2025 Biennial Transmission Projects Report

American Transmission Company, LLC
Central Minnesota Municipal Power Agency
Dairyland Power Cooperative
East River Electric Power Cooperative
Great River Energy
ITC Midwest LLC
L&O Power Cooperative
Minnesota Power
Minnkota Power Cooperative
Missouri River Energy Services
Northern States Power Company
Otter Tail Power Company
Rochester Public Utilities
Southern Minnesota Municipal Power Agency

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1.0 Executive Summary

The 2025 Biennial Transmission Projects Report is the thirteenth such report prepared since the requirement to prepare this report was established by the Minnesota Legislature in 2001. Previous Biennial Reports, beginning with the 2005 Report, are available for review on a webpage maintained by the utilities preparing the Report. That webpage is:

http://www.minnelectrans.com

The requirement is found in Minn. Stat. § 216B.2425. That law requires utilities that own or operate electric transmission facilities in the state to report by November 1 of each odd numbered year on the status of the transmission system, including identifying possible solutions to anticipated inadequacies in the transmission system. The Minnesota Transmission Owners (MTO) has consistently defined an "inadequacy" as essentially a situation where the present transmission infrastructure is unable or likely to be unable in the foreseeable future to perform in a consistently reliable fashion and in compliance with regulatory standards.

The Minnesota Public Utilities Commission (Commission or MPUC) established six transmission planning zones across the state in 2003. Those six transmission planning zones are the Northwest Zone, the Northeast Zone, the West Central Zone, the Twin Cities Zone, the Southwest Zone, and the Southeast Zone. Information about transmission facilities in each of the zones is included in the Report.

The 2025 Biennial Report identifies the present and reasonably foreseeable transmission "inadequacies" in the transmission system that exist in each of these six transmission planning zones. Each inadequacy has been assigned a Tracking Number. Information about each inadequacy identified by a Tracking Number is provided. Projects that were identified in earlier reports and assigned a Tracking Number but which have been completed or withdrawn in the past two years are also identified.

Similar to previous reports, this 2025 Biennial Report is a joint effort of the MTO – those utilities that own or operate high voltage transmission lines in the state of Minnesota. These utilities include the following:[1]

American Transmission Company, LLC
Agency Dairyland Power Cooperative
Great River Energy
L&O Power Cooperative
Minnkota Power Cooperative
Northern States Power Company d/b/a Xcel Energy
Rochester Public Utilities
Central Minnesota Municipal Power
East River Electric Power Cooperative
ITC Midwest LLC
Minnesota Power
Missouri River Energy Services
Otter Tail Power Company
Southern Minnesota Municipal Power Agency

[1] Hutchinson Utilities Commission, Marshall Municipal Utilities and Willmar Municipal Utilities are being served by Missouri River Energy Services who does the reporting for them.

Information about each of the MTO utilities, including their transmission assets in the various zones, is provided in the Report.

As required by Minn. Stat. § 216B.2425, subd. 7, the Biennial Report also provides an update on the status of the utilities' efforts to meet state Renewable Energy Standard (RES) milestones under Minn. Stat. § 216B.1691. In 2023, the Legislature amended Minn. Stat. § 216B.1691 to include carbon-free energy standard (CFS) and additional renewable energy requirements. (Minn. Laws 2023, ch. 7.) Because the Commission has pending dockets on compliance with the CFS, this 2025 Biennial Report includes the status of utilities' efforts to meet the RES standards but does not yet include a gap analysis related to the CFS.

In 2015, the Legislature established a new reporting requirement for certain utilities.[2] This reporting requirement is explained in further detail in Chapter 2, subsection 2.6. Pursuant to that requirement, Xcel Energy (currently the only utility to which the requirement applies), has submitted two separate reports entitled (1) Grid Modernization Report and (2) Hosting Capacity Report to the Commission in separate dockets.

In the Commission's June 12, 2018 Order Accepting Report, Granting Variance, and Setting Additional Requirements, the MTO was ordered to include an improved and expanded assessment on non-wire alternatives and a discussion of relevant actions by FERC, MISO, and the Commission related to distributed energy resources and distribution planning. This information can be found in Chapter 2, Sections 2.7 and 2.8.

In the Commission's August 19, 2020 Order Accepting Report, Granting Variance, and Setting Additional Requirements (2020 Order), the MTO was ordered to provide a full discussion and analysis of next steps for identifying gaps between the existing and currently planned transmission system and the transmission system that will be required to meet the companies' publicly stated clean energy goals and to address any need for new or expanded transmission to accommodate:

1) The public clean energy commitments of the MTO member utilities,
2) The requirements in all approved Minnesota resource plans, and
3) Relevant Minnesota statutory goals.

This information was included in Chapter 9 of the 2021 Report but has not been included in the 2025 Report given the intervening changes to the state's carbon-free and renewable energy standards adopted by the 2023 Legislature and the pending CFS compliance dockets.

The 2020 Order also required the MTO to describe its efforts to engage with Midcontinent Independent Transmission System Operator (MISO) to ensure Minnesota's transmission needs have been met and shall provide an assessment on whether MISO has been responsive to Minnesota's identified and likely transmission needs. This information can be found in Chapter 2, Section 2.9.

[2] Minn. Laws 2015, 1Sp2015, ch. 1, art 3, s 22, codified at Minn. Stat. § 216B.2425, subds. 2(e) and 8.

In the Commission's June 29, 2022 Order Accepting Report, the MTO was ordered to include the information that was required to be filed in the 2021 Report in their 2023 Report as well as the following:

1) Expected sustained HVTL or generation planned outages;
2) Whether those outages are anticipated to have new or incremental congestion; and
3) Whether those outages are anticipated to contribute to sustained incremental congestion.

This information is found in Chapter 9.

In the Commission's June 7, 2024 Order Accepting Report, the MTO was ordered to include the information that was required to be filed in the 2023 Report in their 2025 Report as well as the following:

A. An update on the progress and/or performance of the Grid North Partners' proposal for nineteen transmission upgrade projects aimed at enhancing reliability and easing congestion in Minnesota;
B. Information about short-term solutions to increase the robustness of the transmission system they have deployed or plan on deploying along with a report on their performance such as:
    1) dynamic line ratings,
    2) transmission system optimization and reconfigurations,
    3) adjusting transmission conductor limitations to increase line ratings,
    4) increasing substation limiter sizes, and
    5) other grid enhancing technologies that they have deployed or plan on deploying; and
C. Updates to its response to the PUC Information Requests from May 12, 2023.

As enacted by the 2024 Minnesota Legislature,[3] Minnesota transmission-owning utilities are submitting the inaugural report on Grid Enhancing Technologies (GETs) with this 2025 Biennial Transmission Plan Report. The 2025 GETs Report identified 30 solutions that will be developed to address congestion in the near-term. This report details historic and future congestion information for Minnesota to identify GETs solutions that meet the Commission's defined payback period. GETs are hardware or software that reduce congestion or enhance the flexibility of the transmission system by increasing the capacity of a transmission line or rerouting electricity from overloaded to uncongested lines, while maintaining industry safety standards. GETs include but are not limited to dynamic line rating, advanced power flow controllers, and topology optimization. The 2025 GETs Report builds upon the 2023 Grid North Partners' study which identified 19 solutions to reduce congestion in the mid-term. The Commission held a hearing in July and issued an order on September 10, 2025, providing additional requirements for the GETs Report. A summary of the 2025 GETs Report and a status update on projects identified in the 2023 Grid North Partners' study is contained in Chapter 9. A full copy of the GETs Report (Nonpublic) is available in Appendix B.

The following is a summary of each subsequent chapter of the 2025 Biennial Report.

[3] 2024 Minn. Laws, Ch. 127, Article 42, Section 52.

Chapter 2 describes the biennial reporting requirements. This includes a discussion of the specific information the MPUC directed the utilities to include in the 2025 Biennial Report. Chapter 8 contains information on clean energy goals.

Chapter 3 is titled Transmission Studies. This chapter includes a table listing a number of studies that have been completed over the past two years. In addition, a number of ongoing regional studies are described in some detail, and several more local, load-serving studies are identified in a separate table. A description of the MISO Transmission Expansion Plan (MTEP) Report is included since most planning is now approved by MISO, and the MTEP Reports show most of the information about the pending projects.

Chapter 4 is the Public Participation chapter. Several recent examples are provided regarding ways utilities have provided opportunities for the general public and local government to learn about and participate in the development of new transmission projects. This chapter summarizes the evolution of MPUC requirements relating to transmission planning and the preparation and submission of the Biennial Report. A section is included describing the webpage the MTO maintains (www.minnelectrans.com) that is available to the public to learn about ongoing transmission projects.

Chapter 5 provides general information about the six Transmission Planning Zones in the state.

Chapter 6 is where all the Transmission Needs are identified. The Report identifies approximately 158 separate transmission inadequacies across the state, including 79 new ones identified in the 2025 Biennial Report.

Each inadequacy is assigned a Tracking Number. The Tracking Number reflects the year the inadequacy was identified and the zone in which it is located. A brief description of each project is provided in the Report, and a reference is provided for each one to where detailed information can be found in the applicable MTEP Report. The 2024 MTEP Report, for example, would be called MTEP24. In addition, information about each project pending, by Tracking Number, is provided. This information addresses alternatives considered, a schedule, and the general impacts on the environment and the area once the project is constructed.

The MTEP Report referenced in the table for each Tracking Number will contain detailed information about the project, including alternatives, costs, and a schedule. Chapter 6 also presents comprehensive instructions on how to find the appropriate MTEP Report containing the desired information. The utilities have also attempted to indicate whether a Certificate of Need (CON) from the Commission might be required for a particular project selected to address a named inadequacy.

Certain projects have been completed since the 2023 Report was filed two years ago or are no longer necessary because of a change in demand or some other factor. These completed or cancelled projects are listed in a table for each zone in Chapter 6.

Chapter 7 focuses on the 14 utilities jointly filing this report. A brief description of each utility and the name and address of a contact person are provided. Information about the number of miles of transmission lines in Minnesota is also provided for each utility.

Chapter 8 provides an analysis of the utilities' progress toward compliance with state RES requirements. Not all utilities that own transmission lines are subject to the state RES, and some utilities that are not required to participate in the Biennial Report must meet the RES milestones. All utilities subject to the RES participated in providing information for this part of the Report.

The utilities subject to the RES have provided a Gap Analysis. A Gap Analysis is an estimate of how many more megawatts of renewable generating capacity a utility will require beyond what is presently available to meet an upcoming RES milestone of a certain percentage of retail sales from renewables. Generally, the Gap Analysis shows that the utilities are in compliance with present standards and expect to have enough generation and transmission to meet RES milestones into the future. Future guidance from the Commission regarding compliance with the CFS may also affect this analysis.

Chapter 9 discusses HVTL or generation planned outages, whether those outages are anticipated to have new or incremental congestion; and whether those outages are anticipated to contribute to sustained incremental congestion. Chapter 9 also provides updates on the MTO's work related to congestion and specifically in response to the Commission's March 24, 2025 Order in Docket No. E999/CI-24-316 that required that the MTOs include a cost-benefit analysis in this Report comparing any feasible battery storage solution to status quo conditions and to its performance under planned grid upgrades at the Nobles County Substation area. Xcel Energy performed the studies to evaluate these solutions and address congestion and limitations on local wind generation under the current operation guide for voltage stability. Xcel Energy's Nobles Grid-Forming Battery Screening System Impact Study determined that the proposed Nobles Battery Storage project with grid forming inverter will provide dynamic voltage stability benefits to the system in dispatches with high wind generation. These benefits are observed when utilizing a grid-forming inverter. Real power dispatch of the battery storage project will need to be managed in order to maximize the voltage stability benefits. Xcel Energy also completed an Nobes Battery Economic Screening Analysis using historical Locational Marginal Prices (LMP) to determine if there would be any economic benefit to adding a 300 MW battery storage unit at the Nobles County substation. Based on this preliminary analysis, it shows that a 300 MW battery storage unit would have a positive impact on curtailments in the area if installed. These studies are provided as Appendices C and D of this Report. Xcel Energy will provide further details in future filings with the Commission.

Chapter 10 includes information on MISO Long Range Transmission Plan (LRTP)**.**

Chapter 11 includes compliance items from MPUC Orders and the Minnesota Legislature.

MPUC Process. Upon receipt of this Report, the Commission will solicit comments from the Department of Commerce, interested parties, and the general public. Any person interested in commenting on the Report or following the comments of others should check the efiling docket for this matter or in some other manner contact the Commission. The Docket Number is E999/M-

25-99. The precise schedule for filing comments is established by Minn. Rule Chapter 7848 relating to the biennial reporting process. It is anticipated that the MPUC will make a final decision on the 2025 Biennial Transmission Projects Report in May 2026.

2.0 Biennial Report Requirements

2.1 Generally

Prior Reports
This is the thirteenth Biennial Transmission Projects Report to be filed by those utilities that own or operate electric transmission lines in Minnesota. The obligation to file such a report was created by the Minnesota Legislature in 2001.[4] The statute requires the utilities to file their transmission report by November 1 of each odd-numbered year.

All previous reports are all available on the Commission's eDockets webpage using the Docket Number from the table below. The past reports are also available on the webpage maintained by the utilities: http://www.minnelectrans.com/. The 2025 Report will also be posted on that webpage.

Biennial Report	MPUC Docket Number	MPUC Order
2025	E999/M-25-99	
2023	E999/M-23-91	June 7, 2024
2021	E999/M-21-111	June 29, 2022
2019	E999/M-19-205	August 19, 2020
2017	E999/M-17-377	June 12, 2018
2015	E999/M-15-439	May 27, 2016, Errata June 7, 2016
2013	E999/M-13-402	May 12, 2014
2011	E999/M-11-445	May 18, 2012
2009	E999/M-09-602	May 28, 2010
2007	E999/M-07-1028	May 30, 2008
2005	E999/TL-05-1739	May 31, 2006
2003	E999/TL-03-1752	June 24, 2004
2001	E999/TL-01-961	August 29, 2002

Minn. Stat. § 216B.2425 requires the utilities to list in the report specific present and reasonably foreseeable future inadequacies in the transmission system in Minnesota. The term "inadequacy" was not defined by the Legislature or by the Commission. The utilities have consistently stated that the term "inadequacy" is interpreted to be a situation where the present transmission infrastructure is unable or likely to be unable in the foreseeable future to perform in a consistently reliable fashion and in compliance with regulatory standards. This definition has been accepted by the Commission and others in past dockets.

The statute spells out certain categories of information that should be included in the report for each inadequacy, and the Commission has adopted rules to expand and clarify what is expected to

[4] Minn. Stat. § 216B.2425.

be in the report.[5] These laws generally require not only an identification of present and foreseeable inadequacies but also a discussion of alternative ways of addressing each inadequacy and the potential issues and impacts associated with possible solutions to the situation. The utilities are also required to provide opportunities for public input in the planning and development of solutions to the various inadequacies and to describe in the report the efforts undertaken to involve the public. The utilities discuss in Chapter 4 various efforts that have been undertaken to involve the public in transmission planning.

Over the years, in response to experiences with the rule requirements and to other developments in transmission planning, the MPUC has modified the application of the rules in a number of significant ways. One important modification recognizes that most transmission planning is now approved through MISO. MISO prepares a report each year, called the MTEP Report. MISO transmission planning is conducted in public forums and the MTEP Report is publicly available on the Internet. Unlike this state report, which is prepared every other year and focuses only on Minnesota, the MTEP Report is updated yearly and describes in detail transmission planning needs throughout the entire jurisdictional area of MISO, and not just in Minnesota.

Consequently, for the past seven biennial reports – 2011, 2013, 2015, 2017, 2019, 2021, and 2023 – the Commission has allowed the utilities to reference the latest MTEP Report to provide information about the identified inadequacies in Minnesota. The 2025 Report, with the Commission’s concurrence, also relies on the latest MTEP Report to identify upcoming transmission needs and to provide the necessary information about the possible alternatives considered to address each inadequacy. The utilities explain in Section 6.1 ways to find the pertinent information about each inadequacy in the MTEP Report.

The MPUC has also recognized that holding public meetings around the state and holding a webinar to describe ongoing transmission planning and needs has not resulted in any substantial participation by the public. The MPUC has granted the utilities a variance for the past several years from the requirement in the rules to hold yearly planning meetings in each transmission planning zone. For 2025, the MPUC has continued this variance and exempted the utilities from holding a webinar. However, the utilities continue to conduct transmission planning in a manner that is open to the public and opportunities are provided for the public to participate in such planning and in the discussion of alternative solutions to the transmission needs under review. MISO also holds meetings open to the public to discuss their transmission plans and processes.

In its 2022 Order accepting the 2021 Biennial Report, the Commission said that the MTO shall include content similar to 2021 Report, and include:

1) Expected sustained HVTL or generation planned outages;
2) Whether those outages are anticipated to have new or incremental congestion; and
3) Whether those outages are anticipated to contribute to sustained incremental congestion.

[5] Minn. R. Ch. 7848.

Waiver Request for 2027 Report
The MTO requests the Commission to extend the rule variances granted in the June 7, 2024, Order accepting the 2023 Biennial Report (and previous orders) for the 2027 Biennial Report as well, such that the future report requirements will mirror the content, notice and participation requirements of this 2025 Biennial Report. The MTO requests it be allowed to continue to reference the latest MTEP Report to provide information about the identified inadequacies in Minnesota and that the public meeting or webinar requirements in Minn. Rule 7848.0900 and related to outreach in Minn. Rule 7848.1000 be waived. As has been demonstrated in previous biennial report proceedings, application of these rules would excessively burden the MTO by requiring them to spend money and divert engineers and other experts to producing duplicative information and attend meetings that do not appear to have a corresponding public benefit; prior lack of public participation in the public meetings and webinars demonstrates that waiving the rules does not adversely affect the public interest, and granting the variances is not contrary to any standard imposed by law.

We will continue to provide a link to the report on the MTO website, www.minnelectrans.com as well as directions to access the report via eDockets.

2.2 Reporting Utilities

Minn. Stat. § 216B.2425 applies to those utilities that own or operate electric transmission lines in Minnesota. The MPUC has defined the term "high voltage transmission line" (HVTL) in its rules governing the Biennial Report to be any line with a capacity of 200 kilovolts or more and any line with a capacity of 100 kilovolts or more and that is either longer than ten miles or that crosses a state line.[6] Each of the entities participating in filing this report owns and operates a transmission line that meets the MPUC definition. Information about the utility and transmission lines owned by each utility is provided in Chapter 7 of this Report. In addition, a contact person for each utility is included in Chapter 7.

The statute allows the entities owning and operating transmission lines to file this report jointly. The MTO has elected each filing year to submit a joint report and does so again with this report. The utilities jointly filing this report are:

American Transmission Company, LLC
Central Minnesota Municipal Power Agency
Dairyland Power Cooperative
East River Electric Power Cooperative
Great River Energy
ITC Midwest LLC
L&O Power Cooperative
Minnesota Power
Minnkota Power Cooperative
Missouri River Energy Services

[6] Minn. R. 7848.0100, subp. 5.

Northern States Power Company d/b/a Xcel Energy
Otter Tail Power Company
Rochester Public Utilities
Southern Minnesota Municipal Power Agency

Of the above utilities, East River Electric Power Cooperative, L&O Power Cooperative and Minnkota Power Cooperative are not members of MISO; all the others are. Since the Mid-Continent Area Power Pool (MAPP) was dissolved in late 2015, resulting in the termination of MAPPCOR, the nonprofit organization that did the planning work for the MAPP utilities, MISO has performed many of the planning roles for Minnkota Power Cooperative.

2.3 Certification Requests

Minn. Stat. § 216B.2425, subd. 2, provides that a utility may elect to seek certification of a particular project identified in the Biennial Report. According to subdivision 3, if the Commission certifies the project, a separate CON under Minn. Stat. § 216B.243 is not required.

On May 29, 2025, the MTO filed a letter to the Commission in the instant docket that there would be no certification requests included with the 2025 Biennial Report.

2.4 General Impacts

In its May 12, 2014, Order approving the 2013 Biennial Report, the Commission recognized that reference to the latest MTEP Report was an appropriate way to provide useful information about the inadequacies identified in the Biennial Report, but that the MTEP Report did not provide general information about the potential environmental, social, and economic impacts of possible alternatives to address the inadequacy, as required by Minn. Stat. § 216B.2425, subd. 2(c)(3). The Commission stated in its Order at page 6 that "in the future the information [in the MTEP Report] must be supplemented with a fuller discussion of economic, environmental, and social issues related to proposed alternative solutions to inadequacies listed in the report."

The Commission stated in its May 27, 2016, Order approving the 2015 Report that the MTO "shall include in the 2017 Report the requirements addressed in Minn. Stat. § 216B.2425, subd. 2(c)(3)." Since the Commission and the Department of Commerce staff determined that the information the utilities provided in the 2015 Biennial Report satisfied the obligation to report on these impacts, the MTO will address the potential impacts of the various projects in the same manner in this Report. The discussion below describes how these impacts are addressed.

First, it is difficult to provide significant information about a transmission need expected several years in the future. The MPUC rules require the utilities to identify inadequacies that might affect reliability over the next ten years.[7] A transmission planner is often unable to identify possible alternatives or the impacts of the alternatives, for inadequacies ten years in the future. Moreover,

[7] Minn. R. Ch. 7848.1300, subp. D.

it is not uncommon for a potential reliability issue that may be several years in the future to subsequently be delayed for several more years or even indefinitely because of unforeseen events such as an economic recession or the closing of a large industrial customer or even a change in government policy or tax provisions. Also, more pressing problems may develop that take precedence over more minor concerns and transmission planners may have to focus their attention on other projects.

Importantly, the statute says the utilities are to identify general economic, environmental, and social issues associated with each alternative. These issues are not always possible to know during the planning stage; various issues may evolve when a particular project is developed in more detail. It is sufficient to address potential issues in a general way, as the utilities have done here.

While it is not possible for the utilities to provide specific discussion of potential impacts for each of the approximately 158 separate Tracking Numbers identified in this Biennial Report, transmission planners and utility staff are well aware of the kind of issues that arise with any large energy facility, whether a transmission line or a generating plant. For example, a transmission line may cross a wetland, or run through an agricultural field, or follow a residential street. A new generating plant has a certain footprint, and may result in the emission of various pollutants, and may require the transport of fuel. A large energy project has tax consequences for local government. Jobs will be created by the construction of a new facility, and the local area will be disrupted for a time while construction is ongoing. These are the kind of general impacts that can be addressed for projects that have not developed to the point of specific alternatives having been identified.

An in-depth analysis of potential impacts of a proposed project and the identified alternatives will be provided once the utility has determined that a need for new infrastructure is certain enough and imminent enough that a project must be pursued. This is the time the public generally begins to take notice of the need for a project and to participate in the analysis of alternatives. And this is the time the utility must begin to pull together the information required to complete applications for a CON and for a route permit. These applications, and any environmental review conducted as part of the application process, will examine potential economic, environmental, and social issues in depth, with opportunities for public involvement and input.

The MTO can provide in this Biennial Report only a general discussion of the kind of impacts associated with certain types of energy projects, like transmission lines and substation upgrades and generating facilities. A more detailed discussion of impacts will be provided when a specific project has been identified, alternatives have been considered, and permit application have been submitted.

2.5 Renewable Energy Standards

The utilities are required to include in the Biennial Report a discussion of necessary transmission upgrades required to meet upcoming renewable energy standards.[8] In 2023, the Minnesota Legislature amended the objectives set forth in Minn. Stat. § 216B.1691 to include additional milestones for renewable energy as well as creating new carbon-free energy standards (CFES) (see Minn. Laws 2023, ch. 7). As with previous reports, this discussion is included in Chapter 8.

2.6 Distribution Report & Grid Modernization

In 2015 the Legislature amended Minn. Stat. § 216B.2425 to add two additional requirements for utilities operating under multiyear rate plans, a category that at present includes only Xcel Energy. Subdivision 2(e) requires Xcel Energy, at the time of the Biennial Transmission Projects Report filing, to report:

> *investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.*

This reporting requirement is often referred to as the Grid Modernization Report. The MPUC in May 2015 opened a separate docket for consideration of efforts related to modernization of the transmission and distribution grid. (MPUC Docket No. E999/CI-15-556.)

Further, subdivision 8, which was also added in 2015, provides:

> *Each entity subject to this section that is operating under a multiyear rate plan approved under section 216B.16, subdivision 19, shall conduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources and shall identify necessary distribution upgrades to support the continued development of distributed generation resources, and shall include the study in its report required under subdivision 2.*

These reporting requirements apply only to utilities operating under an approved multiyear rate plan approved by the MPUC under section 216B.16, subd. 1, and Xcel Energy is the only utility currently operating under such a plan and the only utility required to file a distribution study and grid modernization plan. The table below shows the Biennial Distribution-Grid Modernization Reports that Xcel Energy has submitted under Minn. Stat. § 216B.2425.

[8] Minn. Stat. § 216B.2425, subd. 7.

MPUC Docket Number	Date Filed
E002/CI-15-962	October 30, 2015
E002/CI-17-776	November 1, 2017
E002/CI-18-251	November 1, 2018
E002/M-19-666	November 1, 2019
E002/M-21-694	November 1, 2021
E002/M-23-452	November 1, 2023
E002/M-25-142	November 1, 2025

2.7 Non-Wire Alternatives

Overview
In the Commission's June 12, 2018 ORDER ACCEPTING REPORT, GRANTING VARIANCE, AND SETTING ADDITIONAL REQUIREMENTS, in Docket No. E999/M-17-377, Order Point 2 states:

> *In their 2019 Report, the MTO shall include content similar to 2017 Report, and include an improved and expanded assessment of non-wire alternatives . . . .*

This section provides a broad discussion of non-wires alternatives to give context for the analysis that follows in Chapter 6, where potential non-wires alternatives are discussed for applicable transmission projects.

Application of Non-Wires Alternatives
Overall, this Report identified approximately 158 transmission inadequacies in the State and proposes transmission or non-wires alternatives to address them. The identified transmission inadequacies fall into the following general categories: load interconnection, generator interconnection, thermal overloads and voltage violations.

Depending on the type of issue and its magnitude, each project's transmission owner may consider a broad range of alternatives for addressing reliability concerns. Alternatives considered may include both wire and non-wire solutions. The types of alternatives considered for a particular issue are dependent on the nature of the problem to be addressed. To be a viable alternative, a solution must be available (1) at the necessary time, (2) with the necessary response, and (3) for the necessary duration, to address the inadequacy at hand.

Non-wires alternatives are electric utility system supply-and demand-side projects and operating practices that defer or replace the need for specific transmission projects, at lower total resource cost, by reliably reducing transmission congestion at times of high demand in specific grid areas.[9] Examples of non-wires transmission alternatives may include: establishing new operating guides or procedures, demand side management (DSM), distributed generation (DG), and storage of electricity or heat or ponded water.

[9] www.nrri.org.

Generally speaking, certain categories of non-wires alternatives may be best suited to address certain categories of identified transmission inadequacies. For example, the need for local load serving transmission could potentially be alleviated or delayed with DSM or appropriately sited renewable generation including DG interconnections on the distribution system. The availability of DG has the effect of reducing the need to serve the load from the transmission system and has the greatest impact if the DG is available during peak load conditions. Solar PV offers a positive, but not perfect, correlation with high load periods during the summer, while a combination of distributed solar and/or wind with distributed storage offers the greatest impact to reduce effective loads served. Transmission planners continue to evaluate non-wire options that result in the avoidance of establishing new transmission lines. As the costs of non-wire alternatives become more competitive with traditional wire solutions, the transmission planners are closely examining DG and other distribution solutions against transmission alternatives.

Implementation of non-wires alternatives can also bring different challenges. For example, as DG penetration grows, the communication technology will have to be improved to manage DG installations. There will be more points to monitor to ensure load can be reliably served from multiple generation resources. Real time system operations will become more complex as the generation becomes more variable and concentrated. Distribution automation likely will be needed to assist the operator in shifting load to other systems if the expected generation resources are not available.

More DG on the system and in closer proximity to load decreases reliance on the transmission system. Solar is anticipated to be the more common type of DG in the future, but fuel-cell technology or some yet unknown generation source or Load Modifying Resource (LMR) may also become viable alternatives. It is expected that storage capabilities will follow the adoption and installation of solar and wind to allow more full use of the renewable resources and increase their value throughout the daily load cycle. Storage can also increase the off-the-grid opportunities for existing and future electric users.

The table below describes the benefits and challenges of different types of non-wires alternatives in addressing identified categories of transmission deficiencies.

Non-Wire Alternatives			
Type of Trans-mission Project	**Solar + Storage**	**Wind + Storage**	**Demand Side Management**
Load Inter-connection	A combination of solar and storage may be an option for load serving deficiencies. Storage needs to be implemented in ways to ensure reliability performance equal to the reliability provided by transmission options. Based on geographic locations, land constraints may be a challenge to installation of adequate solar generation to meet the new or expanding load. In addition, current costs for solar/storage installations are often higher than transmission load serving options.	A combination of wind and storage may be an option for load serving deficiencies. Storage needs to be implemented in ways to ensure reliability performance equal to the reliability provided by transmission options. In addition, current costs for wind/storage installations are often higher than transmission load serving options.	Demand side management is not applicable for load interconnection projects as the deficiencies are driven by new load. For existing load expansions, DSM is considered but may not be available in quantities or durations needed to reliably address the deficiency.
Generator Inter-connection	Not applicable for these projects.	Not applicable for these projects.	Not applicable for these projects.

Non-Wire Alternatives			
Type of Trans-mission Project	**Solar + Storage**	**Wind + Storage**	**Demand Side Management**
Thermal Overloads	Solar and storage are looked at individually and in combination for transmission thermal overloads. Since transmission availability is ~99%, viable alternatives will have to have similar availability. Solar and storage can help alleviate overloads on a transmission line depending on their duration and location, but the current costs of these options are typically significantly more expensive than traditional transmission solutions.	Wind and storage are looked at individually and in combination for transmission thermal overloads. Since transmission availability is ~99%, any option will have to have similar availability. Wind and storage can help alleviate overloads on a transmission line depending on their duration and location, but the current costs of these options are typically significantly more expensive than traditional solutions.	Demand Side Management is an option for transmission thermal overloads. DSM must be available in adequate amounts and duration and be sufficiently reliable to be called upon to address these transmission inadequacies.

Non-Wire Alternatives			
Type of Trans-mission Project	**Solar + Storage**	**Wind + Storage**	**Demand Side Management**
Voltage Violations	Solar and storage are looked at individually and in combination for voltage violations. Since transmission availability is ~99%, any option will have to have similar availability. Solar and storage can help alleviate low and high voltages depending on location, duration and applicability of the installation, but the current costs of these options typically are significantly more expensive than traditional transmission solutions.	Wind and storage are looked at individually and in combination for transmission voltage violations. Since transmission availability is ~99%, any option will have to have similar availability. Wind and storage can help alleviate low and high voltages depending on location, duration and applicability of the installation, but the current costs of these options typically are significantly more expensive than traditional transmission solutions.	Demand Side Management is an option for transmission voltage violations. DSM must be available in adequate amounts and duration and be sufficiently reliable to be called upon to address these transmission inadequacies. DSM is not generally a viable solution for high-voltage inadequacies.

Conclusion
Non-Wire Alternatives are discussed in Chapter 6 and are deployed as deemed appropriate by the project transmission owner based on the nature of the transmission inadequacy. The Minnesota Transmission Owners remain committed to evaluating non-wires alternatives to proposed transmission projects and may revisit these analyses based on future technological improvements and cost efficiencies.

2.8 FERC, MISO, and Commission Actions Related to Distributed Energy Resources and Distribution Planning

In the Commission's June 12, 2018 ORDER ACCEPTING REPORT, GRANTING VARIANCE, AND SETTING ADDITIONAL REQUIREMENTS, in Docket No. E999/M-17-377, Order Point 2 states:

> *In their 2019 Report, the MTO shall include content similar to 2017 Report, and include . . . a discussion of relevant actions by FERC, MISO, and the Commission related to distributed energy resources and distribution planning.*

The Commission, the Federal Energy Regulatory Commission (FERC), and MISO, discuss distributed energy resources and distribution planning in a wide range of dockets and contexts. In this section we include the discussion of relevant actions by the Commission, FERC and MISO related to distributed energy resources and distribution planning.

Minnesota Public Utilities Commission

Broadly speaking, the Minnesota Public Utilities Commission has addressed distribution planning and distributed energy resources in a wide variety of policy,[10] planning,[11] fact specific[12] and annual reporting dockets.[13]

FERC

The 2021 Biennial Report discussed FERC Order Nos. 841 and 2222 as they pertain to storage and non-storage Distributed Energy Resource (DER) aggregations participating in wholesale markets.

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[10] See, e.g., In the Matter of a Commission Investigation into the Potential Role of Third-Party Aggregation of Retail Customer, Docket No. E999/CI-22-600; In the Matter of a Commission Investigation on Grid and Customer Security Issues Related to Public Display or Access to Electric Distribution Grid Data, Docket Nos. E999/CI-20-800 and E002/M-19-685; In the Matter of Xcel Energy's Tariff Revisions Updating Interconnection Standards for Distributed Generation Facilities Established under Minn. Stat. §216B.1611, Docket No. E002/M-18-714; In the Matter of a Commission Inquiry into the Creation of a Subcommittee under Minn. Stat. §216A.03, subd. 8, Docket No. E999/CI-17-284; In the Matter of Xcel Energy's Petition for Tariff Modifications Implementing Rules on Cogeneration and Small Power Production, Docket No. E002/M-16-222; In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611, Docket Nos. E999/CI-16-521 and E999/CI-01-1023; In the Matter of a Commission Inquiry into Fees Charged to Qualifying Facilities, Docket No. E999/CI-15-755; In the Matter of a Commission Inquiry into Standby Service Tariffs, Docket No. E999/CI-15-115; In the Matter of the Commission Investigation on Grid Modernization, Docket No. E999/CI-15-556; In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10(e) and (f), Docket No. E999/M-14-65; and In the Matter of Possible Amendments to Rules Governing Cogeneration and Small Power Production, Minnesota Rules, Chapter 7835, Docket No. E999/R-13-729.

[11] See, e.g., In the Matter of the Xcel Energy 2022 Hosting Capacity Report Under Minn. Stat. §216B.2425, Subd. 8, Docket No. E-002/M-22-574; In the Matter of the Xcel Energy 2021 Hosting Capacity Report Under Minn. Stat. §216B.2425, Subd. 8, Docket No. E002/M-21-767; In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan, Docket No. E002/M-21-694; In the Matter of the Xcel Energy 2020 Hosting Capacity Report Under Minn. Stat. §216B.2425, Subd. 8, Docket No. E002/M-20-812; In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request, E002/M-19-666; Docket No. E002/CI-18-251; In the Matter of Xcel Energy's 2018 Integrated Distribution Plan, Docket No. E002/CI-18-251; In the Matter of Distribution System Planning for Dakota Electric Association, Docket No. E111/CI-18-255; In the Matter of Distribution System Planning for Minnesota Power, Docket No. E015/CI-18-254, In the Matter of Distribution System Planning for Otter Tail Power, Docket No. E017/CI-18-253.

[12] See, e.g., In the Matter of a Formal Complaint and Petition for Relief by Nokomis Energy LLC and Union Garden LLC Against Northern States Power Company d/b/a Xcel Energy, Docket No. E002/C-22-212; In the Matter of a Formal Complaint and Petition for Expedited Relief by Sunrise Energy Ventures LLC Against Northern States Power Company d/b/a Xcel Energy, Docket No. E002/C-21-160; In the Matter of the Appeal of an Independent Engineer Review Pertaining to the SunShare Linden Project (Community Solar Gardens Program), Docket No. E002/M-19-29; In the Matter of a Formal Complaint Against Xcel Energy by Sunshare, LLC, Docket No. E002/CI-19-203; In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of its Proposed Community Solar Garden Program, Docket No. E002/M-13-867; In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need, Docket No. E002/CN-12-1240.

[13] See, e.g., In the Matter of Annual Cogeneration and Small Power Production Filings, Docket No. E999/PR-25-9; Distributed Generation Interconnection Report, Docket No. E999/PR-25-10.

The 2023 Report discussed FERC Order No. 2023, which adopted reforms to modernize the transmission grid by streamlining the interconnection processes for transmission providers.

Order No. 2023, adopted in July of 2023, includes several reform to the interconnection processes, such as instituting a first-ready-first-served cluster study process, increased financial commitments for interconnection customers, improved efficiency of the interconnection process, firm deadlines and penalties for transmission providers if they fail to complete their interconnection studies on time, and incorporating technological advancements into the interconnection process, such as consideration of advanced transmission technologies in the interconnection study process and an update of modeling and performance requirements for inverter-based resources to ensure continued system reliability. The final rule requires all public utilities to adopt revised pro forma generator interconnection procedures and agreements to ensure that interconnection customers can interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, and to prevent undue discrimination.

MISO

In 2021, MISO noted on its website that "[a] high penetration of [DERs] could have notable implications for MISO and require a stronger transmission and distribution interface. The DER issue [in the MISO stakeholder process] is intended to explore and advance collaboratively developed DER priorities with stakeholders." MISO subsequently held a number of stakeholder workshops that resulted in a number of changes supporting the coordination of DER between DER interconnection customers, distribution providers, transmission owners, and MISO. Most notably, the creation of the MISO DER Affected System Study (AFS) will promote coordination and study of DER that exceed certain impact thresholds on the transmission system. The changes and improvements resulting from this new process may act as an important catalyst for enabling DER participation in the larger power system.

MISO filed its Order No. 841 compliance filing in December 2018 with the provisions regarding DERs. Subsequently, in their response to FERC's request for more information filed in April 2019, MISO updated their Distribution Connected Electric Storage Resource (ESR) form agreement to require an attestation from the ESR that all necessary metering and other arrangements are completed before they can participate as a distribution connected ESR in MISO. FERC accepted MISO's Order No. 841 compliance filing in November 2019 with an effective date of June 2022. The changes associated with this filing went into production on September 1, 2022.[14]

According to FERC, "the main goal of Order No. 2222 is to better enable distributed energy resources (DERs) to participate in the electricity markets run by regional grid operators. The term "DERs" covers a wide variety of resources, including electric battery storage systems, rooftop solar panels, products like smart thermostats that enable one to reduce power usage, energy efficiency measures, thermal energy storage systems such as ice storage, or electric vehicles and their charging equipment."[15] In Order No. 2222, FERC established a compliance deadlines for the

[14] For more information about this process and timeline see https://www.misoenergy.org/stakeholder-engagement/MISO-Dashboard/storage-participation--ferc-order-841-compliance/.

[15] https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy.

Regional Transmission Operators (RTO) and Independent System Operators (ISO). MISO filed a request to extend those deadlines. For MISO, compliance filings are being made in Docket No. ER22-1640. MISO is working toward a two-phase implementation of Order No. 2222. Phase 1 is slated to be completed by June 1, 2027, while final implementation through Phase 2 would occur by June 1, 2029.

Grid North Partners (GNP)
Grid North Partners, an evolution of CapX2020, is a voluntary partnership of 10 Minnesota and surrounding area transmission owning utilities[16] formed in 2004 to collaboratively expand the Upper Midwest transmission grid. GNP has been working to identify solutions to address those key findings via two primary avenues:

- Technical efforts – consisting of collaborative participation in MISO's Long-Range Transmission Planning (LRTP) effort, and
- Education & stakeholder engagement – including dialog with policy makers, utilities, stakeholders, and landowners to discuss needed improvements to ensure the transmission system in the Upper Midwest is prepared to deliver tomorrow's energy 24 hours a day, 7 days a week.

GNP Technical Effort: GNP Members have been actively conducting and coordinating on the Minnesota Grid Enhancing Technologies report as required by statute. The final report is included as Section 9.4 of this Biennial report. The Minnesota Grid Enhancing Technologies study is a sequel to the 2023 Grid North Partners near-term congestion study. An overview of the 2023 study and the current status of the 19 resulting projects is contained in Section 9.3.

Institute of Electrical and Electronics Engineers (IEEE)
While not specifically requested by Commission, another important aspect is various entities' work on IEEE 1547-2018, which is a recently published DER interconnection and interoperability standard.

The revised standard addresses three new broad types of capabilities for DER: local grid support functions; response to abnormal grid conditions; and exchange of information with the DER for operational purposes. The standard was written with a large set of required capabilities with an expectation that not all capabilities would be immediately implemented in the field. In this way, it offers options for grid operators preparing for scenarios with high penetration of DER. Some details associated with implementing the standard are part of the Commission's E002/M-16-521 docket, especially in Phase II which considers statewide technical standards, and other details are expected to be associated in utility business practice decisions.

[16] Grid North Partners member utilities include Central Municipal Power Agency/Services, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy.

In terms of specifying DER response to abnormal grid conditions, IEEE 1547 indicates the Authority Governing Interconnection Requirements and Regional Reliability Coordinator possess a guidance role in implementing these capabilities, which, in Minnesota, are the Minnesota Commission and MISO respectively. Commission Staff requested information and guidance from MISO through a working group associated with the E002/M-16-521 docket. The response from MISO included a plan to convene a stakeholder group so guidance on the topic could be provided on a regional basis. The Commission's interest in resolving questions associated with adopting these capabilities is helping to drive important stakeholder conversations.

Local grid support functions have generated interest in the industry in recent years based on implementation of these functions in states such as Hawaii and California in areas of high DER deployment. The IEEE 1547-2018 standard allows a utility to specify ways local grid support functions are to be used. Xcel Energy proposed in the E002/M-16-521 docket that use of the local grid support functions should be published in utility-specific technical manuals.

The interoperability aspects of IEEE 1547-2018, which include concepts of DER monitoring and control, mark the most future leaning required capabilities. When certified equipment is available, every DER will have a standardized communication interface for exchanging data and performing remote operations. A communication network would be necessary for making use of the interoperability interface.

Electric Power Research Institute (EPRI)
EPRI has led several efforts to understand the general technical needs to meet compliance with FERC Order 2222. The EPRI workplan is divided into phase 1 and phase 2. EPRI released several collaborative reports for phase 1 in July of 2021. Various MTO utilities have been participating in the working groups to aid in the development of the collaborative reports.

The first report focuses on the metering, data, information and telemetry requirements for ISOs and RTOs, distribution utilities, transmission utilities, DERs and aggregators. The report is a guidance for future market and interconnection requirement design.

The second report focuses on the systems interoperability and cyber security of DER and aggregators to ensure best practices are identified to maintain system security in the decentralized environment.

The third report focuses on the role of the distribution utility in enabling market participation for DERs and aggregators in wholesale markets. The report is intended to provide high level technical guidance for what is required to fulfill various roles.

Finally, EPRI is also providing guidance to the Transmission Operators with a shorter technical briefing to provide guidance on the various ways to ensure reliability in a distributed environment.

2.9 MISO and Minnesota's Transmission Needs

In the Commission's August 19, 2020 ORDER ACCEPTING REPORT, GRANTING VARIANCE, AND SETTING ADDITIONAL REQUIREMENTS, in Docket No. E999/M-19-205, Order Point 5(d). states:

> *The MTO shall describe its efforts to engage with MISO to ensure that Minnesota's transmission needs have been met, and shall provide an assessment of whether MISO has been responsive to Minnesota's identified and likely transmission needs.*

Minnesota TOs participate in many different MISO processes to ensure our needs are being addressed and our voices are being heard. MISO has several different TO groups set up to address various functions under MISO control. Below are the MISO Groups and processes that Minnesota TOs are involved in.

MISO Planning Advisory Committee (PAC): The PAC is formed to provide advice to the MISO Planning Staff on policy matters related to the process, adequacy, integrity and fairness of the MISO-wide transmission expansion plan. The Planning Advisory Committee reports to the MISO Advisory Committee.

Issues the MISO PAC deal with are typically related to generation interconnection process, annual MTEP reliability process, and tariff and policy issues.

MISO Planning Advisory Committee (misoenergy.org)

MISO Planning Subcommittee (PSC): The PSC advises, guides, and provides recommendations to MISO staff with the goal to enable better execution of its planning responsibilities, in an efficient and timely manner, as set forth in the MISO Tariff, Transmission Owner Agreement, FERC Order 2000 and other applicable documents.

Recent issues have revolved around how storage is going to be treated in MTEP and Interconnection studies. A link to that Committee follows.

MISO Planning Subcommittee (misoenergy.org)

MISO Subregional Planning Meeting (SPM): In accordance with FERC Order 890 Attachment K, MISO will host a series of SPMs to encourage an open and transparent planning process. Early in the process, stakeholders will participate in discussions of planning issues and proposals on a more local basis to discuss projects, issues and concepts potentially driving new transmission expansion on the grid. A link to those follows.

Subregional Planning Meeting (misoenergy.org)

MISO Regional Expansion Criteria and Benefits Working Group (RECBWB): The RECBWG is the forum for stakeholders to discuss existing or proposed criteria and cost allocation policies for regional and interregional cost-shared transmission projects.

A link to that group follows.

MISO Regional Expansion Criteria and Benefits Working Group (misoenergy.org)

MISO Interconnection Process Working Group (IPWG): The purpose of the Interconnection IPWG is to provide stakeholders a forum to develop revised generator interconnection queue process procedures with the goal of reducing study time and increasing certainty. It is intended that the work product of this Working Group will be included in Tariff filings to FERC and modifications to the Generator Interconnection Business Practice Manual. (BPM-015).

MISO is looking to streamline the process to help with timelines for Interconnection Customers. Some TOs feel this will put pressure on them with an already tight timeframe and MISO should just stick with the timelines already in the tariff. A link to that group follows.

MISO Interconnection Process Working Group (misoenergy.org)

MISO Reliability Operations Working Group (ROWG): This is a closed group with focus on grid operation and reliability of the system.

A recent issue brought to MISO is related to Transmission System reconfiguration requests from third party sources for economic reasons only. During construction or outages there is some significant congestion noted on the system that is costing some customers money, and they feel reconfiguring the transmission system to accommodate outages is a good option. TOs feel these types of requests and studies do not adequately address reliability concerns.

MISO Transmission Owners Compliance Task Team (TOCTT): This is a closed group to deal with the compliance efforts at MISO relating to FERC and North American Electric Reliability Corporation (NERC).

MISO Coordination

In the Commission's June 29, 2022 ORDER ACCEPTING REPORT, in Docket No. E999/M-21-111, Order Point 6 states:

> *The MTO must file, within 90 days, additional information as set forth in ordering paragraph 5(d) of the Commission's August 19, 2020, order, in Docket E-999/M-19-205, which required a filing within 90 days that included "an assessment of whether MISO has been responsive to Minnesota's identified and likely transmission needs."*

The MTO believes MISO has been responsive to Minnesota's identified and likely needed transmission, recognizing a number of challenges that abate progress in these areas.

The need for transmission in Minnesota, and throughout the region, is currently being driven by the continuing transition from central station conventional generation to a generation fleet geographically dispersed and highly dependent on wind and solar as primary fuels, supplemented with hydro, nuclear, and natural gas generation. MISO and the MTO are experiencing continued acceleration in this transition, despite limitations related to planning and constructing the transmission needed to fully facilitate the transition.

Partially in response to a request from the MTO via Grid North Partners and the State, MISO undertook a long-term transmission expansion planning initiative called the Long-Range Transmission Plan or "LRTP" in 2020 to assist in planning for this transition. Since 2020, MISO has approved two phases, referred to as "tranches," and anticipates at least three additional LRTP tranches. The MTO members are actively involved in the pre-planning, planning, and development of MISO’s LRTP. Additional details on the MISO LRTP and the approved phases are in Chapter 10.

3.0 Transmission Studies

3.1 Introduction

The Commission requires the utilities include in each Biennial Report a "list of studies that have been completed, are in progress, or are planned that are relevant to each of the inadequacies identified" in the Report.[17] Since the 2011 Biennial Report, the utilities have broken this chapter up into several subsections, each addressing different types of studies. The same arrangement for reporting the studies is continued in this 2025 Report.

Section 3.2 describes studies completed to either address expansion of the transmission network to provide for generation expansion or address local inadequacy issues (noted with a Tracking Number). Section 3.3 describes ongoing regional studies that focus on expansion of the bulk electric system to address broad regional reliability issues and support expansion of renewable energy in the upper Midwest. Section 3.4 focuses on ongoing load serving studies done to address local inadequacy issues.

The MPUC rules state that the utilities must include in the Biennial Report a copy of "the most recent regional load and capability report of the Mid-Continent Area Power Pool."[18] As the utilities reported in the 2011 Report, however, MISO has taken over most of the planning that occurs in this part of the country. MAPP has not prepared a Load & Capability Report since May 2009. MAPP, in fact, discontinued its existence in October 2015.

3.2 Completed Studies

The following studies were completed since the last Biennial Report was submitted in November 2023. Previously completed studies can be found in previous Biennial Reports and are not repeated here. Where specific transmission projects have been identified, a Tracking Number is provided. The Tracking Number identifies the year the project was first considered for inclusion in a Biennial Report and the zone where the project is located.

Study Title	Year Completed	Utility Lead	Description
Austin Area Load Serving Study	2025	SMMPA	A load study was performed on the Austin area transmission system to assess its capability to serve current and new loads and create plans to address any voltage or thermal violations that were presented.
Grid Enhancing Technologies	2025	GRE/GNP	Identify GETs solutions to mitigate transmission facilities showing historic congestion.

[17] Minn. R. 7848.1300(F).
[18] Minn. R. 7848.1300(B).

Study Title	Year Completed	Utility Lead	Description
Willmar Area Study	2024	MRES GRE	Transmission system assessments indicated that the Willmar area has limited voltage and thermal margin for near term load expansion. This Willmar area study was performed to identify the deficiencies and determine a transmission plan that mitigates the deficiencies.

3.3 Regional Studies

While every study undertaken adds to the knowledge of the transmission engineers and helps to determine the transmission facilities required to address long-term reliability and to transport renewable energy from various parts of the state to the customers, some studies are intentionally designed to take a broader look at overall transmission needs. Regional studies analyze the limitation of the regional transmission system and develop transmission alternatives to support multiple generation interconnection requests, regional load growth, and the elimination of transmission constraints that adversely affect utilities' ability to deliver energy to the market in a cost-effective manner.

3.3.1 MISO Transmission Expansion Plans

MISO engages in annual regional transmission planning and documents the results of its planning activities in the MTEP reports. The MTEP process is explained in detail in Chapter 6 since the latest MTEP reports are being relied on to provide information about the transmission inadequacies identified in this Report. Earlier MTEP Reports were summarized in past Biennial Reports. For convenience, the following brief description of the latest MTEP reports is presented here. The MISO Expansion Plans are available on the MISO webpage. Visit http://www.misoenergy.org and click on "Planning."

MTEP21 Report
The MTEP21 report identified projects required to maintain reliability for the ten-year period through the year 2030 and provides evaluation of projects required for economic needs up to twenty years in the future.

MTEP21 included 335 new transmission projects, equaling $3 billion in investment to address near-term reliability needs and aging infrastructure. Of the $3 billion, $345 million were Generator Interconnection Projects, $187 million were new Baseline Reliability Projects, and approximately $2.5 billion fell into the Other category.

MTEP21 also included the first tranche of MISO's Long Range Transmission Plan (LRTP). The MISO LRTP Tranche 1 includes 18 regional transmission projects totaling approximately $10 billion which span the nine-state MISO Midwest footprint. Three MISO LRTP Tranche 1 projects are located in Minnesota. Additional information on the MISO LRTP Tranche 1 is in Chapter 10.

MTEP22 Report
The MTEP22 report identified projects required to maintain reliability for the ten-year period through the year 2031 and provides an evaluation of projects required for economic need up to twenty years in the future.

MTEP22 includes new transmission projects with $4.3 billion in investment to address current reliability needs and regional upgrades. Of the $4.3 billion, $8 million were Market Participant Funded projects, $547 million were Generator Interconnection Projects, $545 million were new Baseline Reliability projects, and approximately $3.17 billion fell into the Other category.

MTEP23 Report
The MTEP23 report identified projects required to maintain reliability for the ten-year period and provides evaluation of projects required for economic need up to twenty years in the future.

MTEP23 includes 572 new transmission projects with $8.9 billion in investment to address reliability needs and regional upgrades. Of the $8.9 billion, $1.2 billion were Generator Interconnection Projects, $1.7 billion were new Baseline Reliability projects, and approximately $6.0 billion fell into the Other category.

MTEP24 Report
The MTEP24 report identified projects required to maintain reliability for the ten-year period and provides evaluation of projects required for economic need up to twenty years in the future.

MTEP24 includes 459 new local transmission projects with $6.7 billion in investment to address local reliability needs. Of the $6.7 billion, $858 million were Transmission Delivery Service projects, $763 million were Generator Interconnection Projects, $1.1 billion were Baseline Reliability projects, and approximately $4.1 billion fell into the Other category.

In addition to the local transmission projects, MTEP24 also includes the second tranche of MISO's LRTP. The MISO LRTP Tranche 2.1 includes 24 regional transmission projects totaling approximately 3,600 miles which span the nine-state MISO Midwest footprint. Eight MISO LRTP Tranche 2.1 projects are at least partially in Minnesota. Additional information on the MISO LRTP Tranche 2.1 is in Chapter 10.

MTEP25 Report
The MTEP25 Report identifies projects required to maintain reliability and provides a preliminary evaluation of projects that may be required for economic benefit up to twenty years in the future. MISO updated the MTEP portal on August 28, 2025, which can be found at [MTEP25 Report (misoenergy.org)].

3.4 Load-Serving Studies

Load-serving studies focus on addressing load serving needs in a particular area or community. Since many of the inadequacies in Chapter 6 are driven by load serving needs, many of these studies relate to specific Tracking Numbers.

Study Title	Anticipated completion	Utility lead for Study	Description
Great River Energy Large Load Studies	N/A	GRE	Great River Energy has had multiple requests across its member systems' service areas for potential large load installations. These loads have ranged from 2.5 MW to over a 1,000 MW. These requests have non-disclosure agreements and therefore are not communicated until the requesting party makes a decision to allow communication to other parties. Smaller load requests on occasion can be supplied by the existing transmission system, however in most cases new transmission will be required to serve these loads. Upon approval by the requesting party, Great River Energy will work with neighboring transmission owners in assessing the system for impacts for certain desired locations. Great River Energy will work with the State, if needed, upon notification of approval of a selected location for the new load.
Henning/Inman Area Study	2026	GRE	The Henning 230/41.6 kV transformer is due for a replacement due to age and condition, which would involve a new 230/41.6 kV transformer and building the 230 kV bus at Henning GRE standards. GRE is evaluating both the replacement and alternatives which include adding a transformer at Inman with transmission expansion to best meet reliability needs in the Henning/Inman area.

Study Title	Anticipated completion	Utility lead for Study	Description
Xcel Energy Large Load Studies	N/A	NSP	Xcel Energy has several large load requests across the Northern States Power footprint that range from several hundred MWs to over 1 GW. These studies have a non-disclosure agreement that unless the interconnection requestor makes it public, we are withholding information until then. Most of these new large load requests will require new transmission depending on the location and size. Xcel Energy is working with any affected parties to ensure that the transmission system maintains reliability.

4.0 Public Participation

4.1 Public Involvement in Transmission Planning

Both the statute (Minn. Stat. § 216B.2425) and the MPUC rule (Minn. R. 7848.0900) emphasize the importance of providing the public and local government officials with an opportunity to participate in transmission planning. Over the years of filing biennial reports, the utilities have tried, in accordance with MPUC requirements, various methods of advising the public on opportunities to learn about and participate in transmission planning activities.

The MPUC adopted rules for public involvement in transmission planning as part of the biennial report requirements in 2003. Initially, in accordance with Minn. Rule part 7848.0900, the utilities held public meetings across the state in each transmission planning zone to advise the public of potential transmission projects and to solicit input regarding development of alternative solutions to various inadequacies. These public meetings were poorly attended, with little input being offered.

As a result, in May 2008 when the MPUC approved the 2007 Report, the MPUC granted a variance from the obligation to hold these zonal meetings, and that variance has been extended each time since, including in the June 7, 2024 Order regarding this year's Biennial Report. No public meetings were required in the transmission planning zones as part of this year's biennial report submission.

In lieu of the public meetings, beginning with the preparation of the 2009 Report, the utilities held six webinars, one for each transmission planning zone, to report on the transmission inadequacies identified in the Biennial Report for each zone. These webinars were not attended any better than the zonal meetings were in previous years. Few questions and comments were generated.

For the 2011 Report, with Commission approval, the utilities held one webinar. Despite widespread notice of the webinar in a statewide newspaper, only a few people participated, and most of those were utility or state employees. In 2013, after the 2013 Biennial Report was filed, the utilities held another webinar. Again, essentially nobody participated – only one person joined in the webinar.

As a result, the Commission has now determined the utilities are not required to hold a webinar about the Report.

4.2 MISO Transmission Planning

As has been described in previous biennial reports and again in this report, most transmission planning is now conducted through MISO. MISO provides numerous opportunities for the public to be involved in transmission planning. The reality is, however, that not many members of the general public avail themselves of these opportunities. This is understandable because transmission planning is an extremely technical endeavor.

4.3 MTO Website

The MTO have maintained a website (www.minnelectrans.com) for several years now; interested persons can obtain various information there about ongoing transmission planning efforts. Biennial Reports going back to 2005 are available on that website, as are many different transmission-related studies. There is a contact form on the webpage where visitors can ask questions of utilities about proposed projects. Only a handful of questions have ever been submitted using that method.

The MTO have developed a short video to describe how to read the Biennial Transmission Report and engage with transmission owning utilities.

The utilities will continue to post the biennial reports on the webpage and to monitor any questions submitted. The utilities are open to comments from the public about how to improve the webpage.

4.4 Efforts to Involve the General Public and Local Officials on Specific Projects

The MTO utilities are aware of the importance of notifying the general public and local governmental officials of any potential large energy project in their area. The public may not get involved in early transmission planning activities, but public interest and awareness rises when projects are under consideration in a particular locale. The utilities often engage local governmental officials and the public in public meetings to discuss upcoming projects.

In 2024, the State of Minnesota enacted new legislation that changed energy infrastructure permitting before the MPUC. The intent of the new legislation was to streamline the permitting process for energy projects while preserving public due process. The changes focused on amending the Certificate of Need exemptions in Minn. Stat. § 216B.243, subd. 8, along with significant process changes to the Route and Site Permit statutes that are now reflected in Minn. Stat. Ch. 216I titled the "Minnesota Energy Infrastructure Permitting Act" (the Act). The Act went into effect on July 1, 2025.

Minn. Stat. § 216I.05, subd. 5, requires any utility planning to file an application for a route permit with the Commission for a new transmission project to notify local governmental officials within a possible route of the existence of the project and provide the opportunity for a preapplication coordination or feedback. This preapplication coordination often results in a meeting between the local government body and the utility.

As described below, utilities implemented several best practices to encourage public input and stakeholder engagement in transmission planning efforts.

4.4.1 Transmission Project Public Involvement

During the last few years, utilities have developed early stakeholder engagement and public outreach efforts to increase participation in transmission planning and permitting dockets. Utilities' efforts related to the MISO LRTP projects provide a good example of these efforts. Public outreach efforts for the Northland Reliability Project and Maple River to Cuyuna Project are described as an example; however, most other utility-led transmission projects utilize a similar approach to early public outreach.

- Northland Reliability Project (MISO LRTP Tranche 1)

    - Pre-Application Engagement Minnesota Power and Great River Energy employed various engagement methods to provide information about the Northland Reliability Project to the public and federal, state, and local agencies, Tribal Nation representatives, and non-government organizations. The Project team developed a public engagement plan in late summer 2022 that consisted of two engagement phases – Route Corridor and Preliminary Route notifications – with the goal to share information about the project and gather insights on routing opportunities and constraints within the Project Area. Early coordination with stakeholders included project introduction letters along with a series in-person stakeholder workshops held fall 2022. The two phases of public engagement included in-person open houses, virtual self-guided public open houses, direct mailings, paid advertisements in local newspapers, social media posts, a dedicated email and hotline to field questions and comments, an interactive online comment map, a Project website, and detailed maps that could be downloaded and printed from the Project website and mailed project information packets. During the engagement process, the Northland Reliability Project team connected with hundreds of meeting attendees (in-person and virtual), gathered hundreds of routing comments, and had thousands of website visitors reviewing maps and project information.

    - Post-Application Engagement: Once the combined Certificate of Need and Route Permit applications for the Project was filed with the MPUC, addition public engagement meetings and hearings were conducted as part of the statutory Certificate of Need and Route Permit processes. Scoping meetings were held in October of 2023 to identify routing alternatives to be evaluated in the Environmental Assessment conducted by the Department of Commerce Energy Environmental Review and Analysis (EERA). In addition, public hearings were held in July 2024 to gather public comments on the Environmental Assessment and Project routes being considered. As part of each of these meetings and hearings EERA and MPUC Staff held open houses to allow the stakeholders to get questions answered before the meetings and hearings started. Finally, as part of the ongoing commitment to Project engagement, multiple stakeholder meetings were held during the MPUC permitting process to gather information and inform the permitting process. The Northland Reliability Project maintains a website which is regularly updated to provide the public status updates and project team contact information.

- Maple River to Cuyuna (MISO LRTP Tranche 2.1)

- In early 2025, Minnesota Power, Otter Tail Power, and Great River Energy developed a comprehensive public engagement plan for the Maple River to Cuyuna Project. Public outreach began in June by launching a dedicated project website and hosting a series of ten open house meetings across the project area. The website serves as a central hub for landowners, stakeholders, and the public to access up-to-date project information and submit feedback on routing options. The open houses, held in June 2025, drew approximately 300 participants – including community members, agency officials, and other interested stakeholders – providing valuable input on the project's potential routes. A second round of open houses is planned for October 2025 to present refined route options and gather further feedback. The website is a key tool for communication, and the project team will continue updating materials and offering engagement opportunities as the project progresses.

These are the kind of efforts that utilities follow prior to the time an application for a route permit for a new transmission line is filed with the Commission and have proven successful in engaging a wide variety of stakeholders in the transmission planning process.

5.0 Transmission Planning Zones

5.1 Introduction

The Commission divided Minnesota geographically into the following six Transmission Planning Zones when it adopted the rules in chapter 7848 in 2003:

- Northwest Zone
- Northeast Zone
- West Central Zone
- Twin Cities Zone
- Southwest Zone
- Southeast Zone

The map below shows the six Zones.

Chapter 5 describes each of the Transmission Planning Zones in the state. The zones have not changed over the years so the description below for each zone is identical to what was provided in past reports, although any changes in the transmission system in a particular zone that occurred over the past two years are described in each section.

The discussion for each zone contains a list of the counties in the zone and the major population centers. The utilities that own high voltage transmission lines in the zone are also identified. A description of the major transmission lines in the zone is provided.

Transmission systems in one zone are highly interconnected with those in other zones and with regional transmission systems. A particular utility may own transmission facilities in a zone that is outside its exclusive service area, or where it has few or no retail customers. Different segments of the same transmission line may be owned or operated by different utilities. A transmission line may span more than one zone, and transmission projects may involve more than one zone.

Chapter 6 describes the needs for additional transmission facilities identified for each zone. Chapter 7 contains additional information about each of the utilities filing this report, including their existing transmission lines.

5.2 Northwest Zone

The Northwest Planning Zone is located in northwestern Minnesota and is bounded by the North Dakota border to the west and the Canadian border to the north. The Northwest Planning Zone includes the counties of Becker, Beltrami, Clay, Clearwater, Kittson, Lake of the Woods, Mahnomen, Marshall, Norman, Otter Tail, Pennington, Polk, Red Lake, Roseau, and Wilkin.

Primary population centers within the Northwest Planning Zone (population greater than 10,000) include the cities of Bemidji, Fergus Falls, and Moorhead.

The following utilities own transmission facilities in the Northwest Zone:

- Great River Energy
- Minnkota Power Cooperative
- Missouri River Energy Services
- Otter Tail Power Company
- Northern States Power Company d/b/a Xcel Energy

A major portion of the transmission system that serves the Northwest Planning Zone is located in eastern North Dakota. Four 230 kV lines and two 345 kV lines reach from western North Dakota to substations in Drayton, Grand Forks, Fargo, and Wahpeton, North Dakota, along with a 230 kV line from Manitoba and a 230 kV line from South Dakota. Five 230 kV lines run from eastern North Dakota into Audubon, Moorhead, Fergus Falls, and Winger, Minnesota. These five lines then proceed through northwestern Minnesota and continue to substations in west-central and northeastern Minnesota. Additionally, a 230 kV line from Manitoba to the Northeast Zone crosses the northeastern corner of this zone and provides power to local loads. The 230 kV system supports an extensive 115 kV, 69 kV, and 41.6 kV transmission system to deliver power to local loads.

In December 2024 as part of LRTP Tranche 2.1, MISO also approved the Bison-Alexandria 345 kV transmission project. The Bison-Alexandria Project involves adding a new 345 kV transmission circuit on existing transmission line structures from the existing Bison Substation near Fargo, North Dakota to the existing Alexandria Substation near Alexandria, Minnesota. The existing 345 kV structures were previously permitted and constructed as double-circuit capable as part of the Fargo – St. Cloud 345 kV Transmission Project. The proposed 345 kV transmission line will traverse Clay, Wilkin, Otter Tail, Grant, and Douglas counties. The permitting process is currently underway with the Commission.

5.3 Northeast Zone

The Northeast Planning Zone covers the area north of the Twin Cities suburban area to the Canadian border and from Lake Superior west to the Walker and Verndale areas. The zone includes the counties of Aitkin, Carlton, Cass, Cook, Crow Wing, Hubbard, Isanti, Itasca, Kanabec, Koochiching, Lake, Mille Lacs, Morrison, Pine, St. Louis, Todd, and Wadena counties.

The primary population centers in the Northeast Planning Zone include the cities of Brainerd, Cambridge, Cloquet, Duluth, Ely, Grand Rapids, Hermantown, Hibbing, International Falls, Little Falls, Long Prairie, Milaca, Park Rapids, Pine City, Princeton, Verndale, Virginia, and Walker.

The following utilities own transmission facilities in the Northeast Zone:

- American Transmission Company, LLC
- Great River Energy (GRE)
- Minnkota Power Cooperative
- Minnesota Power (MP)
- Otter Tail Power
- Southern Minnesota Municipal Power Agency
- Northern States Power Company d/b/a Xcel Energy

The transmission system in the Northeast Planning Zone consists mainly of 230 kV, 138 kV and 115 kV lines that serve lower voltage systems comprised of 69 kV, 46 kV, 34.5 kV, 23 kV and 14 kV. Xcel Energy, Great River Energy, and Minnesota Power own a 500 kV interconnection coming from Manitoba Hydro with interconnections in Minnesota at Forbes and Chisago County. Minnesota Power owns a second 500 kV interconnection from Manitoba Hydro (the Great Northern Transmission Line), placed in service in 2020, which connects at the Iron Range Substation near Grand Rapids, Minnesota. American Transmission Company's 345 kV line runs between Duluth, Minnesota, and Wausau, Wisconsin. Minnesota Power's +/- 250 kV DC line runs from Center, North Dakota to Duluth, Minnesota. The CapX2020 230 kV line connects the Bemidji area in the Northwest Zone and the Grand Rapids area in the Northeast Zone (the CapX2020 Bemidji-Grand Rapids project). The 345 kV and 230 kV system are used as an outlet for generation and to deliver power to the major load centers within the zone. From the regional load centers, 115 kV lines carry power to lower voltage substations where it is distributed to outlying areas. In a few instances, 230 kV lines serve this purpose. A significant 345 kV network expansion is planned for the northeast zone in the next decade due to the changing energy mix, local and regional reliability needs, regional transfers, and load growth. MP and GRE are building the Northland Reliability Project (2023-NE-N1), an approximately 180-mile, double-circuit 345 kV transmission line from northern Minnesota to central Minnesota, which was approved by MISO in July 2022 as part of LRTP Tranche 1. In addition to the Northland Reliability Project, two additional 345 kV projects in the northeast zone were approved by MISO in December 2024 as part of LRTP Tranche 2.1. The Maple River – Cuyuna 345 kV Project (2025-NE-N1) is a new approximately 165-mile single circuit 345 kV transmission line project developed by MP, GRE, and Otter Tail Power Company (OTP), which will connect the Brainerd area in north-central Minnesota to the Fargo area in eastern North Dakota. The Iron Range – St. Louis County – Arrowhead 345 kV Project (2025-NE-N2) is a new approximately 64-mile 345 kV transmission line project being developed by MP and ATC, which will strengthen the connection between the Iron Range and the Duluth area. The three planned 345 kV projects have targeted in-service dates between 2030 and 2033.

5.4 West Central Zone

The West Central Transmission Planning Zone extends from Sherburne and Wright counties on the east, to Traverse and Big Stone counties on the west, bordered by Grant and Douglas counties on the north and Renville County to the south. The West Central Planning Zone includes the counties of Traverse, Big Stone, Lac qui Parle, Swift, Stevens, Grant, Douglas, Pope, Chippewa, Renville, Kandiyohi, Stearns, Meeker, McLeod, Wright, Sherburne, and Benton.

The primary population centers in the zone include the cities of Alexandria, Buffalo, Elk River, Glencoe, Hutchinson, Litchfield, Sartell, Sauk Rapids, St. Cloud, St. Michael, and Willmar.

The following utilities own transmission facilities in the West Central Zone:

- Central Minnesota Municipal Power Agency and Services (CMPAS)
- East River Electric Power Cooperative
- Great River Energy
- Missouri River Energy Services
- Otter Tail Power Company
- Southern Minnesota Municipal Power Agency
- Northern States Power Company d/b/a Xcel Energy

This transmission system in the West Central Planning Zone is characterized by a 115 kV loop connecting Grant County-Alexandria-West St. Cloud-Paynesville-Willmar-Morris and back to Grant County. These 115 kV transmission lines provide a hub from which 69 kV transmission lines provide service to loads in the zone.

A 345 kV line from Sherburne County to St. Cloud and 115 kV and 230 kV lines from Monticello to St. Cloud provide the primary transmission supply to St. Cloud and much of the eastern half of this zone. Two 230 kV lines from Granite Falls – one to the Black Dog generating plant in the Twin Cities and one to Willmar – provide the main source in the southern part of the zone.

Demand in the St. Cloud area continues to grow and several individual projects have been completed to address the need for more power into this area. The CapX2020 Quarry substation provides significant load-serving capability to the St. Cloud area system deficiencies. The CapX2020 Fargo-St. Cloud 345 kV project was completed in 2015 and transfers power between Fargo, North Dakota and the St. Cloud area. The CapX2020 Brookings, South Dakota-Twin Cities 345 kV project was also completed in 2015. The Riverview 345/115/69 kV substation was built in the St. Cloud Area along the CapX2020 Fargo-Monticello 345 kV line to address some of the area's 69 kV issues. This is a Great River Energy substation connecting to Xcel Energy's 69 kV system.

A pending major addition to the West Central Planning Zone is the addition of the 345 kV MISO LRTP 2 Project. The planned 345 kV line will extend from the Big Stone South Substation in South Dakota to the Alexandria Substation near Alexandria, MN to the Big Oaks Substation near the Sherco Power Plant. The Alexandria to Big Oaks portion of the 345 kV line will complete the second circuit on the CAPX Fargo-Monticello Project. The line was approved as part of MISO MTEP 21 Expansion Plan. The Commission issued a Certificate of Need for the Big Stone South to Alexandria to Big Oaks Project in 2024 and issued a route permit for the Alexandria to Big Oaks Project in 2024. The project is currently under construction. The route permit for the Big Stone South to Alexandria Project is currently pending before the Commission.

5.5 Twin Cities Zone

The Twin Cities Planning Zone comprises the Twin Cities metropolitan area. It includes the counties of Anoka, Carver, Chisago, Dakota, Hennepin, Ramsey, Scott and Washington.

The following utilities own transmission facilities in the Twin Cities Zone:

- CMPAS
- Great River Energy
- Missouri River Energy Services
- Otter Tail Power
- Northern States Power Company d/b/a Xcel Energy

The transmission system in the Twin Cities Planning Zone is characterized by a 345 kV double circuit loop around the core Twin Cities and first tier suburbs. Inside the 345 kV loop, a network of high capacity 115 kV lines serves the distribution substations. Outside the loop, a number of 115 kV lines extend outward from the Twin Cities with much of the local load serving accomplished via lower capacity, 69 kV transmission lines.

The Nexus DC line and its outlet 345 kV circuits tie into the northwest side of the 345 kV loop and are dedicated to bringing generation to Twin Cities and Minnesota loads.

Tie lines extend from the Twin Cities 345 kV loop to three 345 kV lines: one to eastern Wisconsin, one to southeast Iowa and one to southwest Iowa. The other tie is the Xcel Energy 500 kV line from Canada tied into the northeast side of the 345 kV loop.

Major generating plants are interconnected to the 345 kV transmission loop at the Sherburne County generating plant and the Monticello generating plant in the northwest, the Allen S. King plant in the northeast, and Prairie Island in the southeast. On the 115 kV transmission system in the Twin Cities Planning Zone there are three intermediate generating plants: Riverside (located in northeast Minneapolis), High Bridge (located in St. Paul), and Black Dog (located in north Burnsville). There are also two peaking generating plants – Blue Lake and Inver Hills – interconnected on the southeast and the southwest, respectively.

The CapX2020 Brookings-Twin Cities 345 kV project was completed in 2015 and transfers power between the southwest corner of the Twin Cities and Brookings, South Dakota. The CapX2020 345 kV project between the southeast corner of the Twin Cities area, Rochester, and LaCrosse, Wisconsin, was also completed in 2015. In addition, in December 2024, as part of LRTP Tranche 2.1, MISO identified a new, second 345 kV transmission circuit between the North Rochester substation to the Hampton Substation, to be strung on existing double-circuit capable 345 kV structures.

5.6 Southwest Zone

The Southwest Transmission Planning Zone is located in southwestern Minnesota and is generally bounded by the Iowa border on the south, Mankato on the east, Granite Falls on the north and the South Dakota border on the west. It includes the counties of Brown, Cottonwood, Jackson, Lincoln, Lyon, Martin, Murray, Pipestone, Redwood, Rock, Watonwan, and Yellow Medicine.

The primary population centers in the Southwest Zone include the cities of Fairmont, Granite Falls, Jackson, Marshall, New Ulm, Pipestone, St. James, and Worthington.

The following utilities own transmission facilities in the Southwest Zone:

- ITC Midwest LLC
- East River Electric Power Cooperative
- Great River Energy
- L&O Power Cooperative
- Missouri River Energy Services
- Otter Tail Power Company
- Southern Minnesota Municipal Power Agency
- Northern States Power Company d/b/a Xcel Energy

The transmission system in the Southwest Zone consists mainly of three 345 kV transmission lines, one beginning at Split Rock Substation near Sioux Falls and traveling to Lakefield Junction, the second traveling from Mankato, through Lakefield Junction and south into Iowa and a third line, completed in 2018 from Lakefield Junction, east to Huntley and then south into Iowa. Lakefield Junction also serves as a major hub for several 161 kV lines throughout the zone. A number of 115 kV lines also provide transmission service to loads in the area, particularly the large municipal load at Marshall. Much of the load in the southwestern zone is served by 69 kV transmission lines which have sources from 115/69 kV or 161/69 kV substations.

The 115 kV lines also provide transmission service for wind generation along Buffalo Ridge. The transmission system in this zone has changed significantly in recent years with new transmission additions to enable additional generation delivery. Continuing these changes, the system was also enhanced by the addition of the 345 kV Multi-Value Project (MVP) Portfolio, including the Twin Cities-Brookings 345 kV transmission line in 2015 and the MVP 3 Project in 2018, providing additional outlet for the wind generation in the Southwest Zone. In addition to enabling additional delivery of wind generation, these lines provide opportunities for new transmission substations to improve the load serving capability of the underlying transmission system.

Two major planned transmission lines to the Southwest Planning Zone include the addition of (1) the 345 kV Minnesota Energy Connection, and (2) the Brookings-Lyon Co. and Hampton-Helena sections of the double circuit 345 kV line from the CAPX Brookings-TC project. The Minnesota Energy Connection would extend from the Sherco Power Plant in Sherburn County to somewhere in Lyon County. The planned line will carry renewable generation back Sherco Plant as part of the renewable repowering effort. The Brookings-Lyon Co. and Hampton-Helena double circuits are needed to help relieve congestion for renewable power coming from Southwest Minnesota and is a joint project between Xcel Energy, Great River Energy, Otter Tail Power, Missouri River Energy Services, and Central Municipal Power Agency and Services.

The next major planned transmission lines in the Southwest Planning Zone include the addition of a newly proposed 765 kV transmission line identified by MISO in Tranche 2.1 that will begin at the Big Stone South Substation in South Dakota, go to the Brookings Substation, also in South Dakota, then enter Minnesota and connect to the Lakefield Junction Substation in Jackson County, Minnesota, before continuing east into the Southeast Zone. The project, referred to as PowerOn Midwest, will be filing permit applications with the Commission in 2026.

5.7 Southeast Zone

The Southeast Planning Zone includes Blue Earth, Dodge, Faribault, Fillmore, Freeborn, Goodhue, Houston, Le Sueur, Mower, Nicollet, Olmsted, Rice, Sibley, Steele, Wabasha, Waseca, and Winona Counties. The zone is bordered by the State of Iowa to the south, the Mississippi River to the east, the Twin Cities Planning Zone and West Central Planning Zone to the north, and the Southwest Planning Zone to the west.

The primary population centers in the zone include the cities of Albert Lea, Austin, Faribault, Mankato, North Mankato, Northfield, Owatonna, Red Wing, Rochester, and Winona.

The following utilities own transmission facilities in the Southeast Zone:

- CMPAS
- Dairyland Power Cooperative
- Great River Energy

- ITC Midwest LLC
- Missouri River Energy Services
- Otter Tail Power
- Rochester Public Utilities
- Southern Minnesota Municipal Power Agency
- Northern States Power Company d/b/a Xcel Energy

The transmission system in the Southeast Planning Zone consists of 345 kV, 161 kV, 115 kV and 69 kV lines that serve lower voltage distribution systems. The 345 kV system is used to import power from generation stations outside of the area to the Southeast Planning Zone for lower voltage load service. The 345 kV system also allows the seasonal and economic exchange of power from Minnesota to the east and south from large generation stations located within and outside of the zone. The 161 kV and 115 kV systems are used to carry power from the 345 kV system and from local generation sites to the major load centers within the zone. From the regional load centers and smaller local generation sites, 69 kV lines are used for load service to the outlying areas of the Southeast Planning Zone.

The Southeast Planning Zone includes the Huntley-Wilmarth 345 kV line which was completed in 2021. This line improves power flow across the transmission system. It was an economic project that connects part of Southern Minnesota to the Mankato area. The project was identified through the MISO Economic Planning effort.
A planned major transmission line addition to the Southeast Planning Zone is planned 345 kV MISO LRTP 4 Project. This planned 345 kV line will extend from the Wilmarth Substation to North Rochester to the Mississippi River. The line was approved as part of MISO MTEP 21 Expansion Plan and was filed with the Commission in 2024.

As described in the Southwest Zone above, the next major planned transmission lines in the Southeast Planning Zone include the addition of a newly proposed 765 kV transmission line known as the PowerOn Midwest and Gopher to Badger Link Projects. In the Southeast Zone, the PowerOn Midwest Project will begin at the Lakefield Junction Substation in Jackson County, Minnesota, before continuing east to connect to the Pleasant Valley and North Rochester Substations. At the North Rochester Substation, the Gopher to Badger Link 765 kV Project will continue on to the Minnesota/Wisconsin Board, before ultimately connecting the Columbia Substation in Wisconsin. In addition, MISO also identified a new 345 kV transmission circuit from the Pleasant Valley Substation to the North Rochester Substation. The existing 345 kV single-circuit structures are proposed to be removed and replaced with new double-circuit capable 345 kV structures. A new, second 345 kV transmission circuit between the North Rochester substation to the Hampton Substation, to be strung on existing double-circuit capable 345 kV structures.

6.0 Needs

6.1 Introduction

Chapter 6 contains information on each of the present and reasonably foreseeable future inadequacies identified in the six transmission zones. First, for each zone, a table of present inadequacies is presented. The table is ordered by when the inadequacy was first identified, so the older inadequacies are listed first. Following the table of inadequacies, a discussion of each pending project, by Tracking Number, is provided. Finally, a table of completed projects is included.

6.1.1 Needed Projects

For each transmission planning zone, the discussion begins with a table that looks like this.

MPUC Tracking Number	MISO Project Name	MTEP Year & Appendix	MTEP Project Number	CON?	Non-Wire Alt.	Utility

The following describes the information found in each of the columns.

MPUC Tracking Number
The first column in the table is labeled "MPUC Tracking Number." Each inadequacy is assigned a Tracking Number. This numbering system was created in 2005 and has been utilized in every report since. The Tracking Number has three parts to it: the year the inadequacy was first reported, the zone in which it occurs, and a chronological number assigned in no particular order. Tracking Number 2015-NE-N10, for example, indicates this matter is first reported in the 2015 Report and is an inadequacy in the Northeast Zone. An inadequacy with a Tracking Number beginning with 2017, on the other hand, was first identified in the 2017 Report.

MISO Project Name
The second column contains the MISO Project Name for each project. This is the name used in the pertinent MTEP Report for that project. In some cases, for projects that were first identified in earlier years and are still under development, the MISO Project Name may not be exactly the same as the name given in an earlier biennial report, but the project is the same.

MTEP Year & Appendix
The third column contains a reference to a MTEP Report and an Appendix in the report. The MTEP Report is prepared annually by MISO, and each utility that is a member of MISO must participate in the MTEP process. Each report is referred to by the year it is adopted. Thus, the most recent report is MTEP25, although it won't be finally approved by MISO until the end of the year. Additional information about the MISO planning process and the MTEP reports is included in Section 3.3.1 of this Biennial Report, and an explanation of how to find a particular MTEP Report and an Appendix is provided in subsection 6.2.

MTEP Project Number
The fourth column of the table provides a Project Number assigned by MISO for each project. This Project Number is important for finding a particular project in the appropriate MTEP Report. The only utility reporting transmission needs in this biennial report that is not a member of MISO is Minnkota Power Cooperative, and all the MPC projects are in the Northwest Zone. The other non-MISO utilities are East River Electric Power Cooperative (EREPC), and L&O Power Cooperative (L&O), but these utilities are not reporting any transmission needs in this report.

As shown in the table in section 6.3.1, the Minnkota Power Cooperative projects are shown to be "Non-MISO" projects in column three of the table of Needed Projects. Nonetheless, several of these "Non-MISO" projects do include an MTEP Project Number in column four. The reason for this is even though Minnkota is not a MISO member. MISO performs some of Minnkota's transmission planning work.

Certificate Of Need (CON)
The MPUC rules state the biennial report shall contain an approximate timeframe for filing a CON application for any projects identified that are large enough to require a CON.[19] This column provides a simple "Yes" or "No" indication of whether a CON is required. If a CON has already been applied for, the MPUC Docket Number for that filing can be found in the discussion for that particular project. If a Docket Number is given, that docket can be checked to determine whether the CON has already been issued by the Commission.

Non-wires Alternative
This column provides a "Yes" or "No" indication as to whether a non-wires alternative is potentially viable for the identified inadequacy. Section 2.7 of this Report provides a summary of the types of non-wires alternatives able to address certain categories of inadequacies. Where a non-wires alternative was considered, further discussion of the alternative is included in the narrative provided for that particular project.

Utility
This column simply identifies the utility or utilities involved in the project.

6.1.2 Description of Each Project by Tracking Number

In the 2005, 2007, and 2009 Biennial Reports, the utilities provided a separate subsection for each pending project by Tracking Number and included certain information about each project. In the 2011 and 2013 Report, those discussions were eliminated because the Commission had understandably authorized the utilities to rely on the MTEP Reports to provide all the necessary information regarding each project, because transmission facility approval was being conducted by and through MISO.

[19] Minn. R. 7848.1300 § M.

In 2014, as part of its approval of the 2013 Biennial Report, the Commission determined perhaps the MTEP Reports did not satisfy one requirement of the state statute to "identify [in the biennial report] general economic, environmental, and social issues associated with each alternative."[20] The utilities did not object to providing that information in the 2015 Report, but would raise the caveat that for many of the projects, particularly those several years into the future, detailed information is often not available at this stage of development of the project. Also, for many smaller projects, like replacing a transformer, there are no likely alternatives available and not much information is available.

To assist the Commission, and other readers of the report, the utilities have included in this Biennial Report a separate discussion of various matters relating to each project, even though nearly all that information can be found in the MTEP Reports. As part of this discussion, the utilities provide available information on the general impacts associated with the project. In those cases where a certificate of need or a routing permit or both have been applied for, or even granted, most of this type of information is available in the records created in those dockets, and a reference to the MPUC Docket Number is provided. Any reader desiring in-depth information about a project that has been approved or is being considered by the Commission can review the record in that matter for more detailed information.

6.1.3 Completed Projects

The table for Completed Projects is similar to the table for Needed Projects described above.

MPUC Tracking Number	Description	MTEP Year & Appendix	MTEP Project Number	Utility	Date Complete

Most of the columns contain the same information provided for the ongoing projects. However, the last column provides the date the project was completed, and the second column contains a more precise description of the project than just the MISO title. If a certificate of need or a route permit or both were required from the Commission, the docket numbers are provided in the last column. While the last column is entitled "Date Completed," in some cases the project is being removed from the list because the need once perceived is no longer present, and the project is being withdrawn. Readers interested in more information about a completed project can consult earlier Biennial Reports, the MTEP Report, or the MPUC Docket, whichever are applicable.

6.2 The MISO Planning Process

6.2.1 The MISO Transmission Expansion Plan Report

Because nearly all the projects identified in this Report are being undertaken by utilities that are members of MISO, this subsection is provided to assist the reader in finding information about the MISO planning process and the annual MTEP Report prepared each year. Much of the information

[20] Minn. Stat. §216B.2425, subd. 2(c)(3).

provided in this subsection was also available in the 2013, 2015, 2017, 2019, 2021, and 2023 Biennial Reports.

The latest MTEP Reports are available on the MISO webpage at:

http://www.misoenergy.org (Click on "Planning" on the top of the page)

The MTEP process is ongoing at all times at MISO. Generally, utilities submit a list of their newly proposed projects in September. MISO staff evaluates these projects over the next several months, and prepares a draft of the annual MTEP Report around July of the following year. After review by utilities and other interested parties, the MISO board of directors approves the report, usually in December. The process continues with another report finalized the following December. The MTEP25 Report should be approved by the MISO Board of Directors in December of this year.

Each of the MTEP Reports separates transmission projects into two categories and lists them in Appendices as follows:

Appendix A – Projects recommended for approval;
Appendix B – Projects with documented need and effectiveness and long lead time making them not needing approval immediately.

Generally, as projects are first identified, they are listed in Appendix B, and then they move up to Appendix A as they are further studied and ultimately brought forth for construction. Some projects never advance to the final stage – Appendix A – of actually being approved and constructed.

The MTEP Report is an excellent source of information about ongoing transmission studies and projects in Minnesota and throughout a wide area of the country.

- The MTEP Report is prepared annually, so it provides very timely information. The Biennial Report is prepared only every other year.
- The MISO planning process is comprehensive. MISO considers all regional transmission issues, not just Minnesota transmission issues.
- MISO conducts an independent review and analysis of all projects to confirm the benefits stated by the project sponsor. This adds further verification of the benefits of projects.
- MISO holds various planning meetings during the year at which stakeholders can have input into the planning process, so there are more frequent opportunities for input (see next paragraph.)
- All completed projects are listed on the MISO webpage.
- Not duplicating the MTEP Report will save ratepayers money. It is costly to require the utilities to produce all the information found in the MTEP Report.

6.2.2 Finding a Project in a MTEP Report

For each zone, a table is included to describe certain information about each project by Tracking Number. The table looks like this (MPUC Tracking Number 2019-NE-N17 is used for illustrative purposes):

MPUC Tracking Number	MISO Project Name	MTEP Year & Appendix	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2019-NE-N17	Running Cap Bank Retirement	2019/A	16145	No	No	XEL

MPUC Tracking Number 2019-NE-N17 is the Running Capacitor Bank Retirement Project. The project can be found in Appendix A of the MTEP19 Report by following these steps:

Step 1. Go to the MISO homepage at: https://www.misoenergy.org.

Step 2. Click on "Planning" at the top of the page. Click on "MTEP" from the drop-down menu. Then click on the "MTEP Reports" link on the left side of the page.

Step 3. Click on the link for the MTEP19 Report and download the .zip file.

Step 4. Click on the "MTEP19 Appendix A – New Projects."

Step 5. Select the "Projects" tab at the bottom of the spreadsheet downloaded. Hold down the "Ctrl" key and press the "F" key to bring up the "Find" dialog box. Enter the MTEP Project Number, which in this case is 16145, in the dialog box and select "Find Next." Information about the project can then be read from the row the MTEP Project was found during this search.

Similar steps can be followed for all other projects identified in Chapter 6, including those few that are not Appendix A projects (recommended by MISO for approval). If the MTEP Report you are seeking is an older one, you may have to click on Study Repositories to find these other reports at Step 2.

Project Facilities

Appendices A and B also contain information on the specific facilities (such as transmission lines, substations, etc.) that are part of a particular project. The steps below show how to find this information for the example project.

Step 1. To find information on specific facilities (transmission lines, substations, etc.) that are part of a project click on the "Facilities" tab located at the bottom of the spreadsheet that was downloaded at Step 5 in the above example.

Step 2. Hold down the "Ctrl" key and hit the "F" key to bring up the "Find" dialog box. Enter the MTEP Project Number, "16145" in this example, in the dialog box and then click on "Find Next." The "Find Next" link can be clicked until all rows containing information about Project Number 16145 have been found. There will usually be more than one row since most projects involve more than one transmission line or substation or other facility.

This same procedure can be used to find this kind of information for other projects and their associated facilities for the projects listed in the tables in Chapter 6 using the MTEP Report and the MTEP Project Number.

Detailed Project Information
Starting in 2008, if the project has been either approved or recommended for approval by the MISO board of directors (i.e., designated an Appendix A project), additional, detailed information about the project can be found in Appendix B in the MTEP Report for the year the project was approved by MISO. For large projects, this information includes a project map, project justification and information about the system inadequacy the project is intended to correct. For smaller projects, a subset of this information is included. Starting with the MTEP08 Report, projects located in Minnesota are contained in the "West Region Project Justifications" portion of Appendix A or Appendix B in the MTEP Report year that the project was approved or recommended for approval. For information on Minnesota projects approved by MISO prior to 2008, see the appropriate year Minnesota Biennial Transmission Projects Report for the appropriate year.

Continuing with our example of the Running Capacitor Bank Retirement Project, Tracking Number 2019-NE-N17, which is an approved Appendix A project, this additional information can be found by going to Appendix B through the following steps.

Step 1. After following the first three steps described above to get to the appropriate MTEP report, click on the MTEP19 Appendices link.

Step 2. Select MTEP19 Appendix B Projects.

Step 3. Once the desired Appendix B is downloaded, use the .pdf search tool to find Project Number 2019-NE-N17and locate information about this project.

This same procedure can be used to find more detailed information on most projects shown in the tables in Sections 6.3 through 6.8 that have moved to MISO Appendix A since 2008. In addition, if you search for a specific utility's name, you can find information on projects that utility has submitted and have been or are being considered for approval by the MISO board of directors.

6.3 Northwest Zone

6.3.1 Needed Projects

The following table provides a list of transmission needs in the Northwest Zone. As explained in Section 6.1.1, even though Minnkota Power Cooperative is not a member of MISO, some of its planning work is done by MISO. A MTEP Project Number is provided for those Minnkota projects reported in the MTEP reports.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2015-NW-N7	Richwood-Oakland 69 kV (Load Transfers)	Non-MISO	N/A	No	No	MPC
2019-NW-N5	Erie/Audubon Alternate Service	Non-MISO	17144	No	No	MPC
2023-NW-N2	Silver Lake Transformer Replacement	2024/A	25469	No	No	GRE
2023-NW-N3	Cormorant Junction – Tamarac – Pelican Rapids (LR-PC) Line Rebuild	2025A	50284	Yes	No	GRE
2025-NW-N1	Otto Substation Area Rebuild	2026/A	50609	No	No	GRE
2025-NW-N2	J1575 Donaldson South Interconnection	MTEP25	50521	No	No	OTP
2025-NW-N3	J1575 Network Upgrades	MTEP25	50520	No	No	OTP
2025-NW-N4	Bemidji 115/12.5 kV Substation	MTEP24	16289	No	No	OTP
2025-NW-N5	Fargo-St. Cloud-Monticello 345kV Davit Arm Replacement	MTEP25	50720	No	No	XEL, GRE, OTP, MP, MRES

Richwood-Oakland 69 kV Line (Load Transfers)

MPUC Tracking Number: 2015-NW-N7

Utility: Minnkota Power Cooperative (MPC)

Project Description: The scope and schedule of the project has changed to increase reliability to a larger number of area loads.

A new 69 kV line from Richwood Distribution Substation to Oakland Distribution Substation (with conversion of White Earth distribution substation onto the 69 kV system) has been deemed necessary sometime in the future. The proposed project includes 20.0 miles of transmission line work (all new line) and a potential conversion of White Earth 41.6 kV to 69 kV. Previously, this project contained additional transmission in the Erie and Audubon areas; however, that has been moved to project 2019-NW-N5 for administrative purposes.

Need Driver: In response to a neighboring system's request, a new transmission line and substation conversion are being planned for the White Earth Substation. The intent is to transfer load off their system that has grown beyond available back-up capacity. Additionally, a member cooperative has requested service improvements for Richwood and Oakland Substations.

Alternatives:

Transmission Alternatives

> There are several transmission alternatives being considered as part of these load transfers. In a previous Biennial Report, the preferred alternative was a 115 kV line and a substation conversion was the preferred project. However, that project was dismissed in favor of a looped 69 kV line.
>
> The alternatives involve further investigation of a Mahnomen/Ulrich 115 kV load tap (the project that was originally proposed). Alternatives may also include parts of the project described (solely Richwood-White Earth or White Earth-Oakland. Investigations are ongoing, and these alternatives will be compared with the proposed transmission line options.

Non-Wires Alternatives

> Non-transmission solutions such as battery backup are being investigated. The transmission plan may be changed if these investigations provide equally cost-effective projects that are robust.

Analysis: Reliability impacts from the new transmission lines are currently evaluated in the annual MTEP assessments (in terms of forecasting the existing White Earth load). Impacts to the bulk power system are not the reason for these projects. Limitations of the 41.6 kV transmission and member systems are the reason for the transmission projects (and load transfers).

Schedule: The study efforts mentioned above determined that the new transmission lines do not have a strict completion date. A schedule will be developed as definite plans are determined.

General Impacts: This project is primarily rural in location. The route will have to navigate around some lakes, forested areas, and potentially some reservation land within the area. Assuming a one-hundred-foot right-of-way, the project area will be nearly 275 additional acres (some existing transmission may be used for the project), but the affected farmland should only be about 15 acres, assuming some general estimates on electrical poles and farmland equipment navigation. No notable environmental, human, or health concern exists beyond the aforementioned new transmission. This project is still in its early stages of planning, so all this information is subject to change.

This project may require a short-term project crew. If so, this may bring some business to the area in the form of room and/or board. In terms of local government benefits, it is possible that permit costs may be enforced on this project, but this is determined on a case-by-case basis. Also, some landowners may receive income as a result of this project, and the income may be taxable.

This project is the result of a reliability measure and will probably not have a substantial or lasting impact on the community in terms of the environment or health. It will likely impact some farmland; however, it should only amount to about 15 acres, as stated in the environmental considerations.

Erie/Audubon Alternate Service

MPUC Tracking Number: 2019-NW-N5

Utility: Minnkota Power Cooperative (MPC)

Project Description: From the planned Erie Jct. 230/115 kV substation which taps the Audubon-Hubbard 230 kV line, a new 69 kV or 25 kV 7-mile line with associated transformer will be constructed to MPC's Erie distribution substation.

In order to provide alternate service to MPC's Audubon distribution substation, an optional conversion of OTP's Oak Lake-Erie Jct. 41.6 kV line may be converted to 69 kV. This line is part of a previous project (2015-NW-N7) and there is some overlap between these projects.

Need Driver: There is about 10 MW of load in the Detroit Lakes, MN area served by one substation (Erie) on the OTP 41.6 kV system. Extended outage times have been required for planned maintenance and emergency repairs because no alternate source is available. This is a concern for the Detroit Lakes, MN area. Low load management signals are also a concern.

Alternatives:

<u>Transmission Alternatives</u>

Initial project alternatives included a second transformer at Ulrich, an Audubon-Christensen 69 kV line, or Ulrich 69 kV capacitors. All of these failed to provide fully redundant service to Audubon and Erie. Several options exist to provide similar service; however, they are not as cost effective. These include:

- Normal 41.6 kV service from Erie Jct. 230 kV with backup service from Ulrich (or Audubon)
- Normal 41.6 kV service from Audubon, alternate 41.6 kV service from new load tap.
- Normal or alternate 25 kV underground service from Erie Jct. 230 kV

<u>Non-Wires Alternatives</u>

Battery backup for use as a non-wire alternative was explored but was found to be far less cost effective.

Analysis: Reliability impacts from the new transmission lines are currently evaluated in the annual MTEP assessments (in terms of forecasting the existing Audubon and Erie area loads). Impacts to the bulk power system are not the reason for these projects. Limitations of the 41.6/69 kV transmission and member systems are the reason for the transmission projects (and load transfers).

Schedule: This project is budgeted for completion in 2026 to coincide with the construction of the Erie Jct. load tap (2009-NW-N2). A schedule will be developed as definite plans are determined.

General Impacts: This project is primarily rural in location. The route will have to navigate around some lakes, forested areas, and potentially some reservation land within the area. Assuming a one-hundred-foot right-of-way, the project area will be nearly 121 additional acres (some existing transmission may be used for the project), but the affected farmland should only be about 7 acres, assuming some general estimates on electrical poles and farmland equipment navigation. No notable environmental, human, or health concerns exist. This project is still in its early stages of planning, so all of this information is subject to change.

This project may require a short-term project crew. If so, this may bring some business to the area in the form of room and/or board. In terms of local government benefits, it is possible that permit costs may be enforced on this project, but this is determined on a case-by-case basis. Also, some landowners may receive income as a result of this project, and the income may be taxable.

This project is the result of a reliability measure and will probably not have a substantial or lasting impact on the community in terms of the environment or health. It will likely impact some farmland; however, it should only amount to about 20 acres, as stated in the environmental considerations.

Silver Lake Transformer Replacement

MPUC Tracking Number: 2023-NW-N2

Utility: Great River Energy (GRE)

Project Description: Replace existing 230/41.6 kV transformer with a new 230 kV/41.6 kV 56 MVA rated transformer and install 2-41.6 kV breakers

Need Driver: The addition of two-line termination 41.6 kV breakers is needed to prevent tripping at the Silver Lake substation during line faults.

The Silver Lake transformer plays a critical role in providing reliable electric service across a wide area. The existing transformer, manufactured in 1974, has reached the end of its useful life and has experienced failures, raising reliability concerns. Replacing the current unit with a new transformer that is designed to provide additional capacity to support growth in the area was determined to be the most effective and reliable solution.

Alternatives:
Transmission Alternatives

No lower-cost transmission alternative was identified.

Non-Wires Alternatives

The Silver Lake transformer project is a direct replacement necessary to maintain reliable service in a wide area. Non-wires alternatives were not considered viable, as they are typically not a substitute for end-of-life equipment replacements.

Analysis: The replacement transformer will allow GRE to address reliability concerns associated with the existing aging unit, which has had failures and lacks the capacity to support economic development in the area. The proposed transformer will include additional capacity to accommodate growth in the area.

Schedule: This project is planned to be in service by January 2028.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Cormorant Junction – Tamarac – Pelican Rapids (LR-PC) Line Rebuild

MPUC Tracking Number: 2021-NW-N3

Utility: Great River Energy (GRE)

Project Description: Rebuild GRE LR-PC 115 kV line between the Cormorant Junction switch and Pelican Rapids substation.

Need Driver: The existing line has poor reliability and is scheduled for replacement due to its age and deteriorating condition. This transmission line has historically experienced congestion issues, impeding the integration of renewables into the transmission system. The rebuild will increase capacity, ensure a reliable service and create opportunities for interconnection or transfer of generation within the transmission system.

Alternatives:

Transmission Alternatives

This project is driven by the age and condition of the existing transmission line. The only viable solution to address the reliability concerns associated with this critical transmission line, which serves a large area is to replace it with new. This replacement provides an opportunity to resolve other long-standing issues associated with the line’s characteristics, such as congestion and limitations on integrating renewable resources into the grid. No additional alternatives were considered.

Non-Wires Alternatives

Non-wires alternatives were not considered viable for this project due to the nature of the need for this project. The existing transmission line has a low capacity for the current system and in need of replacement due to its age and deteriorating condition. As a main transmission corridor connecting multiple sources serving a wide area, this line plays a critical role in delivering electric service, making non-wires solutions unsuitable as an alternative. Additionally, the line has historically experienced congestion, which hinders the integration of renewable energy into the grid. Rebuilding the line will not only restore reliability but also enhance capacity, enabling future interconnections and transfers of renewable generation. Addressing the issues associated with this transmission line requires physical infrastructure upgrades that cannot be met by non-wires alternatives.

Analysis: The line rebuild project is intended to address the historical reliability issues stemming from the line's age and condition. Furthermore, the increased capacity of the new line will enable interconnection of renewable resources into either the distribution or transmission systems, addressing previous congestion concerns.

A power flow study was performed and found that the line rebuilds do not cause any adverse impacts to the transmission system.

Schedule: The project is planned to be in service by Winter 2030.

General Impacts: The project will be constructed on the existing 115 kV transmission line from Cormorant Junction switch to Tamarac substation to Pelican Rapids substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Otto Substation Area Rebuild

MPUC Tracking Number: 2025-NW-N1

Utility: Great River Energy (GRE)

Project Description: This project is a new interconnection for Lake Region Electric Cooperative (LREC) Otto distribution substation to GRE owned Rush Lake-Schuster Lake 115kV line. GRE will install a 3-way 115kV switch and construct a new 2.7-mile 115kV line from the tap switch to the Otto distribution substation.

Need Driver: The Otto substation was originally constructed as a temporary facility using wood structures and does not conform to LREC's standards. As a result, LREC plans to rebuild the substation to meet its standard specifications.

Currently, the substation is served by a 41.6 kV line with subpar reliability performance. Less than three miles north of Otto is a newer and more reliable GRE-owned 115 kV transmission line. LREC is requesting interconnection to this line to improve electric service reliability.

Alternatives:

Transmission Alternatives

An alternative to this project was evaluated for LREC to rebuild the Otto distribution substation to 41.6 kV specifications and remain connected to the existing 41.6 kV transmission system. This alternative was not pursued further because the current 41.6 kV system does not meet the improved service reliability needs of the area.

Non-Wires Alternatives

Non-wires alternatives were not considered as this is an existing issue with the reliability of the interconnection of Otto distribution substation.

Analysis: Reliability data for the existing 41.6 kV line serving the Otto distribution substation indicated performance issues, highlighting the need for a more dependable interconnection. While one alternative was to rebuild the Otto substation and maintain the 41.6 kV connection, this option was not pursued further due to the reliability issue with the existing 41.6 kV system serving the substation.

In contrast, a new interconnection to the nearby GRE-owned 115 kV transmission line, located less than three miles from the existing substation offers significantly higher reliability and greater capacity. This line is newer, and part of a more robust transmission network. Interconnecting to this 115 kV system not only addresses the immediate reliability concerns but also positions the Otto distribution substation to support future load growth in the area. From both a technical and economic standpoint, the 115 kV interconnection represents the best value solution for enhancing service reliability to the Otto distribution substation

Schedule: The project is planned to be in service by Fall 2028.

General Impacts:

The project will require approximately 2.7 miles of new 115 kV transmission line to the Otto substation. The project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 12 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

J1575 Donaldson South Interconnection

MPUC Tracking Number: 2025-NW-N2

Utility: Otter Tail Power Company (OTP)

Project Description: Build new 3-breaker, 115 kV ring bus on the existing OTP-owned Donaldson – Warsaw 115 kV line, approximately two miles south of Donaldson, to accommodate the interconnection of J1575. J1575 is a 70 MW wind farm from MISO's 2020 DPP cycle with an executed GIA.

Need Driver: This project is needed to accommodate the interconnection of a planned 70 MW wind farm.

Alternatives:

Transmission Alternatives

> This project is required to accommodate the requested Point of Interconnection for a new wind farm. No alternatives were considered.

Non-Wires Alternatives

> This project is required to accommodate the requested Point of Interconnection for a new wind farm. No non-wires alternatives were considered.

Analysis: The J1575 interconnection was studied in MISO's 2020 DPP cycle.

Schedule: The project is planned to be in service by Q3 2028.

General Impacts: This project will be located on a greenfield site along the existing Donaldson – Warsaw 115 kV transmission line, which predominantly runs through agricultural land. Prior to construction, OTP will acquire the necessary land and permits for construction of the project. During construction, OTP and/or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

J1575 Network Upgrades

MPUC Tracking Number: 2025-NW-N3

Utility: Otter Tail Power Company (OTP)

Project Description: MISO's generator interconnection studies identified overloads on the Donaldson – Warsaw 115 kV line due to the J1575 interconnection, a 70 MW wind farm. This Network Upgrade project will replace one 115 kV breaker and two 115 kV disconnects at OTP's Donaldson substation. Additionally, one structure on the Donaldson – Warsaw 115 kV line (future Donaldson – Donaldson South 115 kV line) will be replaced to increase sag limits.

Need Driver: This project is needed to enable sufficient generation outlet for a planned 70 MW wind farm.

Alternatives:
<u>Transmission Alternatives</u>

This project is required to enable sufficient generation outlet for a new wind farm. No alternatives were considered.

<u>Non-Wires Alternatives</u>

This project is required to enable sufficient generation outlet for a new wind farm. No non-wires alternatives were considered.

Analysis: The J1575 interconnection and related Network Upgrades were studied in MISO's 2020 DPP cycle.

Schedule: The project is planned to be in service by the end of 2028.

General Impacts: This project will be replacing equipment in the existing Donaldson 115 kV substation, as well as replacing one structure on the Donaldson – Warsaw 115 kV transmission line, which predominantly runs through agricultural land. Prior to construction, OTP will acquire any necessary permits for construction of the project. During construction, OTP and/or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right of way at the replaced structure will be restored at the end of the project.

Bemidji 115/12.5 kV Substation

MPUC Tracking Number: 2025-NW-N4

Utility: Otter Tail Power Company (OTP)

Project Description: This project involves retiring the 115/69/13.2 kV transformer and the 41.6 kV equipment at the Bemidji 115 kV substation. These retirements will accommodate the addition of a new 115/12.5 kV transformer and a new distribution bus to support existing distribution feeders and multiple new express feeders.

Need Driver: Load growth in Bemidji, MN, has strained the capacity of the distribution facilities in the city. This project adds additional transformer capacity and new express feeders to support backup capabilities and load growth for the city.

Alternatives:
<u>Transmission Alternatives</u>

This project accommodates load growth and improves switching capability on the local distribution system. No alternatives were considered.

<u>Non-Wires Alternatives</u>

This project accommodates load growth and improves switching capability on the local distribution system. No non-wires alternatives were considered.

Analysis: Distribution studies performed in 2024 identified deficiencies in the load serving and backup capabilities of the distribution system in the Bemidji area. These studies resulted in this project, which was found to be the most cost-effective option to support the reliable operation of the city's distribution facilities.

Schedule: The project is planned to be in service by early 2026.

General Impacts: This project involves the retirement of certain equipment and addition of other equipment at the Bemidji 115 kV substation. The substation is located in a suburban area near US Highway 2 on the West side of Bemidji. No new land is required for the changes within the substation or for the new express feeders. During construction, OTP and/or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Fargo – St. Cloud – Monticello 345kV Davit Arm Replacement

MPUC Tracking Number: 2025-NW-N5

Utility: Xcel Energy (XEL), Great River Energy (GRE), Otter Tail Power Company (OTP), Minnesota Power (MP), Missouri River Energy Services (MRES)

Project Description: This project replaces select steel davit arms on the Fargo-St. Cloud-Monticello 345 kV Transmission line. Some of the davit arms have defects and need to be replaced.

Need Driver: Condition replacement of steel davit arms on Fargo-St. Cloud-Monticello 345 kV Transmission line.

Alternatives:
<u>Transmission Alternatives</u>
This project replaces existing defective assets, so no other alternatives were evaluated.
<u>Non-Wires Alternatives</u>
This project replaces existing defective assets, so no non-wires options were evaluated.

Analysis: Physical analysis of the structures revealed davit arms that are defective. For safety and integrity of the davit arms, they must be replaced with non-defective arms.

Schedule: The project is planned to be in service by September of 2030.

General Impacts: No significant impacts are anticipated as this is an existing circuit with the majority of the structure will remain as is, with only replaced davit arms.

6.3.2 Completed Projects

The table below identifies projects that have been completed since our 2023 report.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2019-NW-N3	Erie-Frazee 115 kV Project	ET-2/TL-20-423	GRE/OTP	2024
2021-NW-N2	Henning 230 kV Breaker Addition	N/A	GRE	Moved to study
2021-NW-N3	Inman 230 kV Breaker Addition	N/A	GRE	Moved to study
2021-NW-N4	Cormorant to Pelican Rapids Install Storm Structures	N/A	GRE	Cancelled
2023-NW-N1	Willmar 230/115 kV Interconnection	N/A	Xcel	July, 2022
2007-NW-N3	NW MN Reliability Upgrades	N/A	OTP/MPC	2025

6.4 Northeast Zone

6.4.1 Needed Projects

The following table provides a list of transmission needs identified in the Northeast Zone by MISO utilities. There were no projects identified in this zone by non-MISO utilities.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2007-NE-N1	Duluth Area 230 kV	2014/B	2548	Yes	Yes	MP
2013-NE-N16	HVDC Modernization Project	2013/B	4295	Yes	No	MP
2013-NE-N17	HVDC 900 MW Transmission Line Upgrades	2014/B	3856	No	No	MP
2019-NE-N4	25 Line Rebuild	2024/B	25281	No	No	MP
2019-NE-N8	Badoura 230/115 kv Transformer Replacement	2020/A	15598	No	No	MP
2019-NE-N12	Duluth Loop Reliability Project	2022/A 2022/A	17868 20077	Yes	Yes	MP
2019-NE-N13	National Breaker Replacements	2020/A	17870	No	No	MP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2021-NE-N3	Hibbing Substation Modernization	2020/A	18064	No	No	MP
2021-NE-N4	Verndale Substation Modernization	2020/B	25255	No	No	MP
2021-NE-N5	Badoura 115 kV Substation Modernization	2021/A	18066	No	No	MP
2021-NE-N12	Forbes 230 kV Substation Modernization	2021/A	20075	No	No	MP
2021-NE-N13	Cloquet Substation Modernization	2021/B	20087	No	No	MP
2021-NE-N17	Boswell 115/23 kV Transformer Addition	2025/A	50402	No	No	MP
2021-NE-N19	56 Line Upgrade	2022/B	21764	No	Yes	MP
2021-NE-N21	Riverton 230 kV STATCOM	2025/A	50218	No	Yes	MP
2021-NE-N23	13 Line Rebuild	2022/B	21767	No	No	MP
2023-NE-N1	Northland Reliability Project	2021/A	23370	Yes	Yes	MP/ GRE
2023-NE-N4	Maturi Substation Expansion	2023/A	23707	No	No	MP
2023-NE-N5	Mahtowa Substation Expansion	2023/A	23708	No	No	MP
2023-NE-N6	158 Line Rebuild	2024/A	23076	Yes	No	MP
2023-NE-N7	Arrowhead 115 kV Single Point of Failure	2024/A	25141	No	No	MP
2023-NE-N8	Forbes 115 kV Single Point of Failure	2024/A	25142	No	No	MP
2023-NE-N9	Ridgeview 115/34 kV Transformer Addition	2025/A	25264	No	No	MP
2023-NE-N10	Wrenshall Substation Modernization	2024/B	25265	No	No	MP
2023-NE-N11	133 Line Rebuild	2022/B	22285	No	No	MP
2025-NE-N1	Maple River – Cuyuna 345 kV Project (LRTP Project #21)	2024/A	50553	Yes	Yes	MP / OTP / GRE
2025-NE-N2	Iron Range – St Louis County – Arrowhead 345 kV Project (LRTP Project #21)	2024/A	50554	Yes	Yes	MP / ATC
2025-NE-N3	24 Line Rebuild	2022/B	22286	No	No	MP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2025-NE-N4	Arrowhead 230 kV Single Point of Failure (EEE Replacement)	2025/A	50149	No	No	MP
2025-NE-N5	Transmission Line Pole Replacement 2025	2025/A	50395	No	No	MP
2025-NE-N6	Iron Range 500 kV Reactor Addition	2025/A	50393	No	No	MP
2025-NE-N7	Shannon Capacitor Bank Replacement	2025/A	50365	No	No	MP
2025-NE-N8	26 Line Rebuild	2025/B	50348	No	No	MP
2025-NE-N9	Haines Rd Substation Modernization	2025/B	50344	No	No	MP
2025-NE-N10	180 Line Rebuild	2025/A	25267	No	No	MP
2025-NE-N11	Hat Trick Substation Expansion	2026/B	50674	No	No	MP
2025-NE-N12	Babbitt 115 kV Transmission Project	2025/B	50769	Yes	No	MP
2025-NE-N13	Transmission Line Pole Replacement 2026	2026/A	50618	No	No	MP
2025-NE-N14	Transmission Line Pole Replacement 2027	2026/A	50777	No	No	MP
2025-NE-N15	Brainerd Cap Bank Replacement	2026/A	50817	No	No	MP
2025-NE-N16	Riverton to Mud Lake Temperature Upgrade Project	2024/A	25391	No	No	GRE
2025-NE-N17	LCP Peary Substation Rebuild	2026/A	50938	No	No	GRE
2025-NE-N18	Iona 115 kV Conversion Project	2025/A	5027	No	No	GRE
2025-NE-N19	Heartland Lakes 115 kV Project	2025/A	50273	No	No	GRE
2025-NE-N20	Boulder Lake 115 kV Project	2026/A	50876	No	No	GRE
2025-NE-N21	Pillsbury Area Projects	2026/A	50877	No	No	GRE

Duluth 230 kV Project

MPUC Tracking Number: 2007-NE-N1

Utility: Minnesota Power (MP)

Project Description: Add a second 230/115 kV transformer at the Hilltop Substation and upgrade an existing line from 115 kV to 230 kV between the Arrowhead and Hilltop substations.

Need Driver: Reliability and load growth in the Duluth area. Retirement of local generators on the 115 kV system. Maintaining sufficient 230/115 kV transformer capacity for load serving in the Duluth area during a maintenance outage of one of the existing Arrowhead 230/115 kV transformers or following certain single contingency events.

Alternatives:

Transmission Alternatives

Build a new 230/115 kV substation in the Duluth area.

Non-Wires Alternatives

Install new dispatchable generation in the Duluth area. Non-wire alternatives must be dispatchable to respond when called upon and of sufficient duration to prevent or mitigate overloading. Minnesota Power will continue to consider non-wire alternatives alongside the Duluth 230 kV Project as the need and timing for the project develop.

Analysis: In 1993, Minnesota Power constructed a new 230 kV substation (the Hilltop Substation) in Duluth. This project involved the rebuilding of existing 115 kV lines for 230 kV operation in order to provide a single 230 kV source to the Hilltop Substation and upgrades of several unshielded 115 kV lines to improve reliability. As part of the application for the Hilltop Project MP laid out long range plans which identified the future need for a second 230 kV source to the Hilltop Substation once Duluth load dictated its need. The Commission recognized this future need and approved rebuilding of portions of the unshielded 115 kV lines as part of the Hilltop Project for future 230 kV operation.

Because Minnesota Power anticipated this future need, a relatively minimal amount of transmission line and substation construction will be required to implement the Duluth 230 kV Project when it becomes needed. Due to the configuration of the existing Duluth area transmission system, the Duluth 230 kV Project is expected to be the most cost effective and least environmentally impactful solution to this pending inadequacy. Other transmission alternatives would require longer 230 kV line construction and the establishment of a new substation site, increasing social, environmental and economic impacts associated with construction of such a project. Operational changes that limit through-flow on the Duluth-area 115 kV system have proven helpful in delaying the need for this project, as discussed below. The Duluth Loop Reliability Project (2019-NE-N12) will include incremental improvements at the Arrowhead and Hilltop Substations, such as a larger 230/115 kV transformer and a 230 kV breaker at Hilltop and sectionalization of the Hilltop 230 kV line at Arrowhead. These incremental improvements are expected to further delay the need for the more significant expansion of Duluth area 230/115 kV transformer capacity that would be achieved with the Duluth 230 kV Project.

Schedule: Slower than anticipated load growth, external system improvements such as the Arrowhead-Stone Lake-Gardner Park 345 kV Line, and operational flexibility provided by the phase shifting transformer at the Stinson Avenue Substation in Superior, Wisconsin, have delayed the need for the Duluth 230 kV Project for many years. Based on recent studies indicating a need for improved reliability and capacity of Duluth-area 230/115 kV transformers in the first half of the 2020s, Minnesota Power has included incremental improvements at the Arrowhead and Hilltop Substations as part of the Duluth Loop Reliability Project (2019-NE-N12). The underlying system drivers behind the timing of the incremental improvements included with the Duluth Loop Reliability Project are related to the impact of a number of transitional changes in the nearby North Shore Loop transmission system and changing regional transfers in and through the Minnesota Power system. These incremental improvements will shift the primary need drivers for the Duluth 230 kV Project back to local Duluth-area load growth or retirement of the dispatchable generators at the Hibbard Renewable Energy Center, likely delaying the need for the Duluth 230 kV Project to the late 2020s or even into the 2030s.

General Impacts: The Duluth 230 kV Project will make optimal use of an existing transmission line that was designed for future conversion for 230 kV operation and existing substations designed with space in or adjacent to the existing footprint to accommodate additional 230 kV connections. Since the Duluth 230 kV Project is using existing substations, transmission line corridors and rights-of-way, it is anticipated that no new landowners would be impacted by the project. The Duluth 230 kV Project is needed to maintain adequate power delivery capability from the transmission system to the Duluth area in light of local generator retirements, regional transfers, load growth, and economic development. Therefore, the project contributes to the realization of significant environmental, social, and economic benefits associated with these contributing factors. Minnesota Power's approach to this issue is intended to ensure that the most appropriate solution (in terms of cost and human and environmental impacts) is implemented at the most appropriate time to meet the reliability and capacity needs of Minnesota Power's customers.

HVDC Modernization Project

Formerly Square Butte – Arrowhead HVDC Valve Hall Replacement

MPUC Tracking Number: 2013-NE-N16

MPUC Docket Number: E015/CN-22-607, E015/TL-22-611

Utility: Minnesota Power (MP)

Project Description: Replace the existing Center (Square Butte) and Arrowhead high voltage direct current (HVDC) converter stations and associated assets with modern equipment. To modernize the terminals of the existing Square Butte HVDC Line and implement the latest VSC HVDC technology, new buildings and electrical infrastructure need to be constructed on a new site near the existing HVDC terminals. In Minnesota, to connect the new HVDC terminal to the existing AC system, the Project will require the construction of a new St. Louis County 345 kV/230 kV substation located less than one mile west of the current Arrowhead Substation. The new HVDC terminal will be connected to the St. Louis County Substation by a short 345 kV transmission line, and the new St. Louis County Substation will be connected to the existing Arrowhead Substation by a double-circuit 230 kV transmission line less than one mile in length. Additionally, a short portion of the existing ±250 kV HVDC Line in Minnesota will need to be reconfigured to terminate at the new HVDC terminal. Similar modifications will take place near the existing Center HVDC terminal in North Dakota.

Need Driver: The HVDC Modernization Project is needed to modernize aging HVDC assets, continue to position the transmission grid for clean energy transition, and improve the reliability of the transmission system. The existing HVDC terminal has operated for 47 years—17 years beyond its 30-year design life. In recent years Minnesota Power has experienced HVDC terminal outages due to failures in the control system, power electronics, transformers, and other components. Based on experience with other electric system components, the failure rate is expected to increase, which is of particular concern for the existing HVDC system because of limited parts availability. The orderly replacement of the HVDC terminal equipment is prudent to ensure continuous efficient delivery and expansion of Minnesota Power's renewable, carbon-free energy resources into the future.

In addition to the replacement of the existing HVDC terminals, the new voltage source converter (VSC) HVDC technology implemented for the Project will be designed to provide key reliability attributes including voltage regulation, frequency response, blackstart capability, and bidirectional power transfer capability. These modernizations to the HVDC technology will enable Minnesota Power and the region to continue to support its clean energy transition.

Alternatives:

Transmission Alternatives

Alternatives to the HVDC Modernization Project discussed in the Certificate of Need application include not replacing the HVDC converter stations ("Do Nothing" – risk of extended outage due to equipment failure), retiring the HVDC system and replacing it with new AC transmission improvements ("AC Alternative"), and replacing the HVDC converters with older technology similar to the original stations ("Technology Alternative").

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Center and Arrowhead HVDC converter stations.

Analysis: The HVDC Modernization Project will modernize aging assets that are critical to the reliable delivery of renewable energy to Minnesota Power's customers, improve the reliability of the transmission system and thoughtfully position for continued clean energy system transformation. Under the "Do Nothing" alternative, failure rates of the existing HVDC Converter Station equipment are anticipated to increase, resulting in outages that impact the reliable and efficient delivery of Minnesota Power's North Dakota wind energy and result in direct cost impacts to Minnesota Power's customers and reliability impacts to the regional transmission system. As these outages increase in frequency and duration, the cost and reliability impacts will continue to grow. With no viable plan to modernize the existing HVDC converters, Minnesota Power would immediately need to determine if it were prudent to invest in relatively short-term fixes to keep the HVDC Line operating on a limited basis or to move on from the HVDC Line entirely and begin to develop alternative AC transmission solutions.

Under the "AC Alternative" the alternative AC transmission solutions required to facilitate continued delivery of Minnesota Power's zero fuel cost North Dakota wind energy, mitigate system impacts caused by the retirement of the HVDC Line, and replace the grid support provided by the VSC HVDC converters would come at a substantially higher cost and with greater human and environmental impacts than the HVDC Modernization Project. Given that the AC Alternative would need to include multiple regional-scale 345 kV transmission lines, there would likely be prolonged exposure to outages of the HVDC Line during the 10 or more years it would take to develop these projects. At some point during that time, it may become impossible to continue operating the HVDC Line at its full capacity, leading to extended outages and associated impacts to Minnesota Power's customers and regional reliability.

Were Minnesota Power to choose to invest in relatively short-term fixes to keep the HVDC Line operating on a limited basis, these fixes would result in significant risk of stranded investment as the regional transmission system develops. The "Technology Alternative" including targeted replacements of the existing control system, converter transformers, and thyristor valves could serve to keep the existing LCC HVDC system running for several more decades at its existing capacity. These replacements would not bring the additional grid-supporting attributes associated with VSC technology, and therefore additional investments in STATCOMs, synchronous condensers, or other solutions may become necessary as the clean energy transition continues to challenge the historical operating conditions of the grid. As MISO continues to advance proactive long-range transmission planning solutions to position the grid for the future of clean energy, VSC HVDC solutions will inevitably begin to play a major role in the regional grid. At that point, Minnesota Power's short-term investments in keeping its existing LCC HVDC system may have to be replaced before the end of their useful asset life by a VSC HVDC upgrade similar to the Project in order to continue reliable operation of the Square Butte HVDC corridor and provide the best value for Minnesota Power's customers and the region.

The HVDC Modernization Project is the only prudent solution to limit cost impacts to Minnesota Power's customers in the near-term from increased exposure to HVDC outages, avoid substantial additional long-term cost for alternative projects to address reliability issues created by retirement of the HVDC Line, and align with opportunities to efficiently provide long-term bulk power transfer and grid support solutions for Minnesota Power and the region.

Schedule: Minnesota Power filed a combined Certificate of Need and Route Permit Application for the HVDC Modernization Project on June 1, 2023 [Docket Nos. E015/CN-22-607 and E015/TL-22-611], and the Commission granted the Certificate of Need and Route Permit on October 25, 2024. Site development for the converter stations in both Minnesota and North Dakota began in mid-2025, and the Project has a targeted in-service date between April 2029 and April 2030.

General Impacts: The modernization of Minnesota Power's HVDC converter stations is a prudent and necessary activity to ensure the ongoing operation of this critical piece of transmission infrastructure for Minnesota Power's customers, including the reliable delivery of Minnesota Power's substantial North Dakota wind generation assets.

The HVDC Modernization Project is also a critical component of Minnesota Power's efforts to leverage existing infrastructure to efficiently maintain the current load, gain additional access to renewable resources for customers, and keep momentum for reaching the state's goal of 100 percent carbon-free energy by 2040. The Project innovatively proposes flexible design options to allow for future expansion and additional renewable energy transfer capability, leveraging the unique attributes of VSC HVDC technology—the most efficient way to transfer power over long distances. In addition to the replacement of the existing HVDC terminals, the new Voltage Source Converter (VSC) HVDC technology implemented for the Project will be designed to provide voltage regulation, frequency response, blackstart capability, and bidirectional power transfer capability, all of which will enable Minnesota Power and the region to continue to support its clean energy transition reliably. All of this will be implemented in a relatively small geographic area near the existing Arrowhead 230 kV Substation, limiting human and environmental impacts by leveraging the existing site and contiguous lands to the greatest extent possible.

HVDC 900 MW Transmission Line Upgrades

Formerly Square Butte – Arrowhead HVDC Upgrade

MPUC Tracking Number: 2013-NE-N17

Utility: Minnesota Power (MP)

Project Description: Upgrade the capacity of the existing Square Butte – Arrowhead HVDC transmission line from 550 MW to 900 MW, generally by replacing existing structures with taller structures and reconductoring a short segment of line.

Need Driver: Transmission Service Requests (TSRs) filed with MISO for additional capacity to facilitate increased renewable energy transfers on the HVDC Line following the completion of the HVDC Modernization Project (Tracking No. 2013-NE-N16).

Alternatives:

Transmission Alternatives

Develop AC network upgrades necessary to facilitate the same amount of additional renewable energy interconnection and regional transfer capability.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot provide additional capacity for long-distance renewable energy transfers on the existing HVDC Line.

Analysis: Minnesota Power has assessed the capacity limitations associated with the existing HVDC Line and found that the total capacity of the HVDC Line may be reasonably increased from 550 MW to a maximum of 900 MW following completion of the HVDC Modernization Project (Tracking No. 2013-NE-N16). To achieve the higher capacity, upgrades would be needed at various locations along the length of the 465-mile HVDC transmission line. These upgrades are expected to include replacing existing structures with taller structures to increase conductor-to-ground clearance at a higher operating temperature, as well as replacement of a short segment of smaller conductor in North Dakota. Leveraging the opportunity to incrementally increase the capacity of the HVDC Line following completion of the HVDC Modernization Project provides an efficient solution for facilitating the interconnection and long-distance delivery of additional high-capacity renewable energy resources to Minnesota Power's customers.

Schedule: At the request of Minnesota Power, MISO updated Transmission Service Request ("TSR") System Impact Studies on varying levels of increased HVDC capacity in 2022-2023 and provided Facilities Studies documenting the costs assigned to the TSRs. Two Facilities Construction Agreements ("FCA") for the upgrades necessary to provide the requested incremental transfer capability were executed on February 28, 2024, and subsequently filed with and accepted by FERC. Minnesota Power plans to construct the HVDC transmission line upgrades. in phases between 2026 and 2029 to limit HVDC Line outage impacts.

General Impacts: The additional capacity facilitated by the HVDC 900MW Transmission Line Upgrades Project will facilitate increased wind development in North Dakota, more efficient market operation, and system reliability enhancements for both North Dakota and Minnesota. Since the project is anticipated to take place within the existing transmission line right-of-way, it is anticipated that no new landowners would be impacted by the project.

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25 Line Rebuild

MPUC Tracking Number: 2019-NE-N4

Utility: Minnesota Power (MP)

Project Description: Increase rating of Maturi – Virginia 115 kV Line (25 Line). The project also includes rebuild, reconductor, and switch replacements along the transmission line and in the vicinity of the existing Minntac Tap.

Need Driver: Post-contingent overloads under higher transfer scenarios and multiple-circuit contingency events, as well as age and condition of existing 25 Line structures and hardware.

Alternatives:
Transmission Alternatives

Reconductor existing line, build new parallel line.

Non-Wires Alternatives

Install new dispatchable energy resource in the area. Non-wire alternatives must be dispatchable to respond when called upon, of sufficient duration, and at an effective location to prevent or mitigate overloading. However, non-wire alternatives can only address the capacity needs and would not displace the need for asset renewal components of the project.

Analysis: This issue has been identified in MTEP and in several Minnesota Power studies. The upgrade project provides the needed capacity increase as identified in the studies while also efficiently addressing asset renewal needs along the length of the line.

Schedule: The project has been delayed to align with other asset renewal and substation modernization projects in the area. Minnesota Power is currently targeting a 2029 in-service date for the project.

General Impacts: The 25 Line Upgrade Project will provide necessary system improvements and asset renewal on Minnesota Power's 115 kV system without requiring the establishment of additional transmission line corridors. During construction, MP and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Badoura 230/115 kV Transformer Replacement

MPUC Tracking Number: 2019-NE-N8

Utility: Minnesota Power (MP)

Project Description: Replace existing 230/115 kV transformer at Badoura substation and add 230 kV line breakers.

Need Driver: Age and condition of Badoura transformer. Transformer is also non-standard and there is no direct system spare. Post-contingent overloads following multiple-circuit contingency events in the surrounding area.

Alternatives:

Transmission Alternatives

Increase facility ratings to mitigate post-contingent overloads.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition and non-standard equipment at Badoura.

Analysis: The Badoura 230/115 kV transformer is non-standard for Minnesota Power's system, as it consists of an external 115 kV voltage regulating transformer rather than an internal load tap changer. The transformer is also nearly 60 years old. The project will replace it with a new standard-sized 230/115 kV transformer, for which Minnesota Power maintains a system spare. Studies have indicated that the voltage regulation from the transformer is not necessary and therefore the new transformer will be procured without load tap changers. Additionally, there are no breakers at the Badoura 230 kV Substation, which creates difficulties with relaying and contingencies that cause large parts of the area between Riverton and Park Rapids to lose critical transmission connections. Installing breakers will mitigate issues associated with these contingencies and provide for better protection of the transmission lines and transformer. Post-contingent overloads on the Badoura 230/115 kV Transformer were first identified in the MTEP18 2023 winter peak case.

Schedule: The project is currently targeted for an in-service date of 2027.

General Impacts: The Badoura Transformer Replacement Project will ensure a continuous and reliable power supply to a large area of the Minnesota Power transmission system between Riverton and Park Rapids by replacing aging, non-standard equipment before it fails and by improving system protection through the addition of breakers. The Project will make use of space available inside the existing Badoura 230/115 kV Substation, as all modifications associated with the project will take place within the existing substation fence-line.

Duluth Loop Reliability Project

MPUC Tracking Number: 2019-NE-N12

Utility: Minnesota Power (MP)

Project Description: Construct approximately 14 miles of new 115 kV transmission between the existing Hilltop, Haines Road, and Ridgeview substations. Some existing 115 kV transmission lines in the area will be reconfigured and upgraded. At the existing Ridgeview Substation, the substation yard will be expanded to accommodate a new 115 kV ring bus with 4 new 115 kV circuit breakers and a new transmission line entrance. At the existing Haines Road Substation, a 115 kV circuit breaker will be added to an existing transmission line entrance. At the existing Hilltop Substation, the substation yard will be expanded to accommodate a new 115 kV line entrance, the existing 230/115 kV transformer will be replaced with a larger-capacity transformer, a new 230 kV circuit breaker will be added, and four existing 115 kV circuit breakers will be replaced. At the existing Arrowhead Substation, a new 230 kV transmission line entrance will be constructed. The existing Hilltop 230 kV tap will be disconnected from the Arrowhead – Iron Range 230 kV Line (98 Line) and extended approximately 0.7 miles to the new line entrance at the Arrowhead Substation to become the Arrowhead – Hilltop 230 kV Line (108 Line). The existing Hilltop 230 kV tap transmission line will be upgraded to a higher operating temperature and existing polymer insulators will be replaced. Additional substation and transmission line components will also be replaced as part of the project due to age and condition.

Need Driver: Following conversion, idling, or retirement of coal-fired baseload generators in the North Shore Loop, there is a risk of voltage collapse during maintenance outages of 115 kV lines between Arrowhead, Haines Road, Swan Lake Road, Ridgeview, and Colbyville Substations. Loss of a second transmission line during one of these maintenance outages would leave this part of Duluth on a single 140-mile transmission line originating in the Hoyt Lakes Area, with the transmission system no longer able to support the load over that distance without the baseload generators. The Duluth Loop Reliability Project will restore redundancy and load-serving capability to this area, mitigating the risk of voltage collapse. Duluth area 230/115 kV transformer loading also increases significantly without the local baseload generators online and connected to the 115 kV system. This causes a risk of severe overloads on the existing 230 kV line and the Hilltop 230/115 kV transformer during a maintenance outage of either of the Arrowhead 230/115 kV transformers. Upgrading the capacity of the existing Hilltop 230 kV tap line and Hilltop

230/115 kV transformer will mitigate these severe overloads. Extending the Hilltop 230 kV tap line into the new line entrance at the Arrowhead Substation will greatly improve the reliability of the 230 kV source at the Hilltop Substation by reducing over 64 miles of outage exposure to the sole source to the Hilltop Substation and eliminating a breaker failure event which could simultaneously disconnect two 230/115 kV transformers in the Duluth area. This reconfiguration will also allow significant relay protection improvements to the existing Iron Range – Arrowhead 230 kV Line (98 Line) and the newly established Arrowhead – Hilltop 230 kV Line (108 Line).

Alternatives:
Transmission Alternatives

New 115 kV or 230 kV line parallel to Arrowhead – Colbyville 115 kV path(s).

Non-Wires Alternatives

New dispatchable transmission- or distribution-connected generation in the Duluth 115 kV Loop; dynamic reactive support and transmission line capacity upgrades in the Duluth 115 kV Loop and the North Shore Loop. Non-wire alternatives must be dispatchable to respond when called upon, of sufficient duration, and at an effective location to prevent or mitigate voltage concerns.

Analysis: The Duluth Loop is a network of 115 kV transmission lines and substations which form two parallel connections between the main Duluth-area transmission source of power and system support (the Arrowhead 230/115 kV Substation) and the North Shore Loop (beginning at the Colbyville Substation on the far eastern end of Duluth). Many of the customers in the Duluth area are served from substations connected to the Duluth Loop.

The Duluth Loop Reliability Project meets three critical needs for the Duluth area and the North Shore Loop, as discussed below.

First, the project addresses severe voltage stability concerns by providing another transmission source to the Duluth Loop and North Shore Loop. For most transmission outages in the Duluth Loop, the loss of a second Duluth Loop transmission line during the outage would leave all or part of the Duluth Loop and the North Shore Loop on a single 140-mile transmission line originating in the Hoyt Lakes area. Without the support previously provided by the local baseload generators on the North Shore Loop, the transmission system is no longer able to support the large amount of Duluth Loop load over such a long distance and the expected result would be a post-contingent voltage collapse in the Duluth Loop and extending up the North Shore toward Two Harbors. To manage the risk of voltage collapse in real-time operations, the Regional Transmission Operator (MISO) directs Minnesota Power to open the North Shore transmission connection at Colbyville, separating Duluth from the North Shore Loop during planned outages in the Duluth Loop. This causes Duluth Loop load to be served through a single transmission path from the Arrowhead substation and load along the North Shore to be served through a single transmission path from the Taconite Harbor substation. This operational solution serves mostly to contain the problem rather than resolve it, as the loss of a second Duluth Loop or North Shore Loop transmission line would still result in loss of power for many residential, commercial, and industrial customers. Constructing a new 115 kV transmission line between the Hilltop and Ridgeview substations will replace the redundancy once provided by the local baseload generators such that there is sufficient load-serving capability to support all loads in the area and sufficient flexibility to operate and maintain the system reliably without putting customers at risk.

Second, the project provides load serving capacity to the Duluth Loop and North Shore Loop. For most transmission outages impacting the Taconite Harbor Substation, a majority of load along the North Shore is served through the Duluth Loop. For this scenario, an outage along either connection between the Arrowhead and Colbyville substations could cause significant overloads along the remaining connection. Alternately, if the North Shore Loop is intact and an outage occurs on both transmission connections between the Arrowhead and Colbyville substations, significant overloads could occur on transmission lines between the Taconite Harbor, North Shore, and Big Rock substations. Constructing a new 115 kV transmission line between the Hilltop and Ridgeview substations will provide sufficient Duluth Loop and North Shore Loop transmission capacity to prevent transmission line overloads.

Third, the project improves the reliability of Duluth area transmission sources. Two 230/115 kV transformers at Arrowhead and one at Hilltop deliver power to 115 kV transmission lines in the Duluth area from the regional 230 kV transmission network. The reliance of the Duluth Loop and the North Shore Loop on these transformers has greatly increased with the idling of North Shore Loop coal generators. The Hilltop Substation is served by a single, 72-mile, 230 kV three terminal transmission line which also connects to the Arrowhead and Iron Range substations. Breaking the three terminal transmission line and extending this 230 kV transmission line approximately 0.7 miles and adding a breaker at the Arrowhead Substation will create two distinct transmission lines and reduce line mile exposure to Hilltop from 72 miles to 8 miles, greatly improving the reliability of the sole 230 kV source to the Hilltop. The additional breaker for this line connection at Arrowhead will eliminate a single point of failure which disconnects a 230/115 kV transformer at both Arrowhead and Hilltop, likely causing overloads on the remaining Arrowhead 230/115 kV transformer. Improving the reliability of Duluth Area 230/115 kV transformers will benefit customers in the Duluth Loop and along the North Shore as reliance on these transmission sources increases with the local baseload generators offline.

Schedule: Minnesota Power submitted a combined Certificate of Need and Route Permit application to the Commission in October 2021 [Docket Nos. E015/CN-21-140 and E015/TL-21-141], which was approved in February 2023. Following permitting and engineering activities, project construction began in 2024 and will continue taking place in 2025-26.

General Impacts: The Duluth Loop Reliability Project is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. Replacing redundancy, voltage support, and power delivery capability previously provided by local baseload coal units in the area and improving the reliability of an increasingly critical transmission connection for delivery of power into the North Shore Loop enables the realization of significant economic and environmental benefits from transitioning away from these units. The proposed project will require approximately 0.7 miles of new 230 kV transmission and 14 miles of new 115 kV transmission, some of which will be double circuited with an existing transmission line. New transmission line construction will be primarily along existing transmission line corridors and utilize existing rights-of-way to the greatest possible extent to help navigate areas of Duluth with varying land use and space constraints. Minnesota Power has taken into consideration all relevant human, environmental, and commercial interests in the area and has actively engaged impacted stakeholders in routing and siting of the project.

National Breaker Replacements

MPUC Tracking Number: 2019-NE-N13

Utility: Minnesota Power (MP)

Project Description: Replace end-of-life circuit breakers and associated equipment at National Taconite 115 kV Substation.

Need Driver: Age and condition.

Alternatives:
Transmission Alternatives

> There is no more economical or less impactful solution than replacing the existing circuit breakers.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the National Taconite Substation.

Analysis: Five 115 kV oil circuit breakers from 1966 will be replaced as part of this project.

Schedule: The project has been constructed in stages since 2021 and is presently planned to complete construction in 2026. While most of the project has already been completed, significant outage constraints at the National Taconite Substation have delayed the final completion of this project to align with a planned outage in 2026.

General Impacts: The National Breaker Replacements Project will replace end-of-life substation equipment, supporting continued transmission system reliability in the area. The project will take place entirely within the existing National Taconite Substation, which is located on mine property, making optimal use of the existing site infrastructure to minimize human and environmental impacts.

Hibbing Substation Modernization

MPUC Tracking Number: 2021-NE-N3

Utility: Minnesota Power (MP)

Project Description: The Hibbing Substation is located west of Hibbing, Minnesota, The Hibbing Substation Modernization project involves replacing aging equipment, structures, and civil works at the substation as part of Minnesota Power's asset renewal program

Need Driver: The Hibbing Substation serves the City of Hibbing as well as other Minnesota Power customers in the area surrounding Hibbing. The primary need driver for the Hibbing Substation Modernization project is the age and condition of existing transformers, circuit breakers, disconnect switches, and site infrastructure. Much of the original equipment in this substation is nearing or beyond the end of its useful life, including many of the structures and foundations. Although load will be shifted off the Hibbing Substation onto the expanded Maturi Substation (Project 2023-NE-N4), the Hibbing Substation is still critical for bulk electric transmission system reliability and local load-serving needs in the Hibbing area.

Alternatives:

Transmission Alternatives

Develop area transmission and distribution system to address bulk electric system transmission needs and shift load off the Hibbing Substation to alternative sources.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Hibbing Substation.

Analysis: Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In developing the scope for the Hibbing Substation Modernization Project, Minnesota Power is considering the near-term and long-term needs of the area transmission and distribution system as well as the age and condition of existing site infrastructure and modern design standards for safety, accessibility, and maintainability. The resulting project will involve a nearly complete overhaul of the site, which is expected to ensure the site remains viable and continues to reliably serve the City of Hibbing and Minnesota Power's other customers for many decades to come.

Schedule: The project is currently anticipated to take place in stages from 2027-28 to manage outage and constructability constraints.

General Impacts: The Hibbing Substation Modernization Project will ensure a continuous and reliable power supply to the Hibbing area by replacing aging equipment before it fails. While some minor fence expansion on Minnesota Power-owned property is necessary, the majority of impacts from the project will be contained within the existing Hibbing Substation yard.

Verndale Substation Modernization

MPUC Tracking Number: 2021-NE-N4

Utility: Minnesota Power (MP)

Project Description: The Verndale Substation Modernization Project involves replacing aging electrical equipment, structures, and civil works at the existing Verndale 115/34 kV Substation as part of Minnesota Power's asset renewal program. Multiple substation asset renewal needs will be combined with necessary distribution transformer upgrades to make up the core of this project. This work at the Verndale Substation was combined into one project in order to facilitate efficient coordination of engineering and construction. Due to the location of the existing Verndale Substation, the size of the existing property, and the configuration of the existing substation, site constraints would not allow for a substation modernization project to be safely and reliably implemented at the existing site. Therefore, the Verndale Substation Modernization Project involves rebuilding the Verndale Substation at a new location near the existing site and subsequently retiring the substation at its existing location.

Need Driver: The Verndale Substation serves Verndale, Staples, Wadena and the surrounding area, including customers of Minnesota Power, Great River Energy, and Missouri River Energy Services. The primary need driver for the Verndale Substation Modernization Project is age and condition of existing transformers, circuit breakers, disconnect switches, and site infrastructure. Much of the original equipment in this substation is nearing or beyond the end of its useful life, including many of the structures and foundations. In addition to these asset renewal concerns, historical Verndale Substation loading exceeds firm capacity for loss of a single 115/34 kV transformer, and transformer load-tap changers are needed to provide more effective distribution system voltage regulation.

Alternatives:

Transmission Alternatives

Install new 115/34 kV transformers at nearby Wing River 230/115 kV Substation and reconfigure distribution system to enable retirement of Verndale Substation.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Verndale Substation.

Analysis: Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In developing the scope for the Verndale Substation Modernization Project, Minnesota Power is considering the near-term and long-term needs of the area transmission and distribution system as well as the age and condition of existing site infrastructure and modern design standards for safety, accessibility, and maintainability.

Schedule: The project is currently planned as a multi-year project with construction taking place in 2027-2028.

General Impacts: The Verndale Substation Modernization Project will ensure a continuous and reliable power supply to the Verndale, Staples, and Wadena areas by increasing transformer capacity, improving voltage regulation, and replacing aging equipment before it fails.

Badoura 115 kV Substation Modernization

MPUC Tracking Number: 2021-NE-N5

Utility: Minnesota Power (MP)

Project Description: Move existing 115 kV lines from straight bus in original Badoura 115 kV Substation into the open positions on the newer Badoura #2 Substation 115 kV ring bus. Build out bus work to connect existing cap bank. Demo original Badoura 115 kV Substation including removal of old 115 kV box structure and control house. Adding new alternate station service source to replace feed from 34.5 kV equipment at the Badoura site.

Need Driver: Age and condition of Badoura 40L and 48L 115 kV breakers and control house. Shifting capacitor bank position to mitigate post-contingent low voltage following loss of shared breaker with 230/115 kV transformer.

Alternatives:

Transmission Alternatives

> Replace the breakers in current locations and modernize original Badoura 115 kV Substation yard to retain existing box structure.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot address concerns related to age and condition of 115 kV equipment at Badoura.

Analysis: The existing breakers protecting the two 115 kV lines into the straight bus at Badoura are 1960s-vintage oil breakers connected to a box structure of the same vintage. A newer ring bus was constructed adjacent to the original Badoura Substation in the 2000s as part of the Badoura 115 kV Project. The transmission lines connected to the original Badoura Substation are being relocated to open positions on the newer Badoura 115 kV ring bus to retire the original circuit breakers, box structure, and control house as well as establish a more reliable configuration for the 115 kV lines connected to the Badoura Substation.

Schedule: The project is scheduled to be completed in late 2025.

General Impacts: The Badoura 115 kV Modernization Project will improve safety and transmission system reliability around Badoura by relocating transmission lines from an aging 1960s era site and a straight bus configuration to a newer site in a ring bus configuration. The project will include small fence expansions to accommodate new line entrance equipment on the ring bus at the Badoura 115 kV site, but in general will make optimal use of the existing Badoura Substation site and enable retirement of most of the original Badoura Substation site.

Forbes 230 kV Modernization

MPUC Tracking Number: 2021-NE-N12

Utility: Minnesota Power (MP)

Project Description: Replace end-of-life 230/115 kV transformer and 230 kV capacitor bank, circuit breakers, switches, relay panels, and associated equipment at the Forbes 230 kV Substation.

Need Driver: Age and condition.

Alternatives:
Transmission Alternatives

> There is no more economical or less impactful solution than replacing the existing substation equipment.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Forbes 230 kV Substation.

Analysis: Across Minnesota Power's system there are many transmission substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. At the Forbes 230 kV Substation, the circuit breaker is oil-filled from 1979, and one circuit breaker is an early generation SF6 model of concern. The existing capacitor bank has failed components and a larger replacement capacitor bank will provide additional voltage support to the transmission system. The 230/115 kV transformer is a critical transformer to the surrounding 115 kV system, including the East Range and the North Shore Loop. This transformer has many age and condition-related issues. An extended outage due to failure of this transformer would likely require running local peaking generation for the duration of the outage. There are concerns with moving the aging transformer from another site which has been identified as a spare in the event of failure. It is prudent to proactively replace this transformer in the near future before it fails.

Schedule: The project is presently planned for construction in 2027-2028.

General Impacts: The Forbes 230 kV Modernization Project will ensure that the Forbes 230 kV Substation continues to provide safe and reliable transmission support for Minnesota Power's

230 kV and 115 kV transmission system. The impacts of the project will be entirely contained within the existing Forbes Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Cloquet Substation Modernization

MPUC Tracking Number: 2021-NE-N13

Utility: Minnesota Power (MP)

Project Description: The Cloquet Substation Modernization Project involves replacing aging electrical equipment, structures, and civil works at the existing Cloquet 115/14 kV Substation as part of Minnesota Power's asset renewal program. Multiple substation asset renewal needs will be combined with necessary distribution transformer upgrades to make up the core of this project. This work at the Cloquet Substation was combined into one project in order to facilitate efficient coordination of engineering and construction. Due to the location of the existing Cloquet Substation near the St. Louis River, the size of the existing property, and the configuration of the existing substation, site constraints would not allow for a substation modernization project to be safely and reliably implemented at the existing site. Therefore, the Cloquet Substation Modernization Project involves rebuilding the Cloquet Substation at a new location east of the existing site and subsequently retiring the substation at its existing location.

Need Driver: The Cloquet Substation serves Cloquet, Esko, Scanlon, parts of the Fond Du Lac Reservation and the surrounding area. The primary need driver for the Cloquet Substation Modernization Project is age and condition of existing transformers, circuit breakers, disconnect switches, and site infrastructure. Much of the original equipment in this substation is nearing or beyond the end of its useful life, including many of the structures and foundations.

Alternatives:
Transmission Alternatives

(None)

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Cloquet Substation.

Analysis: Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In developing the scope for the Cloquet Substation Modernization Project, Minnesota Power is considering the near-term and long-term needs of the area transmission and distribution system as well as the age and condition of existing site infrastructure and modern design standards for safety, accessibility, and maintainability.

Schedule: The project is currently planned as a multi-year project with construction taking place in stages from 2027-2028 to manage outage and constructability constraints.

General Impacts: The Cloquet Substation Modernization Project will ensure a continuous and reliable power supply to the Cloquet area by replacing aging equipment before it fails.

Boswell 115/23 kV Transformer Addition

Formerly "West Cohasset Substation"

MPUC Tracking Number: 2021-NE-N17

Utility: Minnesota Power (MP)

Project Description: Boswell 115/23 kV Transformer Addition Project involves adding a new 115/23 kV transformer at the Boswell 230/115 kV Substation and extending new 23 kV feeders from the substation.

Need Driver: The Boswell 115/23 kV Transformer Addition Project is necessary to upgrade the reliability and capacity of the existing 23 kV distribution system in the Cohasset area.

Alternatives:
Transmission Alternatives

> Alternatives would be to install the new transformer at the nearby Boswell SES 115 kV Substation or to rebuild the Lind-Greenway Substation for increased capacity as well as upgrading the feeder tie between Lind-Greenway and Zemple substations to facilitate better backup capability.

Non-Wires Alternatives

> Non-wire alternatives must be available when needed and dispatchable to support reliable load-serving under normal and contingency conditions.

Analysis: The Boswell 115/23 kV Transformer Project will enhance the reliability and capacity of the existing Minnesota Power 23 kV distribution system in the Cohasset area by improving backup capability between distribution sources and increasing reliable load-serving capacity in the area.

Schedule: The project is scheduled to be in service by the end of 2026.

General Impacts: The Boswell 115/23 kV Transformer Addition Project will make optimal use of an existing substation site to preserve and enhance the reliability of the Cohasset-area distribution system. Since the Boswell 230/115 kV Substation was originally designed to accommodate future expansion, including a transmission-distribution transformer, the majority of impacts from the substation expansion part of the project will be contained within the existing substation yard, minimizing human and environmental impacts.

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56 Line Upgrade

MPUC Tracking Number: 2021-NE-N19

Utility: Minnesota Power (MP)

Project Description: Rebuild the existing Colbyville-Ridgeview 115 kV Transmission Line (56 Line) and increase its ratings.

Need Driver: Post-contingent overloads under certain system conditions identified in the MTEP analysis, as well as age and condition of existing structures and hardware.

Alternatives:

Transmission Alternatives

Reconductor existing line, build new parallel line.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission system in the area.

Analysis: This issue has been identified in MTEP and in Minnesota Power internal studies. The upgrade project provides the needed capacity increase as identified in the studies while also efficiently addressing asset renewal needs along the length of the line.

Schedule: The project is planned to be in service by end of year 2031.

General Impacts: The 56 Line Upgrade Project will provide necessary system improvements and asset renewal on Minnesota Power's 115 kV system without requiring the establishment of additional transmission line corridors. During construction, MP and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Riverton 230 kV STATCOM

MPUC Tracking Number: 2021-NE-N21

Utility: Minnesota Power (MP)

Project Description: The Riverton 230 kV STATCOM Project involves the establishment of a new +300 Mvar STATCOM at the existing Riverton 230 kV Substation.

Need Driver: The new Riverton STATCOM is needed to ensure a continuous and reliable source of steady state and dynamic voltage support during times when no large dispatchable generators are online in Northern Minnesota.

Alternatives:

Transmission Alternatives

> Must-run large dispatchable generators such as the Boswell Energy Center for reliability purposes. Retrofit one or more Boswell units with synchronous condenser capability.

Non-Wires Alternatives

> STATCOMs are a non-wire alternative. Other non-wire alternatives must be dispatchable to respond when called upon, able to provide sufficient magnitude, consistency, and availability of system support, and located at an effective location to replace the support previously provided by baseload generators.

Analysis: The Boswell Energy Center units are the last remaining baseload generators operating in Northern Minnesota. As the last remaining baseload generators, the Boswell units provide voltage support and system strength on a continuous basis that support consistent and predictable system operations and properly function protection systems for the transmission system and the lower-voltage distribution systems that depend on it. In addition, Minnesota Power's significant concentration of large industrial customers depend on predictable voltages and fault currents historically and presently provided by the Boswell units to support their large industrial processes and power quality needs. It is typical for large industrial plant design, like utility distribution system design, to take into account as a design basis the fault current contributions and normal operating voltages of the utility transmission system. Without the Boswell units online, the Northern Minnesota transmission system would operate for extended periods of time without any local generators online to provide fault current and voltage regulation. This mode of operation would be unprecedented in the modern history of the Northern Minnesota transmission system and, if not adequately assessed and mitigated, would lead to a great deal of uncertainty and potential degraded operation in the transmission system and lower-voltage industrial, municipal and Minnesota Power distribution system connected to it.

As Minnesota Power has continued to evaluate the issue and potential solutions, studies have consistently demonstrated significant degradation of steady state and dynamic voltage regulation when the Boswell units are offline. Less predictable steady state voltages, lower transient voltage dips during and after fault events, slower transient voltage recovery after fault events, and greater susceptibility to impacts from far-away regional fault events have all been identified as concerns on Minnesota Power's system and propagating out on the regional 230 kV system. To address these concerns, a voltage support solution is needed to provide a continuous, predictable, and redundant source of steady state voltage regulation and dynamic voltage response on Minnesota Power's 230 kV system. Based on Minnesota Power's analysis and experience, a STATCOM is the ideal solution for meeting these steady state and dynamic voltage support needs. STATCOMs require no fuel for continuous operation and produce only reactive power. STATCOMs are capable of providing voltage regulation during normal system operations as well as dynamic voltage response during system disturbances. STATCOMs also provide inherently faster voltage response compared with Synchronous Condensers and are less maintenance intensive.

Minnesota Power conducted a study to identify the size and location that maximize the STATCOM benefits to the system. Based on this analysis, it was determined that a +300 (capacitive)/-300 (inductive) Mvar STATCOM located at the existing Riverton 230/115 kV Substation would provide the most benefit to the system in the form of steady-state and dynamic voltage support.

Schedule: Minnesota Power is presently working with the chosen STATCOM supplier to engineer, procure, and construct the ±300 Mvar STATCOM at the Riverton 230 kV Substation. Minnesota Power anticipates placing the Riverton STATCOM in service in mid-2028.

General Impacts: The establishment of one or more STATCOMs on Minnesota Power's transmission system will provide necessary voltage support for Minnesota Power's customers during times when no large dispatchable generators are online in Northern Minnesota. To the extent possible, new STATCOMs will be located at existing substation facilities. In addition to making optimal use of existing facilities, the establishment of one or more STATCOMs enables the transmission system to continue to operate reliably and predictably during and after changes in operation at the Boswell Energy Center that have social, environmental, and economic benefits. As a result, this project was initiated to install a ±300 Mvar STATCOM at the existing Riverton 230 kV Substation, which is centrally located in a historically weaker area of the Minnesota Power backbone 230 kV network to provide continuous steady-state and dynamic voltage support historically provided by baseload coal generators, such as the Boswell Energy Center. The Riverton STATCOM project will make optimal use of an existing substation site (Riverton) that was designed for future expansion, and the project will take place almost entirely on property already owned by Minnesota Power.

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13 Line Rebuild

MPUC Tracking Number: 2021-NE-N23

Utility: Minnesota Power (MP)

Project Description: The 13 Line Rebuild Project involves replacement of transmission line structures and conductor on the Portage Lake – Riverton 115 kV Line (13 Line) due to age and condition. The project will also include the addition of shield wire and fiber-optic communications on the rebuilt transmission line.

Need Driver: The project will address asset renewal needs on 13 Line related to the age and condition of existing structures and transmission line components, add shield wire to improve reliability by reducing lightning-related outages that directly impact Minnesota Power and Great River Energy customers, and add fiber-optic communications to enhance transmission line protection systems.

Alternatives:

Transmission Alternatives

There are no reasonable alternatives that will address the asset renewal needs for the existing transmission line.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the existing transmission line.

Analysis: Across Minnesota Power's system there are many transmission lines that require age and condition-related upgrades. Many of the original wood pole structures and components on these transmission lines are nearing or beyond the end of their useful lives. As these transmission lines continue to age, the risk of structure and component failures – and therefore the risk of outages, property damage, and safety concerns – will increase. Minnesota Power's Transmission Line Asset Renewal Program involves identification, prioritization, and coordination of transmission line asset renewal projects to address end-of-life wood poles and other components while holistically considering long-term reliability, capacity, and communications needs. The program is designed to extend the lives of these transmission lines so they can continue to reliably serve Minnesota Power's customers and the region for many decades to come. In developing the scope for the 13 Line Rebuild Project, Minnesota Power also took into consideration reasonable enhancements that could be incorporated to improve operational performance and relaying for 13 Line.

Schedule: The 13 Line Rebuild Project is in early stages of project scoping and is presently targeted for phased construction beginning at the earliest in 2029. In reviewing the existing 13 Line and 158 Line (see Project 2023-NE-N6) transmission line corridor, Minnesota Power determined it would be prudent and necessary to file a Certificate of Need and Route Permit Application for the projects. Minnesota Power expects to file the application with the Commission in 2026.

General Impacts: The 13 Line Rebuild Project will ensure that the existing Portage Lake – Riverton 115 kV Line continues to provide a safe and reliable transmission path for Minnesota Power and Great River Energy's customers and the region. The project involves replacement of existing assets on the existing transmission line right-of-way, therefore making optimal use of the existing transmission facilities with little or no additional human or environmental impacts.

Northland Reliability Project

MPUC Tracking Number: 2023-NE-N1

Utility: Minnesota Power (MP) & Great River Energy (GRE)

Project Description: Minnesota Power (MP) and Great River Energy (GRE) are jointly developing the Northland Reliability Project (Project), located in northern and central Minnesota. The Project consists of two major segments of transmission line construction:

1) Segment 1: construction of a new, approximately 140-mile long, double-circuit 345 kV transmission line connecting the existing Iron Range 500-230 kV Substation, a new Cuyuna 345 kV Series Compensation Station, and the existing Benton County 345 kV Substation, generally located near existing transmission line corridors; and
2) Segment 2: replacement of two existing 345 kV transmission lines
   a. Replace an approximately 20-mile 230 kV line with two 345 kV circuits from the Benton County Substation to the new Big Oaks Substation along existing transmission corridors on double-circuit 345 kV structures. Approximately 6 miles of this double circuit line will have 69 kV underbuild; and
   b. Replace an approximately 20-mile 345 kV line from the Benton County Substation to the existing Sherco Substation along existing transmission corridors using double-circuit capable 345 kV structures. Approximately 4 miles of this double circuit line will have a 69 kV circuit.

The Project will also involve the following new or modified substation and series compensation facilities:

- Expansion of the existing Iron Range Substation 500-230 kV Substation, located near Grand Rapids, Minnesota, to include new 500-345 kV transformers, 345 kV bus and breakers, and 345 kV bus-connected shunt reactors
- Construction of a new Cuyuna 345 kV Series Compensation Station located near Riverton, Minnesota, approximately at the midpoint of Segment 1
- Expansion of the existing Benton County 345 kV Substation, located near St. Cloud, Minnesota, to include new 345 kV bus and breakers, and 345 kV bus connected shunt reactors

The proposed Big Oaks 345 kV Substation on the south end of Segment 2 is being permitted, engineered, and constructed by Xcel Energy as part of a separate project, and is not included in this scope of work.

Following the Commission’s route permit decision in February 2025, several underlying system improvements along the final Project route have also been incorporated into the scope of the Project. These underlying system improvements are necessary to maximize the extent to which the new double-circuit 345 kV transmission line can be co-located with and, in some cases, overtake existing rights-of-way. In many cases, the underlying system improvements involve replacement of existing assets that are nearing the end of their useful life, bringing additional asset renewal benefits into the Project. Major underlying system improvements involving the Riverton 230/115 kV Substation, Riverton 115/34 kV Substation, and associated 230 kV, 115 kV, 69 kV, and 34 kV lines are now planned as part of the Northland Reliability Project, along with rebuilding significant segments of the existing Blackberry – Riverton 230 kV Line, Grand Rapids – Riverton 115 kV Line, Riverton – Mud Lake 230 kV Line, and Benton County – Mud Lake 230 kV Line.

Need Driver: The Northland Reliability Project resolves regional reliability constraints resulting from the transition from fossil-fueled baseload generation to renewable energy generators, optimizes the ability to move power from one area to another, and contributes to significant regional transmission benefits associated with the MISO LRTP Tranche 1 portfolio. The Project is a foundational component of positioning the power system in northern Minnesota and the surrounding region for the clean energy transition, and it addresses some of the most challenging transmission system reliability issues from ceasing coal-fired operations and transitioning the baseload generator fleet, including serious regional voltage and transient stability issues. The Project was studied, reviewed, and ultimately approved as part of the MISO Long-Range Transmission Plan (LRTP) Tranche 1 Portfolio by MISO's Board of Directors in July 2022.

Alternatives:
Transmission Alternatives

Transmission system alternatives are addressed in the Certificate of Need Application

Non-Wires Alternatives

Non-Wire Alternatives are addressed in the Certificate of Need Application.

Analysis: The need for the Northland Reliability Project and the benefits of the Project, as summarized in the Certificate of Need Application, are as follows:

- The Project addresses severe regional voltage stability constraints associated with baseload generator fleet transition that have been identified in a multitude of studies over the course of the last decade. Without the Project, coal-fired baseload generation in northern Minnesota may need to continue operating to prevent significant reliability impacts from voltage stability constraints, including the need to potentially reduce northern Minnesota load by up to 1,000 megawatts ("MW") in some cases.
- The Project addresses significant transient stability constraints associated with baseload generator fleet transition and contributes to improved transient stability performance of the regional grid.
- The Project addresses transmission line overloads related to baseload generator fleet transition. In the Applicants' analysis, the Project relieves transmission line overloads on 83 circuits totaling 1,334 miles.
- MISO identified that the Project is both a critical component of the regionally-beneficial LRTP Tranche 1 Portfolio and the most cost-effective solution to maintain reliability in central and northern Minnesota following the cessation of coal-fired operations at legacy fossil fuel units.

The Project provides many additional benefits to Minnesota Power's customers and Great River Energy's members, as well as the regional power system, including beneficial impacts on regional transfer capability, expected economic benefits in the energy market, resiliency and transmission source reliability, and future flexibility and electrification.

Schedule: The project is planned to be in service by June 1, 2030. Following the Commission's February 2025 decision to grant a Certificate of Need and Route Permit for the Project, construction on the first segment of the Project began in the third quarter of 2025.

General Impacts: The project will be constructed along the existing 230 kV transmission line from the Iron Range substation to the Benton County substation, with additional construction along the existing 230 kV transmission line from the Benton County substation to the Monticello substation, terminating at the new Big Oaks substation, and construction along the existing 345 kV transmission line from the Benton County substation to the Sherco substation. The project is located in both forested and agricultural lands across its length. Construction is expected to be completed over 3 years. During this time, MP/GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Maturi Substation Expansion

MPUC Tracking Number: 2023-NE-N4

Utility: Minnesota Power (MP)

Project Description: Expanding the existing Maturi 115/23 kV Substation to accommodate new 23 kV lines to serve local MP distribution loads, and replacing the existing tapped configuration with a more reliable breakered configuration by looping the transmission line in and out of the substation..

Need Driver: The Maturi Substation serves Minnesota Power customers in the Chisholm area and east of Hibbing. The primary need driver for the Maturi Substation Expansion project is to establish a closer source with added redundancy for distribution customers in and around the City of Chisholm and the surrounding area, and to unload adjacent 115/23 kV substations in anticipation of planned substation modernization projects.

Alternatives:

Transmission Alternatives

Establish a new 115/23 kV substation near Chisholm

Non-Wires Alternatives

Install new distribution-connected generation on the Chisholm area 23 kV system. Non-wire alternatives must be available when needed, dispatchable to support reliable load-serving under contingency conditions and have an output characteristic sufficient to reduce the effective peak load in the area.

Analysis: The 23 kV system in the Chisholm area is currently served by a long 23 kV feeder from the Hibbing Substation, with a backup source on an even longer feeder from the Virginia Substation. Both of these substations are scheduled for modernization projects as part of Minnesota Power's asset renewal program. Moving the Chisholm area to a closer source from the nearby Maturi Substation will improve reliability and resiliency of the local 23 kV system, enhance redundancy and load-serving capacity for Maturi, Hibbing, and Virginia, and enable reliable construction of the planned modernization projects at the adjacent substations.

Schedule: The project is planned to be in service by end of year 2026.

General Impacts: The Maturi Expansion Project will ensure a continuous and reliable power supply to the City of Chisholm and the surrounding area. Since the Maturi Substation was designed originally to accommodate two distribution transformers, the majority of impacts from the substation modifications will be contained within the existing Maturi Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts. The project also involves looping 25 Line in and out of the substation on the existing transmission line right-of-way, therefore making optimal use of the existing transmission line with little or no additional human or environmental impacts.

Mahtowa Substation Expansion

MPUC Tracking Number: 2023-NE-N5

Utility: Minnesota Power (MP)

Project Description: The Mahtowa Substation Expansion Project involves replacing aging electrical equipment, structures, and civil works at the existing Mahtowa 115/46 kV Substation as part of Minnesota Power's asset renewal program. The project also includes reliability improvements including expansion of the Mahtowa Substation and conversion of the low-side distribution voltage to 34.5 kV to facilitate reliable back-up connection to feeders in the Cloquet area as well as efficient operations and maintenance from a more standard distribution voltage. Mahtowa Substation is currently connected in a tapped configuration to the existing 26 Line that connects Thomson to Cromwell. This project will also include reconfiguring this connection into a more reliable breakered configuration, resulting in two different lines so that the Mahtowa substation is no longer a radial tap.

Need Driver: The Mahtowa Substation serves Minnesota Power customers along the Interstate 35 corridor between Cloquet and Hinckley. The primary need driver for the Mahtowa Substation Expansion Project is age and condition of the existing transformer and site infrastructure. Much of the original equipment in this substation is nearing or beyond the end of its useful life, including many of the structures and foundations. In addition to these asset renewal concerns, Minnesota Power has developed a program to convert the distribution system in the area from the non-standard 46 kV operating voltage to the standard 34.5 kV operating voltage, facilitating more reliable connections to adjacent sources and more efficient operations and maintenance from the standardized distribution network voltage. The voltage conversion will also enable implementation of a feeder automation project resulting in enhanced FLISR (fault location isolation and restoration) for the 34.5 kV feeder connection between Mahtowa and Cloquet.

Alternatives:

Transmission Alternatives

> There is no more economical or less impactful solution than replacing the existing substation the existing site.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Mahtowa Substation.

Analysis: Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In developing the scope for the Mahtowa Substation Expansion Project, Minnesota Power is considering the near-term and long-term needs of the area transmission and distribution system as well as the age and condition of existing site infrastructure and modern design standards for safety, accessibility, and maintainability, including conversion to a standard distribution voltage.

Schedule: The project is planned for construction starting in 2026 with a targeted in-service date in 2028.

General Impacts: The 115/23 kV transformer located at Mahtowa has reached its end of life and poses a reliability issue. This transformer and the 115/46 kV transformer also at this site will be replaced with a single 115/34 kV transformer. This will increase the reliability of this site, remove the last of the 23 kV voltage class in the Minnesota Power central area, and progress Minnesota Power's efforts to convert from the non-standard 46 kV voltage class to the standard 34.5 kV voltage class. This will help keep the distribution system consistent in the area for operation and maintenance and enhanced connections to adjacent sources. Second, this project will loop 26 Line in and out of the substation to remove Mahtowa as a radial tap. The project will make optimal use of existing infrastructure at the Mahtowa Substation site to reduce human and environmental impacts.

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158 Line Rebuild

MPUC Tracking Number: 2023-NE-N6

Utility: Minnesota Power (MP)

Project Description: The 158 Line Rebuild Project involves replacement of transmission line structures and conductor on the Portage Lake – Cromwell 115 kV Line ("158 Line") due to age and condition. The project will also include the addition of shield wire and fiber-optic communications on the rebuilt transmission line.

Need Driver: The project will address asset renewal needs on 158 Line related to the age and condition of existing structures and transmission line components, add shield wire to improve reliability by reducing lightning-related outages that directly impact Minnesota Power and Great River Energy customers, and add fiber-optic communications to enhance transmission line protection systems.

Alternatives:
Transmission Alternatives

There are no reasonable alternatives that will address the asset renewal needs for the existing transmission line.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the existing transmission line.

Analysis: Across Minnesota Power's system there are many transmission lines that require age and condition-related upgrades. Many of the original wood pole structures and components on these transmission lines are nearing or beyond the end of their useful lives. As these transmission lines continue to age, the risk of structure and component failures – and therefore the risk of outages, property damage, and safety concerns – will increase. Minnesota Power's Transmission Line Asset Renewal Program involves identification, prioritization, and coordination of transmission line asset renewal projects to address end-of-life wood poles and other components while holistically considering long-term reliability, capacity, and communications needs. The program is designed to extend the lives of these transmission lines so they can continue to reliably serve Minnesota Power's customers and the region for many decades to come. In developing the scope for the 158 Line Rebuild Project, Minnesota Power also took into consideration reasonable enhancements that could be incorporated to improve operational performance and relaying for 158 Line.

Schedule: The 158 Line Rebuild Project is in early stages of project scoping and is presently targeted for 1-2 years of phased construction beginning at the earliest in 2028. In reviewing the existing 13 Line (see Project 2021-NE-N23) and 158 Line transmission line corridor, Minnesota Power determined it would be prudent and necessary to file a combined Certificate of Need and Route Permit Application for the projects. Minnesota Power expects to file the application with the Commission in 2026.

General Impacts: The 158 Line Rebuild Project will ensure that the existing Portage Lake – Riverton 115 kV Line continues to provide a safe and reliable transmission path for Minnesota Power and Great River Energy's customers and the region. The project involves replacement of existing assets on the existing transmission line right-of-way, therefore making optimal use of the existing transmission facilities with little or no additional human or environmental impacts.

Arrowhead 115 kV Single Point of Failure

MPUC Tracking Number: 2023-NE-N7

Utility: Minnesota Power (MP)

Project Description: The scope of this project at the Arrowhead 115 kV Substation includes installing a new alarm for the DC battery in case of an open circuit, redundant control wiring where applicable to ensure redundant pathways, installing a redundant DC power supply, and any associated relay panel replacements.

Need Driver: The existing NERC TPL-001standard is a transmission planning requirement aimed at ensuring that the bulk electric system (BES) can operate reliably across a broad range of system conditions and faults. Within the standard, Category P5 focuses on the impacts of a contingency that results from the failure of a non-redundant component of a Protection System with delayed fault clearing. Through the annual MISO Transmission Expansion Plan (MTEP), it was determined that a Category P5 fault at the Arrowhead 115 kV Substation bus resulted in significant violations across the system. As a result, a project was initiated to address any non-redundant components in the Protection System at the Arrowhead 115 kV Substation.

Alternatives:
Transmission Alternatives

There would need to be significant existing transmission line rebuild to upgrade to a larger conductor that would mitigate all violations present after the Category P5 contingency.

Non-Wires Alternatives

The Category P5 contingency can only be mitigated by adding Protection System redundancy or upgrading affected transmission system components.

Analysis: Adding redundancy to the components of the Arrowhead 115 kV Protection System is a more cost-effective system resiliency solution compared to rebuilding transmission lines.

Schedule: The project is planned to be in service by end of year 2026.

General Impacts: This project will introduce redundant Protection System components at the Arrowhead 115 kV Substation. At the end of this project, the Arrowhead 115 kV P5 contingencies can be retired due to the redundant Protection System components at the site. The majority of impacts from the project will be contained within the existing Arrowhead 115 kV Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Forbes 115 kV Single Point of Failure

MPUC Tracking Number: 2023-NE-N8

Utility: Minnesota Power (MP)

Project Description: The scope of this project at the Forbes 115 kV Substation includes installing a new alarm for the DC battery in case of an open circuit, redundant control wiring where applicable to ensure redundant pathways, installing a redundant DC power supply, and any associated relay panel replacements.

Need Driver: The NERC TPL-001-5.1 standard is a transmission planning requirement aimed at ensuring that the bulk electric system (BES) can operate reliably across a broad range of system conditions and faults. Within the standard, Category P5 focuses on the impacts of a contingency that results from the failure of a non-redundant component of a Protection System with delayed fault clearing. Through the annual MISO Transmission Expansion Plan (MTEP), it was determined that a Category P5 fault at the Forbes 115 kV Substation bus resulted in significant violations across the system. As a result, a project was initiated to address any non-redundant components in the Protection System at the Forbes 115 kV Substation.

Alternatives:

Transmission Alternatives

There would need to be significant existing transmission line rebuild to upgrade to a larger conductor that would mitigate all violations present after the Category P5 contingency.

Non-Wires Alternatives

The Category P5 contingency can only be mitigated by adding Protection redundancy or upgrading affected transmission system components.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by end of year 2027.

General Impacts: This project will introduce Protection System components at the Forbes 115 kV Substation site. At the end of the project, the Forbes 115 kV P5 contingencies can be retired due to the redundant Protection System components monitoring at the site. The majority of impacts from the project will be contained within the existing Forbes 115 kV Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Ridgeview 115/34 kV Transformer Addition

MPUC Tracking Number: 2023-NE-N9

Utility: Minnesota Power (MP)

Project Description: Expanding the Ridgeview 115 kV Substation to add a new 115/34 kV transformer, establishing a new source to the local 34.5 kV distribution system.

Need Driver: Distribution reliability capacity, and backup capability, including reliability enhancements on the Duluth 34.5 kV distribution system.

Alternatives:

Transmission Alternatives

Establish a new 115/34 kV substation in Central Duluth or build additional 34.5 kV feeders from existing sources at Swan Lake Road and 15th Avenue West.

Non-Wires Alternatives

Install new distribution-connected generation on the Duluth-area 34.5 kV system. Non-wire alternatives must be available when needed, dispatchable to support reliable load-serving under contingency conditions and have an output characteristic sufficient to reduce the effective peak load in the area.

Analysis: The Duluth 34 kV distribution system has sources at the Swan Lake Road, 15th Avenue West, and LSPI substations, but the majority of the load is located near the midpoint of the 34 kV system in downtown Duluth and the medical district – relatively far from the existing Swan Lake Road and LSPI substation sources. The 34 kV system was originally developed due to the significant challenges associated with the development of additional transmission-distribution substations in central and downtown Duluth. The 34 kV system also provides enhanced reliability to critical loads such as the hospitals by placing them on a high-capacity backbone system with automated fault location, isolation, and system restoration (FLISR) implemented. As more load has transitioned onto the 34 kV system, backing up the entire system from either LSPI or Swan Lake Road has become more challenging due to the feeder distance from the sources to the load. Additional load growth following near-term expansion of one of the two major hospitals in the medical district will further impact backup capability for the Duluth 34 kV system. The 15th Avenue West source was recently established to address these concerns, but the loss of this source is already becoming a reliability concern when significant amounts of downtown-area load are served from the backup source at Swan Lake Road. The addition of a new 115/34 kV transformer at the Ridgeview Substation, which is located much closer to the main Duluth 34 kV system loads, and integration of the new source into the automated 34 kV feeder system will ensure that the Duluth 34 kV system continues to be a very reliable source with sufficient load-serving capability for critical loads in Duluth. The addition of the Ridgeview source will also enable additional stepdowns to be established on the 34 kV system, shifting load off the heavily-loaded 14 kV system, enhancing backup capability, and allowing for more reliable construction of substation modernization projects at the main 115/14 kV substations in the Duluth area.

Schedule: The project is planned to be in service by end of year 2027.

General Impacts: The Ridgeview Transformer Addition Project will preserve and enhance the reliability of the Duluth 34 kV distribution system. Since the Ridgeview Substation was designed originally to accommodate the transformer addition, the majority of impacts from the substation expansion part of the project will be contained within the existing Ridgeview Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Wrenshall Substation Modernization

MPUC Tracking Number: 2023-NE-N10

Utility: Minnesota Power (MP)

Project Description: The Wrenshall Substation Modernization Project involves replacing aging electrical equipment, structures, and civil works at the existing Wrenshall 115/14 kV Substation as part of Minnesota Power's asset renewal program. Multiple substation asset renewal needs will be combined with necessary distribution transformer upgrades to make up the core of this project. This work at the Wrenshall Substation was combined into one project in order to facilitate efficient coordination of engineering and construction.

Need Driver: The Wrenshall Substation serves Minnesota Power customers in the rural areas around Wrenshall and Carlton. The primary need driver for the Wrenshall Substation Modernization Project is age and condition of the existing transformer and site infrastructure, some of which is constructed on wood pole structures. Much of the original equipment in this substation is nearing or beyond the end of its useful life, including many of the structures and foundations. The modernization of the Wrenshall Substation will also result in improved reliability for customers in the area and position the substation to support feeder automation, stronger ties to adjacent distribution infrastructure, future load growth, and distributed energy resource integration.

Alternatives:

Transmission Alternatives

. There is no more economical or less impactful solution than replacing the existing substation on the existing site.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Wrenshall Substation.

Analysis: Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In developing the scope for the Wrenshall Substation Modernization Project, Minnesota Power is considering the near-term and long-term needs of the area transmission and distribution system as well as the age and condition of existing site infrastructure and modern design standards for safety, accessibility, and maintainability.

Schedule: The project is planned to be in service by end of year 2029.

General Impacts: This project will ensure a continuous and reliable power supply to the Wrenshall area by replacing old assets prior to failure. The project will make optimal use of the existing Wrenshall Substation site to reduce human and environmental impacts.

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133 Line Rebuild

MPUC Tracking Number: 2023-NE-N11

Utility: Minnesota Power (MP)

Project Description: Rebuild the existing Verndale – Wing River 115 kV Transmission Line (133 Line) and increase its ratings.

Need Driver: Post-contingent overloads under certain system conditions identified in the MTEP analysis, as well as age and condition of existing structures and hardware.

Alternatives:
Transmission Alternatives
Reconductor existing line, build new parallel line.
Non-Wires Alternatives
Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission system in the area..

Analysis: This issue has been identified in MTEP and in several Minnesota Power studies. The upgrade project provides the needed capacity increase as identified in the studies while also efficiently addressing asset renewal needs along the length of the line.

Schedule: The project is planned to be in service by end of year 2028.

General Impacts: The 133 Line Upgrade Project will provide necessary system improvements and asset renewal on Minnesota Power's 115 kV system without requiring the establishment of additional transmission line corridors. During construction, MP and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Maple River – Cuyuna 345 kV Project

LRTP Project #20

MPUC Tracking Number: 2025-NE-N1

Utility: Minnesota Power (MP), Otter Tail Power (OTP), and Great River Energy (GRE)

Project Description: Minnesota Power (MP), Otter Tail Power (OTP), and Great River Energy (GRE) are jointly developing the Maple River – Cuyuna 345 kV Project, located in northern Minnesota. The Project consists of the construction of a new, approximately 165-mile, single circuit 345 kV transmission line connecting the MP Cuyuna 345 kV Substation to the OTP Maple River 345 kV Substation in North Dakota. This single circuit transmission line will be built on double-circuit capable structures with both circuits strung and jumpered together to meet design requirements specified by MISO and provide a high-capacity, low-impedance west-to-east transmission corridor from eastern North Dakota through central/northern Minnesota. This Project will also involve modifications to the following existing substations:

- Expansion of the Cuyuna 345 kV Substation, located near Riverton, Minnesota, to include an additional 345 kV line exit and shunt reactor.

- Expansion of the Maple River Substation, located near Fargo, North Dakota, to include an additional 345 kV line exit and shunt reactor.

Need Driver: The Project was studied, reviewed, and ultimately approved as a part of the MISO Long-Range Transmission Plan (LRTP) Tranche 2.1 Portfolio by MISO's Board of Directors in December 2024. As a part of this larger portfolio, the Project will enhance the reliability of the local and regional transmission system as the way electricity is produced and is used changes, increase transmission system capacity to reliably deliver energy from where it is produced to where it is used, meet growing electrical demand, enhance resiliency during extreme weather events, and enable cost-effective regional energy transfers supporting economical grid operations.

Alternatives:
Transmission Alternatives
Transmission system alternatives will be addressed in the Certificate of Need Application.
Non-Wires Alternatives
Non-Wire Alternatives will be addressed in the Certificate of Need Application.

Analysis: The need for the Maple River – Cuyuna 345 kV Project and the benefits of the Project will be summarized in the Certificate of Need Application. The project resolves regional voltage and transient stability issues, relieves transmission line overloads, and mitigates low voltage violations, in addition to increasing regional transfer capability and local load-serving capability. It also enables additional generation interconnection and delivery capability and helps reduce energy curtailments by strengthening the transmission backbone and improving system flexibility.

Schedule: The Project is planned to be in service by June 1, 2033.

General Impacts: While the Project is still in the early stages of routing in Minnesota and North Dakota, it is anticipated that the new transmission line will largely follow existing utility corridors to minimize establishment of new rights-of-way and to help navigate the varying land use and space constraints throughout the Project area. MP, OTP, and GRE are taking into consideration all relevant human, environmental, and commercial interests in the area and actively engaging impacted stakeholders in routing and siting of the project. Construction is anticipated to take three to four years to complete. During this time, MP, OTP, and GRE and/or their contractors will be working in the area and will contribute positively to the local economy. The right-of-way will be restored following construction.

Iron Range – St. Louis County – Arrowhead 345 kV Project

LRTP Project #21

MPUC Tracking Number: 2025-NE-N2

Utility: Minnesota Power (MP), American Transmission Company (ATC)

Project Description: Minnesota Power (MP) and American Transmission Company (ATC) are jointly developing the Iron Range – St. Louis County – Arrowhead (ISA) Project, located in northern Minnesota. The Project consists of two major segments of transmission line construction:

1. Iron Range – St. Louis County 345 kV Line: construction of a new, approximately 63-mile, single circuit 345 kV transmission line connecting the MP Iron Range 345 kV Substation to the MP St. Louis County 345 kV Substation. This single circuit transmission line will be built on double-circuit capable structures.
2. St. Louis County – Arrowhead 345 kV Line: construction of a new, approximately 1-mile, double circuit 345 kV transmission line connecting the MP St. Louis County 345 kV Substation to the ATC Arrowhead 345 kV Substation.

This Project will also involve the following modified substation facilities:

- Expansion of the MP Iron Range 345 kV Substation, located near Grand Rapids, Minnesota, to include an additional 345 kV transmission line exit
- Expansion of the MP St. Louis County 345 kV Substation, located in Hermantown, Minnesota to include three additional 345 kV transmission line exits
- Expansion of the ATC Arrowhead 345 kV Substation, located in Hermantown, Minnesota, to include two additional 345 kV transmission line exits

Need Driver: The Project was studied, reviewed, and ultimately approved as a part of the MISO Long-Range Transmission Plan (LRTP) Tranche 2.1 Portfolio by MISO's Board of Directors in December 2024. As a part of this larger portfolio, the Project will enhance the reliability of the local and regional transmission system as the way electricity is produced and is used changes, increase transmission system capacity and regional transfer capability to reliably deliver energy from where it is produced to where it is used, meet growing electrical demand, enhance resiliency during extreme weather events, and enable cost-effective regional energy transfers supporting economical grid operations.

Alternatives:

Transmission Alternatives

Transmission system alternatives will be addressed in the Certificate of Need Application.

Non-Wires Alternatives

Non-Wire Alternatives will be addressed in the Certificate of Need Application.

Analysis: The need for the Iron Range – St. Louis County – Arrowhead 345 kV Project and the benefits of the Project will be summarized in the Certificate of Need Application. The project improves transmission system performance for regional voltage and transient stability issues, optimizes regional transfer capability, enhances transmission system resiliency and reliability, and increases local load-serving capability.

Schedule: The Project is currently planned to be in service by June 1, 2032.

General Impacts: While the project is still in the early stages of routing, it is anticipated that the new transmission line will largely follow or overtake existing utility corridors to minimize establishment of new rights-of-way and to help navigate the varying land use and space constraints throughout the project area. MP and ATC are taking into consideration all relevant human, environmental, and commercial interests in the area and actively engaging impacted stakeholders in routing and siting of the project. Construction is anticipated to take two to three years to complete. During this time, MP and ATC and/or their contractors will be working in the area and will contribute positively to the local economy. The right-of-way will be restored following construction.

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24 Line Rebuild

MPUC Tracking Number: 2025-NE-N3

Utility: Minnesota Power (MP)

Project Description: Rebuild the existing Verndale – Dog Lake 115 kV Transmission Line (24 Line) and increase its ratings.

Need Driver: Post-contingent overloads under certain system conditions identified in the MTEP analysis, as well as age and condition of existing structures and hardware.

Alternatives:
Transmission Alternatives

Reconductor existing line, build new parallel line.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission system in the area.

Analysis: This issue has been identified in MTEP and in several Minnesota Power studies. The upgrade project provides the needed capacity increase as identified in the studies while also efficiently addressing asset renewal needs along the length of the line.

Schedule: The project is planned to be in service by end of year 2029.

General Impacts: The 24 Line Upgrade Project will provide necessary system improvements and asset renewal on Minnesota Power's 115 kV system without requiring the establishment of additional transmission line corridors. During construction, MP and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Arrowhead 230 kV EEE Replacement

MPUC Tracking Number: 2025-NE-N4

Utility: Minnesota Power (MP)

Project Description: The Arrowhead 230 kV EEE Replacement Project will replace the existing 230 kV EEE due to age and condition and includes improvements to mitigate potential single points of failure in the control and protection infrastructure of the Arrowhead 230 kV Substation. These improvements will include installing redundant control wiring where applicable to ensure redundant pathways, installing a redundant DC power supply, relay panel replacements, new cable trench, and making space for future projects panels that would not fit into the old EEE.

Need Driver: The existing NERC TPL-001-5.1 standard is a transmission planning requirement aimed at ensuring that the bulk electric system (BES) can operate reliably across a broad range of system conditions and faults. Within the standard, Category P5 focuses on the impacts of a contingency that results from the failure of a non-redundant component of a Protection System with delayed fault clearing. Through the annual MISO Transmission Expansion Plan (MTEP), it was determined that a Category P5 fault located at the Arrowhead 230 kV Substation bus resulted in significant violations across the system. As a result, a project was initiated to address any non-redundant components in the Protection System at the Arrowhead 230 kV Substation. The existing Arrowhead 230 kV building is also reaching its end-of-life and is experiencing issues with wildlife chewing circuitry cables.

Alternatives:

Transmission Alternatives

> There would need to be significant existing transmission line rebuilds to upgrade to a larger conductor that would mitigate all violations present after the Category P5 contingency. A transmission alternative would also not address the age and condition need of the EEE building, which is reaching its end-of-life and is experiencing issues with wildlife management.

Non-Wires Alternatives

> The Category P5 contingency can only be mitigated by adding Protection System redundancy or upgrading affected transmission system components.

Analysis: Adding redundancy to the components of the Arrowhead 230 kV Protection System is a more cost-effective system resiliency solution compared to rebuilding transmission lines or building new transmission lines.

Schedule: The project is planned to be constructed in 2026 – 2027.The new EEE will be placed in service by the end of the year 2027. Between 2027-2029, among other projects occurring at the Arrowhead 230 kV Substation, panels will be cut over from the old EEE to the new EEE and the old EEE building will be demolished in 2029.

General Impacts: This project will introduce redundant Protection System components at the Arrowhead 230 kV Substation and address the age and condition concerns for the Arrowhead 230 kV EEE building. At the end of the project, the Arrowhead 230 kV P5 contingencies can be retired due to the redundant Protection System components at the site. The majority of impacts from the project will be contained within or immediately adjacent to the existing Arrowhead 230 kV

Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Transmission Line Pole Replacement 2025

MPUC Tracking Number: 2025-NE-N5

Utility: Minnesota Power (MP)

Project Description: This project will replace or modify wood pole transmission structures on 53 existing transmission lines across the Minnesota Power footprint. Where possible, C-Trusses will be added to the structures to stabilize minor issues, otherwise full pole or structure replacements are anticipated.

Need Driver: Through routine groundline inspections of the transmission lines, wood pole structures were identified as in need of repair or replacement due to age or condition.

Alternatives:

Transmission Alternatives

There is no more economical or less impactful solution than replacing the existing wood poles on the existing transmission lines.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission system in the area.

Analysis: Across Minnesota Power's system there are many transmission lines that require age and condition-related upgrades. Many of the original wood pole structures and components on these transmission lines are nearing or beyond the end of their useful lives. As these transmission lines continue to age, the risk of structure and component failures – and therefore the risk of outages, property damage, and safety concerns – will increase. Minnesota Power's Transmission Line Asset Renewal Program involves identification, prioritization, and coordination of transmission line asset renewal projects to address end-of-life wood poles and other components while holistically considering long-term reliability, capacity, and communications needs. The program is designed to extend the lives of these transmission lines so they can continue to reliably serve Minnesota Power's customers and the region for many decades to come. In developing the pole replacement program, Minnesota Power has taken into consideration the condition of wood poles based on field surveys, as well as the near-term and long-term needs for the transmission lines involved, targeting the highest-priority pole replacements for continued safe and reliable operation of the transmission lines.

Schedule: This project is targeted for completion by the end of the year 2025.

General Impacts: This project will enhance the safety and reliability of the transmission system by replacing or stabilizing aging and damaged structures across northeastern Minnesota. The project involves replacement of existing assets on the existing transmission line right-of-way, therefore making optimal use of the existing transmission facilities with little or no additional human or environmental impacts.

Iron Range 500 kV Reactor Addition

MPUC Tracking Number: 2025-NE-N6

Utility: Minnesota Power (MP)

Project Description: This project will add a third line-connected 150 MVAR reactor at the Iron Range 500 kV Substation. This will add a redundant reactor to the substation to allow for better voltage control during routine maintenance and extend the life of the existing reactors.

Need Driver: During circumstances where one reactor is out of service, operation of the 500 kV system with a single reactor may put stress on the remaining reactor under some conditions where system voltages are higher, leading to accelerated aging of the reactor. The addition of the third reactor ensures two reactors will be available, even when one of the reactors at the station is unavailable, and provides a spare in case of a reactor failure.

Alternatives:

Transmission Alternatives

This is an asset renewal issue to ensure optimal life cycle aging of the existing 500 kV reactors at the site and provide redundancy in case of a failure. Other voltage control solutions such as STATCOMs are significantly more expensive.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to the accelerated ageing, redundancy and reliability of critical transmission assets.

Analysis: Shunt reactors are installed at the Iron Range 500 kV Substation to control 500 kV system voltages during light loading conditions and to enable safe and reliable energization of the transmission line. When in service, the reactors absorb reactive power, helping to reduce the system voltage during times of high voltage. Very high voltages can cause the reactors to operate near their design limits, particularly when they occur during moderate to high ambient temperatures, causing heating and potentially reducing the useful life of the reactors. This accelerated aging can lead to premature failures. In the event of a reactor failure, the remaining reactor would see significant stress until a replacement can be installed, potentially subjecting that reactor to earlier failure as well. To limit loss of life and provide needed redundancy, the addition of a third reactor will ensure that two reactors are available practically at all times and reduce the stress placed on the existing reactors during high voltage system conditions.

Schedule: This project is planned to be in service by the end of the year 2030.

General Impacts: This project will increase reliability of the system by allowing for better voltage control during maintenance activities or unplanned outages while also enhancing the lifespan of the existing reactors. The majority of impacts from the project will be contained within or immediately adjacent to the existing Iron Range 500 kV Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Shannon Capacitor Bank Replacement

MPUC Tracking Number: 2025-NE-N7

Utility: Minnesota Power (MP)

Project Description: The 115 kV capacitor bank located on the Shannon 115 kV bus will be replaced with a new standard-sized capacitor bank and relocated for safer and easier access to maintenance crews to access. The two capacitor banks on the Shannon 230 kV bus will also be replaced due to their age with standardized capacitor bank size and configurations.

Need Driver: The capacitor bank located on the Shannon 115 kV Substation is over 50 years old, has been progressively failing, and is located in a spot that is difficult for maintenance crews to replace failed cans. Additionally, all three capacitor banks located at the Shannon Substation, one on the 115 kV and two on the 230 kV, are of a type and size that is no longer a standard for Minnesota Power. Because of the age of all three capacitor banks, and the actively failing Shannon 115 kV capacitor bank, all three need to be replaced in order to maintain reliable transmission voltage support.

Alternatives:
<u>Transmission Alternatives</u>

> There are no transmission alternatives to replacing the aging and non-MP standard assets at the existing Shannon 230/115 kV Substation.

<u>Non-Wires Alternatives</u>

> Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission assets in the area.

Analysis: Across Minnesota Power's system there are many transmission substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. At the Shannon 230/115 kV Substation, routine inspections identified failing components in the existing 230 kV and 115 kV capacitor banks. This project will replace these aging assets with new, standard equipment to prolong the life of the assets, strengthen reliability, and resolve maintenance concerns.

Schedule: This project is planned to be in service by the end of the year 2026.

General Impacts: This project will replace aging transmission assets to ensure continuous and reliable voltage support. The impacts of the project will be entirely contained within the existing Shannon Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

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26 Line Rebuild

MPUC Tracking Number: 2025-NE-N8

Utility: Minnesota Power (MP)

Project Description: The 26 Line Rebuild Project involves replacement of transmission line structures and conductor on the Thomson – Mahtowa - Cromwell 115 kV Line (26 Line) due to age and condition. The project will also include the addition of shield wire and fiber-optic communications on the rebuilt transmission line.

Need Driver: The project will address asset renewal needs on 26 Line related to the age and condition of existing structures and transmission line components, add shield wire to improve reliability by reducing lightning-related outages that directly impact Minnesota Power and Great River Energy customers, and add fiber-optic communications to enhance transmission line protection systems.

Alternatives:
Transmission Alternatives
> There are no reasonable alternatives that will address the asset renewal needs for the existing transmission line.

Non-Wires Alternatives
> Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission system in the area.

Analysis: Across Minnesota Power's system there are many transmission lines that require age and condition-related upgrades. Many of the original wood pole structures and components on these transmission lines are nearing or beyond the end of their useful lives. As these transmission lines continue to age, the risk of structure and component failures – and therefore the risk of outages, property damage, and safety concerns – will increase. Minnesota Power's Transmission Line Asset Renewal Program involves identification, prioritization, and coordination of transmission line asset renewal projects to address end-of-life wood poles and other components while holistically considering long-term reliability, capacity, and communications needs. The program is designed to extend the lives of these transmission lines so they can continue to reliably serve Minnesota Power's customers and the region for many decades to come. In developing the scope for the 26 Line Rebuild Project, Minnesota Power also took into consideration reasonable enhancements that could be incorporated to improve operational performance and relaying for 26 Line.

Schedule: The 26 Line Rebuild Project is in early stages of project scoping and is presently targeted for 3-4 years of phased construction beginning at the earliest in 2030.

General Impacts: The 26 Line Rebuild Project will ensure that the existing Thomson – Mahtowa – Cromwell 115 kV Line continues to provide a safe and reliable transmission path for Minnesota Power and Great River Energy's customers and the region. The project involves replacement of existing assets on the existing transmission line right-of-way, therefore making optimal use of the existing transmission facilities with little or no additional human or environmental impacts.

Haines Road Substation Modernization

MPUC Tracking Number: 2025-NE-N9

Utility: Minnesota Power (MP)

Project Description: The Haines Substation Modernization Project involves replacing aging electrical equipment, structures, and civil works at the existing Haines Road 115/14 kV Substation as part of Minnesota Power's asset renewal program. Multiple substation asset renewal needs will be combined with necessary distribution transformer upgrades to make up the core of this project. This work at the Haines Road Substation was combined into one project to facilitate efficient coordination of engineering and construction.

Need Driver: The Haines Road Substation serves the central part of Duluth, including the Miller Hill Mall, as well as Hermantown and the surrounding area. The primary need driver for the Haines Road Substation Modernization Project is age and condition of existing transformers, circuit breakers, disconnect switches, switchgear, and site infrastructure. Much of the original equipment in this substation is nearing or beyond the end of its useful life, including many of the structures and foundations.

Alternatives:
<u>Transmission Alternatives</u>

(None)

<u>Non-Wires Alternatives</u>

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission and distribution system in the area.

Analysis: Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In developing the scope for the Haines Road Substation Modernization Project, Minnesota Power is considering the near-term and long-term needs of the area transmission and distribution system as well as the age and condition of existing site infrastructure and modern design standards for safety, accessibility, and maintainability.

Schedule: This project is planned to be in service by the end of 2029.

General Impacts: This project will ensure a continuous and reliable power supply to the Haines Road area in Duluth by replacing old assets prior to failure. At present, it is expected that the impacts will be entirely contained within or adjacent to the existing Haines Road Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

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180 Line Rebuild

MPUC Tracking Number: 2025-NE-N10

Utility: Minnesota Power (MP)

Project Description: Increase rating of Hibbing– Maturi 115 kV Line (180 Line). The project also includes rebuild and reconductor of the transmission line to address age and condition issues.

Need Driver: Post-contingent overloads under higher transfer scenarios and multiple-circuit contingency events, as well as age and condition of existing 180 Line structures and hardware.

Alternatives:

Transmission Alternatives

Reconductor existing line, build new parallel line.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission system in the area.

Analysis: This issue has been identified in MTEP and in several Minnesota Power studies. The upgrade project provides the needed capacity increase as identified in the studies while also efficiently addressing asset renewal needs along the length of the line.

Schedule: The project has been delayed to align with other asset renewal and substation modernization projects in the area. Minnesota Power is currently targeting a 2030 in-service date for the project.

General Impacts: The 180 Line Upgrade Project will provide necessary system improvements and asset renewal on Minnesota Power's 115 kV system without requiring the establishment of additional transmission line corridors. During construction, MP and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Hat Trick Substation Expansion

MPUC Tracking Number: 2025-NE-N11

Utility: Minnesota Power (MP)

Project Description: Expanding the existing Hat Trick 115/23 kV Substation to add a second 115/23 kV transformer and accommodate new 23 kV lines to serve local distribution loads.

Need Driver: The Hat Trick Substation serves Minnesota Power customers in the Eveleth area and south of Virginia. The primary need driver for the Hat Trick Substation Expansion project is establish a more reliable source for distribution customers in and around the City of Eveleth and the surrounding area, and to unload adjacent 115/23 kV substations in anticipation of planned substation modernization projects.

Alternatives:
Transmission Alternatives

Establish a new 115/230 kV substation near Eveleth

Non-Wires Alternatives

Install new distribution-connected generation on the Eveleth area 23 kV system. Non-wire alternatives must be available when needed, dispatchable to support reliable load-serving under contingency conditions, and have an output characteristic sufficient to reduce the effective peak load in the area.

Analysis: The 23 kV system in the Eveleth area is currently by the Hat Trick Substation, with one feeder extending toward Virginia and one feeder extending toward the Laskin and Embarrass Substations in the direction of Hoyt Lakes. Both Virginia and Laskin are scheduled for modernization projects as part of Minnesota Power's asset renewal program, and the existing 46 kV feeder currently connected to Virginia is planned for conversion to 23 kV. Establishing a redundant transformer and additional 23 kV feeder connections from Hat Trick Substation will improve reliability and resiliency of the local 23 kV system, enhance load-serving capacity for the area between Eveleth and Hoyt Lakes, enable conversion of the non-standard 46 kV feeder to a standard 23 kV operating voltage, and enable reliable construction of the planned modernization projects at the adjacent substations.

Schedule: The project is currently planned to be in service by end of year 2028.

General Impacts: The Hat Trick Substation Expansion Project will ensure a continuous and reliable power supply to Eveleth and the surrounding area. Since the Hat Trick Substation was designed originally to accommodate two distribution transformers, the majority of impacts from the substation modifications will be contained within the existing Hat Trick Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Babbitt 115 kV Project

MPUC Tracking Number: 2025-NE-N12

Utility: Minnesota Power (MP)

Project Description: Extend a new 115 kV line from the Mesaba Junction Switching Station to the end of Minnesota Power's ownership of existing Embarrass – Babbitt 115 kV Line (137 Line), then loop 137 Line into and out of the Babbitt 115 kV Substation by extending new 115 kV line from the Babbitt Tap to the Babbitt Substation. Following establishment of this redundant connection, the existing segment of 137 Line between Embarrass and North Shore Mine will be rebuilt. At the Mesaba Junction Switching Station, a 115 kV line entrance will be constructed, including a circuit breaker and deadend structure, in an existing ring bus position at the substation. At the Babbitt Substation, the 115 kV bus will be expanded to accommodate an additional 115 kV line entrance.

Need Driver: Age and condition of existing 137 Line and redundancy of service to Babbitt-area customers served from 137 Line.

Alternatives:
Transmission Alternatives

Do nothing – ability to maintain the existing 137 Line is severely limited due to outages and doing nothing may lead to structure failures, which is not an acceptable solution.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission system in the area.

Analysis: The Babbitt 115 kV Project replaces the previously proposed Mesaba Junction 137 Line Project (2021-NE-N14) and 137 Line Rebuild Project (2021-NE-N15), updating and combining the original scope of the two projects into one holistic project. The original Mesaba Junction 137 Line Project became infeasible due to routing constraints in the area, necessitating that the route and scope of the planned improvements in the area be updated. The Babbitt 115 kV Project meets three critical needs for the Babbitt area:

1. Providing redundancy to an industrial load pocket that requires near-constant availability and to the local Babbitt area that is currently served by a single transmission source
2. Enabling asset renewal by allowing the existing 137 Line to be rebuilt
3. Improving reliability with two properly maintained 115 kV transmission sources to the area

With respect to the age and condition concerns on 137 Line, which are the primary drive for the project, rebuilding 137 Line is one of highest priority projects out of many transmission lines across the Minnesota Power system that require age and condition-related upgrades. Many of the original wood pole structures and components on these transmission lines are nearing or beyond the end of their useful lives. As these transmission lines continue to age, the risk of structure and component failures – and therefore the risk of outages, property damage, and safety concerns – will increase. Minnesota Power's Transmission Line Asset Renewal Program involves identification, prioritization, and coordination of transmission line asset renewal projects to address end-of-life wood poles and other components while holistically considering long-term reliability, capacity, and communications needs. The program is designed to extend the lives of these transmission lines so they can continue to reliably serve Minnesota Power's customers and the region for many decades to come.

Schedule: This project is currently being re-scoped and is planned to be in service by the end of 2030 with construction anticipated to start in 2027. Minnesota Power anticipates filing a Certificate of Need and Route Permit Application for the project in 2026.

General Impacts: The Babbitt 115 kV Project will preserve and enhance the reliable delivery of power to an important industrial load pocket and to a local area, the Babbitt area, that is currently served by a single transmission source. The project will also provide the opportunity to address significant age and condition and maintenance-related issues on the existing Embarrass – Babbitt 115 kV Line (137 Line). The project is anticipated to require more than 10 miles of new 115 kV transmission in a remote area of northern Minnesota that has been heavily impacted by historical mining operations, making routing of a new corridor challenging. While the project is still in the early stages of routing, it is anticipated that the new transmission line will follow or replace existing transmission line corridors to greatest reasonable extent to minimize establishment of new rights-of-way and to help navigate the varying land use and space constraints throughout the project area. Rebuilding the 137 Line as part of the project will ensure that the existing Embarrass – Babbitt 115 kV Line continues to provide a safe and reliable transmission path for Minnesota Power's customers. That part of the project also involves replacement of existing assets on the existing transmission line right-of-way, therefore making optimal use of the existing transmission line with little or no additional human or environmental impacts. During construction, MP and/or their contractors will be working in the area and will contribute positively to the local economy. The right-of-way will be restored following construction.

Transmission Line Pole Replacement 2026

MPUC Tracking Number: 2025-NE-N13

Utility: Minnesota Power (MP)

Project Description: This project will replace or modify wood pole transmission structures existing transmission lines across the Minnesota Power footprint. Where possible, C-Trusses will be added to the structures to stabilize minor issues, otherwise full pole or structure replacements are anticipated.

Need Driver: Through routine groundline inspections of the transmission lines, wood pole structures were identified as in need of repair or replacement due to age or condition.

Alternatives:

Transmission Alternatives

There is no more economical or less impactful solution than replacing the existing wood poles on the existing transmission lines.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission system in the area.

Analysis: Across Minnesota Power's system there are many transmission lines that require age and condition-related upgrades. Many of the original wood pole structures and components on these transmission lines are nearing or beyond the end of their useful lives. As these transmission lines continue to age, the risk of structure and component failures – and therefore the risk of outages, property damage, and safety concerns – will increase. Minnesota Power's Transmission Line Asset Renewal Program involves identification, prioritization, and coordination of transmission line asset renewal projects to address end-of-life wood poles and other components while holistically considering long-term reliability, capacity, and communications needs. The program is designed to extend the lives of these transmission lines so they can continue to reliably serve Minnesota Power's customers and the region for many decades to come. In developing the pole replacement program, Minnesota Power has taken into consideration the condition of wood poles based on field surveys, as well as the near-term and long-term needs for the transmission lines involved, targeting the highest-priority pole replacements for continued safe and reliable operation of the transmission lines.

Schedule: This project is targeted for completion by the end of the year 2026.

General Impacts: This project will enhance the safety and reliability of the transmission system by replacing or stabilizing aging and damaged structures across northeastern Minnesota. The project involves replacement of existing assets on the existing transmission line right-of-way, therefore making optimal use of the existing transmission facilities with little or no additional human or environmental impacts.

Transmission Line Pole Replacement 2027

MPUC Tracking Number: 2025-NE-N14

Utility: Minnesota Power (MP)

Project Description: This project will replace or modify wood pole transmission structures existing transmission lines across the Minnesota Power footprint. Where possible, C-Trusses will be added to the structures to stabilize minor issues, otherwise full pole or structure replacements are anticipated.

Need Driver: Through routine groundline inspections of the transmission lines, wood pole structures were identified as in need of repair or replacement due to age or condition.

Alternatives:

Transmission Alternatives

There is no more economical or less impactful solution than replacing the existing wood poles on the existing transmission lines.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission system in the area.

Analysis: Across Minnesota Power's system there are many transmission lines that require age and condition-related upgrades. Many of the original wood pole structures and components on these transmission lines are nearing or beyond the end of their useful lives. As these transmission lines continue to age, the risk of structure and component failures – and therefore the risk of outages, property damage, and safety concerns – will increase. Minnesota Power's Transmission Line Asset Renewal Program involves identification, prioritization, and coordination of transmission line asset renewal projects to address end-of-life wood poles and other components while holistically considering long-term reliability, capacity, and communications needs. The program is designed to extend the lives of these transmission lines so they can continue to reliably serve Minnesota Power's customers and the region for many decades to come. In developing the pole replacement program, Minnesota Power has taken into consideration the condition of wood poles based on field surveys, as well as the near-term and long-term needs for the transmission lines involved, targeting the highest-priority pole replacements for continued safe and reliable operation of the transmission lines.

Schedule: This project is targeted for completion by the end of the year 2027.

General Impacts: This project will enhance the safety and reliability of the transmission system by replacing or stabilizing aging and damaged structures across northeastern Minnesota. The project involves replacement of existing assets on the existing transmission line right-of-way, therefore making optimal use of the existing transmission facilities with little or no additional human or environmental impacts.

Brainerd Capacitor Bank Replacement

MPUC Tracking Number: 2025-NE-N15

Utility: Minnesota Power (MP)

Project Description: The 115 kV capacitor bank located on the Brainerd 115 kV bus will be replaced with a new standard-sized capacitor bank.

Need Driver: The capacitor bank located on the Brainerd 115 kV Substation is over 50 years old, has been progressively failing. Additionally, the capacitor bank is of a type and size that is no longer a standard for Minnesota Power. Because of the age and condition of the capacitor bank, it needs to be replaced in order to maintain reliable transmission voltage support.

Alternatives:

Transmission Alternatives

> There are no transmission alternatives to replacing the aging and non-MP standard assets at the existing Brainerd 115 kV Substation.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the transmission assets in the area.

Analysis: Across Minnesota Power's system there are many transmission substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. At the Brainerd 115 kV Substation, routine inspections identified failing components in the existing capacitor bank. This project will replace these aging assets with new, standard equipment to prolong the life of the assets, strengthen reliability, and resolve maintenance concerns.

Schedule: This project is planned to be in service by the end of the year 2027.

General Impacts: This project will replace aging transmission assets to ensure continuous and reliable voltage support. The impacts of the project will be entirely contained within the existing Brainerd Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Riverton to Mud Lake Temperature Upgrade Project

MPUC Tracking Number: 2025-NE-N16

Utility: Great River Energy (GRE)

Project Description: This project will raise the operating temperature of the line from 195 °F to 212 °F maximizing the full conductor rating of the transmission line via pole replacements.

Need Driver: The Riverton to Mud Lake transmission line facilitates bulk electric transfers. Raising the operating temperature of this line is needed to increase current carrying capacity of the transmission line, resulting in less congestion seen on the system.

Alternatives:
<u>Transmission Alternatives</u>

No transmission alternatives were considered since upgrading the temperature rating of an existing transmission line requires the least amount of transmission construction to take place.

<u>Non-Wires Alternatives</u>

The Riverton – Mud Lake 230 kV line is part of the Bulk Electric System (BES) and is needed to facilitate large power transfers through the region and can't be replaced by a non-wires alternative.

Analysis: Looking at a three-year window of time (2022 – 2024), the Mud Lake – Riverton 'MR' 230 kV line is causing congestion for 194 hours. For the same time period, the Benton County – Mud Lake 'MR' 230 kV line is causing congestion for 373 hours. Collectively, the Riverton-Mud Lake-Benton County path binds 567 hours. Very small changes in conditions can shift which segment binds first, masking the other. Therefore, it is practical to consider the congestion on this path collectively. This project upgrade is the most cost-effective way to add capacity and alleviate congestion.

Schedule: The project is planned to be in service by 2029.

General Impacts: This project will replace existing structures on existing right-of-way and will have almost no impact. The right-of-way will be restored following construction. No new landowners will be impacted by construction. No significant traffic impacts are anticipated.

LCP Peary Substation Rebuild

MPUC Tracking Number: 2025-NE-N17

Utility: Great River Energy (GRE)

Project Description: This project plans to rebuild the Peary substation by building a new Peary substation adjacent to the existing Peary substation.

Need Driver: The Peary substation is nearing the end of its useful life and needs to be rebuilt to continue serving reliable power.

Alternatives:
<u>Transmission Alternatives</u>

No transmission alternatives were considered due to Lake Country Power's need to retain a load serving point at the Peary interconnection.

<u>Non-Wires Alternatives</u>

Non-wires alternatives were not considered as it isn’t feasible for the Peary load serving substation to be replaced by a non-wires solutions.

Analysis:
The Peary rebuild project will replace old equipment to strengthen reliability to the Eveleth area loads served by Lake Country Power.

Schedule: The project is planned to be in service by October 2027.

General Impacts: The Peary rebuild will take place adjacent to the existing Peary substation. No new landowners will be impacted by construction. No significant traffic impacts are anticipated.

Iona 115 kV Conversion Project

MPUC Tracking Number: 2025-NE-N18

Utility: Great River Energy (GRE)

Project Description: This project will build a 0.5-mile, 115 kV tap line to interconnect the Iona substation to the 47 Line.

Need Driver: This project is needed to provide reliable electric service to the Iona Distribution Substation. The Iona Distribution Substation is currently served by a 34.5 kV system with approximately 3.5 miles of radial exposure. This 34.5kV system has poor reliability record and is inadequate for supporting dependable service. A nearby 115 kV transmission system, located just half a mile from the substation, offers superior reliability and greater capacity, making it a more suitable source to meet current service demands and support future economic development in the area.

Alternatives:
Transmission Alternatives

Upgrading the Iona Distribution Substation to connect with the nearby 115 kV transmission line was determined to be the most viable solution. The only alternative, continuing service from the existing 34.5 kV radial system, was not pursued further due to its poor reliability and limited capacity. No additional transmission alternatives were considered.

Non-Wires Alternatives

This project is focused on improving electric service reliability to the Iona Distribution Substation by interconnecting it to a nearby 115 kV transmission line. Because the project involves establishing a direct transmission connection to an existing delivery point, non-wires alternatives are not viable options.

Analysis: The Iona Distribution Substation upgrade project addresses a critical reliability issue stemming from its current service from the 34.5 kV system. The proposed solution, interconnecting the substation to a nearby 115 kV transmission line offers a substantial improvement in reliability and capacity in comparison to the 34.5 kV system.

Schedule: The project is planned to be in service by 2028.

General Impacts: The Iona project requires approximately 0.5 miles of new 115 kV high voltage transmission following County Road 84. The Project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the Project. The preliminary design follows existing road rights-of-way in order to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Heartland Lakes 115 kV Project

MPUC Tracking Number: 2025-NE-N19

Utility: Great River Energy (GRE)

Project Description: This project will build a new, 4.3-mile, 115 kV tap line to interconnect the Heartland Lakes substation which will be served by a breakered position from the Hubbard 115 kV bus.

Need Driver: The Heartland Lakes 115 kV Project is needed to unload Osage, Potato Lake, and RDO distribution substation and provide redundancy to the area, expanding backfeeding capability between substations. This project will serve growing load in the area and provide reliability and operational flexibility.

Alternatives:

Transmission Alternatives

> Transmission alternatives were not considered for this project, as they would not address the core need for establishing an additional delivery point to serve growing load in the area. While this need cannot be achieved through alternative transmission configurations, alternative routing options for the interconnecting transmission line will be evaluated as part of the permitting process.

Non-Wires Alternatives

> A new distribution substation is needed to reliably serve growing loads and to establish redundancy through sufficient backfeed capabilities. These needs cannot be met through non-wires alternatives. Therefore, non-wires options were not considered further for this project.

Analysis: Heartland Lakes will pick up load from the Osage, Potato Lake, and RDO load serving substations to alleviate transformer loading and provide a redundant source. The Heartland Lakes substation will help with forecasted load growth in the area and allow for better operational flexibility. This is a cost-effective way to provide more capacity and redundancy to the distribution system in this area.

Schedule: The project is planned to be in service by winter 2029.

General Impacts: The Heartland Lakes project requires approximately 4.3 miles of new 115 kV high voltage transmission following 129th Ave. The Project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the Project. The preliminary design follows existing road rights-of-way in order to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Boulder Lake 115 kV Project

MPUC Tracking Number: 2025-NE-N20

Utility: Great River Energy (GRE)

Project Description:
This project will build a 4.7-mile, 115 kV tap line to interconnect the Boulder Lake substation.

Need Driver: This project is needed to alleviate transformer loading at Itasca-Mantrap's Nevis, Long Lake, and Mantrap distribution substations. By establishing a new distribution substation, the project will support reliable service for growing load demands and enhance operational flexibility in the area.

Alternatives:
Transmission Alternatives

Transmission alternatives were not considered for this project as they would not address the core need for establishing an additional delivery point to serve growing load in the area. While this need cannot be achieved through alternative transmission configurations, alternative routing options for the interconnecting transmission line will be evaluated as part of the permitting process.

Non-Wires Alternatives

A new distribution substation is needed to reliably serve growing loads in the area. This need cannot be met through non-wires alternatives. Therefore, non-wires options were not considered further for this project.

Analysis: The Boulder Lake substation will help with forecasted load growth in the area and allow for better operational flexibility.

Schedule: The project is planned to be in service by 2030.

General Impacts: The Boulder Lake project requires approximately 4.8 miles of new 115 kV high voltage transmission following 209th Ave, 200th street, and 219th Ave. The Project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the Project. The preliminary design follows existing road rights-of-way in order to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right-of-way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Pillsbury Area Projects

MPUC Tracking Number: 2025-NE-N21

Utility: Great River Energy (GRE)

Project Description: The Pillsbury Project will build a 2.0-mile, 115 kV tap line to interconnect the existing Stearns Electric Association (SEA) Pillsbury distribution substation to the MP-owned 41 Line.

Need Driver: SEA plans to rebuild the Pillsbury Distribution Substation as an end-of-life replacement. While the primary goal is to address aging infrastructure and condition concerns, the project also presents an opportunity to enhance service reliability by upgrading from 34.5kV to 115kV. Transitioning to the 115kV system will support long-term reliable service, improve operational resilience, and provide capacity for future growth at the Pillsbury Distribution Substation

Alternatives:

<u>Transmission Alternatives</u>

> Upgrading the Pillsbury Distribution Substation to connect with the nearby 115 kV transmission line was identified as the most reliable solution. The only other option, continuing service via the existing 34.5 kV system was dismissed due to its limited capacity and need for improved reliability at Pillsbury. Given these constraints, no additional transmission alternatives were evaluated. However, alternative routing options for the new 115 kV transmission line will be explored during the routing and permitting phase of the project.

<u>Non-Wires Alternatives</u>

> This project aims to enhance electric service reliability at the Pillsbury Distribution Substation by transitioning from the existing 34.5 kV interconnection to a nearby 115 kV

transmission line. Since the project involves interconnecting a rebuilt distribution substation, non-wires alternatives were considered unsuitable and not pursued further.

Analysis: The Pillsbury Substation is one of SEA's distribution substations currently served by the 34.5 kV transmission system, which generally offers lower capacity and reliability compared to the 115 kV system. As the substation reaches the end of its service life, its replacement presents a strategic opportunity to enhance reliability and support future growth. Upgrading the substation to 115 kV standards and interconnecting it with a nearby 115 kV transmission line will significantly improve service performance and position the substation to effectively support economic development in the area for the long term.

Schedule: The project is planned to be in service by fall of 2027.

General Impacts: The Pillsbury project requires approximately 2.0 miles of new 115 kV high voltage transmission following County Road 105. The Project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the Project. The preliminary design follows existing road rights-of-way in order to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right-of-way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

6.4.2 Completed Projects

The table below identifies those projects by Tracking Number in the Northeast Zone that were listed as ongoing projects in the 2023 Biennial Report but have been completed or withdrawn since the 2023 Report was filed with the Minnesota Public Utilities Commission in November 2023. Information about each of the completed projects is summarized briefly in the table below. More information about these projects and inadequacies can be found in earlier reports. Projects that were listed as being complete in the 2023 Report are not repeated here, but more information about those projects can be found in these earlier reports.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2019-NE-N15	Portage Lake 115/69 kV Project	N/A	GRE	Completed in 2024
2021-NE-N11	Two Islands 115 kV Project	N/A	GRE	Completed in 2024
2021-NE-N27	Riverton - Wing River Storm Structures	N/A	GRE	Completed in 2024

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2015-NE-N2	Iron Range – Arrowhead 345 kV Line	N/A	MP	Withdrawn: Original project from 2014 replaced by Iron Range – St Louis County – Arrowhead 345 kV Project (2025-NE-N2)
2017-NE-N3	Little Falls Substation Modernization	N/A	MP	Withdrawn
2019-NE-N6	Long Prairie Substation Modernization	N/A	MP	Completed in 2023
2019-NE-N10	Babbitt Area 115 kV Project	N/A	MP	Withdrawn: Replaced by Babbitt 115 kV Project (2025-NE-N13)
2021-NE-N1	HVDC Line Hardening	N/A	MP	First Phase Completed in 2024 Subsequent Phases Placed on Hold Indefinitely
2021-NE-N6	15th Ave West 115/34kV Transformer	N/A	MP	Completed in 2024
2021-NE-N8	LSPI Cap Bank Asset Renewal	N/A	MP	Completed in 2024
2021-NE-N9	Canosia Road Substation 34 kV Expansion	N/A	MP	Completed in 2023
2021-NE-N14	Mesaba Junction 137 Line Extension	N/A	MP	Withdrawn: Replaced by Babbitt 115 kV Project (2025-NE-N13)
2021-NE-N15	137 Line Rebuild	N/A	MP	Withdrawn: Replaced by Babbitt 115 kV Project (2025-NE-N13)

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2021-NE-N20	105 & 106 Line Upgrade	N/A	MP	Completed in 2024
2021-NE-N22	126 Line Asset Renewal	N/A	MP	Completed in 2024
2023-NE-N2	40 Line Rebuild	N/A	MP	Completed in 2024
2023-NE-N3	Brainerd Crypto	N/A	MP	Withdrawn

6.5 West Central Zone

6.5.1 Needed Projects

The following table provides a list of transmission needs identified in the West Central Zone by MISO utilities. There were no projects identified in this zone by non-MISO utilities.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2015-WC-N3	Ortonville 115/41.6 kV Transformer	2015/B	4236	No	No	OTP
2021-WC-N6	Appleton – Benson 115 kV Line	2021/A	20148	Yes	No	GRE/OTP/ MRES
2021-WC-N8	Big Swan Ring Bus and Capacitor Bank Addition	2022/A	20165 23803	No	No	GRE
2023-WC-N2	Milbank, SD Area Upgrades	2023/A	25305	No	No	OTP
2023-WC-N3	Big Stone South – Alexandria – Big Oaks 345 kV	2021/A	23369	Yes	No	GRE, MP, MRES, OTP, XEL
2023-WC-N5	Willmar – Litchfield – Forest City – Hutchinson Rebuild and 115 kV Conversion	2026/A	50873 51094 51053	Yes	No	GRE, MRES, SMMPA
2023-WC-N11	Benton County Solar Farm (J1426)	2023/A	24285	No	No	GRE
2023-WC-N13	Alexandria Light and Power Southeast Substation	2023/A	24232	No	No	MRES

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2023-WC-N14	Alexandria Substation Expansion	2021/A	23369	Yes	No	MRES
2023-WC-N16	Benton County Terminal Upgrade	2024/A	25399	No	No	GRE
2025-WC-N1	Darnen Distribution Substation	2025/A	50587	No	No	GRE
2025-WC-N2	Kimball Area Projects	2023/A	23804	No	No	GRE
2025-WC-N3	Detroit Lakes Jet Substation	2018/A	13647	No	No	MRES
2025-WC-N4	Hutchinson Substation	2022/A	23346	No	No	MRES
2025-WC-N5	Priam Second Transformer and St John's Lake Breaker Station	2025/A	50483 / 50484	No	No	MRES
2025-WC-N6	Erie Road Substation Rebuild	2025/A	50464	No	No	MRES
2025-WC-N7	Bellingham 115 kV Delivery	2025/A	50510	No	No	OTP
2025-WC-N8	Minnesota Energy Connection	2025/B	25282	Yes	No	XEL
2025-WC-N9	0754 Buffalo - Maple Lake Rebuild	2024/A	25286	No	No	XEL
2025-WC-N10	Gaylord Substation Rebuild	2024/A	25378	No	No	XEL
2025-WC-N11	0891 West St Cloud - Crossroads Rebuild	2024/A	25285	No	No	XEL
2025-WC-N12	Horseshoe Lake Substation	2025/A	50437	No	No	XEL
2025-WC-N13	Rebuild 5400 Richmond to Rich Springs Tap	2025/A	50442	No	No	XEL
2025-WC-N14	Install Avon Area Substation	2025/A	50458	No	No	XEL
2025-WC-N15	Line 0868 Le Sauk - Fischer Hills - St Stephens Rebuild	2025/A	50461	No	No	XEL
2025-WC-N16	Knight Substation	2025/A	50494	No	No	XEL

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2025-WC-N17	McLeod 230/115 kV Relay Upgrades	2026/A	50981	No	No	MRES
2025-WC-N18	Reconstruction of Transmission - Erie Rd Sub to Xcel Lyon County Sub	2026/A	50978	No	No	MRES

Ortonville 115/41.6 kV Transformer

MPUC Tracking Number: 2015-WC-N3

Utility: Otter Tail Power Company (OTP)

Project Description: Replace existing Ortonville 115/41.6 kV transformer with a new 40 MVA 115/41.6 kV transformer.

Need Driver: This area is experiencing local load growth and continual growth may cause the current 115/41.6 kV Ortonville transformer to become overloaded and created reliability concerns.

Alternatives:

Transmission Alternatives

With the most recent load forecasts, this project is not presently planned for construction. Alternatives may be considered if or when loads drive the need for this project.

Non-Wires Alternatives

Non-wires alternatives may be considered if this project were to move forward in development; however, they would likely come with a higher cost than replacing this transformer.

Analysis: The replacement of the Ortonville 115/41.6 kV transformer with a larger transformer will address the local load growth that this area is experiencing and will provide reliable service to the customers in the area. This project is the most cost-effective and environmentally responsible project to address the local needs in the Ortonville area.

Schedule: While prior studies identified this need, current load growth projections show no need to replace this transformer based on OTP's *Ten Year Development Study*. However, faster load growth could create a need for this project, and continued studies will monitor this transformer's loading.

General Impacts: The new transformer would replace the existing transformer and would require no additional new land or expansion. Since it will replace the existing transformer, there likely would be no major environmental impacts. This project may require a temporary project crew. If so, this may bring some business to the area in the form of room and board. This is an existing substation and would likely not require any permits or fees from the local government. This project is the product of a reliability measure and will probably not have a substantial or lasting impact on the community in terms of population or other social characteristics.

Appleton – Benson 115 kV Line

MPUC Tracking Number: 2021-WC-N6

Certificate of Need Number: CN-24-263

Utility: Great River Energy (GRE), Otter Tail Power (OTP), Missouri River Energy Services (MRES)

Project Description: Construct approximately 29 miles of new 115 kV transmission line starting from the MRES owned Appleton substation in the city of Appleton to GRE's Benson substation in the city of Benson.

The Project will include upgrading, rebuilding or reconductoring, and/or constructing new transmission lines between the following substations: Appleton, Shible Lake, Moyer, Danvers, Benson, and Benson Municipal Substations. The Shible Lake, Benson, and Benson Municipal substations are existing substations that will be modified and/or expanded to accommodate the project's 115 kV connection. The project also includes the construction of new Appleton substations. The Moyer and Danvers Substations will be expanded or relocated to accommodate connection to the Project.

The new the Appleton Substation will involve construction of a ring bus with four breakers and a 25 MVAr capacitor bank.

Need Driver: The Project is needed to meet load serving needs in the Project area and avoid low voltage issues under certain contingency scenarios driven by the retirement of the 55 MW FibroMinn Energy Center near the City of Benson. The system is currently experiencing low voltages resulting in insufficient capacity to reliably serve all load under contingency conditions. The Project will provide an additional 47 MW of system capacity under the worst single (N-1) contingency, which is expected to meet the demand for electricity for decades to come. Additionally, it will address low voltage concerns during N-2 contingencies that may otherwise result in voltage collapse within the project areas.

Alternatives: Alternatives were studied to confirm that the project was the best performing project for the Study Area. The proposed project will already be an upgrade of existing lines mainly utilizing existing corridor; there are no other existing transmission lines that could be upgraded as an alternative to the project. Different project options were chosen with the aim of providing a new high voltage source into the Study Area that centers on Benson. A voltage of 115 kV was chosen for these alternatives because Benson is at the center of an existing 115 kV network. The Benson Substation also contains 69 kV line terminations. However, the 69 kV transmission system currently has a need for improvement and networking additional 69 kV lines would not provide reliable service to 115 kV connected loads.

Transmission Alternatives

The following alternatives were considered, but were not preferred:

Alexandria – Benson 115 kV ~47-mile line
MN Valley – Benson 115 kV ~44-mile line
Willmar – Benson 115 kV ~35-mile line
Six Mile Grove 230/115 kV substation

Study analysis shows that each alternative configuration performs similarly to address single contingency (N-1) low voltage concerns. Neither the Willmar-Benson nor the Minnesota Valley- Benson alternatives perform better than the Project. Because of their longer lengths, they would also have greater losses and relatively higher cost and impacts, as compared to the project.

Non-Wires Alternatives

Both technical and economic analysis proves that a Non-Wires Alternative (NWA) is not viable for the area of study. In addition to that, the technical solution shows that NWA fails to address some of the issues which can be addressed by the proposed transmission solution, for example P6 contingency low voltage concerns in the Morris to Canby 115 kV system. A report is available upon request.

Analysis: In 2020, Great River Energy, Otter Tail Power, MRES, and Xcel Energy completed a study to evaluate the shutdown of the 55 MW FibroMinn Energy Center near Benson, Minnesota. The FibroMinn plant had played a significant role in supplying power and regulating the reactive power need in the local area. The retirement created near-term load-serving reliability concerns. The Benson Area Load Serving Study (2020) (BAL Study) concluded the need for this transmission project. Since the 2020 BAL Study, several system modifications have been completed and updated forecasts have been made available. A planning study update was performed in 2024 which reanalyzed the load serving need in the area based on the topology changes as updated from the MISO Transmission Expansion Plan (MTEP) 2018 data series to the MTEP 2023 data series. The analysis incorporated the most recent load forecasts for the distribution substations. This analysis confirms the need for additional load-serving support. In summary analysis has shown that:

The Appleton – Benson 115 kV line is the best value plan that addresses the load serving reliability issues in the area that in part was caused by generation retirement in the area. By in large, this project utilizes existing transmission line corridor and will upgrade existing 41.6 kV transmission lines to 115 kV. As such, among the alternatives considered, it is the most environmentally friendly project that addresses reliability issues and fosters economic development in wider area.

The Project will provide the necessary transmission system improvements to service current load and forecasted load for decades to come. The proposed Project addresses NERC standard reliability violations including contingency low voltage and thermal concerns on the 115-kV system, addresses existing N-2 contingency voltage collapse on the 115-kV system, accommodates future load growth in the 41.6-kV and 115-kV transmission systems which is expected to reach a peak demand of 101.61 MW in 2028 and 106.87 MW in 2033, and reduces losses in the Study Area. Overall, the Project will provide an additional 47 MW of system capacity under the worst single (N-1) contingency and an additional 77 MW of capacity under the worst double (N-2) contingency.

Schedule: The project is planned to be in service by March 2030.

General Impacts: The project will require approximately 29 miles of new 115 kV transmission line from Appleton substation to Benson substation. The project is located in predominantly agricultural lands. Prior to construction, GRE and/or OTP will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 24 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Big Swan 115 kV Ring Bus and Capacitor Bank Addition

MPUC Tracking Number: 2021-WC-N8

Utility: Great River Energy (GRE)

Project Description: Rebuild the 115 kV side of the Big Swan substation in a ring bus configuration to accommodate installation of a new capacitor bank and to reterminate the Big Swan to Crow River 115 kV line into a breaker position. Upgrade 115 kV and 69 kV relaying to ensure all protection is redundant. Install a new 40 MVAr capacitor into a position in the ring bus.

Need Driver:
Ring bus addition:
The Big Swan 115 kV bus has an incomplete topology, missing a 115 kV breaker on the Big Swan 115 kV line. For 115 kV line faults between Big Swan and Crow River, three 115 kV lines (all BES) and Big Swan 115/69 kV TR1 need to be tripped to clear the fault. The addition of a 115 kV breaker and 115kV bus connected capacitor bank in the current configuration would create a five-position straight bus. GRE cannot add the new positions to the existing box structure and maintain required electrical clearances. A 115 kV ring bus will allow for safe clearances, higher system reliability/resilience, allow for future expansion, and aligns with GRE standards for a 115 kV facility.

Capacitor bank addition:

The Hutchinson area study identified low voltage concerns in the 115 kV system that is between Hutchinson, Wakefield and Crow River. NERC category P6 contingencies involving prior outages, such as McLeod – Hutchinson 115 kV line, Crow River – Brooks Lake 115 kV line and Wakefield – Stockade 115 kV line causes low voltage problems at 115 kV side of GRE member substations and Hutchinson Municipal substation.

The Hutchinson area study also identified low voltage and overload concerns in the 69 kV transmission system for the loss of the Hutchinson 115/69 kV transformer. Several options have been evaluated to address the voltage concerns and all the options involved installation of capacitor bank at Big Swan to improve the 115 kV system post contingent voltage profile and a second Hutchinson 115/69 kV transformer to address low voltage and overload concerns in the 69 kV system. Per discussion with Xcel Energy and MRES, GRE will be responsible for the installation of the 40 MVAr capacitor bank at Big Swan and Hutchinson Municipal Commission will be responsible for the installation of a second 115/69 kV transformer at Hutchinson substation.

Alternatives:

Transmission Alternatives

Several transmission alternatives were considered, including installation of the capacitor bank at the Hutchinson substation. However, this option was not favored due to the proximity of Hutchinson substation to an industrial plant that could be highly sensitive to voltage transients. As for reterminating the 115 kV line from Crow River with a breaker at Big Swan, no other alternatives were considered.

Non-Wires Alternatives

NWA were not considered for this project. This project modifies existing substations that lack a breaker to re-termination of an existing line. The installation of the capacitor bank is contained within the existing substation fence, making the NWA unnecessary.

Analysis: The addition of capacitor bank at the existing Big Swan substation was found to be the best value and environmentally friendly plan that addresses reliability issues in the area. The Big Swan 115 kV side of the substation is deficient of a line termination breaker for the Crow River to Big Swan 115 kV line and is not up to GRE's current design standard. GRE plans to bring the Big Swan 115 kV side of the substation up to the current design standard while installing the capacitor bank and breaker at the Big Swan substation. This project is contained within GRE's existing property, therefore, it will have minimal impact on landowners in the area.

Schedule: The project is planned to be in service by January 2027.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Milbank, SD Area Upgrades

MPUC Tracking Number: 2023-WC-N2

Utility: Otter Tail Power Company (OTP)

Project Description: Phase 1 of the project will consist of constructing a new 12-mile 115 kV line from the Big Stone 230/115 kV substation (located near Big Stone City, SD) to a new 115/12.5 kV substation located near Milbank, SD. In addition, a portion of the town of Milbank, SD will be moved to the 115 kV system. Phase 1 of the project is located entirely within South Dakota. Phase 2 of the project will consist of construction a new 18.5-mile 115 kV line from the new 115/12.5 kV substation located near Milbank, SD to a new switching station on the Big Stone – Marietta 115 kV line located in Minnesota.

Need Driver: Planned load growth in Milbank, SD will bring the area's 41.6 kV transmission system beyond its capacity. Low voltages have been identified on the 41.6 kV transmission system in studies for the loss of the Highway 12 115 kV source. This project will move load to the 115 kV system and free up capacity on the area's 41.6 kV system.

Alternatives:
Transmission Alternatives

Several transmission alternatives were studied. The selected project is able to maintain system reliability at a low cost and is able to meet the timelines of the load expansion.

- New 230/41.6 kV substation on the Big Stone – Blair 230 kV line
- Big Stone 115 kV – Milbank 115 kV – New 230/115 kV substation on the Big Stone – Blair 230 kV line
- Radial-only 115 kV service for load expansion
- Highway 12 115 kV – Milbank 115 kV – new switching station on Big Stone – Marietta 115 kV line

Non-Wires Alternatives

This project is related to a load expansion, and non-wires alternatives would not provide sufficient availability or reliability to support the load.

Analysis: OTP performed a study to investigate projects to serve a load expansion in Milbank, SD. This analysis reviewed the selected project, as well as the transmission alternatives listed above. The analysis identified the selected project as the lowest-cost option while maintaining system reliability and meeting the timeline of the load expansion.

Schedule: The Minnesota portion of the project is expected to be completed by the end of 2026.

General Impacts: This project will require approximately 30.5 miles of new 115 kV transmission line (approximately 4 miles in Minnesota) from the Big Stone 230/115 kV substation to a new 115/12.5 kV substation near Milbank, SD to a new switching station on the Big Stone – Marietta 115 kV line. The project is located in predominantly agricultural lands. Prior to construction OTP will acquire the necessary right-of-way and permits for construction of the project. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. During this time, OTP and/or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Big Stone South – Alexandria – Big Oaks 345 kV

MPUC Tracking Number: 2023-WC-N3

Utility: **-**Great River Energy (GRE), Minnesota Power (MP), Missouri River Energy Services (MRES), Otter Tail Power Company (OTP), Xcel Energy (XEL)

Project Description: GRE, MP, MRES, OTP, and XEL are jointly developing the Big Stone South – Alexandria – Big Oaks 345 kV line, located in western and central Minnesota. The project consists of two major segments of transmission line construction:

1) Eastern Segment: Adding a second circuit to existing 345 kV structures originally built as part of the CapX2020 Fargo – St. Cloud and St. Cloud – Monticello projects between Alexandria and a new substation near the Sherco power plant in Becker.
2) Western Segment: Constructing a new 345 kV transmission line between the Big Stone South 345 kV substation in South Dakota to the Alexandria 345 kV substation in Minnesota.

Need Driver: This project will help ensure electric reliability, increase resiliency to extreme weather events, reduce transmission congestion, and increase access to low-cost energy in the region. With growth of wind energy projects in the Dakotas and Western Minnesota, there is not enough capacity on the transmission system to transfer that energy from the Dakotas and Western Minnesota to the Twin Cities load center.

Alternatives:
Transmission Alternatives
As part of MISO's LRTP Tranche 1 studies, numerous projects were studied and optimized into the full Tranche 1 project portfolio. Full details of the alternatives analysis are available in the LRTP Addendum to the MTEP21 report.
Non-Wires Alternatives
None.

Analysis: Full details of MISO's LRTP Tranche 1 analysis are available in the LRTP Addendum to the MTEP21 report.

Schedule: The Eastern Segment is expected to be completed in 2026 -2027. The Western Segment is planned to be completed by the end of 2030.

General Impacts: This project will require approximately new **345** kV transmission line from the Big Stone 345 kV substation to the Alexandria 345 kV substation. The project is located in predominantly agricultural lands. Prior to construction, necessary right-of-way and permits will be acquired for construction of the project. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. During this time, GRE, MP, MRES, OTP, and XEL and/or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Willmar Litchfield – Forest City – Hutchinson Rebuild and 115 kV Conversion

MPUC Tracking Number: 2023-WC-N5

Utility: Great River Energy (GRE), Missouri River Energy Services (MRES), Southern Minnesota Municipal Power Agency (SMMPA)

Project Description: Rebuild existing 69 kV transmission lines between the existing substations of Willmar, Litchfield and Hutchinson to a 115 kV standard for a future 115 kV operation. In addition, build a new 115 kV line from Litchfield to the Stockade distribution substation and a new 115 kV breaker station, Forest City, at the current Stockade tap switch point. Existing lines and infrastructure are owned by GRE, SMMPA, Litchfield Municipal, and Hutchinson Municipal. This project will be carried out jointly by these parties.

Need Driver: The lines between Willmar, Litchfield and Hutchinson have a need to be rebuilt due to age and condition concerns. These lines are some of the oldest 69 kV transmission lines in the area. The line rebuild projects will be done in such a way that it makes the load serving transmission system more resilient, creates opportunities for increased penetration of large loads and renewable resources, and solves existing or future reliability concerns in the transmission system.

Alternatives:

Transmission Alternatives

The driver for the line rebuild is primarily age and condition of the transmission line. GRE could rebuild the transmission line to 69 kV standard, but this will limit the load serving capacity of the transmission system in the Litchfield area. In addition, rebuilding the line to 69 kV will not address low voltage problems in the Hutchinson and Glencoe areas.

Non-Wires Alternatives

The primary driver of this project is the age and deteriorating condition of the transmission system, which connects multiple sources across a wide service area. Due to the nature of the reliability challenges and infrastructure requirements, non-wires alternatives are not considered viable solutions for addressing the core needs of this project. As the project proceeds through the Minnesota Certificate of Need filing process, a detailed analysis demonstrating the infeasibility of non-wires alternatives will be included in the Certificate of Need documentation.

Analysis: Transmission system assessment studies have shown that the existing transmission system is not resilient and doesn't have margin to serve new or growing loads in the Hutchinson and Glencoe areas. The Hutchinson and Glencoe areas experience low voltage problems for NERC category P6 contingencies. To improve system, post contingent voltage, address reliability concerns due to the transmission line age and condition, and make capacity available to serve large loads in the system, GRE will coordinate with SMMPA and MRES to construct a 115 kV line between Willmar and Hutchinson substations, via Litchfield and Stockade. Most of this future 115 kV line will involve an upgrade of existing 69 kV lines to 115 kV voltage that will continue to operate at 69 kV until the line is permitted for 115 kV operation.

Operating the transmission at 115 kV would require double circuiting the line between Willmar and Svea (SH), rebuilding the line between Svea substation and Hutchinson (DS/HN), rebuilding the SMMPA operated line between Litchfield Municipal and the Willmar-Hutchinson line (LT) to a double circuit for an in-and-out configuration to Litchfield Municipal, rebuilding the GRE line between Litchfield Municipal and the Big Swan-Atwater line (LN) and construction of 8 miles of new 115 kV line from Litchfield Municipal North Tap to connect to the Stockade substation.

GRE, SMMPA and MRES would first complete the following projects to address age and condition concerns in the transmission system:

- Rebuild DS line to 115 kV standard with 795 ACSS conductor
- Rebuild SH line to double circuit 115 kV / 69 kV. Svea distribution substation will remain at 69 kV service.
- Rebuild LT line as a double circuit to 115 kV standard with 795 ACSS conductor
- Rebuild LN line to 115 kV standard with 795 ACSS conductor
- Rebuild HN line to 115 kV standard with 795 ACSS conductor

Following the completion of the above age and condition related line rebuild projects, GRE, SMMPA and MRES will work on the following projects to operate the transmission system at 115 kV:

- Rebuild the Litchfield Municipal breaker station and installation of 2x20 MVAr capacitor banks
- Construct Forest City 115 kV breaker station
- Construct a new 8-mile 115 kV line from Litchfield Municipal North to the Stockade substation.
- Upgrade Litchfield Municipal distribution substation from 69 kV to 115 kV service

The line rebuild projects bring efficiency improvement as there will be less power loss on the transmission line. It also provides better load serving reliability as it will be new, consist of larger conductor and be constructed to the 115 kV standard. The line rebuild makes capacity available in the transmission system for a new load that may come to the areas.

Schedule: This project is scheduled for Q4 2031 completion.

General Impacts: The project will be constructed on an existing 100-foot right-of-way that is largely located on agricultural lands. While this project is at the end of the planning phase and although some additional temporary workspace may be required, no new landowners are expected to be impacted due to the line rebuild projects. Construction of a new 8-mile 115 kV line from

Litchfield Municipal North to the Stockade substation require acquiring new route and easement and will impact new landowners along the transmission line.

Benton County Solar Farm (J1426)

MPUC Tracking Number: 2023-WC-N11

Utility: Great River Energy (GRE)

Project Description: Add a new 115 kV breaker and a half row and tap line to accommodate the interconnection of the 100 MW solar farm for J1426.

Need Driver: MISO project J1426 has requested interconnection to the 115 kV bus at Benton County. Project J1426 is a 100 megawatt (MW) solar energy generating facility, a 100 MW battery energy storage system, and a 0.4 mile long, 115 kilovolt high voltage transmission line within Minden Township, Benton County, Minnesota.

Alternatives:
Transmission Alternatives

The interconnection was evaluated under the MISO's DPP system impact studies. No alternatives for the interconnections were identified.

Non-Wires Alternatives

Non-wires alternatives are not considered for new generation interconnections as the POI is determined by the interconnection customer.

Analysis: The expansion of facilities at Benton County are required to provide a point of interconnection for project J1426.

Schedule: The Benton County Solar Farm project is planned to be in-service by fall 2026.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Alexandria Light and Power Southeast Substation

MPUC Tracking Number: 2023-WC-N13

Utility: Missouri River Energy Services (MRES)

Project Description: Alexandria Light & and Power (ALP) will build a new distribution substation on the southeast part of town. The substation will tap and existing 115 kV line with an in and out substation. The substation will have a 115 kV to distribution transformer.

Need Driver: Distribution studies showed deficiencies present in the existing distribution system and to the need for a new distribution substation to support additional load growth within the City of Alexandria.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
This is a distribution system improvement, and no alternatives were considered.

Analysis: The need for a new distribution substation to support load growth was identified in Distribution System Planning Update report. The new distribution substation allows for more load growth within the City of Alexandria.

Schedule: The project is planned to be in-service by Q4 2028.

General Impacts: This project is located at the outer edge of town not near residential homes. Construction is expected to be completed in 18 months. During this time the ALP, and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Alexandria Substation Expansion

MPUC Tracking Number: 2023-WC-N14

Utility: Missouri River Energy Services (MRES)

Project Description: Alexandria Substation will be expanded to add positions for new 345 kV transmission line to Big Oaks and Big Stone South substations.

Need Driver: The BSSA/ABP Project, along with the other LRTP Tranche 1 Portfolio of transmission projects, are needed to provide reliable, resilient, and cost-effective delivery of energy as the generation resource mix.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None

Analysis: The generation resource mix is changing as more renewable and variable energy, such as wind and solar, is added to the system and aging coal-fired generation plants are retired. The BSSA/ABP Project, along with the other LRTP Tranche 1 Portfolio of transmission projects, are needed to provide reliable, resilient, and cost-effective delivery of energy as the generation resource mix continues to evolve over the coming years.

Schedule: The project is planned to be fully in-service by Q2 2030. Part of it will be completed by Q2 2027.

General Impacts: The Alexandra Substation is located on the south end of Alexandria, MN. The substation will be expanded to accommodate the transmission lines to Big Oaks and Big Stone South. The project is located in predominantly agricultural lands. Construction is expected to be completed in 24 months. During this time, MRES and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Benton County Terminal Upgrade

MPUC Tracking Number: 2023-WC-N16

Utility: Great River Energy (GRE)

Project Description: Upgrade terminal equipment to 2000 A rating.

Need Driver: This terminal equipment current rating has caused market congestion in the past and is projected to continue to cause market congestion into the future.

Alternatives:

Transmission Alternatives

> No transmission alternatives were considered since this project is replacing equipment in an existing substation.

Non-Wires Alternatives

> No non-wires alternatives were considered since this project is replacing equipment in an existing substation.

Analysis: The equipment upgrade will increase the ratings of the 230 kV lines out of Benton County, reducing the likelihood of these lines causing congestion in the market.

Schedule: The project is planned to be in service by spring 2026.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Darnen Distribution Substation

MPUC Tracking Number: 2025-WC-N1

Utility: Great River Energy (GRE)

Project Description: The Great River Energy (GRE) owned "AG-MB" 115 kV line between Morris and Walden will be tapped to serve a new distribution substation with an 'in-and-out' configuration.

Need Driver: Agralite Electric Cooperative requires a new distribution substation to serve power to a new dairy processing plant. Agralite requested transmission service from GRE to serve this new load. In addition to the new industrial load some existing load will be reallocated to this substation from other nearby Agralite substations to better serve their members. Due to the size of the new interconnected load and the potential for multiple distribution transformers served in a double-ended configuration, the transmission line will be configured in-and-out with the transmission path going into the distribution substation and back out, thereby providing redundant service from Morris or Walden.

Alternatives:

Transmission Alternatives

No transmission alternative can adequately address the need for a new distribution substation to serve the growing load in the area. The nearest potential alternative for interconnecting the Darnen distribution Substation is the 41.6 kV transmission system. However, this system generally has lower capacity and reliability performance compared to the proposed 115 kV transmission system. Given the expected load at Darnen, the 41.6 kV system is not a suitable option.

Non-Wires Alternatives

As the new load cannot be served from existing distribution system a new transmission interconnection is required and therefore NWA was not considered.

Analysis: Power flow analysis was performed and showed no adverse impact on the existing transmission system.

Distribution analysis showed the need for the new transmission interconnection due to insufficient capacity on existing distribution feeders.

Schedule: The project is planned to be in service by fall 2026.

General Impacts: The project will be constructed on a site on the existing 115 kV transmission line with under 1500 feet of new line required. The project is in predominantly agricultural lands. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Kimball Area Projects

MPUC Tracking Number: 2025-WC-N2

Utility: Great River Energy (GRE)

Project Description: Meeker Cooperative Light and Power Association (MCLP) plans to build a new distribution substation to serve load in the area. GRE will construct approximately 3 miles of 115 kV transmission line with 477 ACSR conductor to the high side of MCLP's new Kimball distribution substation.

Need Driver: MCLP needs to establish a new substation north of the city of Kimball to serve growing loads and address low voltage problems in the distribution system.

Alternatives:

Transmission Alternatives

Transmission line alternatives were considered. The original choice was to serve the substation from nearby 69 kV line. This option was not chosen as routing of Xcel Energy's MN Energy Connect project went through the proposed 69 kV route and therefore another route had to be chosen. The 115 kV line was the next best alternative with minimal new line being needed and fewer landowners affected.

Non-Wires Alternatives

As the new load cannot be served from existing distribution system a new transmission interconnection is required and therefore NWA was not considered.

Analysis: Power flow analysis was performed and showed no adverse impact on the existing transmission system.

Distribution analysis showed the need for the new transmission interconnection due to insufficient capacity on existing distribution feeders. The analysis also showed low voltage problems within the distribution system necessitating a new delivery point closer to the load center.

Schedule: The project is planned to be in service by fall 2027.

General Impacts: The project will require approximately 3 miles of new 115 kV transmission line from the existing line to the new substation. The project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 12 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Detroit Lakes Jet Substation

MPUC Tracking Number: 2025-WC-N3

Utility: Missouri River Energy Services (MRES)

Project Description: Detroit Lakes Public Utilities (DLPU) plans to construct a new line-breaker substation adjacent to the existing Detroit Lakes Industrial Substation in order to relocate the existing distribution transformer at Detroit Lakes Industrial Substation, as well as add a second distribution transformer in the new line-breaker substation.

Need Driver: Distribution studies showed deficiencies present in the existing distribution system and the need for a new distribution substation to support additional load growth within the City of Detroit Lakes.

Alternatives:
<u>Transmission Alternatives</u>
None.
<u>Non-Wires Alternatives</u>
This is a distribution system improvement, and no alternatives were considered.

Analysis: The need for a new distribution substation to support load growth was identified. The new distribution substation allows for more load growth within the City of Detroit Lakes. The new substation will also electrically isolate the load served by the Industrial substation sufficiently to not risk the potential of coincident loss of both the Industrial and Front Street substation load for a single outage event. This is a project that is most economical and least impactful to landowners.

Schedule: The project is planned to be in-service by Q4 2026.

General Impacts: This project is located at the outer edge of town not near an industrial park. DLPU and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Hutchinson Substation

MPUC Tracking Number: 2025-WC-N4

Utility: Missouri River Energy Services (MRES)

Project Description: This project will add a second 115/69 kV transformer to the existing City of Hutchinson MN, Hutchinson Substation. The project will also rebuild the Hutchinson 115 kV into a four position ring bus.

Need Driver: Project needed to address multiple low voltage and thermal violations in the area.

Alternatives:
<u>Transmission Alternatives</u>
None
<u>Non-Wires Alternatives</u>
This is a reliability improvement, so no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The projects are set to go in-service in Q4 2026.

General Impacts: The project will be constructed at an existing 115/69 kV substation. Some land outside of the existing substation will need to be acquired to construct the expansion. During construction HUC and/or their contractors will be working in the area and will contribute positively to the local economy. No significant impacts are anticipated. The area around the acquired expansion property will be restored following construction.

Priam Second Transformer and St John's Lake Breaker Station

MPUC Tracking Number: 2025-WC-N5

Utility: Missouri River Energy Services (MRES)

Project Description: Willmar Municipal Utilities (WMU) plans to add a second 115/69 kV transformer at the Priam substation near Willmar and expand the substation buses. They also plan to construct a new 69 kV breaker station near Willmar and rebuild the 69 kV line from the Willmar Municipal Utilities (WMU) tap to this new breaker station to a double circuit line.

Need Driver: Project needed to address multiple low voltage and thermal violations in the area.

Alternatives:
<u>Transmission Alternatives</u>
Option 1: Hawick Breaker Station. Estimated in-service date 2027.
Option 2: Second Priam transformer with a new 115 kV position, Pennock 69 kV Loop, Hawick Breaker Station, St. Johns Lake Breaker Station, rebuild 69 kV from St.

Johns Lake Breaker Station to Willmar Tap to double circuit. Estimated in-service date 2029.

Option 3: Second Priam transformer with a new 115 kV position, Pennock 69 kV loop to Power Plant, Hawick Breaker Station, Breaker Additions at Willmar Plant / Southwest, rebuild 69 kV from St. Johns Lake Area to Willmar Plant to double circuit, and rebuild 69 kV at Willmar Southwest to double circuit. Estimated in-service date 2029.

Option 4: Replace WMU 230/69 kV transformer and upgrade Willmar Southwest Tap to Willmar 69 kV line. Estimated in-service date 2028.

Option 5: Stockade to Willmar 115 kV.

Option 6: Separating Kerkhoven and Maynard sources into two sources that connect to Priam 115 kV.

Non-Wires Alternatives

This is a reliability improvement, so no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The projects are set to go in-service in Q4 2029.

General Impacts: The projects will be constructed at an existing 115/69 kV substation and at an existing 69 kV line from Willmar Municipal Utilities (WMU) tap to a new breaker station. Some land outside of the City of Willmar (near St Johns Lake) will need to be acquired to construct the breaker station. During construction Willmar Municipal Utilities and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The area around the acquired breaker station property and the right-of-way along the existing Willmar Municipal Utilities (WMU) tap to a new breaker station line will be restored following construction.

Erie Road Substation Rebuild

MPUC Tracking Number: 2025-WC-N6

Utility: Missouri River Energy Services (MRES)

Project Description: Marshall Municipal Utilities (MMU) plans to rebuild the Erie Road substation in Marshall with new 115 kV breakers and other equipment..

Need Driver: Project needed to address age and condition issues, and add reliability.

Alternatives:

Transmission Alternatives

None

Non-Wires Alternatives

This is a age and condition / reliability improvement, so no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is set to go in-service by Q1 2029.

General Impacts: The projects will be constructed at an existing substation. Some land outside of the existing substation may need to be acquired to rebuilt it. During construction MMU and/or their contractors will be working in the area and will contribute positively to the local economy. No significant impacts are anticipated. The area around the substation will be restored following construction.

Bellingham 115 kV Delivery

MPUC Tracking Number: 2025-WC-N7

Utility: Otter Tail Power Company (OTP)

Project Description: This project involves a new tap along the Big Stone – Marietta 115 kV transmission line to connect a new distribution substation serving the town of Bellingham, MN. A new 115 kV tap switch will be installed and connected directly to a new distribution substation. Additionally, several miles of new 12.5 kV line will be constructed to connect to the existing distribution network in Bellingham.

Need Driver: Currently, Bellingham is served by a long 12.5 kV line originating at the Odessa 115 kV substation, with backup service from another long 12.5 kV line originating at the Louisburg-Lac Qui Parle 115 kV substation. Distribution studies have identified deficiencies in the backup service capabilities of the local distribution network. A new 115 kV substation serving Bellingham, located in the middle of this local system, provides sufficient backup service capabilities for it.

Alternatives:

Transmission Alternatives

> This project accommodates load growth and improves switching capability on the local distribution system. No alternatives were considered.

Non-Wires Alternatives

> This project accommodates load growth and improves switching capability on the local distribution system. No non-wires alternatives were considered.

Analysis: Distribution studies performed in 2023 identified deficiencies in the backup capabilities of the distribution system in the Bellingham area.

Schedule: The project is planned to be in service by the end of 2030.

General Impacts: This project will be installing a new tap switch along the Big Stone – Marietta 115 kV line. Additionally, land rights will be acquired for the greenfield Bellingham substation and the 12.5 kV line to connect the new substation to the existing network. The project area is predominantly agricultural. Prior to construction, OTP will acquire any necessary land rights and permits for construction of the project. During construction, OTP and/or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Minnesota Energy Connection

MPUC Tracking Number: 2025-WC-N8

Utility: Xcel Energy (XEL)

Project Description: Xcel Energy has applied for a certificate of need and a route permit to construct the Minnesota Energy Connection Project. The project consists of two major components: new substations along with upgrades to existing substations and new 345 kilovolt (kV) high voltage transmission lines (HVTLs).

Proposed substation work involves:

- A new substation to be located near Garvin in Lyon County referred to as the Garvin Substation.

- An intermediate substation to be located 20 miles north of the proposed Garvin Substation referred to as the Intermediate Substation.

- A voltage-support substation to be located 80 miles south of the Sherco Substation in either Meeker, Kandiyohi, or Renville County referred to as the Support Substation.

- Modifications to the existing Sherco Substation and Sherco Solar West Substation near Becker in Sherburne County.

Proposed HVTL work involves:

- A new 345 kV double-circuit HVTL between the Garvin Substation and the existing Sherco Solar West Substation. The applicant's proposed routes are 171 and 174 miles in length and designated as the Purple Route and Blue Route, respectively.

- A new 3.1-mile single-circuit 345 kV transmission line between the existing Sherco Solar West Substation and the Sherco Substation referred to as the Green Segment. The Green Segment would be co-located with applicant's existing Line 5651, occupying the open position on the existing double-circuit-capable structures.

Need Driver: This project will allow Xcel Energy to retire its Sherco Generation facility and repower the plant with renewable carbon free energy in the West Central and Southwest areas of the state. This line is critical for meeting the carbon goals of Xcel Energy and the State of Minnesota.

Alternatives:
Transmission Alternatives
Different alternatives were analyzed and detailed in the CON application.
Non-Wires Alternatives
This project is aimed to recapture injection rights at Sherco and for this reason a non-wires alternative does not apply.

Analysis: This line when built will provide significant carbon free energy to the system and allow the existing coal power plants at Sherco to retire all while keeping the injection rights.

Schedule: This project will be in service by October of 2028.

General Impacts: The project impacts are detailed extensively in the CON application. For more information on impacts and project details, see the docket number CN-22-132.

0754 Buffalo - Maple Lake Rebuild

MPUC Tracking Number: 2025-WC-N9

Utility: Xcel Energy (XEL)

Project Description: Rebuild 8.2 miles 69 kV from Buffalo - Maple Lake with new structures, new OPGW shield wire, and new conductor.

Need Driver: Age and condition rebuild.

Alternatives:
Transmission Alternatives
As this project is an existing asset in poor asset condition, a rebuild was the most prudent choice as opposed to another transmission option.
Non-Wires Alternatives
As this project is an existing asset in poor asset condition, a NWA was not chosen for this project.

Analysis: The replacement of this line will more than double the existing ratings in addition to replacing the existing structures which have many defected poles.

Schedule: This project will be in service by December of 2027.

General Impacts: This project will have minimal impacts as it is a replacement of an existing asset with no new right of way.

Gaylord Substation Rebuild

MPUC Tracking Number: 2025-WC-N10

Utility: Xcel Energy (XEL)

Project Description: Rebuild Gaylord substation at a new location, converting 4.16kV feeders to 13.8kV.

Need Driver: Age and condition rebuild of existing substation.

Alternatives:
Transmission Alternatives

As this project is an existing asset in poor asset condition, a rebuild was the most prudent choice as opposed to another transmission option.

Non-Wires Alternatives

As this project is an existing asset in poor asset condition, an NWA was not chosen for this project.

Analysis: Gaylord substation is an aging substation with a non-standard voltage of 4.16 kV. There is currently a normal overload on two of the feeders and no contingency available for the substation except with the use of a mobile.

Schedule: This project will be in service by December of 2027.

General Impacts: This project will have minimal impacts.

0891 West St Cloud – Crossroads Rebuild

MPUC Tracking Number: 2025-WC-N11

Utility: Xcel Energy (XEL)

Project Description: Rebuild 4.1 miles 115 kV from West St. Cloud - Crossroads with new structures and new OPGW shield wire.

Need Driver: New poles needed to support fiber upgrades.

Alternatives:
Transmission Alternatives

As this project is to accommodate a fiber project and thus no alternatives were considered.

Non-Wires Alternatives

As this project is to accommodate a fiber project and thus no NWA were considered.

Analysis: The fiber upgrades help assist the company with relaying and protection of assets in the area.

Schedule: This project will be in service by November of 2026.

General Impacts: This project will have minimal impacts as it is a replacement of an existing asset with no new right of way.

Horseshoe Lake Substation

MPUC Tracking Number: 2025-WC-N12

Utility: Xcel Energy (XEL)

Project Description: Build new Horseshoe Lake Substation to transfer load from Richmond Substation

Need Driver: The 69 kV line that Richmond substation is on has high throughflow issues due to the parallel configuration with the 115 kV line. The line serves multiple Xcel and GRE substations along with high exposure there is high risk of outage and impact. Building a new substation and connecting to new line removes some exposure.

Alternatives:
Transmission Alternatives

This project will assist in the throughflow issues seen in the area and was the most prudent choice to solve this problem.

Non-Wires Alternatives

This project helps serve existing load and cannot be achieved without a wires project.

Analysis: This project helps reduce exposure seen by multiple company's loads as well as cut down on the throughflow in the area.

Schedule: This project will be in service by January of 2027.

General Impacts: This project is not expected to have major impacts at this time.

Rebuild 5400 Richmond to Rich Springs Tap

MPUC Tracking Number: 2025-WC-N13

Utility: Xcel Energy (XEL)

Project Description: Rebuild 2.6 miles of 69kV Line 5400 from Richmond to Rich Springs Tap.

Need Driver: Age and condition rebuild.

Alternatives:
Transmission Alternatives
As this project is an existing asset in poor asset condition, a rebuild was the most prudent choice as opposed to another transmission option.
Non-Wires Alternatives
As this project is an existing asset in poor asset condition, a NWA was not chosen for this project.

Analysis: Replace end of life poles and install shield wire to improve performance and reliability of the line

Schedule: This project will be in service by December of 2028.

General Impacts: This project will have minimal impacts as it is a replacement of an existing asset with no new right of way.

Install Avon Area Substation

MPUC Tracking Number: 2025-WC-N14

Utility: Xcel Energy (XEL)

Project Description: Install new distribution substation to meet load growth in area

Need Driver: Load growth in area is exceeding capability of existing substations

Alternatives:
Transmission Alternatives
This project is needed to serve growing load in the area and is the best project to meet the need.
Non-Wires Alternatives
A NWA may be applicable here, however the cost greatly outweighs the cost of a new substation. For this reason it was not considered.

Analysis: This area’s load is growing and a new substation will help meet the future needs of the area.

Schedule: This project will be in service by December of 2027.

General Impacts: This project is not expected to have major impacts at this time.

Line 0868 Le Sauk – Fischer Hills – St Stephens Rebuild

MPUC Tracking Number: 2025-WC-N15

Utility: Xcel Energy (XEL)

Project Description: Rebuild 0868 from Le Sauk to Fisher Hills to St. Stephens.

Need Driver: Line is frequently binding and is at end of life.

Alternatives:
Transmission Alternatives

As this project is an existing asset in poor asset condition, a rebuild was the most prudent choice as opposed to another transmission option.

Non-Wires Alternatives

As this project is an existing asset in poor asset condition, a NWA was not chosen for this project.

Analysis: This line often binds and has congestion in addition to be at its end of its useful life. This project will help reduce costs by reducing congestion.

Schedule: This project will be in service by December of 2028.

General Impacts: This project will have minimal impacts as it is a replacement of an existing asset with no new right of way.

Knight Substation

MPUC Tracking Number: 2025-WC-N16

Utility: Xcel Energy (XEL)

Project Description: Install new 115/34.5kV substation in the Dayton area to meet area load growth.

Need Driver: Required for load growth in the area.

Alternatives:
Transmission Alternatives

This project is needed to serve growing load in the area and is the best project to meet the need.

Non-Wires Alternatives

A NWA may be applicable here, however the cost greatly outweighs the cost of a new substation. For this reason it was not considered.

Analysis: This area's load is growing and a new substation will help meet the future needs of the area.

Schedule: This project will be in service by September of 2026.

General Impacts: This project is not expected to have major impacts at this time.

McLeod 230/115 kV Relay Upgrades

MPUC Tracking Number: 2025-WC-N17

Utility: Missouri River Energy Services (MRES)

Project Description: Hutchinson Utilities Commission (HUC) plans to upgrade substation relaying on thei McLeod 230/115 kV substation. The existing 230 kV bus and 230/115 kV transformer have single differential relay schemes. With this relay upgrade, HUC is implementing redundant differential relaying to improve protection.

Need Driver: Redundant relay improvement to avoid single point of failure events.

Alternatives:
Transmission Alternatives
None
Non-Wires Alternatives
This is a protection improvement, so no alternatives were considered.

Analysis: This is a cost-effective system reliability solution.

Schedule: The project is set to go in-service by Q1 2027.

General Impacts: The projects will be constructed at an existing substation. No additional land outside of the existing substation will need to be acquired. During construction HUC and/or their contractors will be working in the area and will contribute positively to the local economy. No significant impacts are anticipated. The area around the substation shouldn't be disturbed materially.

Reconstruction of Transmission - Erie Rd Sub to Xcel Lyon County Sub

MPUC Tracking Number: 2025-WC-N18

Utility: Missouri River Energy Services (MRES)

Project Description: Marshall Municipal Utilities (MMU) plans to rebuild transmission and this will encompass installation of new poles, insulators, and hardware. Retaining existing conductor will be analyzed. The existing steel support structures will stay in place.

Need Driver: Project needed to address age and condition issues and add reliability.

Alternatives:
Transmission Alternatives
None
Non-Wires Alternatives
This is an age and condition / reliability improvement, so no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is set to go in-service by Q4 2030.

General Impacts: The projects will be constructed on existing right-of-way. Some land around the existing transmission lines may need temporary easements to complete the work. During construction MMU and/or their contractors will be working in the area and will contribute positively to the local economy. No significant impacts are anticipated. The area around the transmission lines will be restored following construction.

6.5.2 Completed Projects

The table below identifies those projects by Tracking Number in the West Central Zone that were listed as ongoing projects in the 2023 Biennial Report but have been completed or withdrawn since the 2023 Report was filed with the Minnesota Public Utilities Commission in November 2023. Information about each of the completed projects is summarized briefly in the table below. More information about these projects and inadequacies can be found in earlier reports. Projects that were listed as being complete in the 2023 Report are not repeated here, but more information about those projects can be found in these earlier reports.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2019-WC-N4	Westwood I 115 kV Conversion	N/A	GRE	2025
2021-WC-N9	Kerkhoven 115 kV Breaker Additions	N/A	GRE	CANCELLED
2021-WC-N10	Walden 115 kV Breaker Addition	N/A	GRE	CANCELLED
2021-WC-N11	Benson – Morris Storm Structures	N/A	GRE	2024
2023-WC-N4	Big Swan – Wakefield Storm Structure Addition	N/A	GRE	2024
2023-WC-N6	Lake Mary 115 kV Conversion	N/A	GRE	2024
2023-WC-N7	Hodges Distribution Substation	N/A	GRE	2025

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2023-WC-N10	Cedar Mountain Substation Upgrade	N/A	GRE	2024
2023-WC-N15	Inman – Miltona Upgrade	N/A	GRE	2024
2023-WC-N17	Johnson Junction Switch Upgrade	N/A	GRE	2025
2021-WC-N1	Black Oak – Sauk Centre 69 kV Rebuild	N/A	XEL	2025
2021-WC-N4	Howard Lake to Big Swan, Delano to Howard Lake, Cokato to Winstead Rebuild	N/A	XEL	2024
2023-WC-N1	Sauk Centre North Interconnection	N/A	XEL	2025
2023-WC-N12	Morris to Grant County to East Fergus Falls 115 kV Line Upgrade	N/A	MRES	7/11/2024

6.6 Twin Cities Zone

6.6.1 Needed Projects

The following table provides a list of transmission needs identified in the Twin Cities Zone by MISO utilities. There were no projects identified in this zone by non-MISO utilities.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wires Alt.	Utility
2021-TC-N7	Bunker Lake 345 kV Ring Bus	Future	TBD	No	No	GRE
2021-TC-N8	Medina Breaker Addition and Replacement	2024/A	25453	No	No	GRE
2023-TC-N1	Blue Earth-South Bend Area Upgrades	2022/A	20505	No	No	XEL
2023-TC-N3	NSPM Metro Steel Pole Replacement	2022/A	21845	No	No	XEL
2023-TC-N22	Line 0840 Elliot Park Pumping Plants	2023/A	23501	No	No	XEL
2023-TC-N23	Lake Pulaski TR05 ELR	2023/A	23497	No	No	XEL
2023-TC-N24	Inver Grove TR02 ELR	2023/A	23496	No	No	XEL
2023-TC-N25	Prairie Island TR10 ELR	2023/A	23494	No	No	XEL

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wires Alt.	Utility
2023-TC-N26	Monticello TR06 & TR10 ELR	2023/A	23493	No	No	XEL
2023-TC-N29	Line 0721 STR 71 to 476 Rebuild	2023/A	23475	No	No	XEL
2023-TC-N34	Wilmarth Substation - FRM13	2023/A	23489	No	No	XEL
2023-TC-N37	Pilot Knob to Burnsville Area Projects	2023/A	23921	No	No	GRE
2023-TC-N38	Laketown Distribution Substation	2023/A	23763	No	No	GRE
2023-TC-N39	Cedar Lake Tap Line Relocation	2023/A	22871	No	No	GRE
2023-TC-N41	Lakeville Area Projects	2024/A	25405	No	No	GRE
2023-TC-N42	Burnsville Substation Upgrade	2024/A	25358	No	No	GRE
2025-TC-N1	Blaine to Linwood Area Project	2026/A	50973	No	No	GRE
2025-TC-N3	0890 Granite City - Crossroads Rebuild	2024/A	25322	No	No	XEL
2025-TC-N4	0821 Highbridge - Miriam Park Refurb	2024/A	25289	No	No	XEL
2025-TC-N5	Umore Park 115 kV Substation	2024/A	25507	No	No	XEL
2025-TC-N6	Inver Grove – Inver Hills 115 kV Rebuild to Double Circuit 115 kV	2024/A	25506	No	No	XEL
2025-TC-N7	West Maple Grove Substation	2025/A	50440	No	No	XEL
2025-TC-N8	Coon Creek Breaker ELR	2025/A	50422	No	No	XEL
2025-TC-N9	Rebuild 0737 Gleason Lake to Mound	2025/A	50421	No	No	XEL
2025-TC-N10	Rebuild 0735 St Bonifacius to Mound	2025/A	50417	No	No	XEL
2025-TC-N11	Install Inver Hills TRs and Feeders	2025/A	50398	No	No	XEL
2025-TC-N12	King Transmission Connection	2025/A	25398	Yes	No	XEL

Bunker Lake 345 kV Ring Bus

MPUC Tracking Number: 2021-TC-N7

Utility: Great River Energy (GRE)

Project Description: The project plans to build a 345 kV ring bus at Bunker lack by replacing switches 30JSM1, 30JSM4, and 30JSM5 with 345 kV breakers such that Sherco-Bunker Lake and Bunker Lake-Coon Creek are separate, breakered 345 kV line sections. The 345kV yard will need to be built out to accommodate a ring bus design with breaker and a half optionality. This will require site grading, and a line move for Xcel's 0984 line.

Need Driver: GRE has identified that widespread transient stability violations can occur (transient voltage violations and rotor angle oscillations) under certain faults . Because the transient voltage violations are widespread and the rotor angle oscillations involve large plants, adding 345 kV breakers at Bunker Lake greatly improves system stability by allowing breakers at Sherco, Bunker Lake and Coon Creek to more quickly clear line faults.

Alternatives:
Transmission Alternatives
This project is the only option considered to address the reliability concerns.
Non-Wires Alternatives
This a reliability improvement at the substation and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by summer 2030.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 18 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Medina Breaker Addition and Replacement

MPUC Tracking Number: 2021-TC-N8

Utility: Great River Energy (GRE)

Project Description: Add a breaker at Medina substation on the Crow River – Medina 115 kV line. Add a breaker at the Medina substation on the 115/69 kV transformer. Replace breaker 55WB2.

Need Driver: The Crow River to Medina 115 kV line terminates with a switch at the Medina substation. A fault on the line would trip the entire substation. A fault on certain facilities could result in tripping the entire substation. The breaker being replaced is hydraulic. There are limited parts available and there have been past maintenance issues with this breaker.

Alternatives:
<u>Transmission Alternatives</u>
The need required installation of a breaker to protect the substation from tripping due to a fault. The project was the only alternative considered to address the problem.
<u>Non-Wires Alternatives</u>
This a reliability improvement at the substation and no alternatives were considered.

Analysis: Replacement of the 115 kV switch with a breaker improves the reliability and resiliency of service at the Medina substation. These replacement projects are done within the substation fence and have minimal impact on landowners in the area.

Schedule: The project is planned to be in service by summer 2033.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Blue Earth-South Bend Area Upgrades

MPUC Tracking Number: 2023-TC-N1

Utility: Xcel Energy (XEL)

Project Description: Rebuild approximately 30 miles of 161 kV line and upgrade South Bend TR6 to a 448 MVA transformer.

Need Driver: Address Thermal violations in multiple sensitivity cases.

Alternatives:
<u>Transmission Alternatives</u>
None.
<u>Non-Wires Alternatives</u>
This a reliability improvement to an existing line and transformer and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2026.

General Impacts: The project will be constructed on the existing 161 kV transmission line from Blue Lake substation to the South Bend substation and upgrading the existing South Bend TR6. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right of way will be restored at the end of the project.

NSPM Metro Steel Pole Replacement

MPUC Tracking Number: 2023-TC-N3

Utility: Xcel Energy (XEL)

Project Description: Address painted poles concerns between Riverside Sub and Main Street Sub. Approximately 4-mile of triple circuit structure(35-structures) to be either replaced, painted or a combination of replace/paint.

Need Driver: The existing structures were installed in the 1980s and are experiencing paint peeling and steel deterioration.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by June 2027.

General Impacts: Replacement and/or painting of existing structures. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right of way will be restored at the end of the project.

STY Install TR3 & 115kV Bus Tie

MPUC Tracking Number: 2023-TC-N9

Utility: Xcel Energy (XEL)

Project Description: Install new 115 kV bus tie and associated disconnect switches and bus work and re-terminate 0818/5529 at Rogers Lake Sub.

Need Driver: Needed to accommodate third distribution transformer due to capacity, location, and load.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by November 2026.

General Impacts: Additional bus tie and switches in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Parkers Lake TR09 ELR

MPUC Tracking Number: 2023-TC-N12

Utility: Xcel Energy (XEL)

Project Description: Replace Parkers Lake 345/115 kV TR09 (3 phases).

Need Driver: The ELR transformer program is to proactively replace aging transformers that have past their operational service life and are showing increase signs of degradation.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2025.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0893 NSS-BCK Rebuild

MPUC Tracking Number: 2023-TC-N13

Utility: Xcel Energy (XEL)

Project Description: Rebuild 3.4 miles of 115 kV line between North Star Steel and Battle Creek substations. Portions of this line are double circuited with 0892, this project will separate the two circuits.

Need Driver: Needed to increase reliability and performance of the line due to deterioration from age and wet environment.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Verifying the secondary limit on the Farmington – Lake Marion 69 kV line, and limit may need to be replaced. No other immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by August, 2026.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0718 Arlington - Winthrop Rebuild

MPUC Tracking Number: 2023-TC-N14

Utility: Xcel Energy (XEL)

Project Description: Rebuild 15 miles line 0718 69 kV from Arlington - Winthrop.

Need Driver: Needed for age and condition rebuild.

Alternatives:

Transmission Alternatives

Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

Non-Wires Alternatives

This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by June 2026.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Edina Switch Replacement

MPUC Tracking Number: 2023-TC-N15

Utility: Xcel Energy (XEL)

Project Description: Replace 115 kV switch at Edina, which is limiting the rating of the Edina - St. Louis Park 115 kV line.

Need Driver: Remediates overloads on the Edina - St. Louis Park 115 kV line.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is went into service August 2025.

General Impacts: Switch replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0859 Str 16 to Chemolite Rebuild

MPUC Tracking Number: 2023-TC-N18

Utility: Xcel Energy (XEL)

Project Description: Rebuild 6.9 miles of line 0859 115 kV from Chemolite substation to structure 16.

Need Driver: Needed for age and condition rebuild.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by March 31, 2026.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0771 Rebuild

MPUC Tracking Number: 2023-TC-N21

Utility: Xcel Energy (XEL)

Project Description: Rebuild 2 miles of line 0771 from Young America - Carver County 69 kV substations and add OPGW.

Need Driver: Needed to increase reliability and performance of the line due to deterioration from age and wet environment.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project went in service September 2025.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0840 Elliot Park Pumping Plants

MPUC Tracking Number: 2023-TC-N22

Utility: Xcel Energy (XEL)

Project Description: Upgrades to pumping station for HPFF.

Need Driver: Pumping plant is required to maintain electrical supply to the substation.

Alternatives:
Transmission Alternatives

Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

Non-Wires Alternatives

This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by May 2026.

General Impacts: No environmental issues have been identified. Equipment upgrades will have minimal impacts to existing system performance and footprint.

Lake Pulaski TR05 ELR

MPUC Tracking Number: 2023-TC-N23

Utility: Xcel Energy (XEL)

Project Description: Replace Lake Pulaski 115/69 kV TR05.

Need Driver: The ELR transformer program is to proactively replace aging transformers that have past their operational service life and are showing increase signs of degradation.

Alternatives:

<u>Transmission Alternatives</u>
None.
<u>Non-Wires Alternatives</u>
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2026.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Inver Grove TR02 ELR

MPUC Tracking Number: 2023-TC-N24

Utility: Xcel Energy (XEL)

Project Description: Replace Inver Grove 115/69 kV TR02.

Need Driver: The ELR transformer program is to proactively replace aging transformers that have past their operational service life and are showing increase signs of degradation.

Alternatives:
<u>Transmission Alternatives</u>
None.
<u>Non-Wires Alternatives</u>
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2027.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Prairie Island TR10 ELR

MPUC Tracking Number: 2023-TC-N25

Utility: Xcel Energy (XEL)

Project Description: Replace Prairie Island 345/161 kV TR10.

Need Driver: The ELR transformer program is to proactively replace aging transformers that have past their operational service life and are showing increase signs of degradation.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by June 2027.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Monticello TR06 & TR10 ELR

MPUC Tracking Number: 2023-TC-N26

Utility: Xcel Energy (XEL)

Project Description: Replace Monticello 345/230 kV TR06 and 345/115 kV TR10.

Need Driver: The ELR transformer program is to proactively replace aging transformers that have past their operational service life and are showing increase signs of degradation.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2026.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0892 RRK-BCK Rebuild

MPUC Tracking Number: 2023-TC-N27

Utility: Xcel Energy (XEL)

Project Description: Rebuild 3.4 miles of 115 kV line between Red Rock and Battle Creek substations. Portions of this line are double circuited with 0893, this project will separate the two circuits.

Need Driver: Needed to increase reliability and performance of the line due to deterioration from age and wet environment.

Alternatives:
Transmission Alternatives
  Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
  This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by August 2026.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0736 Arden Hills - Lawrence Creek Rebuild

MPUC Tracking Number: 2023-TC-N28

Utility: Xcel Energy (XEL)

Project Description: Rebuild 33 miles of line 0736 69 kV from Arden Hills - Lawrence Creek and add OPGW.

Need Driver: Needed for age and condition rebuild. Increasing the capacity of this circuit and potentially converting it to 115 kV in the future will reduce overloading of underground transmission cable at White Bear Lake.

Alternatives:

Transmission Alternatives

Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

Non-Wires Alternatives

This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 31, 2027.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0721 STR 71 to 476 Rebuild

MPUC Tracking Number: 2023-TC-N29

Utility: Xcel Energy (XEL)

Project Description: Rebuild 22 miles line 0721 69 kV from Structure 71 - Structure 476.

Need Driver: Needed for age and condition rebuild.

Alternatives:

Transmission Alternatives

Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

Non-Wires Alternatives

This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by November 2028.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Pilot Knob to Burnsville Area Projects

MPUC Tracking Number: 2023-TC-N37

Utility: Great River Energy (GRE)

Project Description The Pilot Knob Substation will be rebuilt to a breaker and a half configuration due to the age and condition of the current equipment. In addition, the DA-PD line from Deerwood substation to Pilot Knob substation will be rebuilt to increase the capacity. The line upgrade will be built to 115 kV standards but operated at 69 kV. The underground portion of the DA-PLX line at Pilot Knob will be retired and replaced with an overhead line. The DA-RE line from Pilot Knob Road to Black Hawk Road will be retired. along with the DA-PKX line from Pilot Knob to Cliff Road.

Need Driver: Pilot Knob substation is old and in poor condition, the substation configuration is non-standard and does not allow for expansion. DA-RE line needs to be retired to allow for the county to upgrade the section of Pilot Knob Road. Following the upgrade, the DA-PKX and DA-RE lines are no longer needed and would be retired.

Alternatives:

Transmission Alternatives

> The project is to rebuild outdated, aging infrastructure and support future load requirements and has been identified as the optimal solution for the region.
>
> Rebuilding the line at 69kV standard was considered, but the developments in the area necessitated the rebuild of this transmission line to 115kV standard. GRE will rebuild the line to 115 kV standard and operate at 69 kV until all associated 69 kV lines and distribution substations are upgraded and the Pilot Knob substation is reconfigured to create a 115 kV looped service between Pilot Knob and Burnsville. High-capacity transmission lines are needed in the area to reliably serve communities that are dependent on this transmission line. In addition, growing industrial developments in the area can only be served with high capacity 15 kV transmission lines.

Non-Wires Alternatives

The driver for the line rebuild is primarily age and condition of the transmission line; therefore, non-wires alternatives were not considered for this project.

Analysis:

With rising load demand in the Eagan, MN area, there is a need to rebuild the existing 69 kV lines to allow for future operation at 115 kV. Following the upgrade of Lebanon Hills to 115 kV service and the retirement of the 69 kV line between Pilot Knob and Lebanon Hills, the DA-RE and DA-PKX lines between Pilot Knob and Deerwood tap are also scheduled for retirement, resulting in only one remaining 69 kV path between Pilot Knob and Burnsville via Deerwood substation. After the retirement project, the Pilot Knob to Deerwood line requires an upgrade, as it reaches its capacity during a loss of Burnsville to River Hills 69kV line. Although upgrading to a higher capacity 69 kV conductor is possible, analysis supports GRE's recommendation to rebuild to the 115 kV standard to provide reliable service and support economic development in the area. The project analysis demonstrated benefits such as reduced voltage drop, improved ability to serve large future loads, and improved reliability in the area.

Schedule: This project is planned to be in-service by December 2028.

General Impacts: The project is located on existing property and exiting GRE 69 kV right of way corridor. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 24 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Laketown Distribution Substation

MPUC Tracking Number: 2023-TC-N38

Utility: Great River Energy (GRE)

Project Description: Construct about 3 to 5 miles 115 kV transmission line from GRE's 115 kV line near Victoria Tap. The interconnecting lines will be constructed as an in-and-out design to accommodate a future double-ended sub.

Need Driver: Minnesota Valley Electric Cooperative (MVEC) is requiring the new Laketown substation because of the additional load planned in Laketown Township. The existing substations in this area will be at capacity and will not be able to serve the additional load in the future.
The majority of MVEC load in this area is concentrated between Waconia and Victoria, north of Airport Road. It is preferred that a new substation be located close to this load center rather than have most of the load at the end of feeders. Shorter feeders close to the load centers improve the reliability of the feeders and reduces voltage drop. Nearly all the load growth expected of around 8.5 MW will be in this area which does not currently have a substation located nearby.
Augusta is not a good substation to serve this growing load as the feed currently from Augusta is 8.1 miles to end of feeder, with the majority of the load at the end. Voltage regulators are already in use on these feeders. Currently 87% of the load served by Victoria is on the northern feeders. The proposed Laketown substation site will be much closer to the load center than either Augusta or Victoria.

With the projected load in the Laketown area backfeeding will become very difficult if not impossible. It would fall on Waconia and Victoria to support each other in addition to the new Laketown area growth. That is a reliability and system integrity risk that would be greatly alleviated with the addition of the Laketown substation. Transmission reliability will also be improved with the addition of a bus-tie breaker to sectionalize the transmission system at Laketown.

Alternatives:

Transmission Alternatives

Alternative 115 kV connections were considered but did not sectionalize the system as well as connecting to the MV-VTT line between Augusta and Victoria. This section provided the best reliability and resiliency.

Non-Wires Alternatives

Non-wires alternatives for this project
were not considered due to new load needing to be fed with no existing transmission infrastructure in the area.

Analysis: A distribution analysis was performed. This showed the need for a new substation in the area due to lack of feeder redundancy, load growth in an area with no distribution substation, and future feeder overload and voltage issues on lines already with voltage regulators in use

Analysis in the distribution system showed that an alternative distribution wasn't feasible:

1. Additional transformers
    a. Neither the Victoria nor Augusta substation have the land space to add a second transformer. Augusta and Victoria are already two of MVEC's most heavily loaded substations with more load expected to come (several developments and large C&I).
    b. Augusta won't be able help serve the Laketown area as its capacity will be needed for future load growth expected around Augusta.
    c. Waconia doesn't have space for a second transformer, but upsizing the transformer is possible. However, the cost of upgrading the Waconia transformer could also be put towards the Laketown substation which solves more reliability and capacity concerns.

2. Additional feeders
    a. A new Victoria feeder is currently being built to support growth south of the Victoria substation. This new line could potentially pick up some of the Laketown area. However, with Augusta tied up, there is no way to back feed Laketown or much of the Victoria substation, which puts a large amount of load at risk for reliability issues.
    b. Any new feeders out of Augusta will go towards the new loads by the Augusta substation.

   c. At least one line out of Waconia will need to go to the Laketown area regardless for backfeeding purposes. For a normal feed from Waconia, MVEC would likely want two feeders, which again is an additional cost that could go towards a Laketown substation.

3. Regulators and Capacitors
   a. There's currently already a bank of regulators and capacitors on the feed for Laketown area. Additional banks can be added but for long term growth this isn't a sustainable solution.
   b. Voltage isn't as big of a driving factor as capacity and reliability. Having the Laketown substation would reduce feeder lengths and would remove the need for additional regulators and capacitor banks.

Transmission analysis showed that adding the new substation did not negatively impact the transmission system, and that including a bus-tie breaker at Laketown contributed to system reliability.

Schedule: The Laketown Substation project is planned to be in-service by fall 2028.

General Impacts: The project will require approximately 3 to 5 miles of new 115 kV transmission line to the Laketown substation. The project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design primarily follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 12 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Burnsville Substation Upgrade

MPUC Tracking Number: 2023-TC-N42

Utility: Great River Energy (GRE)

Project Description: This project involves the following at Burnsville substation: replace and relocate EEE (all new panels/relays/etc.), soil correction at new EEE site, northwest fence line expansion, replacement of 5M197, and add breakers with new 115 kV ring bus configuration on north end of substation.

Need Driver:

- The Electrical Equipment Enclosure (EEE) in the Burnsville substation continues to sink due to unstable, waterlogged soil and persistent flooding. Soil correction is required, as the current conditions are undermining the foundation and causing equipment to gradually settle, threatening both structural integrity and operational safety. Standing water and poor drainage are also accelerating the deterioration of electrical components. The planned rebuild will not only replace aging infrastructure but also include site improvements to correct grading and mitigate flooding risks—ensuring long-term stability and resilience.
- As part of the infrastructure modernization efforts, all electromechanical relays and first-generation microprocessor relays will be systematically replaced. These legacy components have limited diagnostic capabilities and are increasingly prone to failure, creating maintenance challenges and operational risks. The upgrade will deploy modern digital protection relays with enhanced functionality, improved fault analysis, and better integration into SCADA systems. This transition ensures greater reliability, streamlined troubleshooting, and future-readiness of the substation's control systems.
- Prepare site for future to accommodate voltage conversion to 115 kV of existing 69kV transmission lines in the area. Breaker Replacements: these are Siemens BZO breakers with a OA3 Hydraulic mechanism. These breakers have type U bushings with higher power factor test results. Limited spare parts availability. Higher risk scores of the oil breakers left for replacement.

Alternatives:

Transmission Alternatives

This is an equipment reliability improvement project at the existing Burnsville substation and no other transmission alternatives were considered.

Non-Wires Alternatives

This project involves equipment improvement at the substation, and no alternatives were considered.

Analysis: After substation inspection, it was found that much of the equipment at the substation is outdated and increasingly prone to failure, putting system reliability at risk. The EEE site itself is experiencing ground instability, and soil correction is needed to address long-standing drainage and access issues. Without it, the area remains difficult to reach for maintenance vehicles and is unsafe for operations.

Looking ahead, a future project will add a new 115 kV connection to this substation. Preparing for that integration now means fewer outages and smoother implementation down the line. The new 115 kV equipment and bus work will be rated at 3000A to support anticipated load growth in the area.

Taken together, these upgrades will strengthen reliability, improve site access, and prepare the substation for future growth.

Schedule: The Burnsville Substation Upgrade project is planned to be in-service by March 2030.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 18 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Blaine to Linwood Area Project

MPUC Tracking Number: 2025-TC-N1

Utility: Great River Energy (GRE)

Project Description: This project will rebuild the Blaine – Linwood 230 kV 'PR' line from structure 265 to the Linwood substation. The length of line to rebuild is approx. 12.8 miles.

Need Driver:
The line is being replaced due to age and condition.

Alternatives:
Transmission Alternatives

This project replaces existing transmission line due to its age and deteriorating condition. No transmission alternatives were considered for this project, as the proposed project represents the least costly and least impactful solution.

Non-Wires Alternatives

This line is critical for maintaining reliable power transfer in the region; therefore, non-wires alternatives were not considered feasible for this project.

Analysis: This rebuild will refresh aging assets, further extending the life of the facility.

Schedule: The project is planned to be in-service by March 2030.

General Impacts: The Project will be constructed on an existing right-of-way. No new landowners will be impacted by construction, although some additional temporary workspace may be required. GRE has completed a desktop review of environmental features that may be present in the right-of-way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

0890 Granite City – Crossroads Rebuild

MPUC Tracking Number: 2025-TC-N3

Utility: Xcel Energy (XEL)

Project Description: Rebuild 3.7 miles 115 kV line from Granite City - Crossroads with new structures and new OPGW shield wire.

Need Driver: New poles needed to support fiber upgrades.

Alternatives:
Transmission Alternatives
The project is fixing existing assets and was chosen as the best option to meet the need.
Non-Wires Alternatives
The project is fixing existing assets and was chosen as the best option to meet the need.

Analysis: This project will aid the communication and protection of transmission assets by supporting fiber network upgrades.

Schedule: The project is planned to be in service by May of 2028.

General Impacts: This project is expected to have minimal impacts as its replacing existing infrastructure.

0821 Highbridge – Miriam Park Refurb

MPUC Tracking Number: 2025-TC-N4

Utility: Xcel Energy (XEL)

Project Description: Rebuild 3.3 miles 115 kV with new structures and new OPGW shield wire.

Need Driver: Age & Condition rebuild, wood polls reaching end of life.

Alternatives:
Transmission Alternatives
The project is fixing existing assets and was chosen as the best option to meet the need.
Non-Wires Alternatives
The project is fixing existing assets and was chosen as the best option to meet the need.

Analysis: This project will fix aging poles and aid the communication and protection of transmission assets by supporting fiber network upgrades.

Schedule: The project is planned to be in service by December of 2025.

General Impacts: This project is expected to have minimal impacts as its replacing existing infrastructure.

Umore Park 115kV Substation

MPUC Tracking Number: 2025-TC-N5

Utility: Xcel Energy (XEL)

Project Description: New 115kV load serving substation with in-and-out tap to existing Rosemount - Empire 115 kV line 0822. Build 6 miles new double circuit 115 kV line from Umore Park - Inver Grove with one circuit connecting to Inver Hills.

Need Driver: Needed to support new interconnecting load.

Alternatives:
Transmission Alternatives
The project will add new load and thus was chosen as the best option to meet the need.
Non-Wires Alternatives
The project will add new load and thus was chosen as the best option to meet the need.

Analysis: This project builds a new substation to serve a new customer in Rosemount. This project benefits the community with added tax base and local jobs.

Schedule: The project is planned to be in service by December of 2025.

General Impacts: This project is expected to have low impacts as the transmission line is very near the substation location which is owned by the customer.

Inver Grove – Inver Hills 115kV Rebuild to Double Circuit

MPUC Tracking Number: 2025-TC-N6

Utility: Xcel Energy (XEL)

Project Description: Rebuild 2.2 miles 115 kV line 5507 to double circuit from Inver Grove - Inver Hills. Expand Inver Hills substation. Add 1 breaker at Umore substation.

Need Driver: Age & Condition rebuild. Future load serving support.

Alternatives:
Transmission Alternatives

The project will rebuild aging assets and assist in future load serving and thus was chosen as the best option to meet the need.

Non-Wires Alternatives

The project will rebuild aging assets and assist in future load serving and thus was chosen as the best option to meet the need.

Analysis: This project rebuilds an existing transmission line to double circuit which helps serve new load growth. This allows the community to grow its load as well as replaces aging assets.

Schedule: The project is planned to be in service by November of 2027.

General Impacts: This project is expected to have low impacts as the transmission line exists today and will be adding a second circuit in the same ROW.

West Maple Grove Substation

MPUC Tracking Number: 2025-TC-N7

Utility: Xcel Energy (XEL)

Project Description: Build new Substation in Northwest Maple Grove to accommodate load growth

Need Driver: New substation needed in the NW Maple Grove area due to substantial load growth in area

Alternatives:

Transmission Alternatives

The project will add new load and thus was chosen as the best option to meet the need.

Non-Wires Alternatives

The project will add new load and thus was chosen as the best option to meet the need.

Analysis: This project builds a new substation to serve growing load in the Maple Grove area. This new substation allows the city to grow their load and city.

Schedule: The project is planned to be in service by September of 2028.

General Impacts: This project's impacts are unknown at this time and is under further study.

Coon Creek Breaker ELR

MPUC Tracking Number: 2025-TC-N8

Utility: Xcel Energy (XEL)

Project Description: Replace three 345kV and two 115kV breakers at Coon Creek that are at end of life

Need Driver: Breakers are at end of life and are experiencing gas leaks, causing reliability concerns.

Alternatives:

Transmission Alternatives

The project will rebuild aging assets and thus was chosen as the best option to meet the need.

Non-Wires Alternatives

The project will rebuild aging assets and thus was chosen as the best option to meet the need.

Analysis: The replacement of failing substation equipment is key to maintaining reliability of the system.

Schedule: The project is planned to be in service by December of 2025.

General Impacts: This project is expected to have minimal impacts as work is all inside the existing substation.

Rebuild 0737 Gleason Lake to Mound

MPUC Tracking Number: 2025-TC-N9

Utility: Xcel Energy (XEL)

Project Description: Rebuild line 0737 from Gleason Lake to Mound and add OPGW

Need Driver: The existing structures are at end of life and have numerous defects.

Alternatives:

Transmission Alternatives

The project will rebuild aging assets and assist in future load serving and thus was chosen as the best option to meet the need.

Non-Wires Alternatives

The project will rebuild aging assets and assist in future load serving and thus was chosen as the best option to meet the need.

Analysis: OPGW installation on the line will likely replace more than 50% of existing structures, triggering a complete rebuild. Significant load growth is forecasted in the area and increased capacity is needed.

Schedule: The project is planned to be in service by March of 2028.

General Impacts: This project is expected to have minimal impacts as the transmission line exists today and will be rebuilt in the same ROW.

Rebuild 0735 St Bonifacius to Mound

MPUC Tracking Number: 2025-TC-N10

Utility: Xcel Energy (XEL)

Project Description: Rebuild line 0735 from St. Bonifacious to Mound and add OPGW

Need Driver: The existing structures are at end of life and have numerous defects.

Alternatives:
Transmission Alternatives
The project will rebuild aging assets and assist in future load serving and thus was chosen as the best option to meet the need.
Non-Wires Alternatives
The project will rebuild aging assets and assist in future load serving and thus was chosen as the best option to meet the need.

Analysis: OPGW installation on the line will likely replace more than 50% of existing structures, triggering a complete rebuild. Significant load growth is forecasted in the area and increased capacity is needed.

Schedule: The project is planned to be in service by December of 2026.

General Impacts: This project is expected to have minimal impacts as the transmission line exists today and will be rebuilt in the same ROW.

Install Inver Hills TRs and Feeders

MPUC Tracking Number: 2025-TC-N11

Utility: Xcel Energy (XEL)

Project Description: Expand the Inver Hills substation and install two new distribution transformers and feeders to take over the existing Rich Valley loads

Need Driver: Rich Valley substation is currently under loss of load risk due to single bank configuration. This project would add transfer the load from Rich Valley to Inver Hills and add the capacity to support the additional load.

Alternatives:
Transmission Alternatives

The project will rebuild aging assets and adding feeder equipment to serve load. Thus, was chosen as the best option to meet the need.

Non-Wires Alternatives

The project will rebuild aging assets and adding feeder equipment to serve load. Thus, was chosen as the best option to meet the need.

Analysis: The new transformers help the system be flexible, add capacity to serve new area load and provide redundancy.

Schedule: The project is planned to be in service by December of 2028.

General Impacts: This project is expected to have minimal impacts as most work is inside the existing substation.

King Transmission Connection

MPUC Tracking Number: 2025-TC-N12

Utility: Xcel Energy (XEL)

Project Description: New 230kV ~30mi transmission line, 2 switching stations with capacitors, and associated substation upgrades including 2 230/345kV transformers to bring radial renewable generation to AS King substation to replace existing generation.

Need Driver: Project needed to bring renewable generation in WI to AS King substation to replace existing coal generation.

Alternatives:
Transmission Alternatives:

Different alternatives were analyzed and detailed in the CON application.

Non-Wires Alternatives:

This project is aimed to recapture injection rights at Sherco and for this reason a non-wires alternative does not apply.

Analysis: This line when built will provide significant carbon free energy to the system and allow the existing coal power plants at AS King to retire all while keeping the injection rights.

Schedule: This project will be in service by June of 2027.

General Impacts: This projects impacts are significant overall, however fairly minimal in MN. You can find some information about the MN portion with this docket info: MPUC Docket No. E002/TL-25-255. The full project will require a CPCN in Wisconsin, which will be considered in Docket No. 4220-CE-190.

6.6.2 Completed Projects

The table below identifies those projects by Tracking Number in the Twin Cities Zone that were listed as ongoing projects in the 2023 Biennial Report but have been completed or withdrawn since the 2021 Report was filed with the Public Utilities Commission in November 2023. Information about each of the completed projects is summarized briefly in the table below. More information about these projects and inadequacies can be found in earlier reports. Projects that were listed as being complete in the 2023 Report are not repeated here, but more information about those projects can be found in these earlier reports.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2021-TC-N5	Lawndale – Bass Lake 115 kV Line	N/A	GRE	CANCELED
2021-TC-N6	Rush City 230 kV Ring Bus	N/A	GRE	2024
2021-TC-N9	Parkwood 115 kV Ring Bus Expansion	N/A	GRE	2024
2021-TC-N10	Bunker Lake – Elk River Storm Structures	N/A	GRE	2024
2023-TC-N33	Kohlman Lake Substation - FRM13	N/A	XEL	2022
2023-TC-N34	Wilmarth Substation – FRM13	N/A	XEL	2022
2023-TC-N35	Eidswold Distribution Substation	N/A	GRE	2025
2023-TC-N36	Arbor Lake II Distribution Substation	N/A	GRE	2025
2023-TC-N39	Cedar Lake Tap Line Relocation	N/A	GRE	2025
2023-TC-N41	Lakeville Area Projects	N/A	GRE	2025
2023-TC-N2	Elm Creek Sub	N/A	XEL	2023
2023-TC-N4	Hyland Lake Sub	N/A	XEL	2023
2023-TC-N5	Coon Creek Sub	N/A	XEL	2023
2023-TC-N6	Rogers Lake Sub	N/A	XEL	2023
2023-TC-N7	Blue Lake Sub	N/A	XEL	2023

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2023-TC-N8	West Shakopee Sub	N/A	XEL	2023
2023-TC-N10	Line 0811	N/A	XEL	2023
2023-TC-N11	Line 0838	N/A	XEL	2023
2023-TC-N16	Lyon Co Sub	N/A	XEL	2023
2023-TC-N17	South Dayton Sub	N/A	XEL	2023
2023-TC-N19	Chasgo County Sub	N/A	XEL	2023
2023-TC-N20	Scott County Sub	N/A	XEL	2023
2023-TC-N30	Line 0822	N/A	XEL	2023
2023-TC-N31	Inver Hills Sub	N/A	XEL	2023
2023-TC-N32	Parkers Lake TR10	N/A	XEL	2023
2025-TC-N2	2023 Line Clearance	N/A	XEL	2025

6.7 Southwest Zone

6.7.1 Needed Projects

The following table provides a list of transmission needs identified in the Southwest Zone by MISO utilities.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2017-SW-N1	Summit to Dovray 69 kV Rebuild	2016/A	9907	No	No	ITCM
2017-SW-N3	Fulda to Heron Lake 69 kV Rebuild	2016/A	9910	No	No	ITCM
2021-SW-N1	Fieldon Retirement	2021/A	19165	No	No	XEL
2021-SW-N2	Worthington Area Projects	2022/A	GRE:22030/ ITCM:21929/	No	No	GRE/ ITCM/
2023-SW-N1	J1164/J1325 Interconnection	2022/A	21999	No	No	ITCM
2023-SW-N3	Brookings - Lyon, Hampton - Helena 2nd 345 kV Circuits	2022/A	23452	No	No	XEL
2023-SW-N4	Lake Yankton TR02 ELR	2023/A	23456	No	No	XEL
2023-SW-N5	Brookings - Lyon, Hampton - Helena OPGW Replacement	2023/A	24902	No	No	XEL
2023-SW-N6	Steep Bank Lake Line Swap	2023/A	24374	No	No	XEL

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2023-SW-N7	Nighthawk Breaker Station	2023/A	23463	No	No	XEL
2023-SW-N8	Line 0719 Winthrop to STR 45 Rebuild	2023/A	23503	No	No	XEL
2023-SW-N9	Minnesota Valley TR11 ELR	2023/A	23498	No	No	XEL
2023-SW-N10	Fairmont, MN Area Transmission Expansion	2023/A	25252	Yes	No	SMP
2023-SW-N11	Fairmont, 10th St. Substation Modernization	2023/A	25199	No	No	SMP
2023-SW-N12	Lakefield Area Projects	2025/A	50420	No	No	GRE
2025-SW-N13	J1566 Rutland 161 kV Interconnection	2026/A	50606	No	No	SMP
2025-SW-N1	Line 0714 Madelia - Watonwan Rebuild	2023/A	23460	No	No	XEL
2025-SW-N2	JTIQ Lyon Co - Lakefield Junction	2024/A	50710	Yes	No	XEL, ITC
2025-SW-N3	Split Rock - Chanarambie Line JTIQ	2025/A	50489	Yes	No	XEL
2025-SW-N4	Reinforce Tracy Switching Station TR01	2024/A	25294	No	No	XEL
2025-SW-N5	Nobles County Third Transformer	2024/A	25300	No	No	XEL
2025-SW-N6	Brookings County - Lyon County 345kV Davit Arm Replacement	2025/A	50711	No	No	XEL, GRE, OTP, CMPAS, RPU
2025-SW-N7	Fort Ridgely 69kV Rebuild	2025/A	50456	No	No	XEL
2025-SW-N8	Essig Substation Rebuild	2025/A	50423	No	No	XEL
2025-SW-N9	PowerOn Midwest (LRTP Projects 22, 23, 23 and 25)	2024/A	22, 23, 24, 25	Yes	No	XEL, GRE, ITCM

Summit to Dovray 69 kV Rebuild

MPUC Tracking Number: 2017-SW-N1

Utility: ITC Midwest (ITCM)

Project Description: The 12.9 miles-long Summit to Dovray 69 kV line will be reconstructed on the existing right of way.

Need Driver: The line's age and condition and increased maintenance costs have required that this line be rebuilt. The existing line has galloping issues, and the line operates frequently.

Alternatives:
Transmission Alternatives

A rebuild of the line with T2-4/0 ACSR conductor is planned. The rebuild of the line on existing right of way was the sole alternative considered to solve the age and condition issue.

Non-Wires Alternatives

The Summit to Dovray 69 kV line is being replaced due to age and condition. A non-wires alternative is not considered a viable alternative to address the need to replace the Summit to Dovray 69 kV line.

Analysis: The plan to replace the transmission line with new poles, conductor and shield wire will solve the reliability concern caused by the age and condition of the 69 kV line.

Schedule: Construction of the line is expected to be completed by the end of 2025.

General Impacts: The rebuild will occur on existing right of way. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. The rebuild will increase the reliability of electric service in the area.

Fulda Junction to Heron Lake 69 kV Rebuild

MPUC Tracking Number: 2017-SW-N3

Utility: ITC Midwest (ITCM)

Project Description: The approximately 20.1 miles-long Fulda Junction to Heron Lake 69 kV line will be reconstructed on the existing right of way.

Need Driver: The line's age and condition and increased maintenance costs have required that this line be rebuilt. The existing line has galloping issues, and the line operates frequently.

Alternatives:

Transmission Alternatives

A rebuild of the line with T2-4/0 ACSR conductor is planned. The rebuild of the line on existing right of way was the sole alternative considered to solve the age and condition issue.

Non-Wires Alternatives

The Fulda Junction to Heron Lake 69 kV line is being replaced due to age and condition. A non-wires alternative is not considered a viable alternative to address the need to replace the Fulda Junction to Heron Lake 69 kV line.

Analysis: The plan to replace the line with new poles, conductor and shield wire will solve the reliability concern caused by the age and condition of the 69 kV line. The line work is expected to be completed by the end of 2028.

Schedule: Construction of the line is expected to be completed by the end of 2028.

General Impacts: The rebuild will occur on existing right of way. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. The rebuild will increase the reliability of electric service in the area.

Fieldon Retirement

MPUC Tracking Number: 2021-SW-N1

Utility: Xcel Energy (XEL)

Project Description: This project bypasses and retires the Fieldon series capacitor and removes the substation, whose only function is for the series capacitor.

Need Driver: System improvements in the area have removed the need for the Fieldon series capacitor which has had operational issues in the past and has a significant recurring maintenance cost.

Alternatives:

Transmission Alternatives

Leaving the series capacitor in service, with corresponding maintenance burden and cost.

Non-Wires Alternatives

Retirement of an existing asset no longer needed.

Analysis: Retiring this substation produces no adverse effects to the transmission system.

Schedule: This project is expected to be completed in December 2025.

General Impacts: Retirement of the Fieldon substation.

Worthington Area Projects

MPUC Tracking Number: 2021-SW-N2

Utility: Great River Energy (GRE), ITC Midwest (ITCM), Missouri River Energy Services (MRES)

Project Description: Projects consist of multiple line and substation projects in the Worthington area:

MRES: Construction of a new substation, Lorain Substation.

GRE: Construction of approximately 9 miles of 69 kV transmission line from the Lorain substation to the new 161/69 kV substation, Rost Substation, interconnecting the existing GRE owned FE-RH, Heron Lake – Round Lake 69 kV line.

ITCM: Construction of a new substation, Forks Substation which will interconnect to the existing Dickinson – Lakefield Junction 161 kV transmission line. Construction of approximately 6.5 miles of 161 kV transmission line from the Forks substation to the Rost substation.

Need Driver: Operational and reliability issues in the Worthington area of southern Minnesota have existed for some time. Various options have been considered and investigated by the parties who operate in the area and numerous temporary operating guides have been in use over several years.

At present, single contingency bus outages at Elk cause the Worthington load to drop. In addition, there is a challenge to take outages on the 161 kV system, some portions of the 69 kV system, and some portions of the neighboring 345 kV system in order to perform certain maintenance due to voltage concerns with the system in an N-1 condition.

Load growth at the Lorain 69 kV substation has exacerbated prior outage events in the area. Any outage on the 161 kV between Split Rock (Xcel) and Magnolia leaves the system susceptible to low voltages for faults anywhere between Lakefield Junction and Elk 161 kV.

Alternatives:
Several alternatives were studied and considered during the joint study analysis:

<u>Transmission Alternatives</u>

1. Nobles County to Worthington 115 kV Loop
2. Build a 69 kV line from Lakefield Junction to West Lakefield and from West Lakefield to Worthington (Lorain).

3. Rost 161/69 kV substation with Rost Located at intersection of ITCM's 161 kV and GRE's FE-RJ 69 kV line, along with 69 kV line from Worthington to GRE's FE-RH line.

Non-Wires Alternatives

Even though the hybrid solution identified in the NWA study addresses the issues based on the technical analysis, economic analysis reveals that this is not an economically feasible option for the Worthington area. Nonetheless, considering future zero carbon emission goals, the hybrid solution fails to fulfill those requirements as well. Compared to the traditional solution cost, the proposed hybrid solution cost is about 10 times higher than the traditional solution. This study verified that no non-wires alternatives or cost-effective environmentally friendly hybrid alternatives are available today to address the Worthington area's reliability issues in an economical manner. A report is available upon request.

Analysis: Missouri River Energy Services (MRES), Great River Energy (GRE), and ITC Midwest (ITCM) performed a joint study to consider various options for the area.

Based on the analysis, the parties agreed to pursue the Rost project option, which included the additional 161 kV line and Lakefield corners substation. This was based on the largest MW load margin and advantages of being closer to Worthington load.

The biggest advantage is observed with upsizing the capacitors at the Lorain substation and the 150 MVA transformer at Heron Lake. The capacitors will be built to have the ability to upscale.

This new project will allow a strong new source to serve the growing Worthington load, address voltage collapse, and allow the existing 69 kV system to remain in a more system normal configuration during critical prior outages.

Schedule: The project is planned to be in service by November 2027.

General Impacts: The project will require approximately 6.5 miles of new 161 kV transmission line from Forks substation to Rost substation. The project is located in predominantly agricultural lands. Prior to construction, the Utilities will acquire the necessary right-of-way and permits for construction of the project. The Utilities anticipate acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, the Utilities will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 60 months. During this time, the Utilities and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

J1164 and J1325 Generator Interconnection to Magnolia 161 kV

MPUC Tracking Number: 2023-SW-N2

Utility: ITC Midwest (ITCM)

Project Description: To provide for interconnection of two 80 MW (160 MW total) solar-powered generating facility, MISO projects J1164 and J1325, the 161 kV bus at Magnolia will be reconfigured to form a ring bus at the location of the existing Magnolia substation.

Need Driver: MISO projects J1164 and J1325 was studied under the MISO business practices, and the expansion of the Magnolia 161 kV bus to connect projects J1164 and J1325 is required to provide interconnection service to the project under the MISO tariff.

Alternatives:
<u>Transmission Alternatives</u>
> The interconnections were evaluated under the MISO's DPP 2018 and 2019 system impact studies. No alternatives for the interconnections were identified.

<u>Non-Wires Alternatives</u>
> Projects J1164 and J1325 will be interconnected under MISO Tariff requirements. A non-wires is not viable as this project is aiding in the interconnection of two 80 MW (160 MW total) solar-powered generating facilities.

Analysis: The interconnection of projects J1164 and J1325 were evaluated as part of the MISO DPP 2018 and 2019 system impact studies. The expansion of facilities at Magnolia are required to provide a point of interconnection for project J1164 and J1325.

The Magnolia substation is over 60 years old, and the substation was not originally designed or constructed to accommodate additional bus positions on the 161 kV bus. The existing 161 kV substation bus will be rebuilt from a straight bus configuration to a ring bus configuration.

Schedule: The project is planned to be placed in service in 2026.

General Impacts: The upgrades will occur within the existing Magnolia 161 kV Substation. Termination of the J1164 and J1325 generator tie-line will be coordinated with the interconnection customer and necessary authorities. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated.

Brookings - Lyon, Hampton - Helena 2nd 345 kV Circuits

MPUC Tracking Number: 2023-SW-N3

Utility: Xcel Energy (XEL)

Project Description: Install approximately 60 mile second 345 kV circuit between the Brookings County and Lyon County substations. Install approximately 39 mile second 345 kV circuit between the Hampton Corner and Helena substations. Perform substation upgrades associated with installation of line.

Need Driver: Adds second circuit that eliminates current system conditions that impede deliverability of existing resources to demand centers in primarily off-peak periods of high renewable production which results in a reduction of available generation capacity at times of higher-than-average maintenance and construction outages.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

This new line installation uses existing double circuit structures on existing right of way. No alternatives were considered.

Analysis: This is a cost-effective system resiliency solution that reduces system congestion.

Schedule: The project went in service September 15, 2025.

General Impacts: The project will be constructed on the existing 345 kV double circuit structures, using existing right of way. The second circuit will reduce congestion on the transmission system allowing for economical dispatch of renewable energy resources. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. Existing right of way will be restored upon completion of project.

Lake Yankton TR02 ELR

MPUC Tracking Number: 2023-SW-N4

Utility: Xcel Energy (XEL)

Project Description: Replace Lake Yankton 115/69 kV TR02.

Need Driver: The ELR transformer program is to proactively replace aging transformers that have passed their operational service life and are showing increase signs of degradation.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2027.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Brookings - Lyon, Hampton - Helena OPGW Replacement

MPUC Tracking Number: 2023-SW-N5

Utility: Xcel Energy (XEL)

Project Description: This project will replace the aging OPGW on the Brookings - Lyon County and Hampton - Helena 345 kV lines. This project will be performed in tandem with the installation of the Brookings - Lyon County and Hampton - Helena 2nd circuit installation project.

Need Driver: The existing OPGW on the Brookings - Lyon County and Hampton - Helena 345 kV lines are showing signs of degradation and have experienced failures. Replacement is needed to ensure reliable communications and controls on those circuits.

Alternatives:
Transmission Alternatives

None.

Non-Wires Alternatives

This project replaces existing end of life communications equipment. No alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went in service September 15, 2025.

General Impacts: The project will be replacing existing equipment at end of life. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. Existing right of way will be restored upon completion of project.

Steep Bank Lake Line Swap

MPUC Tracking Number: 2023-SW-N6

Utility: Xcel Energy (XEL)

Project Description: This project will Move J460 Steep Bank Lake interconnection to new 345 kV second circuit being built between Brookings County - Lyon County (MTEP ID 23452).

Need Driver: Transferring Steep Bank Lake to the new Brookings County - Lyon County 345 kV line will avoid crossing lines going into the substation and provide additional operational flexibility.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went in service September 2025.

General Impacts: The project will be swapping existing substation to new line on existing right of way eliminating line crossings which could impact reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. Existing right of way will be restored upon completion of project.

Nighthawk Breaker Station

MPUC Tracking Number: 2023-SW-N7

Utility: Xcel Energy (XEL)

Project Description: New 4-line terminal breaker station connecting to Minnesota Valley – Troy 69 kV transmission line (0724), Crook’s substation, and the SMBSC plant.

Need Driver: Improve reliability of service to Southern Minnesota Beet Sugar Corporation (SMBSC), a business adversely impacted by power disruptions.

Alternatives:

Transmission Alternatives

New 230/69 kV substation north of the plant site to supply the two distribution substations supporting SMBS. No indicated load increase; the 69 kV line is capable of providing a well enough source of service to the existing customers. Not enough justification for an additional source in the area

<u>Non-Wires Alternatives</u>

None.

Analysis: Adding a breaker station to the existing 69 kV system will reduce outages and improve reliability for SMBSC. No other immediate overloads or voltage concerns.

Schedule: The project went in service September 26, 2024.

General Impacts: The project will install a new substation along existing 69 kV line. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0719 Winthrop to STR 45 Rebuild

MPUC Tracking Number: 2023-SE-N8

Utility: Xcel Energy (XEL)

Project Description: Rebuild 1.5 miles of line 0719 69 kV from Winthrop - Structure 45.

Need Driver: Asset at end of life and at risk of imminent failures. Increased outage frequency and duration. Failure could provide risk to public safety.

Alternatives:

<u>Transmission Alternatives</u>

Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

<u>Non-Wires Alternatives</u>

This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 2027.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Minnesota Valley TR11 ELR

MPUC Tracking Number: 2023-SE-N9

Utility: Xcel Energy (XEL)

Project Description: Replace Minnesota Valley 115/69 kV TR11.

Need Driver: Asset at end of life and at risk of imminent failures. Increased outage frequency and duration. Failure could provide risk to public safety.

Alternatives:
Transmission Alternatives

Transformer may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

Non-Wires Alternatives

This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 2027.

General Impacts: No environmental issues have been identified. Transformer replacement will have minimal impacts to existing system performance and footprint.

Fairmont, MN Area Transmission Expansion

MPUC Tracking Number: 2023-SW-N10

Utility: Southern Minnesota Municipal Power Agency

Project Description: Building of a new 69/12.5 kV distribution substation "West Industrial Park" (WIP) west of Fairmont, construction of a new 69 kV SMMPA breaker station and construction of two 69 kV transmission lines, one from WIP to the SMMPA's Fairmont Energy Station (FES) substation and one from WIP which will tap Great River Energy's 69 kV line between Rutland substation and the Fairmont 10th Street Substation.

Need Driver: This project was motivated by Fairmont Public Utilities (FPU) to address their need for a new distribution substation.

Alternatives:
Transmission Alternatives

A radial 69 kV transmission line was considered, but ultimately there was too much line exposure to Fairmont load.

Non-Wires Alternatives

Because Fairmont needs to be able to serve load from a new location non-wires alternatives were not considered.

Analysis: These additions will add a reliable 69 kV transmission loop through town. This increases the load serving capability in town as well as minimizes the possibility of transmission outages to area load.

Schedule: Expected in service date is late 2026.

General Impacts: The new FPU substation is likely to be built on existing city owned land. The new SMMPA substation will be built on existing SMMPA owned land. Most of the line routing will be done on existing distribution right of way. Where needed right of way will be expanded or added to, environmental impacts will be minimized on the project. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

Fairmont, 10th St. Substation Modernization

MPUC Tracking Number: 2023-SW-N11

Utility: Southern Minnesota Municipal Power Agency

Project Description: Current breakers were installed in 1985, and they have become unreliable and difficult to maintain with their age. Along with these breakers, the associated switches and relays will also be replaced with newer and more reliable equipment. The new equipment includes new PTs, arresters, and new solid-state relay panels.

Need Driver: Old breakers have become difficult to maintain with reoccurring problems and parts shortages, effectively driving maintenance costs up. Other equipment upgrades are being made to switch from electromechanical to the more reliable solid-state equipment.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: N/A

Schedule: New equipment expected to be in service on June 1, 2026.

General Impacts: The 10th St. substation is on existing city owned land. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

Lakefield Area Projects

MPUC Tracking Number: 2023-SW-N12

Utility: Great River Energy (GRE)

Project Description: Expansion of the 345 kV Gen tie bus at the Lakefield substation to accommodate the Three Waters Wind (340 MW) Wind Farm. Installation of new 345 kV breakers on the existing generator and installation of the GRE controlled EEE, 1500' of 345 kV Transmission to the interconnect 161 kV/345 kV step up substation.

Need Driver: Additional 345 kV interconnection required to connect the Three Waters wind farm.

Alternatives:
Transmission Alternatives
> This project is necessary to facilitate the connection of a new wind farm. This is an existing generation site and was deemed the best interconnection point, therefore alternatives were not considered.

Non-Wires Alternatives
> Non-wires alternatives are not considered for new generation interconnections as the POI is determined by the interconnection customer.

Analysis: The interconnection of the Three Waters Wind Farm at Lakefield was evaluated as part of the MISO DPP system impact studies.

Schedule: The Lakefield Area Projects are planned to be in-service by November 2026.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0714 Madelia – Watonwan Rebuild

MPUC Tracking Number: 2025-SW-N1

Utility: Xcel Energy (XEL)

Project Description: Rebuild 22 miles of line 0714 69 kV from Medelia - Watonwan.

Need Driver: Needed for age and condition rebuild.

Alternatives:
Transmission Alternatives
> The project is replacing existing assets and was chosen as the best option to meet the need.

Non-Wires Alternatives

The project is replacing existing assets and was chosen as the best option to meet the need.

Analysis: The plan to replace the transmission line with new poles, conductor and shield wire will solve the reliability concern caused by the age and condition of the 69 kV line.

Schedule: Construction of the line is expected to be completed by December of 2025.

General Impacts: This project is expected to have minimal impacts as its replacing existing infrastructure.

JTIQ Lyon Co – Lakefield Junction

MPUC Tracking Number: 2025-SW-N2

Utility: Xcel Energy (XEL), ITC Midwest (ITCM)

Project Description: 345kV JTIQ line from Lyon County - Lakefield Junction

Need Driver: Project is part of the JTIQ portfolio used to provide stability and improve transfers at the MISO SPP seam.

Alternatives:

Transmission Alternatives

The project was a joint MISO-SPP project and was chosen as the best option to meet the need.

Non-Wires Alternatives

The project was a joint MISO-SPP project and was chosen as the best option to meet the need.

Analysis: This project will help fix existing issues on the seams between MISO and SPP. This project is key to aiding the interconnection queues of both regions. This project will have a CON in the state of Minnesota. The details of the project will be discussed at length in the application.

Schedule: The project is planned to be in service by June of 2031.

General Impacts: This a major project and will have a CON application which will detail those impacts.

Split Rock - Chanarambie 345kV line JTIQ

MPUC Tracking Number: 2025-SW-N3

Utility: Xcel Energy (XEL)

Project Description: 345kV JTIQ line from Split Rock - Chanarambie

Need Driver: Project connects to the JTIQ portfolio to provide stability and remediate N-1-1 contingency thermal violations.

Alternatives:

Transmission Alternatives

> The project was used to mitigate N-1-1 contingency thermal violations and better serve local load growth.

Non-Wires Alternatives

> The project resolves N-1-1 contingency thermal violations and was chosen as the best option to meet the need.

Analysis: This project will help fix existing N-1-1 contingency thermal violations in the area and improve load serving. The details of the project will be discussed at length in the application.

Schedule: The project is planned to be in service by June of 2033.

General Impacts: This a major project and will have a CON application which will detail those impacts.

Reinforce Tracy Switching Station TR01

MPUC Tracking Number: 2025-SW-N4

Utility: Xcel Energy (XEL)

Project Description: Upgrade existing transformer at Tracy Switching Station to 14 MVA. Convert town of Tracy to 13.8 kV and retire Tracy (TRA) substation.

Need Driver: Needed to mitigate transformer overloads at Tracy Switching Station.

Alternatives:

Transmission Alternatives

> The project is fixing existing distribution overloads was chosen as the best option to meet the need.

Non-Wires Alternatives

> The project is fixing existing distribution overloads was chosen as the best option to meet the need.

Analysis: This project will fix existing distribution load serving issues and will replace an aging transformer.

Schedule: The project is planned to be in service by May of 2028.

General Impacts: This project is expected to have minimal impacts as its replacing existing infrastructure in an existing substation.

Nobles Third Transformer

MPUC Tracking Number: 2025-SW-N5

Utility: Xcel Energy (XEL)

Project Description: Add third 345/115 kV transformer with tertiary reactor at Nobles County.

Need Driver: Needed to prevent overloads for P6 contingencies in high wind scenarios.

Alternatives:
Transmission Alternatives
The project is adding a third transformer and will fix contingencies required by NERC to find solutions for. This project was chosen as the best option to meet the need.
Non-Wires Alternatives
The project is adding a third transformer and will fix contingencies required by NERC to find solutions for. This project was chosen as the best option to meet the need.

Analysis: This project will fix a P6 contingency at Nobles and is expected to help congestion in the area.

Schedule: The project is planned to be in service by May of 2028.

General Impacts: This project is expected to have minimal impacts as its work done in the existing substation.

Brookings County – Lyon County 345kV Davit Arm Replacement

MPUC Tracking Number: 2025-SW-N6

Utility: Xcel Energy (XEL), Great River Energy (GRE), Otter Tail Power Company (OTP), Central Municipal Power Agency Services (CMPAS), Rochester Public Utilities (RPU)

Project Description: This project replaces select steel davit arms on the Brookings County-Lyon County line. Some of the davit arms have defects and need to be replaced.

Need Driver: Condition replacement of steel davit arms on Brookings County-Lyon County 345 kV Transmission line.

Alternatives:
Transmission Alternatives
This project replaces existing defective assets, so no other alternatives were evaluated.

Non-Wires Alternatives
This project replaces existing defective assets, so no non-wires options were evaluated.

Analysis: Physical analysis of the structures revealed davit arms that are defective. For safety and integrity of the davit arms, they must be replaced with non-defective arms.

Schedule: The project is planned to be in service by September of 2030.

General Impacts: No significant impacts are anticipated as this is an existing circuit with the majority of the structure will remain as is, with only replaced davit arms.

Fort Ridgely 69kV Rebuild

MPUC Tracking Number: 2025-SW-N7

Utility: Xcel Energy (XEL)

Project Description: Upgrade 69 kV lines Fort Ridgley-GRE Schilling Tap, Lafayette-GRE Lafayette, GRE Schilling Tap-GRE Lafayette Tap, and Winthrop-Lafayette.

Need Driver: Line overloads on these lines were observed in the MTEP24 Appendix D6 generator deliverability study. These lines are also at end of life.

Alternatives:
Transmission Alternatives
The project is replacing existing assets and was chosen as the best option to meet the need.
Non-Wires Alternatives
The project is replacing existing assets and was chosen as the best option to meet the need.

Analysis: The plan to replace the transmission line with new poles, conductor and shield wire will solve the reliability concern caused by the age and condition of the 69 kV line.

Schedule: Construction of the line is expected to be completed by January of 2029.

General Impacts: This project is expected to have minimal impacts as its replacing existing infrastructure.

Essig Substation Rebuild

MPUC Tracking Number: 2025-SW-N8

Utility: Xcel Energy (XEL)

Project Description: Rebuild end of life Essig substation at neighboring site, converting old 2.4 kV system to standard 12.47kV

Need Driver: Substation is at end of life and is showing deterioration and is nonstandard 2.4 kV

Alternatives:
Transmission Alternatives

The project will rebuild the existing substation that is at the end of its life and thus was chosen as the best option to meet the need.

Non-Wires Alternatives

The project will rebuild the existing substation that is at the end of its life and thus was chosen as the best option to meet the need.

Analysis: The project will rebuild the existing substation that is at the end of its life and thus was chosen as the best option to meet the need.

Schedule: The project is planned to be in service by September of 2027.

General Impacts: This project is expected to have low impacts.

J1566 Rutland 161 kV Interconnection

MPUC Tracking Number: 2025-SW-N13

Utility: Southern Minnesota Municipal Power Agency

Project Description: An interconnection to a 150 MW solar farm on the 161 kV ring bus at Rutland Substation.

Need Driver: MISO project J1566 was studied under the MISO business practices, and the expansion of the Rutland 161 kV bus to connect project J1566 is required to provide interconnection service to the project under the MISO tariff.

Alternatives:
Transmission Alternatives

None.

Non-Wires Alternatives

None.

Analysis: The interconnection of project J1566 was evaluated as part of the MISO DPP-2020 study. The expansion of facilities at Byron is required to provide a point of interconnection for project J1566.

Schedule: New equipment expected to be in service in 12/31/2027.

General Impacts: This project is located on SMMPA owned property. No significant traffic impacts are anticipated. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

PowerOn Midwest

LRTP Projects #22, 23, 24, and 25

MPUC Tracking Number: 2025-SW-N9

Utility: Great River Energy (GRE), ITC Midwest (ITCM), and Xcel Energy (XEL)

Project Description: The Project consists of approximately 271 miles of new 765 kilovolt (kV) transmission lines across southern Minnesota that will be part of a 765 kV path connecting Minnesota, South Dakota, Iowa, and Wisconsin. The Project includes expansion of the existing Lakefield Junction, Pleasant Valley, and North Rochester Substations for 765 kV facilities. The Project also includes approximately 69 miles of a new 345 kV line between the Pleasant Valley, North Rochester and Hampton Substations and modifications at all three 345 kV substations. For the new 345 kV circuit, a new, second, approximately 38-mile 345 kV transmission line circuit would be strung on existing double-circuit-capable 345 kV structures between the North Rochester and Hampton Substations. Between the Pleasant Valley and North Rochester Substations, approximately 31 miles, the existing single-circuit-capable structures are proposed to be removed and replaced with double-circuit-capable structures to accommodate the second line.

Need Driver: The Project was studied, reviewed, and approved as part of the MISO LRTP Tranche 2.1 Portfolio. The Project is needed to maintain regional and local system reliability amid fundamental changes in demand for electricity and the type and amount of generation interconnected to the grid within the MISO footprint.

Alternatives:

<u>Transmission Alternatives</u>

Transmission system alternatives will be addressed in the Certificate of Need Application. Details of MISO's LRTP Tranche 2.1 analysis are available in the LRTP section of the MTEP24 report.

<u>Non-Wires Alternatives</u>

Non-Wire Alternatives will be addressed in the Certificate of Need Application. Details of MISO's LRTP Tranche 2.1 analysis are available in the LRTP section of the MTEP24 report.

Analysis: The need for PowerOn Midwest and the benefits of the Project will be summarized in the Certificate of Need Application. Details of MISO's LRTP Tranche 2.1 analysis are available in the LRTP section of the MTEP24 report.

Schedule: The 765kV and 345kV portions of PowerOn Midwest are planned to be in-service in 2034 and 2032 (respectively).

General Impacts: Project routing discussions will occur in late 2025, 2026 and 2027. GRE, ITCM, and XEL will consider all relevant human, environmental, and community interests in the area and will actively engage impacted stakeholders in routing and siting of the project. Construction is anticipated to take upwards of five years to complete. During this time, GRE, ITCM, and XEL and/or their contractors will be working in the area and will contribute positively to the local economy. The right-of-way will be restored following construction.

6.7.2 Completed Projects

The table below identifies those projects by Tracking Number in the Southwest Zone that were listed as ongoing projects in the 2023 Biennial Report but have been completed or withdrawn since the 2023 Report was filed with the Minnesota Public Utilities Commission in November 2023. Information about each of the completed projects is summarized briefly in the table below. More information about these projects and inadequacies can be found in earlier reports. Projects that were listed as being complete in the 2023 Report are not repeated here, but more information about those projects can be found in these earlier reports.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2013-SW-N1	Heron Lake 161 kV Substation Rebuild	N/A	ITCM	2025
2017-SW-N2	Dovray to Fulda 69 kV Rebuild	N/A	ITCM	2025
2021-SW-N2	Worthington Area Projects (Lorain Substation)	N/A	MRES (20608)	2/16/2023
2025-SW-NX	Worthington Sub 2 Breaker	N/A	MRES	3/13/2025

6.8 Southeast Zone

6.8.1 Needed Projects

The following table provides a list of transmission needs identified in the Southeast Zone by MISO utilities. There were no projects identified in this zone by non-MISO utilities.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2019-SE-N2	Adams to Stewartville 69 kV Rebuild	2012/A	3630	No	No	ITCM
2023-SE-N2	Line 0749 Waseca - ITC Tap Rebuild	2023/A	23459	No	No	XEL
2023-SE-N3	Line 0714 Medelia - Watonwan Rebuild	2023/A	23460	No	No	XEL
2023-SE-N4	Line 0708 STR 78 to 476 Rebuild	2023/A	23461	No	No	XEL
2023-SE-N5	Gaiter Lake Substation	2023/A	23528	No	No	XEL
2023-SE-N6	Rock Dell to Pleasant Valley 69 kV Rebuild	2025	50272	No	No	DPC
2023-SE-N7	Genoa to Ringe 69 kV Rebuild	2025	50271	No	No	DPC
2023-SE-N8	J898 Interconnection at Beaver Creek	2024/A	25498	No	No	DPC
2023-SE-N9	Kellogg 161 kV Transmission Substation	2021/A	23371	No	No	DPC
2025-SE-N1	Marion Road to Mississippi River 765 kV Transmission Line Segment	2024/A	50559	Yes	No	DPC
2025-SE-N2	Owatonna – 161/69 kV Transmission Expansion	Future	TBD	No	No	SMP
2025-SE-N3	Owatonna Cap Bank Addition	2025/A	50153	No	No	SMP
2025-SE-N4	Byron Substation – Pleasant Valley Terminal Upgrade	2025/A	50501	No	No	SMP
2025-SE-N5	Byron J1124 Interconnection	2026/A	50605	No	No	SMP
2025-SE-N6	Byron – Cascade Creek Line Relocation	2025/A	50498	No	No	SMP
2025-SE-N7	Byron Substation Modernization	Future	TBD	No	No	SMP
2025-SE-N8	Spring Creek Area Upgrade Projects	2024/A	25456	No	No	GRE
2025-SE-N9	Medford Area Projects	2026/A	50875	No	No	GRE

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2025-SE-N10	0774 Goodview - Str 444 Rebuild	2024/A	25288	No	No	XEL
2025-SE-N11	Rebuild Wabasha Substation	2024/A	25379	No	No	XEL
2025-SE-N12	Cleveland – Sheas Lake Rebuild	2024/A	25345	Yes	No	ITCM
2025-SE-N13	Hayward – County Line – Ellendale 69 kV Rebuild	2025/A	50211	No	No	ITCM
2025-SE-N14	Gopher to Badger Link (LRTP #26)	2024/A	26	Yes	No	XEL, DPC

Adams to Stewartville 69 kV Rebuild

MPUC Tracking Number: 2019-SE-N2

Utility: ITC Midwest (ITCM)

Project Description: The approximately 35 miles-long Adams to Stewartville 69 kV line will be reconstructed on the existing right of way.

Need Driver: The Adams to Stewartville 69 kV line was built over 50 years ago, and increased maintenance costs will require the line to be reconstructed due to its age and condition.

Alternatives:
Transmission Alternatives

A rebuild on existing ROW was the sole alternative considered to solve the age and condition issue.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition on the Adams to Stewartville 69 kV circuit.

Analysis: The plan to replace the over 50-years-old transmission line with new poles, conductor and shield wire will solve the reliability concern caused be the age and condition of the 69 kV line.

Schedule: Initial rebuild of the line is expected to be completed in 2028.

General Impacts: The line is near the end of its useful life. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. The rebuild of the line will increase the reliability of electric service in the area.

Line 0749 Rebuild

MPUC Tracking Number: 2023-SE-N2

Utility: Xcel Energy (XEL)

Project Description: Rebuild 6.7 miles of 69 kV line 0749 from Waseca - ITC Tap and add OPGW.

Need Driver: Needed for age and condition rebuild.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project went in service June 30, 2025.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0714 Medelia - Watonwan Rebuild

MPUC Tracking Number: 2023-SE-N3

Utility: Xcel Energy (XEL)

Project Description: Rebuild 22 miles of line 0714 69 kV from Medelia - Watonwan.

Need Driver: Needed for age and condition rebuild.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

Non-Wires Alternatives

This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 31, 2025.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0708 STR 78 to 476 Rebuild

MPUC Tracking Number: 2023-SE-N4

Utility: Xcel Energy (XEL)

Project Description: Rebuild 16 miles of line 0708 69 kV from Eagle Lake - Waterville and add OPGW.

Need Driver: Needed to address galloping issues on this line.

Alternatives:

Transmission Alternatives

Line may be used as is, but this runs the risk of reliability issues. No alternatives were considered.

Non-Wires Alternatives

This is replacing an existing asset.

Analysis: Rebuilding to address galloping concerns. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 31, 2027.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Gaiter Lake Substation

MPUC Tracking Number: 2023-SE-N5

Utility: Xcel Energy (XEL)

Project Description: Build new Gaiter Lake substation in Waseca to pick up load off of Clarks Grove, Meridan, and Waseca substations. Retire Clarks Grove and Meridan substations.

Need Driver: Needed due to age and condition of Clarks Grove and Merdian substations, as well as capacity needs.

Alternatives:

Transmission Alternatives

Rebuild of existing substations would not increase load serving capability, leaving load at risk and would involve full rebuild of two substations opposed to construction of one new substation.

Non-Wires Alternatives

None.

Analysis: Transferring load from existing substations to new substation in same area. No immediate overloads or voltage concerns.

Schedule: The project went in service June 30, 2025.

General Impacts: The project will install a new substation along existing 69 kV line and retirement of two existing substations. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Rock Dell to Pleasant Valley 69 kV Rebuild

MPUC Tracking Number: 2023-SE-N6

Utility: Dairyland Power Cooperative (DPC)

Project Description: Rebuild 2.2 miles of DPC's Maple Leaf to Airport 69 kV line between the Rock Dell and Pleasant Valley distribution substations on existing and new right-of-way.

Need Driver: DPC purchased this line from People's Energy Cooperative in July of 2022. This line was identified for rebuild due to age and condition.

Alternatives:

Transmission Alternatives

A rebuild solely on existing right-of-way was considered. However, a portion of the existing right-of way runs through a lower lying area that is also in the Rock Dell Wildlife Management Area. For this reason, a mix of existing and new right-of way is also being considered.

Non-Wires Alternatives

None.

Analysis: The 2.2-mile section 69 kV transmission line rebuild will address the reliability concerns due to age and condition. The potentially relocated section of this rebuild will also improve accessibility for maintenance.

Schedule: Construction of the line is expected to be completed by early-2028.

General Impacts: The line is near the end of its useful life. Dairyland construction crews will rebuild this line in early-2028, requiring approximately three weeks to construct. The portion of the rebuild on existing right-of-way will have minimal impacts, while the portion being considered for new right-of-way will improve accessibility.

Genoa to Ringe 69 kV Rebuild

MPUC Tracking Number: 2023-SE-N7

Utility: Dairyland Power Cooperative (DPC)

Project Description: Rebuild 8.9 miles of DPC's Maple Leaf to Rochester 69 kV line between the Genoa and Ringe distribution substations on existing and new right-of-way.

Need Driver: DPC purchased this line from People's Energy Cooperative in July of 2022. This line was identified for rebuild due to age and condition.

Alternatives:
Transmission Alternatives

A rebuild solely on existing right-of-way was considered. Relocating portions of the line has added reliability benefits.

Non-Wires Alternatives

None.

Analysis: The 8.9-mile section 69 kV transmission line rebuild will address the reliability concerns due to age and condition. The relocated section of this rebuild will also improve line exposure and reliability.

Schedule: Construction of the line is expected to be completed by late 2028.

General Impacts: The line is near the end of its useful life. Dairyland construction crews will rebuild this line in 2028, requiring approximately eleven weeks to construct.

J898 Interconnection at Beaver Creek 161 kV

MPUC Tracking Number: 2023-SE-N8

Utility: Dairyland Power Cooperative (DPC)

Project Description: Replace the 161 kV Beaver Creek Tap three-way switches with a 4-breaker substation approximately 6 miles south of the Beaver Creek Tap to allow for the interconnection of 100 MW of wind-powered generation with the potential for additional capacity in the future. A 6-mile portion of 161 kV transmission line on new right-of-way will be constructed to connect the new transmission substation back to the existing Harmony to Beaver Creek 161 kV transmission line. A 4-mile stretch of existing 161 kV transmission line between Harmony and the Beaver Creek Tap will be retired.

Need Driver: The new 3-breaker substation and 6-mile portion of 161 kV transmission line are required as part of the MISO Tariff for the interconnection of 100 MW of wind-powered generation for project J898.

Alternatives:
Transmission Alternatives

> The interconnection for J898 was evaluated under MISO's DPP August 2017 West system impact study. An alternative of upgrading the 69 kV transmission to the south of SMMPA's Rice substation was considered.

Non-Wires Alternatives

> None.

Analysis: The interconnection of project J898 was evaluated under MISO's DPP August 2017 West and 2020 West system impact study. Potential overloads of the underlying 69 kV system under contingent conditions were identified. The proposed project was determined to be the most reliable and cheapest mitigation for these overloads.

Schedule: The in-service date for the substation portion of the project is late-2026, while the new 161 kV transmission line portion of the project is late-2027.

General Impacts: The 161 kV transmission line portion of this project will be built on new right-of-way, with approximately 4 miles of existing transmission line to be retired. The resulting configuration will replace the existing 3-terminal 161 kV transmission line between Harmony, Adams and Rice with three 2-terminal transmission lines, providing additional reliability benefits. The Commission considered the potential route permit impacts in Docket No. ET3/TL-24-95.

Kellogg 161 kV Transmission Substation

MPUC Tracking Number: 2023-SE-N9

Utility: Dairyland Power Cooperative (DPC)

Project Description: Construct a new 5-breaker 161/69 kV transmission substation, named Kellogg on DPC's Wabaco to Alma 161 kV transmission line. Construct 9 miles of 161 kV transmission line on new right-of-way, connecting between Wabaco and Kellogg from existing transmission into the Kellogg substation. Install a 112 MVA 161/69 kV transformer at Kellogg and reterminate DPC's Utica to Alma 69 kV transmission line into the Kellogg substation. Retire the remaining 2.5-mile Mississippi River crossing portion of the 69 kV transmission line between Alma and the Weaver distribution substation.

Need Driver: These projects are required by MISO's Long Range Transmission Plan (LRTP) and are included in the identified Tranche 1 projects to address needs associated with the changing resource mix across the MISO Midwest subregion. The new DPC facilities are required to replace the 69 kV Mississippi River crossing between Alma and the Weaver distribution substation with the North Rochester to Tremval 345 kV transmission line.

Alternatives:

Transmission Alternatives

The MISO LRTP planning efforts considered several alternatives to the recommended Tranche 1 projects.

Non-Wires Alternatives

None.

Analysis: The Kellogg substation, new 161 kV transmission line and 69 kV retermination frees up the Mississippi River crossing for the new North Rochester to Tremval 345 kV transmission line, without sacrificing local reliability.

Schedule: The in-service date for the project is late-2027 to early-2028.

General Impacts: The new Kellogg substation and 69 kV retermination will have minimal need for new right-of-way, but will allow for new 345 kV Mississippi River crossing on existing right-of-way. The 9 miles of new 161 kV transmission will be constructed on new right-of-way. The LRTP Tranche 1 projects are renewable-enabling, allowing for reliable, green energy in the future.

Loon Lake Substation Modernization

MPUC Tracking Number: 2023-SE-N10

Utility: Southern Minnesota Municipal Power Agency

Project Description: Current breakers were installed in 1985, and they have become unreliable and difficult to maintain with their age. Along with these breakers, the associated switches and relays will also be replaced with newer and more reliable equipment. The new equipment includes new PTs, arresters, and new solid-state relay panels.

Need Driver: Old breakers have become difficult to maintain with reoccurring problems and parts shortages, effectively driving maintenance costs up. Other equipment upgrades are being made to switch from electromechanical to the more reliable solid-state equipment.

Alternatives:

Transmission Alternatives:

None.

Non-Wires Alternatives:

None

Analysis: N/A

Schedule: New equipment expected to be in service by June 01, 2026.

General Impacts: This project is located on SMMPA owned property. No significant traffic impacts are anticipated. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

Pleasant Valley Area Projects

MPUC Tracking Number: 2023-SE-N11

Utility: Great River Energy (GRE)

Project Description: This project involves expansion of the 161 kV bus at the Pleasant Valley substation to accommodate the Phase 1 Wind (170 MW) and Phase 2 Wind (150 MW) Wind Farms interconnection. It also includes expansion of the control house to accommodate additional equipment.

Need Driver: This project is needed to support renewable energy development interconnecting to GRE's Pleasant Valley substation. GRE will upgrade the Pleasant Valley substation by adding 161 kV transmission bays to connect to the Dodge County and Timber Wind farms, while also expanding the Pleasant Substation westward with an additional breaker row. This configuration will enable smooth integration of wind generation through the 161 kV line and improve fault isolation, enhancing system reliability.

Alternatives:

Transmission Alternatives

This project is driven by wind interconnection, and no transmission alternatives were considered. An alternative design to install dead end and breakers in the existing opening between existing breakers 19QB6 and 19QB7 was however considered in the design phase.. This would eliminate the need to expand the current yard. This alternative design was not further considered as it would require extensive bus outages and limitations on generation at Pleasant Valley to allow for safe installation and maintenance of equipment.

Non-Wires Alternatives

Non-wires alternatives were not considered as it is a wind generation interconnections project driven by an interconnection customer.

Analysis: The interconnection of the Dodge County Wind and Timberwolf Wind farms was assessed through the MISO Definitive Planning Process (DPP) system impact studies. As part of this process, MISO conducted a Surplus Interconnection Study to evaluate the effects of integrating the new Dodge County Wind project into the existing Pleasant Valley substation.

The study included evaluations based on Local Planning Criteria (LPC), covering steady-state performance, dynamic stability, and LPC-specific dynamic stability.

- Steady State Analysis: No thermal overloads or voltage violations were identified on the MISO system because of the project.
- Dynamic Stability Analysis: The system demonstrated acceptable dynamic performance, with no violations of stability criteria attributable to the new wind generation.
- LPC Dynamic Stability Analysis: Results confirmed stable system behavior, with no criteria violations observed.

Overall, the study concluded that the interconnection of the Dodge County Wind project does not adversely impact the reliability or stability of the MISO transmission system.

Schedule: The Pleasant Valley Area Projects are planned to be in service by the end of 2026.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Pleasant Valley Terminal Upgrade

MPUC Tracking Number: 2023-SE-N12

Utility: Great River Energy (GRE)

Project Description: Upgrade terminal equipment to 3000 A ratings.

Need Driver: The 161 kV transmission line between Pleasant Valley and Byron experienced 1169 hours of market congestion between July 2020 and July 2022, according to a study by Grid North Partners. The average shadow price during those hours was $92. The congestion is primarily caused by terminal equipment rated at 2000 A, which restricts the full utilization of the conductor's capacity. Without upgrades, this limitation is expected to continue contributing to market congestion in the future.

Alternatives:
<u>Transmission Alternatives</u>

No transmission alternatives were considered since this project is replacing the most limiting equipment in an existing substation.

<u>Non-Wires Alternatives</u>

No non-wires alternatives were considered since this project is replacing the most limiting equipment in an existing substation.

Analysis: Upgrading the circuit breakers at the Pleasant Valley substation from a 2000 A rating to a 3000 A rating would enable full utilization of the Pleasant Valley to Byron 161 kV transmission line's conductor capacity. This change would eliminate terminal equipment as the limiting factor, allowing the line to operate at its designed capacity and significantly reducing the potential for market congestion.

Addressing the terminal rating constraint through this targeted equipment upgrade is identified as the most cost-effective solution to mitigate congestion, while also improving overall system reliability.

Schedule: The project is planned to be in service by winter 2027.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Marion Road to Mississippi River 765 kV Transmission Line Segment

MPUC Tracking Number: 2025-SE-N1

Utility: Dairyland Power Cooperative (DPC)

Project Description: Construct a new 110-mile, 765/161 kV double circuit transmission line from southeast Rochester, MN to the Mississippi River south of Brownsville, MN and across the river from Genoa, WI. This project represents a segment of the MISO Long Range Transmission Plan (LRTP) Project 26, which constructs a 273-mile 765 kV transmission line between North Rochester and Columbia County, WI.

Need Driver: These projects are required by MISO's Long Range Transmission Plan (LRTP) and are included in the identified Tranche 2.1 projects to address needs associated with the changing resource mix across the MISO Midwest subregion.

Alternatives:
<u>Transmission Alternatives</u>

The MISO LRTP planning efforts considered several alternatives to the recommended Tranche 2.1 projects. Additional details regarding MISO's alternatives analysis for Tranche 2.1 can be found in the LRTP section of the MTEP24 Report.

Non-Wires Alternatives:

None.

Analysis: Full details of MISO's LRTP Tranche 2.1 analysis are available in the LRTP section of the MTEP24 report.

Schedule: The MISO LRTP Tranche 2.1 projects are targeting in-service dates from 2032 to 2034.

General Impacts: The Marion Road to Mississippi River segment of the MISO LRTP-26 project team is evaluating routing alternatives including utilizing existing 161 kV transmission right-of-way in the area.

Owatonna – 161/69 kV Transmission Expansion

MPUC Tracking Number: 2025-SE-N2

Utility: Southern Minnesota Municipal Power Agency

Project Description: Building of a new 69/12.5 kV distribution substation "NE Owatonna Substation" (NEOS), construction of a new 161/69 kV substation, North Owatonna Substation (NOS) tapping the West Owatonna Substation-South Faribault Substation 161 kV transmission line, and construction of two 69 kV transmission lines, one from NOS to the NEOS and one from NEOS to East Owatonna Substation.

Need Driver: This project was motivated by Owatonna Public Utilities (OPU) to address their need for a new distribution substation.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

None.

Analysis: A study was conducted to verify the effectiveness of these additions, and it was able to mitigate voltage violations that were occurring on the Owatonna Subsystem.

Schedule: Expected in-service date is June 01, 2030.

General Impacts: This project is located on SMMPA owned property. No significant traffic impacts are anticipated. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

West Owatonna Substation – Cap Bank Addition

MPUC Tracking Number: 2025-SE-N3

Utility: Southern Minnesota Municipal Power Agency

Project Description: Addition of a 50 MVAR Cap Bank on the 161 kV bus at West Owatonna Substation.

Need Driver: Under certain N-1 and N-1-1 contingencies, low voltage violations will occur on the Owatonna Subsystem.

Alternatives:

Transmission Alternatives

A third 161 kV source to the West Owatonna Substation was considered and studied.

Non-Wires Alternatives

None.

Analysis: A study was conducted to verify the effectiveness of this addition, and it was able to mitigate voltage violations that were occurring on the Owatonna Subsystem.

Schedule: Expected in-service date is January 1, 2027.

General Impacts: This project is located on SMMPA owned property. No significant traffic impacts are anticipated. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

Byron Substation - Pleasant Valley Terminal Upgrade

MPUC Tracking Number: 2025-SE-N4

Utility: Southern Minnesota Municipal Power Agency

Project Description: Upgrade terminal equipment to 3000 A rating.

Need Driver: Upgrade of terminal equipment of Byron - Pleasant Valley 161kV line to match joint facility owners.

Alternatives:
<u>Transmission Alternatives</u>

No transmission alternatives were considered since this project is replacing the most limiting equipment in an existing substation.

<u>Non-Wires Alternatives</u>

No non-wires alternatives were considered since this project is replacing the most limiting equipment in an existing substation.

Analysis: This upgrade will prevent terminal equipment from being the binding rating and allow for the line conductor capacity rating to be fully utilized, reducing the likelihood of the line causing congestion in the market.

Schedule: The project is planned to be in service by December 01, 2027.

General Impacts: This project is located on SMMPA owned property. No significant traffic impacts are anticipated. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

J1124 Interconnection at Byron 345 kV Substation

MPUC Tracking Number: 2025-SE-N5

Utility: Southern Minnesota Municipal Power Agency

Project Description: Addition of 345kV terminal at Byron substation to support a 100MW solar interconnection.

Need Driver: MISO project J1124 was studied under the MISO business practices, and the expansion of the Byron 345 kV bus to connect project J1124 is required to provide interconnection service to the project under the MISO tariff.

Alternatives:
<u>Transmission Alternatives</u>

None.

<u>Non-Wires Alternatives</u>

None.

Analysis: The interconnection of project J1124 was evaluated as part of the MISO DPP-2018 study. The expansion of facilities at Byron is required to provide a point of interconnection for project J1124.

Schedule: Expected in-service date of November 1, 2027

General Impacts: This project is located on SMMPA owned property. No significant traffic impacts are anticipated. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

Byron – Cascade Creek Line Relocation

MPUC Tracking Number: 2025-SE-N6

Utility: Southern Minnesota Municipal Power Agency

Project Description: Relocation of 1.2miles of 161kV transmission lines from Byron Substation to Cascade Creek Substation.

Need Driver: MNDoT requires the line to be moved due to the construction of an interchange at the intersection of Hwy 14 and 44.

Alternatives:
Transmission Alternatives
None.

Non-Wires Alternatives
None.

Analysis: N/A

Schedule: Planned in-service by December 31, 2026.

General Impacts: This project is located on SMMPA owned property. No significant traffic impacts are anticipated. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

Byron Substation Modernization

MPUC Tracking Number: 2025-SE-N7

Utility: Southern Minnesota Municipal Power Agency

Project Description: Substation contains two breakers that were installed in 1988 and 1995, and they have become unreliable and difficult to maintain with their age. Along with these breakers, the associated switches and relays will also be replaced with newer and more reliable equipment. The new equipment includes new CTs, PTs, arresters, and new solid-state relay panels.

Need Driver: Old breakers have become difficult to maintain with reoccurring problems and parts shortages, effectively driving maintenance costs up. Other equipment upgrades are being made to switch from electromechanical to the more reliable solid-state equipment.

Alternatives:

Transmission Alternatives

No transmission alternatives were considered since this project is replacing the most limiting equipment in an existing substation.

Non-Wires Alternatives

No non-wires alternatives were considered since this project is replacing the most limiting equipment in an existing substation.

Analysis: N/A

Schedule: TBD

General Impacts: This project is located on SMMPA owned property. No significant traffic impacts are anticipated. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

Spring Creek Area Upgrade Projects

MPUC Tracking Number: 2025-SE-N8

Utility: Great River Energy (GRE)

Project Description: Replace the two 161/69 kV 70 MVA transformers with 140 MVA units and complete the 161 kV topology to a ring bus.

Need Driver: This project is needed to address post contingent overloads that have been seen at the Spring Creek 161/69 kV transformers. The GRE Spring Creek substation has 161/69kV, 70 MVA transformers. Each of these transformers overload for loss of the other transformer. This project aims to address the overload by replacing each unit with a 140 MVA transformer. As part of this project, the ring bus design at the Spring Creek substation will be updated to align with current design standards.

Alternatives:

Transmission Alternatives

This transmission project was identified as the most cost-effective and reliable solution for addressing transformer overloads and completing the substation topology at Spring Creek. As a result, no other transmission options were formally evaluated.

However, one alternative was considered during early planning: converting the existing 161/69 kV transformers to a 115/69 kV configuration. This option was ultimately dismissed due to several key factors:

- Capacity limitations with the 115 kV line would reduce system resilience during contingencies.
- Higher infrastructure complexity, including the need for dual high-side transformers and a new distribution transformer at Ravenna.
- Limited strategic benefit, as other substations in the region would continue operating on 161/69 kV, undermining standardization efforts.
- Reduced need for spares, since installing two 140 MVA units at Spring Creek would sufficiently cover future reliability needs.

In summary, the selected upgrade path—retaining the 161/69 kV configuration and enhancing capacity with 140 MVA units—was deemed the most practical and cost-efficient approach for long-term system performance.

Non-Wires Alternatives

Non-wires alternatives were deemed infeasible for addressing the transformer overload issue and the required upgrade of the ring bus to meet current design standards.

Analysis: Contingency analysis has confirmed overloads at the Spring Creek 161/69 kV transformers during events such as the loss of one transformer or a simultaneous outage involving the 161 kV transmission line and a transformer. These reliability risks are consistently reflected in -the planning models, reinforcing the urgency of corrective action. As part of the broader mitigation strategy, the project seeks to complete the existing non-standard configuration by converting it to a ring-bus. Currently, the absence of a high-side breaker on the 161 kV line results in transformer outages whenever there a fault on the 161 kV line. Upgrading to a ring-bus design will improve operational flexibility and resilience during contingency events.

Schedule: The project is planned to be in service by winter 2027.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Medford Area Projects

MPUC Tracking Number: 2025-SE-N9

Utility: Great River Energy (GRE)

Project Description: Construct a 161 kV tap line from SMMPA's West Owatonna–South Faribault 161 kV transmission line to the high side of the Medford distribution substation, which will be constructed and owned by Steele-Waseca Electric Cooperative (SWEC).

Need Driver: This project is needed to interconnect SWEC's Medford distribution substation. SWEC plans to construct the Medford distribution substation to address critical challenges—including voltage drop issues, feeder overloads, limited feeder redundancy, and aging equipment. This project is designed to strengthen system reliability, enhance operational flexibility, and improve overall power quality.

Alternatives:

Transmission Alternatives:

Interconnection to the 69 kV transmission system was considered; however, the 161 kV transmission system located much closer to the Medford distribution substation was determined to offer superior reliability and capacity to support long-term reliable service to the substation

Non-Wires Alternatives:

This project is to interconnect SWEC'S Medford distribution substation to the transmission system. Non-wires alternatives were not considered viable option.

Analysis: Power flow analysis was performed and showed no adverse impact on the existing transmission system.

Distribution analysis showed the need for the new delivery point due to challenges including voltage drop issues, feeder overloads, limited feeder redundancy, and aging equipment.

Schedule: The project is planned to be in service by Summer 2026.

General Impacts: The project will be constructed on a site on the existing 161 kV transmission line with under 1500 feet of new line required. The project is in predominantly agricultural lands. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

0774 Goodview – Str 444 Rebuild

MPUC Tracking Number: 2025-SE-N10

Utility: Xcel Energy (XEL)

Project Description: Rebuild 3 miles 69 kV with new structures, new OPGW shield wire, and new conductor.

Need Driver: Age & Condition rebuild, wood polls reaching end of life.

Alternatives:
Transmission Alternatives
The project is replacing existing assets and was chosen as the best option to meet the need.
Non-Wires Alternatives
The project is replacing existing assets and was chosen as the best option to meet the need.

Analysis: The plan to replace the transmission line with new poles, conductor and shield wire will solve the reliability concern caused by the age and condition of the 69 kV line.

Schedule: Construction of the line is expected to be completed by December of 2025.

General Impacts: This project is expected to have minimal impacts as its replacing existing infrastructure.

Rebuild Wabasha Substation

MPUC Tracking Number: 2025-SE-N11

Utility: Xcel Energy (XEL)

Project Description: Rebuild Wabasha substation at a nearby location due to flooding concerns.

Need Driver: Wabasha substation is susceptible to flooding during early spring season.

Alternatives:
Transmission Alternatives
The project will rebuild the existing substation that is in a location that floods and thus was chosen as the best option to meet the need.
Non-Wires Alternatives
The project will rebuild the existing substation that is in a location that floods and thus was chosen as the best option to meet the need.

Analysis: The project will rebuild the existing substation that is in a location where flooding occurs seasonally. This project will move the substation to a dry location.

Schedule: The project is planned to be in service by December of 2028.

General Impacts: The project is expected to have minimal impacts because it moves the substation out of an area of flooding to a dryer location.

Cleveland – Sheas Lake Rebuild

MPUC Tracking Number: 2025-SE-N12

Utility: ITC Midwest (ITCM)

Project Description: GRE will be rebuilding their portion of the existing Cleveland – Sheas Lake 69 kV line to address loading and congestion. GRE requested ITC Midwest also rebuild the ITC Midwest portion of the line, approximately 10 miles, to allow a significant increase in the thermal rating of the line instead of the very marginal increase that would only be achieved with a GRE only rebuild. Approximately 10 miles of the ITC Midwest portion Cleveland – Sheas Lake 69 kV line will be reconstructed on the existing right of way. The line will be re-constructed with a larger conductor size and will also be insulated to allow a potential conversion to a higher operating voltage in the future.

Need Driver: In addition to the needed increased thermal rating on the ITC Midwest portion of the Cleveland – Sheas Lake line, the ITC Midwest portion of the line was built over 50 years ago.

Alternatives:

<u>Transmission Alternatives</u>

A rebuild on existing ROW was the sole alternative considered to increase the thermal rating of the line and also address the age and condition issue.

<u>Non-Wires Alternatives</u>

Non-wire alternatives are not viable because they cannot address concerns related to age and condition on the circuit.

Analysis: The plan to replace the over 50-years-old transmission line with new poles, conductor and shield wire will solve the reliability concern caused be the age and condition of the 69 kV line. By using a new larger standard conductor as part of the rebuild, the contingent loading concerns are addressed. By re-constructing the line to higher operating voltage standards, the area will be better situated for a future conversion to a higher operating voltage.

Schedule: Initial rebuild of the line is expected to be completed in 2029.

General Impacts: The line is near the end of its useful life. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. The rebuild of the line will increase the reliability of electric service in the area.

Hayward – County Line – Ellendale 69 kV Rebuild

MPUC Tracking Number: 2025-SE-N13

Utility: ITC Midwest (ITCM)

Project Description: The approximately 19 miles-long Hayward – County Line - Ellendale 69 kV line will be reconstructed on the existing right of way.

Need Driver: The Hayward – County Line - Ellendale 69 kV line was built over 50 years ago, and in addition, there has been increased contingent loading on this line and due to the increased time of the year when an operating guide is required to address contingent loading, a line rebuild was determined to be required to increase the thermal rating of the line.

Alternatives:

Transmission Alternatives

A rebuild on existing ROW was the sole alternative considered to solve the age and condition issue. In addition, use of the existing right of way to rebuild the line and increase the thermal rating while limiting impacts to land owners.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition on the Hayward – County Line - Ellendale 69 kV circuit.

Analysis: The plan to replace the over 50-years-old transmission line with new poles, conductor and shield wire will solve the reliability concern caused be the age and condition of the 69 kV line. By using a new larger standard conductor as part of the rebuild, the contingent loading concerns are addressed.

Schedule: Initial rebuild of the line is expected to be completed in 2028.

General Impacts: The line is near the end of its useful life. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. The rebuild of the line will increase the reliability of electric service in the area.

Gopher to Badger Link

LRTP Project #26

MPUC Tracking Number: 2025-SE-N14

Utility: Xcel Energy (XEL) and Dairyland Power Cooperative (DPC)

Project Description: The Project consists of a (1) single-circuit 765 kV high voltage transmission line between the existing North Rochester Substation and a point near Marion, Minnesota; (2) a 765 kV/161 kV double-circuit high voltage transmission line from near Marion, Minnesota, to the Wisconsin border; and (3) 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 between the new switching station and the existing Genoa Substation in Wisconsin.

Need Driver: The Project was studied, reviewed, and approved as part of the MISO LRTP Tranche 2.1 Portfolio. The Project is needed to maintain regional and local system reliability amid fundamental changes in demand for electricity and the type and amount of generation interconnected to the grid within the MISO footprint.

Alternatives:

Transmission Alternatives

Transmission system alternatives will be addressed in the Certificate of Need Application. Details of MISO's LRTP Tranche 2.1 analysis are available in the LRTP section of the MTEP24 report.

Non-Wires Alternatives

Non-Wire Alternatives will be addressed in the Certificate of Need Application. Details of MISO's LRTP Tranche 2.1 analysis are available in the LRTP section of the MTEP24 report.

Analysis: The need for Gopher to Badger Link and the benefits of the Project will be summarized in the Certificate of Need Application. Details of MISO's LRTP Tranche 2.1 analysis are available in the LRTP section of the MTEP24 report.

Schedule: The Project planned to be in-service in 2034.

General Impacts: Project routing discussions will occur in late 2025 and 2026. XEL and DPC will consider all relevant human, environmental, and community interests in the area and will actively engage impacted stakeholders in routing and siting of the project. During construction, XEL, DPC, and/or their contractors will be working in the area and will contribute positively to the local economy. The right-of-way will be restored following construction.

6.8.2 Completed Projects

The table below identifies those projects by Tracking Number in the Southeast Zone that were listed as ongoing projects in the 2023 Biennial Report but have been completed or withdrawn since the 2023 Report was filed with the Minnesota Public Utilities Commission in November 2023. Information about each of the completed projects is summarized briefly in the table below. More information about these projects and inadequacies can be found in earlier reports. Projects that were listed as being complete in the 2023 Report are not repeated here, but more information about those projects can be found in these earlier reports.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2019-SE-N3	J523 Generator Interconnection to Adams 161 kV	N/A	ITCM	2023
2019-SE-N5	Thisius 161/69 kV Substation	N/A	ITCM	2023
2021-SE-N3	Hayward 161/69 kV Transformer Replacement	N/A	ITCM	2025
2021-SE-N2	Northfield to Farmington Line Rebuild	N/A	XEL	2023
2023-SE-N1	Line 0761 Rebuild	2022/A	XEL	2024

7.0 Transmission-Owning Utilities

7.1 Introduction

In this chapter of the 2025 Report, the utilities have provided the following information.

Background Information and Contact Person

For ease of reference, the utilities have provided much of the same background information provided in the 2023 Report. This information relates to the history of each utility and the extent of its service territory and operations. An Internet link is provided where additional information about each utility can be found. In addition, a contact person is identified for each utility.

Transmission Line Ownership

In the 2007 Biennial Report, the utilities reported on the miles of transmission lines each utility owned in Minnesota. The MTO updated that information in subsequent biennial reports in 2009, 2011, 2013, 2015, 2017, 2019, 2021, and 2023, and they are updating it again in this report. The table below is the latest information on the transmission lines in Minnesota owned by each utility. In addition, information specific to each utility is included in the discussion for that utility.

Miles of Transmission

Utility	<100 kV	100-199 kV	200-299 kV	> 300 kV	DC
American Transmission Company, LLC	0	0	0	12	0
Central Minnesota Municipal Power Agency	28	14	0	0	0
Dairyland Power Cooperative	424	153	0	9	0
East River Electric Power Cooperative	166	46	0	0	0
Great River Energy	3,086	642	524	146	0
ITC Midwest LLC	669	310	0	115	0
L&O Power Cooperative	43	8	0	0	0
Minnesota Power	0.22	1,310	618	266	232
Minnkota Power Cooperative	1,008	153	268	0	0
Missouri River Energy Services	32	239	24	47	0
Northern States Power Company d/b/a Xcel Energy	1588.4	1745.9	390.7	1,106.7	0
Otter Tail Power Company	1,293	585	186	565	0
Rochester Public Utilities	0	43	0	0	0
Southern Minnesota Municipal Power Agency	150	135	17	0	0
CapX2020 Jointly Owned	0	0	68	614	0 Jointly Owned
Totals:*	8,579	5,409	2,103	3,082	232

*Individual cells may not sum to total due to rounding.

7.2 American Transmission Company, LLC

Background information. American Transmission Company (ATC) began operations on January 1, 2001, the first multi-state electric transmission-only utility in the country. The company is head-quartered in Pewaukee, Wisconsin.

At least 28 utilities, municipalities, municipal electric companies, and electric cooperatives from Wisconsin, Michigan, and Illinois have invested transmission assets or money for ownership stake in the company. ATC is responsible for operating and maintaining the transmission lines of its equity owners. It owns more than 9,921 circuit miles of transmission lines and 577 substations in Wisconsin, Michigan, Illinois, and Minnesota. ATC has $5.5 billion in total assets.

ATC is a transmission-owning member of the MISO, and its transmission system is located in both the Midwest Reliability Organization and ReliabilityFirst Corporation.

More information about the company is available on its website at:

http://www.atcllc.com

Contact Person: John Sealy
Transmission Planning Engineer
American Transmission Co.
P.O. Box 47
Waukesha, WI 53187-0047
Phone: (262) 506-6700
e-mail: jsealy@atcllc.com

Transmission lines. ATC owns more than 9,921 miles of transmission lines, including 12 miles in Minnesota. The transmission line segment in Minnesota extends from the Arrowhead Substation in the Duluth area to the St. Louis River and is part of the 220-mile 345-kV Arrowhead-Weston line that extends from the Arrowhead Substation to the Gardner Park Substation in Wausau, Wisconsin. The Arrowhead-Weston line, which cost $439 million to construct, was energized in January 2008. Arrowhead-Weston provides such benefits as improving reliability, enhancing transfer capability between Minnesota and Wisconsin, and providing ATC and other utilities greater opportunities to perform maintenance on other parts of the electric system, which reduces operating costs.

(1) American Transmission Company Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
0	0	0	12	0

7.3 Central Minnesota Municipal Power Agency

Background information. Central Minnesota Municipal Power Agency (CMMPA) is a municipal corporation and political subdivision of the State of Minnesota, headquartered in Eden Prairie, Minnesota. CMMPA was created in 1987 and has twelve municipally-owned utilities as members, located predominantly in south-central Minnesota. Central Municipal Power Agency/Services (CMPAS) serves as the utility services agent for CMMPA and provides energy management and consulting services to public power members and affiliates in Minnesota and Iowa. CMMPA has transmission assets that are part of MISO.

More information about the company is available on its website at:

http://www.cmpas.org

Contact Person:

Jodi Walters
Policy Manager
Central Municipal
Power Agency/Services
7550 Corporate Way
Eden Prairie, MN 55344
Phone: (763) 710-3933
e-mail:

Transmission lines. CMMPA is one of the eleven members of the CapX2020 group, and one of the five co-owners in the Brookings-Hampton 345 kV line. In addition, CMMPA is the transmission owner in MISO for the following transmission assets owned by its members.

(2) **Central Minnesota Municipal Power Agency**

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
28	14	0	0	0

7.4 Dairyland Power Cooperative

Background Information. Dairyland Power Cooperative (DPC), a Touchstone Energy Cooperative, was formed in December 1941. A generation and transmission cooperative, Dairyland provides the wholesale electrical requirements to 24 member distribution cooperatives and 17 municipal utilities in Wisconsin, Minnesota, Iowa and Illinois. Today, the cooperative's generating resources include coal, hydro, solar, wind, natural gas, landfill gas and animal waste. Dairyland Power Cooperative joined MISO in 2010.

More information about Dairyland Power Cooperative is available at:

http://www.dairylandpower.com

Contact Person:
Chase Lakowske
Planning Engineer II
Dairyland Power Cooperative
3200 East Avenue South
La Crosse, WI 64601
Phone: (608) 787-1265
Email: chase.lakowske@dairylandpower.com

Transmission Lines. Dairyland delivers electricity via 3,720 miles of transmission to 400 distribution substations located throughout the system's 44,500 square mile service area. Dairyland has the following transmission facilities in Minnesota:

(3) **Dairyland Transmission Lines**

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
423.80	152.75	0	8.88	0

7.5 East River Electric Power Cooperative

Background Information. East River Electric Power Cooperative (East River), headquartered in Madison, South Dakota, is a wholesale electric power supply and transmission cooperative serving 24 rural distribution electric cooperatives and one municipally-owned electric system, which in turn serve more than 250,000 member-owners. East River's 40,000 square mile service area covers the rural areas of 41 counties in eastern South Dakota and twenty-two counties in western Minnesota.

Six of East River's member systems have service areas entirely in western Minnesota and one member system has service areas in both eastern South Dakota and western Minnesota. The remaining seventeen member systems have service areas entirely in eastern South Dakota.

East River is a part of the Southwest Power Pool and has transmission facilities in MISO.

More information about East River Electric Power Cooperative is available at:

http://www.eastriver.coop

Contact Person:
John Knofczynski
Transmission Policy Administrator
East River Electric Power Cooperative
P.O. Box 227
211 South Harth Avenue
Madison, SD 57042
Phone: (605) 256-4536
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e-mail: jknofczynski@eastriver.coop

Transmission Lines. East River delivers electricity via approximately 3,000 miles of transmission lines and 240 substations located throughout the system's 40,000 square mile service area in eastern South Dakota and western Minnesota. East River has the following transmission facilities in Minnesota:

East River Electric Power Cooperative Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
166	46	0	0	0

7.6 Great River Energy

Background Information. Great River Energy (GRE) is a not-for-profit electric cooperative owned by 26 member distribution cooperatives. The organization generates and transmits electricity for those members, which are located from the outer-ring suburbs of the Twin Cities, up to the Arrowhead region of Minnesota and down to the farming communities in the southwest part of the state. GRE's largest distribution cooperative serves more than 116,000 member-consumers, while the smallest serves approximately 4,400. Collectively, GRE's member cooperatives distribute electricity to approximately 566,000 member accounts. GRE serves approximately 1.7 million people through its member-owned cooperatives and customers. The majority are served by 26 member-owners that collectively own GRE. In addition, GRE is part of MISO.

More information about Great River Energy is available at:

http://www.greatriverenergy.com

Contact Person: Matt Ellis
Director, Transmission Planning & Compliance Great River Energy
12300 Elm Creek Blvd
Maple Grove, MN 55369-4718
Ph: (763) 445-5955
Fax: (763) 445-5050
e-mail: mellis@grenergy.com

Transmission Lines. Great River Energy has the following transmission lines:

(4) **GRE Transmission Lines**

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
3,080	651	524	146	0

7.7 ITC Midwest LLC

Background Information. ITC Midwest LLC (ITC Midwest) is an independent transmission company subsidiary of ITC Holdings Corp. ITC Midwest purchased the transmission assets of Interstate Power and Light, a subsidiary of Alliant Energy, in December 2007. The Commission approved the sale in an Order dated February 7, 2008 in MPUC Docket No. E001/PA-07-540.

ITC Midwest has headquarters in Cedar Rapids, Iowa, and ITC Holdings Corp. is headquartered in Novi, Michigan. ITC Midwest also has offices in Dubuque and Des Moines, Iowa, and in St. Paul, Minnesota. Minnesota warehouses are located in Albert Lea and Lakefield, Minnesota. In addition, ITC Midwest's transmission system is part of MISO.

More information about ITC Midwest and ITC Holdings Corp. can be found at:

http://www.itctransco.com

Contact Person: Brian Drumm
Director, Regional Policy and RTO Engagement
ITC Holdings, LLC
27175 Energy Way
Novi, MI 48377
Phone: 703-731-8831
e-mail: bdrumm@itctransco.com

Transmission Lines. The ITC Midwest system includes approximately 6,600 miles of transmission lines, operating at voltages from 34.5 kV to 345 kV in Minnesota, Iowa, Illinois, and Missouri.

ITC Midwest owns approximately 1,094 miles of transmission line in the state of Minnesota, operating at voltages of 345 kV, 161 kV and 69 kV. The total miles of these transmission lines are listed by voltage class in the table below.

(5) **ITC Midwest Transmission Lines**

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
669	310	0	115	0

7.8 L&O Power Cooperative

Background Information. L&O Power Cooperative (L&O), headquartered in Rock Rapids, Iowa, is a wholesale electric power supply and transmission cooperative serving three rural distribution electric cooperatives. These member cooperatives in turn serve more than 5,600 homes and businesses across Rock and Pipestone counties in southwest Minnesota, and Lyon and Osceola counties in northwest Iowa. Approximately 2,700 of the total 5,600 total consumers served are located in Minnesota.

Additional information about L&O is available at:

http://www.landopowercoop.com

Contact Person: Jarrod Luze
Engineering & Operations Manager
L&O Power Cooperative
P.O. Box 511
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Phone: (712) 472-2556
Fax: (712) 472-2710
e-mail: jarrod.luze@dgr.com

Transmission Lines. L&O delivers wholesale electricity via approximately 183 miles of transmission lines and 16 substations located throughout the system's four county service area in southwestern Minnesota and northwestern Iowa. L&O has the following transmission facilities in Minnesota:

(6) **L&O Power Cooperative Transmission Lines**

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
43.17	8.32	0	0	0

7.9 Minnesota Power

Background Information. Minnesota Power (MP), a division of ALLETE, Inc., is an investor-owned utility headquartered in Duluth, Minnesota. Minnesota Power provides electricity in a 26,000 square-mile electric service area located in northeastern Minnesota. Minnesota Power serves approximately 150,000 residential and commercial customers, 14 municipalities, and some of the nation's largest industrial customers. Minnesota Power's transmission and distribution components include 8,742 miles of lines and 164 substations. Minnesota Power's transmission network is interconnected with the transmission grid to promote reliability and is part of MISO.

More information is available on the company's web page at:

http://www.mnpower.com

Contact Person:

Christian Winter
Minnesota Power
30 West Superior Street
Duluth, MN 55802
Phone: (218) 355-2908
e-mail: cwinter@mnpower.com

Transmission Lines. The number of miles of transmission in Minnesota owned by Minnesota Power is shown in the following table.

(7) **Minnesota Power Transmission Lines**

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
0.22	1,310.02	617.65	265.52	231.56

7.10 Minnkota Power Cooperative

Background Information. Minnkota Power Cooperative, Inc. (Minnkota or MPC) is a regional generation and transmission cooperative serving 11 member-owner distribution cooperatives in northwestern Minnesota and eastern North Dakota. Minnkota's service area is approximately 34,500 square miles over the two states. Minnkota is also the operating agent for the Northern Municipal Power Agency (NMPA), an association of 12 municipal utilities in the same service region. Together Minnkota and the NMPA comprise the Joint System and serve more than 151,000 consumers.

Additional information about Minnkota is available at:

http://www.minnkota.com

Contact Person:

Kasey Borboa
Senior Manager Power Delivery Operations
Minnkota Power Cooperative, Inc.
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Grand Forks, ND 58201-3312
Phone: (701) 795-4328
Fax: (701) 795-4333
e-mail: kborboa@minnkota.com

Transmission Lines. The Joint System owns 1,429.52 miles of transmission line in Minnesota and 1,951.35 miles in North Dakota. The miles of Minnesota transmission lines are shown in the following table:

(8) **Joint System Transmission Lines**

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
1,008.38	153.20	267.94	0	0

7.11 Missouri River Energy Services

Background Information. Missouri River Energy Services (MRES) began in the early 1960s as an informal association of northwest Iowa municipalities with their own electric systems that decided to coordinate their efforts in negotiating the purchase of power and energy from the United States Bureau of Reclamation of the United States Department of the Interior (USBR). MRES was established as a body corporate and politic organized in 1965 under Chapter 28E of the Iowa Code and exists under the intergovernmental cooperation laws of the states of Iowa, Minnesota, North Dakota, and South Dakota. Municipalities in Minnesota, North Dakota and South Dakota subsequently joined MRES pursuant to compatible enabling legislation in each state.

MRES is comprised of 61 municipally owned electric utilities in the states of Iowa, Minnesota, North Dakota, and South Dakota. The MRES member cities' service territories roughly coincide with the boundaries of the respective incorporated cities. MRES has no retail load, and all of its firm sales are made to municipal or other wholesale utilities. MRES acts as an agent for the Western Minnesota Municipal Power Agency (WMMPA), which itself was incorporated as a municipal corporation and political subdivision of the State of Minnesota. WMMPA provides a means for its members to secure, by individual or joint action among themselves or by contract with other public or private entities within or outside the State of Minnesota, an adequate, economical and reliable supply of electric energy. Current membership in WMMPA consists of 24 municipalities located in Minnesota, each of which owns and operates a utility for the local distribution of electricity. In addition, MRES is part of MISO and the Southwest Power Pool (SPP).

More information about Missouri River Energy Services can be found at:

http://www.mrenergy.com

Contact Person:

Andrew Berg
Missouri River Energy Services
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P.O. Box 88920
Sioux Falls, SD 57109-8920
Phone: (605) 330-6986
Fax: (605) 978-9396
e-mail: andrew.berg@mrenergy.com

Transmission Lines. The number of miles of transmission in Minnesota owned by Missouri River Energy Services is shown in the following table.

(9) **Missouri River Energy Services Transmission Lines**

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
32.16	239.32	24.02	47	0

7.12 Northern States Power Company

Background Information. Northern States Power Company, a Minnesota corporation (NSP), is a public utility organized under the laws of the State of Minnesota and is a wholly-owned subsidiary of Xcel Energy Inc., a publicly-traded company listed on the Nasdaq Stock Market. NSP is headquartered in Minneapolis, Minnesota. Xcel Energy Inc.'s other utility subsidiaries are Northern States Power Company, a Wisconsin corporation (NSPW), headquartered in Eau Claire, Wisconsin, Public Service Company of Colorado, headquartered in Denver, Colorado, and Southwestern Public Service Company, headquartered in Amarillo, Texas. NSP provides electricity and natural gas to customers in a service territory that encompasses the Twin Cities, many mid-size and small towns throughout Minnesota, and also to portions of South Dakota and North Dakota. NSP and NSPW operate an integrated generation and transmission system (the NSP System). In addition, Northern States Power Company is part of MISO.

More information can be found on Xcel Energy's web page at:

http://www.xcelenergy.com

Contact Person:

Jason Standing
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414 Nicollet Mall
Minneapolis, MN 55401
Phone: (612) 330-7768
Fax: (612) 330-6357
e-mail: jason.t.standing@xcelenergy.com

Transmission Lines. Northern States Power Company owns about 5,775 miles of transmission lines in Minnesota. The miles of Minnesota transmission lines are shown in the following table.

(10) **NSP Transmission Lines**

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
1,679.96	1,771.17	466.54	1,922.38	0

7.13 Otter Tail Power Company

Background Information. Otter Tail Power Company (OTP) is an investor-owned electric utility headquartered in Fergus Falls, Minnesota, and a subsidiary of Otter Tail Corporation (NASDAQ Global Select Market: OTTR). It provides electricity and energy services to more than 130,000 residential, commercial, and industrial customers in a service territory of 70,000 square miles that cover over 400 communities throughout Minnesota, South Dakota, and North Dakota, with approximately 63,100 customers in Minnesota. The company was originally incorporated in 1907 and first delivered electricity in 1909 from the Dayton Hollow Dam on the Otter Tail River. In addition, Otter Tail Power Company is part of MISO.

To learn more about Otter Tail Power Company visit www.otpco.com. To learn more about Otter Tail Corporation visit www.ottertail.com.

Contact Person: Dylan Stupca
Manager, Delivery Planning
Otter Tail Power Company
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone: (218) 739-8200
Fax: (218) 739-8442
e-mail: dstupca@otpco.com

Transmission Lines. OTP has the following transmission lines in Minnesota:

(11) **OTP Transmission Lines**

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
1,293.2	584.6	186.3	564.8	0

7.14 Rochester Public Utilities

Background Information. Rochester Public Utilities (RPU), a department of the City of Rochester, Minnesota, is the largest municipal utility in the state of Minnesota. RPU serves roughly 59,481 electric customers. In 1978, Rochester joined the Southern Minnesota Municipal Power Agency (SMMPA) with City Council approval. Initially, RPU was a full-requirements member with SMMPA controlling all of Rochester's electric power. Today, RPU is a partial requirements member of SMMPA and retains control over its own generating units. All of RPU's load and generation are serviced by MISO through its market function.

More information about Rochester Public Utilities is available at:

http://www.rpu.org/about

Contact Person:
Scott Nickels
Director of Power Delivery
Rochester Public Utilities
4000 East River Road NE
Rochester, MN 55906
Phone: (507) 280-1585
Fax: (507) 280-1542
e-mail: snickels@rpu.org

Transmission Lines. RPU has the following transmission lines in Minnesota.

(12) **Rochester Public Utilities Transmission Lines**

<100 kV	**100-199 kV**	**200-299 kV**	**>300 kV**	**DC**
0	42.56	0	0	0

7.15 Southern Minnesota Municipal Power Agency

Background Information. SMMPA is a not-for-profit municipal corporation and political subdivision of the State of Minnesota, headquartered in Rochester, Minnesota. SMMPA was created in 1977 and has seventeen municipally owned utilities as members, located predominantly in south-central and southeastern Minnesota. SMMPA serves approximately 112,000 retail customers. In addition, SMMPA is part of MISO.

More information about SMMPA is available at:

http://www.smmpa.com

Contact Person:
Seth Koneczny
Manager of Power Delivery
Southern Minnesota Municipal Power Agency
500 First Avenue Southwest
Rochester, MN 55902-6451
Phone: (507) 292-6456
e-mail: st.koneczny@smmpa.org

Transmission Lines. SMMPA has the following transmission lines in Minnesota:

(13) **SMMPA Transmission Lines**

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
149.84	135.48	17.09	0	0

8.0 Renewable Energy Standards

8.1 Introduction

Minn. Stat. § 216B.2425, subd. 7, states that in the Biennial Report the utilities shall address necessary transmission upgrades to support development of renewable energy resources required to meet the objectives set forth under Minn. Stat. § 216B.1691 (formerly the Renewable Energy Standards). In its May 30, 2008, Order approving the 2007 Biennial Report and Renewable Energy Standards Report, the Commission said, "Future biennial transmission projects reports shall incorporate, and address transmission issues related to meeting the standards and milestones of the new renewable energy standards enacted at Minn. Laws 2007, ch. 3." By 2020, the utilities had largely met the current Renewable Energy Standards, and many had additionally announced voluntary renewable or clean energy standards that exceeded the statutory objectives. As a result, in its 2020 Order approving the 2019 Report, the Commission said the 2021 Report should include content similar to the 2019 Report, along with new information regarding additional clean-energy goals and related transmission needs. The 2021 Biennial Report included this information in Chapter 9 of that report.

In 2023, the Minnesota Legislature amended the objectives set forth in Minn. Stat. § 216B.1691 to include additional milestones for renewable energy as well as creating new carbon-free energy standards (CFS) (*see* 2023 Minn. Laws Ch. 7). The statutory objectives now include:

	2025	2030	2035	2040
Renewable Energy	25%		55%	
Solar Energy*	1.5%	10%		
Carbon-free Energy		80% for public utilities; 60% for other electric utilities	90%	100%

**See* Minn. Stat. § 216B.1691, subd. 2f for additional detail relevant to the solar energy standards. For example, the 10% solar energy target by 2030 is established as a goal, rather than a requirement, and the legislation includes several other targets for smaller-scale solar energy.

In this Report, similar to prior reports, the utilities are reporting on their best estimates for the amounts of renewable generation required in future years and the efforts under way to ensure adequate transmission will be available to transmit that energy to the necessary market areas. A Gap Analysis is provided to illustrate the amount of renewable generation already available and the amounts required in the future to meet the standard. The narrative in this chapter is similar in many respects to the narrative and explanations provided in the 2023 Report, but all figures and charts and tables have been updated to reflect current legislation. As discussed more fully below, a gap analysis has not been provided for the carbon-free energy standards, as the Commission is continuing to evaluate and provide guidance on how this new standard will be implemented.

8.2 Reporting Utilities

It should be pointed out, as was done in previous reports, the utilities required to submit the Biennial Transmission Projects Report are not identical to those required to meet the Renewable Energy Standards. The information in this chapter reflects the work of all the utilities required to meet RES milestones, regardless of whether they own transmission lines and are required to participate in the Biennial Report. A list of those utilities participating in the Biennial Transmission Projects Report can be found in Chapter 2.0. The utilities participating in this part of the 2025 Biennial Report on renewable energy are the following.

Investor-owned Utilities

Minnesota Power
Northern States Power Company d/b/a Xcel Energy
Otter Tail Power Company

Generation and Transmission Cooperative Electric Associations

Basin Electric Power Cooperative
Dairyland Power Cooperative
East River Electric Power Cooperative
Great River Energy
L&O Power Cooperative
Minnkota Power Cooperative

Municipal Power Agencies

Central Minnesota Municipal Power Agency
Minnesota Municipal Power Agency
Southern Minnesota Municipal Power Agency
Rochester Public Utilities
Western Minnesota Municipal Power Agency/Missouri River Energy Services

Power District

Heartland Consumers Power District

8.4 Compliance Summary

Minnesota utilities continue to increase the size and expand the diversity of their renewable portfolios. The table provided in the introduction details the RES and SES obligations Minnesota utilities are working to achieve. Overall, Minnesota utilities have a 2025 collective obligation of 24.5% RES and 1.5% SES, as a percentage of applicable retail sales. The most recent reporting is summarized by the Minnesota Department of Commerce in Docket No. E999/PR-24-12, dated January 15, 2025. All utilities have satisfied their respective compliance requirements and expect to continue to achieve and maintain all compliance requirements in the future. All utilities continue to plan for the addition of increased renewable generation. The utilities have provided a Gap Analysis regarding compliance with the upcoming 2025 Solar Energy Standard in Section 8.6 as well.

8.4 Gap Analysis

A Gap Analysis is an estimate of how many more megawatts of renewable generating capacity a utility expects it will require beyond that which is presently available to obtain the required amount of renewable energy. A Gap Analysis is not an exercise intended to verify the validity of forecasted energy sales and associated capacity needs. It is done for transmission planning purposes only. This is the tenth time the utilities have prepared a Gap Analysis; a Gap Analysis was also prepared for the 2007, 2009, 2011, 2013, 2015, 2017, 2019, 2021, and 2023 Biennial Reports.

8.5 Base Capacity and RES Forecast

The chart below presents a system-wide overview of existing capacity in 2025 (used as a base figure throughout the various milestone periods) and forecasted renewable capacity requirements to meet Minnesota RES as well as non-Minnesota renewable energy standards (RES). Each utility provided its own forecast of Minnesota RES and non-Minnesota RES renewable energy standards and converted such estimates into capacity based on their own mix of renewable resources (e.g., wind, biomass, hydropower, solar) using the most appropriate capacity factors unique to their specific generating resources. It is important to note that the data presented in this Report represents MTO members' efforts to report on metrics that are part of a regulatory construct that is evolving because of the 2023 legislation. The Commission is currently in the process of issuing guidance to electric utilities on implementation of the RES, SES and CFS requirements in Docket Nos. E999/CI-23-151[21] and E999/CI-24-352[22]. Accordingly, MTO utilities remain in the planning stages related to compliance with the Minnesota Legislature's 2023 amendments.[23] To the extent that there are relevant updates informing implementation of these standards, MTO utilities are committed to coordinating with stakeholders if additional information is requested.

[21] The Commission has issued orders on implementing the changes to Minn. Stat. § 216B.1691 on December 6, 2023, April 12, 2024, November 7, 2024, August 7, 2025, and September 16, 2025.
[22] See November 7, 2024 Order Initiating New Docket and Clarifying "Environmental Justice Area".
[23] Because MTO utilities have either just received or are waiting for additional guidance for how to implement the CFS, this metric is not captured in this Report. MTO utilities will provide this information in the next Biennial report and will work with stakeholders if additional information in required in this proceeding.

The following Table 1 shows a more specific breakdown of each utility's Minnesota RES and non-Minnesota RES needed capacity forecast.

Table 1. MN & Non-MN RES Forecast (MW)						
Utility	2027		2030		2035	
	MN RES	Non-MN RES	MN RES	Non-MN RES	MN RES	Non-MN RES
Basin Electric[1]	231.8	805.1	220.8	981.8	525.5	1,111.6
CMMPA	28.6	-	29.1	-	65.8	-
Dairyland	119.0	91.0	119.0	92.0	263.0	93.0
GRE	371.8	0.5	379.5	0.5	864.1	0.5
Heartland	10.5	4.6	6.9	4.9	12.8	5.1
Minnkota	81.9	-	83.7	-	190.9	-
MMPA	162.8	-	219.6	-	456.4	-
MN Power	472.0	23.7	618.1	26.2	1,406.9	28.4
Otter Tail	156.4	70.1	158.0	70.2	344.8	70.3
RPU	-	NA	350.0	NA	350.0	NA
SMMPA	224.0	-	100.0	-	490.0	-
WMMPA/MRES	237.2	29.0	576.9	29.3	898.4	30.1
Xcel Energy[2]	5,255.9	1,944.0	7,421.7	2,745.0	9,803.4	3,625.9
TOTAL	7,351.8	2,967.86	10,283.3	3,949.9	15,672.1	4,964.8

Note:

1. Majority of the non-MN RES is from voluntary renewable energy objectives in North and South Dakota.

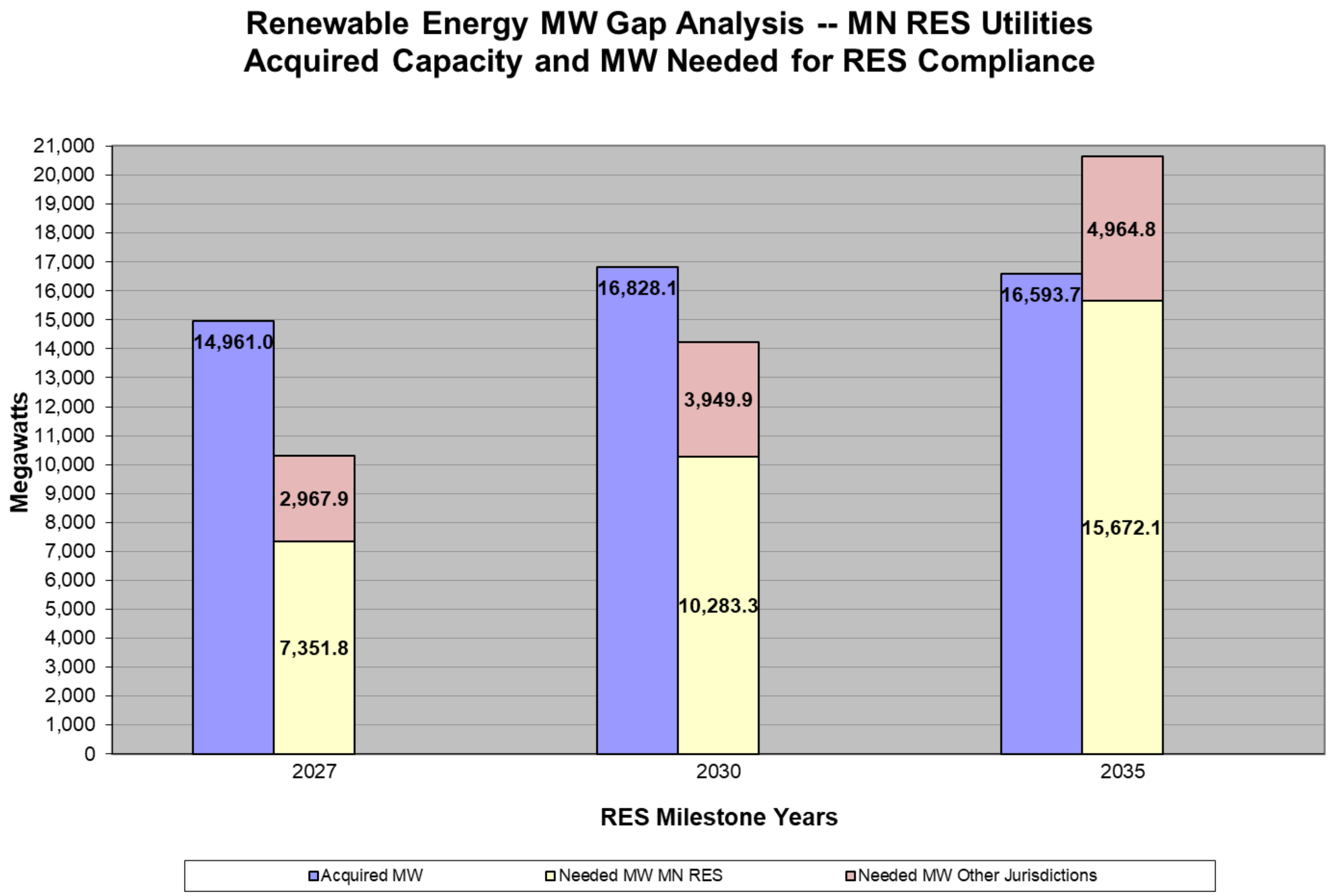
2-1. Generation (MW) forecasts are from the 2024-2040 IRP approved by the Commission in April 2025.

2-2. MW values for the entire NSP System are multiplied by NSPM (MN) I/A allocation factor for MN RES and non-MN RES values (73% for MN and 27% for non-MN).

2-3. 2025 Biennial Report capacity and resource production (energy) forecasts were based on the 2020-2034 IRP Alternate Preferred Plan (filed 6/2021, approved 4/2022).

8.5.1 RES Capacity Acquired and Net RES Need

The following chart represents the total renewable capacity system-wide that will be acquired and lost between 2027 and 2035, as well as the total Minnesota RES and non-Minnesota RES needs between 2027 and 2035. Capacity losses are attributable to the expiration of various power purchase agreements for renewable energy generation, and these losses are implicitly incorporated into the datasets provided.



As can be seen, the Minnesota RES utilities have sufficient capacity acquired to meet the Minnesota RES needs through 2035. When considering the RES needs, including other jurisdictions outside of Minnesota, the Minnesota RES utilities have enough capacity to meet RES needs beyond 2027. In addition, some utilities with less than sufficient capacity to meet the Minnesota RES need may use renewable energy credits to fulfill their requirement.

Focusing back on just Minnesota RES needs, Table 2 below provides a more specific breakdown of each utility’s forecast.

Table 2. RES Capacity Acquired & Net MN RES Capacity Need (MW)						
Utility	**2027**		**2030**		**2035**	
	RES Cap Acq.	MN RES Net	RES Cap Acq.	MN RES Net	RES Cap Acq.	MN RES Net
Basin Electric	3,103.0	-	2,981.0	-	2,893.0	-
CMMPA	43.4	-	43.4	-	33.5	32.3
Dairyland	1,128.2	-	2,086.6	-	2,086.6	-
GRE	1,946.9	-	1,708.1	-	1,708.1	-
Heartland	41.0	-	41.0	-	41.0	-
Minnkota	150.0	-	305.4	-	305.4	-
MMPA[1]	375.7	-	566.1	-	783.9	-
MN Power	1,836.8	-	2,301.3	-	2,501.3	-
Otter Tail	306.2	-	743.5	-	733.8	-
RPU	10.0	-	10.0	340.0	10.0	340.0
SMMPA	224.0	-	124.0	-	107.0	383.0
WMMPA/MRES	539.8	-	539.9	50.3	536.9	434.3
Xcel Energy[2]	5,255.9	-	5,377.7	2,044.0	4,853.2	4,950.2
TOTAL	14,961.0	-	16,828.1	2,434.3	16,593.7	6,139.9

Note:
1. Capacity acquired includes resources active as of 2025 and planned resources.
2. Acquired MW are non-generic resources and Legislated CSG (both 2016-2024 and 2024+) from the 2024-2040 IRP Settlement "Resource Annual" tab of the EnCompass Output (EO) file (DG Solar MW is NOT included for SES).

Note that the "Needed MW MN RES" bar in the bar chart in this section represents the total level of RES megawatts required (or need) in Minnesota. Conversely, the column in Table 2 labeled "MN RES Net" represents the additional RES capacity presently identified to meet RES megawatts required. To the extent there is a shortfall, or "gap," between MN RES megawatts required and the additional RES capacity identified points to the likelihood that some utilities will seek additional renewable capacity. Alternatively, some utilities may use renewable energy credits to fulfill their RES requirements.

8.6 Solar Energy Standard

In 2013, the Minnesota Legislature established a separate solar standard for public utilities, effective by the end of 2020.[24] That statute requires public utilities subject to the SES to report to the Commission on July 1, 2014, and each July thereafter, on progress towards achieving the 1.5 percent solar energy standard.

Chapter 8 of the Biennial Report discusses utilities' compliance with Minnesota Renewable Energy Standards. Additionally, a brief summary regarding the status of compliance with the 2027 Solar Energy Standard (SES) is included below. Utilities file annual reports to demonstrate compliance with the SES on June 1 of each year as required by the statute and directed by the Commission.

[24] Minn. Laws 2013, Ch. 85, § 3, codified at Minn. Stat. § 216B.1691, subd. 2f (Solar Energy Standard or SES).

Table 3 shows a more specific breakdown of each utility's Minnesota SES and non-Minnesota SES megawatts required capacity forecast.

Table 3. MN & Non-MN SES Forecast (MW)						
Utility	**2027**		**2030**		**2035**	
	MN SES	Non-MN SES	MN SES	Non-MN SES	MN SES	Non-MN SES
MN Power	27.3	-	31.5	-	32.6	-
Otter Tail	23.5	-	23.7	-	23.5	-
Xcel Energy[1]	2,318.5	-	2,672.8	-	4,103.5	-
TOTAL	2,369.2	-	2,728.0	-	4,159.6	-

Note:

1-1. Generation (MW) forecasts are from the 2024-2040 IRP approved by MN PUC in April 2025

1-2. SES and CFS MW values are considered to be 100% of the NSP System total for MN because there is no SES or CFS requirement in WI, SD or ND (MI does have a CFS but it accounts for less than 1% of the NSP System total retail MWh)

1-3. 2023 Biennial Report capacity and resource production (energy) forecasts were based on the 2020-2034 IRP Alternate Preferred Plan (filed 6/2021, approved 4/2022).

Note: SES is the MN Solar Energy Standard which will require additional solar beyond the MN RES.

Additionally, Table 4 below provides SES Utilities' planned level of solar capacity additions.

Table 4. SES Capacity Acquired & Net MN SES Capacity Need (MW)						
Utility	**2027**		**2030**		**2035**	
	SES Cap Acq.	MN SES Net	SES Cap Acq.	MN SES Net	SES Cap Acq.	MN SES Net
MN Power	36.9	-	36.9	-	36.9	-
Otter Tail	91.9	-	339.8	-	339.8	-
SMMPA	5.0	-	5.0	-	5.0	-
Xcel Energy*	2,318.5	-	2,672.8	-	2,922.4	1,181.1
TOTAL	2,452.2	-	3,054.5	-	3,304.1	1,181.1

Note:
* Acquired MW are non-generic resources and Legislated CSG (both 2016-2024 and 2024+) from the 2024-2040 IRP Settlement "Resource Annual" tab of the EnCompass Output (EO) file (DG Solar MW is NOT included for SES)

8.7 Carbon-Free Standard

Table 5. MN & Non-MN CFS Forecast (MW)								
Utility	2027		2030		2035		2040	
	MN CFS	Non-MN CFS	MN CFS	Non-MN CFS	MN CFS	Non-MN CFS	MN CFS	Non-MN CFS
Basin Electric[1]	-	-	530.0	-	860.0	-	-	-
CMMPA	-	-	69.8	-	107.7	-	122.9	-
Dairyland	119.0	91.0	119.0	92.0	263.0	93.0	485.0	95.0
GRE	371.8	-	910.8	-	1,413.9	-	1,628.0	-
Heartland	16.8	-	13.8	-	18.6	-	24.0	-
Minnkota	-	-	50.2	-	171.8	-	196.2	-
MMPA	-	-	477.2	-	746.8	-	802.4	-
MN Power	-	-	1,995.5	-	2,321.1	-	2,613.3	-
Otter Tail	-	-	505.6	70.2	564.2	70.3	627.4	70.3
RPU	-	NA	350.0	NA	350.0	NA	400.0	NA
SMMPA	-	-	100.0	-	490.0	-	490.0	-
Xcel Energy[2]	8,937.9	2,413.2	11,904.8	3,214.3	15,167.3	4,095.2	17,617.8	4,756.8
TOTAL	9,445.4	2,504.24	17,026.7	3,376.47	22,474.5	4,258.4	25,007.0	4,922.1

Note:

1. No other states in BEPC's territory have a Carbon Free Standard

2-1. Generation (MW) forecasts are from the 2024-2040 IRP approved by MN PUC in April 2025

2-2. CFS forecast includes nuclear as the Monticello and Prairie Island extensions were approved as part of the 2024-2040 IRP

2-3. SES and CFS MW values are considered to be 100% of the NSP System total for MN because there is no SES or CFS requirement in WI, SD or ND (MI does have a CFS but it accounts for less than 1% of the NSP System total retail MWh)

Table 6. CFS Capacity Acquired & Net MN CFS Capacity Need (MW)								
Utility	2027		2030		2035		2040	
	MN CFS	Non-MN CFS	MN CFS	Non-MN CFS	MN CFS	Non-MN CFS	MN CFS	Non-MN CFS
Basin Electric	3,103.0	-	2,981.0	-	2,893.0	-	-	-
CMMPA	56.0	-	56.0	13.8	39.5	68.2	39.5	83.4
Dairyland	1,128.2	-	2,086.6	-	2,086.6	-	1,031.6	-
GRE	1,946.9	-	1,708.1	-	1,708.1	-	1,629.8	-
Heartland	41.0	-	41.0	-	41.0	-	-	-
Minnkota	-	-	305.4	-	305.4	-	305.4	-
MMPA[1]	-	-	566.1	-	783.9	-	802.7	-
MN Power	1,873.7	-	2,338.2	-	2,538.2	-	2,538.2	75.1
Otter Tail	-	-	743.5	-	733.8	-	733.8	-
RPU	10.0	-	10.0	340.0	10.0	340.0	10.0	390.0
SMMPA	-	-	124.0	-	107.0	383.0	-	490.0
Xcel Energy[2]	8,937.9	-	9,104.8	2,800.0	8,386.2	6,781.1	8,065.9	9,551.9
TOTAL	17,096.7	-	20,064.8	3,153.80	19,632.7	7,572.3	15,157.0	10,590.4

Note:

1. Capacity acquired includes resources active as of 2025 and planned resources.
2. Acquired MW are non-generic resources and Legislated CSG (both 2016-2024 and 2024+) from the 2024-2040 IRP Settlement "Resource Annual" tab of the EnCompass Output (EO) file (DG Solar MW is NOT included for SES)

8.8 Gap Analysis Summary

As demonstrated by the data provided in this section, MTO utilities continue to make tangible progress to satisfy RES and SES requirements. Though generally encouraged by this progress, MTO utilities emphasize that continuing progress is also closely linked to the ability to procure the necessary transmission resources, which is analyzed throughout this Report. Further, MTO utilities continue to analyze the Commission's implementation of the CFS and how compliance with the CFS may impact transmission needs and anticipate providing additional information in the next biennial report in 2027.

9.0 Outages & Congestion

9.1 Introduction

The Commission's June 29, 2022 Order Accepting Report required MTO to include the information required to be filed in the 2021 Report in their 2023 Report as well as the following:

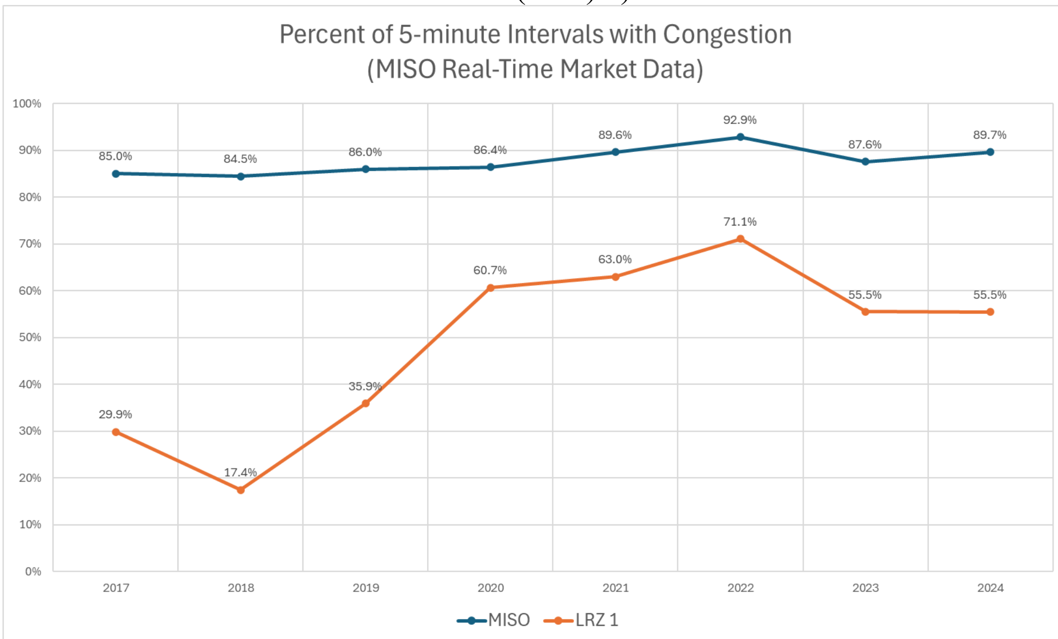
4) *Expected sustained HVTL or generation planned outages;*
5) *Whether those outages are anticipated to have new or incremental congestion; and*
6) *Whether those outages are anticipated to contribute to sustained incremental congestion.*

The 2025 Report also provides updates on Grid North Partners and the MTO's work related to congestion and specifically in response to the Commission's March 24, 2025 Order in Docket No. E999/CI-24-316.

9.2 System Changes and Upcoming Projects Addressing Congestion Relief

Congestion is a limitation, constraint, or "bottleneck" on the transmission grid which prevents the lowest cost-generation from serving load. Congestion exists on the transmission system at nearly all times. Some level of congestion is expected and normal as the transmission grid is built for the lowest total costs to serve customer and member demands. Eliminating all congestion does not result in a lower total cost as it would require a significantly overbuilt transmission grid. Total costs consider the out-the-door impacts of both transmission and generation cost. Thus, when evaluating congestion projects, it is typical to determine if the generation savings results from reducing congestion exceed the capital cost of the transmission expansion. Congestion relief project effectiveness is typically measured in either net savings (generation savings less transmission costs) or a benefit to cost ratio (generation savings divided by transmission cost).

Figure 1 - Congestion Trends in MISO and Minnesota and the surrounding area (Local Resource Zone (LRZ) 1)



For the past five years, congestion levels across MISO and Minnesota and the surrounding area have been on the rise, as shown in Figure 1. However, recently overall congestion levels in Minnesota have decreased also as shown in Figure 1. Congestion levels are driven by several factors including:

- **System outages**: Similar to road construction causing traffic back-ups, transmission line or generation outages can cause increased congestion. Generally, the more outages, the more congestion. It should be noted that to construct congestion relief projects or other transmission upgrades, it often requires outages on the transmission elements which are most congested, exacerbating congestion in the short-term.
- **Generation and transmission construction timelines**: Generators can typically be constructed faster than the transmission facilities needed to fully accommodate the generation. This lag in transmission construction results in a temporary increase in congestion.
- **Weather**: As wind and solar generation constitute a larger share of the generation fleet, weather patterns, especially atypical weather patterns, can result in increased congestion levels.
- **Demand levels:** The transmission grid moves generation from where it is produced to where it is needed, and thus it is not only generation output but more so how it is coupled with demand levels and location.

As the transmission grid does not stop at state borders, transmission limitations in other states can drive congestion in Minnesota, and vice versa.

The MTO utilities have taken numerous actions in the short-, mid-, and long-term to alleviate congestion throughout the state.

Long-Term Actions: Complete solutions which address existing congestion and proactively accommodate future changes but typically require five to ten years to implement. Long-term MTO actions include:

- MISO Long-Range Transmission Plan (LRTP) Tranche 1 portfolio which includes three 345kV projects in Minnesota – see Section 10.2 for additional information.
- MISO Long-Range Transmission Plan (LRTP) Tranche 2.1 portfolio which includes five high-voltage projects in Minnesota – see Section 10.3 for additional information.
- Xcel Energy's MN Energy Connection and King Connection, which are designed to utilize existing transmission access rights. The MISO interconnection queue has a significant number of new interconnection requests currently seeking to connect to a system that is already very congested. Reusing existing transmission rights through the MN Energy Connection and King Connection Projects allows Xcel Energy to interconnect additional MWs through its existing transmission rights, avoiding long delays often related to MISO queue interconnection studies.

Near-Term Actions: Incremental solutions to maximize use of existing assets such as rating adjustment technologies and other limited scope fixes which can be implemented within a few years. MTO near-term actions include:

- In 2025, the MTO via the GETs study identified 26 solutions which will be implemented by MTO utilities. Solutions include GETs, substation equipment upgrades, and transmission line upgrades – see Section 9.4 and Appendix B for additional information.
- GRE has a dynamic line rating (DLR) pilot program with Heimdall. As of June 2025, GRE has ten lines with DLR which are monitored by 50 physical sensors and 37 "virtual sensors." GRE is planning on expanding the pilot program with seven additional sensors in late summer 2025. In addition, GRE is evaluating further expansion of its DLR program and other technologies.[25]
- Xcel Energy implemented a process to study reconfiguration requests from outside entities. These requests are looked at to determine effectiveness, duration, and impact to the transmission system. Reliability is the primary determinant of whether a reconfiguration request is approved.
- Xcel Energy initiated an internal study process to determine any transmission system reconfigurations on the underlying transmission system able to have a positive impact on the bulk transmission system and congestion. Xcel Energy Transmission Operations factor system reliability, curtailment, and congestion when considering/scheduling transmission outages.

Mid-Term Actions: Grid expansion designed to incrementally decrease congestion and bridge to long-term solutions. Mid-term solutions typically require two to five years to implement depending on complexity. MTO near-term actions include:

[25] Additional information on GRE's DLR pilot program and the first-year results can be found at: https://www.heimdallpower.com/whitepaper-one-year-gre?utm_campaign=150436053-one-year-gre

- In 2023, Grid North Partners announced plans to construct 19 transmission solutions, 18 of which will be in Minnesota, to reduce transmission congestion in the near-term for the broader benefit of customers throughout the Upper Midwest – see Section 9.3 for additional information.
- NSP System Upgrades: Xcel Energy conducted an internal analysis to determine projects designed to remove system limiters on congested lines in southwest Minnesota. These projects typically addressed substation equipment and sag limits. See Section 9.6 for additional information.
- Xcel Energy initiated an out-of-cycle request for MISO in 2023 to complete the second 345 kV circuit from Brookings Co-Lyon Co and Helena-Hampton for the existing CAPX Brookings-TC facility. The Brookings County to Lyon County circuit and the Helena to Hampton circuit are currently in-service.

In addition to implementing physical solutions, the MTO is working with MISO to help ensure study processes and assumptions more proactively address congestion. As an example, the MTO worked with MISO and other stakeholders to change how ERIS impacts are identified in the MISO DPP process. The previous distribution factor (DF) was 20% and as proposed by the MTO, the current DF is 10% which helps ensure that more generation is not interconnected without necessary transmission facilities being built to deliver the energy to the system.

These examples represent MTO members' commitment to actively addressing congestion issues impacting the grid statewide. Going forward, MTO will continue collaborating with other stakeholders to address congestion issues.

9.3 Grid North Partners 2023 Near-Term Congestion Study

In late 2023, Grid North Partners announced plans to construct 19 transmission solutions, 18 of which will be in Minnesota, to reduce transmission congestion in the near-term for the broader benefit of customers throughout the Upper Midwest.[26] These solutions are expected to provide congestion relief savings in excess of cost and furthermore will help reduce congestion caused during the construction of MISO's Long Range Transmission Plan.

Grid North Partners, an evolution of CapX2020, is a voluntary partnership of ten Minnesota and surrounding area transmission-owning utilities. The Grid North Partnership members include Central Municipal Power Agency/Services, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy. Additional information on Grid North Partners can be found at https://gridnorthpartners.com/.

Grid North Partners utilities collectively and individually have advocated for and continue to participate in MISO's long-range transmission planning efforts. While those long-range plans are the true solution to address congestion in Minnesota, in parallel Grid North Partners has been collectively analyzing congestion to identify near-term congestion solutions.

[26] Congestion-projects-press-release-Grid-North-Partners-2023.pdf (gridnorthpartners.com).

In 2023, Grid North Partners conducted a study to identify solutions to incrementally address congestion in the near-term (i.e. in-service within three years). The ten Grid North Partners utilities collectively analyzed both historical congestion from the past two years and forward congestion projections for Minnesota and the surrounding region. For every congested element, the limiting element (e.g., conductor, substation equipment, sag, structure, etc.) and time and cost to upgrade were identified. Ultimately, 19 solutions were identified, shown in Table 1, which will be constructed by the individual Grid North Partner member. While one of the 19 solutions is larger scale - the Brookings second circuit (Docket No. ET-2/TL-08-1474)– the others are mostly small-scale upgrades of existing equipment with no new required right-of-way.

As shown in Table 1, the status of the 19 projects as of September 2025 is:

- **Fourteen (count) projects** - Completed and in-service
- **One** - Under-construction and expected to be in service by year-end
- **Two** – Planned or under-development. Construction pending material delivery and/or outage schedules.
- **Two** – On hold/temporarily cancelled. Cost for materials necessary to complete have increased where congestion savings are no longer expected to exceed solution costs. Congestion trends and material costs will continue to be monitored to determine if/when projects will move forward.

Table 1: Grid North Partner 2023 Near Term Congestion Project Status

No.	Project	Counties	Status as of September 2025
1A	CapX Brookings 2nd Circuit	Lincoln, Lyon	In Service
1B	CapX Helena 2nd Circuit	Scott, Dakota	In Service
3	Hoot Lake - Fergus Fa1ls 115kV	Otter Tail	In Service
4	Morris - Grant County 115kV	Grant, Stevens	In Service
5	Franklin - Ft Ridgely - Swan Lake 115kV	Nicollet	Planned
6	Swan Lake - Wilmarth 115kV	Nicollet	In Service
7	Red Rock - Raptor 115kV	Washington	In Service
8	Johnson Junction - Morris 115kV	Big Stone, Stevens	In Service
9	Canby - Granite Falls 115kV	Yellow, Medicine	In Service
10	Inman – Elmo - Parkers Prairie - Miltona - Alex 115kV	Otter Tail, Douglas	In Service
11	Mud Lake - Benton 230kV	Crow Wing, Morrison, Benton	In Service
12	Rogers Lake - High Bridge 115kV	Ramsey, Dakota	In Service
13	Wakefield - St Cloud 115kV	Stearns	In Service
14	Pleasant Valley - Byron 161kV	Mower, Dodge, Olmsted	Planned
15	Big Stone - Blair 230kV	SD - Grant, Deuel	In Service
16	Coon Creek - Terminal 345kV	Anoka, Ramsey	Cancelled

17	Coon Creek - Kohlman Lake 345kV	Anoka, Ramsey	Cancelled
18	AAR[27] Forbes-Iron Range 230kV	St. Louis, Itasca	In Service
19	AAR Blackberry-Riverton 230kV	Crow Wing, Aitkin, Itasca	In Service

When Grid North Partners announced the near-term projects in 2023, plans were also announced to conduct a second iteration of the study after MISO's Long-Range Transmission Plan Tranche 2.1 portfolio[28] was solidified. Due to the similar mandated outcomes of Minnesota 2024 statute changes on GETs,[29] the second iteration of the Grid North Partners near-term congestion study was merged into the GETs Study described in Section 9.4. As described in Section 9.4 the GETs Study identified both GETs as defined by Minnesota law as well as near-term solutions like those identified in the 2023 Grid North Partners study. The full GETs Report is available in Appendix

9.4 Grid Enhancing Technologies (GETs) Study Summary

Appendix B provides the full Grid Enhancing Technologies (GETs or GETS Report) as required by Minnesota legislation to be filed in conjunction with the 2025 BTPR. The GETs Report addresses 30 solutions that are being developed to address congestion in the near term. This report details historic and future congestion information for the Grid North Partner's (GNP),[30] ITCM, and MPC footprint within Minnesota. The legislation states that any electric utility owning more than 750 miles of transmission in Minnesota must review historical congestion facilities, determine GETs solutions for each congestion point, and develop implementation plans for those GETs solutions that meet Commission defined payback period. GETs are hardware or software that reduces congestion or enhances the flexibility of the transmission system by increasing the capacity of a high-voltage transmission line or rerouting electricity from overloaded to uncongested lines, while maintaining industry safety standards. Grid enhancing technologies include but are not limited to dynamic line rating, advanced power flow controllers, and topology optimization.

9.5 Potential Congestion Based on Future Facility Additions

Notwithstanding the MTO's efforts described in Section 9.2, MTO believes that there is the potential for continued congestion issues over the next decade. Efforts to bring new transmission resources are underway; however, the planning, approval, and construction processes take time. Additionally, as described in Section 9.2, congestion relief projects often require outages of transmission lines temporarily exacerbating congestion issues.

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[27] AAR: Ambient Adjusted Rating
[28] See Section 10 for additional information on the Long Range Transmission Plan
[29] 2024 Minn. Laws, Ch. 127, Article 42, Section 52.
[30] Grid North Partners, an evolution of CapX2020, is a voluntary partnership of ten Minnesota and surrounding area transmission-owning utilities. The Grid North Partners members include Central Municipal Power Agency/Services, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy.

In 2024, MISO conducted the Near-Term Congestion Study to identify the congestion impacts caused by the construction of the LRTP Tranche 1 portfolio lines. While the LRTP Tranche 1 portfolio is expected to reduce congestion and provide $13 to $18 billion in congestion and fuel savings over the first twenty years of service,[31] construction is expected to take five years. MISO's study shows that during those five years of construction historical congestion issues will increase and shift some congestion to other facilities. MISO's report shows that construction sequencing can help decrease construction related congestion. MISO's report also solicits for potential Grid Enhancing Technology (GETs) solutions, like those being implemented by MTO members described in Section 9.2 and 9.3, to decrease construction related congestion. A full copy of MISO's Near-Term Congestion Study can be found at the following URL: https://cdn.misoenergy.org/MTEP24%20Near-Term%20Congestion%20Study%20Report657728.pdf

In addition, in December 2024, the MISO Board of Directors approved the Tranche 2.1 portfolio which includes 24 high-voltage transmission projects across the Midwest – see Chapter 10.3 for additional information. A key feature of the portfolio is the creation of a new 765 kV transmission backbone, including across southern MN, to transfer large amounts of electricity efficiently across the region to maintain reliability and reduce congestion and curtailment. The projects are scheduled to be in service between 2032 and 2034. The constructing MTO members will coordinate with MISO and the various Tranche 2.1 owners to sequence construction to help minimize facility outages and congestion. In addition, the MTO continues to look for creative solutions to minimize system congestion while waiting for additional transmission resources to come online.

9.6 Nobles County Congestion Analysis

Xcel Energy Transmission Planning performed a screening system impact study (SIS) to evaluate voltage stability benefits of a future battery energy storage system (BESS) to the local area around the Nobles 115/345 kV station.[32] The most recent operations guide for the Southwest Minnesota wind region lists outages requiring local wind generation to be limited to maintain voltage stability. The guide describes operating conditions causing voltage instability if select groups of wind generators exceed a pre-determined MVA threshold. This screening SIS determined that a 300 MW BESS with grid forming inverter at the Nobles station will provide dynamic voltage stability benefits to the system in dispatches with high wind generation.[33] These benefits are observed when utilizing a grid-forming inverter. This Nobles Grid-Forming Battery Screening System Impact Study is provided in Appendix C.

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[31] MTEP21 Addendum-LRTP Tranche 1 Report with Executive Summary625790.pdf – page 50

[32] A screening-level study was conducted to evaluate the potential impact of a 300 MW BESS at Nobles. The results are preliminary and rely on assumptions about the grid-forming inverter, which will be refined once Xcel Energy selects the final technology.

[33] Xcel Energy submitted an application into the MISO ERAS process for a BESS at its Nobles Substation and is continuing to develop the details of the project and expects to request approval of the Nobles BESS and other ERAS projects in early 2026.

Xcel Energy also completed an screening economic analysis using historical Locational Marginal Prices (LMP) to determine if there would be any economic benefit to adding a 300 MW Energy Storage Unit at the Nobles County substation. Based on this preliminary analysis it shows that a 300 MW BESS would have a positive impact on curtailments in the area if installed. This Nobles Battery Economic Screening Study is provided as Appendix D. Final analysis will need to be performed once final determinations are made regarding the specific technical details of the Nobles BESS.

10.0 MISO LRTP

10.1 Overview

The MISO Long-Range Transmission Plan (LRTP) is a multi-year multi-phase study to identify a regional transmission network necessary to cost-effectively maintain reliability and serve future needs. Recognizing that transformational changes in the generation fleet require significant changes to the transmission grid to maintain reliability, in 2020 MISO launched the LRTP. Given the magnitude of necessary grid expansion, a multi-year multi-phase effort is necessary given the finite construction labor force and equipment manufacturing capability as well as outage coordination.

The LRTP is one component of MISO's Reliability Imperative[34] – a shared responsibility of electricity providers, 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.

MISO's objective of the LRTP is to provide an orderly and timely transmission expansion plan that supports these primary goals:

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

MISO evaluates the projects in the LRTP in accordance with MISO's federally approved tariff. For any project to be deemed needed under MISO's tariff, it must meet defined criteria. In MISO's LRTP, MISO and stakeholders worked to identify a transmission plan that simultaneously addresses multiple regional needs – which under the MISO tariff is defined as a Multi-Value Project (MVP). For a project to be deemed needed by MISO as an MVP it must:

- **Reliability** - Address transmission issues to maintain national reliability standards,
- **Economic** - Provide multiple types of economic value across multiple pricing zones with a benefit-to-cost ratio of 1.0 or higher, or

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

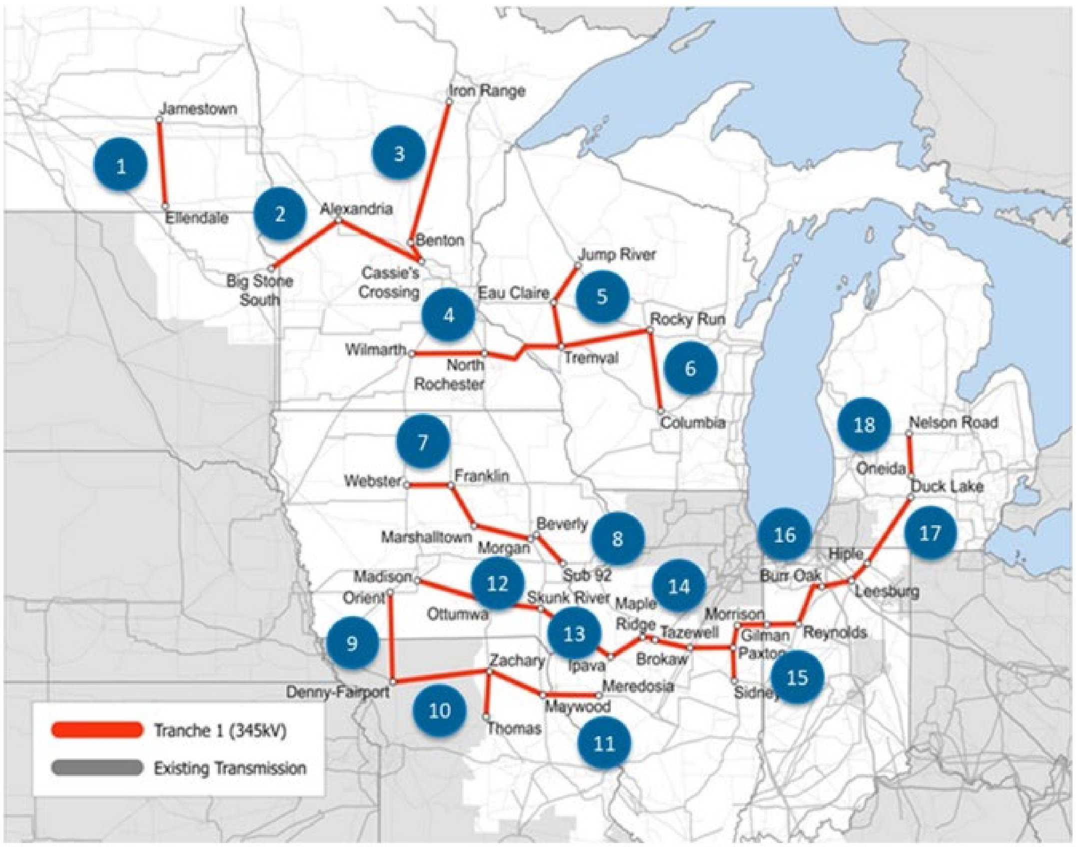
- **Policy** - Support the reliable and economic delivery of energy in support of documented energy policy mandates or laws.

10.2 Tranche 1

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

Figure 1 MISO LRTP Tranche 1 Portfolio

(Source: MISO)



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-22-416 and TL-22-415

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

MISO 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- but also inter-state transfers. 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.

- 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.

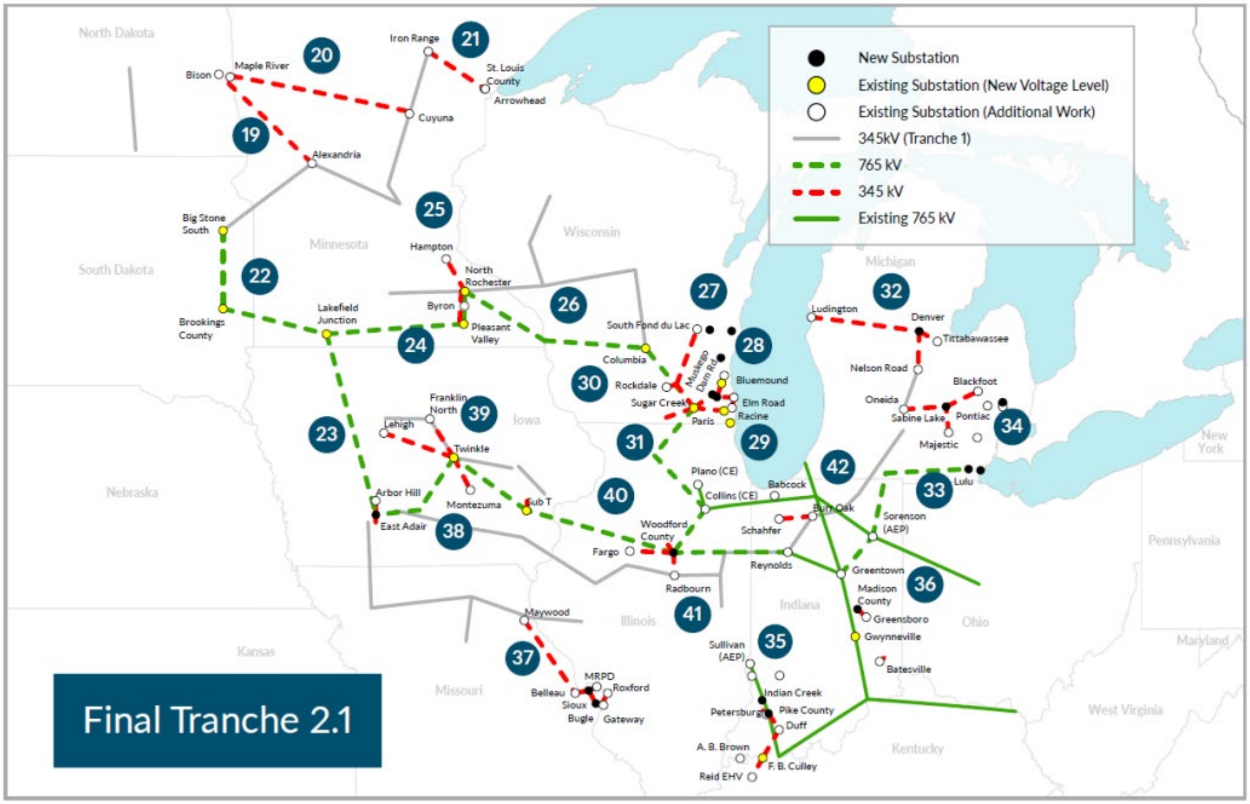
MISO LRTP Tranche 1 portfolio also was designed to bolster the existing 345kV to position the grid for future LRTP tranches.

A full copy of the MISO LRTP Tranche 1 report is available at: [cdn.misoenergy.org/MTEP21 Addendum-LRTP Tranche 1 Report with Executive Summary625790.pdf]

10.3 Tranche 2.1

In 2024, MISO approved the next phase of the LRTP ("LRTP Tranche 2.1") which establishes a new 765kV "backbone" across the Midwest, shown in Figure 2. 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.

Figure 2 MISO LRTP Tranche 2.1 Portfolio
(Source: MISO)



The LRTP Tranche 2.1 includes the following projects in Minnesota:

- Fargo to Alexandria (LRTP#19): Commission Docket Number: CN-25-116
- Maple River to Cuyuna (LRTP#20): Commission Docket Number: CN-25-109
- Iron Range to Arrowhead (LRTP#21): Commission Docket Number CN-25-111
- PowerOn Midwest (LRTP#22, 23, 24, 25): Commission Docket Numbers: CN-25-117, CN-25-118, CN-25-119, and CN-25-120.
- Gopher to Badger Link Project (LRTP#26): Commission Docket Number CN-25-121

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.[35] The LRTP Tranche 2.1 portfolio is needed for:

[35] https://www.misoenergy.org/planning/long-range-transmission-planning/

- **Reliability:** Address reliability violations across the Midwest.[36]
- **Economic Efficiency:** The $21.8 billion portfolio has a benefit-to-cost ratio of 1.8 to 3.5. This means that every dollar invested in transmission will result in economic benefits of $1.8 to $3.5 dollars. Per MISO's analysis, the LRTP Tranche 2.1 is expected to provide net economic savings of $23.1 billion to $72.4 billion over the first 20-years of service.[37]
- **Policy:** Alleviates congestion and enables interconnection of approximately 116,000 GW of primarily carbon-free resources[38] to reduce Midwest carbon-dioxide emissions by 127-199 million metric tons over 20 to 40 years to help states like Minnesota to comply with its decarbonization law.[39]

A full copy of MISO's LRTP Tranche 2.1 Portfolio report can be found at: https://cdn.misoenergy.org/MTEP24%20Chapter%202%20-%20Regional%20Long%20Range%20Transmission%20Planning658124.pdf

10.4 Future Tranches

MISO has committed to at least three additional LRTP tranches focused on:

- MISO's Midwest region (includes Minnesota),
- MISO's South region (does not include Minnesota), and
- increasing the connection between MISO's Midwest and South regions.

Per MISO,29 planning of LRTP Midwest and LRTP South (formerly referred to as Tranches 2.2 and 3 (respectively)) is expected to occur in 2026 and 2027, with the LRTP focused on the Midwest and South connection region (formerly referred to as Tranche 4) tentatively expected to occur in 2027 and 2028. Schedule is subject to change based on system needs and priorities.

At the publication of this report, in November 2025, MISO is in the pre-planning stage of LRTP Midwest (Tranche 2.2) which includes refreshing forecasts and assumptions and model development. Issue identification and solution development is expected to begin in 2026. The MTO members are actively engaged in the MISO LRTP Tranche 2.2 process.

MISO's LRTP is an open and transparent planning process. Additional information on MISO's LRTP efforts and meetings can be found on MISO's website: https://www.misoenergy.org/planning/long-range-transmission-planning/

[36] Id. Page 29 Figure 2.19.
[37] Id. Page 125 Figure 2.137. Net savings are 20-year NPV in $-2024.
[38] Id. Page 75
[39] Id. page 142

11.0 Compliance

11.1 Introduction

To facilitate review of the 2025 Report, Chapter 11 consolidates the various compliance requirements from the Commission's orders, Minnesota legislation, and prior Commission Staff Information Requests.

11.2 2024 Order Accepting 2023 Report Compliance

In the Commission's June 27, 2024 Order Accepting Report in Docket No. E999/M-23-91, the MTO was ordered to include the information required to be filed in the 2023 Report in their 2025 Report as well as the following:

A. An update on the progress and/or performance of the Grid North Partners' proposal for nineteen transmission upgrade projects aimed at enhancing reliability and easing congestion in Minnesota;
    - See Chapter 9 for an update on Grid North Partners work related to congestion and related issues.

B. Information about short-term solutions to increase the robustness of the transmission system they have deployed or plan on deploying along with a report on their performance such as:

    1) dynamic line ratings,
    2) transmission system optimization and reconfigurations,
    3) adjusting transmission conductor limitations to increase line ratings,
    4) increasing substation limiter sizes, and
    5) other grid enhancing technologies that they have deployed or plan on deploying;

    - Appendix B provides the GETs Report in compliance with the Commission's September 10, 2025 ORDER ESTABLISHING REQUIREMENTS, in Docket No. E999/M-25-99. The specific order points are addressed within the GETs Report.

C. Updates to its response to the PUC Information Requests from May 12, 2023.

    - Section 11.5 below provides an update to these Information Requests.

11.3 Order Establishing Filing Requirements-Nobles County Substation Docket

In the Commission's March 24, 2025 Order in Docket No. E999/CI-24-316 requires:

1. The MTOs shall include a cost-benefit analysis in their 2025 Biennial Transmission Report that compares any feasible battery storage solution to status quo conditions and to its performance under planned grid upgrades at the Nobles County Substation area.

2. In the 2025 Biennial Transmission Projects Report, to the MTOs shall include an update of the WECS curtailment and economic impact data as provided in the Department's December 3, 2024 supplemental comments for the Nobles County Substation area and the areas of congestion identified as part of the GETs Study required under the 2024 Session Laws Ch. 126, article 6, section 52, subd. 2. In addition, the MTOs shall consult with the Department in preparation for the 2025 Biennial Transmission Projects Report.

Xcel Energy completed an screening economic analysis using historical Locational Marginal Price (LMP) data using a 300 MW BESS for years 2024 through 2025. Based on our current assumptions on how the BESS would typically operate it was concluded that a 300 MW BESS would help reduce curtailment in the Nobles area. In addition to the economic analysis, Xcel Energy completed a screening system impact study to determine the potential impact of adding 300 MW BESS at Nobles substation. The preliminary conclusion is a 300 MW BESS with grid forming capabilities improves the area response to local faults. These preliminary studies are available in Appendices C and D. The next steps are to perform a final analysis after the specific Nobles BESS details are determined and work with MISO to determine if the Operating Guide that limits generation due to prior outages can be modified to reduce the amount of generation needed to keep the system stable or remove the Operating Guide completely. This process will take time to complete.

11.4 Legislative Requirements (2024 Minn. Laws, Ch. 127, Article 42, Section 52)

2024 Minn. Laws, Ch. 127, Article 42, Section 52 requires that entities that own more than 750 miles of transmission lines in Minnesota provide a Grid Enhancing Technologies (GETs) Report as part of the 2025 Report. The full GETs Report is provided in Appendix B in compliance with the Minnesota legislation.

11.5 Updates to Responses to PUC Information Requests from May 12, 2023

Order point C from the Commission's Order Accepting Report requires the MTO to update its response to the PUC Information Requests from May 12, 2023.

MPUC Information Request No. 1

Question:
Staff requests that the MTOs provide an assessment of the current transmission system in Minnesota and its ability to reach the carbon-free standard by 2040, as required by Minnesota Laws 2023, Chapter 7, section 10 recently passed by the Minnesota Legislature.

Response:
Minnesota Laws 2023, Chapter 7, contains several updates to the clean energy standards set forth in Minn. Stat. § 216B.1691, including additional milestones for renewable energy and new carbon-free energy standards. The standards now include:

	2025	2030	2035	2040
Renewable Energy (RES)	25%		55%	
Solar Energy* (SES)	1.5%		10%	
Carbon-free Energy (CFS)		80% for public utilities; 60% for other electric utilities	90%	100%

**See* Minn. Stat. § 216B.1691, subd. 2f, for additional detail relevant to the solar energy standards.

As noted in previous Biennial Reports, the utilities that are required to submit the Biennial Transmission Projects Report are not identical to those that are required to meet the RES, SES, and now the CFS. The utilities participating in this part of the 2025 Biennial Report that will also report on renewable and carbon-free energy include the following:

Investor-owned Utilities
Minnesota Power
Northern States Power Company
Otter Tail Power Company

Generation and Transmission Cooperative Electric Associations
Basin Electric Power Cooperative
Dairyland Power Cooperative
East River Electric Power Cooperative[23]
Great River Energy
L&O Power Cooperative[40]
Minnkota Power Cooperative

Municipal Power Agencies
Central Minnesota Municipal Power Agency
Minnesota Municipal Power Agency
Southern Minnesota Municipal Power Agency
Western Minnesota Municipal Power Agency/Missouri River Energy Services

[40] L&O Power Cooperative ("L&O") and East River Electric Power Cooperative ("EREPC") are members of and contract with Basin Electric Power Cooperative ("Basin") to supply all generation beyond L&O's and EREPC's Western Area Power Administration ("WAPA") allocation. It will be Basin's obligation to adhere to the applicable generation laws in Minnesota. Also, L&O and EREPC are members of Southwest Power Pool ("SPP") who performs the transmission planning on the system. L&O and EREPC intend to construct new or upgrade existing facilities as directed by SPP as a result of additional load flows realized by the addition of local carbon-free generation sources.

Power District
Heartland Consumers Power District

Further details on RES and SES requirements are found in Chapter 8. As noted there, future biennial transmission plans will address the CFS as the Commission is currently providing guidance to utilities on various aspects of implementing this new standard.

MPUC Information Request No. 2

Question:
What upgrades, improvements, and future investments in transmission are being planned in order to achieve this requirement?

Response:
The MTO has been participating, along with Commission Staff and other stakeholders, in the robust planning effort that MISO is undertaking through the Long-Range Transmission Planning (LRTP) process. The base planning assumptions for Tranche 2.1 included implementing Minnesota's new carbon free energy standards by 2040. Further details on MISO LRTP are provided in Chapter 10.

MPUC Information Request No. 3

Question:
Staff requests that the MTOs provide an assessment of how their project planning process will include an analysis of project impacts on environmental justice areas as defined in Minnesota Law 2023, Chapter 7, section 3, including an assessment of the expected local benefits as detailed in section 15 of the same law.

Response:
While each utility's planning efforts differ slightly, the MTO anticipates the following analyses and engagement will be conducted as part of the planning activities for newly proposed transmission lines in Minnesota:

1. Early in the planning process, mapping tools will be used to identify and assess environmental justice (EJ) communities in the vicinity of each project area. Utilities have relied on the Minnesota Pollution Control Agency's (MPCA) screening tools to help identify EJ areas.[41] The MTO anticipates that MPCA's screening tools will be updated to reflect the new EJ definition in Minnesota Laws 2023, Chapter 7, Section 3.

2. Utilities will engage with these potentially affected EJ communities to ensure equitable access to the planning processes, solicit diverse and representative input, and work to understand community values. This engagement is likely to occur through several outreach efforts, including open houses, discussions with community leaders, social media, and other efforts. The goals of this engagement include developing initial understanding of

[41] See e.g., https://mpca.maps.arcgis.com/apps/MapSeries/index.html?appid=f5bf57c8dac24404b7f8ef1717f57d00.

potential project impacts, both beneficial and adverse; gathering preliminary feedback; and establishing an ongoing two-way engagement process.

Tribal governments and Tribal Historic Preservation Offices, identified through the U.S. Department of Housing and Urban Development's Tribal Directory Assessment Tool or the Minnesota Indian Affairs Council as having historic ties to land in proximity to planned project areas will be notified early in the planning process, so that Tribes have the opportunity to advise of any sensitive historical or cultural sites to be avoided.

3. In parallel with the identification and engagement processes, the utilities will also work to identify local benefits as listed in Minnesota Laws 2023, Chapter 7, Section 15.

Consistent with current practice, the MTO anticipate information gathered in these processes will be reflected in any resulting Minnesota certificate of need and route permit applications, so the information is available for the MPUC's consideration as part of the full record.

MPUC Information Request No. 4

Question:
Staff requests the MTOs provide comments on what actions are being taken to alleviate congestion in Southwest Minnesota and to help limit the curtailing of wind resources in that area.

Response:
MTO utilities have taken numerous actions in recent years to alleviate congestion in Southwest Minnesota in an effort to limit curtailment of wind resources in this area. These efforts include:

a. NSP System Upgrades: Xcel Energy did an internal analysis to determine small projects designed to remove system limiters on congested lines in Southwest Minnesota. These projects typically focused on substation equipment and sag limits. Projects budgeted are listed below:

Xcel Energy Congestion Projects

Transmission Line	Scott County-Blue Lake
Scope	Increased line capacity by removing an old meter that had a maximum reading below what the connecting substation could handle.
Property Units	
ISD	Q3 2022

Substation	Chisago County (CHI)
Scope	Replace primary and secondary 115 kV bus 1 differential relays for TR05 and TR06
Property Units	(4) Control System
ISD	8/1/2022

Substation	Kohlman Lake (KOL)
Scope	Replace meter on breaker 5P106
Property Units	(1) Control System
ISD	8/1/2022

Substation	Prairie (PRA)
Scope	Replace meter on breaker 5G8
Property Units	(1) Control System
ISD	8/1/2022

Substation	Scott County (SCO)
Scope	Replace busbar
Property Units	(1) Conductor
ISD	3/1/2023

Substation	Wilmarth (WLM)
Scope	Replace bushing current transformers on breaker 5S11, and switches 8S26B1, 8S25B, 8S25A, 8S26B1
Property Units	(1) Circuit Breaker (BCT) (4) Switches
ISD	3/1/2023

Substation	Inver Hills (IVH)
Scope	Replace busbar
Property Units	(1) Conductor
ISD	3/1/2023

Substation	Red Rock (RRK)
Scope	Replace bushing current transformers on breaker K2, switches K2B1, 946B, K2B2, 946A, and meters on 946 and K2
Property Units	(1) Circuit Breaker (BCT) (4) Switches (2) Control Systems
ISD	3/1/2023

Transmission Line	Wilmarth-Swan Lake

Scope	Increase ratings on line to reflect short-term flood forecasts
Property Units	
ISD	Q3 2024

b. Xcel Energy initiated an out-of-cycle request to MISO for completing the second 345 kV circuit from Brookings Co-Lyon Co and Helena-Hampton for the existing CAPX Brookings-TC facility. This project is fully in service as of September 2025.

c. Market congestion projects:
   i. Forman 230/115 kV transformer upgrade
   ii. De-bifurcation of High Bridge to Rogers Lake 115 kV line to give High Bridge additional outlet using existing transmission availability.
   iii. Fergus Falls-Morris 115 kV line upgrades
   iv. Hoot Lake 115 kV substation upgrades
   v. Canby-Granite Falls 115 kV line upgrade
   vi. Xcel Energy and ITC Midwest constructed the Huntley-Wilmarth 345 kV Market Efficiency Project (MEP)

d. Transmission System Reconfiguration: Xcel Energy implemented a process to study reconfiguration requests from outside entities. These requests are looked at to determine effectiveness, duration, and impact to the transmission system. Reliability is the primary determinant to whether a reconfiguration request is approved. MISO is working on setting up their process which Xcel Energy will participate in.

e. The MTOs worked with MISO and other stakeholders to change how ERIS impacts are identified in the MISO DPP process. The original distribution factor (DF) was 20% and the proposal reduced the DF to 10% in some instances, to ensure that more generation is not interconnected without necessary transmission facilities being built to deliver the energy to the system.

f. Xcel Energy has initiated two projects, MN Energy Connection and King Connection, that are designed to utilize existing transmission access rights. The MISO interconnection queue has a significant number of new interconnection requests currently seeking to connect to a system that is already very congested. Reusing existing transmission rights through the MN Energy Connection and King Connection Projects allows Xcel Energy to interconnect additional MWs through its existing transmission rights, avoiding long delays often related to MISO queue interconnection studies.

g. Xcel Energy confirmed the first system reconfiguration project in Southwest Minnesota to help alleviate congestion in the area. This request was reversed after several months due to a policy issue with MISO and SPP. In October 2022, MISO and SPP began coordinating their Day Ahead studies to recognize some of each other's flowgates which will help reduce SPP flows on the system. SPP previously did not recognize MISO flowgates and set a dispatch that could negatively impact MISO's dispatch.

h. In 2023, Grid North Partners conducted a study which identified 19 projects which will address system congestion in the near-term. In 2025, the MTO published the inaugural GETs Study which identified 34 additional solutions to reduce congestion. See Section 9 for additional details.

i. MISO LRTP Tranche 1 projects in Minnesota are utilizing the existing 345 kV second circuit capabilities where possible which will increase the overall ability to transfer power across the system.

j. MISO LRTP Tranche 2.1 projects in Minnesota, specifically the PowerOn Midwest 765 kV line and transformation to the 345 kV system (Big Stone – Brookings, Brookings – Lakefield) will increase overall transfer capability of the system and should alleviate some of the acute congestion in Southwest Minnesota.

k. Xcel Energy has initiated an internal study process to determine any transmission system reconfigurations on the underlying transmission system able to have a positive impact on the bulk transmission system and congestion. Xcel Energy Transmission Operations takes system reliability and curtailment and congestion cost impact into consideration when scheduling transmission outages.

l. Xcel Energy has been monitoring congestion and curtailment on a weekly basis to find new issues as they arise and determine whether a permanent solution is warranted or if the congestion is related to temporary system conditions.

   GRE is examining factors that have led to increased market congestion, where congestion is occurring and what we can do in the near-term to address present congestion. GRE is undertaking this congestion effort with the goal of positioning the grid for operational reliability and market efficiency.

   In April 2021, GRE was asked to develop an operating guide associated with the Helena-Scott County 345 kV outage and the Chub Lake 345/115 kV transformer to alleviate congestion.

MPUC Information Request No. 5

<u>Question:</u>
Staff requests that the MTOs provide information on recent congestion problems, solutions to the problems implemented over the last 3 years, and potential mitigation alternatives still under consideration, including non-transmission alternatives.

<u>Response:</u>

See MTO's response to MPUC Information Request No. 4 and the GETs Report in Appendix B.

MPUC Information Request No. 6

Question:
Staff requests that the MTOs provide comments on Minnesota area congestion problems and mitigation including non-transmission alternatives which may not be obvious from MISO MTEP planning.

Response:
Grid North Partners (DPC, OTP, MP, MRES, CMMPA, RPU, SMMPA, WPPI, Xcel Energy and GRE) conducted a study to identify the root causes of congestion from July 2020 to July 2022. The study identified 94 facilities in and around Minnesota causing congestion in Minnesota. The second circuit on the Brookings Co-Lyon Co and Helena-Hampton transmission lines, along with five other projects to upgrade facilities are already submitted in MISO's MTEP to mitigate some of this congestion. The study identified 19 facilities able to be upgraded to mitigate congestion. Much of the congestion observed is due to high-wind weather patterns with much longer duration that the typical 4-hour batteries available as non-transmission alternatives.

Xcel Energy and other TOs have been working with MISO through the stakeholder process to request changes to the Generator Interconnection studies to ensure that necessary system upgrades are identified in the study process. Xcel, and other stakeholders including Transmission Owners have advocated for a few policy changes, including different Dispatch Assumptions within GI studies (for example, ensuring that Existing Resources of the same Type as the Study resources are dispatched at the same level as the Study Resources interconnecting at the same Bus) or changing the DFAX % which triggers upgrades. MISO did change the DFAX%, but has not agreed to change Dispatch Assumptions. Local Planning Criteria could be utilized to piecemeal these requirements, as OTP and others have done.

Also see MTO's response to MPUC Information Request No. 4 and the GETs Report in Appendix B.

MPUC Information Request No. 7

Question:
Staff requests information about the status of MISO's Long Range Transmission Planning (LRTP) and the MISO-Southwest Power Pool (SPP) Joint Targeted Interconnection Queue (JTIQ) processes.

> For the LRTP, provide specific information on the status of the MISO-approved Tranche 1 projects and the Tranche 2 study.

Response:
See Chapter 10 for information regarding MISO LRTP and related MISO projects in Minnesota.

MISO and SPP released the completed JTIQ study in March of 2022.[42] The study identified a seven-project JTIQ Portfolio with a planning level estimated cost of $1.65 billion. The recommended JTIQ Portfolio is expected to fully address the set of transmission constraints evaluated in the JTIQ Study as being significant barriers to the development of new generation along the SPP-MISO seam. The Planning Advisory Committee within MISO presented the JTIQ draft tariff additions and revisions on April 26, 2023, and comments were due by May 10, 2023. MISO and SPP are targeting filings with FERC for approval of the tariff and related interconnection agreements in Q3 of 2023 and MISO and SPP Board approvals in December of 2023 or Q1 of 2024.[43]

MPUC Information Request No. 8

Question:
Staff requests as assessment of whether the LRTP and JTIQ processes are progressing and that the identified upgrades will be available in a timely manner.

Response:
See response to MPUC Information Request No. 7. The MTO utilities are working with MISO to ensure these projects are approved in a timely manner, but the nature of cost allocation changes increases uncertainty in approval timing.

With respect to LRTP processes, the MTO utilities are progressing on a timeline to place the projects in service by the MISO-approved dates. We are continually analyzing project timelines to leverage any efficiencies that may be available.

MPUC Information Request No. 9

Question:
Staff requests a discussion of the steps taken by utilities to encourage MISO to keep the LRTP and JTIQ processes on-track for a timely decision by MISO's board of directors.

Response:
Both LRTP Tranche 2.1 and JTIQ Portfolios were approved in December of 2024 by the MISO Board of Directors.

Each of the MTO utilities that are members of MISO regularly participated in MISO workshops and planning activities to support the timeline completion of the LRTP and JTIQ processes. These efforts include, but are not limited to, providing timely responses to information requests and carefully reviewing modeling assumptions to ensure they are as accurate as possible.

For example, Xcel Energy is a regular participant in open stakeholder meetings, as well as individual meetings with MISO staff and leadership to underscore the urgency needed in these efforts. To better assist MISO, Xcel Energy has increased the rigor of feedback and provided detailed information on model building as well as early routing and siting impacts to ensure efforts

[42] https://www.spp.org/engineering/spp-miso-jtiq/
[43] https://cdn.misoenergy.org/20230426%20PAC%20Item%2006c%20JTIQ%20Update%20and%20Draft%20Tariff%20Presentation628664.pdf

to advance JTIQ and LRTP Tranche 2.1 aren't subjected to excessive iteration in the stakeholder process. Xcel Energy has also increased coordination with our neighboring utilities to better understand the positions of each company and address any misalignment prior to MISO's project submission and alternatives request.

L&O and EREPC are members of SPP's Zone 19 (Upper Missouri Zone or "UMZ") and participate in the applicable UMZ meetings. Due to their location along the SPP-MISO seam, L&O and EREPC promote SPP-MISO coordination and proposed projects & improvements along the seam. This includes helping to keep the JTIQ process moving forward.

11.6 Congestion Order

Chapter 9 provides the information in compliance with the Commission's March 24, 2025 ORDER ESTABLISHING FILING REQUIREMENTS, in Docket No. E999/CI-24-316.