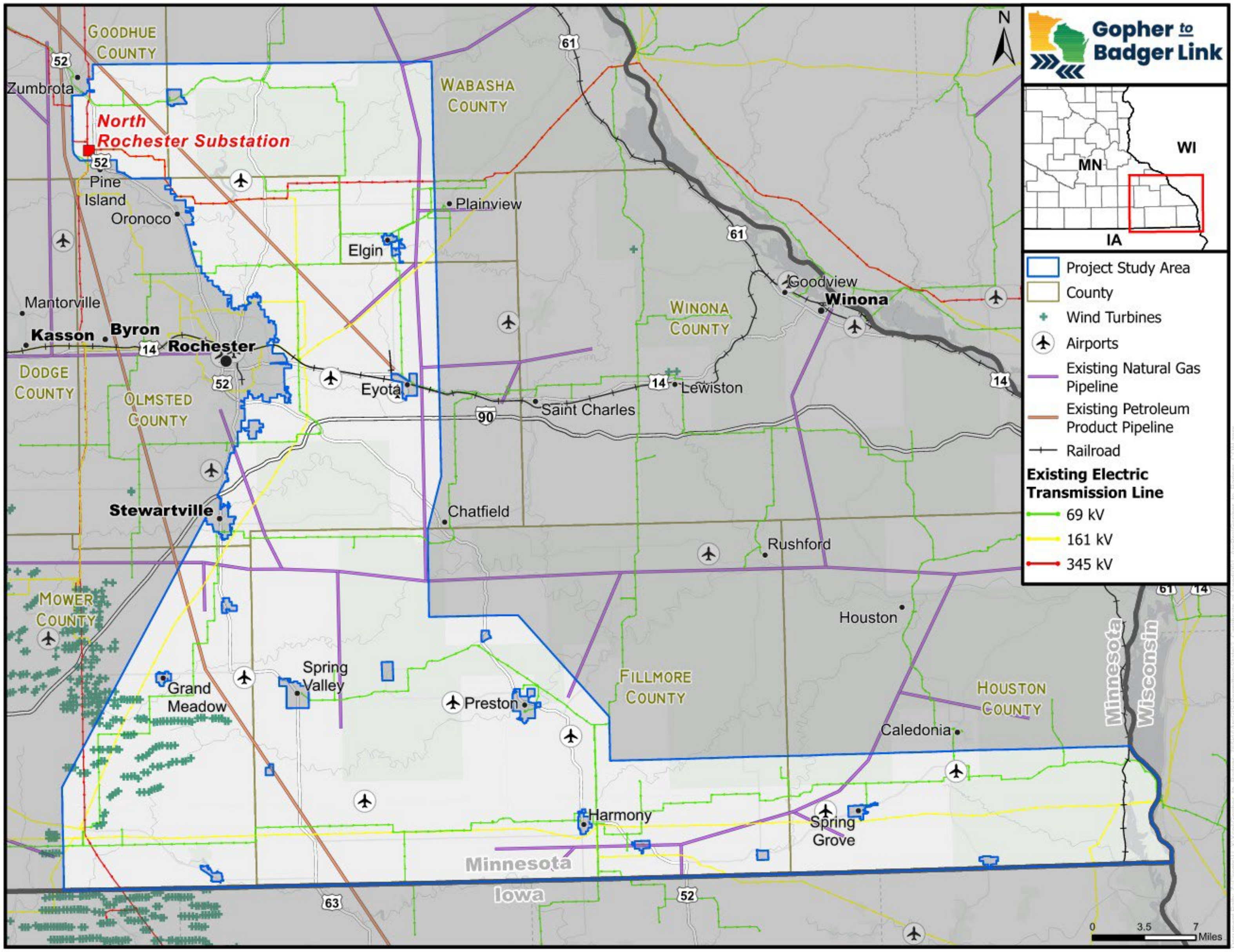
271 Minn. Stat. § 216B.1691, subd. 1(e).

272 2025. Understanding Environmental Justice mapping tool. Available online at: https://experience.arcgis.com/experience/bff19459422443d0816b632be0c25228/page/Page?views=Near-an-EJ-area. Accessed October 2025.

10.6.3 Public Services

Public services in the Project Study Area are similar to public services found elsewhere in Minnesota. Roads, railways, and airports are present throughout. Many residents outside cities and towns rely on private wells and septic systems. Churches and cemeteries exist throughout the Project Study Area.

Figure 10.6-1: Existing Infrastructure in the Project Study Area.



10.6.3.1 Drinking Water

The Project Study Area is primarily located in a rural setting in southeastern Minnesota (**Figure 10.1-1**). 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 population centers provide municipal water and sewer treatment via buried public infrastructure. There are Drinking Water Supply Management Areas and Wellhead Protection Areas within the Project Study Area generally located around the population centers. Minnesota Department of Health tailors source water protection requirements and recommendations for public water suppliers.

10.6.3.2 Roads

Existing road infrastructure within the Project Study Area is a mix of federal, state, and county highways and roads, and township roads. Interstate 90 bisects the Project Study Area in Olmsted County south of Rochester. Major transportation networks include Minnesota State Highways 16, 30, 42, 43, 44, 76, and 26 and U.S. Highways 14, 52, and 63. Three national scenic byways pass through the Project Study Area: Historic Bluff Country Scenic Byway (Fillmore County), Great River Road (Houston County), and Shooting Star Scenic Byway (Mower and Fillmore Counties).

10.6.3.3 Railroads

There are two railroad lines (**Figure 10.6-1**) located within the Project Study Area. One railroad is between Rochester and Winona and operated by the Dakota, Minnesota and Eastern Railroad (DM&E), a fully owned subsidiary of the Canadian Pacific Railway system. The line is presently a freight-only route hosting an average of three trains per day on a single track, with all in-town road crossings at grade. DM&E also operates another line on the eastern edge of the Project Study Area in Houston County. The line is presently a freight-only route hosting an average of thirteen trains per day on a single track, with all in-town road crossings at grade.

10.6.3.4 Airports

Based on information from the Minnesota Department of Transportation (MnDOT), there are eight airports located within the Project Study Area, including six private airports and two public airports (**Figure 10.6-1**; **Table 10.6-3**). The public airports are located in Caledonia (Houston County Airport) and Preston (Fillmore County Airport). Private airports are privately-owned landing strips. Rochester International Airport is located just outside the Project Study Area, but its airspace overlaps with the Project Study Area.

TABLE 10.6-3 Public and Private Airports in the Project Study Area		
County	**Public Airports**	**Private Airports**
Houston	1	1
Fillmore	1	1
Mower	0	1
Olmsted	0	3
Goodhue	0	0
Wabasha	0	0
TOTAL	**2**	**6**
Source: MnDOT Aeronautics ASE, 2022.		

Airport impacts for the Project can be addressed through the route selection process (generally through avoidance) and structure design (where an airport cannot be avoided). Detailed analysis will be conducted as part of the routing process, and the Applicants will coordinate with the Federal Aviation Administration.

10.6.3.5 Utilities & Generation

Electric transmission and distribution lines exist throughout the Project Study Area, as depicted in **Figure 10.6-1**. 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.

Oil and gas transmission and distribution pipelines are present throughout the Project Study Area. Oil and gas transmission pipelines are generally sited away from population centers, while the distribution lines typically supply population centers.

The location of pipelines will be identified with more specificity as routes are developed for the Project. If the Project is routed near or crosses public infrastructure, roads, railroads, pipelines, etc., appropriate engineering standards will be incorporated into Project design, and any required crossing permissions or agreements will be obtained from the applicable owners/operators and/or agencies. As Project design progresses, the Applicants will also meet with MnDOT and local road authorities to identify upcoming road projects that could impact Project design or construction activities.

The Applicants reviewed publicly available records of existing photovoltaic solar farms 1 MW or more to identify solar farms in the Project Study Area.[273] Review of the Commission's Energy Infrastructure Permitting webpage[274] also indicates that facilities greater than 50 MW are being proposed and permitted in counties within and adjacent to the Project Study Area. Applicants will continue to attempt to identify existing and proposed solar facilities as part of the routing process and will coordinate with owners/developers of those facilities, as needed.

273 USGS. 2025. U.S. Large-Scale Solar Photovoltaic Database. Available online at: https://energy.usgs.gov/uspvdb/. Accessed October 2025.

274 Minnesota Public Utilities Commission. 2025. Energy Infrastructure Permitting. Available online at: https://puc.eip.mn.gov/. Accessed October 2025.

The Applicants reviewed the U.S. Wind Turbine Database Viewer to identify existing wind farms in the Project Study Area.[275] Applicants also reviewed the Commission's Energy Infrastructure Permitting webpage to determine whether wind farms are being proposed in the Project Study Area.[276] Applicants will continue to attempt to identify existing and proposed wind facilities as part of the routing process and will coordinate with owners/developers of those facilities, as needed.

The Applicants reviewed the MPUC Energy Infrastructure Permitting webpage for battery energy storage systems.[277] These systems are being proposed in counties within the Project Study Area. The Applicants will continue to attempt to identify existing and proposed battery energy storage systems facilities as part of the routing process and will coordinate with owners/developers of those facilities, as needed.

10.7 AESTHETICS

The visual character and setting of the majority of the Project Study Area includes largely flat agricultural fields on plateaus broken up by areas with greater levels of topography, generally associated with forested areas and/or waterbodies. As discussed in **Section 10.6**, outside of municipalities, which range from small towns to large cities, farms, churches, cemeteries, community facilities, and rural residences dot the landscape. Additional built infrastructure that is visible across the landscape includes roads, overhead distribution and transmission lines, substations, pipelines, wind turbines, solar farms, railroads, and other infrastructure such as grain silos.

Structures, conductors, insulators, aeronautical safety markings, avian diverters, vegetation clearing, and access roads constructed as part of this Project will also be visible on the landscape. The Applicants will consider potential aesthetic impacts as part of the routing process, which will also include input from stakeholders regarding minimization of aesthetic impacts.

10.8 ARCHAEOLOGICAL AND HISTORICAL RESOURCES

Previously identified archaeological sites (e.g., pre-contact artifact assemblages, burial mounds, and earthworks) are present in the Project Study Area, primarily along the margins of rivers (e.g., Zumbro) and other surface waters. The Project Study Area also contains historic architectural resources, the majority of which are located within municipalities (e.g., churches, grain elevators, banks, railroads). Some rural farmsteads and bridges are also considered historic architectural resources. Some of the archaeological sites and historic architectural resources are listed or considered eligible for listing in the National Register of Historic Places (NRHP), while other sites have yet to be evaluated.

Once a proposed route is identified for the Project, the Applicants will complete a Phase I literature review to characterize the prehistoric and historic context along the route and to identify previously recorded archaeological sites and historic architectural resources. A summary of the findings in the Phase Ia literature review will be presented in the Route Permit Application.

Effects to historic sites can be avoided through routing efforts, such as placement of structures and access outside of historic site boundaries. If impacts to any recorded site cannot be avoided

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275 USGS. 2025. U.S. Wind Turbine Database Viewer. Available at: https://www.usgs.gov/tools/us-wind-turbine-database-uswtdb-viewer. Accessed October 2025.

276 MPUC. 2025. Energy Infrastructure Permitting. Available online at: https://puc.eip.mn.gov. Accessed October 2025.

277 Id.

by the Project, that recorded site will require formal significance evaluation to determine if it meets the eligibility requirements of the NRHP. If found significant, mitigation strategies will be undertaken to reduce impacts. This could include identifying the site in detail prior to construction, limiting construction access and activities as much as possible, and having appropriate staffing during construction to monitor work. If properties 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 will work with the appropriate state, federal and tribal agencies during the routing process to avoid known historic resources as much as possible.

10.9 OTHER PERMITS AND APPROVALS

In addition to the Certificate of Need requested in this Application, the Project will require a Route Permit from the Commission. Other permits required to construct the Project will depend on the final route selected and conditions encountered during construction. Once the Commission issues a Route Permit, local zoning, building, and land use regulations and rules are preempted per Minn. Stat. § 216I.18, subd. 1. A list of the permits and approvals that could potentially be required for the Project is provided in **Table 10.9-1**.

TABLE 10.9-1 Summary of Potential Permits and Approvals Potentially Required for the Project	
Permit	**Jurisdiction**
Federal	
Section 404 Clean Water Act Permit	United States Army Corps of Engineers, St. Paul District
Section 10 Rivers and Harbors Act Permit	United States Army Corps of Engineers, St. Paul District
Endangered Species Act, Migratory Bird Treaty Act, and Bald and Golden Eagle Protection Act Consultation, National Wildlife Refuge Administration Act (16 USC668 dd)	United States Fish and Wildlife Service
Part 7460 Airport Obstruction Evaluation	Federal Aviation Administration
State	
Certificate of Need	Minnesota Public Utilities Commission
Route Permit	Minnesota Public Utilities Commission
State Natural Heritage Review and Coordination	Minnesota Department of Natural Resources
Utility Crossing License (Lands and Waters)	Minnesota Department of Natural Resources
Work in Public Waters Permit	Minnesota Department of Natural Resources
Water Appropriation Permit – Temporary Construction Dewatering	Minnesota Department of Natural Resources
National Pollutant Discharge Elimination System Construction Stormwater General Permit	Minnesota Pollution Control Agency
Section 401 Clean Water Act Water Quality Certification	Minnesota Pollution Control Agency
National Historic Preservation Act Consultation Minnesota Field Archaeology Act Minnesota Historic Sites Act Minnesota Private Cemeteries Act	State Historic Preservation Office Tribal Historic Preservation Office
Utility Accommodation on Trunk Highway Right-of-Way	Minnesota Department of Transportation
Driveway/Access Permit	Minnesota Department of Transportation
Oversize/Overweight Permit	Minnesota Department of Transportation
Local[278]	
Utility Permit/Utility Installation Permit	County, Township, City
Access / Driveway Entrance / Approach Permit	County, Township, City
Oversize/Overweight Permit and/or Moving Permit	County, Township, City
Other	
Utility License Agreements	Utilities (Pipelines, Transmission Lines)
Crossing Agreements	Other Utilities (Railways)

278 Pursuant to Minn. Stat. § 216I.18, the issuance of a Route Permit required by the Commission is the sole site or route approval required to be obtained by the permittee. The permit supersedes and preempts all zoning, building, or land use rules, regulations, or ordinances promulgated by regional, county, local and special purpose government.

11 AGENCY, TRIBAL, AND PUBLIC OUTREACH

11.1 AGENCY AND TRIBAL OUTREACH

11.1.1 Tribal Nations

In December 2025, the Applicants sent Project introduction letters to the 11 designated Tribes in Minnesota, including the Tribal Historic Preservation Offices (see **Appendix H**).

In January 2026, the Applicants also sent notification letters to Tribal Nations as part of the Notice Plan implementation. This included the 11 designated Minnesota Tribes and Tribal Nations with interest within the proposed Notice Area, but which may be located outside the State of Minnesota in accordance with the Commission's July 2025 "Guidance for successful Tribal engagement" document. These same Tribal representatives were also sent an open house invitation on January 3, 2026. The Applicants will continue to coordinate with interested Tribes throughout the permitting, development, and construction processes.

11.1.2 Federal Agencies

In March 2024, Dairyland submitted a U.S. Fish and Wildlife Service Ecological Services Field Office – IPaC Review to determine the presence/absence of threatened and endangered species in the Project Area.

In June and December 2025, Dairyland contacted the USACE, St. Paul District to discuss the Project. Additional topics included transmission line clearances above a navigation channel and the potential applicability of the Utility Regional General Permit.

Dairyland began coordination with the USFWS Upper Mississippi National Wildlife and Fish Refuge staff in January 2024 and has met regularly with staff since that time. The Applicants expect extensive ongoing coordination with USFWS.

11.1.3 State Agencies

The Applicants plan to send pre-application coordination letters to the state technical representatives in early Q1 2026 to coordinate with state agencies as part of their pre-application route development process.

11.1.4 Local Government Units

The Applicants met with county commissioners in Olmstead and Houston Counties in October and November 2025, and Mower County in February 2026, to provide an overview of the MISO Tranche 2.1 projects, describe the Project benefits, and outline the process the Applicants will use to work with landowners. Local officials were also invited to the November 2025 and January 2026 open houses, as described in **Section 11.2** below. The Applicants will continue to conduct outreach to and coordination with local governments as the Project proceeds.

11.2 PUBLIC OUTREACH

11.2.1 Overview

Prior to filing this Application, the Applicants began conducting public outreach to inform stakeholders about the Project and solicit input from communities within the Notice Area. This outreach included open houses, online engagement tools, mailings and newspaper notices, and a Project website. This initial engagement was designed to keep communities informed well in advance of forthcoming routing processes and subsequent engagement related to those efforts.

11.2.2 Communication Channels

Website

The Applicants launched the Gopher to Badger Link website at GophertoBadgerLink.com on January 2, 2026. The website will remain open throughout the CN and route permitting and construction. The website provides Project-specific information and resources for visitors. Screenshots of the website, along with usage statistics, are included in **Appendix H** to this filing. As of January 22, 2026, there have been 6,291 views of the project website.

The Project website includes an interactive map where the public can leave comments pinned to a geographic marker. Contact information is also included on the website for participants to reach the project team with questions or information requests.

Project Email and Information Line

The Applicants also established a dedicated Project information line at 612-474-7799 and a Project email address Connect@GophertoBadgerLink.com.

The Project information line was set up in November 2025, prior to the January 2026 open houses, for the public to contact the Project team and obtain information. Callers were greeted with a short message and asked to provide their information and questions. Gopher to Badger Link team members would then follow up with additional information as requested by the caller.

The Project email address was created for interested people to send a message to the Gopher to Badger Link team with a question or comment. The Gopher to Badger Link team would then respond with the requested information or let the person who emailed know that their comment is being reviewed and considered as part of the Gopher to Badger Link development process.

11.2.3 November 2025 Open Houses

Dairyland and GLH hosted two open houses for the public along Segment 2 on November 17-18, 2025, in Grand Meadow and Caledonia, Minnesota. Postcard invitations were mailed to landowners along Dairyland's existing 161 kV line where Applicants are proposing to double-circuit the line as part of Segment 2. Postcard invitations were also mailed to Dairyland's member cooperatives and local government officials located within the project area.

Information regarding Segment 2 and the November open houses were also published in the following newspapers: LeRoy Mower County Independent, Preston Fillmore County Journal, and the Caledonia Argus. The media was notified of the event via a media advisory approximately one week prior to the open houses. Segment 2's website, www.maribelltransmission.com, was also updated to reflect information on the open houses.

Attendance at the Grand Meadow open house was estimated at approximately 50 attendees, and the Caledonia session drew approximately 100 attendees. The open houses included informational posters and each poster station was staffed by a subject matter expert from the Project team who could help answer questions. The posterboards included information Segment 2, including a Project overview, potential schedule, an overview on MISO, information on the Commission permitting process, and details regarding potential structure design. Recurring themes from the sessions included questions regarding the potential routes, community benefits, aesthetics, and agricultural impacts.

11.2.4 January 2026 Open Houses

The Applicants hosted open houses in January 2026 and provided notice of the open houses as follows:

- **Stakeholder letter** – The Applicants sent 235 letters to certain stakeholders throughout the Project Study Area in advance of the open houses. Letters were mailed on December 15, 2025. The letter introduced Gopher to Badger Link and detailed upcoming engagement opportunities. These letters went out to the local government leaders, regional economic development commissions, state senators and representatives in the Project area, US Senators and Representatives, and certain community groups. Examples of the letter are shown in **Appendix H**.

- **Invite postcard** – Using available parcel data, a landowner mailing list was generated to mail a postcard to approximately 15,546 landowners, landowners, local government units, stakeholders, tribes in the Project Notice Area. The postcards included information about the project, engagement opportunities, Study Area map, how to provide a comment, highlighted the virtual open house, and contact information. Examples of the postcard are shown in **Appendix H**.

- **Social media** – Facebook, X, LinkedIn, and Instagram were used by the Applicant's existing communication channels to promote the in-person public open houses and virtual engagement opportunities in January 2026. Examples of social media posts and analytics are shown in **Appendix H**.

- **Paid advertisements** – Paid advertisements were placed in six local newspapers with distribution in the Project Notice Area announcing the public open houses and virtual open house. The paid advertisement newspaper name, run dates, county, and circulation numbers are shown in **Appendix H.**

In-Person Open Houses

Between January 12-15, 2026, the Applicants hosted seven open houses at seven venues across southeastern Minnesota in/adjacent to the Project Notice Area.

Each open house provided the same information, including Project displays and detailed Project Study Area maps. Attendees were greeted and connected with a Project team member, guiding the attendee(s) through the displays and maps and answering their questions along the way. Attendees also had the opportunity to sit with a GIS/mapping specialist to view their specific locations of interest, discuss potential constraints or opportunities for their parcel(s) or community, and get a PDF map printed and/or emailed to them. The feedback received through in-person and virtual open houses will be reviewed and considered by the Applicants during the route development process.

The materials presented at the open houses are included in **Appendix H.**

Approximately 360 people attended the open houses. Table 11.2-1 details the number of attendees from each open house.

TABLE 11.2-1

In-Person Open Houses

Date /Time	County	Location	Attendance
Monday January 12th 4 pm - 6pm	Goodhue	Zumbrota VFW, 25 E 1st Street, Zumbrota, MN 55992	57
Tuesday, January 13 10 am – 12 pm	Olmsted	Blue Moon Ballroom 2030 Hwy 14 East Rochester, MN 55904	81
Tuesday January 13 4 pm – 6pm	Mower	LeRoy Community Center 204 West Main Street, LeRoy, MN 55951	55
Wednesday, January 14 10am – 12pm	Olmsted	Stewartville American Legion 110 2nd Avenue NW, Stewartville, MN 55976	34
Wednesday January 14 4 pm – 6 pm	Fillmore	Preston Depot Museum and Riverfront Center 304 Fillmore St. E Preston, MN 55695	47
Thursday January 15 10 am – 12pm	Fillmore	Mabel Community Center 201 Main Street S Mabel, MN 55954	31
Thursday January 15 4 pm – 6 pm	Houston	Four Seasons Community Center 900 N Kingston Street Caledonia, MN 55921	55
		TOTAL	**360**

Virtual Open House

The virtual open house was available on demand between January 7 – January 21, 2026, and included the same content presented during the in-person open houses in a website-type format. As of January 22, 2026, there have been 89 views of the virtual open house. Screen shots of the virtual open house are available in **Appendix H**.