2021 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 2021 Biennial Transmission Projects Report is the eleventh 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 2021 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 Projects that were identified in earlier reports and assigned a Tracking Number but which have been completed or withdrawn in the past two years are also identified.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 2021 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	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

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

[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.

As required by the statute, the Biennial Report also provides an update on the status of the utilities' efforts to meet state Renewable Energy Standard milestones.

In 2015, the Legislature established a new reporting requirement for certain utilities. Minn. Laws 2015, 1Sp2015, ch. 1, art 3, s 22, codified at Minn. Stat. § 216B.2425, subds. 2(e) and 8. 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 can be found in Chapter 9.

The 2020 Order also required the MTO to describe its efforts to engage with Midcontinent Independent Transmission System Operator (MISO) to ensure that 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.

The following is a summary of each subsequent chapter of the 2021 Biennial Report.

Chapter 2 describes the biennial reporting requirements. This includes a discussion of the specific information the MPUC directed the utilities to include in the 2021 Biennial Report. Chapter 9 contains the information on clean energy goals.

Chapter 3 is entitled 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 conducted by MISO, and the MTEP Reports are where most of the information about the pending projects can be found.

Chapter 4 is the Public Participation chapter. Several recent examples are provided regarding how 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 103 separate transmission inadequacies across the state, including 58 new ones identified in the 2021 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 2020 MTEP Report, for example, would be called MTEP20. In addition, information about each pending project, by Tracking Number, is provided. This information addresses issues like alternatives considered, a schedule, and the general impacts on the environment and the area if the project were 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 2019 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 that are 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 Renewable Energy Standards. Not all utilities that own transmission lines are subject to the state Renewable Energy Standards, 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.

For the past several reporting periods, and again this year at the direction of the MPUC, 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 through 2022, although demands of neighboring states for renewable energy will undoubtedly affect what resources will be required.

Chapter 8 also provides a brief summary of the information a number of the utilities just submitted to the MPUC pursuant to a statute that requires annual reporting regarding compliance with upcoming solar energy standards.

Chapter 9 provides 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. More specifically, it addresses 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.

MPUC Process. Upon receipt of this Report, the Commission will solicit comments from the Department of Commerce, interested parties, and the general public about the Report. 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-21-111. 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 2021 Biennial Transmission Projects Report in May 2022.

2.0 Biennial Report Requirements

2.1 Generally

Prior Reports

This is the eleventh 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. Minn. Stat. § 216B.2425. 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 2021 Report will also be posted on that webpage.

Biennial Report	MPUC Docket Number	MPUC Order
2021	E999/M-21-111	
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 that expand and clarify what is expected to be in the report (Minn. Rules Chapter 7848). 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 what efforts were 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 done 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 five biennial reports – 2011, 2013, 2015, 2017 and 2019 – the Commission has allowed the utilities to reference the latest MTEP Report to provide information about the identified inadequacies in Minnesota. The 2021 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 to addressing each inadequacy. The utilities explain in section 6.1 how 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 2021, 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.

In its 2020 Order accepting the 2019 Biennial Report, the Commission said that the MTO shall include content similar to 2019 Report, and include 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. The MTO shall also 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.

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.

Consequently, the 2021 Report closely tracks the 2019 Report but also includes discussions on gaps in transmission related to companies' clean energy goals and efforts to engage with MISO regarding Minnesota's transmission needs.

Waiver Request for 2023 Report

The MTO requests that the Commission extend the rule variances granted in the August 19, 2020 Order accepting the 2019 Biennial Report (and previous orders) for the 2023 Biennial Report as well, such that the future report requirements will mirror the content, notice and participation requirements of this 2021 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 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” 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. Minn. Rule part 7848.0100, subp. 5. Each of the entities that is 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
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 26, 2021, the MTO filed a letter to the Commission in the instant docket that there would be no certification requests included with the 2021 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 found 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 that is several years in the future. The MPUC rules require the utilities to identify inadequacies that might affect reliability over the next ten years. Minn. Rule part 7848.1300, subpart D. A transmission planner is often unable to identify possible alternatives or the impacts of the alternatives, for projects that are ten years in the future. Moreover, 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 user 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 that the utilities are to identify general economic, environmental, and social issues associated with each alternative. This is a recognition that it is not always possible to know during the planning stage what 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 103 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 where specific alternatives have been identified.

An in-depth analysis of potential impacts of a proposed project and the identified alternatives will be provided when 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 when the public generally begins to take notice of the need for a project and to participate in the analysis of alternatives. And this is when the utility must begin to pull together the information that is required to complete applications for a CON and for a permit. These applications, and any environmental review that is 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 that are 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. Minn. Stat. § 216B.2425, subd. 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.

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

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 103 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 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 particular issue at hand.

Non-wires alternatives are electric utility system supply-and demand-side projects and/or 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 maximum demand in specific grid areas.[1] Examples of non-wires transmission alternatives may include: establishing new operating guides or procedures, demand side management (DSM), distributed generation (DG), and electricity and thermal storage.

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 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

[1] www.nrri.org.

solar and/or wind with storage offers the greatest impact to reduce loads regardless of season. Transmission planners continue to evaluate non-wire options that result in the avoidance of establishing new transmission corridors. 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 that 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 thus making it difficult to know how, when or where to reliably deliver the energy. Distribution automation likely will be needed to assist the operator in shifting load to other systems if the expected generation resource is 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 resource and increase its 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 is needed to ensure that reliability is equal to the availability of 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 is needed to ensure that reliability is equal to the availability of transmission options. Based on geographic locations, land constraints may be a challenge to installation of adequate wind generation to meet the new or expanding load. 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 flows 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 flows 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.

Conclusion
Non-Wire Alternatives are discussed in Chapter 6 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,[2] planning,[3] fact specific[4] and annual reporting dockets.[5]

Federal Energy Regulatory Commission (FERC)

The 2019 Biennial Report discussed Federal Energy Regulatory Commission (FERC) Order No. 841, which addresses two different levels of participation of storage resources in wholesale markets. Since the last report, FERC issued Order No. 2222, which removes barriers for

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[2] For example, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Dockets No. E999/CI-16-521 and E999/CI-01-1023; *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 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 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 Possible Amendments to Rules Governing Cogeneration and Small Power Production, Minnesota Rules, Chapter 7835*, Docket No. E999/R-13-729; *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 Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10(e) and (f)*, Docket No. E999/M-14-65; *In the Matter of the Commission Investigation on Grid Modernization*, Docket No. E999/CI-15-556.

[3] For example, *In the Matter of Xcel's 2017 Biennial Distribution Grid Modernization Report*, Docket No. E002/M-17-776; *In the Matter of Xcel Energy's 2018 Integrated Distribution Plan*, Docket No. E002/CI-18-251; *In the Matter of Xcel's 2017 Hosting Capacity Study*, Docket No. E002/M-17-777; *In the Matter of Xcel's 2018 Hosting Capacity Study*, Docket No. E002/M-18-684; *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request,* E002/M-19-666; *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.

[4] For example, *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 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 d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need,* Docket No. E002/CN-12-1240.

[5] For example, *In the Matter of Annual Cogeneration and Small Power Production Filings,* Docket No. E999/PR-21-9; *Distributed Generation Interconnection Report*, Docket No. E999/PR-21-10.

distributed energy resource (DER) aggregations to participate in wholesale markets. The following is a brief summary of Order Nos. 841 and 2222 as they pertain to storage and non-storage DER aggregations participating in wholesale markets.

Order No. 841, adopted in February 2018, requires that RTOs and ISOs accommodate the various types of services that electric storage resources can provide, regardless of whether they are interconnected at transmission voltage or to the distribution system.

In September 2020, FERC expanded the requirements applicable to participation of resources interconnected to the distribution system in wholesale markets with issuance of Order No. 2222 in Docket No. RM18-9-000, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators.

FERC's Order 841, to the extent it addresses wholesale market participation by DER storage resources, and FERC's Order 2222, left many key details regarding implementation to resolution by RTOs/ISOs and distribution utilities. Under the rule, FERC has jurisdiction over the manner in which DER storage resources and DER aggregations participate in wholesale markets while FERC has devolved to the relevant electric retail regulatory authorities (RERRAs) responsibility for regulatory requirements needed to maintain the safety and reliability of the distribution system and allocation of costs associated with accommodating market participation by DER storage resources and DER aggregations.

MISO

According to its website, MISO has noted that "[a] high penetration of Distributed Energy Resources (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." To that end, MISO has been hosting a series of workshops on DERs throughout the year. MISO is currently working with the Organization of MISO States (OMS) and other MISO stakeholders to develop a DER participation model that accounts for the distinctive characteristics of the MISO region and promotes reliability on a least cost basis.

MISO filed its Order No. 841 compliance filing in December 2018 with the provisions regarding DERs.[6] Subsequently, in their response to FERC's request for more information filed in April

[6] Excerpt from 2018 IDP regarding key aspects of MISO's compliance filing: "One of the key aspects of MISO's compliance filing will be the relationship between MISO, the DER, and the applicable distribution system operator (DSO). After reviewing MISO's draft agreement with the DER, we have tentatively concluded that it may be appropriate to file a tariff at FERC that would address aspects of DER participation in wholesale markets. If the Company were to go forward with this concept, the tariff would address matters such as direct assignment of distribution system upgrade costs incurred due to DER participation in wholesale markets, the need for a DER to establish to the satisfaction of the utility that it has metering capability needed to ensure that it does not charge a storage resource at wholesale rates for retail usage, mechanisms to limit DER output to the extent that reliability of

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.

In Order No. 2222, FERC established a compliance date for the RTOs/ISOs of July 19, 2021. MISO filed a request to extend that date until April 18, 2022 and FERC granted MISO's request.

In January 2021 MISO held the first meeting of its DER Task Force (DERTF). The DERTF has met every regularly since then and will continue meeting until MISO makes its Order No. 2222 compliance filing in April 2022. In addition to the regular monthly meetings of the DERTF, MISO has held one workshop to coordinate Order No. 2222 implementation with the relevant electric retail regulatory authorities (RERRAs) and has another workshop planned in October.

Grid North Partners

Grid North Partners, an evolution of CapX2020, is a voluntary partnership of 10 Minnesota and surrounding area transmission owning utilities[7] formed in 2004 to collaboratively expand the Upper Midwest transmission grid. A year ago, Grid North Partners, recognizing that a rapid change was occurring and the challenges facing the transmission grid needed to be identified, so solutions could be identified, published the CapX2050 Transmission Vision Report.[8] While CapX2020 is a subset of the MTO members, the issues identified in the CapX2050 Transmission Vision Report impact all MTO entities.

The CapX2050 Transmission Vision Report highlighted four key implications which must be addressed for the future grid to remain reliable for all hours of the year:

- Current dispatchable resources support the electric grid, by providing reliability attributes, in ways that wind and solar resources presently cannot
- The ability for system operators to meet real-time operational demands will be more challenging and, therefore, we will need to develop new tools and operating procedures to address the challenges.
- More transmission system infrastructure will be needed in the upper Midwest to accommodate the transition of resources.
- Wind and solar alone will be incapable of meeting all consumer energy requirements at all times and therefore, we will need to understand and promote a future electric grid that can continue to meet consumer energy requirements safely, reliably and affordably.

the distribution system is compromised by the DER's activities, and cost recovery for services provided by the distribution system operator to the DER."

[7] 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

[8] https://gridnorthpartners.com/wp-content/uploads/2021/02/CapX2050_TransmissionVisionReport_FINAL.pdf

Since the CapX2050 Transmission Vision Report's publication, Grid North Partners has been working to identify solutions to address those key findings via two primary avenues:

- Technical effort – Collaborative participation in MISO's Long-Range Transmission Planning (LRTP) effort, and
- Education & stakeholder engagement – Dialog with policy makers, utilities, stakeholders, and landowners discuss what it will take to ensure the transmission system in the Upper Midwest is prepared to deliver tomorrow's energy 24 hours a day, 7 days a week.

Grid North Partners Technical Effort: In May 2020, CapX2020 sent a letter to the MISO requesting MISO initiate a comprehensive, long-term transmission planning analysis using an integrated approach to identify a plan to optimally meet the 2030 goals of utilities, their customers, and policymakers in the Upper Midwest. The letter supported the future assumptions MISO identified for use in their 2021 MTEP LRTP initiative. MISO kicked-off this planning effort at the August 12, 2020 Planning Advisory Committee meeting.

Grid North Partners members both individually and collectively are engaged and participating in the MISO LRTP effort. In support of the MISO LRTP, Grid North Partners has commenced an informal technical study effort focused on more localized issues within the Grid North Partners footprint. All relevant potential options and findings have and will be supplied to MISO for potential inclusion in the LRTP.

Education and Stakeholder Engagement: The CapX2050 report identified that changing fleet will have wide ranging implications and it will require everyone from legislators, regulators, local governments, property owners, utilities, environmental groups and others working together to ensure our transmission system is prepared. To help facilitate a dialog, on June 12, 2021 Grid North Partners hosted a conference called 'Finding True North.'[9] The conference was attended by over 300 registrants and included panel discussions featuring different Upper Midwest expert perspectives on planning the grid for resiliency, operating our future system, policy and the next regional buildout, and a keynote on planning for 100% clean energy.

Institute of Electrical and Electronics Engineers (IEEE)

While not specifically requested by Commission another important aspect is various entity's work on IEEE 1547-2018, which is a recently published distributed energy resources (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

[9] A full recording of the conference is available at: https://gridnorthpartners.com/conference/

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 with Xcel Energy's business practice decisions.

In terms of specifying DER response to abnormal grid conditions, IEEE 1547 indicates that 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 that 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 how local grid support functions are 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 has released several collaborative reports for phase 1 in July of 2021. Xcel Energy has 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/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 Process to ensure that our needs are being addressed and that 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 Process that Minnesota TOs are involved in.

MISO Planning Advisory Committee (PAC): The Planning Advisory Committee 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 Planning Subcommittee (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.

MISO Planning Subcommittee (misoenergy.org)

MISO Subregional Planning Meeting (SPM): In accordance with FERC Order 890 Attachment K, the MISO will host a series of subregional planning meetings (SPM) 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 that are potentially driving new transmission expansion on the grid.

Subregional Planning Meeting (misoenergy.org)

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

The main issue for this group currently is cost allocation related to the recent LRTP effort on-going in MISO. Efforts to split MISO vs one RTO as it relates to benefits and who pays is causing some tension across MISO stakeholders.

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

MISO Interconnection Process Working Group (IPWG): The purpose of the Interconnection Process Working Group (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.

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

MISO Interconnection Process Working Group (misoenergy.org)

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

A recent issue brought up 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 feel reconfiguring the transmission system to accommodate outages is a good option. TOs feel that these types of requests and studies do not adequately address reliability concerns.

MISO Transmission Owners Compliance Task Team (TOCTT): This is a closed group that deals with the compliance efforts at MISO relating the FERC and NERC.

3.0 Transmission Studies

3.1 Introduction

The Commission requires that 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. Minn. Rule part 7848.1300, item F. 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 2021 Report.

Section 3.2 describes a number of studies that have been completed that either address expansion of the transmission network to provide for generation expansion, in particular renewable energy, 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 that are attempting to resolve 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" (MAPP). Minn. Rule part 7848.1300, item B. As the utilities reported in the 2011 Report, however, the Midcontinent Independent Transmission Operator (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 October 2019. 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
Great River Energy Long Range Plan (LRP)	2019	GRE	A study of the Great River Energy load serving transmission through 2029.
Benson Area Study	2020	GRE	A study of the Benson area.

Study Title	Year Completed	Utility Lead	Description
CapX2050 Transmission Vision Study	2020	Grid North Partners	In March 2020, the Grid North Partners utilities, an evolution of CapX2020, published the CapX2050 Transmission Vision Report to educate and inform Upper Midwest policymakers and other stakeholders on the implications of a future that is more reliant on wind and solar resources. This holistic long-term study is critical to the eventual development of a comprehensive plan that will ensure the continued reliable delivery of low-cost electricity in a cost-effective manner. The full report is available at: https://gridnorthpartners.com Grid North Partners, an evolution of CapX2020, is a joint initiative of 10 transmission-owning utilities consisting of: 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.
Northern Minnesota Voltage Stability Study	2020	MP	Evaluate voltage stability concerns identified in Boswell Attachment Y2 Study to understand causes, stability thresholds, and related issues
Duluth Area Transmission Study	2021	MP	Continued analysis of the Duluth-area issues identified in previous studies to identify preferred long-term solutions; Duluth 115 kV Loop (2019-NE-N12), Duluth Area 230 kV (2007-NE-N1).

3.3 Regional Studies

While every study that is undertaken adds to the knowledge of the transmission engineers and helps to determine what transmission will be 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 that support multiple generation interconnect 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.

MISO started a Regional Transmission Overlay Study (RTOS) in 2016, but due to limited benefits identified in the study MISO has put the study effort on hold.

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. 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."

MTEP20 Report
The MTEP20 report identified projects required to maintain reliability for the ten year period through the year 2029 and provides a preliminary evaluation of projects that may be required for economic benefit up to twenty years in the future.

According to the MTEP20 Executive Summary, the MISO staff is recommending approval of approximately $2.5 billion in new transmission infrastructure investment. Of the $2.5 billion, $1 billion is new Baseline Reliability Projects, $606 million is Generation Interconnection Projects, and the remainder falls into the Other category.

MTEP21 DRAFT Report
The MTEP21 DRAFT report identified projects required to maintain reliability for the ten year period through the year 2030 and provides a preliminary evaluation of projects that may be required for economic benefit up to twenty years in the future.

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 load serving situations, many of these studies relate to specific Tracking Numbers.

Study Title	Anticipated completion	Utility lead for Study	Description
South Washington Load Serving Study	2019	NSP	Develop a comprehensive plan to serve the growing load around the City of Woodbury in eastern Twin Cities Area.

Study Title	Anticipated completion	Utility lead for Study	Description
Wendell Interconnection and Nashua Elevator Load Serving Study	2019	OTP	Load growth in the Western Minnesota area caused a need for system upgrades. Various transmission and non-transmission alternatives were investigated to determine a best-fit project for the new load.
Worthington Area Study	2021	GRE ITCM MRES	GRE, ITCM & MRES studied the transmission system in the Worthington area to serve a potential load addition as well as mitigating existing reliability and operational concerns. See chapter 6, Southwest Zone, Worthington Area Projects.
Winton Area Study	2021	MP	Evaluate the need for capacitor banks and long-term reliability upgrades on the 115/46 kV system serving Tower, Ely, Winton, and Babbitt.
Great River Energy Large Load Studies	N/A	GRE	Great River Energy has had multiple request across its member system's service areas for potential large load installations. These loads have ranged from 2.5 MW to 500 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 with 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.

Study Title	Anticipated completion	Utility lead for Study	Description
Barnesville Area	2022	GRE MRES OTP	GRE, MRES, and OTP are studying the transmission system in the Barnesville area to address local load serving concerns, and potential reliability benefits for the surrounding load pocket looking out towards the end of the planning horizon. The study is expected to be completed early 2022.
Pilot Knob Area Study	2022	GRE	Evaluate long range options for the Pilot Knob area. There is a future need to rebuild the Pilot Knob substation due to age and condition. This study will determine the feasibility of converting the area to 115 kV.
Verndale Area Study	2022	MP	Evaluate load-serving needs in the Verndale area to identify long-term transmission and distribution solutions, particularly as they may impact the scope of the Verndale Substation Modernization Project (2021-NE-N4).
Onigum Area Study	2024	GRE	Study the Onigum area for a possible 115 kV conversion.

4.0 Public Participation

4.1 Public Involvement in Transmission Planning

Both the statute – Minn. Stat. § 216B.2425 – and the MPUC rules – Minn. Rule part 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 of 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 every time since, including in the August 19, 2020, 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 any better attended 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 in a statewide newspaper of the webinar, 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 that the utilities are not required to hold a webinar with regard to 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 the 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. It 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, on which interested persons can obtain various information 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 even developed two short videos detailing items of interest to the general public about transmission lines that are available on the webpage. One video describes generally how the transmission planning process is done at utilities in Minnesota. The second video describes 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 that are 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.

Minn. Stat. § 216E.03, subds. 3a and 3b, requires any utility that is 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 the opportunity for a preapplication meeting. The utilities do this, of course, and often local governmental bodies request a meeting with the utility.

In the 2015 Biennial Report, in Section 4.4, the utilities provided several examples of the steps the utilities take to involve local government and the general public in specific projects. A few additional examples are included below.

4.4.1 Plymouth-Area Power Upgrade MPUC Tracking Number 2017-TC-N6

On May 25, 2016, Xcel Energy held two public open houses, from 12 to 2 p.m. and from 4 to 7 p.m., at the Medina Ballroom in Medina, to gather public input on the three different electrical options that the Company studied to meet the electrical needs of the Plymouth area. Notice for these public open houses were sent to over 7,700 landowners and other stakeholders and notice was also published in the Minneapolis Star Tribune and in the local Sun Sailor newspaper on May 19, 2016. Approximately 80 people attended the two public open house sessions.

At these two public open houses, Xcel Energy presented information about the three electrical alternatives (Alternatives A-C) that Xcel Energy has identified to help solve Plymouth's identified electrical needs. A summary of these three alternatives is provided below:

- Alternative A: construct a new Pomerleau Lake Substation south of Schmidt Lake Road and west of I-494, construct two new 34.5 kV distribution feeders from this substation to the west, reinforce existing feeders and extend one existing 13.8 kV feeder from the Parkers Lake Substation, and install approximately 12 pad-mounted transformers.

- Alternative B: expand Parkers Substation near I-494 and County Road 6, construct two new 34.5 kV feeders from the Parkers Lake Substation to the west, reinforce existing feeders and extend one existing 13.8 kV feeders from the Parkers Lake Substation, and install approximately 12 pad-mounted transformers.

- Alternative C: expand existing Hollydale Substation and build three new 13.8 kV feeders from the Hollydale substation, construct new Pomerleau Lake Substation, extend the existing 69 kV line 0.7 miles from Hollydale to Pomerleau Lake and re-energize the Hollydale-Pomerleau Lake 69 kV line, keep the Medina-Hollydale 69 kV line energized, reinforce existing feeders and extend one existing 13. 8 kV feeder from Parkers Lake Substation.

All three of these options met the immediate, near-term, and long-term load-serving needs of Plymouth. Maps of each of these three alternatives were available to the public.

Additional information regarding these three alternatives was available in Xcel Energy's electrical study, "Plymouth-Area Engineering Study Report," a copy of which was available on the Company's website:
http://www.transmission.xcelenergy.com/Projects/Minnesota/Plymouth-Project.

In addition to presenting information about these three alternatives including maps and photos of typical facilities, the public open houses also featured stations with information about Xcel Energy's DSM programs, electricity 101, need for electrical improvements, vegetation management, construction, and right-of-way.

At the public open houses, Xcel Energy had comment forms available for landowners to submit comments. The Company website also included a comment form, as well as an email address and a telephone number for comments. The deadline for submitting comments was June 25, 2016. Xcel Energy spent many hours responding to the comments that were received and posted answers on its website to many of the questions that were received.

Transmission Project Public Involvement

During the past two years Great River Energy (GRE) has applied for permitting on several transmission and substation projects both with the Commission and at the local level. Regardless of the permitting authority, GRE follows the standard procedure of involving the public prior to the application and throughout the permitting process to keep the public informed. Some recent examples of public outreach are:

- Lake Eunice 115 kV Transmission Conversion Project –
    - This project involved two private landowners. Early in the project development phase, Great River Energy's land agent contacted the landowners and provided them with information on the project.
- Frazee to Erie 115 kV Transmission Project – Becker County
    - GRE held a public open house informational meeting in February 2020 to inform the public about this project. Over 100 invitations for the meeting were mailed to private landowners and business along the anticipated project route 13 days prior to the open house, and display advertisements were published a total of five times in three local newspapers. Seventeen people signed into the open house.

As GRE continues to work on new transmission and substation projects, public participation will continue to be a focal point to a successful project.

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.

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 essentially 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 and/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 that have been 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
- 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 one 345 kV line 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 on 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 which delivers power to local loads.

The major change in the transmission system in the Northwest Zone since 2011 is the addition of a 230 kV line between Grand Rapids in the Northeast Zone and Bemidji in the Northwest Zone (a CapX2020 project). This line was energized in November 2012. This project has been referenced under Tracking Number 2005-NW-N2 and MPUC Docket No. E015,ET6,E017/TL-07-1327.

The MPC Center-Grand Forks 345 kV project was completed in early 2014 and will bring power from Center, North Dakota to Grand Forks, North Dakota. Also, the CapX Fargo-St. Cloud 345 kV project was completed in 2015 and will transfer power between Fargo, North Dakota and the St. Cloud area.

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
- Minnkota Power Cooperative
- Minnesota Power
- Southern Minnesota Municipal Power Agency
- 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 is 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.

North Shore Loop

A number of projects in the Northeast Zone are part of what is called the North Shore Loop. The North Shore Loop refers to an approximately 140-mile portion of 115 kV and 138 kV transmission lines in the northeastern Minnesota transmission system that is used by Minnesota Power and Great River Energy to serve customers along the North Shore of Lake Superior and in the Hoyt Lakes area. The following discussion about the North Shore Loop and the changes in generation that are taking place in the area is helpful in understanding the need for a number of projects in the Northeast Zone.

The North Shore Loop extends approximately 70 miles along the North Shore of Lake Superior from east Duluth to the Taconite Harbor Energy Center near Schroeder, then turns west and extends approximately another 70 miles to the Laskin Energy Center near Hoyt Lakes. Historically, the North Shore Loop was characterized by an abundance of coal-fired baseload generation, including Minnesota Power's Laskin and Taconite Harbor Energy Centers and a large industrial cogeneration facility located in Silver Bay. A geographical representation of the North Shore Loop transmission system is shown in Figure 1 below.

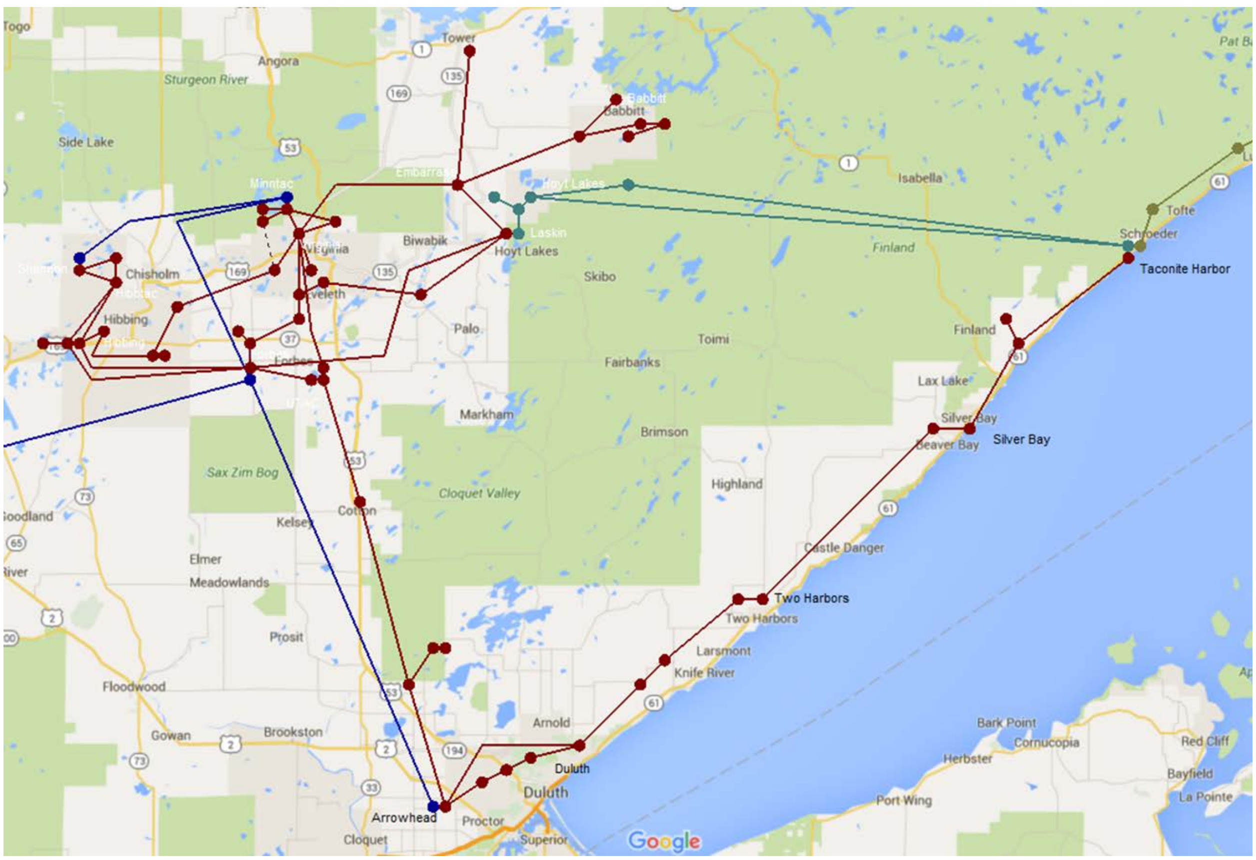

Figure 1: North Shore Loop Transmission System Geographical Representation

Over a span of approximately five years beginning in 2015, all seven of the coal-fired generating units located at these three sites have been idled, retired, or converted to peaking operation. In 2015, the two units at the Laskin Energy Center were converted from coal-fired baseload units to natural gas peaking units. Also in 2015, Minnesota Power retired one of the units at Taconite Harbor. With Commission approval in the 2015 Integrated Resource Plan, Minnesota Power idled the other two Taconite Harbor units in the fall of 2016 with all coal-fired operations to cease at the facility by 2020. In June 2016, Silver Bay Power Company began operating with one of the two Silver Bay units normally idled. Finally, near the end of September 2019 Silver Bay Power Company idled both of the Silver Bay units and began operating with no generators online. The cumulative impact of these operational changes leaves no baseload generators normally online in the North Shore Loop.

The local baseload generators at Laskin, Taconite Harbor, and Silver Bay have, for decades, contributed to the reliability of the North Shore Loop transmission system by providing redundancy, voltage support, and power delivery capacity. As a result of the rapid decarbonization of the North Shore Loop, several transmission projects throughout and adjacent to the North Shore Loop have been implemented since 2016. These projects are necessary to ensure the continued reliability of the transmission system in the area by restoring redundancy, addressing unacceptably low voltage and voltage stability concerns, and mitigating transmission line and transformer overloads. Projects located in the North Shore Loop or related to the transitional changes in the North Shore Loop include (MPUC tracking number and actual/planned year of completion listed in parenthesis):

- Minntac 230 kV Bus Reconfiguration (2015-NE-N10, Completed 2016)
- Forbes 230/115 kV Transformer Addition (2015-NE-N11, Completed 2016)
- North Shore Switching Station & Cap Banks (2017-NE-N7, Completed 2017)
- Babbitt Capacitor Bank (2017-NE-N8, Completed 2017)
- ETCO Capacitor Bank (2017-NE-N9, Completed 2017)
- Forbes 3T Breaker Replacement (2017-NE-N10, Completed 2017)
- 18 Line Upgrade (2017-NE-N17, Completed 2018)
- North Shore Transmission Line Upgrades (2017-NE-N19, Completed 2019)
- Two Harbors 115 kV Project (2017-NE-N20, Completed 2019)
- North Shore STATCOM (2017-NE-N15, Completed 2019)
- Laskin-Tac Harbor Transmission Line Upgrades (2017-NE-N21, Planned 2019-22)
- 38 Line Upgrade (2019-NE-N11, Completed 2020)
- Mesaba Junction 115 kV Project (2017-NE-N23, Planned 2020-22)
- Laskin-Taconite Harbor Voltage Conversion (2017-NE-N2, Planned 2022)
- Forbes 37 Line Upgrade (2019-NE-N2, Planned 2021-22)
- Forbes Tie Breaker Addition (2017-NE-N6, Planned 2021-22)
- Duluth 115 kV Loop (2019-NE-N12, Planned 2023-25)

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:

- Great River Energy
- Missouri River Energy Services
- Otter Tail Power Company
- Southern Minnesota Municipal Power Agency
- 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 are being considered to address the need for more power into this area. The new CapX Quarry substation will provide significant relief to the St. Cloud area system deficiencies. The CapX Fargo-St. Cloud 345 kV project was completed in 2015 and transfers power between Fargo, North Dakota and the St. Cloud area. The CapX Brookings, South Dakota-Twin Cities 345 kV project was also completed in 2015.

The Riverview 345/115/69 kV substation has been built in the St. Cloud Area along the CapX Fargo-Monticello 345 kV line to address some of the area 69 kV issues. This is a Great River Energy substation connecting to the Xcel Energy's 69 kV system.

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:

- Great River Energy
- Xcel Energy

There are no major changes in the transmission facilities located in the Twin Cities Zone since 2013, although several projects are under review by the Commission.

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 GRE DC line and 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 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 that is 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 CapX 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 CapX 345 kV project between the southeast corner of the Twin Cities area, Rochester, and LaCrosse, Wisconsin, was also completed in 2015.

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
- 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 the wind generation that is occurring 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 will provide opportunities for new transmission substations to improve the load serving capability of the underlying transmission system.

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:

- Dairyland Power Cooperative
- Great River Energy
- ITC Midwest LLC
- Rochester Public Utilities
- Southern Minnesota Municipal Power Agency
- Xcel Energy

The major addition to the Southeast Planning Zone will be the addition of the Huntley-Wilmarth 345 kV line that will help improve renewable flow across the transmission system. This is an economic project that connects part of Southern Minnesota to the Mankato area. This project was identified through the MISO Economic Planning effort.

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 to the Southeast Planning Zone for lower voltage load service from generation stations outside of the area. The 345 kV system also allows the seasonal and economic exchange of power from Minnesota to the east and south from large generation stations that are 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.

6.0 Needs

6.1 Introduction

Chapter 6 contains information on each of the present and reasonably foreseeable future inadequacies that have been identified in the six transmission zones. For each zone, a table of present inadequacies is first presented, in order of when the inadequacy was first identified, so the older inadequacies are listed first. Then 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/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility

The following describes what information is 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 that 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 2007, on the other hand, was first identified in the 2007 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/App
The third column contains a reference to a MTEP Report and an Appendix in the report. The MTEP Report is prepared annually by the 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 MTEP21, 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 the 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 because even though Minnkota is not a MISO member. MISO performs some of Minnkota's transmission planning work.

Certificate Of Need

The MPUC rules (Minn. Rules part 7848.1300, item M) state that 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. 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 that could 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 that are 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 planning was being conducted by and through MISO.

In 2014, as part of its approval of the 2013 Biennial Report, the Commission determined that 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." Minn. Stat. §216B.2425, subd. 2(c)(3). 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 that are 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 as well, 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/App	MTEP Project Number	Utility	Date Completed

Most of the columns contain the same information that is 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 was required from the Commission, or both, 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 that was 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 of 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 that is prepared each year. Much of the information provided in this subsection was also available in the 2013, 2015, 2017 and 2019 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 usually approves the report in December. The process continues with another report finalized the following December. The MTEP21 Report should be approved by the MISO Board of Directors in December of this year.

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

Appendix A – Projects recommended for approval,
Appendix B – Projects with documented need and effectiveness, and

Generally, when 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 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 more timely information. The Biennial Report is prepared every other year.
- The MISO planning process is comprehensive. MISO considers all regional transmission issues, not just Minnesota transmission issues.
- MISO conducts an independent 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 redo all the information that is found in the MTEP Report.

6.2.2 Finding a Project in a MTEP Report

For each zone, a table is included that describes 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/App	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 Cap 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 the arrow by "MTEP" tab. Then click on the "Previous MTEP Reports" link on the left side of the page.

Step 3. Click on the link for the MTEP19 Report.

Step 4. Click on the "MTEP19 Appendix A or B."

Step 5. Select the "Projects" tab at the bottom of the spreadsheet that was just 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, probably earlier than 2011, 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, which is "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, more 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 that 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 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 Cap 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 West.
>
> 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.

Specific Utility Projects

One additional useful tool with the MTEP Reports is the ability to find projects that an individual utility has submitted to MISO. Also, the Appendices can be sorted to show all projects for a particular utility, (or, depending on the version of Excel you are using, a group of utilities). To do this, from the Appendices ABC page, click on the down arrow located in the column C heading "Geographic Location by TO Member System," and then select the code for the individual utility you are interested in from the drop-down list. (NOTE: some versions of Excel will allow you to select multiple utilities).

Utility	MISO Geographic Code
American Transmission Company, LLC	ATC LLC
Dairyland Power Cooperative	DPC
Great River Energy	GRE
ITC Midwest LLC	ITCM
Minnesota Power	MP
Missouri River Energy Services	MRES
Otter Tail Power Company	OTP
Southern Minnesota Municipal Power Agency	SMP
Xcel Energy	XEL

It is also possible to sort other columns in the Appendices in a similar manner. For example only projects or facilities in Appendix A can be identified by clicking on the arrow in Column A and selecting the desired choice from the drop-down list.

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
2007-NW-N3	NW MN Reliability Upgrades	2014/B	4232	No	No	OTP/ MPC
2015-NW-N7	Richwood-Oakland 69 kV (Load Transfers)	Non-MISO		No	No	MPC
2019-NW-N1	Hoot Lake 115 kV Capacitor Bank Addition	2019/A	15725	No	No	OTP
2019-NW-N2	Norcross Area Upgrades	2019/A	17225	No	No	OTP
2019-NW-N3	Erie-Frazee	2019/A	15344	No	Yes	GRE/ OTP
2019-NW-N5	Erie/Audubon Alternate Service	Non-MISO	17144	No	No	MPC
2021-NW-N1	Hoot Lake 115/41.6 kV Transformer Replacement	2020/A	19685	No	No	OTP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2021-NW-N2	Henning 230 kV Breaker Addition	Future	TBD	No	No	GRE
2021-NW-N3	Inman 230 kV Breaker Addition	Future	TBD	No	No	GRE
2021-NW-N4	Cormorant to Pelican Rapids Install Storm Structures	2022/A	21825	No	No	GRE

NW MN Reliability Upgrades

MPUC Tracking Number: 2007-NW-N3

Utilities: Minnkota Power Cooperative (MPC) & Otter Tail Power Company (OTP)

Project Description: A suite of 115 kV projects including a second Winger 230/115 kV transformer in 2023, a 230/115 kV tap of Drayton-Prairie 230 kV (Lake Ardoch) and associated Oslo 115 kV substation in 2024, and depending on future load growth, a potential second Winger-Plummer 115 kV line and associated substation expansions sometime after 2028. Previously called “The Winger-Thief River Falls 230 kV Line Project.” Automatic Under Voltage Load Shedding (UVLS) will be added to ~100 MW of peak demand.

Need Driver: The Northwestern Minnesota area is a developing hub of crude oil pipelines, and those pipelines require pumping stations. These pumping stations are served by a network of 115 kV lines with three 230 kV sources at Drayton, Grand Forks and Winger. Loss of any one source forces the load to be served from the remaining two sources. Additionally, loss of any transmission between Drayton, Grand Forks and Winger weakens the reliability of the Northwest Minnesota transmission system. The automatic UVLS is needed to mitigate N-1-1 issues.

Alternatives:

Transmission Alternatives

Several different transmission alternatives were developed as part of OTP’s High Voltage Study to assess the ability of the transmission system to serve the Northwest Minnesota load. These included:

- A new Thief River Falls 230 kV substation, an expanded Winger 230 kV substation, and a new Winger-Thief River Falls 230 kV line
- a new Lake Ardoch Substation (230 kV), a new substation at Thief River Falls (230 kV), and a new Lake Ardoch-Thief River Falls 230 kV line,
- a new Drayton-Kennedy-Donaldson 115 kV line,
- a new Lake Ardoch Substation (230 kV and 115 kV), a new substation at Oslo (115 kV), and a new Lake Ardoch-Oslo 115 kV line, or

- a new Drayton-Kennedy-Donaldson 115 kV line, a new Winger-Plummer Pipe 115 kV line, and a second Winger 230/115 kV transformer.

The options above have been considered and compared with the aforementioned suite of 115 kV projects and it was determined that the benefits of such a project are more robust and cost effective than the other options that were considered.

Non-Wires Alternatives

One part of the NW MN Reliability Upgrades project is the addition of Automatic Undervoltage Load Shedding (UVLS) at several locations, which is a non-wires alternative. This UVLS mitigates some of the most severe but unlikely contingencies in the NW MN area and is not expected to operate frequently.

Additional non-wires alternatives beyond UVLS would not have sufficient availability or would be prohibitively expensive.

Analysis: Reliability improvements from the previously mentioned projects were evaluated in the "2018 NW MN Timing Analysis," which was performed by OTP with support from MPC. The study showed that a fault on one of the 115 kV lines into Northwest Minnesota from the three 230 kV sources caused violations within Northwest Minnesota. The study demonstrated a final upgrade requirement of several new 230 kV sources between 2021 and 2028.

Schedule: The study efforts mentioned above determined that an upgrade to mitigate post-contingent service issues to the Northwest Minnesota area transmission is required by the winter of 2023. This date is a revised date from the initial draft of the "High Voltage Study" report, and the revised date came from the "Winger-Thief River Falls Timing Analysis." A refreshed study effort was completed in early 2019 to determine a more definitive mitigation plan and schedule. With the new planned set of projects, a Certificate of Need is not expected to be filed in Minnesota unless load growth warrants the construction of the second Winger – Plummer 115 kV line. The associated UVLS has been implemented.

General Impacts: The area where this project will occur is almost entirely rural. There are no notable sites or locations along the route of any new transmission line between the endpoints. Any new transmission line will likely have to navigate through some wetlands and avoid some lakes along any route. There may be some impact on farmland from the location of a new transmission line, but assuming a one hundred and thirty foot right-of-way and some general estimates on electrical poles and farm equipment navigation, of a project area of 741 acres, only 65 acres will actually be impacted.

The economic and social impacts will be slight for any project to address this situation. The project may require a temporary project crew to construct the equipment, which could bring some business to the area in the form of room and board. Some landowners may receive a financial payment as a result of this project. Finally, the project will improve the reliability of the system in the area, although it is difficult to measure the quantified value of improved reliability.

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 described project (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 concerns exist beyond the aforementioned new transmission. 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 15 acres, as stated in the environmental considerations.

Hoot Lake 115 kV Capacitor Bank Addition

MPUC Tracking Number: 2019-NW-N1

Utility: Otter Tail Power Company (OTP)

Project Description: A new 115 kV capacitor bank is proposed at the Fergus Falls Hoot Lake substation. A total of 50 MVAR in two 25 MVAR stages is proposed along with the necessary substation modifications.

Need Driver: The planned retirement of the Hoot Lake coal plant in 2021 leaves the transmission system in the Fergus Falls area with a lack of reactive support. This capacitor bank is being proposed to mitigate a variety of low voltage concerns on the area 41.6 kV system following the retirement of the plant.

Alternatives:

Transmission Alternatives

> These capacitor banks are a relatively low-cost improvement. Transmission alternatives include a new 345 kV tie at Fergus Falls or reconductoring select 115 kV and 41.6 kV transmission lines in the area to improve voltage performance.

Non-Wires Alternatives

> Non-wires alternatives such as energy storage systems would be more expensive and have inferior availability compared to these capacitor banks.

Analysis: These capacitors were recommended in the *Otter Tail Power Company Ten Year Development Study*. The study found a need for reactive support for the area 41.6 kV system for several different outages following the retirement of Hoot Lake. In addition to several distribution capacitor installations, the 115 kV Hoot Lake capacitor mitigates any low voltage concerns associated with the plant's retirement.

Schedule: The Hoot Lake capacitors are expected to go into service by late October 2021 such that they will be available before the winter peak season following the plant's retirement.

General Impacts: This project enables the retirement of aging fossil fuel generation. It is located entirely at the existing Hoot Lake substation. There is no new transmission included in this project. No notable sites or locations are near the site of this project. This project is still in its early stages of planning, but all of this information is relatively inconsequential to the nearby environment.

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, minimal impact is expected as a result of the substation modifications.

Norcross Area Upgrades

MPUC Tracking Number: 2019-NW-N2

Utility: Otter Tail Power Company (OTP)

Project Description: This project consists of a new 115/41.6 kV substation near Norcross, MN, as well as a new 7-mile 115 kV line from the existing Grant County substation to the new Norcross substation.

Need Driver: The existing 41.6 kV system in the Norcross area is not able to reliably support load growth. This project provides an additional 115 kV source to this 41.6 kV system to accommodate new planned loads.

Alternatives:

Transmission Alternatives

> A tie into the WAPA Moorhead – Morris 230 kV line was considered, but this was a higher cost option for little to no reliability benefit over the final project.

Non-Wires Alternatives

> 41.6 kV STATCOMs were considered as an alternative, but this proved to be infeasible due to a low short-circuit ratio on the area 41.6 kV system.

Analysis: The *Wendell Interconnection and Nashua Elevator Load Serving Study* examined various projects that could mitigate the reliability concerns in the Norcross area. The recommended project as described above was found to be the most reliable and lowest-cost alternative. The STATCOM solution proved to be infeasible due to a low short-circuit ratio on the area 41.6 kV system. The WAPA 230 kV tie compared unfavorably to the preferred project due to some unmitigated N-1 concerns as well as additional ongoing SPP transmission service costs.

Schedule: In order to meet the schedule of new loads planned in the area, this project is planned for completion by early 2022.

General Impacts: The area where this project will occur is almost entirely rural. There are no notable sites or locations along the route of any new transmission line between the endpoints. There will be some impact on farmland from the location of a new transmission line, but assuming a one hundred and thirty foot right-of-way and some general estimates on electrical poles and farm equipment navigation, of a project area of 110 acres, only approximately 10 acres will actually be impacted.

The economic and social impacts will likely be minimal to address this situation. The project may require a temporary project crew to construct the equipment, which could bring some business to the area in the form of room and board. Some landowners may receive a financial payment as a result of this project. Finally, the project will improve the reliability of the system in the area, although it is difficult to measure the importance of an improved system.

Erie – Frazee

MPUC Tracking Number: 2019-NW-N3

MPUC Docket Number: ET-2/TL-20-423

Utility: Great River Energy (GRE) and Otter Tail Power Company (OTP)

Project Description: This project consists of a new Erie 230/115 kV substation that will tap the existing Audubon to Hubbard 230 kV line. The 115 kV side of the Frazee substation will be rebuilt to a ring bus configuration to accommodate a new 115 kV line from Erie. Approximately 9 miles of 115 kV line will be constructed between the new Erie substation and the Frazee substation. A 30 MVAr capacitor bank will be installed at the Frazee substation.

Need Driver: Driven by load growth and proposed retirement of Hoot Lake generation.

Alternatives:
Transmission Alternatives
The following alternatives were considered in the study. These alternatives were not preferred for the reasons related to not providing significant reliability improvement, high cost, or low incremental load serving capability when compared with the project (preferred plan).

1. Audubon 230/115 kV upgrade

2. Audubon 230/115 kV upgrade with 115 kV line to future Lake Eunice Tap

3. 230/115 kV substation along Audubon – Hubbard 230 kV line with 115 kV line to a breaker point on existing 115 kV system

    a. Todd Lake 230/115 kV sub with 115 kV line to Frazee

    b. Mountain Road 230/115 kV sub with 115 kV line to DLPU

4. Fergus Falls to Edgetown – Pelican Rapids 115 kV double circuit line

Non-Wires Alternatives
Following two NWA were identified to address the Frazee area reliability issues. For detailed analysis, refer to the NWA report done by GRE.

NWA – 1

- 40 MVAr STATCOM at Frazee
- 10 MW solar PV with 20 MWh ES at Pelican Turkey
- 40 MW solar PV with 80 MWh ES at Frazee

NWA – 2 (with capacitor banks)

- 20 MW solar PV with 40 MWh ES at Pelican Turkey
- 20 MW solar PV with 40 MWh ES at Frazee

Analysis: The Erie – Frazee project was determined to be the most reliable and least cost project.

Schedule: The Erie – Frazee project is planned to be in-service by winter 2023.

General Impacts: The project will require approximately 9 miles of new 115 kV transmission line from the Erie Junction substation to the Frazee 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 is along 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 9 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. The MPUC's environmental assessment was issued May 14, 2021. The MPUC is expected to issue the route permit for this project in late October 2021.

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:

Transmission Alternatives

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

Non-Wires Alternatives

Battery backup for use as a non-wire alternative was explored but was found to 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 2024 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 15 acres, as stated in the environmental considerations.

Hoot Lake 115/41.6 kV Transformer Replacement

MPUC Tracking Number: 2021-NW-N1

Utility: Otter Tail Power Company (OTP)

Project Description: The existing 115/41.6 kV transformer the Fergus Falls Hoot Lake substation is planned to be replaced with a higher-capacity 115/41.6/34.5 kV transformer equipped with a Load Tap Changer (LTC) on the 41.6 kV winding.

Need Driver: There are three primary need drivers for this project:

The first driver is the age & condition of the existing transformer. The transformer is early 1960s vintage and is showing signs that it is nearing end-of-life. The transformer has two secondary bushings showing signs of degradation and other issues that will lead to imminent failure. Repair work for these issues is not economical for a transformer of this age.

The second driver is system performance concerns. OTP has identified some low voltage concerns on the 41.6 kV transmission system around Hoot Lake. Low voltages can develop in the Pelican Rapids area and in the Silver Lake area for single-element outages during winter peak conditions. The existing transformer is not equipped with an LTC that could improve voltage performance during these outages, but the replacement transformer provides the opportunity to add an LTC to address these concerns. Additionally, the transformer is nearing its thermal capacity for some single-element outages, so the replacement will be sized appropriately to add some thermal margin.

The final need driver is that OTP plans to replace some of the generation capacity of the retiring Hoot Lake coal plants with a 49.9 MW solar farm (MISO generator replacement project R1001). A 34.5 kV tertiary winding on the replacement transformer is the most cost-effective solution to accommodate the interconnection of this solar farm. The Hoot Lake coal plants retired in late May 2021, and the solar farm is expected to be in service in 2022.

Alternatives:
Transmission Alternatives

Several alternatives were identified to address the same concerns as the Hoot Lake transformer replacement project. The first alternative was to add a second 115/41.6 kV transformer in parallel with the existing unit. The second alternative was to move the town of Pelican Rapids load to the 115 kV system and add a capacitor near Silver Lake on the 41.6 kV system. The final alternative was to add a 115/41.6 kV substation at Rothsay and a capacitor near Silver Lake on the 41.6 kV system. All these projects had substantially higher costs than the replacement transformer project, and none of them addressed the age & condition issues of the existing transformer.

Non-Wires Alternatives

Any non-wires alternatives would not have addressed the age & condition issues of the existing transformer, and none would have accommodated the interconnection of the Hoot Lake solar farm.

Analysis: The need for voltage support around Hoot Lake was identified in the *Otter Tail Power Company Ten Year Development Study*. The replacement 115/41.6/34.5 transformer with a 41.6 kV LTC effectively mitigates these voltage concerns.

Schedule: The Hoot Lake 115/41.6/34.5 kV replacement transformer is expected to go in service around mid-2022.

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. Additionally, this project enables the interconnection of new solar generation.

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, minimal impact is expected as a result of the substation modifications.

Henning 230 kV Breaker Addition

MPUC Tracking Number: 2021-NW-N2

Utility: Great River Energy (GRE)

Project Description: Add two 230 kV breakers at the Henning substation.

Need Driver: Prevent Henning – Inman 230 kV and Henning – Silver Lake 230 kV line faults from tripping off entire substation.

Alternatives:
Transmission Alternatives
None.
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 2029.

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.

Inman 230 kV Breaker Addition

MPUC Tracking Number: 2021-NW-N3

Utility: Great River Energy (GRE)

Project Description: Add a 230 kV breaker at the Inman substation on the line to Wing River.

Need Driver: Prevent Inman – Wing River 230 kV line faults from tripping off the 230/115 kV transformer.

Alternatives:
Transmission Alternatives
None.
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 2035.

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 – Pelican Rapids Storm Structures

MPUC Tracking Number: 2021-NW-N4

Utility: Great River Energy (GRE)

Project Description: Install storm structures in the Cormorant – Pelican Rapids 115 kV line.

Need Driver: GRE is continuing to look at making the system more resilient. GRE has H-frame construction on multiple lines that have shown to be prone to line cascading (domino effect) resulting in long duration outages. One way is to limit the damage of cascading is to install stop structures, such as a storm structure. GRE is proposing to install storm structures that will limit damage from cascading to 5 to 10 mile sections rather than without storm structures, whereby significantly longer mileage of damage could occur.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

This a reliability improvement to an existing line to prevent cascading structure failure and no alternatives were considered.

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

Schedule: The project is planned to be in service by June 2024.

General Impacts: The project will be constructed on the existing 115 kV transmission line from Cormorant substation to Pelican Rapids substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 2 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.

6.3.2 Completed Projects

The table below identifies projects that have been completed since our 2019 report.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2015-NW-N1	Clearbrook 115 kV-Bagley West 230 kV	None	MPC/OTP	Cancelled
2015-NW-N5	Ulrich 115/69 kV Transformer Replacement	9652	MPC	11/1/2019
2019-NW-N4	Lake Eunice	Not Required	GRE	2021

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	Square Butte—Arrowhead HVDC Valve Hall Replacement	2013/B	4295	No	No	MP
2013-NE-N17	Square Butte—Arrowhead HVDC Upgrade	2014/B	3856	No	No	MP
2015-NE-N12	Iron Range-Arrowhead 345 kV Project	2014/B	3832	Yes	No	MP
2015-NE-N14	83 Line Upgrade	2016/A	9622	No	Yes	MP
2017-NE-N2	Laskin-Tac Harbor Voltage Conversion	2016/A	10383	No	No	MP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2017-NE-N3	Little Falls Substation Modernization	2020/A	18110	No	No	MP
2017-NE-N6	Forbes Tie Breaker Addition	2019/A	10285	No	No	MP
2017-NE-N21	Laskin-Tac Harbor Transmission Line Upgrades	2018/A	13504	No	Yes	MP
2017-NE-N23	Mesaba Junction 115 kV Project	2018/A	13485	No	Yes	MP
2019-NE-N2	Forbes 37 Line Upgrade	2019/A	15591	No	Yes	MP
2019-NE-N4	25 Line Upgrade	2020/A 2022/A	15593 21605	No	Yes	MP
2019-NE-N5	29 Line Upgrade	2019/B	15594	No	Yes	MP
2019-NE-N6	Long Prairie Substation Modernization	2019/A	15596	No	No	MP
2019-NE-N8	Badoura Transformer Replacement	2020/A	15598	No	No	MP
2019-NE-N10	Babbitt Area 115 kV Project	2018/B 2018/B	16069 16070	No	Yes	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
2019-NE-N14	Laskin Breaker Replacements	2020/A	17871	No	No	MP
2019-NE-N15	Portage Lake 115/69 kV Project	2020/A	17664	No	No	GRE
2021-NE-N1	Square Butte – Arrowhead HVDC Line Hardening	2022/A	18058	No	No	MP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2021-NE-N2	8 Line Relocation	2020/A	18060	No	No	MP
2021-NE-N3	Hibbing Substation Modernization	2020/A	18064	No	No	MP
2021-NE-N4	Verndale Substation Modernization	2020/A	18065	No	No	MP
2021-NE-N5	Badoura 115 kV Substation Modernization	2021/A	18066	No	No	MP
2021-NE-N6	15th Ave West Transformer Addition	2020/A	18109	No	Yes	MP
2021-NE-N7	98 Line Asset Renewal	2021/A	18945	No	No	MP
2021-NE-N8	LSPI Cap Bank Asset Renewal	2021/B	20030	No	No	MP
2021-NE-N9	Canosia Road Substation 34 kV Expansion	2021/A	20032	No	No	MP
2021-NE-N10	95 Line Asset Renewal	2021/B	20071	No	No	MP
2021-NE-N11	Two Islands 115 kV Project	2022/A	20074	No	No	MP/ GRE
2021-NE-N12	Forbes 230 kV Modernization	2021/A	20075	No	No	MP
2021-NE-N13	Cloquet Substation Modernization	2021/B	20087	No	No	MP
2021-NE-N14	Mesaba Junction 137 Line Extension	2022/A	21686	No	Yes	MP
2021-NE-N15	137 Line Rebuild	2022/B	21762	No	No	MP
2021-NE-N16	North Shore Transformer Addition	2022/A	21763	No	No	MP
2021-NE-N17	West Cohasset Substation	2022/A	21606	No	No	MP
2021-NE-N18	Boise Breaker Addition	2022/B	21607	No	No	MP
2021-NE-N19	56 Line Upgrade	2022/B	21764	No	Yes	MP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2021-NE-N20	105 & 106 Line Upgrade	2022/A	21608	No	Yes	MP
2021-NE-N21	Iron Range Synchronous Condenser	2022/B	21765	No	Yes	MP
2021-NE-N22	126 Line Asset Renewal	2022/A	21766	No	No	MP
2021-NE-N23	13 Line Rebuild	2022/B	21767	No	No	MP
2021-NE-N24	Fond du Lac - Wrenshall	Future	TBD	No	No	GRE
2021-NE-N25	Shamineau Lake	2022/A	21830	No	No	GRE
2021-NE-N26	Wing River 230 kV Ring Bus	2021/A	20143	No	No	GRE
2021-NE-N27	Riverton - Wing River Storm Structures	2022/A	21824	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, expand Hilltop Substation to a 4-position 230 kV ring bus, 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.

Square Butte – Arrowhead HVDC Valve Hall Replacement

MPUC Tracking Number: 2013-NE-N16

Utility: Minnesota Power (MP)

Project Description: Replace the Center (Square Butte) and Arrowhead HVDC converter stations and associated assets with modern equipment on Square Butte – Arrowhead HVDC line.

Need Driver: The Center (Square Butte) and Arrowhead HVDC converter stations were designed by General Electric (GE) for a 30 year operating lifetime and as of 2021 they have been operating reliably for over 40 years. The main components of the HVDC converter stations include power electronics (thyristor valves) and their associated cooling system, converter transformers, smoothing reactors, harmonic filters and reactive resources to complete the conversion between alternating current (AC) and direct current (DC). The original vendor, GE, left the HVDC business in the 1980s and in recent years it has been increasingly difficult to procure spare parts **f**or the converter stations as the technology is becoming obsolete and the original designers are well into retirement. Minnesota Power has researched reverse engineering solutions to this technology issue, but has had limited results and thus spare and replacement parts for the converter stations remain limited. Modernizing the converter stations by replacing the thyristors, cooling system, converter transformers, smoothing reactors, harmonic filters, reactive resources, and control system will greatly reduce the likelihood of an extended outage due to component failures in the HVDC converter stations.

Alternatives:

Transmission Alternatives

> There are two alternatives. "Do Nothing" (risk of extended outage due to equipment failure) or implement the Square Butte – Arrowhead HVDC Upgrade (Tracking Number 2013-NE-N17).

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: Replacement of the existing thyristor valves with modern equipment is the minimum necessary project to maintain the reliability of Minnesota Power's HVDC line and reduce the risk of extended outages due to equipment failure.

Schedule: At this time, Minnesota Power is focused on developing the Square Butte – Arrowhead HVDC Upgrade (Tracking Number 2013-NE-N17). At the request of Minnesota Power, MISO performed Transmission Service Request (TSR) System Impact Studies on varying levels of increased HVDC capacity in 2019-2020 and provided Facilities Studies to the TSR customers documenting the associated costs. While the timing of the HVDC Modernization and Capacity Upgrade projects has been fluid in recent years due to Minnesota Power's ongoing assessment of the risks, value proposition, and long-term opportunities associated with the projects, Minnesota Power presently anticipates proceeding with an HVDC converter station modernization and upgrade project to be complete and placed in service by the end of 2027.

General Impacts: The modernization of the HVDC equipment is a prudent and necessary activity to ensure the ongoing operation of this critical piece of transmission for Minnesota Power's customers, including the reliable delivery of Minnesota Power's substantial North Dakota wind generation assets. Since the project is anticipated to take place within the footprint of the existing converter terminal buildings and substations, it is anticipated that no new landowners would be impacted by the project.

Square Butte – Arrowhead HVDC Upgrade

MPUC Tracking Number: 2013-NE-N17

Utility: Minnesota Power (MP)

Project Description: Replace the Center (Square Butte) and Arrowhead HVDC converter stations and associated assets with modern equipment on Square Butte – Arrowhead HVDC line and upgrade existing line and terminal equipment to 750 MW or higher capacity.

Need Driver: The Center (Square Butte) and Arrowhead HVDC converter stations were designed by General Electric (GE) for a 30 year operating lifetime and as of 2021 they have been operating reliably for over 40 years. The main components of the HVDC converter stations include power electronics (thyristor valves) and their associated cooling system, converter transformers, smoothing reactors, harmonic filters and reactive resources to complete the conversion between alternating current (AC) and direct current (DC). The original vendor, GE, left the HVDC business in the 1980s and in recent years it has been increasingly difficult to procure spare parts for the converter stations as the technology is becoming obsolete and the original designers are well into retirement. Minnesota Power has researched reverse engineering solutions to this technology issue, but has had limited results and thus spare and replacement parts for the converter stations remain limited. Modernizing the converter stations by replacing the thyristors, cooling system, converter transformers, smoothing reactors, harmonic filters, reactive resources, and control system will greatly reduce the likelihood of an extended outage due to component failures in the HVDC converter stations.

The modernization of the existing Center and Arrowhead HVDC converter stations presents a once-in-a-generation opportunity to consider enhancements to the long-term value of the HVDC system. At a time when there is increasing focus on long-term regional transmission needs and renewable energy integration, it is especially worthwhile to evaluate the costs and benefits of increasing the capacity and usefulness of the Square Butte – Arrowhead HVDC corridor. 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 concurrently with modernization of the converter stations. Upgrades would also be needed along the 465-mile HVDC transmission line to achieve increased capacity above 550 MW. Depending on the long-term value outlook, a lower total capacity such as 750 MW may ultimately prove to be the most cost-effective and efficient solution for Minnesota Power's customers. Modern HVDC technology at the converter stations would also enhance HVDC dispatch capability and allow energy to flow in both west to east and east to west directions, adding new flexibility and optionality for the regional transmission system. More significant changes to the capacity, operating voltage, and converter technology of the HVDC system could also provide enhanced long-term value for Minnesota Power and the region, but would come at considerably higher cost. Minnesota Power is in the process of carefully considering the long-term value of the HVDC corridor both internally and with MISO in order to determine the best path forward for its customers and the region.

Alternatives:

Transmission Alternatives

Square Butte – Arrowhead HVDC Valve Hall Replacement (Tracking Number 2013-NE-N16).

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: Replacement of the existing thyristor valves with modern equipment is the minimum necessary project to maintain the reliability of Minnesota Power's HVDC line and reduce the risk of extended outages due to equipment failure. Given the nature of the HVDC modernization project and the long life of the assets (30+ years anticipated), additional modifications to the HVDC system enabling higher transfer capability on the line will provide the most optimal value-added long-term solution for Minnesota Power at a reasonable incremental cost.

Schedule: At the request of Minnesota Power, MISO performed Transmission Service Request ("TSR") System Impact Studies on varying levels of increased HVDC capacity in 2019-2020 and provided Facilities Studies to the TSR customers documenting the associated costs. While the timing of the HVDC Modernization and Capacity Upgrade projects has been fluid in recent years due to Minnesota Power's ongoing assessment of the risks, value proposition, and long-term opportunities associated with the projects, Minnesota Power presently anticipates proceeding with an HVDC converter station modernization and upgrade project to be complete and placed in service by the end of 2027.

General Impacts: The modernization of the HVDC equipment is a prudent and necessary activity to ensure the ongoing operation of this critical piece of transmission for Minnesota Power's customers, including the reliable delivery of Minnesota Power's substantial North Dakota wind generation assets. The additional capacity facilitated by the Square Butte – Arrowhead HVDC Upgrade Project has the potential to 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 footprint of the existing converter terminal buildings and substations and on the existing transmission line right-of-way, it is anticipated that no new landowners would be impacted by the project.

Iron Range-Arrowhead 345 kV Line

MPUC Tracking Number: 2015-NE-N12

Utility: Minnesota Power (MP)

Project Description: Expand planned Iron Range 500 kV Substation to include two 1200 MVA 500/345 kV transformers and extend a double circuit 345 kV line from Iron Range to the existing Arrowhead 345 kV Substation. This project was formerly coupled together with the Great Northern Transmission Line (Tracking Number 2013-NE-N13) but the two projects were subsequently decoupled due to the lack of sufficient transmission service requests to justify the 345 kV connection to Arrowhead.

Need Driver: When paired with the Great Northern Transmission Line (Tracking Number 2013-NE-N13), the Iron Range-Arrowhead 345 kV Line was found by MISO in the Manitoba Hydro Wind Synergy Study to facilitate significant regional benefits associated with the synergies between wind and hydroelectric generation resources. However, the near-term needs for incremental export capability from Manitoba to the United States were realized by the development of the Great Northern Transmission Line Project alone, without a 345 kV extension to Arrowhead. Because there were not sufficient transmission service requests to justify the 345 kV connection to Arrowhead at the time, Minnesota Power determined that it would not pursue construction of the Iron Range-Arrowhead 345 kV Project in the foreseeable future. Should the project become necessary in the future due to additional transmission service requests or other system reliability needs or regional transmission benefits, it will be advanced at that time based on its own merits.

Alternatives:
Transmission Alternatives
    No other alternatives are currently being considered.
Non-Wires Alternatives
    None.

Analysis: Minnesota Power and Manitoba Hydro's analysis of the transmission necessary to enable 883 MW of incremental Manitoba-United States transfer capability identified that the Iron Range-Arrowhead 345 kV Line was not needed or economically justified at the time to achieve the desired level of Manitoba Hydro export.

Schedule: Minnesota Power has no current plans to construct the Iron Range-Arrowhead 345 kV Project.

General Impacts: The optimization of the new Manitoba to United States interconnection that allowed for deferral of the Iron Range-Arrowhead 345 kV Line provided benefit to Minnesota Power's ratepayers, local landowners, and the region by implementing a right-sized solution for the current need and avoiding extraneous transmission line construction. Should future additional transmission service requests or other regional transmission system needs justify construction of the Iron Range-Arrowhead 345 kV Line, the project could reasonably be expected to build upon the already-substantial social, economic, and environmental benefits provided by the Great Northern Transmission Line Project.

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83 Line Upgrade

MPUC Tracking Number: 2015-NE-N14

Utility: Minnesota Power (MP)

Project Description: Replace limiting 230 kV terminal equipment at the Boswell and Blackberry substations to restore transmission line capacity.

Need Driver: The Boswell-Blackberry 230 kV lines (MP "83 Line" and "95 Line") were derated after a NERC-mandated equipment audit identified undersized terminal equipment at the Boswell and Blackberry substations. The 83 Line Upgrade Project restores the capacity of 83 Line, a critical outlet for Boswell generation, to its original capacity.

Alternatives:
Transmission Alternatives

Build a third Boswell-Blackberry 230 kV 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.

Analysis: There is no more economical or less impactful solution than replacing the limiting equipment to restore the capability of the existing line.

Schedule: This issue was first identified when 83 Line and 95 Line were derated; however, single contingency overloads on 83 Line following the derate have not been identified in any studies to date. Minnesota Power is monitoring MTEP reliability assessment results, as well as the results of Minnesota Power internal studies, to determine if and when a project is needed to restore 83 Line to its original capacity.

General Impacts: 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 address any issues caused by derating 83 Line.

Laskin-Tac Harbor Voltage Conversion

MPUC Tracking Number: 2017-NE-N2

Utility: Minnesota Power (MP)

Project Description: The Laskin-Tac Harbor Voltage Conversion involves converting the legacy 138 kV system between the Laskin and Taconite Harbor substations to 115 kV operation. The work includes removing 138/115 kV transformers, replacing 138 kV equipment with 115 kV equipment, and replacing other aging equipment at the existing Laskin, Skibo, Hoyt Lakes and Tac Harbor substations. A previously-planned expansion of the existing Hoyt Lakes Substation has been eliminated from the scope of the project due to space limitations at the existing substation as well as constructability and maintainability concerns. Instead, a new switching station was constructed on a nearby site as part of the Mesaba Junction 115 kV Project (Tracking Number 2017-NE-N23).

Need Driver: Age and condition, removal of single points of failure, standardization of equipment, redundancy and voltage support concerns without local coal-fired generators online in the North Shore Loop.

Alternatives:
Transmission Alternatives

Continue to operate at 138 kV.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the 138 kV system assets or standardization of equipment.

Analysis: The Laskin-Tac Harbor 138 kV system was originally established by a mining company in the mid-1900s to connect its generating assets at Taconite Harbor to its plant operations in Hoyt Lakes. Over the years, improvements were made to provide redundancy to the area by connecting the 138 kV system to Minnesota Power's 115 kV system. Today, Minnesota Power owns the transmission in the Laskin-Tac Harbor 138 kV system and it provides a transmission connection that is critical for the reliability of service to all Minnesota Power and Great River Energy customers in the North Shore Loop.

The transition away from local baseload coal-fired generators in the North Shore Loop has served to increase the importance of the Laskin-Tac Harbor connection for the reliable delivery of power into the North Shore Loop from external sources, in addition to causing a need for additional voltage support in the area. The Laskin-Tac Harbor Voltage Conversion Project leads to the elimination of single points of failure with long replacement lead times (138/115 kV transformers), providing a more redundant and reliable transmission connection for the North Shore Loop. These reliability objectives are accomplished by the project in addition to the inherent benefits of replacing aging equipment, eliminating a non-standard voltage class from the Minnesota Power transmission system, and avoiding the cost of additional 138/115 kV transformers for redundancy, replacement, or the establishment of new transmission connections.

Beyond the benefits described above, the Voltage Conversion Project positions the northern end of the North Shore Loop for the establishment of other local redundancy and voltage support projects, including the Mesaba Junction 115 kV Project (Tracking Number 2017-NE-N23) and the Babbitt Area 115 kV Project (Tracking Number 2019-NE-N10). Continued operation of the Laskin-Tac Harbor system at 138 kV would significantly increase the cost and complexity of making these transmission improvements in the area.

Schedule: The project will be coordinated with the construction of the Mesaba Junction 115 kV Project and is expected to be in service by the end of 2022. Outage coordination as well as lead times on engineering and materials have led to delays in implementation of the project.

General Impacts: The Laskin-Tac Harbor Voltage Conversion Project will eliminate a non-standard voltage class from the Minnesota Power system, mitigating single points of failure, replacing aging equipment, and avoiding the future cost of adding or replacing other equipment unique to the 138 kV system. It is the most efficient and least environmentally impactful solution for meeting the near-term and long-term needs of the North Shore Loop, making good use of the existing 138 kV facilities by converting them to 115 kV. The Voltage Conversion Project is also a critical component of maintaining a reliable system in the face of significant changes in the North Shore Loop. Replacing voltage support previously provided by baseload coal units in the area and improving the redundancy 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.

Little Falls Substation Modernization

MPUC Tracking Number: 2017-NE-N3

Utility: Minnesota Power (MP)

Project Description: The Little Falls Substation Modernization Project involves replacing aging equipment, structures, and civil works and correcting deficiencies at the existing Little Falls 115/34 kV Substation in an effort to improve substation safety and reliability for the foreseeable future. Multiple substation asset renewal needs will be combined with necessary distribution transformer upgrades and a reconfiguration of the existing 115 kV bus to move a line-connected transformer to a bus-connected configuration to make up the core of this project. This work at the Little Falls Substation was combined into one project in order to facilitate efficient coordination of engineering and construction.

Need Driver: The Little Falls Substation serves the City of Little Falls and the surrounding rural areas. The primary need driver for the Little Falls Substation Modernization is age and condition of existing transformers, distribution circuit breakers, disconnect switches, and site infrastructure. While transmission circuit breakers have been replaced in recent years, much of the remaining 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, the project will also address previously-identified low voltage concerns for the Little Falls area. Low voltage was identified at the Pepin Lake, Blanchard, Bellevue, and Little Falls Substations following contingency events involving the Little Falls 115 kV bus. These contingency events result in loss of the existing Little Falls capacitor bank plus all but one of the 115 kV lines serving the substation and will be resolved by transitioning a line-connected transformer to a bus-connected configuration.

Alternatives:

Transmission Alternatives

> Establish a replacement 115/34 kV distribution station in the Little Falls area. Add another 115 kV capacitor bank in the area or reconfigure the Little Falls 115 kV bus to include a bus tie breaker.

Non-Wires Alternatives

> Install new distribution-connected generation on Little Falls, Blanchard, or Pepin Lake 34.5 kV systems. Non-wire alternatives must be available when needed and have an output characteristic sufficient to reduce the effective peak load in the area. However, non-wire alternatives cannot address concerns related to age and condition at the Little Falls 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 Little Falls Substation Modernization Project, Minnesota Power considered 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 involves significant improvements to equipment and infrastructure at the site, which is expected to ensure the site remains viable and continues to reliably serve Minnesota Power's customers for many decades to come.

The low voltage issue was first identified in the MTEP15 assessment and has continued to show up in MTEP and Minnesota Power studies. The addition of a bus tie breaker at the Little Falls Substation was originally submitted as a potential Corrective Action Plan. However, further investigation of protective relaying and historical fault events in the area has proven that a more appropriate solution would be to change the connection point for one of the Little Falls 115/34.5 kV transformers so that it is not directly connected to the Little Falls – Blanchard 115 kV line. This reconfiguration will eliminate the potential low voltage concern at a reasonable cost and without degrading the reliability of the Little Falls Substation. The reconfiguration of the transformer connection will be packaged with the planned substation modernization project for the Little Falls Substation in order to realize efficiencies in engineering and construction.

Schedule: The project is currently planned as a multi-year project and has been prioritized behind nearer-term needs in the area, including Long Prairie and Verndale. Civil and site work is expected to begin in 2025, with above-grade construction taking place in stages for 1-2 years after that to manage outage and constructability constraints.

General Impacts: The Little Falls Substation Modernization Project will ensure a continuous and reliable power supply to the Little Falls area by replacing aging equipment before it fails and by resolving known post-contingent voltage issues. At present, it is expected that the impacts will be entirely contained within the existing Little Falls Substation yard and no expansion area will be necessary.

Forbes Tie Breaker Addition

MPUC Tracking Number: 2017-NE-N6

Utility: Minnesota Power (MP)

Project Description: Reconfigure Forbes 115 kV bus to install a redundant bus tie breaker. One 115 kV transmission line entrance will be relocated to the end of the bus to make room for the redundant tie breaker. Replace end-of-life circuit breakers and associated equipment.

Need Driver: Internal fault or failure of breaker to operate causes overloading on area transmission lines and low post-contingent voltages. Installation of a redundant bus tie breaker will eliminate the contingency causing these issues. Age and condition of existing Forbes 38-44 MW breaker, 37L breaker, and 38L breaker along with equipment such as switches and relay panels.

Alternatives:

Transmission Alternatives

> Install breaker failure relay on existing Forbes 38-44MW 115 kV bus tie breaker, thermal upgrade overloaded transmission lines, and install additional voltage support in the area.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the breakers and associated equipment.

Analysis: This issue has been identified in MTEP assessments and Minnesota Power studies going back to MTEP15. Subsequent Minnesota Power studies have indicated that changes in the North Shore Loop which increase reliance on the Forbes 230/115 kV source for delivery of power once provided locally by baseload generators cause the Forbes tie breaker failure contingency to become more severe than initially anticipated in MTEP15. Therefore, Minnesota Power concluded that the addition of a redundant bus tie breaker is the most comprehensive long-term solution for the area, while also being cost-effective and limiting impact to the Forbes Substation and the immediately adjacent transmission line entrances.

Schedule: In coordination with the construction of other projects related to changes in the North Shore Loop, the Forbes Tie Breaker Addition is presently planned to be constructed over the 2021 and 2022 summer and fall seasons.

General Impacts: Minnesota Power's approach to this issue is intended to ensure that the most appropriate solution (in terms of cost, human, and environmental impacts) is implemented at the most appropriate time to address the issue first identified in the MTEP15 assessment and any related issues that may be efficiently addressed with the same project. Per the scope discussed above, the impacts will be mostly contained within the existing Forbes Substation yard and no expansion area will be necessary. The only impacts outside the substation yard will be due to the relocation of a transmission line entrance to make room for the redundant tie breaker.

Laskin-Tac Harbor Transmission Line Upgrades

MPUC Tracking Number: 2017-NE-N21

Utility: Minnesota Power (MP)

Project Description: Thermal upgrades of the existing Hoyt Lakes-Laskin line (MP "43 Line") and double circuit Hoyt Lakes-Taconite Harbor lines (MP "1 Line" and "2 Line"). Replace limiting equipment on 43 Line at Hoyt Lakes and Laskin.

Need Driver: Post-contingent overloading following conversion, idling, or retirement of North Shore Loop coal-fired generators.

Alternatives:

Transmission Alternatives

Build additional lines between Laskin and Taconite Harbor to relieve loading on existing transmission lines.

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.

Analysis: Following a transition away from baseload coal-fired generators in the North Shore Loop, the power formerly generated locally must be delivered from remote sources outside the North Shore Loop. This causes post-contingent overloading on several area transmission lines, including 43 Line, 1 Line, and 2 Line. The coordinated upgrade of these three transmission lines via thermal upgrades of existing conductors, minor modification of existing structures, and replacement of limiting substation equipment provides the needed capacity to ensure reliable delivery of power into the North Shore Loop following transition away from the local generation.

Schedule: The project will be completed in two stages. The initial need for increased capacity on the Laskin – Hoyt Lakes transmission line (43 Line) was addressed in 2019 with a thermal upgrade and replacement of limiting terminal equipment at Laskin and Hoyt Lakes. Additional capacity on 43 Line, as well as modifications to increase capacity on 1 Line and 2 Line, will be realized in 2022 following completion of the Mesaba Junction 115 kV Project (Tracking Number 2017-NE-N23) and the Laskin-Tac Harbor Voltage Conversion Project (Tracking Number 2017-NE-N2).

General Impacts: The Laskin-Tac Harbor Transmission Line Upgrades are a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. Increasing the rating of these transmission lines allows for the reliable delivery of power to the area from remote sources following the transition away from local baseload coal units, enabling the full realization of significant economic and environmental benefits from transitioning away from these units. The project will provide necessary system improvements to the North Shore Loop without requiring the establishment of additional transmission line corridors, which will minimize any potential environmental impacts.

Mesaba Junction 115 kV Project

(formerly known as "Hoyt Lakes 115 kV Project")

MPUC Tracking Number: 2017-NE-N23

Utility: Minnesota Power (MP)

Project Description: The new Mesaba Junction Switching Station will be constructed and interconnected to the existing transmission lines in the area connecting to the Taconite Harbor, Hoyt Lakes, and Laskin substations. In addition to the transmission line connections, the new switching station will include two switched capacitor banks to provide voltage support. Approximately 5.4 miles of new 115 kV line will be constructed along the existing Laskin –

Hoyt Lakes transmission line corridor to extend the existing Forbes – Laskin 115 kV Line (“38 Line”) into Mesaba Junction. The existing connection to the Laskin Substation will be eliminated.

Need Driver: Redundancy, reliability, voltage support, and transmission capacity concerns following conversion, idling, or retirement of North Shore Loop coal-fired generators.

Alternatives:

Transmission Alternatives

> Build a second Laskin-Hoyt Lakes transmission line and reconfigure (or rebuild) Laskin Substation to eliminate single points of failure.

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.

Analysis: The Mesaba Junction 115 kV Project meets four critical needs for the North Shore Loop, as discussed below.

First, the project supports redundancy by providing a third transmission source into the area, establishing a more robust substation configuration, and enabling a standardized network voltage. The Mesaba Junction 115 kV Project establishes a new 115 kV line parallel to the existing Laskin – Hoyt Lakes 115 kV Line and a new switching station that replaces the simple straight bus configuration of the existing Hoyt Lakes Substation with a more reliable ring bus configuration. The Project will be coordinated with the Laskin-Tac Harbor Voltage Conversion Project (Tracking Number 2017-NE-N2), greatly enhancing the constructability of that project and enabling Minnesota Power to realize all the benefits of a standardized network voltage.

Second, the project enhances reliability by providing a modern, utility-controlled path for power flow into the North Shore Loop. The Mesaba Junction 115 kV Project will place the customer-owned Hoyt Lakes Substation in a dedicated local network, relocating the regionally-important bulk electric system path into a new switching station that is designed, owned, operated and maintained by Minnesota Power. The modern design of the new switching station will also provide safer accessibility and maintainability. The result is improved personnel safety, enhanced system reliability, and reduced compliance risk associated with multiple NERC standards. This key benefit became possible when space constraints at the Hoyt Lakes Substation, as well as constructability and maintainability concerns with the facility, caused the previously-planned expansion of the Hoyt Lakes Substation to become infeasible.

Third and fourth, the project improves voltage support and provides transmission capacity to deliver power into the North Shore Loop. Previously, local baseload generators provided both voltage support on a continuous basis and a local source of power that met and, much of the time, exceeded the need for power in the North Shore Loop. New capacitor banks at the Mesaba Junction Switching Station will replace the voltage support that has been lost due to generator retirements. The extension of the existing Forbes – Laskin 115 kV Line into Mesaba Junction will increase power delivery capability into the North Shore Loop for 230/115 kV sources located west of the North Shore Loop to deliver the power no longer being produced by the retired generators.

Schedule: The Mesaba Junction Switching Station was constructed in 2020. Extension of the Forbes – Laskin 115 kV Line into Mesaba Junction is currently under construction and planned for completion in the first half of 2022, with first energization of Mesaba Junction from Forbes sometime in early second quarter 2022. Subsequently, the remaining transmission line interconnections to Mesaba Junction will be completed as the Laskin-Tac Harbor Voltage Conversion (Tracking Number 2017-NE-N2) is constructed in 2022. Both projects are planned for completion by the end of 2022. Outage coordination as well as lead times on engineering and materials have led to delays in implementation of the projects.

General Impacts: The Mesaba Junction 115 kV 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 project will require approximately 5 miles of new 115 kV transmission in a remote area of northern Minnesota that has been heavily impacted by historical mining operations.

Forbes 37 Line Upgrade

MPUC Tracking Number: 2019-NE-N2

Utility: Minnesota Power (MP)

Project Description: Increase rating of Forbes – 37 Line Tap 115 kV Line.

Need Driver: Post-contingent overloads for loss of various parallel circuits following conversion, idling, or retirement of North Shore Loop coal-fired generators and anticipated load growth in the Hoyt Lakes area.

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.

Analysis: Following a transition away from baseload coal-fired generators in the North Shore Loop, the power formerly generated locally must be delivered from remote sources outside the North Shore Loop. This causes post-contingent overloading on several area transmission lines, including the Forbes – 37 Line Tap 115 kV Line. The upgrade project provides the needed capacity to ensure reliable delivery of power to the East Range and into the North Shore Loop following transition away from the local generation.

Schedule: Due to wetlands in the area traversed by the transmission line, construction is advantageous during frozen ground conditions. In coordination with the construction of other projects related to changes in the North Shore Loop, the Forbes 37 Line Upgrade is presently planned to be constructed in the 2021-22 winter season.

General Impacts: The Forbes 37 Line Upgrade is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. Increasing the rating of this transmission line allows for the reliable delivery of power to the area from remote sources following the transition away from local baseload coal units, enabling the full realization of significant economic and environmental benefits from transitioning away from these units. The project will provide necessary system improvements to the North Shore Loop without requiring the establishment of additional transmission line corridors, which will minimize any potential environmental impacts.

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25 Line Upgrade

MPUC Tracking Number: 2019-NE-N4

Utility: Minnesota Power (MP)

Project Description: Increase rating of Hibbing – Virginia 115 kV Line ("25 Line"). A second phase has been added to the project to address asset renewal needs on 25 Line and adjacent segment of the Hibbing – 44 Line Tap 115 kV Line ("44 Line"). 25 Line and 44 Line will be rebuilt on double circuit structures from the Hibbing Substation to the 44 Line Tap. The project also includes rebuild, reconductor, and switch replacements 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 and particularly at the Hibbing substation termination.

Schedule: The project is currently planned for phased construction beginning in 2021 and continuing through 2023.

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.

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29 Line Upgrade

MPUC Tracking Number: 2019-NE-N5

Utility: Minnesota Power (MP)

Project Description: Increase rating of Boswell – Grand Rapids 115 kV Line ("29 Line").

Need Driver: Overloads following multiple-circuit contingency events in the surrounding area.

Alternatives:

Transmission Alternatives

Reconductor, establish new transmission.

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.

Analysis: Post-contingent overloads on the Boswell – Grand Rapids 115 kV Line were first identified in the MTEP18 2020 and 2023 summer off-peak cases and are being monitored. A thermal upgrade of the existing line to increase its capacity was submitted as a potential Corrective Action Plan based on the information available at the time. The same issue has not been observed consistently in subsequent MTEP assessments. Depending on if and how the issue shows up in subsequent assessments, further analysis will be done to clarify the issue and determine what the most appropriate solution is.

Schedule: This issue was first identified in the MTEP18 2020 and 2023 summer off-peak cases and is related to multiple-circuit contingency events. Minnesota Power is monitoring MTEP reliability assessment results to determine if and when a project is needed.

General Impacts: 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 address the issue first identified in the MTEP18 assessment.

Long Prairie Substation Modernization

MPUC Tracking Number: 2019-NE-N6

Utility: Minnesota Power (MP)

Project Description: The Long Prairie Substation Modernization Project involves replacing aging electrical equipment, structures, and civil works, and correcting deficiencies at the Long Prairie 115/34 kV Substation in an effort to improve substation safety and reliability for the foreseeable future. Multiple substation asset renewal needs will be combined with necessary distribution transformer upgrades (replacing with higher-capacity load-tap changing transformers) to make up the core of this project. The work at the Long Prairie Substation was combined into one project to facilitate efficient coordination of engineering and construction.

Need Driver: The Long Prairie Substation serves Long Prairie and the surrounding rural area. The primary need driver for the Long Prairie 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 structures and foundations. In addition, these asset renewal concerns, the project will address previously-identified distribution reliability concerns including post-contingent overloading of the existing Long Prairie transformers and low post-contingent 34.5 kV bus voltage following 115 kV bus fault events.

Alternatives:

Transmission Alternatives

> Develop area distribution system to shift load off Long Prairie.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Long Prairie 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 Long Prairie 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 involves significant improvements to equipment and infrastructure at the site, which is expected to ensure the site remains viable and continues to reliably serve Minnesota Power's customers for many decades to come.

The Long Prairie Substation Modernization Project will provide firm capacity and improved voltage regulation to the 34.5 kV distribution feeders out of Long Prairie. This will allow MP to take an outage on one of the two transformers to perform maintenance work without having to transfer load to another substation. Reconfiguring the line-connected distribution transformer would eliminate outages on the transmission line when a fault occurs on the distribution system. In considering whether or not non-wires solutions such as distribution-connected generation or demand side management presented a viable alternative to the project, Minnesota Power considered the fact that the assets involved in the replacement project would need to be replaced due to age and condition within the next 5-10 years anyway. Since the non-wires solutions would not eliminate the need for age and condition based replacements, the replacement project was ultimately determined to be the only viable long-term solution.

Schedule: The project is currently planned as a multi-year project with construction taking place in stages from 2021-2023 to manage outage and constructability constraints.

General Impacts: The Long Prairie Substation Modernization Project will ensure a continuous and reliable power supply to the Long Prairie area by increasing transformer capacity, improving voltage regulation, and replacing aging equipment before it fails. Per the scope discussed above, the impacts will be entirely contained within the existing Long Prairie Substation yard and no expansion area will be necessary.

Badoura Transformer Replacement

MPUC Tracking Number: 2019-NE-N8

Utility: Minnesota Power (MP)

Project Description: Replace existing 230/115 kV transformer at Badoura substation. 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 2025.

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 fenceline.

Babbitt Area 115 kV Project

MPUC Tracking Number: 2019-NE-N10

Utility: Minnesota Power (MP)

Project Description: Establish a high capacity, networked connection between the Embarrass Substation and the Mesaba Junction Switching Station by either acquiring and rebuilding 6 miles of existing customer-owned 115 kV transmission or constructing approximately 4 miles of new 115 kV transmission south from the existing Babbitt Tap to the Mesaba Junction 137 Line Extension.

Need Driver: Reliability for important load-serving substations in the Babbitt Area, as well as redundancy, voltage support, and transmission capacity to the Hoyt Lakes area and the North Shore Loop to support existing customers and enable load growth.

Alternatives:

Transmission Alternatives

> Purchase and rebuild 6 miles of existing customer-owned 115 kV transmission through an active mining area to connect 137 Line from the Embarrass Substation to the 137 Line Extension from the Mesaba Junction Switching Station; or construct approximately 4 miles of new 115 kV transmission south from the Babbitt Tap to the 137 Line Extension to avoid acquiring the customer-owned segment through the mine.

Non-Wires Alternatives

> Non-wire alternatives involve new dispatchable energy resources, like reciprocating engines, combustion turbines, or possibly long-duration energy storage, in both the Hoyt Lakes and Babbitt areas. Non-wire alternatives must be dispatchable to respond when called upon, of sufficient duration, and at effective locations to prevent or mitigate overloading.

Analysis: The Babbitt Area 115 kV Project will connect two radially-operated transmission lines that are critical sources to the Babbitt area and provide an additional redundant connection to the North Shore Loop transmission system. The project will enhance the reliability of the Babbitt 115/46 kV Substation, which is a critical load-serving substation for Minnesota Power and Great River Energy customers in the Tower, Ely, and Babbitt areas, by networking the radial line that currently is the only source to the Babbitt Substation. The project will also build upon previous improvements from the Mesaba Junction 137 Line Extension (2021-NE-N14) to enhance redundancy and flexibility for the industrial load pocket in the Babbitt area, which requires near-constant availability of power. In doing so, the project makes optimal use of existing transmission line assets that are underutilized when operated as a radial system, taking advantage of the asset renewal improvements from the 137 Line Rebuild (2021-NE-N15) which are made possible by the Mesaba Junction 137 Line Extension Project (2021-NE-N14).

The Babbitt Area 115 kV Project also continues to support redundancy and power delivery enhancements for the Hoyt Lakes area and the North Shore Loop by establishing an additional transmission source to the Mesaba Junction Switching Station. Much has changed about how the North Shore Loop transmission system is operated following transition of local coal-fired baseload generators to retirement or idling over the last 5+ years. As the use of the system by existing customers in the Hoyt Lakes area and the North Shore Loop evolves over time, incremental long-term improvements like the Babbitt Area 115 kV Project will continue to become necessary to support the reliable operation of the system. The additional 115 kV source from Embarrass into the Mesaba Junction Switching Station established by this project prevents potential voltage collapse and transmission line overload concerns associated with loss of the Forbes – Mesaba Junction and Laskin – Mesaba Junction 115 kV lines, and therefore the project is crucial to enabling the long-term maintenance of these transmission lines in the area.

Schedule: The Babbitt Area 115 kV Project cannot be implemented until both the Mesaba Junction 137 Line Extension (2021-NE-N14) and the 137 Line Rebuild (2021-NE-N15) are constructed. Based on the anticipated schedule for those projects, preliminary plans are for project construction to take place in 2025-26.

General Impacts: The Babbitt 115 kV Project will ensure a continuous and reliable power supply to Minnesota Power and Great River Energy customers in the Tower, Ely, and Babbitt areas, as well as a nearby industrial load pocket. Establishing a high-capacity networked Embarrass – Mesaba Junction 115 kV Line (137 Line) enhances reliability to the local area and also allows for the continued reliable delivery of power into the North Shore Loop and the Hoyt Lakes area under a range of normal and maintenance conditions, effectively continuing to replace transmission system support previously provided by nearby baseload coal units as the system continues to evolve into the future. Utilizing most or all of existing 137 Line to complete this new connection makes optimal use of existing transmission assets while minimizing human and environmental impacts associated with establishing the new transmission connection.

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 till 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. 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 a maintenance outage would leave this part of Duluth on a single 140-mile transmission line originating in the Hoyt Lakes Area, and the transmission system is no longer able to support the load over that distance. 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 transmission line which also connects to the Arrowhead and Iron Range substations. Extending this 230 kV transmission line approximately 0.7 miles and adding a breaker at the Arrowhead Substation will 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 substation at the same time an additional 115 kV line is being brought out of it to support the Duluth Loop. 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 is planning to submit 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]. Following permitting and engineering activities, preliminary plans are for project construction to take place in 2023-25.

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 is presently planned for staged construction in 2021-22.

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.

Laskin Breaker Replacements

MPUC Tracking Number: 2019-NE-N14

Utility: Minnesota Power (MP)

Project Description: Replace end-of-life circuit breakers and associated equipment at Laskin 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 Laskin Substation.

Analysis: Three 115 kV oil circuit breakers from 1962-69 and a transmission-to-distribution transformer of a similar vintage will be replaced as part of this project.

Schedule: The project is currently planned for construction in 2024 after Minnesota Power recently reviewed and updated substation asset renewal priorities.

General Impacts: The Laskin 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 Laskin Substation, which is located at the Laskin Energy Center, making optimal use of the existing site infrastructure to minimize human and environmental impacts.

Portage Lake 115/69 kV Project

MPUC Tracking Number: 2019-NE-N15

Utility: Great River Energy (GRE)

Project Description: GRE will interconnect to Minnesota Power's (MP) 13 Line (Riverton – Cromwell 115 kV) with a 4 position, 115 kV ring bus, to be called Portage Lake, at or near the existing Mille Lacs Electric Cooperative (MLEC) Kimberly substation. The new 115 kV Portage Lake ring bus will have four positions; 115 kV line to Riverton (13 Line), 115 kV line to Cromwell (158 Line), 115/69 kV transformer with a 9.5-mile line to Palisade, and a 115-kV position for MLEC's Kimberly distribution substation.

Need Driver: Long radial line exposure. Thermal overloading during winter peak.

Alternatives:
Transmission Alternatives

> *Upgrade Four Corners Transformer*
>
> > The Four Corners 115/69 kV transformer has a top rating of 28 MVA. An option that was evaluated was to add more transformation capacity at Four Corners. This option is relatively inexpensive, but it does nothing to alleviate the radial MW-

mile exposure seen by the 4 substations served from the Palisade Radial 69 kV system.

Gowan 115/69 kV

The Gowan 115/69 kV concept utilizes the 156 Line (Cromwell – Savanna 115 kV) that passes by GRE's Gowan substation and interconnects to the existing 69 kV lines at Gowan via a 115/69 kV transformer. This project will alleviate the loading concerns on Four Corners transformer but falls short of alleviating the radial MW-mile exposure seen by the 4 substations served from the Palisade Radial 69 kV system.

Non-Wires Alternatives

A non-wires alternative (NWA) such as generation (solar, wind), demand response (load management), or energy storage (battery, plug-in hybrid vehicles) could be used to solve or partially solve the thermal overloads and voltage violations resulting from the loss of the Cromwell – Palisade Tap 69 kV line but it does not address the 32 miles of transmission line that the four Member substations are exposed to.

The system's peak loading is happening at night during winter months. The area is not wind rich and would have to rely on solar and since the peak is at night, it would have to be solar plus battery technology.

Analysis: The 69 kV Palisade Radial Line is made up of 3 Lake Country Power (LCP) delivery points (Wright, Round Lake and Big Sandy) and one MLEC delivery point, Palisade, with 32 miles of total line exposure. The Palisade Radial peaks at 25.9 MW in the winter and 15.3 MW. For the loss of the Cromwell – Palisade Tap 69 kV line during winter peak loading, the whole Cromwell-Four Corners 69 kV system is sourced from the Four Corners 115/69 kV transformer and the thermal loading reaches 110%.

Schedule: The project is planned to be in service by November 2023.

General Impacts: The project will require approximately 10 miles of new 69 kV transmission line from Portage Lake substation to Palisade 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 10 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.

Square Butte – Arrowhead HVDC Line Hardening

MPUC Tracking Number: 2021-NE-N1

Utility: Minnesota Power (MP)

Project Description: Targeted structure replacements on the Square Butte – Arrowhead HVDC line to install more robust anti-cascade structures at major infrastructure crossings along the 465-mile length of the line.

Need Driver: Reduce the likelihood of structure failures at locations where failures would have a more significant impacts to the surrounding area or be more difficult to restore.

Alternatives:

Transmission Alternatives

> Due to the nature of the issue, the only other alternative is to "Do Nothing" – which would proliferate the risk of extended outages, difficult restoration, and adverse on-the-ground impacts from HVDC structure failures at high-profile or high-impact locations.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot address the structural failure concerns.

Analysis: In coordination with the planned modernization of the converter stations and the capacity upgrade of the Square Butte – Arrowhead HVDC system (2013-NE-N16 and/or 2013-NE-N17), Minnesota Power is also planning a transmission line "hardening" project. While the modernization of the converter stations will result in refurbished HVDC components at Center and Arrowhead that should last for many years, the two converter stations will still be connected by a 40+ year old 465 mile transmission line. The existing original HVDC transmission line structures have proven to be susceptible to failure in extreme weather events. The transmission line hardening project planned for implementation in parallel with the HVDC Upgrade Project will consist of targeted structure replacements at strategic locations – for example, near major infrastructure crossings – where anti-cascade structures that limit the impact of failures and allow for rapid line restoration would provide the most value. Executing the HVDC Line Hardening Project in coordination with the HVDC Upgrade Project will limit on-the-ground impacts from structure failures near more heavily-trafficked areas and provide a more robust HVDC transmission line connection between the converter stations as the Square Butte – Arrowhead HVDC system continues to be an important part of the transmission system for Minnesota Power and the region for many years following completion of the modernization project.

Schedule: The Project is expected to be constructed in phases over a 4-5 year period as it is packaged with the transmission line capacity upgrade component of the HVDC Upgrade Project (2013-NE-N17). The earliest start date for construction of the project is 2022.

General Impacts: The hardening of the HVDC line structures at key locations is a prudent and necessary activity to reduce failure risks and impacts and ensure the ongoing operation of this critical piece of transmission for Minnesota Power's customers, including the reliable delivery of

Minnesota Power's substantial North Dakota wind generation assets. Since the project is expected to take place at existing structure locations, it is anticipated that no new landowners would be impacted by the project.

8 Line Relocation

MPUC Tracking Number: 2021-NE-N2

Utility: Minnesota Power (MP)

Project Description: Relocate existing Fond du Lac – Thomson 115 kV Line (8 Line) off of a failing slope onto a shared Right-Of-Way with Fond du Lac – Hibbard 115 kV Line (15 Line). The rest of 8 Line will then be rebuild and reconductored due to age and condition, replacing transmission line components and obtaining additional capacity. At the Fond du Lac Substation, aging equipment will be replaced, and a new 115 kV circuit breaker, relay panel, and associated equipment will be added. Limiting jumpers will be replaced at both the Thomson and Fond du Lac substations.

Need Driver: MNDOT requested relocation of Fond du Lac – Thomson 115 kV (8 Line) off of a failing slope near Highway 210. There are also age and condition replacement needs and a long-term capacity need as well.

Alternatives:
Transmission Alternatives

Do nothing with the transmission line and reinforce the failing slope.

Non-Wires Alternatives

Non-wire alternatives cannot displace the need for age and condition-related upgrades to the existing transmission line.

Analysis: A structure on the Fond du Lac – Thomson 115 kV Line is located near a failing slope to the west of the Highway 210 crossing. For reliability reasons, it is necessary to relocate 8 Line away from this slope. In 2017, MNDOT requested that both 8 Line and 15 Line be relocated off of this particular failing slope as the steep grade between the structures atop this failing slope presents a risk to Highway 210 travelers. 15 Line leaving Fond du Lac Substation was relocated away from this failing slope in 2018 and sufficient right-of-way was obtained and cleared at the time to accommodate paralleling 8 Line along the south side of this 15 Line corridor. From the point where the existing 15 Line corridor turns North after crossing Highway 210, 8 Line will turn southwest to obtain an alignment with the existing 8 Line river crossing. The remaining length of 8 Line will be rebuilt and reconductored due to age and condition, similar to other transmission line asset renewal projects that Minnesota Power is developing.

Schedule: The project is presently planned for construction in 2022.

General Impacts: The 8 Line Relocation Project will ensure that the existing Fond du Lac – Thomson 115 kV Line continues to provide a safe and reliable transmission path for Minnesota Power's customers and hydroelectric assets in the Duluth and Cloquet areas. The short segment of relocation will be primarily located adjacent to an existing transmission line, and will improve transmission reliability and public safety by moving away from the failing slope. The rest of the project involves replacement of existing assets on the existing transmission line right-of-way. In both cases, the project will make optimal use of existing transmission line corridors in the area 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, south of the Hibbing Taconite mining operations. The Hibbing Substation Modernization project involves replacing aging equipment, structures, and civil works and correcting deficiencies at the substation in an effort to improve substation safety and reliability for the foreseeable future. Multiple substation asset renewal needs were combined with necessary capacity upgrade projects on 14 Line (Hibbing – 14 Line Tap) and 25 Line (Hibbing – Virginia) to make up the core of this project. This work at the Hibbing Substation was combined into one project in order to facilitate efficient coordination of engineering and construction.

Need Driver: The Hibbing Substation serves the City of Hibbing as well as Minnesota Power retail customers in the area surrounding Hibbing and Chisholm. 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. The Hibbing 25L breaker is from 1976 and the 44L breaker is from 1988, both of which are historically problematic breaker models that are high on the breaker replacement priority list. Replacing these high-priority breakers in advance of failure is necessary to ensure safety and reliability, enhance long-term planning, and optimize lifecycle value.

Alternatives:
<u>Transmission Alternatives</u>

> Develop area distribution system to shift load off the Hibbing Substation to existing or new distribution substations.

<u>Non-Wires Alternatives</u>

> 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 considered 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 involves a nearly complete overhaul of the site, which is expected to ensure the site remains viable and continues to reliably serve Minnesota Power's customers for many decades to come.

Schedule: The project is currently planned as a multi-year project. Civil and site work is expected to begin in fall 2022, with above-grade construction taking place in stages from 2023-2024 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 entirely 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 and correcting deficiencies at the existing Verndale 115/34 kV Substation in an effort to improve substation safety and reliability for the foreseeable future. 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.

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:

<u>Transmission Alternatives</u>

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

<u>Non-Wires Alternatives</u>

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 stages from 2024-2025 to manage outage and constructability constraints.

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. At present, it is expected that the impacts will be entirely contained within the existing Verndale Substation yard and no expansion area will be necessary.

<u>Badoura 115 kV Substation Modernization</u>

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.

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 build out a new alternate station service source for the 115 kV and 230 kV yards as well as remove existing 34.5 kV equipment in 2022. The line relocations and cap bank bus buildout is scheduled for 2023 for a final in-service date of 2023.

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.

15th Avenue West Transformer Addition

MPUC Tracking Number: 2021-NE-N6

Utility: Minnesota Power (MP)

Project Description: The 15th Avenue West Transformer Addition Project involves adding a new 115/34 kV transformer in an existing future transformer position at the 15th Avenue West Substation in downtown Duluth. Additional upgrades and reconfigurations will take place in the Duluth 34 kV system to integrate the new 34 kV source.

Need Driver: Load growth and reliability enhancements on Duluth 34 kV distribution system.

Alternatives:

Transmission Alternatives

> Establish a new 115/34 kV substation near downtown Duluth; reinforce existing Duluth 34 kV system by building new feeders to existing sources at Swan Lake Road and LSPI substations.

Non-Wires Alternatives

> Install new distribution-connected generation on Duluth 34 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 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 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 addition of a new 115/34 kV transformer at the 15th Avenue West Substation, which is located much closer to the 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.

Schedule: The 15th Avenue West Transformer Addition Project is presently planned for construction in 2023.

General Impacts: The 15th Avenue West Transformer Addition Project will preserve and enhance the reliability of the Duluth 34 kV distribution system. Since the 15th Avenue West 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 15th Avenue West Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

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98 Line Asset Renewal

MPUC Tracking Number: 2021-NE-N7

Utility: Minnesota Power (MP)

Project Description: The 98 Line Asset Renewal Project involves asset renewal and structure replacements to increase the clearance of spans for the existing 954 ACSR "Cardinal" conductor on the existing Iron Range – 98 Line Tap 230 kV Line.

Need Driver: Replacing old structures and increasing conductor to ground clearance margins. The project is also being coordinated with additional asset renewal work on 98 Line to address identified age & condition issues.

Alternatives:

Transmission Alternatives

> There are no reasonable alternatives that will address the clearance and asset renewal requirements for the existing structures on 98 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.

Schedule: Construction on the 98 Line Asset Renewal Project was completed in 2021.

General Impacts: The 98 Line Asset Renewal Project will ensure that the existing Iron Range – 98 Line Tap 230 kV Line continues to provide a safe and reliable transmission path for Minnesota Power'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 line with little or no additional human or environmental impacts.

LSPI Cap Bank Asset Renewal

MPUC Tracking Number: 2021-NE-N8

Utility: Minnesota Power (MP)

Project Description: LSPI Cap Bank Asset Renewal Project involves refurbishing the existing 115 kV capacitor bank at the LSPI Substation in West Duluth by replacing fuses, fuse holders, and other components.

Need Driver: The existing fuses are supposed to release on failure but are not working properly, resulting in capacitor bank outages that decrease the availability of the capacitor bank and increase maintenance costs for the site.

Alternatives:

Transmission Alternatives

Remove and replace the entire capacitor bank.

Non-Wires Alternatives

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

Analysis: The LSPI Substation capacitor bank provides important voltage support and regulation for the West Duluth area. This project involves low-cost targeted asset renewal improvements that will enhance the reliability and availability of this capacitor bank. There is no more economical or less impactful solution than replacing the existing fuses and fuse holders.

Schedule: The project is being targeted for implementation in 2022 or 2023 depending on overall project priorities and availability.

General Impacts: The LSPI Cap Bank Asset Renewal Project will ensure continued reliable voltage support for West Duluth by replacing failing components. The impacts of the project will be entirely contained within the existing LSPI Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Canosia Road Substation 34 kV Expansion

MPUC Tracking Number: 2021-NE-N9

Utility: Minnesota Power (MP)

Project Description: The Canosia Road Substation 34 kV Expansion Project involves expanding the existing Canosia Road Substation into a four position ring bus by adding two 115 kV breakers in order to interconnect a new 115/34 kV transformer. Additional upgrades and reconfigurations will take place in the Cloquet-area distribution system to integrate the new 34 kV source.

Need Driver: Establish a new 34 kV source for the Cloquet area to achieve asset renewal and distribution voltage standardization, increased system capacity and constructability for the Cloquet Substation Modernization Project (2021-NE-N13), improved reliability, and prepare for grid modernization project implementation.

Alternatives:

<u>Transmission Alternatives</u>

> Establish a new 115/24 kV or 115/46 kV source from Canosia Rd to tie into existing non-standard voltages in the Cloquet area; build a new 115/34 kV substation at a different location.

<u>Non-Wires Alternatives</u>

> Non-wire alternatives are not viable because they cannot address concerns related to age and condition and voltage standardization for the Cloquet-area distribution system.

Analysis: The Canosia Road Substation 34 kV Expansion will be the first step and foundation in a mutli-year plan to modernize and improve the Cloquet-area distribution system. There are several factors driving the need for improvements in the Cloquet area:

Asset Renewal & Standardization: Implementing a standard 34 kV backbone distribution network for the Duluth/Cloquet area. There are presently three different backbone distribution voltages between Duluth, Cloquet, and Hinckley. The Canosia Road Expansion and subsequent projects will convert existing 24 kV and 46 kV systems to 34 kV while addressing asset renewal needs for existing feeders and stepdowns associated with these systems

System Capacity & Asset Renewal Project Constructability: Enabling the Cloquet Substation Modernization Project (2021-NE-N13) to take place. Cloquet Substation is one of the highest-priority asset renewal sites in the Minnesota Power system, but the distribution system lacks sufficient capability to reliably support the Cloquet area during the extended outage of the Cloquet Substation that would be needed to implement the asset renewal project

Reliability & Grid Modernization: Improving reliability for Cloquet-area customers by reducing feeder exposure, providing backup capability from new feeders and 34/14 kV stepdowns, and enabling feeder automation projects to be implemented for enhanced visibility and rapid system restoration

Schedule: The project at the Canosia Road Substation is currently planned for implementation in 2022, with associated distribution system upgrades taking place in 2022 and 2023.

General Impacts: The Canosia Road Substation 34 kV Expansion Project will enhance the reliability of the Cloquet-area distributions system while also addressing significant age and condition and maintenance-related issues on the distribution system. Since the Canosia Road Substation was designed originally to accommodate the expansion, the majority of impacts from the substation expansion part of the project will be contained within the existing Canosia Road Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

<u>95 Line Asset Renewal</u>

MPUC Tracking Number: 2021-NE-N10

Utility: Minnesota Power (MP)

Project Description: The 95 Line Asset Renewal Project involves replacement of transmission line components on the Boswell – Blackberry 230 kV Line ("95 Line") due to age and condition.

Need Driver: The project will address asset renewal needs on 95 Line related to the age and condition of existing structures, conductor, guy attachments, and other hardware.

Alternatives:

Transmission Alternatives

> There are no reasonable alternatives that will address the asset renewal needs for the existing transmission line components on 95 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.

Schedule: The 95 Line Asset Renewal Project is presently targeted for construction in 2026.

General Impacts: The 95 Line Asset Renewal Project will ensure that the existing Boswell – Blackberry 230 kV Line continues to provide a safe and reliable transmission path for Minnesota Power'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 line with little or no additional human or environmental impacts.

Two Islands 115 kV Project

MPUC Tracking Number: 2021-NE-N11

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

Project Description: The Two Islands 115 kV Project involves the construction of a new switching station that will serve as the connecting point to replace the original Taconite Harbor Substation in the North Shore Loop transmission system. The new Two Islands Switching Station will be constructed across the highway from the original Taconite Harbor Substation and will consist of a 5-6 position ring bus and a new capacitor bank. Great River Energy hosts a

115/69 kV delivery point at the existing Taconite Harbor Substation that will be relocated to a new GRE Two Islands Substation adjacent to the MP Two Islands Switching Station. A second 115/69 kV transformer will be added at the GRE Two Islands Substation to provide redundancy for the GRE 69 kV system east of Taconite Harbor.

Need Driver: The new switching station will replace the original Taconite Harbor Substation, increasing reliability and safety by moving away from a compact original box structure in a straight bus configuration to a new ring bus configuration constructed according to modern standards for clearances, access, and maintainability. A major overhaul of the Taconite Harbor Substation would be required to extend the life of the existing site, but access and maintainability would still be limited due to the compact site layout. A complete overhaul of the Taconite Harbor Substation would require an extended outage that would leave the entire North Shore Loop on radial feeds for multiple weeks, which would increase risk of blackouts if any outage event should occur on the radial feeds.

Alternatives:

Transmission Alternatives

Complete overhaul of the Taconite Harbor Substation, including removal and reconstruction of foundations and steel structures and reconfiguration of bus work. This alternative results in unacceptable risk to the North Shore Loop with significant periods of radial feeds greatly reducing reliability in the region. GRE investigated the alternative to continue using Taconite Harbor and avoid building a 115/69 kV delivery point at the new GRE Two Islands Substation. This alternative was not embraced because MP couldn't commit to the duration that the existing Taconite Harbor Substation would continue to exist. The last remaining generators from the Taconite Harbor Energy Center recently completed Attachment Y studies with MISO to decommission.

Non-Wires Alternatives

Non-wire solutions are not viable as they would not address the aging condition and safety and reliability concerns associated with the existing Taconite Harbor Substation.

Analysis: The existing Tac Harbor Substation is a compact site originally purpose-built by a mine for the generators at the Taconite Harbor Energy Center. This compact style of substation creates safety concerns and outage constraints during maintenance with the condensed equipment locations. With the retirement of the generators, the substation now serves the primary purpose of providing reliable transmission support to the North Shore Loop. The Taconite Harbor Substation also provides a 115/69 kV step-down to source a 50 mile long radial 69 kV line that provides service to four of Arrowhead Electric Cooperative Incorporated's (AECI) distribution substations (Colvill, Maple Hill, Lutsen, and Cascade), one of Co-op Light & Power's distribution substations (Schroeder) and one of SMMPA's distribution substations (Grand Marais). GRE owns a generation station at the end of the line providing 18 MW of backup generation. The Taconite Harbor Substation is very critical to providing reliable power to a remote, radial system and is justified in rebuilding due to age and condition.

MP Schedule: The project is planned to be in service by the end of 2023, with civil work beginning in 2022.

GRE Schedule: The project is planned to be in service by the end of 2024.

General Impacts: The Two Islands 115 kV Project will improve reliability of the North Shore Loop with the new ring bus. A cap bank at this new facility will also improve voltage control on the North Shore Loop. The new ring bus will minimize outage concerns at the site with additional reliability and protection. As the Two Islands 115 kV Project will be a new facility, a new site location on Minnesota Power-owned property has been identified for all construction. The project will also require approximately 0.1 miles of new 69 kV transmission line from Two Islands Substation to the existing “SG” 69 kV line. The project is located in an area that is predominantly impacted by the historical utility usage of the nearby Taconite Harbor Energy Center. Prior to construction, MP and 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 69 kV 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 over 18-24 months. During this time, MP and 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 and maximizes the use of existing utility-controlled lands and infrastructure.

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: One 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 a failure. It is prudent to proactively replace this transformer in the near-term future before it fails.

Schedule: The project is presently planned for construction in 2023-24.

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 and correcting deficiencies at the existing Cloquet 115/14 kV Substation in an effort to improve substation safety and reliability for the foreseeable future. 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.

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

> Establish a new 115/14 kV substation east of Cloquet and reconfigure distribution system to enable retirement of Cloquet Substation or expand Canosia Rd 34 kV system and establish new 34/14 kV stepdowns to enable retirement of Cloquet Substation.

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 2023-24 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. At present, it is expected that the impacts will be entirely contained within the existing Cloquet Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Mesaba Junction 137 Line Extension

MPUC Tracking Number: 2021-NE-N14

Utility: Minnesota Power (MP)

Project Description: Extend a new 115 kV line approximately 8 miles from the Mesaba Junction Switching Station to the end of a customer-owned segment of 115 kV line connecting back to the existing Embarrass – Babbitt 115 kV Line ("137 Line"). A normal open point will be established near the Argo Lake tap due to the relatively small existing conductor on 137 Line. 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.

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.

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. In this case, the non-wire alternatives must also be able to continue to support and follow load when isolated from the transmission system due to outages on the only transmission source to the area (137 Line).

Analysis: The Mesaba Junction 137 Line Extension Project meets three critical needs for the Babbitt area:

1. Providing redundancy to an industrial load pocket that requires near-constant availability
2. Enabling asset renewal by allowing the 137 Line Rebuild Project (Project Number 2021-NE-N15) to be constructed
3. Improving reliability with two properly maintained 115 kV transmission sources to the area

For an outage affecting the Mesaba Junction end of 137 Line, the issue can be isolated and service can be restored from Embarrass end by closing the normal open point. For a planned outage affecting the Mesaba Junction end of 137 Line, the normal open point can be closed and a segment of the line can be isolated without a customer outage.

Schedule: Due to wetlands in the area traversed by the transmission line, transmission line construction is advantageous during frozen ground conditions. Below grade construction at the Mesaba Junction Switching Station is presently planned for the 2022 fall season. Transmission line construction and above grade construction at the substation is presently planned to be constructed in the 2022-23 winter season.

General Impacts: The Mesaba Junction 137 Line Extension Project will preserve and enhance the reliable delivery of power to an important industrial load pocket in the Babbitt area. 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 as part of the 137 Line Rebuild (2021-NE-N15). The project will require approximately 8 miles of new 115 kV transmission in a remote area of northern Minnesota that has been heavily impacted by historical mining operations.

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137 Line Rebuild

MPUC Tracking Number: 2021-NE-N15

Utility: Minnesota Power (MP)

Project Description: Rebuild existing Embarrass – Babbitt 115 kV Line (137 Line) from the Embarrass Substation to the North side of the Peter Mitchell Mine pit crossing with a larger conductor.

Need Driver: Age and condition.

Alternatives:

Transmission Alternatives

There are no reasonable alternatives that will address the asset renewal needs for the existing transmission line components on 137 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.

Schedule: Due to wetlands in the area traversed by the transmission line, construction is advantageous during frozen ground conditions. The 137 Line Rebuild is presently planned to be constructed in stages from 2023-25, maximizing use of the winter construction season.

General Impacts: The 137 Line Rebuild 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. The project 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.

North Shore Transformer Addition

MPUC Tracking Number: 2021-NE-N16

Utility: Minnesota Power (MP)

Project Description: The North Shore Transformer Addition Project involves adding a new 115/14 kV transformer at the existing North Shore Switching Station and reconfiguring the Silver Bay area distribution system to interconnect to the new transformer. An existing 115 kV capacitor bank will be relocated to a different bus position to accommodate interconnection of the new transformer. As a result of the project, the existing Silver Bay Hillside Substation will be retired.

Need Driver: The Silver Bay Hillside Substation serves the City of Silver Bay. The substation was scheduled for replacement as part of Minnesota Power's Substation Modernization Program, however upon field review of site conditions and constructability review it was determined that installing a new transformer at the nearby North Shore Switching Station would be a more optimal long-term solution for the area. The retirement of the Silver Bay Hillside Substation will enable that site to be converted to a mobile substation interconnection location, enhancing Minnesota Power's contingency plans for the City of Silver Bay distribution system following completion of the project.

Alternatives:

Transmission Alternatives

> Rebuild Silver Bay Hillside Substation; establish a new 115/14 kV distribution substation near the City of Silver Bay and reconfigure distribution system to interconnect to it.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the Silver Bay Hillside 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 for construction in 2022.

General Impacts: The North Shore Transformer Addition Project will ensure a continuous and reliable power supply to the City of Silver Bay by replacing aging equipment before it fails. At present, it is expected that the impacts will be entirely contained within the existing North Shore Switching Station yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

West Cohasset Substation

MPUC Tracking Number: 2021-NE-N17

Utility: Minnesota Power (MP)

Project Description: The West Cohasset Substation Project involves re-establishing a 115/23 kV transformer at the Boswell SES 115 kV Substation and extending new 23 kV feeders from the substation. The Boswell SES Substation will be renamed as part of the project to eliminate redundant naming with the adjacent Boswell 230/115 kV Substation.

Need Driver: The West Cohasset Substation Project is necessary to upgrade the reliability and capacity of the existing 23 kV distribution system in the Cohasset area in order to interconnect a new manufactured wood products plant.

Alternatives:

Transmission Alternatives

> Extend 115 kV from Zemple, Boswell, or an existing 115 kV line to a new substation site; interconnect to existing Boswell – Zemple 230 kV Line at a new substation site; upgrade existing distribution substations that are remote from the West Cohasset site and build new 23 kV feeder(s) to support additional load.

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 West Cohasset Substation Project will enhance the existing Minnesota Power 23 kV distribution system while enabling a large new load to be interconnected in the Cohasset area.

Schedule: The project must be in-service by mid-2023 to enable interconnection of the new load.

General Impacts: The West Cohasset Substation 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 SES 115 kV Substation was originally designed to accommodate 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. The West Cohasset Substation Project is needed to maintain adequate power delivery capability to the Cohasset-area distribution system upon interconnection of a new manufactured wood products plant. Therefore, the project contributes to the realization of significant social and economic benefits for the Cohasset area while minimizing human and environmental impacts by locating new transmission facilities in areas that are already largely dedicated to utility usage.

Boise Breaker Addition

MPUC Tracking Number: 2021-NE-N18

Utility: Minnesota Power (MP)

Project Description: The Boise Breaker Addition Project involves the installation of a new 115 kV circuit breaker on the International Falls – Boise 115 kV Line (“134 Line”) at the Boise Substation.

Need Driver: The Boise Breaker Addition Project is needed to improve transmission line and bus protection systems for 134 Line and the Boise Substation, provide clearer delineation between Minnesota Power's transmission system and the customer-owned electric distribution system at the Boise Substation, and improve reliability of service to the paper mill customer. The project also includes replacement of existing metering CTs due to their age and condition.

Alternatives:

Transmission Alternatives

> The only reasonable alternative is to do nothing, and continue with the existing configuration.

Non-Wires Alternatives

> Non-wire alternatives cannot address system protection design issues.

Analysis: As currently configured, there is no 115 kV breaker on 134 Line at the Boise Substation. This means that for any faults on 134 Line, circuit breakers on the low side of the customer-owned transformers must open to isolate the fault. In addition to complicating the protection system design by intertwining Minnesota Power's transmission line protection with customer-owned bus and transformer protection, this configuration also inhibits the customer from continuing to operate reliably during and after fault clearing. The project will improve protection design and reliability for the transmission system and the paper mill customer by creating separation between the transmission line and the substation.

Schedule: The project is presently intended for construction in 2023, in coordination with the paper mill so as to minimize impacts to its operations.

General Impacts: The Boise Breaker Addition Project will enhance the reliability of service to the paper mill while simplifying protection system designs for both Minnesota Power and Boise. The project is likely to require a fence expansion of the existing Boise Substation, but since the substation is located entirely on paper mill property the expansion will only impact the paper mill.

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56 Line Upgrade

MPUC Tracking Number: 2021-NE-N19

Utility: Minnesota Power (MP)

Project Description: Thermal upgrade on Ridgeview – Colbyville 115 kV (56 Line)

Need Driver: Post-contingent overloads for loss of Arrowhead – Colbyville 115 kV (57 Line) and a Taconite Harbor transmission line.

Alternatives:

<u>Transmission Alternatives</u>

Reconductor existing line, build new parallel line.

<u>Non-Wires Alternatives</u>

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.

Analysis: Minnesota Power's internal studies have indicated that there is potential for overloading on the Ridgeview – Colbyville 115 kV Line (56 Line) under certain contingency conditions. The contingency conditions that cause this overload result in a radial North Shore Loop transmission system configuration in which all load from Colbyville to the east is served through 56 Line. Because of the radial nature of the issue, its likelihood depends greatly on the total amount of load at the Colbyville Substation and eastward in the North Shore Loop. The upgrade project would provide the needed capacity to ensure reliable delivery of power from the Duluth area into the North Shore Loop. Minnesota Power is monitoring the annual MTEP reliability assessment results and continuing to evaluate the issue in internal studies to gain a better understanding of the load level threshold and timing for this project.

Schedule: The project is presently planned for construction no earlier than 2026.

General Impacts: The 56 Line Upgrade Project will ensure a continuous and reliable power supply to Minnesota Power and Great River Energy customers in the Duluth and North Shore Loop areas under a range of normal and maintenance conditions, effectively continuing to replace transmission system support previously provided by nearby baseload coal units as the system continues to evolve into the future. The project is expected to be completed entirely on the existing right-of-way, making optimal use of existing transmission assets while minimizing human and environmental impacts.

<u>105 & 106 Line Upgrade</u>

MPUC Tracking Number: 2021-NE-N20

Utility: Minnesota Power (MP)

Project Description: The 105 Line & 106 Line Upgrade Project involves reconductoring segments of the two existing Iron Range – Blackberry 230 kV lines and replacing limiting terminal equipment at the Blackberry Substation.

Need Driver: Post-contingent overloads for loss of parallel circuits.

Alternatives:

<u>Transmission Alternatives</u>

Build new parallel line; relocate one or more existing 230 kV line terminations from Blackberry to Iron Range to reduce post-contingent flows on the Iron Range – Blackberry 230 kV Lines.

<u>Non-Wires Alternatives</u>

Non-wire alternatives must be dispatchable to respond when called upon, of sufficient duration, and at an effective location to prevent or mitigate overloading.

Analysis: This issue has been identified in Minnesota Power internal and MISO MTEP studies, and is also discussed in Minnesota Power's Integrated Resource Plan as it relates to changes in operation of the Boswell Energy Center units. With at least one Boswell unit moving from baseload operation to economic dispatch, overloads on these transmission lines are expected to show up more frequently as they are critical outlets for the delivery of replacement energy from the Iron Range and Forbes 500/230 kV sources.

Schedule: The project is presently targeted for implementation in 2023-24.

General Impacts: The 105 Line & 106 Line Upgrade Project will provide necessary system improvements for Minnesota Power's 230 kV system without requiring the establishment of additional transmission line corridors. In addition to making optimal use of existing facilities, the project supports changes in operation at the Boswell Energy Center that have social, environmental, and economic benefits.

<u>Iron Range Synchronous Condenser</u>

MPUC Tracking Number: 2021-NE-N21

Utility: Minnesota Power (MP)

Project Description: The Iron Range Synchronous Condenser Project involves the establishment of a synchronous condenser at the existing Iron Range 230 kV Substation.

Need Driver: The new synchronous condenser is needed to ensure a continuous and reliable source of voltage support and system strength during times when no large dispatchable generators are online in Northern Minnesota.

Alternatives:

<u>Transmission Alternatives</u>

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

<u>Non-Wires Alternatives</u>

Synchronous condensers 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.

Given the significance of system strength as a potential impact of changing operations of the Boswell Energy Center units, Minnesota Power is in the process of determining how best to evaluate this issue and ensure a minimum level of system strength is maintained at all times for Northern Minnesota in the event that both Boswell units are offline due to a Boswell unit tripping offline unexpectedly while the other one was operating in economic dispatch or due to both units operating in economic dispatch. There is inherent risk involved in depending entirely on external resources – over which Minnesota Power has no control or influence in the long-term planning of – for essential reliability services such as system strength and voltage support that directly impact the reliability and operations of Minnesota Power's customers and protection systems. Therefore, some amount of local short circuit capability and voltage support is needed to provide a continuous, predictable, and redundant source to Minnesota Power's system. Besides large local generators like the Boswell units, establishment of one or more new synchronous condensers on the Minnesota Power system would appear to provide the best option for maintaining a local source of short circuit capability. A synchronous condenser is essentially a generator that is driven by the transmission system rather than by a steam turbine or some other form of mechanical energy. Synchronous condensers require no fuel for continuous operation and produce only reactive power. Synchronous condensers are capable of providing voltage regulation during normal system operations as well as dynamic voltage response and fault current during system disturbances.

Schedule: Minnesota Power is presently evaluating options for synchronous condenser development and does not anticipate placing a synchronous condenser in service before 2023.

General Impacts: The establishment of one or more synchronous condensers on Minnesota Power's transmission system will provide necessary voltage support and system strength for Minnesota Power's customers during times when no large dispatchable generators are online in

Northern Minnesota. To the extent possible, new synchronous condensers will be located at existing facilities or, in the case of unit conversion, within an existing generation plant. In addition to making optimal use of existing facilities, the establishment of one or more synchronous condensers 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.

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126 Line Asset Renewal

MPUC Tracking Number: 2021-NE-N22

Utility: Minnesota Power (MP)

Project Description: The 126 Line Asset Renewal Project involves replacement of transmission line components on the Little Fork – International Falls 115 kV Line ("126 Line") due to age and condition. The project will also include age-related replacements of a 115 kV circuit breaker and relay panel at the Little Fork Substation and a relay panel at the International Falls Substation.

Need Driver: The project will address asset renewal needs on 126 Line related to the age and condition of existing structures and transmission line components, an oil-filled 115 kV circuit breaker, and older relay panels that have been found to be susceptible to component failures.

Alternatives:

Transmission Alternatives

> There are no reasonable alternatives that will address the asset renewal needs for the existing transmission line and substation components associated with 126 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 or substation equipment.

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.

Similarly, there are many transmission assets across Minnesota Power's system that require age-related upgrades. In developing the scope for the 126 Line Asset Renewal Project, Minnesota Power is also considering targeted replacements at the substations that will address age-related concerns and contribute to more reliable operation of the transmission system.

Schedule: The 126 Line Asset Renewal Project is presently targeted for construction in 2023.

General Impacts: The 126 Line Asset Renewal Project will ensure that the existing Little Fork – International Falls 115 kV Line continues to provide a safe and reliable transmission path for Minnesota Power's customers in the International Falls area and the region. The project involves replacement of existing assets on the existing transmission line right-of-way and within existing substations, therefore making optimal use of the existing transmission facilities with little or no additional human or environmental impacts.

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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 Cromwell – 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 3-4 years of phased construction beginning at the earliest in 2023.

General Impacts: The 13 Line Rebuild Project will ensure that the existing Cromwell – 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.

Fond du Lac - Wrenshall

MPUC Tracking Number: 2021-NE-N24

Utility: Great River Energy (GRE)

Project Description: Build a new 115 kV transmission line from MP's Wrenshall to GRE's Fond du Lac substation and establish 115/69 kV transformation at Fond du Lac.

Need Driver: GRE's 69/46 kV Fond du Lac substation provides a back up to East Central Electric's (ECE) Amnicon, Bardon, and Summit delivery points when the main source from Stinson is lost. MP has eluded to removing the 23 Line that provides a 46 kV source to the Fond du Lac substation due to its ROW traverses Jay Cooke State Park which is very hilly and hard to access for maintenance and outage restoration.

Alternatives:

Transmission Alternatives

> Rebuild 46 kV 23 Line (Bear Creek – Thomson H.E) that traverses Jay Cooke State Park with very rugged terrain.

Non-Wires Alternatives

> This project is still being studied. Non-transmission alternatives will be studied and considered prior to project initiation.

Analysis: Building the Wrenshall – Fond du Lac 115 kV project will allow for MP to remove their 23 Line from the Jay Cooke State Park and provide a more robust solution going forward.

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

General Impacts: The project will require approximately 5.1 miles of new 115 kV transmission line from the Wrenshall substation to the Fond du Lac 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 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.

Shamineau Lake

MPUC Tracking Number: 2021-NE-N25

Utility: Great River Energy (GRE)

Project Description: Crow Wing Power (CWP) has requested a new distribution substation, to be named Shamineau Lake, that will be served by GRE's "CW-MFT," 115-kV line radially served from the 155 line (Dog Lake – Scearcyville). The interconnection to the "CW-MFT" line will be made via 3-way, load break, 2000-amp, transmission switch.

Need Driver: The addition of regulators and capacitor banks was considered as a solution to allow for CWP to keep serving load from the Ward delivery point but it's not a robust solution. The regulators on the feeders from Ward have been working overtime to keep up with the 34.5kV voltage fluctuations.

Alternatives:

Transmission Alternatives

> There is no other high voltage transmission line within 10 miles of the Shamineau Lake area load pocket making it extremely expensive and not practical to bring a line from another source.

Non-Wires Alternatives

> Distribution driven project for capacity need.

Analysis: CWP has been utilizing a circuit from Todd-Wadena from the Ward substation to serve their Shamineau Lake load pocket which is 6 miles out of CWP's service territory making it hard to maintain proper end-of-the-line voltage after load has grown over the years. CWP has deployed as much voltage regulation as possible and have now requested a new distribution substation closer to the load pocket to provide better voltage to their customers.

Schedule: The project is planned to be in service by October 2022.

General Impacts: The project will require approximately 0.1 miles of new 115 kV transmission line from "CW-MFT" 115 kV line to Shamineau Lake 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.

Wing River 230 kV Ring Bus

MPUC Tracking Number: 2021-NE-N26

Utility: Great River Energy (GRE)

Project Description: Reconstruct the Wing River 230 kV bus to ring bus configuration.

Need Driver: Age and condition necessitates reconstruction of the Wing River 230 kV bus.

Alternatives:
Transmission Alternatives
    None.
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 April 2022.

General Impacts: This project is located on GRE owned property. 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.

Riverton – Wing River Storm Structures

MPUC Tracking Number: 2021-NE-N27

Utility: Great River Energy (GRE)

Project Description: Install storm structures in the Riverton – Wing River 230 kV line.

Need Driver: GRE is continuing to look at making the system more resilient. GRE has H-frame construction on multiple lines that have shown to be prone to line cascading (domino effect) resulting in long duration outages. One way is to limit the damage of cascading is to install stop structures, such as a storm structure. GRE is proposing to install storm structures that will limit damage from cascading to 5 to 10 mile sections rather than without storm structures, whereby significantly longer mileage of damage could occur.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

This a reliability improvement to an existing line to prevent cascading structure failure and no alternatives were considered.

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

Schedule: The project is planned to be in service by November 2023.

General Impacts: The project will be constructed on the existing 230 kV transmission line from Riverton substation to Wing River substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 2 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.

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 2019 Biennial Report but have been completed or withdrawn since the 2019 Report was filed with the Minnesota Public Utilities Commission in October 2019. 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 2019 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
2007-NE-N6	Onigum Area	Not Required	GRE	Moved to study
2011-NE-N2	15 Line Upgrade	Not Required	MP	2019
2011-NE-N12	Wrenshall Substation	Not Required	MP	Cancelled
2013-NE-N13	Great Northern Transmission Line	CN-12-1163 TL-14-21	MP	2020
2013-NE-N22	Elisha 115/34.5 kV Project	Not Required	GRE	2021
2015-NE-N2	868 Line Upgrade	Not Required	MP	2021
2015-NE-N5	16 Line Relocation	TL-14-977	MP	2020
2015-NE-N16	Two Inlets Pumping Station (X1A)	Not Required	GRE	2021
2015-NE-N17	Backus Pumping Station (X2A)	Not Required	GRE	2021
2015-NE-N18	Swatara Pumping Station (X3A)	Not Required	GRE	2021
2015-NE-N19	Hingley Pumping Station (X4A)	Not Required	GRE	2021
2017-NE-N4	Nashwauk 14 Line Upgrade	Not Required	MP	2019
2017-NE-N5	53 Line Upgrade	Not Required	MP	2019
2017-NE-N15	North Shore STATCOM	Not Required	MP	2019
2017-NE-N16	51 Line Upgrade	Not Required	MP	Cancelled
2017-NE-N22	Blackberry Breaker Replacements	Not Required	MP	2020
2017-NE-N25	Boswell 230 kV Fast-Switched Capacitor	Not Required	MP	Cancelled
2019-NE-N1	11 Line Upgrade	Not Required	MP	2020

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2019-NE-N3	Hibbing 14 Line Upgrade	Not Required	MP	2021
2019-NE-N7	Savanna Transformer	Not Required	MP	2021
2019-NE-N9	Midway Substation Retirement	Not Required	MP	2019
2019-NE-N11	38 Line Upgrade	Not Required	MP	2020
2019-NE-N16	Forbes SVC Retirement	Not Required	XEL	2020
2019-NE-N17	Running Cap Bank Retirement	Not Required	XEL	2020

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
2009-WC-N6	Elk River-Becker Area	2012/C	2691	No	Yes	GRE
2015-WC-N3	Ortonville 115/41.6 kV Transformer	2015/B	4236	No	No	OTP

MPUC Tracking Number	MISO Project Name	MTEP Year/ App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2019-WC-N1	Litchfield 69kV LT Tap Line	NA	NA	No	No	SMP
2019-WC-N3	Morris-Johnson Jct.-Ortonville J493/J526 Upgrade	2019/A	17006	No	No	MRES/ GRE/OTP
2019-WC-N4	Westwood 1 115 kV Conversion	2020/A	17971	No	No	GRE
2021-WC-N1	Black Oak – Sauk Centre 69 kV Rebuild	2021/A	19889	No	No	XEL
2021-WC-N2	Minnesota Valley TR12 ELR	2021/A	19886	No	No	XEL
2021-WC-N3	Watkins – Kimball Line Rebuild	2021/A	19890	No	No	XEL
2021-WC-N4	Howard Lake to Big Swan, Delano to Howard Lake, Cokato to Winstead Rebuild	2021/A	19913	No	No	XEL

MPUC Tracking Number	MISO Project Name	MTEP Year/ App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2021-WC-N5	Panther – Big Swan Rebuild	2021/A	20135	No	No	XEL
2021-WC-N6	Appleton – Benson 115 kV Line	2021/A	20148	Yes	No	GRE/ OTP/MRES
2021-WC-N7	Granite Falls - Willmar (WB) Line Upgrade	2022/A	20707	No	No	GRE
2021-WC-N8	Big Swan Breaker Addition	2022/A	20165	No	No	GRE
2021-WC-N9	Kerkhoven 115 kV Breaker Additions	Future	TBD	No	No	GRE
2021-WC-N10	Walden 115 kV Breaker Addition	Future	TBD	No	No	GRE
2021-WC-N11	Benson – Morris Storm Structures	2022/A	21823	No	No	GRE

Elk River-Becker Area

MPUC Tracking Number: 2009-WC-N6

Utilities: Great River Energy (GRE)

Project Description: Build the Orrock 345/115 kV Substation northwest of Elk River. Build 115 kV lines from Orrock to Enterprise Park & Liberty.

Need Driver: This project is needed to address load growth and thermal overloading during a two overlapping single contingency event (NERC TPL-001-4 P6).

Alternatives:

Transmission Alternatives

> Reconductor the Crooked Lake-Parkwood line to ACSS conductor and add a second 345/115 kV transformer at Elm Creek.

Non-Wires Alternatives

> This project is still being studied. Non-transmission alternatives will be studied and considered prior to project initiation.

Analysis: The project is proposing a double circuit 115/69 kV line that would provide more capacity to a narrow transmission corridor than either a single circuit 115 or 69 kV line could offer. Furthermore, the Waco breaker station was designed to accept a 115/69 kV transformation and such a transformer would offload the Elk River 230/69 kV transformers. An Elk River Area 345/115 kV source would also offer a termination point for a 115 kV line going east towards the Crooked Lake Substation.

Schedule: This schedule for this project will be driven by the area load growth. Some portions of the 69 kV transmission will be converted to 115 kV design when needed due to age and condition.

General Impacts: The project will be constructed on an existing 69 kV transmission right-of-way that is located on residential and agricultural lands. The existing line will be upgraded from 69 kV to 115 kV construction and operation. A new substation will be built on approximately 22 acres near where the Xcel Energy 345 kV 0984 & 0992 transmission lines cross the GRE 69 kV EB line. 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. Construction schedule and duration is uncertain at this time but will likely be spread out over several years. 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.

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: 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.

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.

Litchfield 69 kV LT Tap Line

MPUC Tracking Number: 2019-WC-N1

Utility: Southern Minnesota Municipal Power Agency (SMP)

Project Description: Rebuild SMMPA's existing 69 kV LT tap line from the GRE DS Line to the Litchfield Substation to 115 kV standard with 795 ACSR conductor for continued operation at 69 kV.

Need Driver: This project is motivated by the GRE rebuild of the DS line to a 115 kV standard. See project 2017-WC-N5 for more information.

Alternatives:

Transmission Alternatives

> The line rebuild will provide increased load serving capability to Litchfield as well as increased reliability in the area.

Non-Wires Alternatives

> None.

Analysis: If GRE proceeds with their decision to rebuild this area to a 115 kV standard, SMMPA will have no choice but to upgrade this line to the same standard. Therefore, there are no non-wires alternatives to consider for SMMPA.

Schedule: The schedule is currently unknown. See project 2017-WC-N5.

General Impact: The line will be rebuilt on existing right-of-way and will have little impact on landowners.

Morris-Johnson Jct.-Ortonville J493/J526 Upgrade

MPUC Tracking Number: 2019-WC-N3

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

Project Description: This project consists of upgrades to the GRE/MRES/OTP owned Ortonville to Morris 115 kV transmission line to accommodate the interconnection of wind generators, J493/J526. These facilities consist of:

1. Ortonville to Johnson Jct. 115 kV line
2. Ortonville Substation
3. Morris to Johnson Jct. 115 kV line

Need Driver: Network Upgrades to the Transmission Owner's transmission line required for the interconnection of the Interconnection Customers' Project J493/J526.

Alternatives:

Transmission Alternatives

> Building additional 345 kV lines at a higher cost.

Non-Wires Alternatives

> This is an uprate of an existing line, required for generation outlet for MISO interconnection projects J493 and J526. Any non-wires alternatives would not provide sufficient outlet capability for these interconnection projects.

Analysis: The Morris – Johnson Jct. – Ortonville 115 kV line upgrade is needed to accommodate the wind generation outlet of the MISO J493 & J526 projects.

Schedule: The project is planned to be in service by spring 2022.

General Impacts: The project will be constructed on an existing 100-foot right-of-way that is largely located on agricultural lands. No new landowners will be impacted by construction, although some additional temporary workspace may be required. GRE/MRES/OTP have 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. Construction is expected to be completed in 24 months. During this time, GRE/MRES/OTP 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.

Westwood 1 115 kV Conversion

MPUC Tracking Number: 2019-WC-N4

Utility: Great River Energy (GRE)

Project Description: Convert the Westwood 1 substation to 115 kV service.

Need Driver: Improve service reliability to Westwood 1, LeSauk and Five Points distribution substations. Abide by existing agreement with MP to limit the number of substations between breaker stations at a maximum of three. The West St. Cloud to Little Falls 115 kV line has been a congested interface. Removing Le Sauk and Five Points substations from this line will provide some relief to this congestion.

Alternatives:

Transmission Alternatives

> The alternative to abiding by existing agreement with MP is to install a 115 kV breaker station at St. Stephen. While it is costly, it would not provide the redundancy that the project provides to Westwood 1, LeSauk and Five Points substations.

Non-Wires Alternatives

> GRE is replacing existing wires to transition two substations from radial service to a looped service. An NWA was not considered for this alternative as the corridor is existing and the desire for better reliability to the loads impacted.

Analysis: Westwood 1 conversion will also utilize the 115 kV transmission line that Westwood 2 is connected to this could result in losing both Westwood 1 and Westwood 2 substations at the same time. Therefore, the project described in the description is the best value plan for the system.

Schedule: The project is planned to be in service by fall 2023.

General Impacts: The project will be constructed on an existing 70-foot right-of-way that is largely located on agricultural lands. The approximately 2.5 miles of existing line will be upgraded from 69 kV to 115 kV construction and operation. 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. Construction is expected to be completed in 3 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.

Black Oak – Sauk Center 69 kV Rebuild

MPUC Tracking Number: 2021-WC-N1

Utility: Xcel Energy (XEL)

Project Description: Rebuild and upgrade conductor on approximately 6.64 miles from Black Oak to Sauk Center.

Need Driver: Structures exceed planned service life - built in 1951. 4/OA and 3/#6 CU line sections overloading on N-1 contingencies.

Alternatives:

Transmission Alternatives

The alternative option for this project is to perform maintenance and refurb on the line without upgrading the conductor. However, this option would still result in thermal overloads caused by N-1 contingencies.

Non-Wires Alternatives

None as this is an age and condition project of an existing line.

Analysis: Upgrading conductor on this line to current 69 kV standards will mitigate the thermal issues seen on line as well as increase load serving capability in the area.

Schedule: The project is planned to be in service by June 1, 2024.

General Impacts: Line rebuild to take place along existing centerline in rural setting adjacent to roadways. Structure heights are likely to increase. Road lane closure may be required during some construction.

Minnesota Valley TR12 ELR

MPUC Tracking Number: 2021-WC-N2

Utility: Xcel Energy (XEL)

Project Description: Like for like replacement of Minnesota Valley TR12. Transformer is 68 years old and is experiencing performance issues.

Need Driver: Transformer is 68 years old and has indications of some overheating issues, moisture, bad joints, and active thermal degradation.

Alternatives:
<u>Transmission Alternatives</u>

Keep old transformer. Not replacing would result in more frequent and long term outages.

<u>Non-Wires Alternatives</u>

None as this is replacing an existing transformer.

Analysis: Like for like transformer replacement will have minimal impacts to existing system performance.

Schedule: The project is planned to be in service by December 15, 2021.

General Impacts: Like for like transformer replacement will have minimal impacts to existing system performance and footprint.

Watkins - Kimball Line Rebuild

MPUC Tracking Number: 2021-WC-N3

Utility: Xcel Energy (XEL)

Project Description: Rebuild and upgrade approximately 6.56 miles of existing line. Replace EOL switches and MODs.

Need Driver: 83 year old poles. Age and condition do not support repairs. Load growth requires upgrade of small conductor. Potential for increased outage frequency and duration. Failure could provide risk to public.

Alternatives:
<u>Transmission Alternatives</u>

Do nothing. Not replacing would result in more frequent and long term outages.

Non-Wires Alternatives

None, this is an age and condition replacement of an existing line.

Analysis: Upgrading the line to current 69 kV standards will reduce losses as well as improve load serving capability in the area.

Schedule: The project is planned to be in service by December 15, 2022.

General Impacts: Line rebuild to take place along existing centerline in rural setting adjacent to roadways. Structure heights are likely to increase. Road lane closure may be required during some construction.

Howard Lake to Big Swan, Delano to Howard Lake, Cokato to Winstead Rebuild

MPUC Tracking Number: 2021-WC-N4

Utility: Xcel Energy (XEL)

Project Description: Howard Lake to Big Swan - Rebuild 16.0 miles, Delano to Howard Lake – Rebuild 19.7 miles, Cokato to Winstead – Rebuild 14.3 miles to current 69 kV standard for end of life asset renewal.

Need Driver: Re-occurring system reliability issues increase, public safety concerns
Inability to serve load in long term.

Alternatives:
Transmission Alternatives

Do nothing. Not replacing would result in more frequent and long term outages.

Non-Wires Alternatives

None, this is an age and condition replacement of existing lines.

Analysis: Upgrading the line to current 69 kV standards will reduce losses as well as improve load serving capability in the area.

Schedule: The project is planned to be in service by June 15, 2024.

General Impacts: Primarily rural/agricultural land use with scattered urban/ developed areas; main environmental concerns are storm water control, environmental reclamation, and bird flight diverters. DNR water crossing permits will be required, as necessary.

Panther – Big Swan Rebuild

MPUC Tracking Number: 2021-WC-N5

Utility: Xcel Energy (XEL)

Project Description: Rebuild 90% of line from Panther – Big Swan to current 69kV standard, replace Litchfield hard tap structure with double circuit structure, installation of a breaker station at Adams Wind Tap.

Need Driver: Panther – Big Swan 69 kV is one of NSP's worst performing lines with 60+ miles of line exposure. This project will cut the line exposure into thirds in addition to mitigating thermal issues, voltage issues, and 3-terminal relay issues.

Alternatives:

Transmission Alternatives

Partial rebuild of identified line segments or progressive end of life replacements as failures occur. These options would cause increased time, cost, and line outages as well as not address the system performance reliability.

Non-Wires Alternatives

None.

Analysis: Upgrading the line to current 69 kV standards will reduce losses as well as mitigate thermal, voltage, and 3-terminal issues seen in the area.

Schedule: The project is planned to be in service by December 31, 2026.

General Impacts: Project will be split into four stages and coordinated with other rebuilds occurring in that area within a similar timeframe. Line will be rebuilt using existing right-of-way.

Appleton – Benson 115 kV Line

MPUC Tracking Number: 2021-WC-N6

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

Project Description: Construct approximately 27 miles of 115 kV transmission line from the MRES Appleton substation to GRE Benson substation. Convert 2 GRE and 3 OTP 41.6 kV distribution substations to 115 kV service. Add 2 115 kV breakers to the Benson Municipal substation. Reconfigure line terminations at GRE Benson and Benson Municipal.

Need Driver: Improve local area load serving and future load growth. Address low voltage issues during N-2 contingencies that lead to voltage collapse.

Alternatives:

Transmission Alternatives

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

Non-Wires Alternatives

Both technical and economic analysis proves that the NTA solution is not viable for the Benson area. In addition to that, the technical solution shows that NTA 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: The Appleton – Benson 115 kV line is the lowest cost solution.

Schedule: The project is planned to be in service by May 2025.

General Impacts: The project will require approximately 27 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.

Granite Falls - Willmar (WB) Line Upgrade

MPUC Tracking Number: 2021-WC-N7

Utility: Great River Energy (GRE)

Project Description: Increase the line rating by replacing 10 poles.

Need Driver: In MISO’s TPL-001-4 study for MTEP20, thermal violations on the Granite Fall-Willmar 230 kV line were identified for a NERC category P6 contingency (loss of transmission element, followed by system adjustments, followed by loss of another transmission element) in the 2025SH90 and 2025SLL90 models (shoulder and light load models with wind dispatched at

90% of nameplate). GRE's identified Corrective Action Plan for the violation is a re-temp of the WB line to 212 deg. F.

Alternatives:
Transmission Alternatives

While system re-dispatch is allowed for NERC category P6 contingencies, the amount of generator re-dispatch required to mitigate this overload (over 2 GW) is not a realistic Corrective Action Plan.

Non-Wires Alternatives

This a minor upgrade to an existing line and no alternatives were considered.

Analysis: Not doing the project risks non-compliance with NERC standard TPL-001-4.

Schedule: The project is planned to be in service by January 2025.

General Impacts: The project will be constructed on the existing 230 kV transmission line from Granite Falls substation to Willmar 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.

Big Swan 115 kV Breaker Addition

MPUC Tracking Number: 2021-WC-N8

Utility: Great River Energy (GRE)

Project Description: Add a 115 kV line breaker at the Big Swan substation

Need Driver: Prevent line faults from tripping off entire substation.

Alternatives:
Transmission Alternatives

None.

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 November 2022.

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.

Kerkhoven 115 kV Breaker Addition

MPUC Tracking Number: 2021-WC-N9

Utility: Great River Energy (GRE)

Project Description: Add two 115 kV line breakers at the Kerkhoven substation

Need Driver: Prevent line faults from tripping off entire substation.

Alternatives:
Transmission Alternatives
None.
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 after completion of the Appleton – Benson 115 kV project.

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.

Walden 115 kV Breaker Addition

MPUC Tracking Number: 2021-WC-N10

Utility: Great River Energy (GRE)

Project Description: Add 2 115 kV line breakers at the Walden substation.

Need Driver: Prevent line faults from tripping off entire substation.

Alternatives:
Transmission Alternatives
None.

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 after completion of the Appleton – Benson 115 kV project.

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.

Benson – Morris Storm Structures

MPUC Tracking Number: 2021-WC-N11

Utility: Great River Energy (GRE)

Project Description: Install storm structures in the Benson – Morris 115 kV line.

Need Driver: GRE is continuing to look at making the system more resilient. GRE has H-frame construction on multiple lines that have shown to be prone to line cascading (domino effect) resulting in long duration outages. One way is to limit the damage of cascading is to install stop structures, such as a storm structure. GRE is proposing to install storm structures that will limit damage from cascading to 5 to 10 mile sections rather than without storm structures, whereby significantly longer mileage of damage could occur.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

This a reliability improvement to an existing line to prevent cascading structure failure and no alternatives were considered.

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

Schedule: The project is planned to be in service by November 2023.

General Impacts: The project will be constructed on the existing 115 kV transmission line from Benson substation to Morris substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 2 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.

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 2019 Biennial Report but have been completed or withdrawn since the 2019 Report was filed with the Minnesota Public Utilities Commission in October 2019. 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 2019 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
2017-WC-N5	DS Line Rebuild Project	None	GRE	Original Project Withdrawn
2019-WC-N2	Howard Lake-Maple Lake 115 kV Rebuild	None	GRE	Original Project Withdrawn

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
2017-TC-N1	Airport-Rogers Lake 115 kV Rebuild	2016/B>A	10074	No	No	XEL
2021-TC-N1	High Bridge-Rogers Lake Bifurcation to Double Circuit	2021/A	19914	No	No	XEL

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wires Alt.	Utility
2021-TC-N2	Elm Creek TR4	2021/A	19892	No	No	XEL
2021-TC-N3	Barnes Grove Interconnection	2021/A	19905	No	No	XEL
2021-TC-N4	South Dayton Substation	2022/A	21829	No	No	GRE
2021-TC-N5	Lawndale – Bass Lake 115 kV Line	2015/A	7912	No	No	GRE
2021-TC-N6	Rush City 230 kV Ring Bus	Future	TBD	No	No	GRE
2021-TC-N7	Bunker Lake 345 kV Ring Bus	Future	TBD	No	No	GRE
2021-TC-N8	Medina Breaker Addition	Future	TBD	No	No	GRE
2021-TC-N9	Parkwood 115 kV Ring Bus Expansion	2022/A	22025	No	No	GRE
2021-TC-N10	Bunker Lake – Elk River Storm Structures	2022/A	21826	No	No	GRE

Airport-Rogers Lake 115 kV Rebuild

MPUC Tracking Number: 2017-TC-N1

Utility: Xcel Energy (XEL)

Project Description: Rebuild the existing Airport to Rogers Lake 115 kV line due to age and condition.

Need Driver: The existing Airport to Rogers Lake 115 kV line structures have reached end of life and need to be replaced. The line will be rebuilt using the same right of way.

Alternatives:

Transmission Alternatives

> An alternative to rebuilding the existing 115 kV line would be to construct a new 115 kV line in the area to replace the existing line. However, this line needs to connect to substations in a congested metro area and connects directly to the Minneapolis-St. Paul International Airport. It was determined that rebuilding the line in place was the best alternative.

Non-Wires Alternatives

> None, this is an age and condition replacement of existing line.

Analysis: Nearly 70% of the existing structures are overloaded and in failure mode.

Schedule: The project is planned to be in-service by December 2021.

General Impacts: This project will be constructed on ~3.2 miles of existing right of way that is located in the Twin Cities metro area. No new landowners will be impacted by this project. Xcel Energy performed a preliminary review of the route shows that the existing line crossed the Mississippi River, close to multiple lakes, two cemeteries, three highways, and an interstate crossing. The company will work with all appropriate agencies during the permitting phase of the project. 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.

High Bridge-Rogers Lake Bifurcation to Double Circuit

MPUC Tracking Number: 2021-TC-N1

Utility: Xcel Energy (XEL)

Project Description: Convert the bifurcated 115 kV line from High Bridge to Rogers Lake to a double circuit 115 kV line to alleviate curtailment on the High Bridge Generating Plant. Construct new breaker positions at High Bridge and Rogers Lake to accommodate the second 115 kV circuit.

Need Driver: Relieve congestion issues historically seen at the High Bridge 115 kV substation.

Alternatives:

Transmission Alternatives

Do nothing, continue having congestion at High Bridge due to N-1 contingencies.

Non-Wires Alternatives

None.

Analysis: This project splits a bifurcated line into two separate lines and will remove the need to curtail generation at High Bridge due to an N-1 outage.

Schedule: The project is planned to be in service by May 1, 2023.

General Impacts: This project will remove the bifurcation ties at both ends of the High Bridge – Rogers Lake 115 kV line and add breaker positions at both substations.

Elm Creek TR4

MPUC Tracking Number: 2021-TC-N2

Utility: Xcel Energy (XEL)

Project Description: Install Elm Creek TR4 at 115 kV/34.5 kV with one new 34.5 kV feeders exiting the substation to remediate N-1 overloads and allow proposed new customer load.

Need Driver: Extended outage duration under Transformer N-1 contingency to mitigate overloads. New customer load interconnecting to substation.

Alternatives:

Transmission Alternatives

Offload surrounding 34.5 kV feeders to reduce N-1 risk or build a new substation to increase area capacity.

Non-Wires Alternatives

None.

Analysis: Due to increasing load on the surrounding 34.5 kV feeders, the Elm Creek TR2 34.5 kV transformer can no longer find sufficient load relief through feeder load transfers. For this reason, the N-1 risk on Elm Creek TR2 has dramatically increased (the entire load of the transformer) marking it as a high consequence risk. The best mitigation for addressing this risk is the installation a new 34.5 kV transformer and feeders which will immediately solve the high transformer risk, as well as alleviate pressure from the surrounding 34.5 kV feeders.

Schedule: The project is planned to be in service by December 15, 2021.

General Impacts: Transformer addition will have minimal impacts to existing system performance and footprint.

Barnes Grove Interconnection

MPUC Tracking Number: 2021-TC-N3

Utility: Xcel Energy (XEL)

Project Description: Install 3-way switch on 69 kV line between Inver Grove - Keagan Lake Tap to accommodate GRE's new Barnes Grove interconnection (MTEP 2589).

Need Driver: GRE interconnecting new Barnes Grove substation to serve new customer load.

Alternatives:

Transmission Alternatives

No alternatives were considered; GRE's Coop has been planning on building a 69 kV substation on this property for 10+ years. The site has been graded since 2009.

Non-Wires Alternatives

Distribution driven project for capacity need.

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's in-service date was March 31, 2021.

General Impacts: New interconnection will have minimal impacts to existing system performance and footprint.

South Dayton

MPUC Tracking Number: 2021-TC-N4

Utility: Great River Energy (GRE)

Project Description: Construct the new Connexus Energy (CE) South Dayton 115 kV in-and-out distribution substation in the Xcel 5522 line.

Need Driver: Accommodate local area load growth.

Alternatives:

Transmission Alternatives

Add second transformer at the CE Hennepin substation.

Non-Wires Alternatives

Distribution driven project for capacity need.

Analysis: The new CE South Dayton substation is closer to load growth areas than the CE Hennepin substation.

Schedule: The project is planned to be in service by May 2023.

General Impacts: The project will require approximately 0.10 miles of new 115 kV transmission line from the Xcel 5522 115 kV line to South Dayton 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.

Lawndale – Bass Lake 115 kV Line

MPUC Tracking Number: 2021-TC-N5

Utility: Great River Energy (GRE)

Project Description: Construct approximately 2 miles of new 115 kV transmission line from the new Lawndale #2 115 kV distribution substation to an interconnection with the GRE Bass Lake – Cedar Island 115 kV transmission line on existing GRE 69 kV corridor.

Need Driver: Accommodate existing and future local area load growth.

Alternatives:
Transmission Alternatives

Build Lawndale #2 as 69 kV service.

Non-Wires Alternatives

This project is still being studied. Non-transmission alternatives will be studied and considered prior to project initiation.

Analysis: Adding an alternate 115kV source into the Lawndale Substation property will provide better diversity and overall reliability to the area as opposed to doubling the load and number of customers on a transmission line that does not have an alternate source in the case of damage.

Schedule: The project is planned to be in service by November 2024.

General Impacts: The project will require approximately 2 miles of new 115 kV transmission line from Lawndale #2 substation to an interconnection with the GRE Bass Lake – Cedar Island 115 kV line. The project is located in existing 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.

Rush City 230 kV Ring Bus

MPUC Tracking Number: 2021-TC-N6

Utility: Great River Energy (GRE)

Project Description: Complete Rush City 230 kV ring bus. Build independent terminals for the Rock Creek – Rush City and Red Rock – Rush City 230 kV lines.

Need Driver: Overloads during NERC TPL-001-4 P6 events. Age and condition.

Alternatives:
Transmission Alternatives
None.
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 January 2024.

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.

Bunker Lake 345 kV Ring Bus

MPUC Tracking Number: 2021-TC-N7

Utility: Great River Energy (GRE)

Project Description: Build Bunker Lake 345 kV ring bus.

Need Driver: Deficient line switching for 345 kV lines.

Alternatives:
Transmission Alternatives
None.
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

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.

Need Driver: A fault on the Crow River – Medina 115 kV line trips the entire substation. A fault on the Medina 115/69 kV transformer trips the entire substation.

Alternatives:
Transmission Alternatives
None.
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 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.

Parkwood 115 kV Ring Bus Expansion

MPUC Tracking Number: 2021-TC-N9

Utility: Great River Energy (GRE)

Project Description: Rebuild the 115 kV bus at Parkwood substation as a ring bus.

Need Driver: Overloads during NERC TPL-001-4 P6 events. A 115 kV fault trips the entire substation.

Alternatives:
Transmission Alternatives
None.
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 June 2024.

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.

Bunker Lake - Elk River Storm Structures

MPUC Tracking Number: 2021-TC-N10

Utility: Great River Energy (GRE)

Project Description: Install storm structures in the Bunker Lake - Elk River 230 kV line.

Need Driver: GRE is continuing to look at making the system more resilient. GRE has H-frame construction on multiple lines that have shown to be prone to line cascading (domino effect) resulting in long duration outages. One way is to limit the damage of cascading is to install stop structures, such as a storm structure. GRE is proposing to install storm structures that will limit damage from cascading to 5 to 10 mile sections rather than without storm structures, whereby significantly longer mileage of damage could occur.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

This a reliability improvement to an existing line to prevent cascading structure failure and no alternatives were considered.

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

Schedule: The project is planned to be in service by June 2024.

General Impacts: The project will be constructed on the existing 230 kV transmission line from Bunker Lake substation to the Elk River substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 2 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.

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 2019 Biennial Report but have been completed or withdrawn since the 2019 Report was filed with the Public Utilities Commission in October 2019. 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 2019 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
2017-TC-N4	Black Dog-Wilson 115 kV Upgrade		XEL	04/30/2021
2017-TC-N5	Wilson Substation		XEL	12/21/2020

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2017-TC-N6	Plymouth Area Power Upgrade	12-113	XEL	10/30/2018
2017-TC-N7	Lebanon Hills 115 kV	Not Required	GRE	2020
2019-TC-N2	South Afton Substation		XEL	05/29/2021
2019-TC-N1	Red Rock Transformer Replacement		XEL	Cancelled
2019-TC-N3	East Metro Area Upgrades		XEL	Cancelled
2021-TC-N3	Barnes Grove Interconnection		XEL	03/31/2021

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. 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
2013-SW-N1	Heron Lake 161 kV Substation Rebuild	2012/A	3528	No	Yes	ITCM
2015-SW-N3	Buffalo Ridge Cutover	2015/A	8017	No	No	XEL
2017-SW-N1	Summit to Dovray 69 kV Rebuild	2016/A	9907	No	No	ITCM
2017-SW-N2	Dovray to Fulda 69 kV Rebuild	2016/A	9908	No	No	ITCM
2017-SW-N3	Fulda to Heron Lake 69 kV Rebuild	2016/A	9910	No	No	ITCM

MPUC Tracking Number	MISO Project Name	MTEP Year/ App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2021-SW-N1	Fieldon Retirement	2021/A	19165	No	No	XEL
2021-SW-N2	Worthington Area Projects	2022/A	GRE:22030/ ITCM:21929/ MRES:20608	No	No	GRE/ITC M/MRES
2021-SW-N3	Luverne to Trosky 69 kV Rebuild	N/A	N/A	No	No	L&O

Heron Lake 161 kV Substation Rebuild

MPUC Tracking Number: 2013-SW-N1

Utility: ITC Midwest (ITCM)

Project Description: Heron Lake 161 kV Substation Rebuild.

Need Driver: As part of a joint study with GRE & MRES, ITC Midwest has revised and reduced the scope of the Heron Lake 161 kV project. In the updated configuration, the capacitor banks are no longer needed and the 161 kV configuration changes from a breaker-and-a-half to a ring bus.

Alternatives:
Transmission Alternatives

The capacitor bank were re-evaluated during the ad hoc study and it was determined to no longer be needed with the addition of the 'Worthington Area Projects.'

Non-Wires Alternatives

This project was first proposed in 2013, and system changes, like the Worthington area projects, have removed the initial need for capacitor banks. Substation age and condition issues remain, and a non-wires alternative would not resolve the need to address the age and condition of Heron Lake substation.

Analysis: Transmission studies revealed that voltage in the area is depressed by the relatively long 69 kV lines in the area and the lack of sources in the area. In addition, outages on either the 69 kV or 161 kV systems drove voltage below ITC Midwest's planning criteria. The Heron Lake 161 kV substation will be constructed as a four position ring but with a single 161/69 kV transformer.

Schedule: Due to outage constraints and the addition of the Worthington Area Projects, the new expected in-service date would be no later than December 2027.

General Impacts: The addition of the 'Worthington Area Projects' allowed ITC Midwest to reduce the scope and cost of the existing Heron Lake Capacitor Bank Addition and subsequent substation expansion. The new plan provides better electrical performance at a reduced cost, while adding the additional benefit of geographic diversity which significantly improves customer reliability.

Summit to Dovray 69 kV Rebuild

MPUC Tracking Number: 2017-SE-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 2024.

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.

Dovray to Fulda Junction 69 kV Rebuild

MPUC Tracking Number: 2017-SE-N2

Utility: ITC Midwest (ITCM)

Project Description: The approximately 14.5 mile-long Dovray to Fulda 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 Dovray to Fulda Junction 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 Dovray to Fulda Junction 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-SE-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 2019.

Schedule: Construction of the line is expected to be completed by the end of 2026.

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 July 2022.

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) hereinafter referred to as "the Utilities."

Project Description: Construct the Lakefield Corners substation interconnection in the Dickinson – Lakefield Junction 161 kV transmission line. Construct the Rost 161/69 kV substation interconnection in the Heron Lake – Round Lake 69 kV transmission line. Construct approximately 6.5 miles of 161 kV transmission line from the Lakefield Corners substation to the Rost substation. Construct approximately 9 miles of 69 kV transmission line from the Lorain substation to the Rost substation.

Need Driver: 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:

Transmission Alternatives

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: 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 Lakefield Corners 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.

Luverne to Trosky 69 kV Rebuild

MPUC Tracking Number: 2021-SW-N3

Utility: L&O Power Cooperative (L&O)

Project Description: The 16.6 miles-long Luverne to Trosky 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. A portion of the line was rebuilt after a 2019 ice storm and this project will rebuild the remaining portions.

Alternatives:
Transmission Alternatives

> 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 referenced 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 referenced 69 kV line.

Analysis: The plan to replace the transmission line with new poles and shield wire will solve the reliability concern caused by the age and condition of the 69 kV line. The existing 477 ACSR conductor is planned to be transferred.

Schedule: Initial rebuild of the line is expected to commence in 2022.

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. L&O will work with the appropriate permitting agencies to receive necessary approvals. L&O 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.

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 2019 Biennial Report but have been completed or withdrawn since the 2019 Report was filed with the Minnesota Public Utilities Commission in October 2019. 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 2019 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
2015-SW-N3	Buffalo Ridge Cutover		XEL	Cancelled
2019-SW-N1	Lismore 115 kV Interconnection	Not Required	GRE	2021
2019-SW-N2	Rutland Substation 161kV Ring Bus Addition	NA	SMP	12/1/2019

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
2015-SE-N6	Waseca Junction to Montgomery 69 kV rebuild	2013/A	4101	No	No	ITCM
2015-SE-N7	Ellendale to Owatonna 69 kV Rebuild	2013/A	4108	No	No	ITCM
2017-SE-N1	Huntley to Wilmarth 345 kV MEP Project	2016/A	11883	Yes	Yes	XEL/ITCM
2017-SE-N3	Rochester-Wabaco 161 kV Rebuild	2018/A	16184	No	No	DPC
2019-SE-N2	Adams to Stewartville 69 kV Rebuild	2012/A	3630	No	No	ITCM
2019-SE-N3	J523 Generator Interconnection to Adams 161 kV	2020/A	TBD	No	No	ITCM
2019-SE-N4	Adams 161 kV Maintenance	2020/A	13879	No	No	ITCM
2019-SE-N5	Thisius 161/69kV Substation	2020/A	17968	No	Yes	ITCM
2021-SE-N1	Replace Green Isle Substation	2021/A	19891	No	No	XEL
2021-SE-N2	Northfield to Farmington Line Rebuild	2021/A	19888	No	No	XEL
2021-SE-N3	Hayward 161/69 kV Transformer Replacement	2022/Target A	21935	No	No	ITCM

Waseca Junction to Montgomery 69 kV Rebuild

MPUC Tracking Number: 2015-SE-N6

Utility: ITC Midwest (ITCM)

Project Description: The 29.6 mile-long Waseca Junction to Montgomery 69 kV line will be reconstructed on the existing right of way.

Need Driver: This 69 kV line was built in 1946 and increased maintenance costs have required that this line be rebuilt due to 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 Waseca Junction to Montgomery 69kV circuit

Analysis: The plan to replace the approximately 70-year-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: Construction of the line is expected to be completed by the end of 2021.

General Impacts: The line is near the end of its useful life. The line will be reconstructed on the 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 line rebuild will increase the reliability of the electric system in the area.

Ellendale to West Owatonna 69 kV Rebuild

MPUC Tracking Number: 2015-SE-N7

Utility: ITC Midwest (ITCM)

Project Description: The 13.2 miles-long Ellendale to West Owatonna 69 kV line will be reconstructed on the existing right of way.

Need Driver: This 69 kV line is a known, real-time system constraint. The line is also nearing the end of its useful life.

Alternatives:

Transmission Alternatives

Replacement of the 69 kV transmission line with new poles, conductor and shield wire addresses a capacity constraint and provides for needed upgrade of the 50-year-old 69 kV line.

Additional analysis is ongoing. The Ellendale to West Owatonna 69 kV has also been a source of system congestion due to area wind energy, and evaluation of a possible voltage conversion from 69 kV to 161 kV along a corridor from the Hayward or Freeborn 161 kV substations to Owatonna and other alternatives are also being evaluated in effort to better address possible future generation outlet and load-serving needs.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition on the Ellendale to West Owatonna 69kV circuit.

Analysis: Rebuilding the line to a greater capacity on existing right-of-way was the sole alternative considered to alleviate the system capacity constraint.

Schedule: The rebuild of the line is expected to be completed in 2022.

General Impacts: Replacement of the line will provide for additional system capacity and reduce maintenance cost on the existing, aging infrastructure. It is expected that the line will be reconstructed 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 of the line will increase the reliability of the electric system in the area.

Huntley to Wilmarth 345 kV MEP Project

MPUC Tracking Number: 2017-SE-N1

Utilities: Xcel Energy (XEL) & ITC Midwest (ITCM)

Project Description: Construct new 345 kV circuit from the Wilmarth Substation to the Huntley Substation.

Need Driver: This is a market efficiency project to relieve congestion on the Huntley to Blue Earth 161 kV line.

Alternatives:

<u>Transmission Alternatives</u>

Several solutions such as rebuilding the South Bend to Blue Earth to Huntley 161 kV, a new Freeborn to West Owatonna 161 kV circuit, and a new Wilmarth to North Rochester 345 kV circuit were also studies to relieve the congestion observed.

<u>Non-Wires Alternatives</u>

None.

Analysis: The Huntley to Wilmarth 345 kV project was found to alleviate the observed congestion at the Minnesota/Iowa border. The proposed project met the MISO present value cost to benefit ratio required for Market Efficiency projects.

Schedule: Planned in service date is end of 2021. A certificate of need and route permit were granted for this project in 2019.

General Impacts: This project utilizes the existing Wilmarth and Huntley substations. Some additional new right-of-way was acquired to construct the new 345 kV circuit on the approved route, but approximately 40% of the line is being constructed as a double circuit with the existing Wilmarth-Lakefield Jct. 345 kV line. An Environmental Impact Statement was prepared for the project and is available on eDockets in MPUC Docket Nos. E002,ET-6675/CN-17-184 and TL-17-185. Unique environmental features were addressed to minimize environmental impacts that could occur during construction. Xcel worked with the appropriate permitting agencies to receive necessary approvals. Xcel contractors and personnel are contributing positively to the local economies. No significant traffic impacts are anticipated.

Rochester-Wabaco 161 kV Rebuild

MPUC Tracking Number: 2017-SE-N3

Utility: Dairyland Power Cooperative (DPC)

Project Description: Rebuild 13.2 miles of 161 kV line between DPC’s Rochester and Wabaco transmission substations. This project will increase the line’s capacity with upgraded conductor, switches and substation jumpers.

Need Driver: This 161 kV line was identified as a limiting transmission congestion point as part of the MTEP18 assessment. The line shows a significant amount of congestion when other west-to-east lines at the interface of Minnesota and Wisconsin are out of service.

Alternatives:

<u>Transmission Alternatives</u>

The ability for the existing structures to handle a larger conductor was reviewed. The existing structures would not be able to carry a larger conductor to achieve a higher capacity on this line. The MTEP18 transmission study reviewed three other solutions involving larger 345 kV lines, which did not pass the present value analysis due to very high costs.

Non-Wires Alternatives

None.

Analysis: The project to replace the line with new poles, conductor and substation jumpers at the endpoints of the Rochester and Wabaco substations will alleviate the congestion issues as determined by MISO. Dairyland Power Cooperative has reached an agreement with a third party to fund the Rochester-Wabaco 161 kV Rebuild Project.

Schedule: Construction is scheduled to occur October 2021 to March 2022.

General Impacts: Dairyland construction crews will rebuild this line in 2021 into 2022 requiring approximately twenty-four weeks to construct. The upgraded line will reduce congestion on the transmission system.

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 69kV 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 commence in 2023.

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.

J523 Generator Interconnection to Adams 161 kV

MPUC Tracking Number: 2019-SE-N3

Utility: ITC Midwest (ITCM)

Project Description: To provide for interconnection of the 50 MW solar-powered generating facility, MISO project J523, the 161 kV bus at Adams will be reconfigured to form a breaker-and-1/2 terminal at the location of the existing Adams 161 kV bus-tie breaker. Also, as part of the work for the J523 generation, the 161 kV terminal to the 345/161 kV transformer will be reterminated at a new terminal in the newly created breaker-and-1/2 row that will serve as the point of interconnection for project J523.

Need Driver: MISO project J523 was studied under the MISO business practices, and the expansion of the Adams 161 kV bus to connect project J523 is required to provide interconnection service to the project under the MISO tariff.

Alternatives:

Transmission Alternatives

The interconnection was evaluated under the MISO's DPP February 2016 system impact study. No alternatives for the interconnection were identified.

Non-Wires Alternatives

Project J523 will be interconnected under MISO Tariff requirements. A non-wires is not viable as this project is aiding in the interconnection of a 50 MW solar-powered generating facility.

Analysis: The interconnection of project J523 was evaluated as part of the MISO February 2016 system impact study. The expansion of facilities at Adams are required to provide a point of interconnection for project J523.

The Adams substation is approximately 55 years old, and the substation was originally designed to accommodate conversion to a breaker-and-1/2 bus configuration. In conjunction with the interconnection of project J523, a separate maintenance project will be developed to convert the remaining 161 kV substation bus from a straight bus configuration to a breaker-and-1/2 configuration.

Schedule: The project will be placed in service in September of 2022.

General Impacts: The upgrades will occur within the existing Adams 161 kV Substation. Termination of the J523 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.

Adams 161 kV Maintenance

MPUC Tracking Number: 2019-SE-N4

Utility: ITC Midwest (ITCM)

Project Description: The Adams 161 kV currently has two generating facilities, 5-161 kV lines, a 161/69 kV transformer and a 345/161 kV transformer connected to the 161 kV bus in a straight bus configuration. The greater than 55 years old substation was initially designed with capability for the 161 kV bus to be converted to a breaker-and-1/2 configuration, and in conjunction with the interconnection of project J523, additional circuit breakers will be installed, and the 161 kV bus will be converted to a breaker-and-1/2 configuration.

Need Driver: The breaker-and-1/2 configuration will provide greater operational flexibility by avoiding generating facility outages and line outages otherwise required for maintenance, and it will increase system reliability by avoiding loss of multiple system elements in the event of a fault. The Adams 161 kV bus reconfiguration will also eliminate the overload of the Adams to Rose Wind 69 kV line for a breaker failure contingency of bus L2 at Adams 161 kV.

Alternatives:

Transmission Alternatives

> Rebuilding the Adams 161 kV substation near the existing facility would require significant line relocation and new equipment, and it was considered a too costly alternative.

Non-Wires Alternatives

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

Analysis: Reconfiguring the substation to a breaker-and-1/2 configuration in conjunction with the interconnection of project J523 will provide operational flexibility if performing system maintenance while also providing for increased system reliability. The operational flexibility also removes the need to reduce area generation in the event of a bus fault or breaker failure event at Adams 161 kV.

Schedule: The project work will be coordinated with the work to interconnect project J523, which has a September 2022 in service date. It is expected that the Adams 161 kV maintenance work will be completed in the second quarter of 2022, prior to the in service date for J523.

General Impacts: Coordination with generating facilities' owners, Xcel Energy and Dairyland Power Cooperative will be required for outages facilities construction. The upgrades will occur within the existing Adams 161 kV Substation. 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.

Thisius 161/69 kV Substation

MPUC Tracking Number: 2019-SE-N5

Utility: ITC Midwest (ITCM)

Project Description: The project calls for the Huntley to Freeborn 161 kV line to be tapped approximately 6.1 miles west of Freeborn. A new 161/69kV substation would be constructed to accommodate a 100 MVA, 161/69 kV transformer with load-tap changer.

Need Driver: The 69 kV system around Albert Lea, MN experiences low voltage and thermal loading issues under multiple NERC P2 contingencies. This area is primarily fed from the Huntley and Hayward substations and the line between them is approximately 50 miles long. This 69 kV system is operated radially, and the existing 161 kV sources are stretched on high impedance conductor over great distances.

Alternatives:
Transmission Alternatives

Rebuilding Huntley 69 kV to a ring-bus configuration and re-terminating Corn Plus substation's load to a consolidated substation near Winnebago Local in conjunction with rebuilding the Hayward 161 kV Substation to a breaker-and-½ configuration were also considered.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot meet the duration requirements to alleviate the voltage concerns.

Analysis: The new substation at Thisius will help support future load growth on the 69 kV system and provide a much needed source between the Huntley and Hayward substations. The location of the Thisius 69 kV station can also accommodate future 161 kV expansion necessary to address future area needs.

Schedule: It is expected that the project would be placed in service by early June 2023.

General Impacts: Line routing and facilities siting will be coordinated with necessary local, state and federal authorities. ITC contractors and personnel will work with landowners to address their concerns during construction. Impacts to landowners will be minimized. Temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITC will work with the appropriate permitting agencies. No significant traffic impacts are anticipated. ITC contractors and personnel will contribute positively to the local economy. The new facilities will increase the reliability of the electric system in the area.

Replace Green Isle Substation

MPUC Tracking Number: 2021-SE-N1

Utility: Xcel Energy (XEL)

Project Description: Replace existing Green Isle substation with a new 69/13.8 kV substation on a new site.

Need Driver: The existing transformer TR1 has contingency risk following planned addition of industrial load. The existing substation is 4 kV and needs to be converted to conform with standards, and the existing site is not sized to fit the new design.

Alternatives:
Transmission Alternatives
Increasing the transformer size would not conform with standard distribution voltage and substation yard constraints are a concern.
Non-Wires Alternatives
None, this is replacing an existing asset.

Analysis: The existing transformer TR1 has contingency risk following planned addition of industrial load.

Schedule: The work will take approximately one year to complete and use Xcel Energy employees. The required in-service date is subject to the timing of the industrial load growth.

General Impacts: This project will require land for a new distribution substation.

Northfield to Farmington Line Rebuild

MPUC Tracking Number: 2021-SE-N2

Utility: Xcel Energy (XEL)

Project Description: This project involves the rebuilding of an approximately 1.6-mile portion of the 69 kV between Farmington substation (FRM) and Northfield substation (NOF). The intent of the rebuild is to increase reliability and performance of the line, reduce the likelihood of a forced outage occurring and increase the capacity for project future load growth.

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

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 December 15, 2022.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Hayward 161/69 kV Transformer Replacement

MPUC Tracking Number: 2021-SE-N3

Utility: ITC Midwest (ITCM)

Project Description: Due to age and condition, ITC Midwest is replacing both 161/69 kV transformers at the Hayward substation near Hayward, MN, with a single larger unit.

Need Driver: Both transformers are nearing end of their life and are needing to be replaced.

Alternatives:

Transmission Alternatives

Replacing both existing units with a pair of larger/standard transformers. However, with the addition of *'2019-SE-N5 Thisius 161/69 kV Substation'* there was no longer a need to have two transformers in this substation.

Non-Wires Alternatives

Non wires alternative was not considered. Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Hayward Substation.

Analysis: This project is pending submittal to MISO's MTEP study but is expected to be included in the MTEP22 Study.

Schedule: The in-service date for this project is by year end 2025.

General Impacts: The project is being completed within the existing Hayward substation property lines and minimal impacts to neighboring landowners is expected.

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 2019 Biennial Report but have been completed or withdrawn since the 2019 Report was filed with the Minnesota Public Utilities Commission in October 2019. 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 2019 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
2011-SE-N5	Arlington-Green Isle 69 kV		XEL	11/21/2020
2015-SE-N4	Line 0714 Rebuild		XEL	12/15/2017
2017-SE-N6	J407 Generator Interconnection	N/A	ITCM	8/2020
2019-SE-N1	Cannon River Park Tap Line	Not Required	GRE	2021
2019-SE-N8	Blooming Prairie N86 69 kV Line Rebuild	NA	SMP	11/30/2020

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2019-SE-N9	Preston N-22 69 kV Line Rebuild	NA	SMP	05/01/2020
2019-SE-N10	West Owatonna 161 kV Ring Bus Addition and Load Interconnection	NA	SMP	12/1/2019

7.0 Transmission-Owning Utilities

7.1 Introduction

In this chapter in the 2021 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 that was provided in the 2019 Report. This information relates to the history of the 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 and 2019, 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	18	14	0	0	0
Dairyland Power Cooperative	423.8	152.75	0	8.88	0
East River Electric Power Cooperative	164	46	0	0	0
Great River Energy	3,027	626	520	118	436
ITC Midwest LLC	688.6	307.9	0	92.6	0
L&O Power Cooperative	43.17	8.32	0	0	0
Minnesota Power	0.22	1,310.02	617.65	265.52	231.56
Minnkota Power Cooperative	998.67	153.26	268.09	0	0
Missouri River Energy Services	32.16	239.32	24.02	47	0
Northern States Power Company d/b/a Xcel Energy	1,677.4	1,760.76	466.37	1,871.03	0
Otter Tail Power Company	1,300.99	540.95	181.18	619.02	0
Rochester Public Utilities	0	42.42	0	0	0
Southern Minnesota Municipal Power Agency	149.84	135.48	17.09	0	0
Totals:	8,523.85	5,337.12	2,094.4	3,034.05	667.56

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 an 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.
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Waukesha, WI 53187-0047
Phone: (262) 506-6700
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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.

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 Blue Earth, 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 MN and IA. CMMPA transmission assets are part of MISO.

More information about the company is available on its website at:

http://www.cmpas.org

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Central Municipal Power Agency/Services
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Transmission lines. CMMPA is one of the eleven members of the CapX group, and one of the five investors 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.

Central Minnesota Municipal Power Agency

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
18	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

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Transmission Lines**.** Dairyland delivers electricity via more than 3,100 miles of transmission lines and nearly 300 substations located throughout the system's 44,500 square mile service area. Dairyland has the following transmission facilities in Minnesota:

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 eighteen 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:
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Transmission Policy Administrator
East River Electric Power Cooperative
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Phone: (605) 256-4536
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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
164	46	0	0	0

7.6 Great River Energy

Background Information. Great River Energy (GRE) is a not-for-profit electric cooperative owned by 28 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. Great River Energy's largest distribution cooperative serves more than 138,000 member-consumers, while the smallest serves approximately 4,400. Collectively, Great River Energy's member cooperatives distribute electricity to approximately 715,000 member accounts, or about 1.7 million people. In addition, Great River Energy is part of MISO.

More information about Great River Energy is available at:

http://www.greatriverenergy.com

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Director, Transmission Planning & Compliance
Great River Energy
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Maple Grove, MN 55369-4718
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Fax: (763) 445-5050
e-mail: gpietsch@grenergy.com

***Transmission Lines*. ** Great River Energy has the following transmission lines:

GRE Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
3,027	626	520	118	436

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. 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 6,700 miles of transmission lines, operating at voltages from 34.5 kV to 345 kV in Minnesota, Iowa, Illinois, and Missouri.

ITC Midwest owns approximately 1,089 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.

ITC Midwest Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
688.6	307.9	0	92.6	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

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L&O Power Cooperative
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e-mail: troy.metzger@dgr.com

***Transmission Lines*.** L&O delivers wholesale electricity via approximately 193 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:

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 about 145,000 residential and commercial customers, 15 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

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Minnesota Power
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Duluth, MN 55802
Phone: (218) 355-2908
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Transmission Lines. The number of miles of transmission in Minnesota owned by Minnesota Power is shown in the following table.

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

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Transmission Lines. The Joint System owns 1,419.96 miles of transmission line in Minnesota and 1,952.47 miles in North Dakota. The miles of Minnesota transmission lines are shown in the following table:

Joint System Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
998.67	153.26	268.09	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 existing 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 can be found at:

http://www.mrenergy.com

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Sioux Falls, SD 57108-8920
Phone: (605) 330-6986
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e-mail: brian.zavesky@mrenergy.com

Transmission Lines. The number of miles of transmission in Minnesota owned by Missouri River Energy Services is shown in the following table.

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

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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.

NSP Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
1,677.4	1,760.76	466.37	1,871.03	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 61,100 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.

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P.O. Box 496
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e-mail: dstupca@otpco.com

Transmission Lines. OTP has the following transmission lines in Minnesota:

OTP Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
1,300.99	540.9	181.18	619.02	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 48,219 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

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Fax: (507) 280-1542
e-mail: snickels@rpu.org

***Transmission Lines*.** Rochester Public Utilities owns 42.42 miles of 161 kV transmission line in Minnesota. Rochester Public Utilities is one of the eleven members of the CapX group, and is one of the five investors in the Hampton-Rochester-La Crosse CapX project. Beyond this CapX project, Rochester Public Utilities has no immediate plans for future transmission expansion.

Rochester Public Utilities Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
0	42.42	0	0	0

7.15 Southern Minnesota Municipal Power Agency

Background Information. Southern Minnesota Municipal Power Agency (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 eighteen 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
Power Delivery Engineer
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:

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 upcoming Renewable Energy Standard milestones. 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." In its 2020 Order approving the 2019 Report, the Commission said that 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 additional information is presented in Chapter 9.

Accordingly, in this Report, as in past years, the utilities are reporting on their best estimates for how much renewable generation will be required in future years and what efforts are underway to ensure that 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 that is already available and how much will be 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 2019 Report but all figures and charts and tables have been updated since those provided two years ago.

8.2 Reporting Utilities

It should be pointed out, as was done in previous reports, that the utilities that are required to submit the Biennial Transmission Projects Report are not identical to those that are required to meet the Renewable Energy Standards. The information in this chapter reflects the work of all the utilities that are 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 2021 Biennial Report on renewable energy are 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
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
Western Minnesota Municipal Power Agency/Missouri River Energy Services

Power District

Heartland Consumers Power District

8.3 Compliance Summary

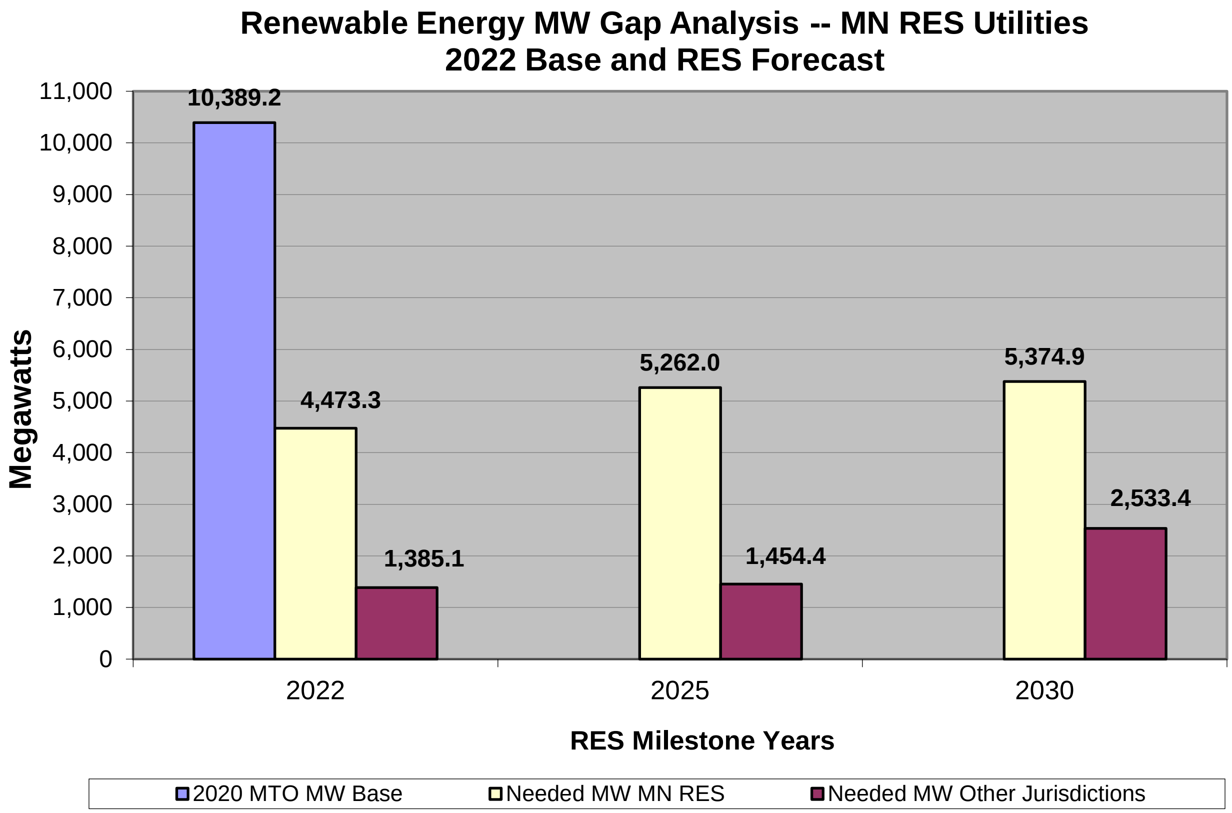
The utilities have continued to make substantial progress with respect to meeting future RES milestones. The RES requirement beginning in 2020 is 20% for MN utilities, except for Xcel Energy which is 30% of retail sales for the respective reporting year All utilities have satisfied their respective compliance requirements and expects to continue to achieve and maintain all compliance requirements into the future. In addition, several new wind and solar projects have achieved commercial operations during 2020 and 2021. The addition of these new projects greatly contributes to the ability to meet RES requirements going forward. In addition, the utilities have provided a Gap Analysis regarding compliance with the upcoming 2022 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 to need beyond what is presently available to obtain the required amount of renewable energy that must come from renewable sources at a particular time in the future. 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 eighth time the utilities have prepared a Gap Analysis; a Gap Analysis was prepared for the 2007, 2009, 2011, 2013, 2015, 2017 and 2019 Biennial Reports also.

8.5 Base Capacity and RES/REO Forecast

The chart below presents a system-wide overview of existing capacity in 2022 (used as a base figure throughout the various milestone periods) and forecasted renewable capacity requirements to meet Minnesota RES as well as non-Minnesota RES/REO needs. Each utility provided its own forecast of Minnesota RES and non-Minnesota RES/REO renewable energy needs, and converted such estimates into capacity based on their own mix of renewable resources (wind, biomass, hydropower, solar) using the most appropriate capacity factors unique to their specific generating resources.



2022 MTO MW Base: RES capacity acquired, actually installed and operational ("in the ground and running") regardless of geographic location Does not include projects under contract but not yet under construction, and it does not include projects under construction but not yet completed.

Needed MW MN RES: Renewable capacity required to meet the RES energy goals for each utility serving customers in Minnesota.

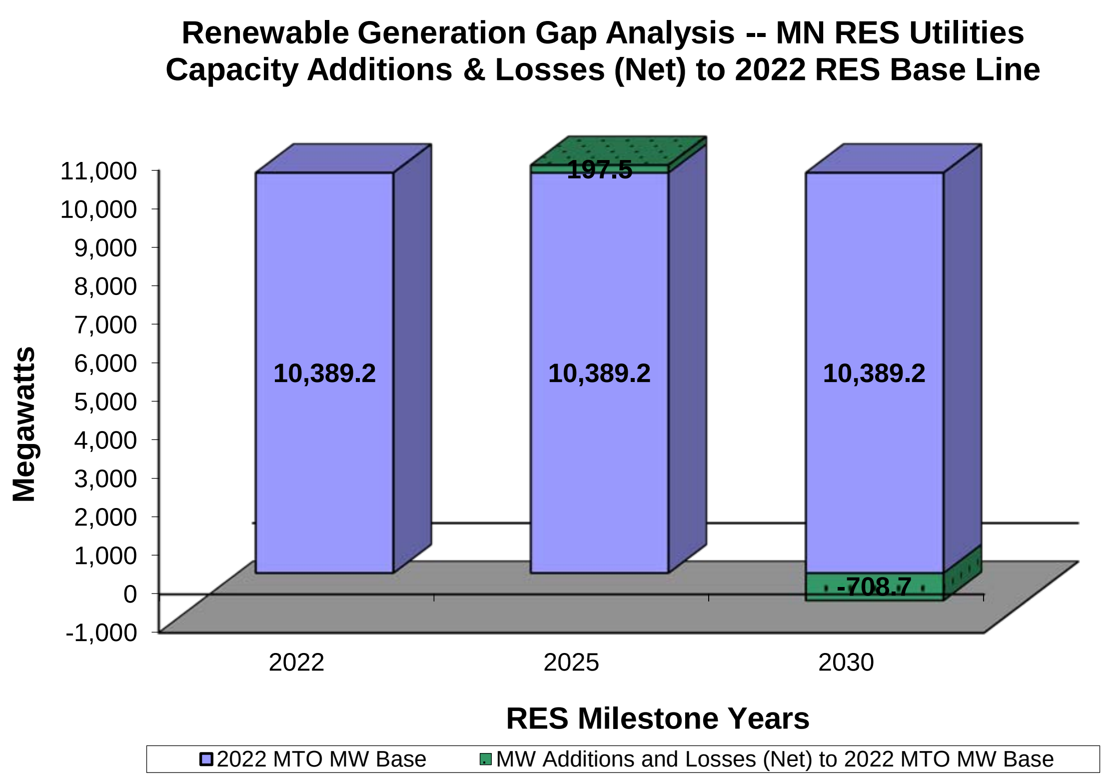
Needed MW Other Jurisdictions: Gross non-MN renewable capacity required to meet RES requirements or REO goals in states served by the reporting utility other than Minnesota.

Table 1 on the following page shows a more specific breakdown of each utility's Minnesota RES and non-Minnesota RES/REO needed capacity forecast.

Table 1. MN & Non-MN RES Forecast (MW)[1]						
Utility	**2022**		**2025**		**2030**	
	MN RES	Non-MN RES	MN RES	Non-MN RES	MN RES	Non-MN RES
Basin Electric [2]	112.5	658.2	171.0	789.1	194.9	1,110.5
CMMPA	18.0	-	26.0	-	35.0	-
Dairyland	54.0	88.0	82.0	89.0	102.0	90.0
GRE	571.0	135.0	713.0	23.0	713.0	736.0
Heartland	11.1	6.1	13.9	6.2	4.5	5.5
Minnkota	109.0	-	144.0	-	149.0	-
MMPA	109.0	-	139.5	-	144.5	-
MN Power	486.4	19.7	616.8	23.1	622.6	23.5
Otter Tail	155.0	67.0	222.0	69.0	222.0	69.0
SMMPA	180.0	-	224.0	-	100.0	-
WMMPA/MRES	114.4	23.2	145.0	23.4	158.6	23.9
Xcel Energy	2,553.0	387.9	2,764.8	431.5	2,928.8	475.0
TOTAL	4,473.3	1,385.06	5,262.0	1,454.4	5,374.9	2,533.4
Note:						
1. Capacity factor assumptions established by each utility						
2. These quantities include Basin Electric Power Cooperative, L&O Power Cooperative, and East River Electric Power Cooperative						

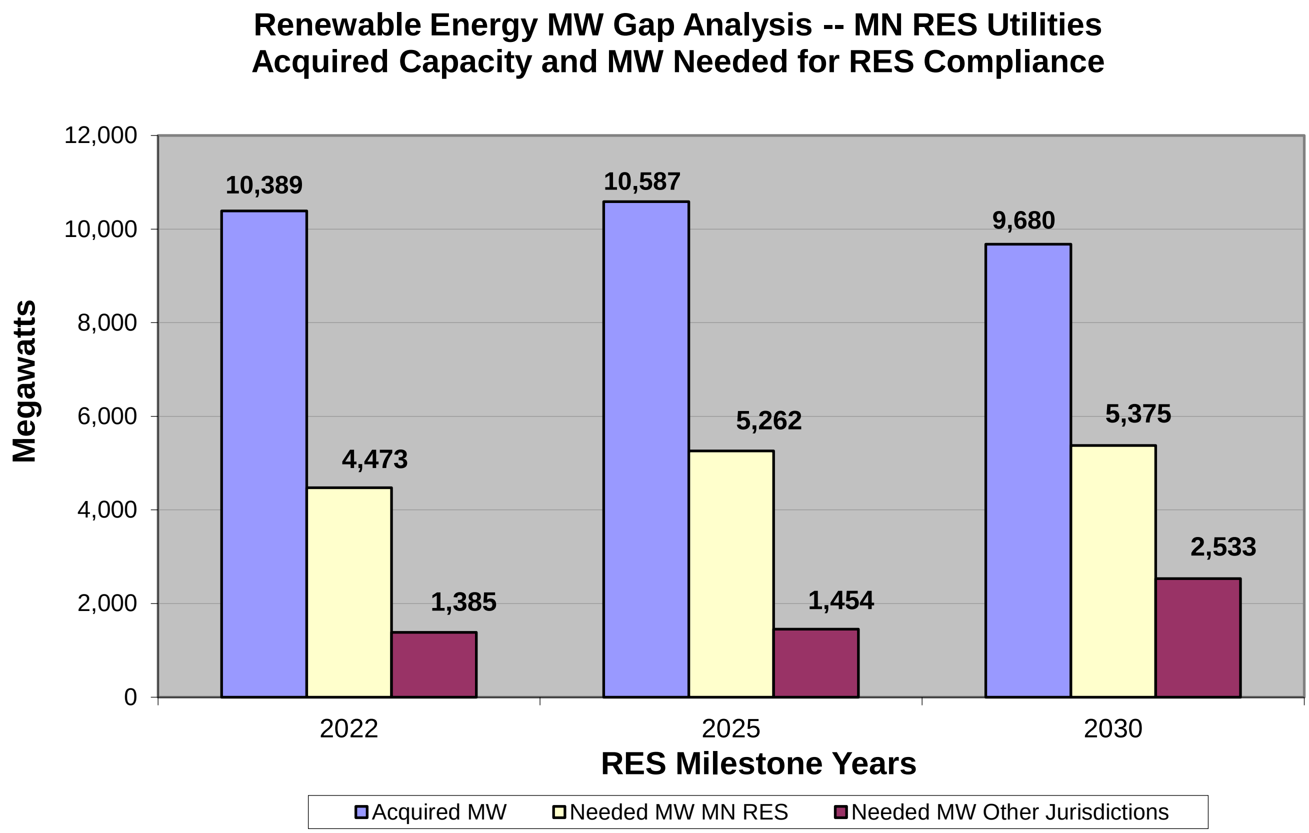
8.5.1 Capacity Acquisitions & Expirations

This chart presents a system-wide overview of additional renewable capacity that will be acquired by individual utilities beginning in 2022 and capacity that will expire between 2022 and 2030. Such losses are attributable primarily to the expiration of various power purchase agreements for renewable energy generation.



8.5.2 RES Capacity Acquired and Net RES/REO Need

This chart represents the total renewable capacity system-wide that will be acquired and lost between 2022 and 2030, as well as the total Minnesota RES and non-Minnesota RES/REO needs between 2022 and 2030.



As can be seen, the Minnesota RES utilities have sufficient capacity acquired to meet the Minnesota RES needs through 2030. When considering the RES needs, including other jurisdictions outside of Minnesota, the Minnesota RES utilities have enough capacity to meet RES needs beyond 2022. 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)[1]						
Utility	2022		2025		2030	
	RES Cap Acq.	MN RES Net	RES Cap Acq.	MN RES Net	RES Cap Acq.	MN RES Net
Basin Electric [2]	1,754.6	-	2,060.1	-	2,255.1	-
CMMPA	32.0	-	32.0	-	26.0	9.0
Dairyland	273.0	-	419.0	-	377.0	-
GRE	655.7	-	655.7	-	655.7	-
Heartland	41.0	-	41.0	-	41.0	-
Minnkota	458.1	-	458.1	-	458.1	-
MMPA	334.5	-	339.3	-	235.1	-
MN Power	1,044.4	-	1,044.4	-	1,044.4	-
Otter Tail	404.0	-	404.0	-	404.0	-
SMMPA	224.0	-	224.0	-	124.0	-
WMMPA/MRES	146.7	-	146.7	18.8	146.7	29.9
Xcel Energy	5,021.2	-	4,762.4	-	3,913.4	-
TOTAL[3]	10,389.2	-	10,586.7	18.8	9,680.5	38.9
Note:						
1. Capacity factor assumptions established by each utility						
2. These quantities include Basin Electric Power Cooperative, L&O Power Cooperative, and East River Electric Power Cooperative						
3. Some Utilities with less than sufficient capacity to meet the MN RES need may use renewable energy credits to fulfill their requirement.						

Note that the "Needed MW MN RES" bar in the bar chart in this section represents the total level of RES need in Minnesota. Conversely, the column in Table 2 that is labeled "MN RES Net" represents the additional RES capacity that is presently identified to meet RES need. The shortfall, or "gap," between MN RES need and the additional RES capacity identified points to the need for some utilities to seek additional renewable capacity and when they need to do so. 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. Minn. Laws 2013, Ch. 85, § 3, codified at Minn. Stat. § 216B.1691, subd. 2f (Solar Energy Standard or SES). That statute requires public utilities subject to the SES to report to the Commission on July 1, 2014, and each July thereafter, on progress in achieving the standard. In the 2013 Biennial Report, even though the first report was not due until 2014, Northern States Power Company provided a brief analysis of its anticipated needs for solar energy in future years.

The first solar energy reports required under the statute were filed in May or June 2014 and the Commission accepted these filings in an Order dated October 23, 2014. MPUC Docket No. E999/M-14-321. The second reports were filed in summer 2015 and were approved by the Commission on October 28, 2015. MPUC Docket No. E999/M-15-462. Readers are referred to those dockets for more information about the utilities' progress in meeting the upcoming SES.

Because this Chapter 8 of the Biennial Report discusses utilities' compliance with Minnesota Renewable Energy Standards, however, a brief summary regarding the status of compliance with the 2022 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.

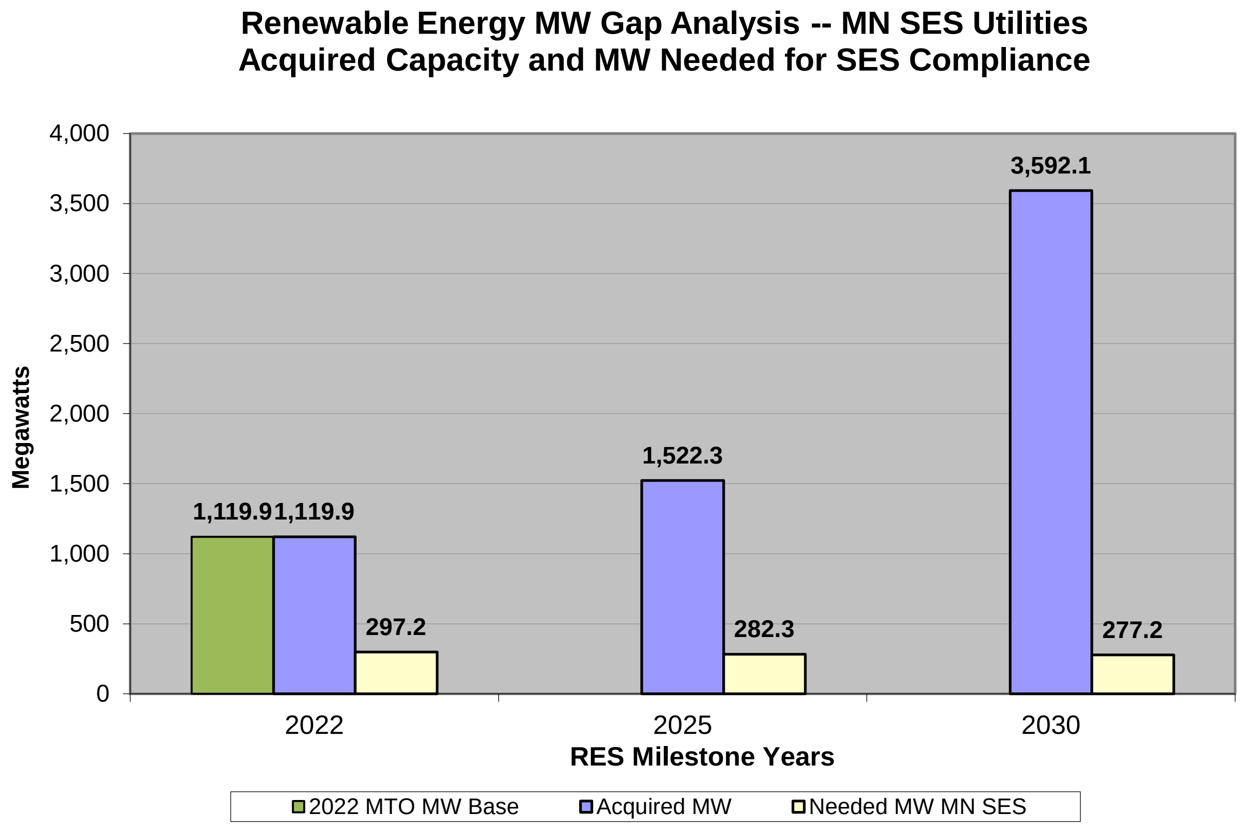


Table 3 shows a more specific breakdown of each utility's Minnesota SES and non-Minnesota SES needed capacity forecast.

Table 3. MN & Non-MN SES Forecast (MW)

Utility	2022		2025		2030	
	MN SES	Non-MN SES	MN SES	Non-MN SES	MN SES	Non-MN SES
MN Power	29.0	-	23.7	-	25.1	-
Otter Tail	30.0	-	30.0	-	30.0	-
Xcel Energy	238.2	-	228.6	-	222.1	-
TOTAL	297.2	-	282.3	-	277.2	-

Note: SES is the MN Solar Energy Standard which will require additional solar beyond the MN RES

This chart presents a system-wide overview of additional renewable capacity that will be acquired by individual utilities beginning in 2022 and capacity that will expire between 2022 and

2030. Such losses are attributable primarily to the expiration of various power purchase agreements for renewable energy generation.

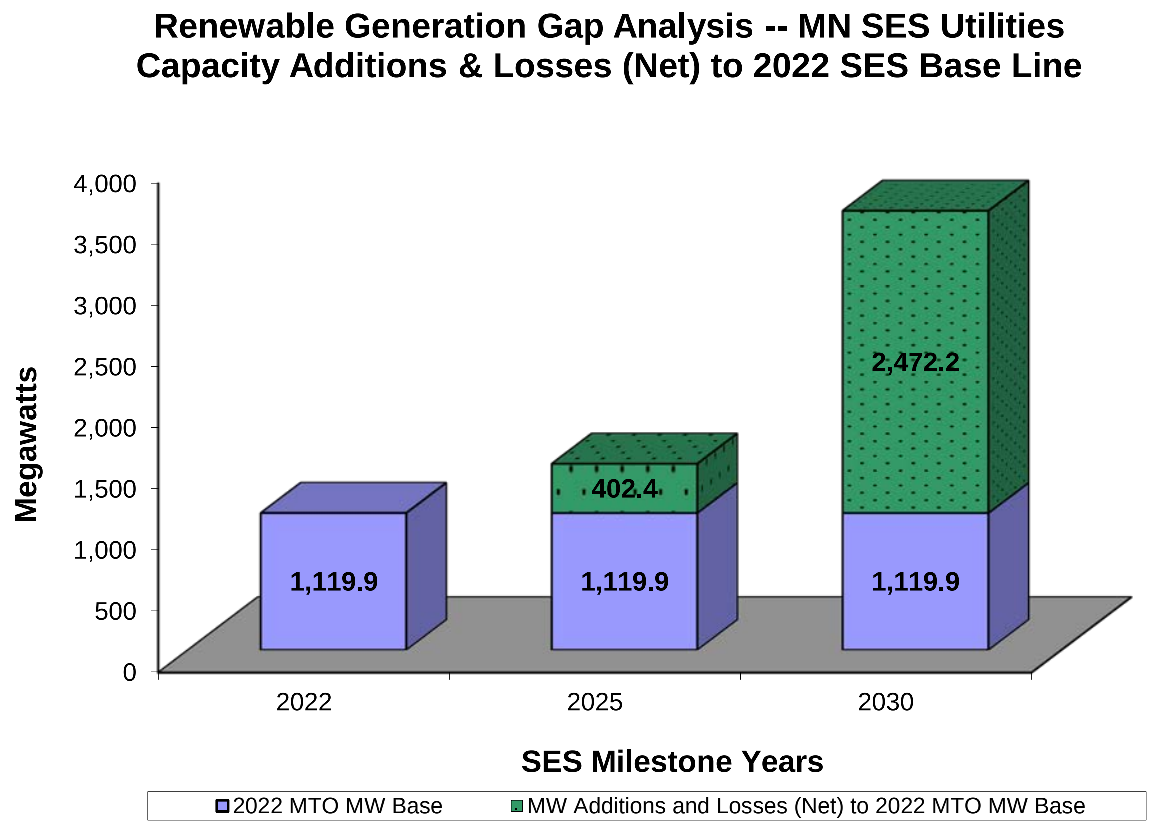


Table 4 below provides SES Utilities' planned level of solar capacity additions.

Table 4. SES Capacity Acquired & Net MN SES Capacity Need (MW)						
Utility	**2022**		**2025**		**2030**	
	SES Cap Acq.	MN SES Net	SES Cap Acq.	MN SES Net	SES Cap Acq.	MN SES Net
Dairyland	27.0	-	190.0	-	190.0	-
Heartland	0.1	-	0.1	-	0.1	-
MN Power	17.7	11.3	31.0	-	31.0	-
Otter Tail	-	30.0	49.9	-	49.9	-
SMMPA	5.0	-	5.0	-	5.0	-
WMMPA/MRES	1.0	-	1.0	-	1.0	-
Xcel Energy	1,069.1	-	1,245.3	-	3,315.1	-
TOTAL	1,119.9	41.3	1,522.3	-	3,592.1	-
Note: SES is the MN Solar Energy Standard which will require additional solar beyond the MN RES						

9.0 Clean Energy Goals

9.1 Introduction

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

> *The MTO shall 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. The MTO shall also 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.*

9.2 Clean Energy Commitments

CLEAN ENERGY GOALS	
American Transmission Company	
Stated Goal	**Comment**
N/A – transmission only entity.	N/A
Central Minnesota Municipal Power Agency	
Stated Goal	**Comment**
N/A	CMMPA currently provides approximately 43% of is energy needs from carbon free resources.
Dairyland Power Cooperative	
Stated Goal	**Comment**
Dairyland is transitioning to a more diverse and balanced generation portfolio. In 2020, Dairyland's Board of Directors approved a goal of a 50 percent reduction in carbon dioxide intensity by 2030 (from 2005 levels). Dairyland's Sustainable Generation Plan focuses on system reliability and affordability for Dairyland's members on the path to a low-carbon future.	Dairyland's focus is on reducing economy-wide carbon emissions. Our initiatives to foster beneficial electrification, combined with our progressive investments in renewable resources to support this evolution. For example, Dairyland's latest wind energy investment, the 52 MW Tatanka Ridge wind energy facility (South Dakota), began commercial operation in January 2021. Dairyland has a PPA for the entire 149 MW Badger State Solar facility, in development by Ranger Power in southern Wisconsin, which is expected to be in service in 2023. As we transition to a low-carbon future, safety and reliability remain at the forefront.

East River Electric Power Cooperative	
Stated Goal	**Comment**
N/A	From 2013 to the date of this filing, East River's power supplier, Basin Electric has entered into thirteen Power Purchase Agreements for a total of 1,514 MW of wind and solar power. Of that, 1,054 MW of wind projects were operating as of October 2021. A power purchase agreement for 142 MW was signed in 2019 for the Aurora Wind project which is scheduled to deliver energy starting January 1, 2023. Five solar Power Purchase Agreements totaling 318 MW were signed in late 2019 through June 2021. The Custer, West River, Wild Springs, and the Cabin Creek I and II Solar projects are scheduled to be operational between the of 2022 and 2024.
Great River Energy	
Stated Goal	**Comment**
Serve its all-requirements member-owner cooperatives with energy that is 50 percent renewable by 2030.	Great River Energy is committed to an escalating, annual renewable energy goal for its all-requirements members: 25% until 2030, and 50% thereafter. Great River Energy has executed 910 MW of new wind purchases that will supply 3.5 million MWh per year, which combined with existing renewable purchases, is projected to exceed these renewable goals. These new wind projects and expected to be operational in 2021-2024 period, provide low cost energy to our member-owners, and reduce Great River Energy's power supply carbon intensity.
ITC Midwest	
Stated Goal	**Comment**
N/A – transmission only entity.	N/A
L&O Power Cooperative	
Stated Goal	**Comment**
N/A	From 2013 to the date of this filing, L&O's power supplier, Basin Electric has entered into thirteen Power Purchase Agreements for a total of 1,514 MW of wind and solar power. Of that, 1,054 MW of wind projects were operating as of October 2021. A power purchase agreement for 142 MW was signed in 2019 for the Aurora Wind project which is scheduled to deliver energy starting January 1, 2023. Five solar Power Purchase Agreements totaling 318 MW were signed in late 2019 through June 2021. The Custer, West River, Wild Springs, and the Cabin Creek I and II Solar projects are scheduled to be operational between the of 2022 and 2024.

Minnesota Power	
Stated Goal	**Comment**
Deliver 70% renewable power supply by 2030, reduce carbon emissions 80% by 2035, with a vision for a 100% carbon-free energy future by 2050	At Minnesota Power, our EnergyForward strategy has reshaped the Company's power supply from an energy mix that was 95 percent coal in 2005 to one that is now delivering 50 percent renewable energy to customers. The 2021 Integrated Resource Plan is Minnesota Power's further vision for a sustainable path to a carbon-free energy future by 2050, and outlines bold next steps in the clean energy transition that are centered on a commitment to the climate, customers, and communities. Minnesota Power has committed to achieve an 80 percent reduction in carbon emissions by 2035 compared to 2005 levels, and outlined a goal of delivering 100 percent carbon-free energy by 2050. If approved, the 2021 Plan will facilitate a power supply that is 70 percent renewable in 2030, reduce carbon emissions by 80 percent by 2035 and result in a generation mix that is coal-free by 2035 while helping to ensure reliable and affordable power for Minnesota Power customers.
Minnesota Municipal Power Agency (MMPA)	
Stated Goal	**Comment**
100% renewable when economical.	MMPA has no coal in its portfolio. MMPA's renewable generation exceeded 22% of its load in 2020 and with its Walleye Wind PPA, renewable generation is projected to provide in excess of 40% of its load in 2023. MMPA regularly exceeds the MN state goals for carbon emissions reductions.
Minnkota Power Cooperative	
Stated Goal	**Comment**
Committed to finding opportunities to reduce carbon emissions while maintaining system reliability.	Minnkota's present electric generation capacity of 34% renewable and 8% hydroelectric resources provide a significant proportion of our energy portfolio that is non-CO2 emitting. Minnkota is also focused on development efforts for Project Tundra, which if constructed, would pioneer the effort to capture approximately 4 million metric tons of CO2 per year.

Missouri River Energy Services (including Hutchinson Utilities Commission, Willmar Municipal Utilities and Marshall Municipal Utilities)	
Stated Goal	**Comment**
N/A	Creating a cleaner energy future is a top priority for MRES and our members, and we are delivering affordable, reliable, and ever-increasing clean energy to our members and their customers. Over the past 17 years, MRES has added renewable and carbon-free resources to our power supply mix, including nuclear, wind and solar resources. We recently completed a new clean, renewable, and reliable hydroelectric power plant near Pella, Iowa. And, MRES launched the Bright Energy Choices program on January 1, 2020, which allows members and their customers to choose 100 percent renewable or net-zero carbon-free energy through the purchase of Renewable Energy Certificates to offset the portion of their power supply that comes from fossil fuels. MRES continues to evaluate opportunities for additional clean energy resources as part of the ongoing commitment of MRES to the environment, and to help MRES members meet state renewable energy objectives/standards. In our decisions, we've focused on environmental stewardship, along with reducing risk, and increasing reliability.
Northern States Power Company d/b/a Xcel Energy	
Stated Goal	**Comment**
Goal to reduce carbon emissions 80% by 2030, with a vision to provide 100% carbon-free electricity to customers by 2050.	Xcel Energy is the first major U.S. power company with an aspiration to provide 100% carbon-free electricity. We know that climate change is an urgent issue for many policy makers and investors and is a growing concern for our customers who look to Xcel Energy to act. It is a priority for us as well, and the reason we set an ambitious interim goal to reduce carbon emissions 80% by 2030 from the electricity we provide customers and aim to deliver 100% carbon-free electricity by 2050.
Otter Tail Power Company	
Stated Goal	**Comment**
N/A	We continue to be innovative as we create a stronger, smarter energy grid and cleaner energy future. We project that by 2023 our customers will receive approximately 35% of their energy from renewable resources. Carbon emissions from our owned generation resources are targeted to be 50% lower than 2005 levels by 2025 and 97% lower than 2005 levels by 2050—all while keeping residential rates among the lowest in the nation.

Rochester Public Utilities	
Stated Goal	**Comment**
100% renewable energy by 2030.	RPU will be redefining the energy mix used to supply RPU's customers by procuring new energy and capacity sources for 2030. As published in RPU's most recent resource plan, the RPU Board gave staff the direction to further pursue and investigate two options with 100% renewable energy. RPU is projected to procure the renewable energy from 50 MW of solar and 350 MW to 450 MW of wind, with capacity requirements being met from either 300 MW of battery storage or natural gas combustion turbines. The exact mix of wind, solar, and capacity resources will be determined at dates closer to 2030 based on available technologies and economics at that time. The mix of RPU ownership to PPAs will also be determined at a later date.
Southern Minnesota Municipal Power Agency	
Stated Goal	**Comment**
80% carbon free in 2030.	SMMPA plans to retire Sherco 3 and cease owning coal generation in 2030. In place, SMMPA will be investing in significant levels of wind and solar (approximately 187MW of each). This will allow SMMPA to reduce its carbon emissions by nearly 90% from 2005 levels, pushing our total generation fleet to 80% carbon free in 2030. To move beyond 80% new technology and solutions will need to be designed, tested, and implemented. SMMPA is committed to exploring these new technologies, like storage, but we believe they should be deployed when cost-effective. Moving forward there will be a continued need for regional transmission investment to meet these goals. SMMPA is committed to being an active participant, with other utilities, to analyze, plan and build the transmission infrastructure necessary to support this transition to a carbon free future.

9.3 Approved Minnesota Resource Plans and Other Relevant Statutory Goals

Company Name	Last Approved IRP	Transmission Need Identified
Great River Energy	ET-2/RP-17-286	There was no transmission need identified as part of this IRP.
Minnesota Power	E015/RP-15-690	In approving the 2015 IRP, the Commission ordered Minnesota Power to remedy the transmission system issues related to the closure of Taconite Harbor units. The Taconite Harbor units are located in the "North Shore Loop" which has been an area of particular interest for transmission planning for Minnesota Power and is discussed in greater detail, including a list of associated transmission projects, in Section 5.3.

Company Name	Last Approved IRP	Transmission Need Identified
Minnkota Power Cooperative	ET6/RP-19-416	Minnkota staff will continue to analyze the cost-effectiveness of integrating demand side management programs and renewable energy resources into the NMPA and Minnkota's Joint System power supply resource mix. There was no transmission need identified as part of this IRP.
MMPA	ET-6133/RP-18-524	There was no transmission need identified as part of this IRP.
Otter Tail Power Company	E017/RP-16-386	There was no transmission need identified as part of this IRP.
Xcel Energy	E002/RP-15-21	There was no transmission need identified as part of this IRP.

9.4 Ongoing Studies

MISO Long Range Transmission Planning (LRTP)

Long Range Transmission Planning (LRTP) is an essential element of planning the regional grid to be reliable and efficient over short and long-range planning horizons. The MISO MTO utilities participate in LRTP efforts at MISO. MISO is currently working to identify potential grid needs in support of the resource transformation underway and as contemplated under the MISO Futures. This extensive stakeholder process includes monthly workshops, periodic discussions at the Planning Advisory Committee, plus additional stakeholder meetings addressing cost allocation through the Regional Expansion Criteria and Benefits Working Group. Project recommendations resulting from this process will be then presented for Board of Director review and approval over several MTEP cycles as analyses proceed and recommendations are developed. Details of MISO's Long Range Transmission Planning study progress are summarized in Sections 3.1 and 3.2 of the MTEP21 Report.

MTEP20 Report (misoenergy.org)

Appendix A

Appendix A contains the pertinent pages from the 2020 NERC Long Term Reliability Assessment. The entire assessment along with previous assessments can be found here:

https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2020 Long-Term Reliability Assessment

December 2020

Contents

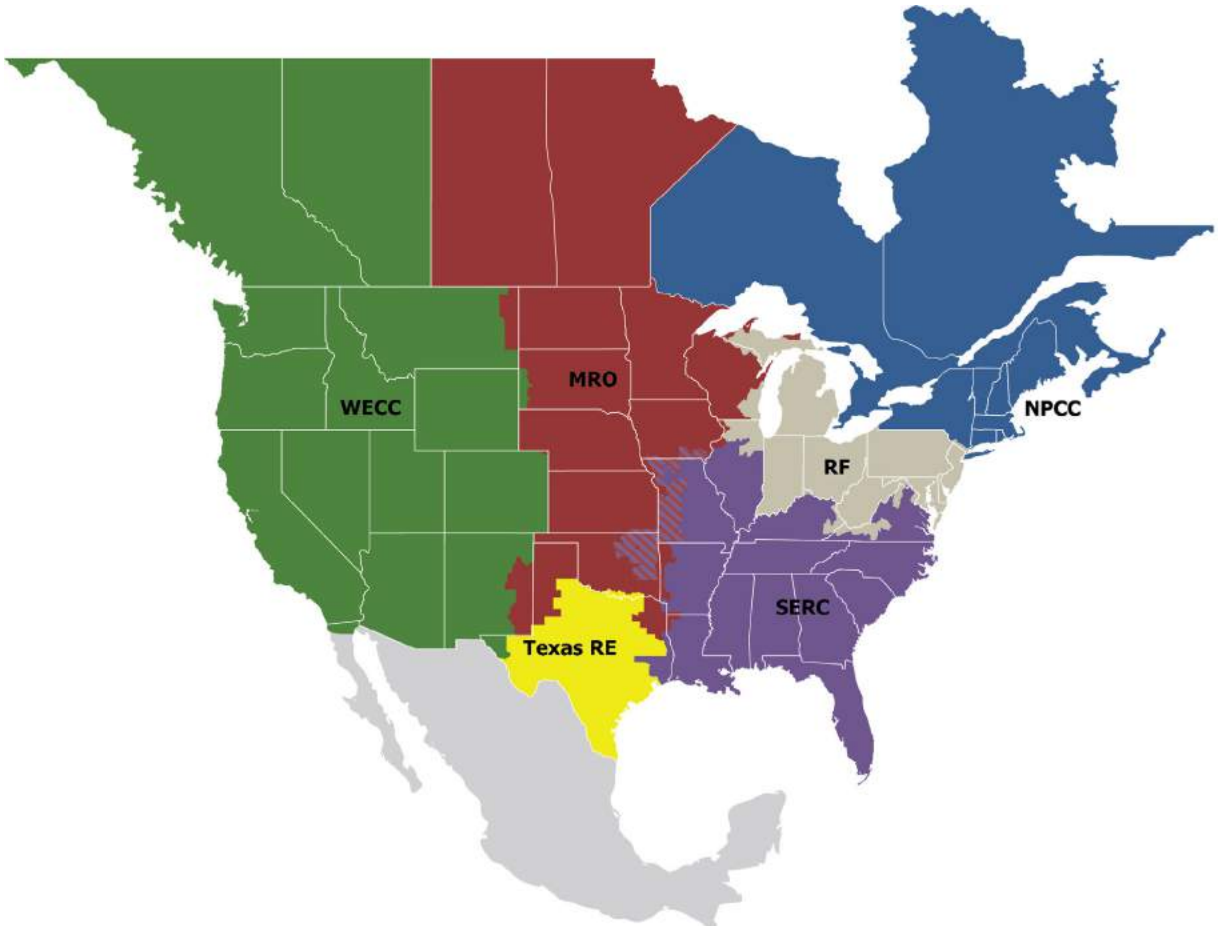
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners/Operators participate in another.



About This Assessment

NERC is a not-for-profit international regulatory authority whose mission is to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC, Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, serving more than 334 million people. Section 39.11(b) of the U.S. FERC's regulations provide that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information collected by NERC from the six REs on an assessment area basis to independently assess the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees (Board) subsequently accepted this assessment and endorsed the key findings.

The Long-Term Reliability Assessment (LTRA) is developed annually by NERC in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] also referred to as Section 215 of the Federal Power Act, that instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

Projections in this assessment are not predictions of what will happen, rather they are based on information supplied in July 2020 about known system changes with updates incorporated prior to publication. The assessment period for this *2020 LTRA* includes projections for years 2021–2030; however, some figures and tables examine data and information for the 2020 year. The assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Regional Assessments** section of this report. Reliability impacts related to physical and cyber security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multifaceted approach through the Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information sharing efforts with the electricity industry.

The LTRA data used for this assessment create a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data and information from each NERC RE are also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and portion of Baja California Norte, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators and to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

1 NERC Rules of Procedure - Section 803

2 Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each RE, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

3 Title 18, § 39.11 of the Code of Federal Regulations

4 BPS reliability, as defined in the **Demand Assumptions and Resource Categories** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

5 *ERO Reliability Assessment Process Document*, April 2018: https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ERO%20Reliability%20Assessment%20Process%20Document.pdf

In this *2020 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2020. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame has been and included where appropriate.
- Peak demand and Planning Reserve Margins (PRMs) are based on average weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each RE's self-assessment.
- Generating and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in-service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

In April 2020, NERC published its *Special Report Pandemic Preparedness and Operational Assessment: Spring 2020* to advise electricity stakeholders about elevated risk to electric reliability as a result of the global health crisis.[7] NERC continues to assess risks to the reliability and security of the BPS from the global health crisis and reports on industry actions and preparedness in this *LTRA*.

6 Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electricity use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

7 https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Pandemic_Preparedness_and_Op_Assessment_Spring_2020.pdf

Reading this Report

This report is compiled into two major parts:

ERO-Wide Reliability Assessment

- Evaluate industry preparations to meet projections and maintain reliability
- Identify trends in demand, supply, and reserve margins
- Identify emerging reliability issues
- Focus the industry, policy makers, and the general public's attention on BPS reliability issues
- Make recommendations based on an independent NERC reliability assessment process

Regional Reliability Assessment

- 10-year data dashboard
- Summary assessments for each assessment area
- Focus on specific issues identified through industry data and emerging issues
- Identify regional planning processes and methods used to ensure reliability

Executive Summary

The electricity sector is undergoing significant changes that are unprecedented in both transformational nature and rapid pace. Such extraordinary evolution presents new challenges and opportunities for reliability, resilience, and security. Advances in technology, customer preferences, policies, and market forces are altering the generation resource mix and challenging the conventional understanding of the reliability role of baseload power that was traditionally provided by large, centralized generating units. While efforts are underway to address these risks, the management of reliability, resilience, and security will require increased focus by all.

The addition of variable energy resources, primarily wind and solar, and the retirement of conventional generation is fundamentally changing how the BPS is planned and operated. Resource planners must consider greater uncertainty across the resource fleet as well as uncertainty in electricity demand that is increasingly being effected by demand-side resources. As a result, reserve margins and capacity-based estimates can give a false sense of comfort and need to be supplemented with energy adequacy assessments. Energy assessments are key to understanding the reliability needs of a future BPS and are presented in this report.

This *2020 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to meet electricity demand across North America over the next ten years. It also identifies area trends and emerging issues that affect the long-term reliability and security of the BPS.

A summary of the key findings is as follows:

Most areas are projecting to have adequate resource capacity to meet annual peak demands. However, measures of energy adequacy from the ERO's probabilistic assessment (ProbA), which accounts for all hours in selected study years of 2022 and 2024, are cause for concern in several areas. The following explains these concerns in detail:

- Nearly all parts of the Western Interconnection (WI), with the exception of Alberta, face heightened loss of load risk. The WECC-CAMX assessment area (primarily California), which was a subject of concern when the prior ProbA was conducted in 2018, could face periods where resources are insufficient for area energy needs, potentially resulting in up to 22 hours of load-loss in 2022. The recent experience during the wide-area heat wave in August 2020 provides evidence of the challenges faced in the WI to reliably serve the changing demand profile with the evolving resource mix. In the Northwestern United States and Rocky Mountain areas, probabilistic studies are beginning to show potential for loss of load as well. Like California, the risk is concentrated during the summer months and occurs in the late afternoon or early evening hours after demand has peaked but as solar resource output diminishes. Across the WI, an increased reliance on transfers from neighboring areas is an emerging risk, particularly during western-wide weather events.
- In Texas, a large amount of new wind and solar generation has recently been added, providing on-peak capacity to lift reserve margins for summer peak demand. However, there is increasing risk of tight operating reserves during other periods as thermal generation capacity has declined. Although recent probabilistic studies do not reveal unserved energy, ERCOT studies show reduced availability of operating reserves over a range of several hours around the time of peak demand in summer. They also show the amount of available reserves in nonpeak months, such as March and October, to be declining to become months that see the lowest peak-day reserves during the year.

- In the Midcontinent Independent System Operator (MISO) area, most risk remains concentrated during summer peak periods. Reserve margin projections of on-peak capacity are falling and are projected to be below Reference Margin Level targets beginning in 2025. However, the ProbA is identifying the emergence of risk during times when demand is not at peak levels (e.g., during spring or fall seasons when planned generator outages for maintenance could coincide with unseasonably high load). MISO's probabilistic study shows 27.3 MWh of unserved energy and the potential for 0.2 hours of load shed in 2022.

To ensure reliability during the transition to greater reliance on wind and solar resources, emerging resource and energy adequacy issues must be addressed. Planning for long-term resource adequacy is becoming increasingly complex with a resource mix that is more unpredictable and less energy-assured. Furthermore, tomorrow's grid operators will use a resource mix that is delivered by the long-term planning decisions of today and must be equipped with models, technology, and strategies to ensure they can do so effectively. These are challenges that need to be overcome but are not insurmountable. The emerging reliability challenges are characterized as follows:

- The capacity that variable resources contribute to serving peak electricity demand differs from thermal generation because output depends on the environment, climate, and local weather conditions. As a result, variable resources typically contribute less on-peak capacity than the rated nameplate value. To assess reserve margins, variable energy resources are "derated" to reflect estimated energy production during peak hours. In the operating time frame, grid operators face the risk of forecast inaccuracy from unanticipated weather or environment conditions. Forecast errors can affect reliability in two ways: there is the potential for energy production from wind and solar resources to be less than anticipated as well as the potential for demand forecasts to be inaccurate in areas with increasingly embedded solar PV generation from the distribution network. As a result, operators must increasingly balance uncertain loads with uncertain generation.
- As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability. This is placing more operating pressure on those (typically natural gas) resources and makes them the key to securing BPS reliability. Insufficient flexible resources was a contributing cause to the load shed event in California during the wide-area heat wave in August 2020.
- Natural-gas-fired generation provides 40% of the aggregate on-peak electricity supply capacity in North America, and 41 GW of that capacity is in late-stage planning for addition over the next 10 years. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages due to both insufficient natural gas infrastructure or alternate fuel delivery and/or disruption to natural gas or alternate fuel deliveries. These risks are most heightened in New England, the desert Southwest, and California, where there is increased reliance on natural gas generation and limited back-up fuel.

The latest industry projections included in this *2020 LTRA* provide further evidence of the rapid growth of inverter based resources on the BPS and distribution networks; these include most solar and wind as well as new battery or hybrid generation. These resources respond to disturbances and dynamic conditions based on programmed logic and inverter controls as opposed to physics and mechanical characteristics. Some inverter-based resource performance issues have been significant enough to result in grid disturbances that affect BPS reliability, such as the tripping of a number of BPS-connected solar PV generation units that occurred during the 2016 Blue Cut Fire, the 2017 Canyon 2 Fire, and 2020 San Fernando Disturbance in California. Several findings and recommendations in this report are aimed at promoting the reliable integration of these resources by addressing modeling and coordination needs. In addition to ensuring planning studies and operating models accurately account for new resource types, heightened cyber security awareness and risk-reduction engineering should be pursued to reduce the attack surface and mitigate reliability and security concerns.

To address these emerging risks and prevent similar issues from happening in other areas, NERC has developed the following recommendations for the industry and policy makers:

- Regulators and policymakers in risk areas should coordinate with electric industry planning and operating entities to develop policies that prioritize reliability, such as promoting the development and use of additional flexible resources, energy-assured generation, and resource diversity.
- Regulators and policy makers should consider revising their resource adequacy requirements to consider new risks that emerge during non-peak hours, limitations from neighboring systems during system-wide events, and the reduced resource diversity and/or increased reliance on a single fuel source or delivery mode.

- Industry should identify and commit flexible resources to meet increasing ramping and load-following requirements that result from increased variable energy resources and not solely to meet peak load capacity requirements.

Furthermore, to ensure the ERO and industry are developing solutions in advance of these emerging risks, NERC has developed the following recommendations for the ERO and the industry:

- The ERO should enhance the reliability assessment process by evaluating energy adequacy risks in seasonal reliability assessments to help inform stakeholders of reliability needs and potential solutions in the short-term.
- To better identify fuel supply risks during planning, the ERO should collaborate with industry to identify design-basis fuel supply scenarios of normal and extreme events for use by BPS and resource planners. Design-basis criteria should then be considered in planning-related Reliability Standards, such as TPL-001.
- The ERO should increase communication and outreach with state and provincial policymakers on resource adequacy risks and challenges to ensure the risks being presenting in all ERO reliability assessments are well known and understood.
- The ERO should advance the efforts to modify existing Reliability Standards to account for inverter-based resource performance and characteristics. In particular, protection and control, data sharing, and modeling-related standards all need to consider the new risks imposed by inverter-based resources connected to both distribution systems and the BPS.
- The industry should verify that inverter-based resource models used for steady state and dynamic power systems analysis agree with the as-built, plant-specific settings, controls, and behaviors of the facility. Generator Owners/Operators should engage with equipment manufacturers and coordinate with their Transmission Planner/Planning Coordinators to understand the modeling challenges and proactively address deficiencies identified in several ERO event reports and power system modeling assessments. Industry has achieved success by using ERO guidelines to support system-specific interconnection and control design requirements.
- REs and model-building designees should enhance their reviews of steady-state power flow and dynamics base case models for model deficiencies associated with existing and newly-interconnecting BPS-connected inverter-based resources.
- The ERO and industry should address aggregate DER data needs for transmission planning and operational studies and develop guidance for BPS planning with increasing DERs.

NERC Reliability Standards

BPS reliability encompasses two priorities that must be addressed simultaneously. The first is operating reliability, supporting the operational needs of the grid to maintain stability and withstand sudden disturbances. The second is adequacy, the ability of the electricity system to produce and deliver energy to end-use customers at all times.

NERC Reliability Standards are the planning and operating rules that electric utilities follow to support and maintain a reliable electricity system. These standards are developed by the industry by using a balanced, open, fair and inclusive process accredited by the American National Standards Institute (ANSI). While NERC does not have authority to set Reliability Standards for resource adequacy (e.g., reserve margin criteria) or to order the construction of resources or transmission,* NERC independently evaluates where reliability issues may arise as well as identifies emerging risks through reliability assessment. This information, along with NERC recommendations, is then available to policy makers and federal, state, and provincial regulators to support decision making within the electric sector.

* NERC is prohibited by Section 215 of the 2005 Federal Power Act from adopting standards that require adequate resources be in place or order construction of generation or transmission. Resource adequacy and the contruction of bulk power facilities is fully within state and/or provincial jurisdiction and authority.

Key Findings

Resource Adequacy—PRMs: Projected reserves fall below the Reference Margin Level (RML) in NPCC-Ontario beginning in 2022 and in MISO in 2025. There is sufficient electricity resource capacity in all other areas. Details include the following:

- Throughout this assessment period and particularly in the first five years, there is heightened uncertainty in demand projections stemming from the progression of the coronavirus (COVID-19) pandemic and the response of governments, society, and the electricity industry. Reserve margins are sensitive to demand forecast uncertainty. The uncertainty in demand forecast projections could exacerbate planning reserve shortfalls in areas that are below or near RMLs.
- Ontario's Anticipated Reserve Margins (ARMs) fall below the RML during the first five years of the assessment period, driven largely by the nuclear refurbishments, demand forecast uncertainty, and expiration of a number of generation contracts. The Independent Electric System Operator (IESO), the system operator for the area, expects to acquire the required electricity resources through capacity auctions or other acquisition tools.
- The MISO area will have adequate, but tighter, reserve margins for 2021. MISO and participating stakeholder action is needed to ensure future resource adequacy by achieving certainty of prospective resources beginning in 2025 when their ARM falls below the RML.
- NPCC Maritimes is at or near RML throughout the assessment period. Utilities can address near-term shortfalls through electricity import contracts.
- Sufficient resources are planned to be available throughout the assessment period in all other areas.

Assessment of Resource Adequacy across All Hours (Energy Adequacy): While the ERO's biennial ProbA indicates that resource adequacy meets or exceeds resource adequacy benchmarks, there is increasing risk of resource shortfalls during nonpeak hours in parts of the WI, MISO, and Texas. Details include the following:

- This *2020 LTRA* includes the ERO's biennial ProbA that provides insights into the ability of the future resource mix to meet the projected demand at all times. While the deterministic PRM assessment findings above indicated sufficient resources are planned to be available throughout this assessment period for most areas, except MISO and Ontario, the findings provide evidence that the deterministic PRM metric, especially in areas with higher penetrations of resources with energy limitations and uncertainty (i.e., wind, solar, natural gas, hydro), may not be a completely accurate way to measure an area's resource adequacy during all hours of the year.
- WECC's 2020 ProbA continues to note several hours that pose a potential risk for loss of load for almost all WI areas over studied years. The CAMX area was the only concern in the 2018 ProbA, but now all areas except Alberta (AESO) are seeing hours of potential loss of load. Exacerbated by the recent western area heat wave event that saw load shed over the summer, all areas are reviewing the level of resource adequacy considering forecast variability.
- The traditional methods of assessing resource adequacy at peak load times may not accurately or fully reflect the ability of the new resource mix to supply energy and reserves for all hours. Energy limitations can exist, requiring probabilistic analysis methods to identify risks to reliability that result from shortfalls in the conversion of capacity to energy (energy adequacy). The new resource mix includes natural-gas-fired generation; unprecedented proportions of nonsynchronous resources, including renewables and battery storage; DR; smart- and micro-grids; and other emerging technologies. Collectively, the new resources are more susceptible to energy sufficiency uncertainty.

Resource Mix Changes: Variable energy resources continue to grow, and thermal resource capacity declines in most areas throughout this assessment period; as a result, increased attention is required to the planning and operating of a more complex resource mix. Details include the following:

- In many areas, variable energy resources are increasingly important to meet electricity demand. Texas and California rely on variable energy resources to meet peak hour demand; this can lead to operational risk during unanticipated conditions that reduce the resource output. Other areas are trending toward increasing reliance on variable energy resources over this assessment period. Sufficient flexible resources are needed in areas with high levels of variable generation to avoid shortfalls when variable resource output is insufficient to meet demand.
- Inverter based resources, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. Maintaining a reliable system as the penetration of inverter-based resources increases requires planners and operators to be cognizant of potential disturbance-related performance issues.
- Recently the ERO conducted a review of base case models used in transmission planning within the WI and identified modeling issues with wind and solar photo voltaic (PV) generators. Invalid or inaccurate generator models can contribute to steady-state or dynamic study result errors, affecting the reliability of the interconnected transmission system.[8]
- Additional fossil-fueled generator retirements could occur as a result of economic uncertainty and environmental goals.

DER Growth: DER growth continues, prompting the ERO, planners, and operators in areas where penetrations have reached or are approaching impactful levels to take actions to ensure planning processes and operating measures are in place to ensure reliability. Details include the following:

- Texas, Ontario, and areas in the Northeast United States are approaching impactful DER levels presently seen in the WI, leading to the implementation of more sophisticated planning and operating measures. Other areas are closely monitoring DER growth and incorporating DER projections in long-term planning.

8 See NERC-WECC Joint Report—*WECC Base Case Review: Inverter-Based Resources*, August, 2020.

Pandemic Impacts: The ongoing pandemic is not presenting specific threats or degradation to the reliable operation of the BPS for this assessment period. However, it is producing increased uncertainty in future electricity demand projections and presents cyber security and operating risks. Details include the following:

- Most assessment areas did not adjust long-term forecasts for pandemic impacts in this *2020 LTRA* because the effects on peak demand levels were unclear and duration of the pandemic is unpredictable. Summer operating experience in many areas showed increased residential demand that altered hourly load profiles and made up for decreased commercial/industrial load to match prepandemic peak demand levels.
- Reduced industrial load can affect the availability of DR programs that rely on curtailment of industrial customers during periods of high demand.
- Personnel protections for operators and field crews, mitigating heightened cyber risks, and systems operations planning will be persistent areas for risk management throughout the pandemic.

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

Adequacy: The ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components

Operating Reliability: The ability of the electricity system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfalls, system operators can and should take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its load serving entities (LSEs) via contract or agreement for curtailment[9]
- Voltage reductions (sometimes referred to as “brownouts” because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term “rotating” is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as “cascading blackouts,” the uncontrolled successive loss of system elements triggered by an incident at any location.

NERC Reliability Standards are intended to provide guidance so that an adequate level of reliability (ALR) can occur,[10] which is defined by the following characteristics:

Adequate Level of Reliability: It is the state that the design, planning, and operation of the Bulk Electric System (BES) will achieve when the following reliability performance objectives are met:

- The BES does not experience instability, uncontrolled separation, cascading,[11] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[12]
- BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
- BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
- Adverse reliability impacts on the BES following low probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.
- Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

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9 Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in reliability standards: https://www.nerc.com/files/glossary_of_terms.pdf

10 https://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_Technical_Report_clean.pdf

11 NERC’s Glossary of Terms defines Cascading: “Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.”

12 NERC’s Glossary of Terms defines Disturbance: “1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.”

Detailed Key Findings

Key Finding 1: Projected reserves fall below the RML in NPCC-Ontario beginning in 2022 and in MISO in 2025. Projected electricity resources are sufficient in all other areas.

Key Points

- Throughout this assessment period and particularly in the first five years, there is heightened uncertainty in demand projections stemming from the progression of the COVID-19 pandemic and the response of governments, society, and the electricity industry. Reserve margins are sensitive to demand forecast uncertainty. The uncertainty in demand forecast projections could exacerbate planning reserve shortfalls in areas that are below or near RMLs.
- Ontario's ARMs fall below the RML during the first five years of this assessment period, driven largely by the nuclear refurbishments, demand forecast uncertainty, and expiration of a number of generation contracts. IESO, the system operator for the area, expects to acquire the required capacity through capacity auctions or other acquisition tools.
- The MISO area will have adequate but tighter reserve margins for 2021. MISO and participating stakeholder action is needed to ensure future resource adequacy by achieving certainty of prospective resources beginning in 2025 when their ARM falls below the RML.
- NPCC-Maritimes is at or near the RML throughout this assessment period. Utilities can address near-term shortfalls through electricity import contracts.
- Sufficient resources are planned to be available throughout this assessment period in all other areas.

For the majority of the BPS, PRMs appear sufficient to maintain reliability during the long-term, 10-year horizon. However, there are challenges facing the electricity industry that may shift current industry projections, constrain resources from delivering expected energy and capacity, or otherwise and cause NERC's assessment to change (for example, see **Variable Energy Resource** findings, conventional **Generation Retirements**, and **Maintaining Fuel Assurance**). Where markets exist, signals for new capacity must be effective for planning purposes and reflect the lead times necessary to construct new generation, associated transmission, and natural gas infrastructure if needed. Although generating plant construction lead times have been significantly reduced, environmental permitting for energy infrastructure and transmission planning and approval still require significant lead times.[13]

How NERC Evaluates Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. NERC assesses resource adequacy by evaluating each assessment area's PRM relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis.

On the basis of the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

Adequate: ARM is greater than RML.

Marginal: ARM is lower than RML and PRM is higher than RML.

Inadequate: ARMs and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

13 Capacity supply and PRM projections in this assessment do not necessarily take into account all generator retirements that may occur over the next 10 years or account for all replacement resources explicitly linked with potential retiring resources. While some generation plants have already announced and planned for retirement, there are still many economically vulnerable generation resources that have not determined and/or announced their plans for retirement.

As shown in **Figure 1**, the ARM in all assessment areas is above the RML in 2025 with the exception of MISO and NPCC-Ontario.

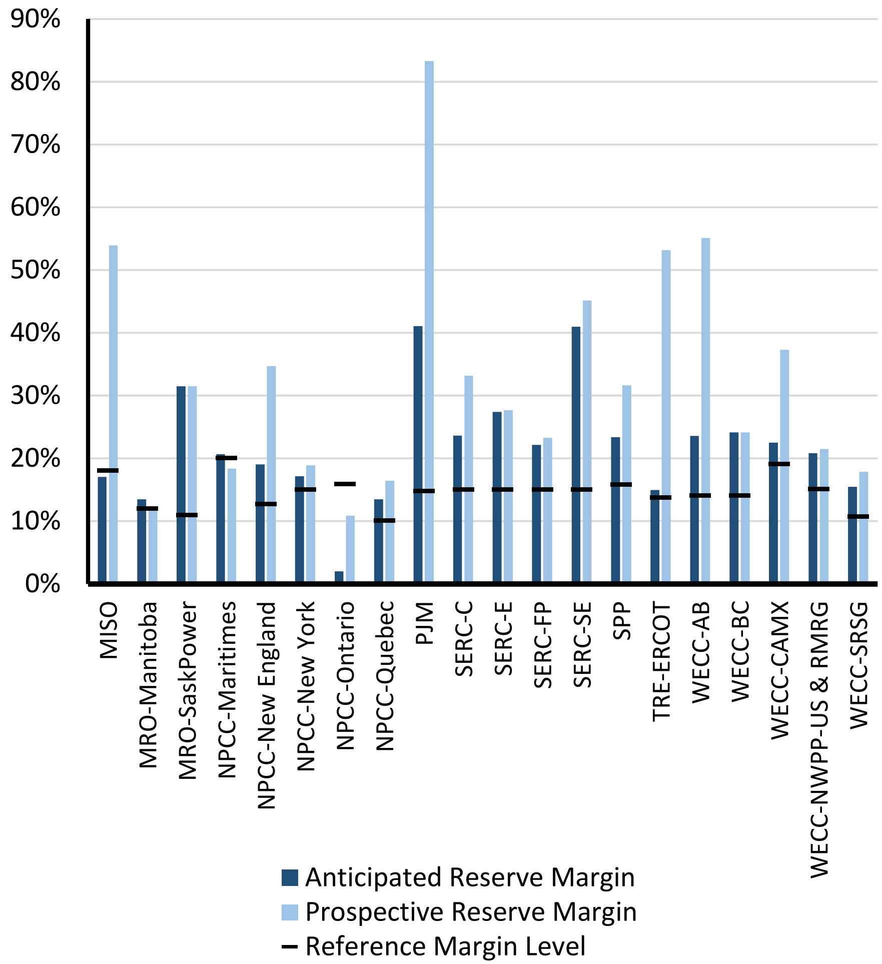


Figure 1: Anticipated and Prospective Reserve Margins for 2025 Peak Season by Assessment Area

The arrival of COVID-19 in North America in 2020 has introduced uncertainty into future electricity demand forecasts and PRM projections. Prior to Summer 2020, when government stay-at-home orders and societal response were at their highest, some areas reported as much as 15% drop in peak demand. However, these observed demand impacts varied across North America and in some areas were negligible. Electricity demand forecasts used in resource adequacy planning account for long-term trends in electricity usage based on inputs, such as weather patterns, economic growth projections, and EE initiatives and trends. Pandemic impacts can affect the accuracy of demand projections in the near term and have the potential to either exacerbate or alleviate planning reserve shortfalls in areas that are below or near RMLs. Over time, demand forecast models can be expected to better account for economic and customer behavior changes that are occurring as a result of the pandemic.

NERC PRM Categories

Anticipated Resources:

- **Existing-Certain Generating Capacity**: operable capacity expected to be available to serve load during the peak hour with firm transmission
- **Tier 1 Capacity Additions:** capacity that is either under construction or has received approved planning requirements
- **Firm Capacity Transfers (Imports minus Exports):** transfers with firm contracts
- **Confirmed Retirements:** capacity with formalized and approved plans to retire

Prospective Resources:

- **Anticipated Resources:** as described above
- **Existing-other Capacity:** operable capacity that could be available to serve load during the peak hour but lacks firm transmission and could be unavailable during the peak or a number of reasons
- **Tier 2 Capacity Additions:** capacity that has been requested but approval for planning requirements not received
- **Expected (nonfirm) Capacity Transfers (imports minus exports):** transfers without firm contracts but a high probability of future implementation
- **Unconfirmed Retirements:** expected to retire based on the result of an assessment area generator survey or analysis (capacity aggregated by fuel type)

The results of NERC's risk determination for all assessment areas is shown in **Table 1**. NPCC-Ontario is identified as "Inadequate," MISO and Maritimes as "Marginal," and all other areas identified as "Adequate" through 2025.[14] See the **NERC Assessment Areas** section for demand and supply trends through 2030.

Table 1: NERC's Risk Determination of All Assessment Areas 5-Year Projected Reserve Margins

Assessment Area	2025 Peak Anticipated Reserve Margin	2025 Reference Margin Level	Expected Capacity Surplus or Shortfall (MW)	Assessment Results Though 2025
MISO	17.0%	18.0%	-1,161	Marginal
MRO-Manitoba	13.5%	12.0%	70	Adequate
MRO-SaskPower	31.5%	11.0%	742	Adequate
NPCC-Maritimes	20.7%	20.0%	36	Marginal (2022, 2023)
NPCC-New England	19.0%	12.7%	1,522	Adequate
NPCC-New York	17.1%	15.0%	661	Adequate
NPCC-Ontario	2.0%	15.9%	-3,236	Inadequate
NPCC-Quebec	13.5%	10.1%	1,264	Adequate
PJM	41.1%	14.8%	37,856	Adequate
SERC-C	23.6%	15.0%	3,469	Adequate
SERC-E	27.4%	15.0%	5,667	Adequate
SERC-FP	22.2%	15.0%	3,439	Adequate
SERC-SE	40.9%	15.0%	11,907	Adequate
SPP	23.4%	15.8%	4,124	Adequate
TRE-ERCOT	14.3%	13.8%	412	Adequate
WECC-AB	23.6%	14.1%	1,211	Adequate
WECC-BC	24.1%	14.1%	1,163	Adequate
WECC-CAMX	22.5%	19.1%	1,852	Adequate
WECC-NWPP-US and RMRG	20.8%	15.0%	3,764	Adequate
WECC-SRSG	15.5%	10.7%	1,315	Adequate

14 *Note about NPCC-NY: While the total resources calculation is above the LTRA reference margin of 15%, there is no PRM criteria in New York. *The 2020 NYISO Reliability Needs Assessment* (RNA) preliminary results and other assessments identified potential reliability needs (*i.e.*, transmission security issues starting 2023, and resource adequacy issues starting 2027). The resource adequacy LOLE criterion used to identify reliability violations is based on a probabilistic assessment in accordance with New York State Reliability Council Reliability Rules. The RNA will be completed in 2020 and will be followed in 2021 by the Comprehensive System Plan (CRP), under which solutions for the final reliability needs will be identified.

PRMs in NPCC-Ontario

The projected five-year ahead ARMs are below the RML over the five-year period. (**Figure 2**). The ARMs fall below the RML for the first five years of this assessment period and are driven by the nuclear refurbishment program, demand forecast uncertainty, and the assumption that certain generation resources are not available once their generation contracts have expired. Planned nuclear outages are a significant contributor of the reserve margin. A period of elevated planned nuclear outages in 2021 and 2022 could lead to adequacy risks throughout the summer season. More planned reserves are needed when nuclear resources are off-line due to the high availability and capacity factor of nuclear generators compared to the other resources that may replace them.

The IESO has stated their intention to address resource adequacy needs in short-, mid-, and long-term time frames that will facilitate competition and provide business planning certainty. The IESO will work with stakeholders through a resource adequacy engagement to further develop a long-term competitive strategy to meet Ontario's resource adequacy needs reliably and cost-effectively while recognizing the unique needs of different resources. Resources, including DR, eligible to participate in a capacity auction are not included in the PRM until they have received a firm commitment in an auction. Consequently, prospective resources tend to be conservative. The IESO's capacity auction for the Summer 2021 commitment period will replace the existing DR auction and enable off-contract generators, system-backed capacity imports, and storage resources to participate and compete alongside DR. The IESO also expects to address adequacy risks from elevated planned outages through outage management.

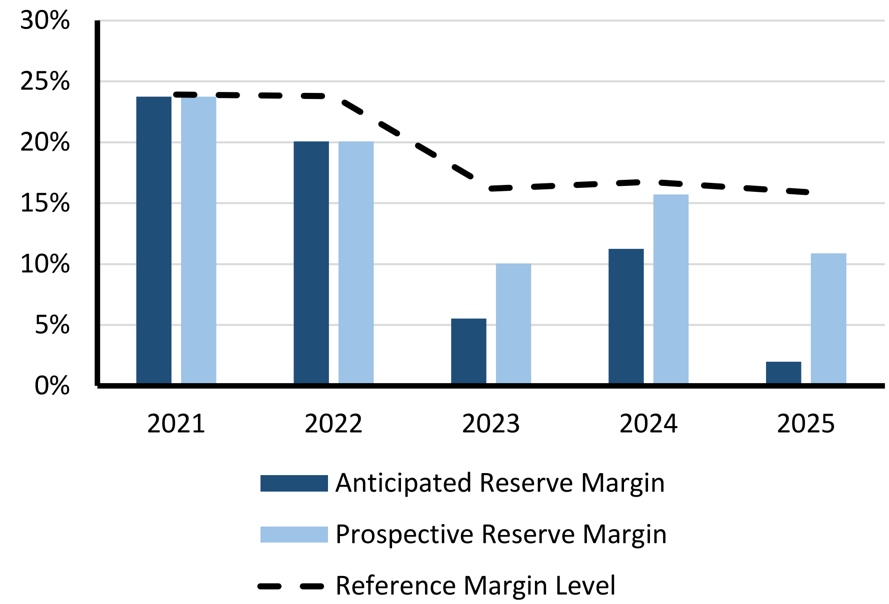


Figure 2: NPCC-Ontario 5-year Projected Reserves (ARM and PRM)

PRMs in MRO-MISO

The projected five-year ahead ARMs indicate a regional surplus through 2023 before falling near or below the RML in 2024 and beyond (**Figure 3**). The *2019 LTRA* also showed that MISO would fall below the RML beginning in 2025. The RML in MISO has increased from 16.8% to 18% as the resource mix and load shape has changed. Consequently MISO continues to have potential shortfall in the latter half of the assessment period even though anticipated resources have increased.

MISO anticipates that each zone within the MISO will have sufficient resources to meet their local requirements for serving load within their boundaries. However, the zone for lower Michigan (Zone 7) is close to the local requirement for the near term. New unit additions and possible transmission builds may help to address local needs in the future.

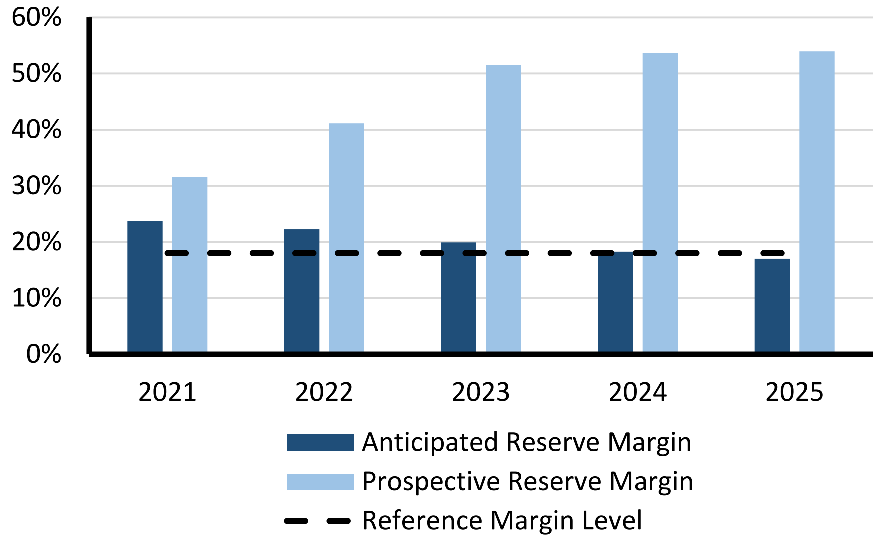


Figure 3: MISO Five-Year Projected Reserves (ARM and PRM)

Over the past several years, the near-term ARMs have been consistently above the current RML of 18% as shown in **Figure 3**. Note: Projections are Year 1 projections from prior LTRAs (see **Figure 4**). For example, the 2011 value is based on the *2010 LTRA's* 2011 projection.

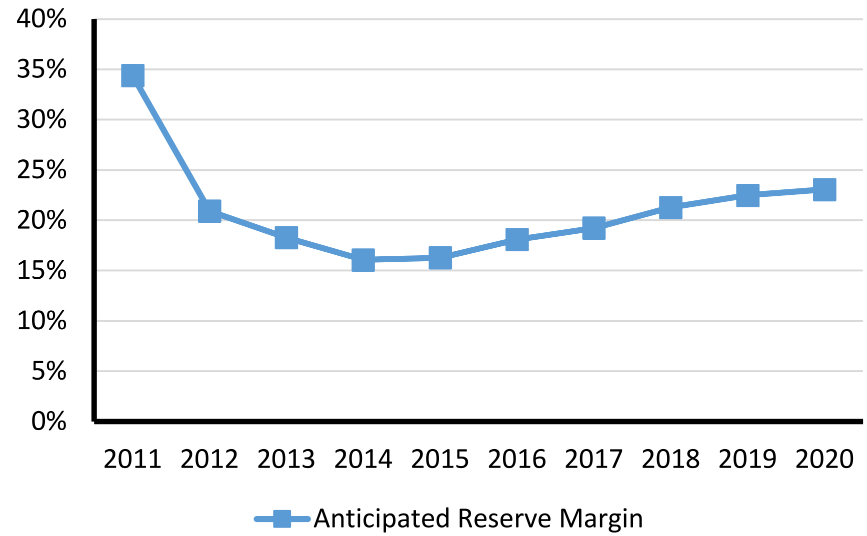


Figure 4: MISO Historical Projected Reserves Margins

PRMs in NPCC-Maritimes

The ARMs in NPCC-Maritimes fall slightly below the RML during the winter periods, beginning in the winter of 2022–2023 (**Figure 5**). An increase in the winter peak hour demand forecast, reduction in the achievable EE and conservation forecast, and planned retirement of two units at an oil-fired thermal generating station of 40 MW in year 2022 in Prince Edward Island collectively contribute to the reserve margins falling below the reference level. Contributions from Tier 2 resources help in reducing the gap but still fail to meet the 20% RML.

A long-term firm energy contract is in place with a neighboring jurisdiction to buy a minimum of 2 TWh/year until 2030 and then 2.5 TWh/year until 2040. This, along with the ability to purchase energy in day ahead and real time markets, will assist in meeting the RML for the first five years.

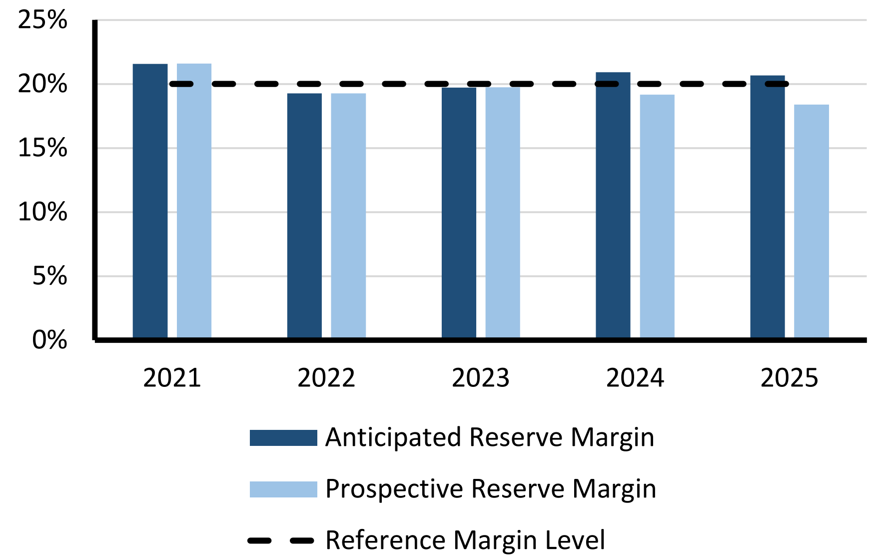


Figure 5: NPCC-Maritimes Five-Year Projected Reserves (ARM and PRM)

PRMs in TRE-ERCOT

NERC's *2019 LTRA* and previous reports have identified reliability concerns with PRMs in Texas. Beginning in 2010, a downward trend in ERCOT's reserve margins led to scarce resources during the peak and less operating flexibility (**Figure 6**). To some extent, this is an expected outcome of managing resource adequacy through an energy-only market construct.[15] However, over the past year, generation resources have been added and more are in development for connection over this assessment period, helping to reduce concerns of resource shortfalls.

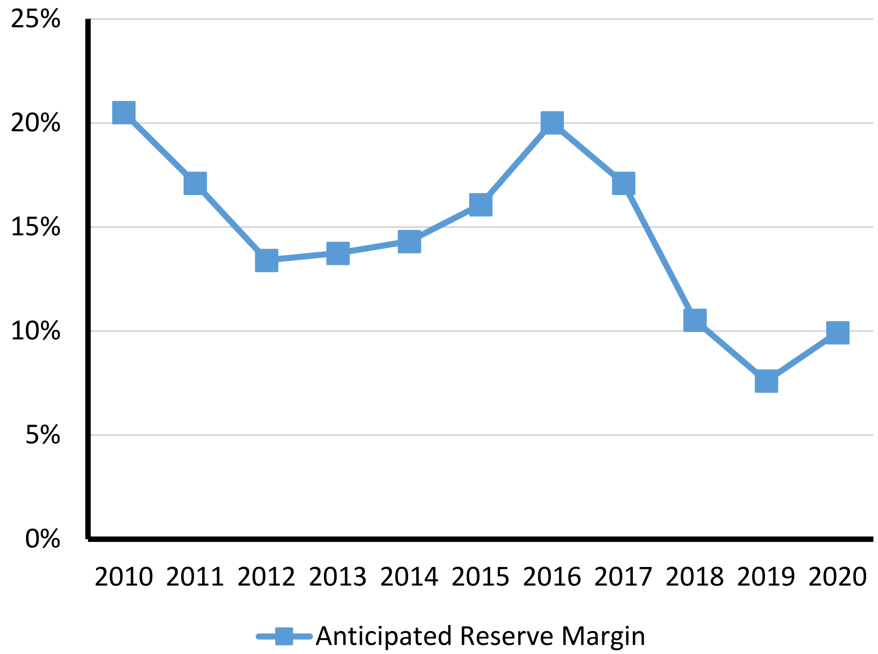


Figure 6: TRE-ERCOT Historical Projected Reserve Margins

15 Energy-only markets pay resources only when they provide energy on a day-to-day basis. Conversely, capacity markets aim to ensure resource adequacy by paying resources to commit capacity for delivery years into the future also.

The projected five-year ahead ARMs stays above the RML of 13.75% over the five-year period (**Figure 7**). This improvement since the *2019 LTRA* results from Tier 1 resources expected to come into service over the five-year period, totaling almost 14,000 MW. Nearly 9,500 MW of these additions are solar generation.

In Texas, regulators ensure reliability through a mechanism called scarcity pricing, allowing real-time electricity prices to reach as high as $9,000/megawatt hour (MWh) in response to capacity shortage conditions. Instead of guaranteeing revenue to capacity resources through a capacity market, the opportunity of high prices is intended to incentivize generators to build new plants and keep them ready to operate. Recent performance over the last several years has proven the ERCOT market and system operations to be successful with no load shedding events despite setting system-wide peak demand records.

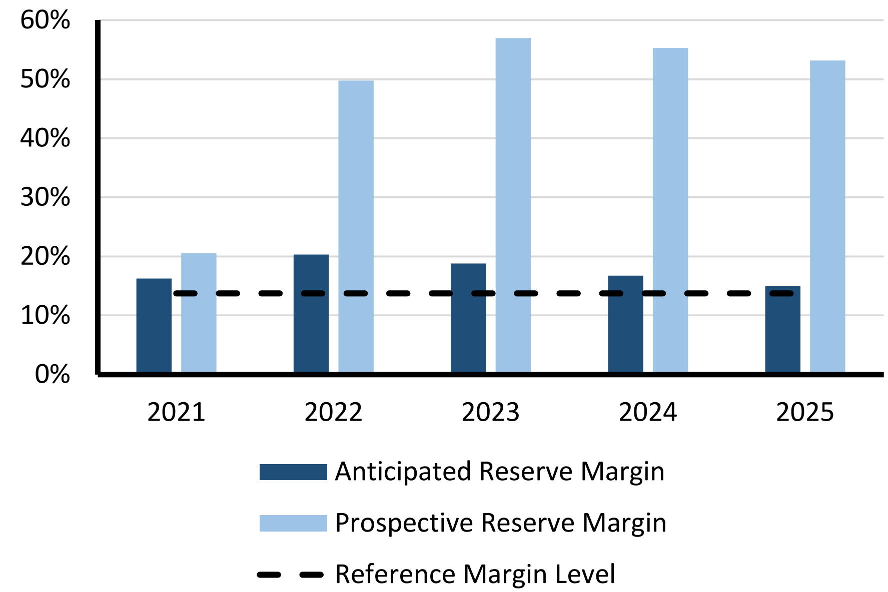


Figure 7: TRE-ERCOT Five-Year Projected Reserves (ARM and PRM)

Key Finding 2: While the ERO's biennial ProbA indicates that resource adequacy meets or exceeds resource adequacy benchmarks, there is increasing risk of resource shortfalls during nonpeak hours in parts of the WI, MISO, and Texas.

Key Points

- This *2020 LTRA* includes the ERO's biennial ProbA that provides insights into the ability of the future resource mix to meet the projected demand at all times. While the deterministic PRM assessment findings above indicated sufficient resources are planned to be available throughout this assessment period for most areas, except MISO and Ontario, the findings provide evidence that the deterministic PRM metric, especially in areas with higher penetrations of resources with energy limitations and uncertainty (i.e., wind, solar, natural gas, hydro), may not be a completely accurate way to measure an area's resource adequacy during all hours of the year.
- WECC's 2020 ProbA continues to note several hours that pose a potential risk for loss of load for almost all WI areas over studied years. The CAMX area was the only concern in the 2018 probabilistic assessment, but now all areas except Alberta (AESO) are seeing hours of potential loss of load. Exacerbated by the recent western area heat wave event, which saw load shed over the summer, all areas are reviewing the level of resource adequacy considering forecast variability.
- The traditional methods of assessing resource adequacy at peak load times may not accurately or fully reflect the ability of the new resource mix to supply energy and reserves for all hours. Energy limitations can exist, requiring probabilistic analysis methods to identify risks to reliability resulting from shortfalls in the conversion of capacity to energy (energy adequacy). The new resource mix includes natural-gas-fired generation; unprecedented proportions of nonsynchronous resources, including renewables and battery storage; DR; smart- and micro-grids; and other emerging technologies. Collectively, the new resources are more susceptible to energy sufficiency uncertainty.

Probabilistic evaluations identify resource adequacy risks during nonpeak conditions

The analytical processes used by resource planners range from relatively simple calculations of PRMs to rigorous reliability simulations that calculate system loss of load expectation (LOLE) or loss of load probability (LOLP) values.[16] The 1-event-in-10-year (0.1 events per year) LOLE is produced from this type of probabilistic analysis. This planning criterion requires an electricity system to maintain sufficient capacity such that system peak load is not likely to exceed available supply more than once in a 10-year period. Utilities, system operators, and regulators across North America rely on variations of the 1-event-in-10 year criterion for ensuring and maintaining resource adequacy.[17] Assessment area on-peak reserve margins determined from NERC's biennial ProbA are provided in **Table 2**.[18] The forecast operable reserve margin is defined as the ratio of anticipated resources derated by forced outage rates less on peak demand.

ProbA Results Summary

As part of a biannual process, this *2020 LTRA* includes a probabilistic evaluation for each assessment area and calculates LOLH and EUE for the third and fifth years of the LTRA. This year's analysis calculates the probabilistic resource measures for 2022 and 2024. A summary of the indices are show **Table 3**.

The color shading in **Table 3** is used to identify relative risk for loss-of-load hours. Green shading indicates that the risk is low (calculated LOLH is less than 0.1 hours per study year). Yellow shading indicates greater risk, with a threshold of between 0.1 and 2.4 hours per year. Instances where ProbA results are greater than 2.4 hours per year are shaded with orange. When calculated LOLH exceeds 2.4 hours per year, the study is indicating that the area may have a loss-of-load expectation that is greater than 1-day-in-10 years; this is a criterion used in many areas for determining Reference Margin Levels (see link to **Table 10**).

16 A traditional planning criterion used by some resource planners or load-serving entities is maintaining system LOLE below 1-day-in-10 years. LOLE is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. This is the original metric that is calculated using only the peak load of the day (or the daily peak variation curve). However, this metric is not being reported as part of this assessment. Currently, some assessment areas also calculate the LOLE as the expected number of days per year when the available generation capacity is insufficient to serve the daily demand (instead of the daily peak load) at least once during that day.

17 https://www.nerc.com/comm/PC/Probabilistic%20Assessment%20Working%20Group%20PAWG%20%20Relat/Probabilistic%20Adequacy%20and%20Measures%20Report.pdf

18 The *2022 marker in **Table 2** and **Table 3** denotes the results from the 2018 ProbA's 2022 projection. The ProbA from the prior iteration is used for comparison because the first year (in this case 2022) is the same study year in both the prior and current ProbA.

Table 2: 2022 and 2024 Projected Peak Reserve Margins									
	Reserve Margin (RM) Percent								
	LTRA Anticipated			LTRA Reference			ProbA Forecast Operable		
Assessment Area	**2022***	**2022**	**2024**	**2022***	**2022**	**2024**	**2022***	**2022**	**2024**
WECC-CAMX	21.3%	27.8%	26.8%	22.8%	15.8%	19.1%	22.7%	17.4%	15.3%
MRO-SaskPower	17.7%	34.7%	37.0%	11.0%	11.0%	11.0%	11.7%	27.3%	22.8%
WECC-NWPP-US and RMRG	30.3%	24.6%	21.6%	16.5%	16.1%	15.1%	21.3%	28.0%	24.9%
MISO	18.9%	22.3%	18.3%	17.1%	18.0%	18.0%	13.7%	17.9%	17.8%
SERC-FP	24.4%	21.1%	22.3%	15.0%	15.0%	15.0%	20.2%	10.2%	11.4%
NPCC-New England	28.5%	29.4%	18.9%	16.4%	13.2%	12.7%	13.2%	20.0%	9.8%
NPCC-Maritimes	25.4%	19.3%	20.9%	20.0%	20.0%	20.0%	27.6%	18.5%	16.7%
MRO-Manitoba	31.6%	17.7%	15.8%	12.0%	12.0%	12.0%	31.0%	14.0%	10.2%
NPCC-New York	22.5%	19.8%	18.6%	15.0%	15.0%	15.0%	13.7%	12.2%	11.3%
WECC-BC	56.8%	20.6%	21.2%	13.0%	12.3%	14.1%	22.2%	20.5%	21.1%
SERC-E	22.3%	22.8%	23.9%	15.0%	15.0%	15.0%	18.0%	14.9%	15.9%
Texas RE-ERCOT	10.6%	19.6%	16.0%	13.8%	13.8%	13.8%	4.6%	13.7%	10.3%
WECC-SRSG	11.7%	17.3%	14.7%	14.6%	11.9%	10.8%	15.6%	8.0%	5.5%
SERC-SE	32.4%	35.8%	39.1%	14.4%	15.0%	15.0%	24.7%	26.9%	30.2%
NPCC-Ontario	23.6%	20.1%	11.3%	18.5%	23.8%	16.7%	11.5%	12.6%	4.4%
SERC-C	25.2%	26.4%	27.0%	15.0%	15.0%	15.0%	17.7%	17.9%	18.4%
NPCC-Québec	13.6%	13.8%	14.1%	12.6%	10.1%	10.1%	7.1%	11.0%	7.1%
PJM	35.2%	38.4%	41.9%	15.8%	14.9%	14.8%	22.5%	25.6%	29.0%
SPP	25.0%	26.5%	24.2%	12.0%	15.8%	15.8%	17.1%	13.6%	13.3%
WECC-AB	28.2%	26.3%	24.0%	10.0%	12.3%	14.1%	19.9%	14.3%	20.2%

Table 3: 2022 and 2024 Probabilistic Indices by Assessment Area									
	EUE (MWh)			EUE (ppm)			LOLH (hours/year)		
Assessment Area	**2022***	**2022**	**2024**	**2022***	**2022**	**2024**	**2022***	**2022**	**2024**
WECC-CAMX	207,344	1,005,716	2,402,976	769.00	3,721.39	8,817.86	2.30	22.06	55.61
MRO-SaskPower	4,495	80	26	167.00	3.34	1.07	39.02	0.96	0.28
WECC-NWPP-US and RMRG	2,553	12,779	248,573	8.58	32.69	621.80	0.58	0.25	4.39
MISO	32	27	14	0.04	0.04	0.02	0.21	0.20	0.09
SERC-FP	0	23	2	0.00	0.00	0.00	0.00	0.03	0.00
NPCC-New England	3	3	59	0.02	0.02	0.47	0.01	0.01	0.10
NPCC-Maritimes	0	1	1	0.00	0.02	0.04	0.00	0.01	0.02
MRO-Manitoba	0	3	3	0.00	0.11	0.13	0.00	0.00	0.00
NPCC-New York	0	1	7	0.00	0.00	0.05	0.00	0.00	0.03
WECC-BC	0	19	8	0.00	0.32	0.14	0.00	0.00	0.00
SERC-E	0	1	5	0.00	0.00	0.02	0.00	0.00	0.01
Texas RE-ERCOT	1,089	0	13	2.64	0.00	0.03	0.87	0.00	0.03
WECC-SRSG	0	11	81	0.00	0.11	0.75	0.00	0.00	0.00
SERC-SE	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
NPCC-Ontario	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
SERC-C	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
NPCC-Québec	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
PJM	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
SPP	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
WECC-AB	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00

Figures 8 and **9** show the 2022 and 2024 projected peak reserve margins compared to the LOLH index. The graphics are sorted from left to right by the areas with the highest calculated LOLH.

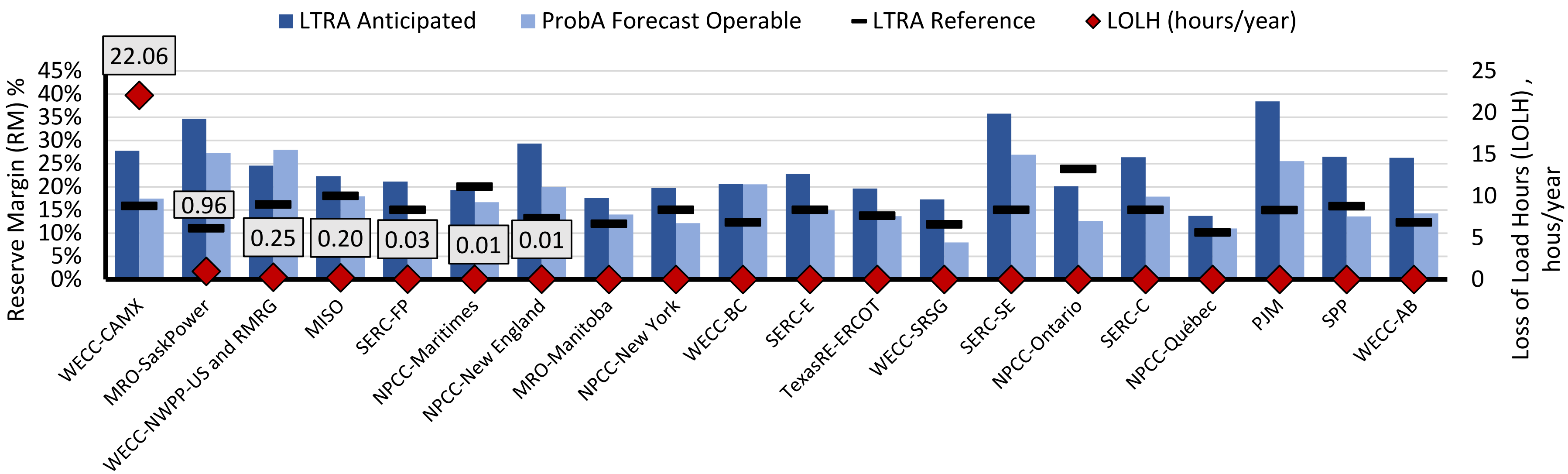


Figure 8: 2022 Assessment Area Reserve Margins and LOLH

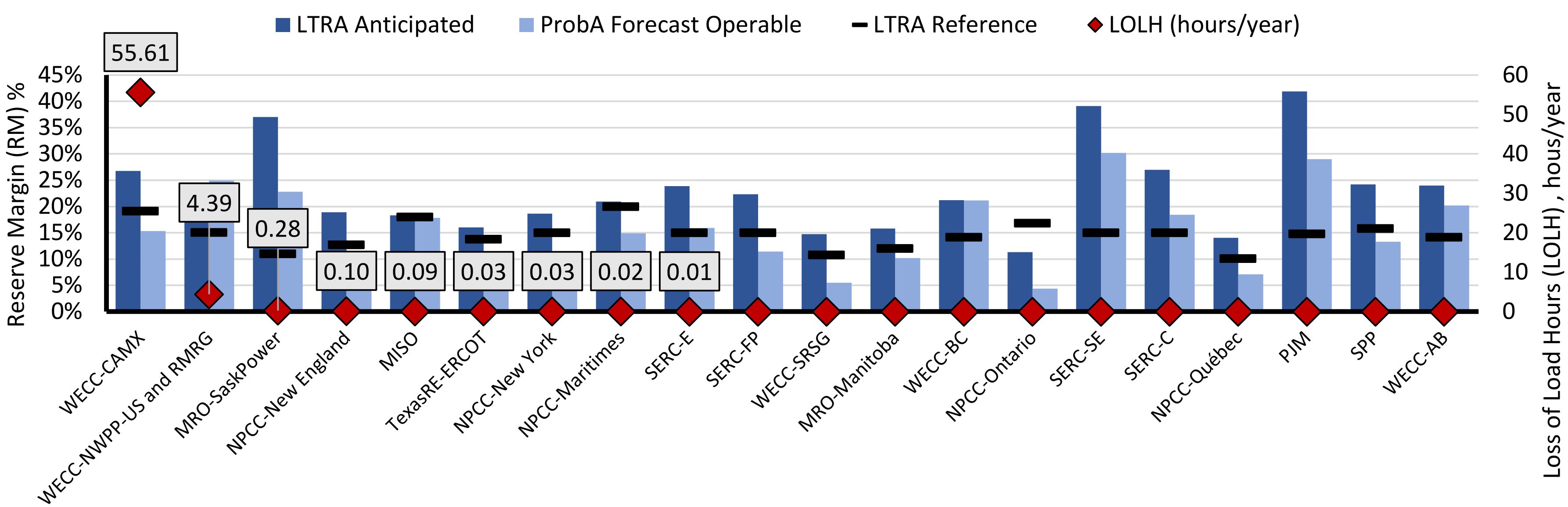


Figure 9: 2024 Assessment Area Reserve Margins and LOLH

In its probabilistic analysis, WECC found reserve margins for the WECC-CAMX area are over 27% for 2022 and over 26% for 2024, but levels of LOLH of 22 and 56 hours and levels of EUE of ~1m and ~2.4m, respectively, are due in part to the changing resource mix. It should be noted that almost all of the LOLH and EUE are associated with the Mexico portion of CAMX. The California portion has improved since the 2018 ProbA. Results with the California portion split out are shown in **Table 4**.

Table 4: Probabilistic Base Case Summary Results for WECC-CAMX			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	21.3%	27.8%	26.8%
Reference	22.8%	15.84%	19.14%
ProbA Forecast Operable	22.7%	17.4%	15.3%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	41,468	1,005,716	2,402,976
EUE (ppm)	513.8	3721	8818
LOLH (hours/year)	2.3	22	56
Annual Probabilistic Indices (CA Only)			
	2022*	**2022**	**2024**
EUE (MWh)	40,357	36,930	6,886
EUE (ppm)	157.35	146.05	27.15
LOLH (hours/year)	2.0	0.8	0.15

*Represents the 2018 ProbA results for 2022.

In **Figure 10**, a comparison of LOLH is provided that shows a general decrease in the LOLH metric. **Figure 11** shows that there is a general increase in the LOLH metric from the study year 2022 to 2024.

In addition to the annual metrics, the NERC 2020 ProbA provided monthly LOLE metrics and specific sensitivities to stress the forecasted system to provide more information on potential risks occurring for all hours, not only for the peak hour. Results are available for the ProbA Base Case while the results for the sensitivity case will be available early next year.

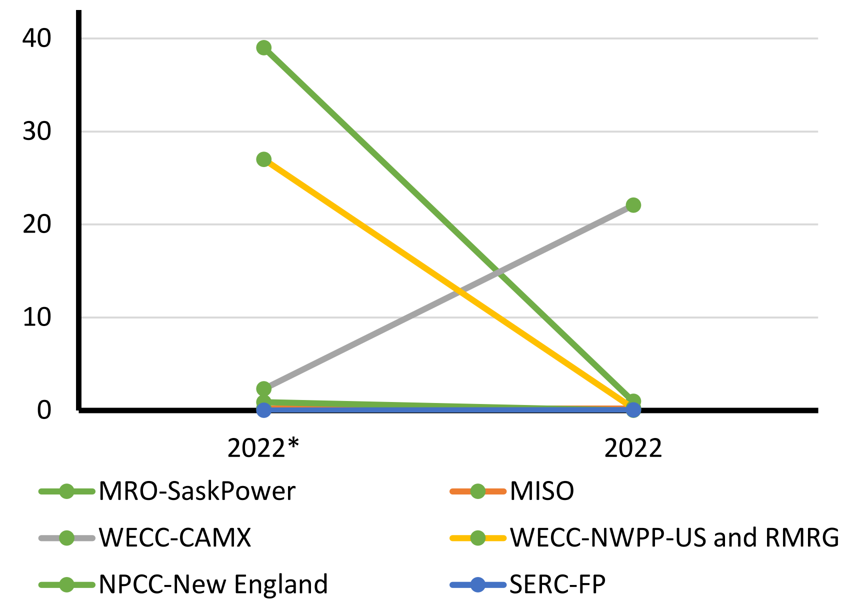


Figure 10: Comparison of the 2018 vs. the 2020 Probabilistic Analysis, LOLH Notable Trends for the 2022 Study Year

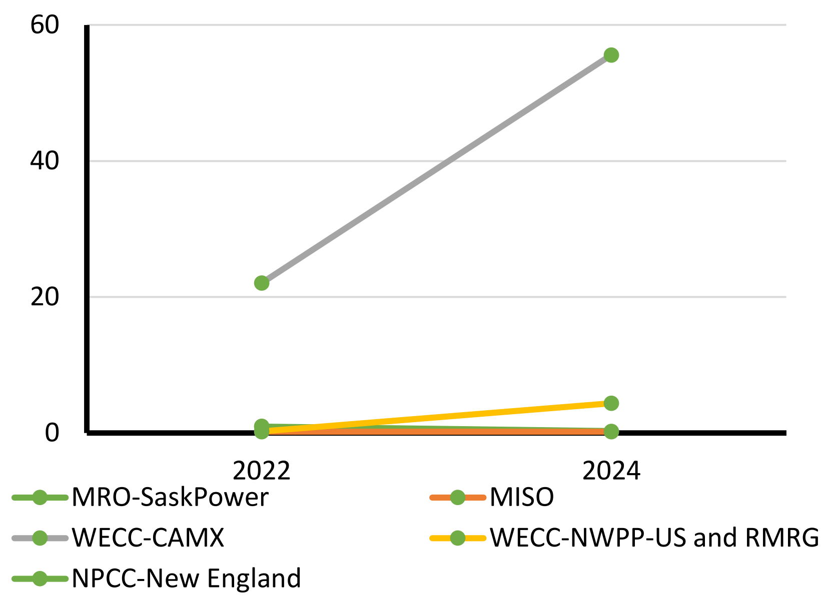


Figure 11: Comparison of 2020 Probabilistic Analysis, LOLH Notable Trends for the 2022 to 2024 Study Year

Figure 12 is an example of the MISO monthly indices, indicating LOLH in the nonpeak months.

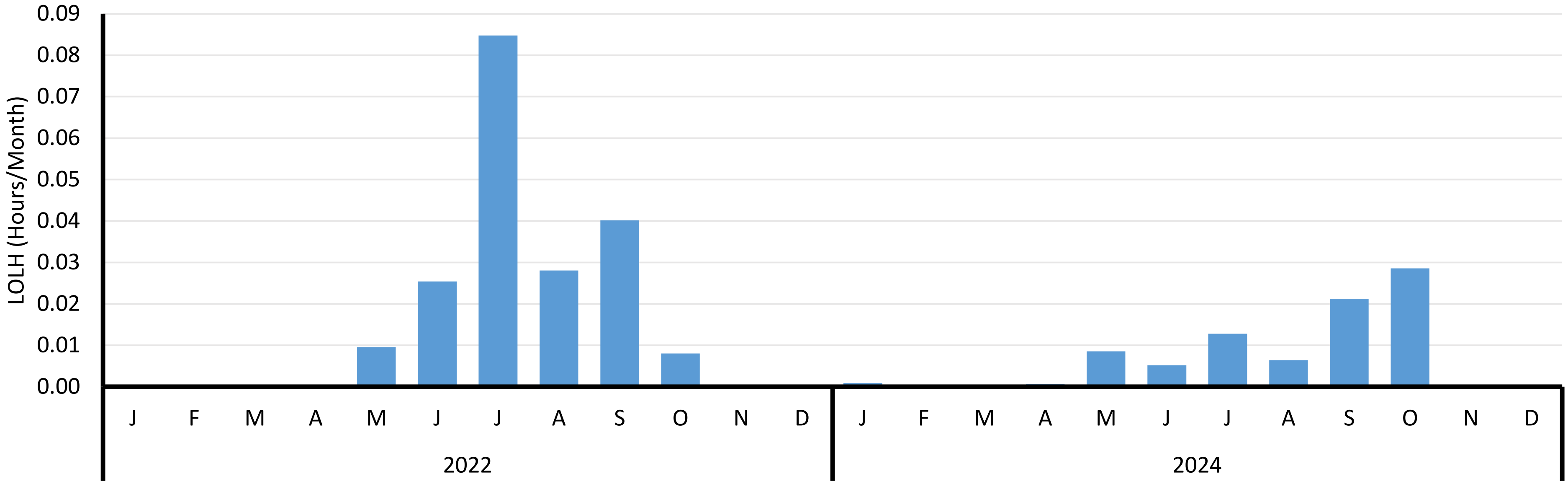


Figure 12: MISO LOLH Indices for Study Year 2022 and 2024

Additionally, the LTRA narrative questions and ProbA narrative questions were enhanced to provide further information on the emerging energy adequacy risks away from the on-peak net demand hour. Responses indicated that many assessment areas have shown off-peak energy risks in the ProbA Base Case results and other internal studies. **Table 5** provides a summary of these results, while more detailed information is contained in the **NERC Assessment Areas**.

The findings provide evidence that the deterministic PRM metric, especially in areas with higher penetration of resources with energy limitations and uncertainty (i.e., wind, solar, natural gas, hydro), may not be a completely accurate way to measure an area's resource adequacy during all hours of the year; additionally, as reserve surpluses diminishes towards the RML, this can become more pronounced. Namely, energy limitations can exist, requiring more advanced probabilistic analysis methods to identify risks to reliability that result from shortfalls in the conversion of capacity to energy (energy adequacy).

Table 5: Summary of Assessment Area ProbA Results for Energy Assurance and Off-Peak Hour Risk	
Assessment Area	**Summary**
MISO	ProbA results show some EUE in all months with the majority occurring in the summer during the afternoon peak hours. The average duration of EUE events is around two hours. EUE during the summer is driven primarily by high load and high forced outages. There are instances where EUE occurs during nonpeak hours in the assessment, when high planned outages overlap with unseasonably high load. This is magnified in zones that are transmission constrained when the zone is unable to import enough energy to meet peak demand.
MRO Manitoba	ProbA Base Case indices indicate low energy adequacy risk (near-zero EUE and LOLH values). Manitoba Hydro system is a winter-peaking system and the vast majority of its generating facilities are use-limited or energy-limited hydro units. A regional risk probabilistic scenario is being conducted that will examine water flow conditions of the tenth percentile or lower, which tend to increase the LOL probability.
NPCC Ontario	The ProbA Base Case indices indicate low energy adequacy risk (near-zero EUE and no LOLH). This indication is somewhat unexpected given the reserve shortfall shown in the PRM deterministic assessment. It results from the resources being modeled in the ProbA, including emergency operating procedures and significant amounts of emergency assistance. Demand forecasters at the IESO in Ontario have observed that summer peaks have moved later in the day; they attribute this to the increased penetration of embedded solar generation and the critical peak pricing program. Peaks are expected to increase over time due to policy changes that could reduce conservation program spending and the IESO’s assessment that DERs are plateauing in the area.
TRE-ERCOT	An increase in wind and solar capacity is contributing to growing reliability risk in off-peak periods. In ProbA study years, the months of March and October (typically nonpeak periods) have the lowest monthly available reserves on the peak day. Although currently EUE and LOLH indices are negligible, ERCOT and resource planning stakeholders must manage the risk that further increases in renewable penetration could potentially result in the risk of firm load shed in shoulder months when planned outages are scheduled. To further assess risks from their increasingly-variable resource portfolio, ERCOT is performing a probabilistic scenario to evaluate risks from a low-wind event. Simulated LOL events in ERCOT are largely driven by high load with low wind output conditions. These conditions occur rarely, however, a small change in their frequency could have significant impact on the expected reliability of the ERCOT system. The risk scenario for ERCOT was designed to stress test the impact of a difference in the realized frequency of high load and low wind events from that in the synthetic profiles used for the Base Case simulations.
WECC-BC	In the 2020 ProbA, LOLH and EUE are increasing over the 2018 analysis with occurrences in the month of March, October, and November for study year 2022 and the months of February and October for study year 2024. The hours of risk are at 6:00 a.m., one hour before the peak demand for the day. Overall the LOLH and EUE values remain very low and do not indicate a reliability risk.
WECC-CAMX	The 2020 ProbA shows overall increasing risk of load loss and unserved energy in this area, though risk is more concentrated in the Baja California (Mexico) portion. The Mexico portion of the CAMX area has seen a significant increase in their demand forecast since the 2018 ProbA. This new demand forecast, coupled with the absence of energy transfers coming from California after the peak hours as the California system is itself constrained, has led to a significant increase in EUE for this area. Looking at the California portion of this area, the LOLH and EUE have improved since last ProbA with large improvements by 2024. Typical peak months of July and August are when most LOL occurrences are expected. However, the hours of greatest risk occur at 6:00 p.m., one hour past the peak demand for the day in California. These hours are also when the greatest EUE occurs.
WECC-NWPP-RMRG	The 2020 ProbA indicates the greatest risk of load loss occurs in the summer months during the one to three hours after peak demand for the day. The magnitudes of EUE during these periods range from less than a MW to 2,000 MWh in one hour.
WECC-SRSG	The 2020 ProbA indicates the greatest risk of load loss occurs in the summer months of July and August. The greatest risk occurrence during these months is during the hour ending at 6:00 p.m., one hour past the peak demand for the day. The magnitudes of EUE during these periods are low, ranging from from less than 1 MWh to 35 MWh in one hour.

Key Finding 3: Variable energy resources continue to grow, and thermal resource capacity declines in most areas throughout the assessment period. As a result, increased attention is required for planning and operating a more complex resource mix.

Key Points

- In many areas, variable energy resources are increasingly important to meet electricity demand. Texas and California rely on variable energy resources to meet peak hour demand; this can lead to operational risk during unanticipated conditions that reduce the resource output. Other areas are trending toward increasing reliance on variable energy resources over the assessment period. Sufficient flexible resources are needed in areas with high levels of variable generation to avoid shortfalls when variable resource output is insufficient to meet demand.[19]
- Inverter based resources, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. Maintaining a reliable system as the penetration of inverter-based resources increases requires planners and operators to be cognizant of potential disturbance-related performance issues.
- Recently the ERO conducted a review of base case models used in transmission planning within the WI and identified modeling issues with wind and solar PV generators. Invalid or inaccurate generator models can contribute to steady state or dynamic study result errors, affecting the planned reliability of the interconnected transmission system.[20]
- Additional fossil-fueled generator retirements could occur as a result of economic uncertainty and environmental policies.

Variable Energy Resources

Variable energy resources include wind, solar, and run-of-river hydroelectric plants for which electric output can change according to the primary diver (e.g., wind, sunlight, moving water), resulting in plant output fluctuations on all time scales. Planners and operators must address and prepare for the uncertainty associated with these resources because the magnitude and timing of variable generation output is less predictable than for conventional generation.

19 Flexible resources refer to dispatchable conventional as well as dispatchable variable resources, energy storage devices, and dispatchable loads.

20 See NERC-WECC Joint Report–*WECC Base Case Review: Inverter-Based Resources*, August, 2020.

Figure 13 shows the assessment areas with solar and wind resources over 5% of their peak demand for the years 2020, 2025, or both. Year 2025 projections include the expected on-peak capacity contribution of anticipated resources. The percentages located beside the bars indicate that WECC-CAMX and TRE-ERCOT rely on these variable resources to meet peak demand as their peak demand exceeds the total capacity of conventional resources. Several other assessment areas are becoming increasingly reliant on solar and wind resources to meet peak demand. In the event that solar and wind output are below expectations, CAMX and TRE-ERCOT may need to rely on additional internal resources and/or external resources to cover the shortfall.

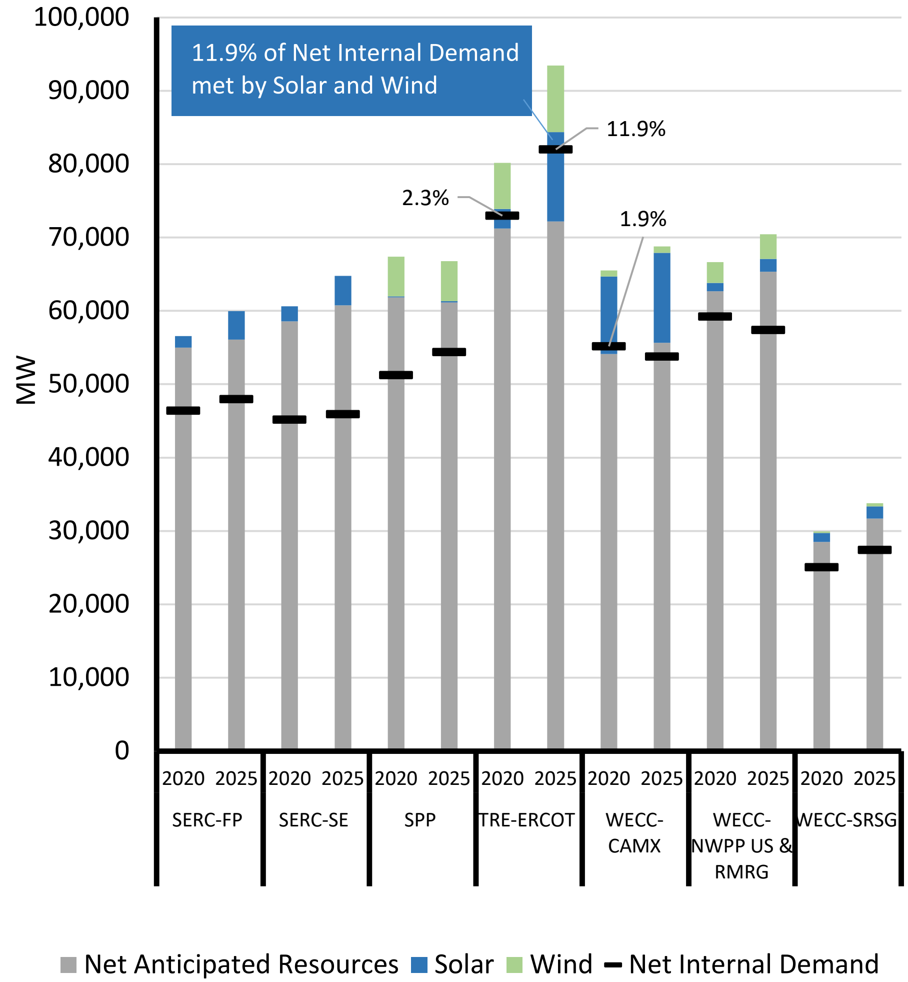


Figure 13: Assessment Areas with Solar and Wind Capacity Greater than 5% of On-Peak Demand

Capacity Additions

Wind, solar, and natural-gas-fired generation are the overwhelmingly predominant generation types in the planning horizon for addition to the BPS. The generation resources for all fuel types are shown in **Figure 14** (for Tier 1 planning) and in **Figure 15** (for Tier 1 and 2 planning).

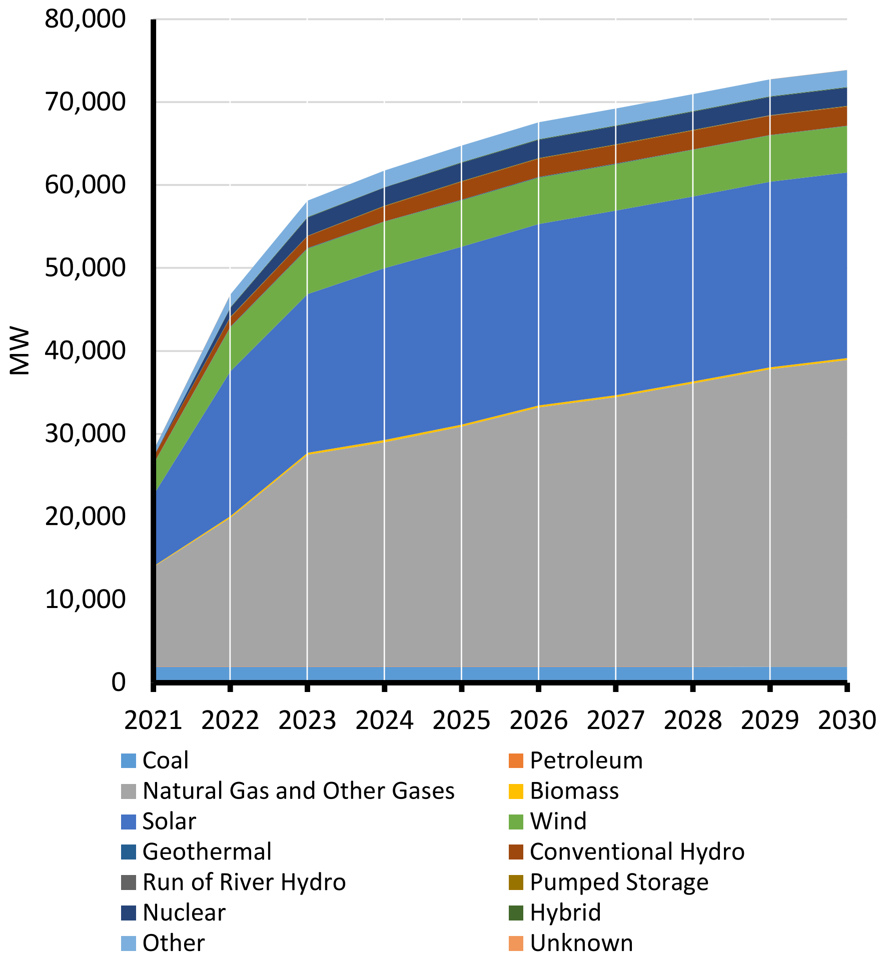


Figure 14: Tier 1 Planned Resources Projected Through 2030

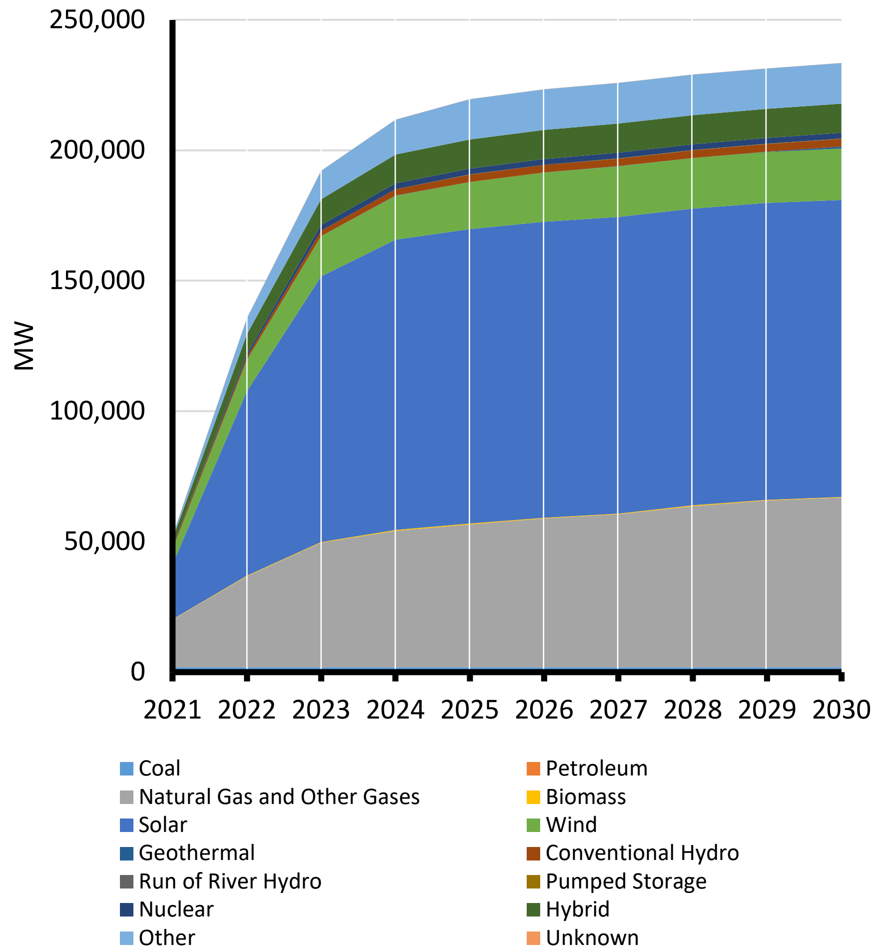


Figure 15: Tier 1 and 2 Planned Resources Projected Through 2030

NERC Capacity Supply Categories

Future capacity additions are reported in three categories:

Tier 1: Planned capacity that meets at least one of the following requirements are included as anticipated resources:

- Construction complete (not in commercial operation)
- Under construction
- Signed/approved Interconnection service agreement
- Signed/approved power purchase agreement
- Signed/approved Interconnection construction service agreement
- Signed/approved wholesale market participant agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to vertically integrated entities)

Tier 2: Planned capacity that meets at least one of the following requirements are included as prospective resources:

- Signed/approved completion of a feasibility study
- Signed/approved completion of a system impact study
- Signed/approved completion of a facilities study
- Requested Interconnection service agreement
- Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (applies to regional transmission organizations (RTOs)/independent system operators (ISOs))

Tier 3: Tier 3 is other planned capacity that does not meet any of the above requirements.

Significant solar and wind capacity additions are expected over the next 10 years. **Table 6** identifies solar and wind installed capacity additions by assessment area. From an installed capacity perspective, over 390 GW of new solar and wind are planned through 2030, including Tier 1, 2, and 3 resources. Of all generation resource additions, future solar capacity is expected to be the largest contributor at 197 GW when considering Tier 1 and 2 resources and 248 GW when considering Tier 3 resources. Wind capacity is expected to nearly double by 2030 when considering Tier 1 and Tier 2 resources.

Table 6: Solar and Wind Nameplate Capacity, Existing and Planned Additions through 2030										
	Nameplate MW of Solar					Nameplate MW of Wind				
	Existing	Tier 1	Tier 2	Tier 3	Total	Existing	Tier 1	Tier 2	Tier 3	Total
MISO	204	1,718	49,292	7,025	58,240	22,062	4,119	19,281	2,921	48,383
MRO-Manitoba	-	-	-	-	-	259	-	-	-	259
MRO-SaskPower	-	11	10	57	79	242	385	-	400	1,027
NPCC-Maritimes	1	3	-	-	4	1,146	78	-	30	1,254
NPCC-New England	1,371	197	1,064	2,742	5,374	1,419	88	7,835	4,382	13,724
NPCC-New York	32	23	-	2,350	2,404	1,739	646	500	4,850	7,736
NPCC-Ontario	478	-	-	-	478	4,486	460	-	-	4,946
NPCC-Quebec	-	-	-	-	-	3,772	54	-	-	3,827
PJM	2,067	6,125	52,522	-	60,714	8,787	3,029	25,820	-	37,636
SERC-C	10	674	175	5,060	5,919	480	-	-	-	480
SERC-E	555	94	-	-	649	-	-	-	-	-
SERC-FP	3,418	6,955	-	-	10,374	-	-	-	-	-
SERC-SE	2,005	2,042	1,665	5,837	11,549	-	-	-	-	-
SPP	273	284	11,103	-	11,659	21,892	2,646	15,641	5,253	45,432
TRE-ERCOT	3,249	12,738	37,031	20,990	74,008	24,895	12,426	10,772	8,361	56,453
WECC-AB	15	245	-	100	360	1,781	1,129	-	1,050	3,960
WECC-BC	1	1	21	-	23	717	-	-	45	762
WECC-CAMX	14,592	2,879	5,916	-	23,387	7,692	541	2,245	-	10,477
WECC-NWPP-US and RMRG	3,880	2,044	1,448	5,197	12,568	13,028	2,554	10	3,975	19,567
WECC-SRSG	1,630	580	279	2,349	4,838	1,162	1,452	-	-	2,615
Total	33,781	36,614	160,526	51,705	282,626	115,558	29,607	82,104	31,267	258,536

Figure 16 shows the planned solar capacity for selected assessment areas through 2030. Texas, PJM, and MISO have the most solar capacity in planning.

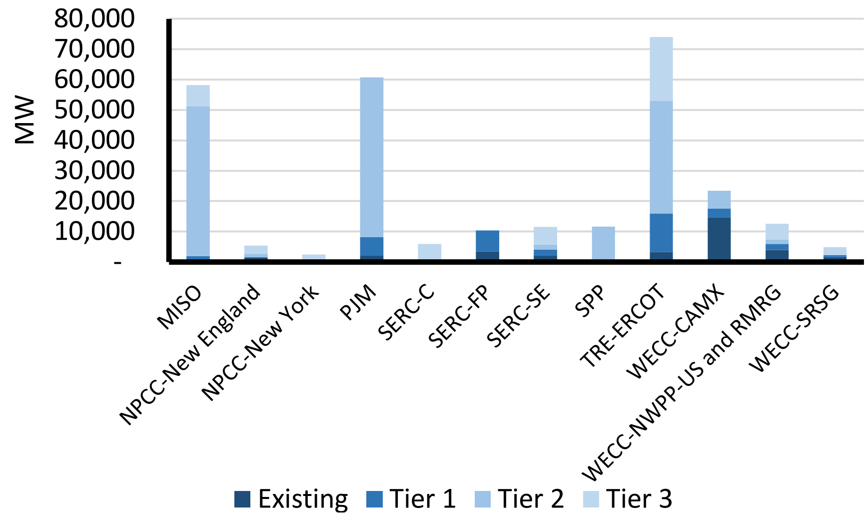


Figure 16: Solar Capacity Planned and Existing

Figure 17 shows the planned wind capacity for selectedassessment areas through 2030. MISO, PJM, SPP, and Texas RE-ERCOT have the most wind capacity in planning.

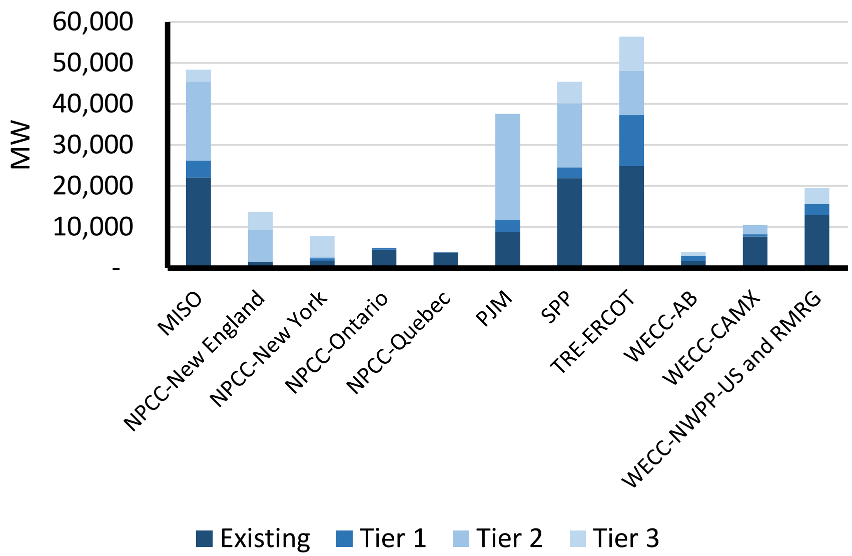


Figure 17: Wind Capacity Planned and Existing

The nameplate capacities shown in **Table 6, Figure 16,** and **Figure 17** are based on the design ratings of the generators and in general do not indicate the capacity that resource types will deliver to serve demand. On-peak resource capacity, in contrast, reflects the expected capacity that the resource type will provide at the hour of peak demand. Because the electrical output of variable energy resources (e.g., wind, solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. **Table 7** (on the next page) shows the capacity contribution of existing wind and solar resources for each assessment area.

While some areas of North America have and continue to see more rapid resource mix changes, overall North America has a diverse fuel mix. A 10-year projection of North America peak capacity is shown in **Figure 18**. The changes level off around 2024 as planning for wind, solar, and natural-gas-fired generation can typically take place within five-year time horizons.

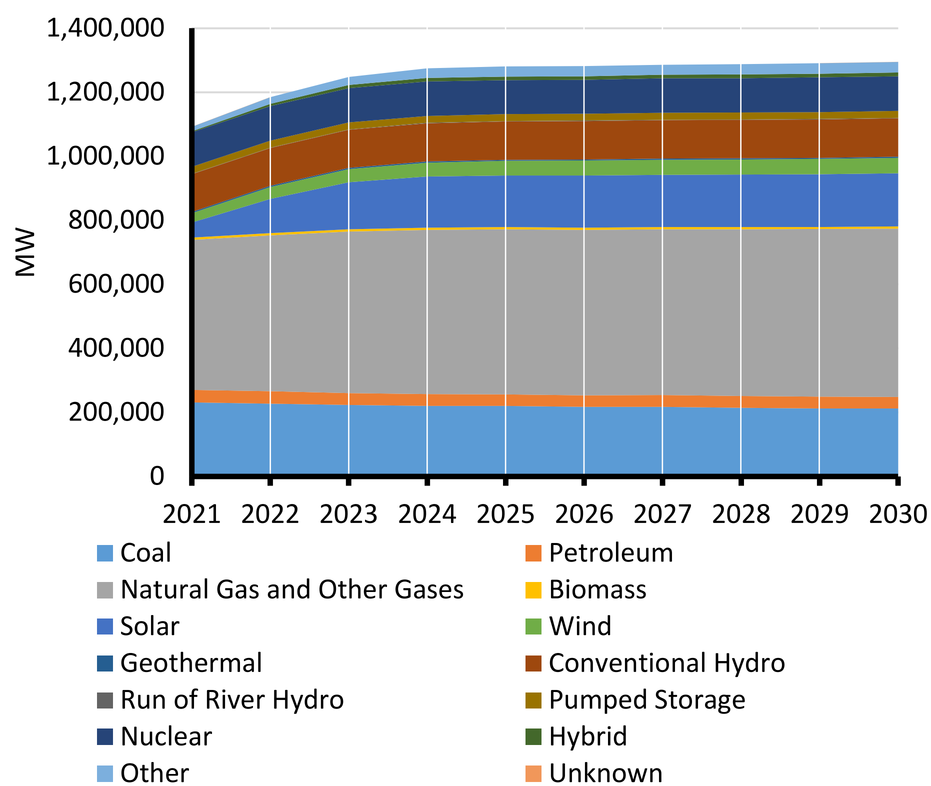


Figure 18: Existing, Tier 1, and Tier 2 Planned Resources Projected Through 2030

Table 7: BPS Wind and Solar Generation Resources by Assessment Area

Nameplate (MW)	Wind			Solar		
	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/ Nameplate (%)	Nameplate (MW)	Available Peak Demand Hour Capacity (MW)	Available/ Nameplate (%)
MISO	22,062	4,072	18.5%	204	119	58.0%
MRO-Manitoba Hydro	259	43	16.6%	-	-	-
MRO-SaskPower	242	25	10.4%	-	-	-
NPCC-Maritimes	1,146	221	19.3%	1	-	0.0%
NPCC-New England	1,419	174	12.3%	1,371	110	8.0%
NPCC-New York	1,739	297	17.1%	32	16	50.2%
NPCC-Ontario	4,486	633	14.1%	478	64	13.4%
NPCC-Quebec	3,772	104	2.8%	-	-	-
PJM	8,787	1,339	15.2%	2,067	997	48.2%
SERC-C	480	456	95.0%	10	8	80.0%
SERC-E	-	-	-	555	546	98.5%
SERC-FP	-	-	-	3,418	1,582	46.3%
SERC-SE	-	-	-	2,005	1,504	75.0%
SPP	21,892	5,157	23.6%	273	162	59.5%
Texas RE-ERCOT	24,895	6,182	24.8%	3,249	2,480	76.3%
WECC-AB	1,781	175	9.8%	15	5	30.0%
WECC-BC	717	144	20.1%	1	0	30.0%
WECC-CAMX	7,692	825	10.7%	14,592	10,602	72.7%
WECC-NWPP-US and RMRG	13,028	2,805	21.5%	3,880	1,164	30.0%
WECC-SRSG	1,162	203	17.5%	1,630	1,221	74.9%

Generation Retirements

Figure 19 shows the net change of generating capacity since 2012 and the planned retirements for the forward looking 10-year period. Coal and petroleum both have negative net changes; this is an indication that coal and petroleum are being phased out in favor of other resources. The capacity of coal and petroleum is reduced by nearly 50 GW and nearly 7 GW, respectively, since 2012. During the same period, natural-gas-fired capacity increased by almost 130 GW.

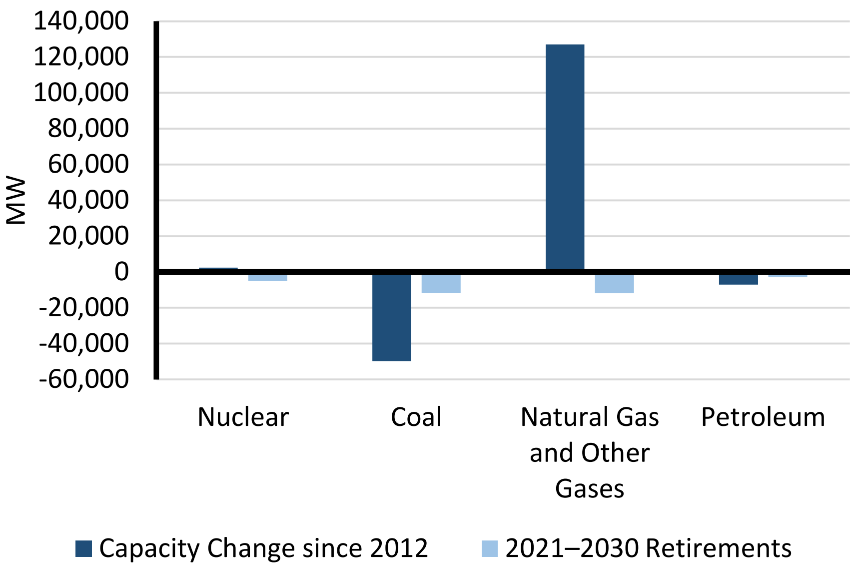


Figure 19: Capacity Changes since 2012 and Retirements Projected through 2030

Operating Reliability Risks Due to Conventional Generation Retirements

Capacity retirements located near metropolitan areas or large load centers that have limited transmission import capability present the greatest potential risk to reliability. Unless these retirements are replaced with plants in the same vicinity, these load centers will require increased power imports and dynamic reactive resource replacement.[21] If the transmission links between an area and generation sources are relatively weak, voltage instability can result; dynamic reactive power must be provided to prevent voltage collapse. Solutions to preventing voltage instability could range from extensive transmission improvements to optimal placement of static VAR compensators, synchronous condensers, and/or locating new generation in the load pocket or local energy storage. Retiring generation units in a generation "pocket" might cause the remaining units to become "reliability must run" units, and additional action or investment in equipment to maintain voltage stability could be required.

21 Dynamic reactive support is measured as the difference between its present VAR output and its maximum VAR output. Dynamic reactive support is used to support system state transients occurring post-contingency. NERC's *Reactive Power Planning Reliability Guideline* provides strategies and recommended practices for reactive power planning and voltage control and accounts for operational aspects of maintaining reliable voltages and sufficient reactive power capability on the BPS:

https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability%20Guideline%20-%20Reactive%20Power%20Planning.pdf

Figure 20 displays the capacity retirements for the previous 7-year period as well as the 10-year projected cumulative retirements through 2030. The 10-year projected retirements are based on committed retirements known to date and is expected to increase as the time horizon progresses.

This *2020 LTRA* does not predict future generator retirements, but instead reports on confirmed retirements. Additional retirements beyond what is reported as confirmed in this *LTRA* are to be expected and will continue to alter the resource mix. Because generator retirement announcements can be made as late as 90 days prior to planned deactivation in some areas, long-range retirement projections based on confirmed retirements could be significantly understated. **Table 8** shows a comparison of the projected coal-fired and nuclear generation capacity in selected assessment areas for peak seasons in 2022 based on the *2018 LTRA* and current (*2020 LTRA*) data to illustrate how projections based on confirmed retirements can differ over assessment years.

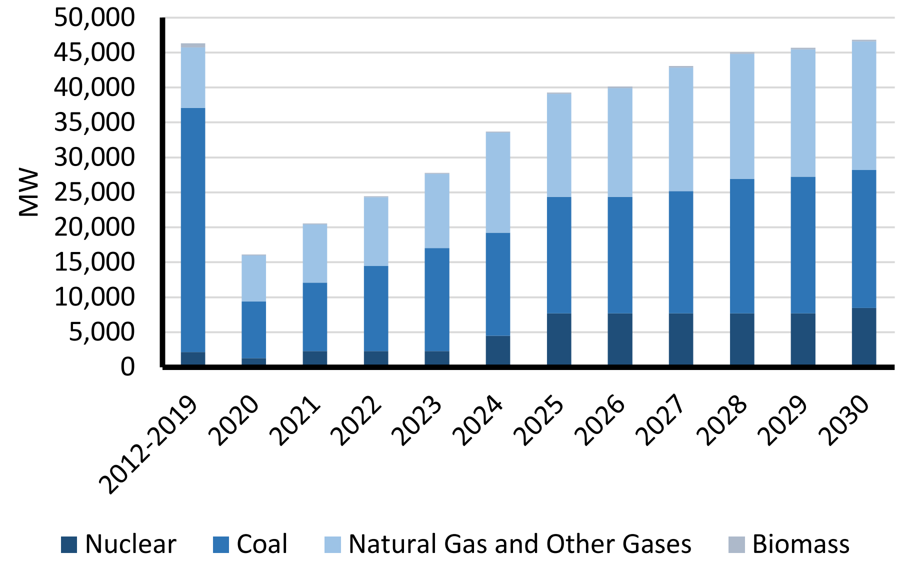


Figure 20: Capacity Retirements since 2012 and Projected Cumulative Retirements through 2030

Table 8: Generation Resource Projections of Year 2022

	2022 Capacity Projected in 2018		2022 Capacity Projected in 2020		2022 Capacity Based On 2018 Stress Test	
Area	**Coal (MW)**	**Nuclear (MW)**	**Coal (MW)**	**Nuclear (MW)**	**Coal (MW)**	**Nuclear (MW)**
MISO	57,792	11,955	51,948	12,169	40,454	6,575
NPCC New England	917	3,331	533	3,321	644	3,331
NPCC New York	1,011	3,334	-	3,343	707	3,334
PJM	54,432	28,620	52,405	32,626	38,103	15,602
SERC-E	17,384	8,653	15,552	12,104	12,169	4,759
SERC-SE	18,979	8,018	16,935	6,918	13,286	5,818
SPP	23,439	1,943	23,172	1,944	16,407	1,173
TRE-ERCOT	14,696	4,981	13,995	4,973	10,287	4,981
WECC-SRSG	8,964	3,937	5,616	2,856	6,275	2,624

In many cases, coal-fired resource capacity falls as the time-horizon to operating year draws closer; nuclear capacity is less volatile and on some occasions the projected retirements did not materialize. The set of capacity values at the right side of **Table 8** shaded in grey came from the 2018 *NERC Generation Retirements Scenario Special Reliability Assessment* report, which was developed to be a stress-test case for coal-fired and nuclear retirements.[22] With few exceptions, this *2020 LTRA* is projecting that coal-fired and nuclear capacity for the year 2022 will be above the levels that were used for the stress-test scenario, indicating that the 2018 scenario still represents a bound for informing risk insights.

Figure 21 shows the proportion of existing coal-fired generation capacity in each assessment area that is currently committed or planned for retirement.

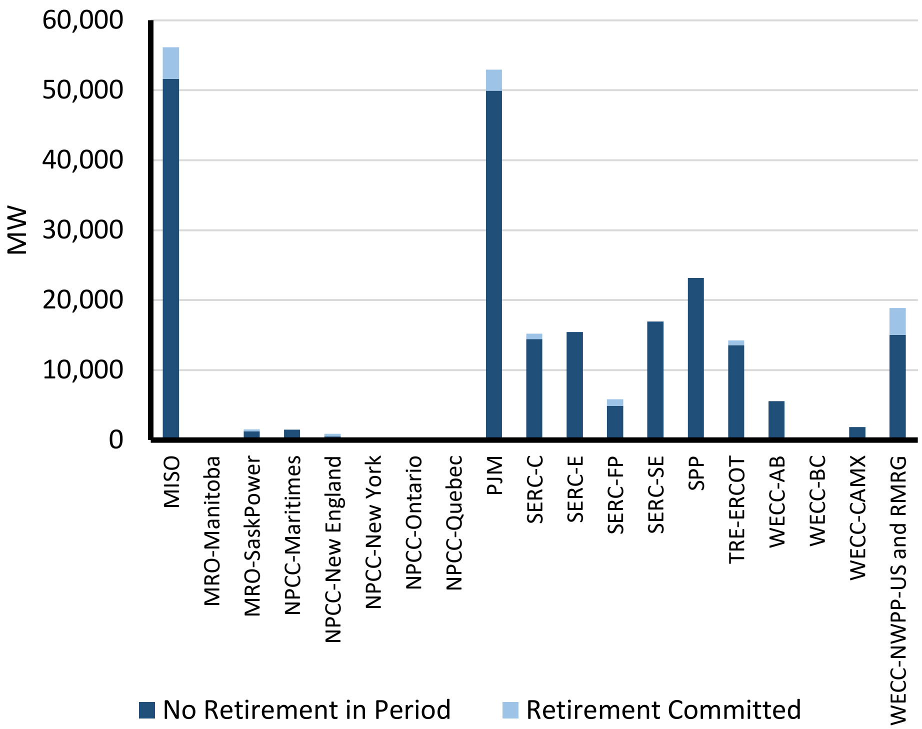


Figure 21: Portion of Existing Coal-fired Generation Capacity with Retirement Commitments through 2026

22 *Generation Retirement Scenario Special Reliability Assessment*, December 2018: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Retirements_Report_2018_Final.pdf

Maintaining Fuel Assurance

Fuel assurance mechanisms offer important reliability benefits, particularly in areas with high levels of natural gas and limited pipeline infrastructure. Fuel assurance, while not explicitly defined, refers to the confidence system planners have in a given resource's availability based on its fuel limitations. In some areas, natural gas delivery pipelines were built and sized to serve customers of natural gas utilities—not specifically to serve electricity generators. Firm contracts for natural gas can drive development of new pipelines. Higher reliance on natural gas can lead to fuel-security issues, particularly during extreme cold weather periods when demand on the natural gas delivery system can be stressed, exposing electricity generation to fuel supply and delivery vulnerabilities.

Mechanisms Promoting Fuel Assurance	Planning Considerations
Fuel Service Agreements	• Service-level arrangements should be considered in resource adequacy planning. • In areas with constrained natural gas pipeline infrastructure, generators with firm fuel service are likely to be available more often than those with interruptible service. • Generators that have procured firm service on a secondary market may also be interrupted prematurely. • Firm service does not guarantee delivery if a *force majeure* is in effect.
Alternative Fuel Capabilities	• Dual-fuel firing capability and seasonal inventories should be considered in capacity and energy adequacy planning. • Generators with dual fuel capabilities are likely to have greater availability than those without. • Backup fuel inventory must be maintained in order for dual fuel capabilities to promote fuel assurance.
Pipeline Connections	• More pipeline connections from different sources can increase the resilience of a plant's fuel supply. • Greater fuel assurance can be reached if multiple fuel supply sources and transportation paths are used to supply a given generator.
Market and Regulatory Rules	• Market and other state, federal, and provincial rules, incentives, and penalties can be used to compel Generator Owners to perform in a manner that promotes reliability, resilience, and fuel assurance. • Regulatory policies can help attract greater access and installation of fuel supplies, including resilience in pipeline transportation.
Vulnerability to Disruptions	• Geography and access to natural resources can impact a given area's vulnerability to disruption. • Areas at the "end of the line" will likely have an overall greater risk profile than those in close proximity to fuel supply sources. • Areas relying on liquefied natural gas (LNG) are vulnerable to fuel supply and delivery disruptions that are very different to pipeline vulnerabilities, including political unrest and global commodity prices.
Pipeline Expansions	• Areas that have an increasing amount of pipeline transportation capacity being added may be reducing their fuel-supply risks. • Pipeline expansion into constrained areas significantly promotes BPS fuel assurance.

Replacing coal-fired and nuclear generation with nonsynchronous and natural-gas-fired generation requires careful attention. Planning considerations include ensuring there is adequate inertia, ramping capability, frequency response, and fuel assurance on the system. NERC data and analysis indicate that inertia and frequency response are adequate for all Interconnections and generally trending in a positive direction.[23] As the resource mix continues to evolve, industry must be watchful not only for resource adequacy criteria but also for the essential reliability services that that must be maintained.

Natural Gas Capacity Additions

ERO-wide natural-gas-fired on-peak generation has increased from 280 GW in 2009 to 446 GW today. Another 41 GW of Tier 1 planned capacity can be expected over the next decade as shown in **Figure 22**. Compared to the *2019 LTRA*, the total natural-gas-fired generation in Tier 1 and Tier 2 planning for this 10-year assessment horizon has fallen from 88 GW reported in 2019 to just over 70 GW in 2020.

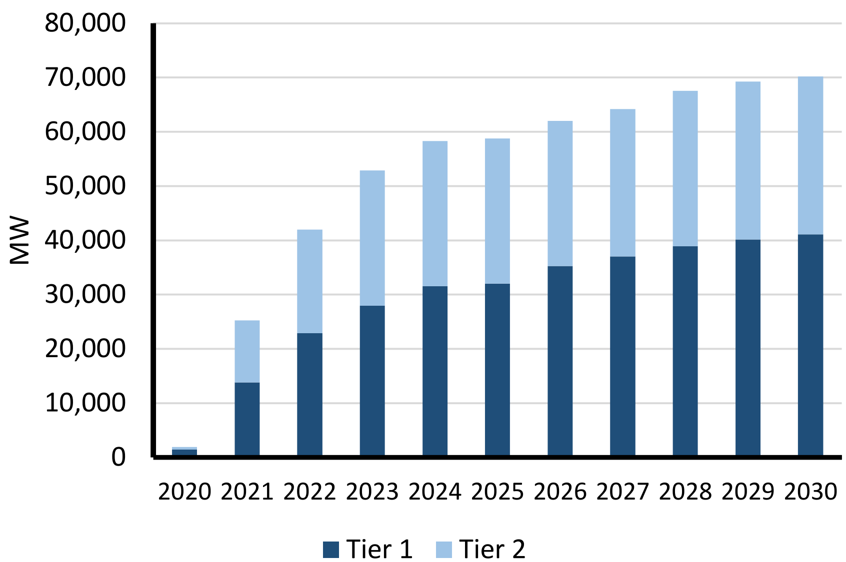


Figure 22: Natural Gas Capacity Planned Additions through 2029, Tier 1 and 2

Unlike other conventional generation with on-site storage, natural gas generation uses the natural gas pipeline system to receive just-in-time fuel to burn for its electricity production. Pipeline transportation service is subject to interruption and curtailment depending on the generator's level of service. In constrained natural gas markets, generation without firm transportation may not be served during peak pipeline conditions (more prevalent in winter), and arrangements for alternative fuels should be considered. Some plants no longer have the option of burning a liquid fuel. Furthermore, regardless of fuel service arrangements, natural gas generation is subject to curtailment during a *force majeure* event.

In November 2017, NERC published the *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*.[24] In the report, NERC made numerous recommendations for assessing disruptions to natural gas infrastructure and related impacts to the reliable operation of the BPS in planning studies. The Electric-Gas Working Group (EGWG)[25] was created to gather industry experts and drive the development of tools and other resources to better educate and inform the electricity industry about how to reduce risks related to the disruption of fuel supplies.

23 Key Finding 3 in *2018 LTRA*: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

24 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

25 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf

New England is currently fuel constrained in winter; this has been identified as one of the most significant risks to the area. Output restrictions at dual-fuel plants due to air emission regulations also contribute to this risk. With its existing fuel infrastructure, New England has faced challenging operating conditions, particularly in extreme cold weather. Given the shift in the current resource mix, these challenges are likely to extend beyond the winter season. During extreme cold periods, electricity needs have been met through a combination of generators using natural gas from pipelines, LNG, and the now-declining nuclear, coal, and oil-fired generators. Although new natural-gas-fired generation is being added to the fuel mix, the regional natural gas pipelines continue to have limited fuel deliverability for any power generators without firm natural gas transportation contracts. Additionally, LNG deliveries to New England that are influenced by global economics and logistics can also be uncertain without firm supply contracts. Environmental permitting for new dual-fuel capability (typically, natural gas and fuel oil) is becoming more difficult under tightening state and federal air emissions regulations. Even when these units are granted permits, their run times for burning fuel oil are usually restricted to limit their ozone season (i.e., May 1–September 30) air emissions.

Energy Storage

Energy storage provides important capabilities to maintain grid reliability and stability. With the exception of pumped hydro storage facilities, only a limited number of large-scale energy storage demonstration projects have been built. With increasing requirements for system flexibility as variable generation levels increase and energy storage technology costs decrease, bulk system and distributed stationary energy storage applications may become more viable and prevalent. Storage may be used for load shifting and energy arbitrage—the ability to purchase low-cost, off-peak energy and resell the energy during on-peak, high cost periods. Storage may also provide ancillary services, such as regulation, load following, contingency reserves, and peaking capacity. This is true for both bulk storage, which acts in many ways like a central power plant, and distributed storage technologies.

Battery storage and hybrid generation resource projects, which combine energy storage with a generating plant, such as a wind or solar farm, are now in BPS planning processes for development and connection within the first years of the assessment period (**Figure 23**). Grid planners and operators need to address modeling, study, and operating issues in the near term for reliable integration. Inverter based resources continue to grow providing battery storage with the opportunity to complement renewable projects in the form of hybrid facilities, which typically incorporate a battery storage component as part of a utility-scale solar or wind development. Additionally, battery storage has the capability to provide essential reliability services (ERSs) to the BPS, such as voltage support, frequency response, and system inertia allowing for battery storage to compete with synchronous resources that provide those same necessary characteristics to the grid. Further analysis should be conducted by system planners to model a system with significant battery storage and hybrid power plants. System planners must conduct adequate studies to determine the transmission system stability impacts on battery energy storage system interconnection, the capability to provide capacity to meet reserve margin requirements, and the ability to provide ERSs. **Figure 23** shows the current and future installations of both battery and hybrid storage through 2024.

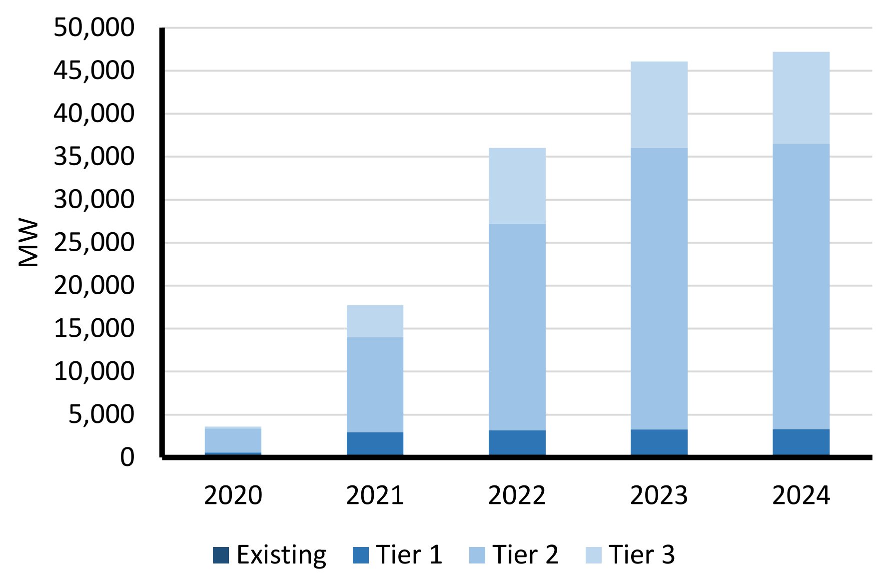


Figure 23: NERC-Wide Grid Battery and Hybrid Generation–Existing and Planning

Managing Risks as the Resource Mix Evolves

The addition of variable resources, primarily wind and solar, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources. Important reliability implications include the following:

- **Ensuring sufficient flexible resources:** In order to maintain load-and-supply balance in real time with higher penetrations of variable supply and less-predictable demand, operators are seeing the need to have more system ramping capability. As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. This can be accomplished by adding more flexible resources within their committed portfolios or by removing system constraints to flexibility.[26] Variable energy resources can provide ramping and other ERSs, and procurement mechanisms can be used to obtain flexible resources for operator needs. The following highlight activities that are underway in areas where variable energy resources make up a large share of the resource mix:

  - **California:** Increasing solar generation increases the need for flexible resources. California Independent System Operator's (CAISO's) *2020 Flexible Capacity Needs Assessment* continues to show monthly maximum three-hour ramp requirements increase each year over the assessment period.[27] **See the CAISO section of the text box on page 41.**

  - **Texas:** ERCOT has managed ramping needs from increasing amounts of wind generation through forecasting tools that give operators the ability to curtail wind production and/or reconfigure the system in response to wind output changes. To support reliable operations with growth in solar capacity, ERCOT is developing a short-term solar forecasting tool that can be integrated in generation dispatching to aid in meeting flexible needs for solar up and down ramps.

Planning and Operating with Inverter-Based Resources: Inverter based resources, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. Some inverter-based resource performance issues have been significant enough to result in grid disturbances that affect the reliability of the BPS, such as the tripping of a number of BPS-connected solar PV generation units that occurred during the 2016 Blue Cut fire and 2017 Canyon 2 fire disturbances in California. More recently, fault events on the BPS occurred in the Southern California area causing around 1,000 MW of BPS-connected solar PV resources to reduce power output and likely some DER tripped off-line.[28] Planning studies and operating models must accurately account for these newer resource types. In 2020, the NERC Inverter-Based Resource Performance Working Group (IRPWG) submitted requests that will begin the process for improving NERC Reliability Standards to include verifications of inverter-based resource parameters used in BPS planning and operating models.[29] The ERO continues to focus resources on addressing potential reliability issues associated with the ever-increasing penetration of inverter-based resources.[30]

26 https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERS_Measure_6_Forward_Tech_Brief_03292018_Final.pdf

27 See CAISO 2021 Flexible Capacity Needs Assessments: http://www.caiso.com/Documents/Final2021FlexibleCapacityNeedsAssessment.pdf

28 July 2020 San Fernando Solar PV Reduction Disturbance Report: https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx

29 Information about the standards authorization requests for Reliability Standards MOD-026-1 and MOD-027-1 can be found in the IRPWG White Paper: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf

30 In 2019, NERC published a summary of ERO activities to maintain reliability of the BPS through the growth of inverter-based resources in the resource mix. A discussion of significant grid disturbances, NERC alerts, and mitigating activities is included in the summary: https://www.nerc.com/comm/PC/Documents/Summary_of_Activities_BPS-Connected_IBR_and_DER.pdf

- **Managing fuel-related risks to electricity generation (fuel assurance):** Natural gas for electricity generation is an essential fuel bridging the rapid development of variable energy resources. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC Reliability Guideline *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System* provides planning guidance.[31] Disruptions to the fuel delivery results from adverse events that may occur, such as line breaks, well freeze-offs, or storage facility outages. The pipeline system can be impacted by events that occur on the electricity system (e.g., loss of electric motor-driven compressors) that are compounded when multiple plants are connected through the same pipeline or storage facility. Furthermore, additional pipeline infrastructure is needed to reliably serve load.

31 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

Key Finding 4: DER growth continues, prompting the ERO, planners, and operators in areas where penetrations have reached or are approaching impactful levels to take actions to ensure planning processes and operating measures are in place to ensure reliability.

Key Point

- Texas, Ontario, and areas in Northeast United States are approaching impactful DER levels presently seen in the WI, leading to the implementation of more sophisticated planning and operating measures. Other areas are closely monitoring DER growth and incorporating DER projections in long-term planning.

Projection of Solar DERs

Behind the meter (BTM) solar PV is an increasingly prevalent DER seen across NERC's footprint. BTM solar PV is defined as the solar PV resources connected directly to the distribution system. Residential rooftop solar PV comprises most of the BTM solar PV installed.

Figure 24 shows the amount of DER NERC-wide through 2030. The amount of DERs is projected to more than double by 2026 and surpass 60 GW total capacity over this 10-year period.

Figure 25 shows the amount of solar DER by assessment area by 2030. Increasing DER levels in New York, New England, Ontario, and Texas are approaching levels that can impact grid reliability in some conditions, leading entities in those areas to take steps for reliable planning and operations. California and parts of the WI have planning and operating measures in place that continue to evolve with growing DER levels.

At low penetration levels, the effects of DERs may not present a risk to BPS reliability; however, the effect of these resources can present certain reliability challenges that require attention, particularly as penetrations increase. This leads to areas where further consideration is needed to better understand the impacts and how those effects can be included in planning and operations of the BPS. The NERC report, *Distributed Energy Resources: Connection, Modeling, and Reliability Considerations*, provides a detailed assessment of DERs and their potential impact on BPS reliability.[32]

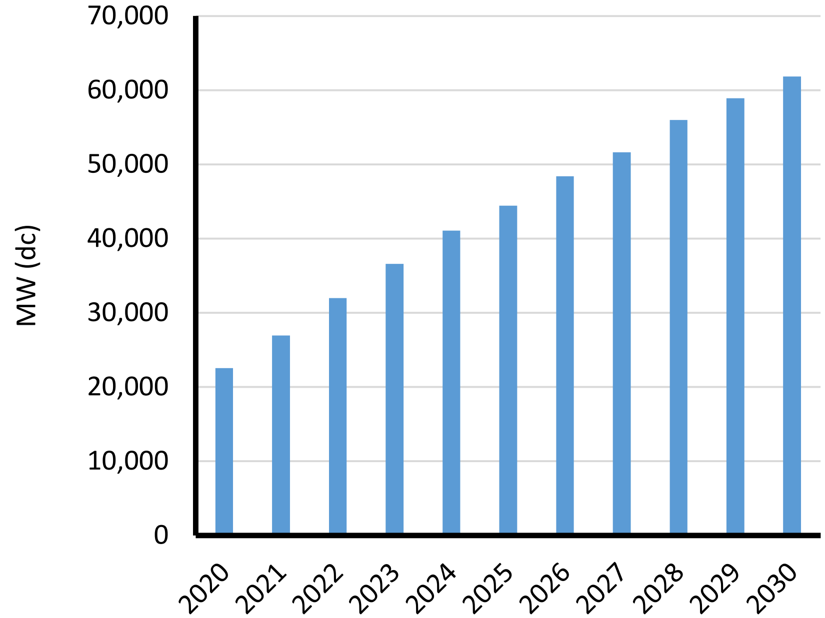


Figure 24: NERC-Wide Cumulative Distributed Solar PV Capacity—2020 through 2030

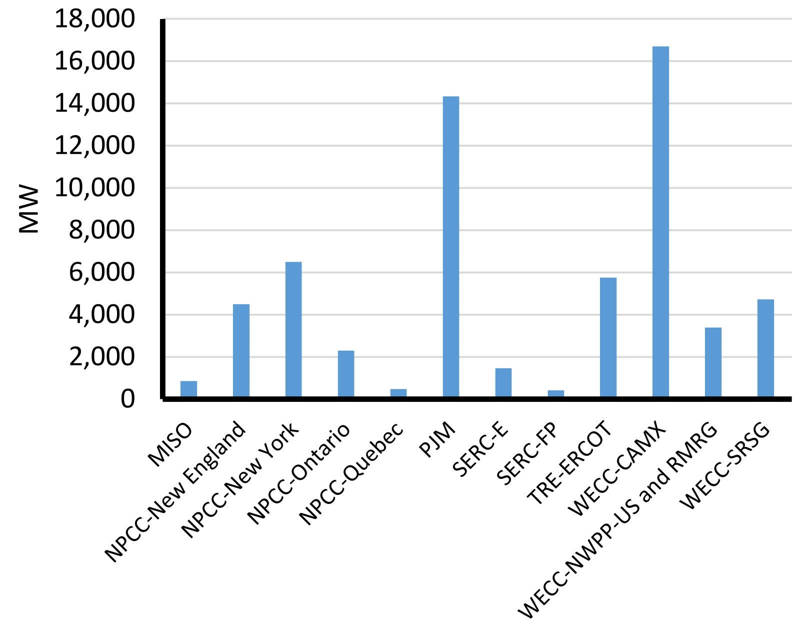


Figure 25: Solar DER by Assessment Area by 2030

32 *NERC Distributed Energy Resources: Connection, Modeling, and Reliability Considerations*: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

An illustrative example of this can be found in **Figure 26**, which shows that as solar PV is added to a particular system, increased ramping capability is needed to support the increased ramping requirements. This is not a completely new concern for operators as some resources and imports have a long history of nondispatchability due to physical or contractual limitations. However, variable resources (particularly solar generation due to its daily production patterns) are the primary driver leading to increased ramping requirements. Other dispatchable resources are needed in reserve to offset the lack of electricity production when variable fuels (e.g., sun, wind) are not available.

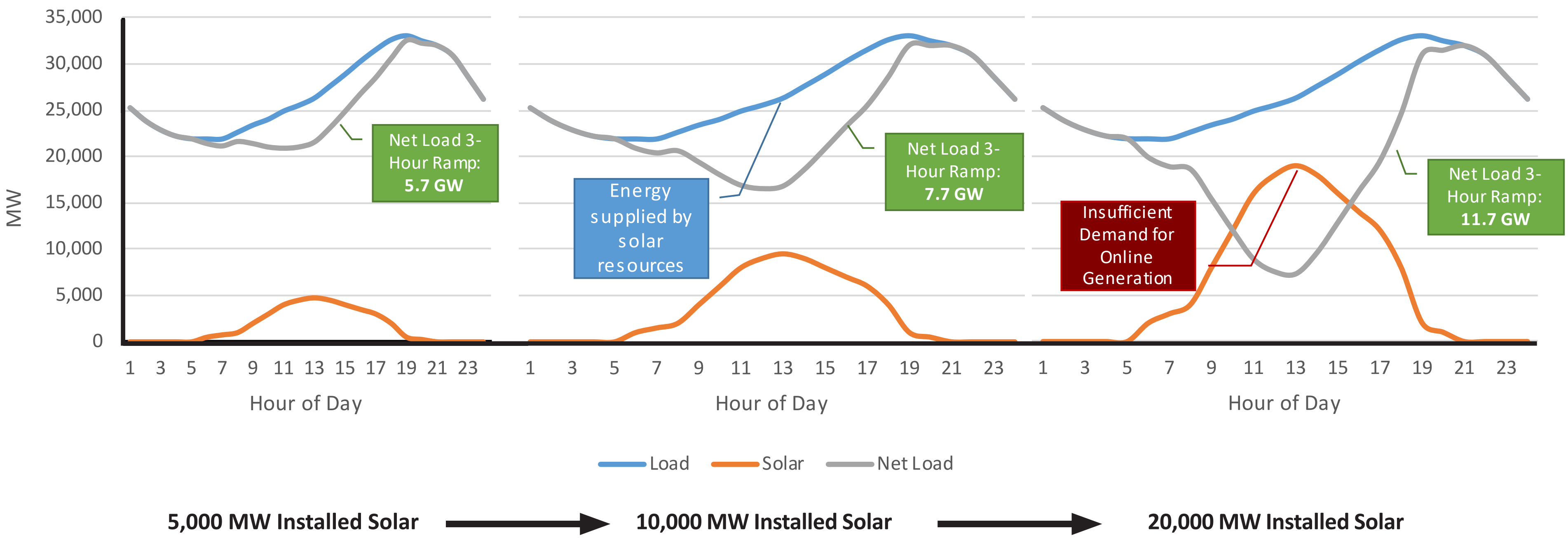


Figure 26: Example of Increasing Solar Resources Leading to Increased Ramping Requirements

Ramping

Ramping is a term used to describe the loading or unloading of generation resources in an effort to balance total demand with supply during daily system operations. Changes in the amount of nondispatchable resources, system constraints, load behaviors, and the generation mix can impact the needed ramp capability and amount of flexible resources needed to keep the system balanced in real-time. For areas with an increasing penetration of nondispatchable resources, the consideration of system ramping capability is an important component of planning and operations. Therefore, a measure to track and project the maximum one-hour and three-hour ramps for each assessment area can help understand the significant need for flexible resources.

CAISO Photovoltaic Generation and Ramping

Predominant drivers for increasing ramps have been due to changes in California's load patterns and can be attributed to an increased integration of PV DER generation across its footprint. For example, CAISO has over 11 GW of solar supply and must proportionally increase reserves to respond to a sudden increase in demand associated with cloud cover, rain, or inverter-related issues. Solar, rooftop or otherwise, is well dispersed throughout the state, reducing the expectations of widespread generation disruptions due to localized weather conditions (overcast skies in Northern California with clear skies in Southern California).

With continued rapid growth of distributed solar, CAISO's three-hour net-load ramping needs have already exceeded 15 GW. Based on current projections, maximum three-hour upward net-load ramps are projected to exceed 18,680 MW in March by 2021, an increase of just under 10% compared to the March 2021 projection from 2019 (see **Figure 27**). Upward ramping shortages are most prevalent in late afternoon when solar generation output decreases while system demand is still high. Without sufficient upward ramping capability within the balancing area to offset the loss of solar output during these times, neighboring BAs would have to provide the necessary support to balance supply and demand.

Continued increases in projected maximum three-hour ramps reinforces CAISO's near-term need for access to more flexible resources in their footprint.

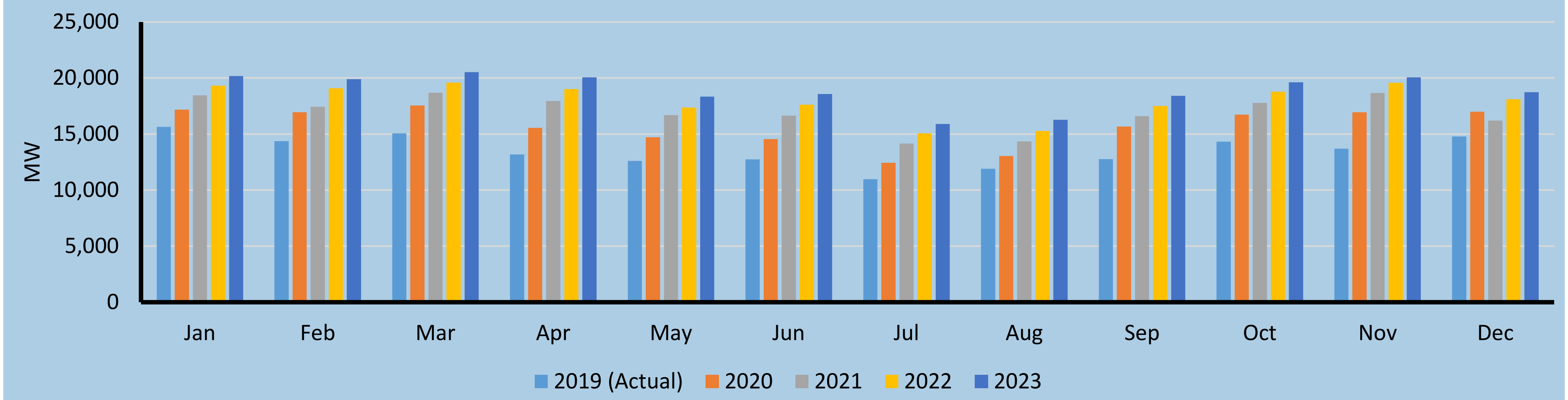


Figure 27: Maximum Three-Hour Ramps in CAISO (Actual and Projected) through 2023

Industry is already adapting by planning for the impacts of DERs. Some areas are already adapting in the following ways:

- **NPCC-New England:** ISO-NE has conducted studies regarding the higher penetration of DER (mostly solar resources) in the system and results conclude that the growth in DER still presents some concerns for system operators and planners. Concerns for ISO-NE include the following:
  - Difficulty in obtaining and managing the amount of data concerning DG/DER resources, including their size, location, and operational characteristics
  - A current inability to observe and control most DG/DER resources in real time
  - A need to better understand the impacts on system operations of the increasing amounts of DG/DERs, including ramping, reserve, and regulation requirements for both utility-based and BTM distributed generation

  To address these concerns, ISO-NE has developed various solar forecasting tools to help successfully integrate these burgeoning resources into planning and operations
- **NPCC-New York:** The historical solar PV data used to develop the demand forecast were obtained from the New York State Energy Research and Development Authority (NYSERDA),[33] which compiles information about expected solar installations. For the resource adequacy probabilistic planning assessments, the projected BTM PV is discretely modeled as an hourly (8,760 hours) shape. Nonsolar DER historical values reflect information from Transmission Owners and from NYSERDA's DER Integrated Data System database.
- **NPCC-Ontario:** The IESO is working to increase coordination between the grid operator and embedded resources directly or through integrated operations with local distribution companies with the aim to improve DER visibility and identify opportunities for a more coordinated operation of Ontario's electricity system.
- **PJM:** The Generation Attribute Tracking System collects distributed solar generation that is BTM. Utilizing this collection of data, PJM estimates the amount of distributed solar generation in terms of dc nameplate capacity.

33 https://der.nyserda.ny.gov/

- **Texas TRE-ERCOT:** ERCOT has developed a modified s-curve methodology for projecting growth for solar PV less than one MW with an underlying set of assumptions for three different scenarios (conservative, moderate, and aggressive) based on studies done for ERCOT. DER quantities in ERCOT are reported to the ERCOT Supply Analysis Working Group. One of the improvements in DER reporting over prior years was a result of NPRR891.[34] DER information from all available sources in Texas can be found in summary at the ERCOT website.[35]
- **WECC:** DER impacts on the individual LSEs are well understood and are in included in local assessments. For example, CAISO has approximately 5,132 MW of BTM solar supply and must proportionally increase reserves to respond to a sudden increase in demand associated with cloud cover, rain, or inverter-related issues. Solar, rooftop or otherwise, is well dispersed throughout the state, reducing the expectations of widespread generation disruptions due to localized weather conditions (overcast skies in Northern California with clear skies in Southern California).[36]

34 NPRR891

35 http://www.ercot.com/content/wcm/key_documents_lists/195745/2015_to_2019_DER_data_v1_pdf.pdf

36 In addition to local assessments, operating states are continuously monitored: http://www.caiso.com/TodaysOutlook/Pages/supply.aspx

The NERC Planning Committee (a predecessor of the RSTC) formed the NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG), which focusing on the BPS impacts of DER from a transmission planning and system analysis perspective. NERC's SPIDERWG focuses on four key aspects of DER impacts to the BPS:

- **Modeling:** Representing aggregate DERs in BPS reliability studies, advancing industry capabilities and expertise with representing DERs in these reliability studies, and developing robust and reasonable data sets for power flow and dynamic simulations
- **Verification:** Ensuring that the models used in studies provide a reasonable and suitable representation of the actual aggregate performance of these resources, benchmarking software platforms to ensure uniformity in tools, and recommending analysis techniques for accounting for aggregate DERs during large BPS disturbances
- **Studies:** Improving study techniques and methods to ensure the most stressed operating conditions are chosen for BPS reliability studies, identifying key operating conditions and sensitivities to perform, and improving software tools and study capabilities
- **Coordination:** Supporting coordination between transmission and distribution entities for improved data exchange and coordinating with IEEE leadership to support the application of IEEE Std. 1547- 2018 across North America

The NERC SPIDERWG will develop recommended practices and guidelines around these topics to ensure registered entities have the tools and capabilities to advance transmission planning studies in light of rapidly growing penetrations of DERs. SPIDERWG also serves as an excellent forum for distribution and transmission entities to exchange ideas and sharing needs in terms of information for modeling and situational awareness. SPIDERWG also supports the review and applicability of NERC Reliability Standards and identifies whether these standards may need to be modified to ensure reliable operation of the BES in light of the potential DER impacts.[37]

37 SPIDERWG information can be found on the NERC website: https://www.nerc.com/comm/PC/Pages/System-Planning-Impacts-from-Distributed-Energy-Resources-Subcommittee-(SPIDERWG).aspx

Key Finding 5: The ongoing pandemic is not presenting specific threats or degradation to the reliable operation of the BPS for the assessment period. However, it is producing increased uncertainty in future electricity demand projections and presents cyber security and operating risks.

Key Points

- Most assessment areas did not adjust long-term forecasts for pandemic impacts in this *2020 LTRA* because the effects on peak demand levels were unclear and duration is unpredictable. Summer operating experience in many areas showed increased residential demand that can offset decreased commercial/industrial load.
- Reduced industrial load can affect the availability of DR programs that rely on curtailment of industrial customers during periods of high demand.
- Personnel protections for operators and field crews, mitigating heightened cyber risks, and systems operations planning will be persistent areas for risk management throughout the pandemic.

The global health crisis has elevated the electricity reliability risk profile due to potential workforce disruptions, supply chain interruptions, and increased cyber security threats. In April, NERC released its *Pandemic Preparedness and Operational Assessment: Spring 2020* (special report) to advise electricity stakeholders of the reliability considerations and assess the operational preparedness of BPS owners and operators during pandemic conditions in April and May 2020. In its special report, NERC did not identify any specific threat or degradation to the reliable operation of the BPS for the spring time frame. The ERO continues to assess risks and conditions and is pursuing all available avenues to continue coordination with federal, state, and provincial regulators as well as work with industry to identify reliability implications and lessons learned.

Since the start of the widening COVID-19 infection in North America in February 2020, registered entities have taken steps from pandemic plans and industry advisories to maintain the reliability and security of the BPS. In March 2020, the Electricity Subsector Coordinating Council (ESCC) issued the first version of the *ESCC Resource Guide*[38] as a resource for electricity power industry leaders to guide informed localized decisions in response to the COVID-19 global health emergency; it is updated on a regular basis as new approaches, planning considerations, and issues develop. The guide highlights data points, stakeholders, and options to consider while making decisions about operational status while protecting the health and safety of employees, customers, and communities. Sharing experiences and expertise helps users of the guide to make independent, localized decisions aimed at reducing negative impacts to the BPS's power supply during the COVID-19 global pandemic. In addition to immediate measures designed to protect critical operations, personnel, and functions, entities are working to minimize risk to resource and BPS equipment availability, assure fuel supplies, and prepare operating personnel for peak season.

The pandemic is negatively impacting electricity demand in many parts of North America just as it has elsewhere around the world. Prior to Summer 2020, when government stay-at-home orders and societal response were at their highest, some areas reported as much as 15% decrease in peak demand. However, these observed demand impacts varied across North America and were negligible in some areas. Throughout the pandemic, ISOs and RTOs have periodically reported on demand impacts.[39] In most areas, weather continues to be the predominant factor in electricity demand.

Many areas are experiencing variations in hourly load shapes as a result of changing societal behaviors and mechanisms implemented to halt the spread of COVID-19. In general, these areas are seeing below-normal ramp in demand in morning hours and lower evening demand as can be seen in **Figure 28**. Changes to pre-pandemic patterns can affect the accuracy of day-ahead demand forecasts that are relied upon to ensure resources are available for each hour of the day. In recent years, demand and resource forecasting has become more complex and more critical as the generation resource mix has changed to include higher levels of variable generation and an altered load shape with increasing solar PV resources. When operating entities began observing discrepancies between predicted and actual demand as a result of pandemic behavior, many instituted measures designed to improve the accuracy of forecasts made available to system operators. In MISO and other ISOs, support teams have increased the frequency of short-term demand forecast simulations.

38 https://www.electricitysubsector.org/

39 For example, see reports from ERCOT and CAISO: http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf and http://www.ercot.com/content/wcm/lists/200201/ERCOT_COVID-19_Analysis_FINAL.pdf

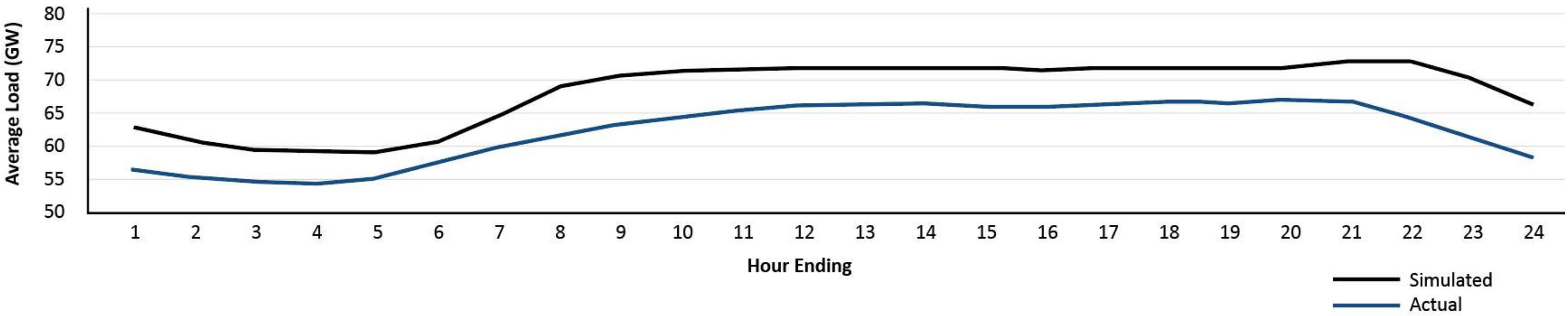


Figure 28: Average Simulated and Actual Load in MISO Area for April 4–10, 2020

Reduced industrial load has the potential to negatively affect the availability of DR resources used by operators during periods of peak demand. In assessing resource adequacy in NERC reliability assessments, entities project the MW capacity of demand that operators can modify through direct control and dispatch during the peak hour to alleviate shortages. Often DR resources are contracted industrial customers that agree to electricity curtailments during periods when operators have a shortage of operating reserves. If industrial demand is reduced already by lower industrial output and a period of extreme temperatures were to occur that drive space-heating loads, operators could find their demand-response curtailments to have little effect. Figure 29 shows the anticipated controllable and dispatchable DR contributions as a percentage of total internal demand for 2021 in selected assessment areas. In each area, DR resources are a varying mix of commercial, industrial, and residential loads.

Potential Demand and Resource Challenges for System Operators

As noted in previous ERO assessments of pandemic impacts, system operators could encounter difficult system characteristics, such as increased impact of DERs on load profiles, reverse power flows on distribution circuits, higher than usual operating voltages, and minimum demands at all-time lows; operating challenges like these need to be addressed in real-time, often by using complex tools for studying these dynamic system conditions.

The effect of DERs on system performance is becoming more pronounced as synchronous generation is replaced, particularly during periods of lower minimum demand; operators could face challenges in maintaining sufficient amounts of frequency-responsive reserves necessary to regulate or arrest fre-

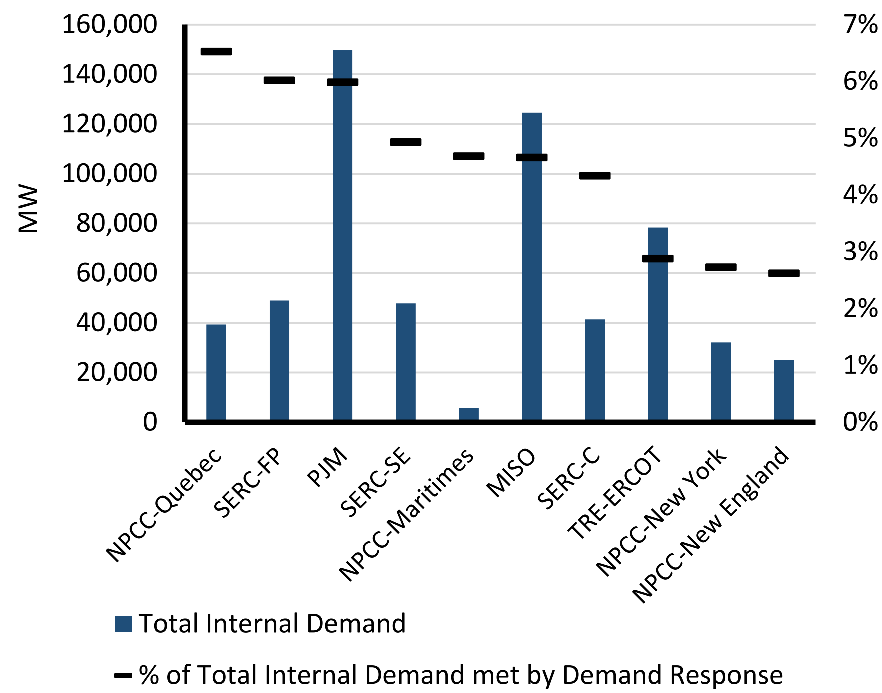


Figure 29: Projected 2021 Peak Season DR–Assessment Areas with Highest DR Contribution to Meeting Total Peak Demand

quency deviations. Typically, DER effects on the system are more pronounced in the spring when milder temperatures reduce air conditioning load and increase efficiency in solar PV modules. In areas with higher DER penetrations (e.g., California, North Carolina), minimum loads and reverse power flows from the distribution system can cause challenges for system operators.

The potential lack of industrial and commercial load could alter underfrequency or undervoltage load shedding plans that rely on tripping these dispatchable loads as well as DR programs that may be relied on to support emergency operations.

Utility Crews and Operators Must Stay Postured for Reliability, Security, and Resilience

As the COVID-19 crisis unfolded, the industry prepared to operate with a significantly smaller workforce, an encumbered supply chain, and limited support services for an extended and unknown period of time. Vigilance to cyber security threats intensified as risks are elevated due to a greater reliance on remote working arrangements. The business continuity and pandemic plans developed by the different operating entities are designed to protect the people working for them and to ensure critical electricity operations and infrastructure are supported properly throughout an emergency.

Protecting the critical electricity industry workforce during the COVID-19 pandemic remains a priority for reliability and resilience. System and Generator Operators have implemented operating postures and personnel restrictions prescribed by their pandemic plans in order to protect essential personnel and support reliable operations. Many of these measures will need to be maintained or be reinstituted during periods of resurgence. There is a continuing risk that control centers or plants could be temporarily shut down if a significant number of operators or plant employees test positive for COVID-19 despite preparedness efforts, including employee sequestration. While entities have developed return to work plans, the majority are expected to maintain protective protocols for operating personnel into 2021. When relaxations can be implemented, operators will likely need to stay postured to return to heightened protections if warranted by changing public health conditions.

Operating Reliability Considerations

- Increased uncertainty in demand projections and daily use
- Potential for increased forced outages due to deferred maintenance, staff unavailability, or limited supplies and/or fuel
- Higher than usual operating voltages
- Light load conditions
- Reverse power flow and increased DER penetration levels
- Potential for reduced effectiveness in underfrequency/voltage load shedding schemes as industrial and commercial load may not be on-line

An important component of BPS resilience and recovery from hurricanes and major storms is the effective mutual assistance rendered by organizations from outside the storm-affected areas. Over the past summer, industry cooperation played a significant factor in the effective response and restoration of the power system from multiple hurricanes and tropical storms that battered areas along the U.S. Gulf of Mexico area. The comprehensive plans in place to rapidly deploy support teams and equipment take on even greater complexity due to the need to safeguard personnel from COVID-19. In April, the ESCC updated its *Resource Guide* to provide lessons learned from the experience of the utilities, electricity cooperatives, and investor-owned electricity companies affected by a series of storms in late March and early April of this year.[40] Lessons learned include considerations for maintaining social distancing at all times, planning for personnel protection equipment needs, and the increased need for local logistical and coordination personnel to support a decentralized response.

Cyber Security Risk and Information Sharing

Electricity and other critical infrastructure sectors face elevated cyber security risks arising from the COVID-19 pandemic in addition to ongoing risks. Opportunistic actors are attempting to find and exploit new vulnerabilities that arise as entities shift work processes and locations to maintain business continuity. The E-ISAC exchanges information with its members, including communications and guidance from the ESCC and from government partners as well as advisories about emerging cyber threats.

40 See *ESCC Resource Guide*, Version 7, April 27, 2020, p. 47–48.

Demand, Resources, Reserve Margins, and Transmission

Demand Projections

In 2020, there is heightened uncertainty in demand projections that stems from the progression of the COVID-19 pandemic and the response of governments, society, and the electricity industry. NERC-wide electricity peak demand and energy growth rates have leveled off, or even declined, after the increasing growth rates reported in the *2019 LTRA*.

Figure 30 identifies the 10-year compound annual growth rate (CAGR) of peak demand that is declining for summer but increasing slightly for winter when compared to the prior year. The projected 10-year energy growth rate is 0.43%, which is down from 0.6% reported in the *2019 LTRA* (**Figure 31**).

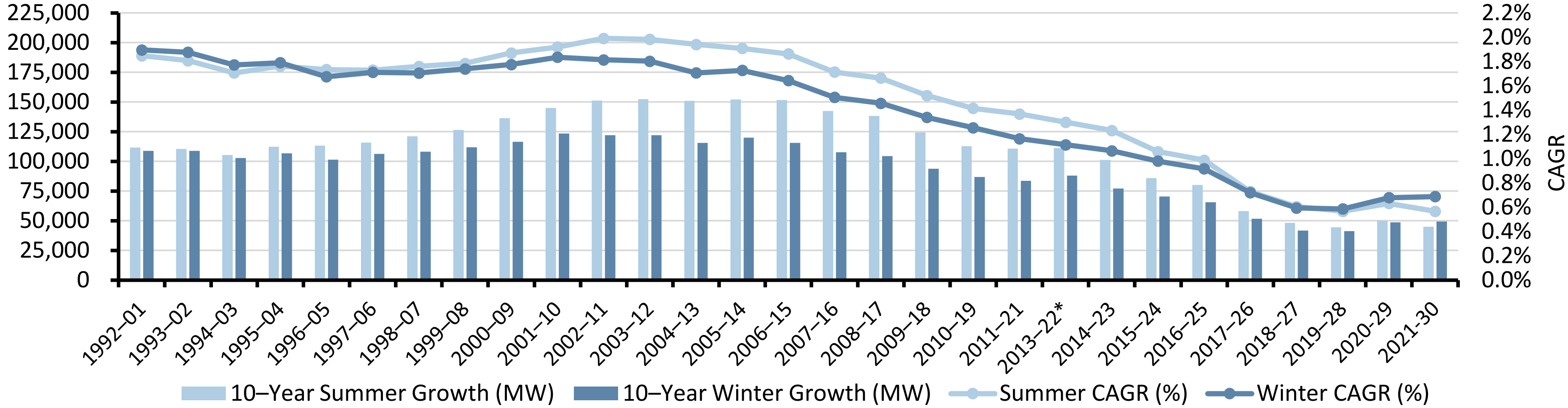


Figure 30: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electricity industry continues to monitor electricity use and generally revise their forecasts on an annual basis or as their resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically "equal probability" forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of demand side management (DSM) programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.

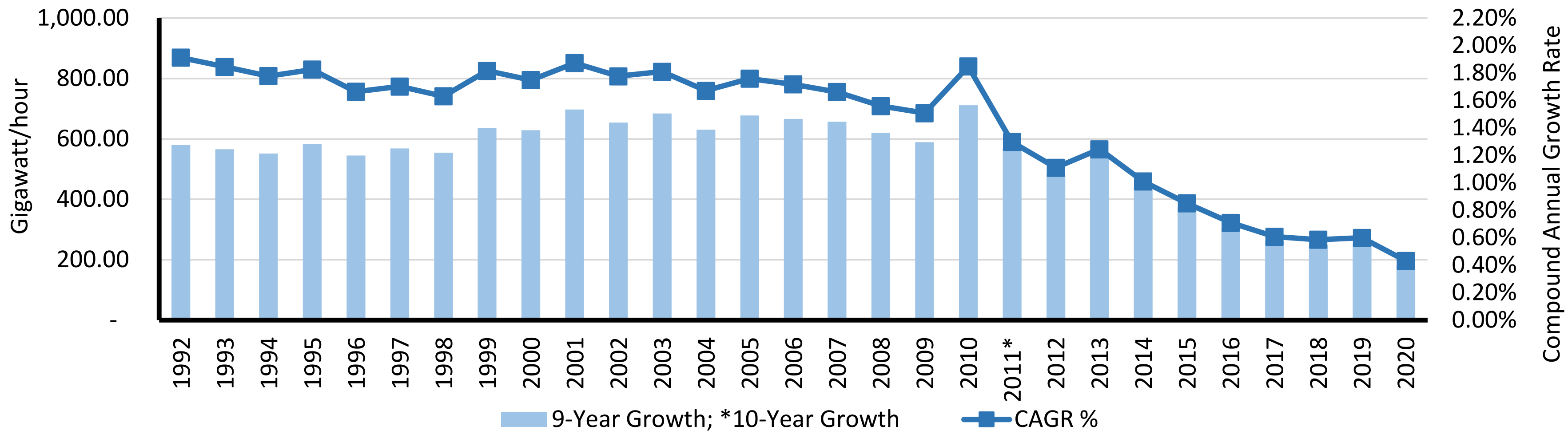


Figure 31: 10-Year Net Energy to Load Growth and Rate Projection Trends

The 10-year demand growth rate in all assessment areas is 1.7% or less per year with three assessment areas projecting reductions in peak demand (Figure 32). Note NPCC NY, NPCC Ontario, and NPCC Quebec have adjusted demand forecasts to account for anticipated impacts from the ongoing COVID pandemic.

Continued advancements of EE programs combined with a general shift in North America to less energy-intensive economic growth are contributing factors to slower electricity demand growth. There are 30 states in the United States that have adopted EE policies that are contributing to reduced peak demand and overall energy use.[41] Additionally, DERs and other BTM resources continue to increase in number and reduce the net demand for the BPS even further.

Fuel Mix Changes

Figures 33 and 34 identify the components of the fuel mix for the North American BPS. Figure 33 shows the installed capacity composition of generating resources NERC-wide as of July 2020 compared to the projected installed capacity composition of 2030 (includes Tier 1 additions).

Figure 34 shows the on peak capacity composition of generating resources NERC-wide as of July 2020 compared to the projected on peak capacity composition of 2030 (includes Tier 1 additions). On-peak capacity gives an idea of what a resource is capable of producing at peak demand.

41 EIA - Today in Energy: Many states have adopted policies to encourage EE.

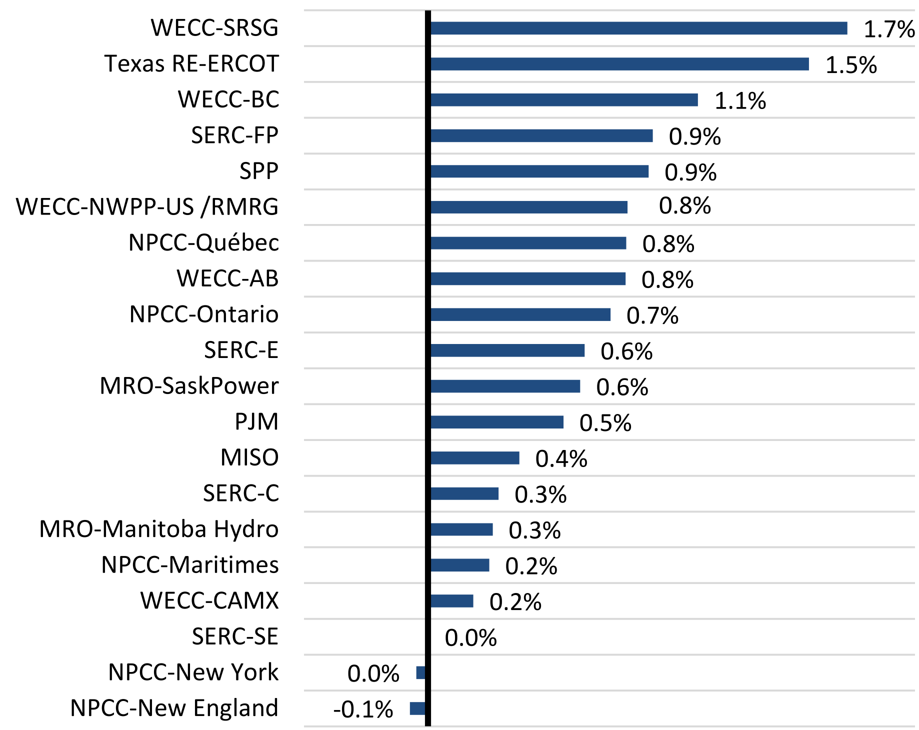


Figure 32: Annual Peak Demand Growth Rate for 10-Year Period by Assessment Area

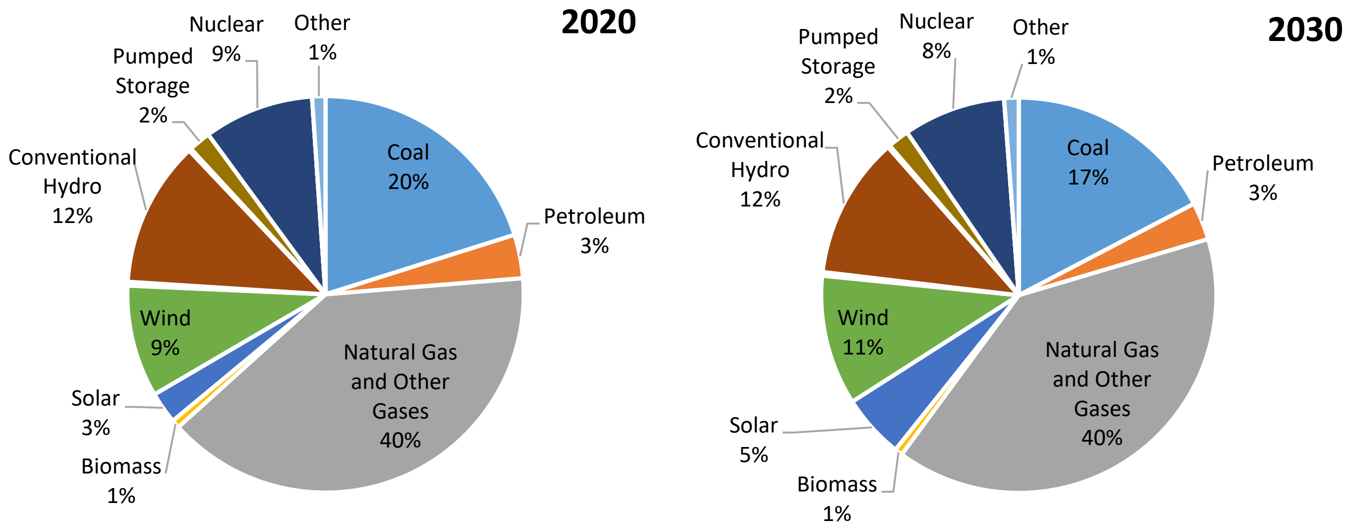


Figure 33: Installed Nameplate Capacity by Fuel Mix Trend (Includes Future Tier 1 Resources)

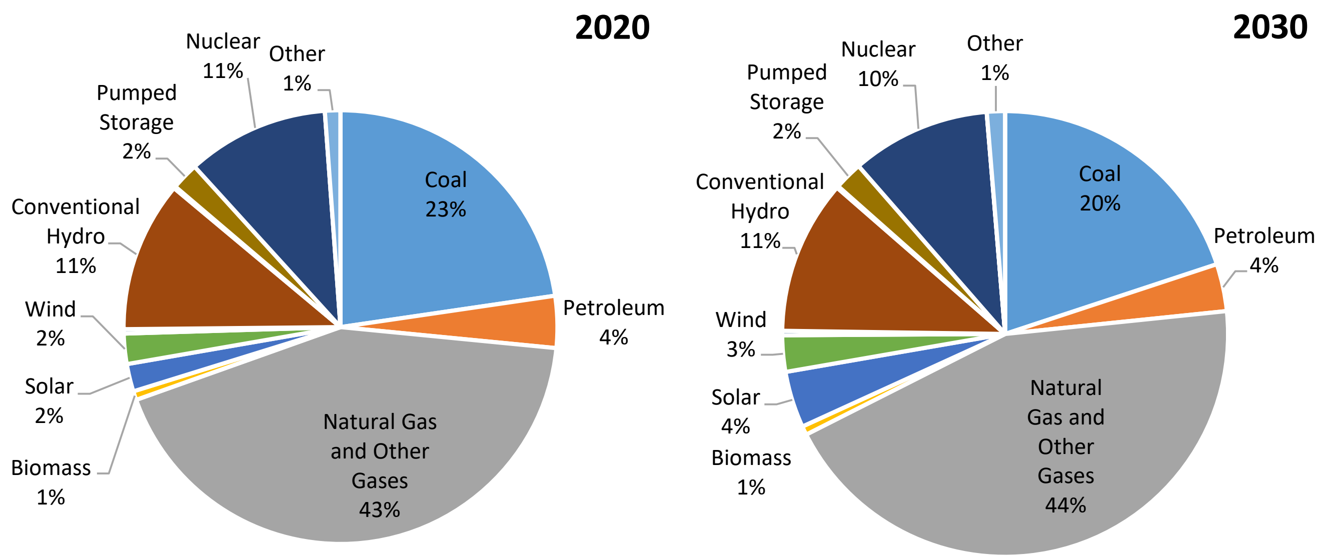


Figure 34: Installed On-Peak Anticipated Capacity Trend by Fuel Mix

The PRMs for the years 2021–2025 are shown in Table 9. Table 10 shows the RMLs for each assessment area.

Table 9: Planning Reserve Margins (2021–2025)

Assessment Area	Reserve Margins (%)	2021	2022	2023	2024	2025
MISO	Anticipated Reserve Margin	23.8%	22.3%	19.9%	18.3%	17.0%
	Prospective Reserve Margin	31.6%	41.1%	51.6%	53.7%	53.9%
	Reference Margin Level	18.0%	18.0%	18.0%	18.0%	18.0%
MRO-Manitoba	Anticipated Reserve Margin	19.8%	17.7%	16.0%	15.8%	13.5%
	Prospective Reserve Margin	18.4%	16.2%	14.6%	14.4%	12.1%
	Reference Margin Level	12.0%	12.0%	12.0%	12.0%	12.0%
MRO-SaskPower	Anticipated Reserve Margin	34.3%	34.7%	30.0%	37.0%	31.5%
	Prospective Reserve Margin	34.3%	34.7%	30.0%	37.0%	31.5%
	Reference Margin Level	11.0%	11.0%	11.0%	11.0%	11.0%
NPCC-Maritimes	Anticipated Reserve Margin	21.6%	19.3%	19.7%	20.9%	20.7%
	Prospective Reserve Margin	21.6%	19.3%	19.7%	19.2%	18.4%
	Reference Margin Level	20.0%	20.0%	20.0%	20.0%	20.0%
NPCC-New England	Anticipated Reserve Margin	30.9%	29.4%	28.3%	18.9%	19.0%
	Prospective Reserve Margin	34.8%	34.7%	40.1%	32.2%	34.7%
	Reference Margin Level	13.1%	13.2%	12.7%	12.7%	12.7%
NPCC-New York[1]	Anticipated Reserve Margin	19.4%	19.8%	17.8%	18.6%	17.1%
	Prospective Reserve Margin	19.7%	20.1%	19.5%	20.4%	18.9%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Ontario	Anticipated Reserve Margin	23.8%	20.1%	5.5%	11.2%	2.0%
	Prospective Reserve Margin	23.8%	20.1%	10.1%	15.7%	10.9%
	Reference Margin Level	23.9%	23.8%	16.2%	16.7%	15.9%
NPCC-Quebec	Anticipated Reserve Margin	13.3%	13.5%	12.2%	14.0%	13.5%
	Prospective Reserve Margin	16.2%	16.5%	15.2%	16.9%	16.4%
	Reference Margin Level	10.1%	10.1%	10.1%	10.1%	10.1%
PJM	Anticipated Reserve Margin	39.1%	38.4%	41.5%	41.9%	41.1%
	Prospective Reserve Margin	47.1%	64.5%	77.5%	83.2%	83.3%
	Reference Margin Level	15.1%	14.9%	14.8%	14.8%	14.8%

1 The NERC RML for NY is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2020–2021 IRM at 18.9%. All values in the IRM calculation are based upon full Installed Capacity (ICAP) MW values of resources. The NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year.

Table 9: Planning Reserve Margins (2021–2025)						
Assessment Area	**Reserve Margins (%)**	**2021**	**2022**	**2023**	**2024**	**2025**
SERC-C	Anticipated Reserve Margin	29.3%	28.7%	29.6%	25.9%	23.6%
	Prospective Reserve Margin	34.8%	34.1%	37.8%	35.4%	33.2%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-E	Anticipated Reserve Margin	22.7%	24.3%	23.7%	27.0%	27.4%
	Prospective Reserve Margin	22.9%	24.5%	23.9%	27.3%	27.6%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-FP	Anticipated Reserve Margin	22.3%	21.1%	23.7%	22.3%	22.2%
	Prospective Reserve Margin	23.5%	22.3%	24.8%	23.4%	23.3%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-SE	Anticipated Reserve Margin	34.2%	37.9%	39.5%	41.4%	40.9%
	Prospective Reserve Margin	36.0%	41.7%	43.6%	45.6%	45.1%
	Reference Margin Level	15.0%	15.0%	15.0%	15.0%	15.0%
SPP	Anticipated Reserve Margin	29.5%	26.5%	25.1%	24.2%	23.4%
	Prospective Reserve Margin	38.2%	35.0%	33.5%	32.5%	31.7%
	Reference Margin Level	15.8%	15.8%	15.8%	15.8%	15.8%
TRE-ERCOT	Anticipated Reserve Margin	16.2%	19.6%	18.0%	16.0%	14.3%
	Prospective Reserve Margin	20.5%	49.8%	57.0%	55.3%	53.1%
	Reference Margin Level	13.75%	13.75%	13.75%	13.75%	13.75%
WECC-AB	Anticipated Reserve Margin	22.6%	26.3%	22.8%	24.0%	23.6%
	Prospective Reserve Margin	32.2%	42.1%	50.5%	55.6%	55.1%
	Reference Margin Level	13.8%	12.3%	13.8%	14.1%	14.1%
WECC-BC	Anticipated Reserve Margin	21.4%	20.6%	19.1%	21.2%	24.1%
	Prospective Reserve Margin	21.4%	20.6%	19.1%	21.3%	24.2%
	Reference Margin Level	13.8%	12.3%	13.8%	14.1%	14.1%
WECC-CAMX	Anticipated Reserve Margin	21.4%	27.8%	27.3%	26.8%	22.5%
	Prospective Reserve Margin	21.4%	35.3%	40.8%	41.7%	37.4%
	Reference Margin Level	18.2%	15.8%	19.1%	19.1%	19.1%
WECC-NWPP-US and RMRG	Anticipated Reserve Margin	25.9%	24.6%	23.4%	21.6%	20.8%
	Prospective Reserve Margin	25.9%	24.8%	24.0%	22.2%	21.5%
	Reference Margin Level	15.4%	16.1%	15.2%	15.1%	15.0%
WECC-SRSG	Anticipated Reserve Margin	18.1%	17.3%	17.0%	14.7%	15.5%
	Prospective Reserve Margin	18.1%	18.1%	19.5%	17.2%	17.9%
	Reference Margin Level	10.9%	11.9%	11.0%	10.8%	10.7%

Table 10: Reference Margin Levels for Each Assessment Area (2021–2025)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	18.0%	PRM	Yes: Established Annually[42]	0.1 day/Year LOLE	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	11.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
NPCC-Maritimes	20.0%[43]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	12.7–13.2%	Installed Capacity Requirement (ICR)	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE; NPCC Criteria
NPCC-New York	15.0%[44]	Installed Reserve Margin (IRM)	Yes: one year requirement; established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC; NPCC Criteria
NPCC-Ontario	14.4–23.8%	Ontario Reserve Margin Requirement (ORMR)	Yes: established annually for all years	0.1 day/Year LOLE	IESO; NPCC Criteria
NPCC-Québec	10.1%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro Québec; NPCC Criteria
PJM	14.8–15.5%	IRM	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers; Reliability*First* BAL-502-RFC-02 Standard

42 In MISO, the states can override the MISO PRM

43 The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

44 The NERC LTRA RML for NY is 15%; however, there is no planning reserve margin criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2020–2021 IRM at 18.9%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

Table 10: Reference Margin Levels for Each Assessment Area (2021–2025)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-C	15.0%[45]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-E	15.0%[46]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-FP	15.0%[47]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-SE	15.0%[48]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SPP	15.8%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP RTO Staff and Stakeholders
TRE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustment for non-modeled market considerations	ERCOT Board of Directors
WECC-AB	11.15–13.18%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-BC	11.15–13.18%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-CAMX[49]	15.65–19.14%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-NWPP-US & RMRG	14.54–16.12%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-SRSG	10.29–11.86%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC

45 SERC does not provide RMLs or resource requirements for its sub-regions. However, SERC members perform individual assessments to comply with any state requirements.

46 SERC does not provide RMLs resource requirements for its sub-regions. However, SERC members perform individual assessments to comply with any state requirements.

47 SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.

48 SERC does not provide RMLs or resource requirements for its sub-regions. However, SERC members perform individual assessments to comply with any state requirements.

49 California is the only state in the WI that has a wide-area PRM requirement, currently 15%.

Transmission

Historical Trend

Figure 35 shows the historical 10-year transmission projections for the past 10 years, each year being a 10-year projection. Between the years 2011 and 2016, considerably more transmission was planned than more recent years. For example, in 2012, nearly 40,000 circuit miles of high voltage transmission was planned for the next 10 years. Current projections show less than 15,000 circuit miles of planned transmission for the next 10 years. NERC's transmission projection data is limited to planned projects and does not identify completed projects.

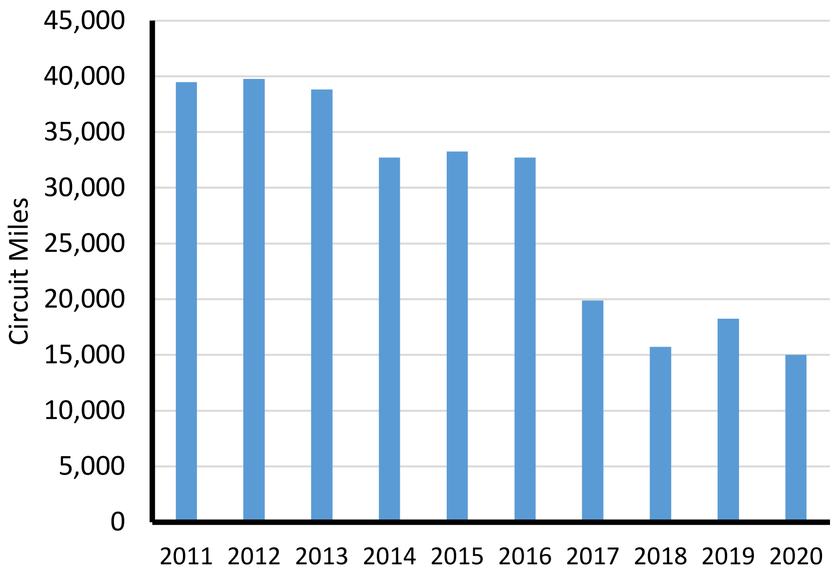


Figure 35: Historical 10-Year Transmission Projections

Future Projections

Figure 36 highlights that ERO-wide transmission additions during the 10-year period include plans for over 14,000 circuit miles, including conceptual projects. NERC continues to monitor the progress of transmission projects across North America. This amount represents a considerable reduction in the amount of transmission miles planned in nearly a decade, compared with the 30,000+ miles planned each year during the period 2011–2016 (from **Figure 35**). ISO/RTOs and utility planners must dedicate resources to planning processes that support the reliable integration of wind and solar generation into the transmission system.

Future Transmission Project Categories

Under Construction: Construction of the line has begun.

Planned (any of the following):

- Permits have been approved to proceed
- Design is complete
- Needed in order to meet a regulatory requirement

Conceptual (any of the following):

- A line projected in the transmission plan
- A line that is required to meet a NERC TPL standard or powerflow model and cannot be categorized as "Under Construction" or "Planned"
- Other projected lines that do not meet requirements of "Under Construction" or "Planned"

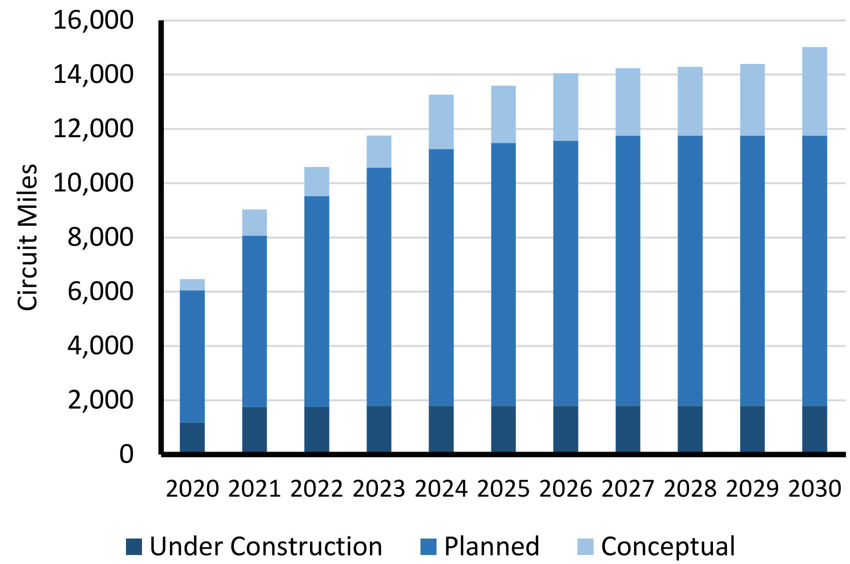


Figure 36: Future Transmission Circuit Miles >100 kV, by Project Status

Figure 37 shows the future transmission circuit miles by voltage class.

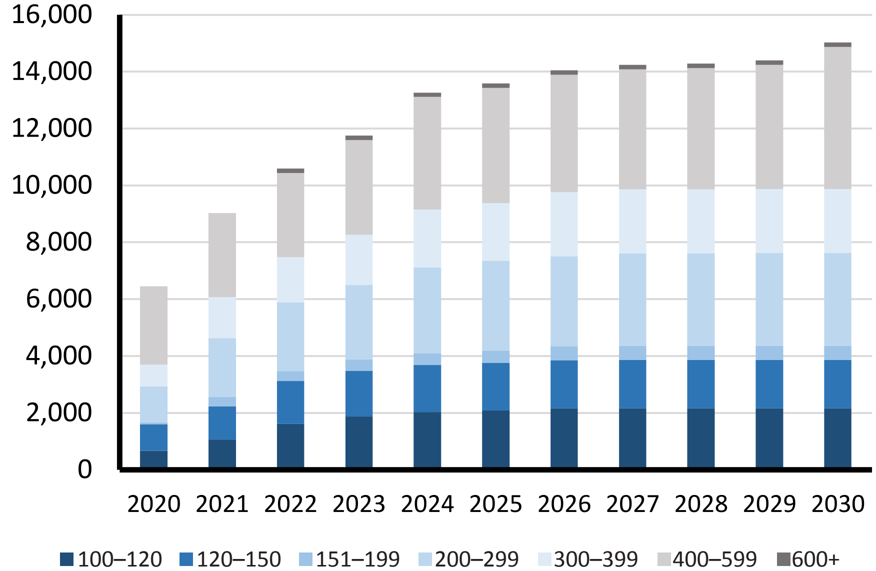


Figure 37: Future Transmission Circuit Miles >100kV, by Voltage Class

Figure 38 shows that most planned transmission projects are shorter in line length, and fewer longer length projects are being planned. However, with the amount of solar and wind coming online in the next 10 years, area planning processes may identify needs for longer length transmission projects to capture and transmit renewable energy from areas distant from load centers.

Figure 39 shows the percentage of future transmission circuit miles by primary driver over this 10-year assessment period. According to industry, new transmission projects are being driven to support new generation and enhance reliability. Other reasons include congestion alleviation and addressing aging assets and infrastructure.

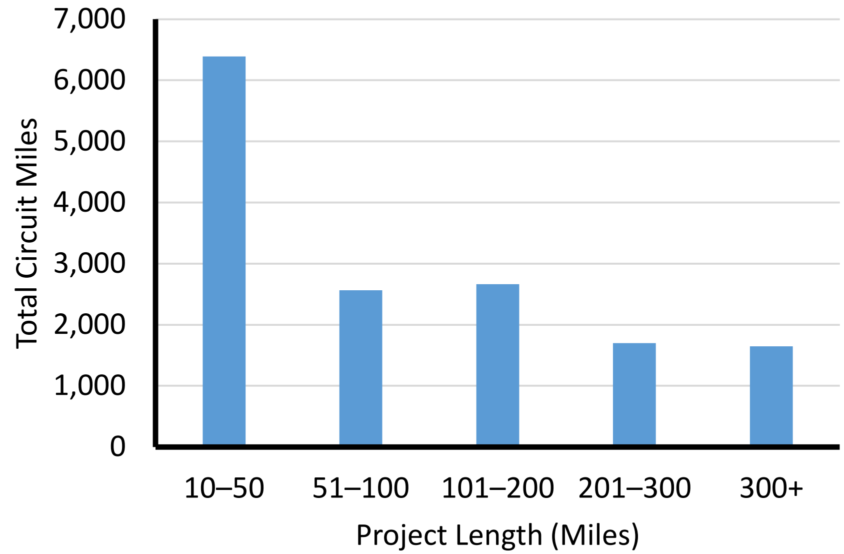


Figure 38: Line Miles Projected through 2030

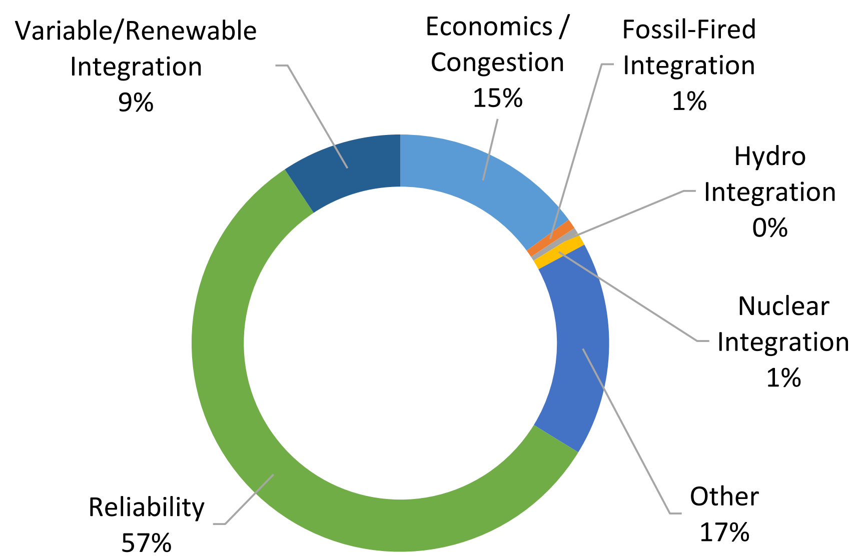


Figure 39: Future Transmission Circuit Miles by Primary Driver

Figure 40 shows the assessment areas as net capacity importers or exporters for the year 2021. Net importers are shown in yellow and net exporters are shown in blue. The grey assessment areas are below 100 MW of capacity imported or exported for 2021.

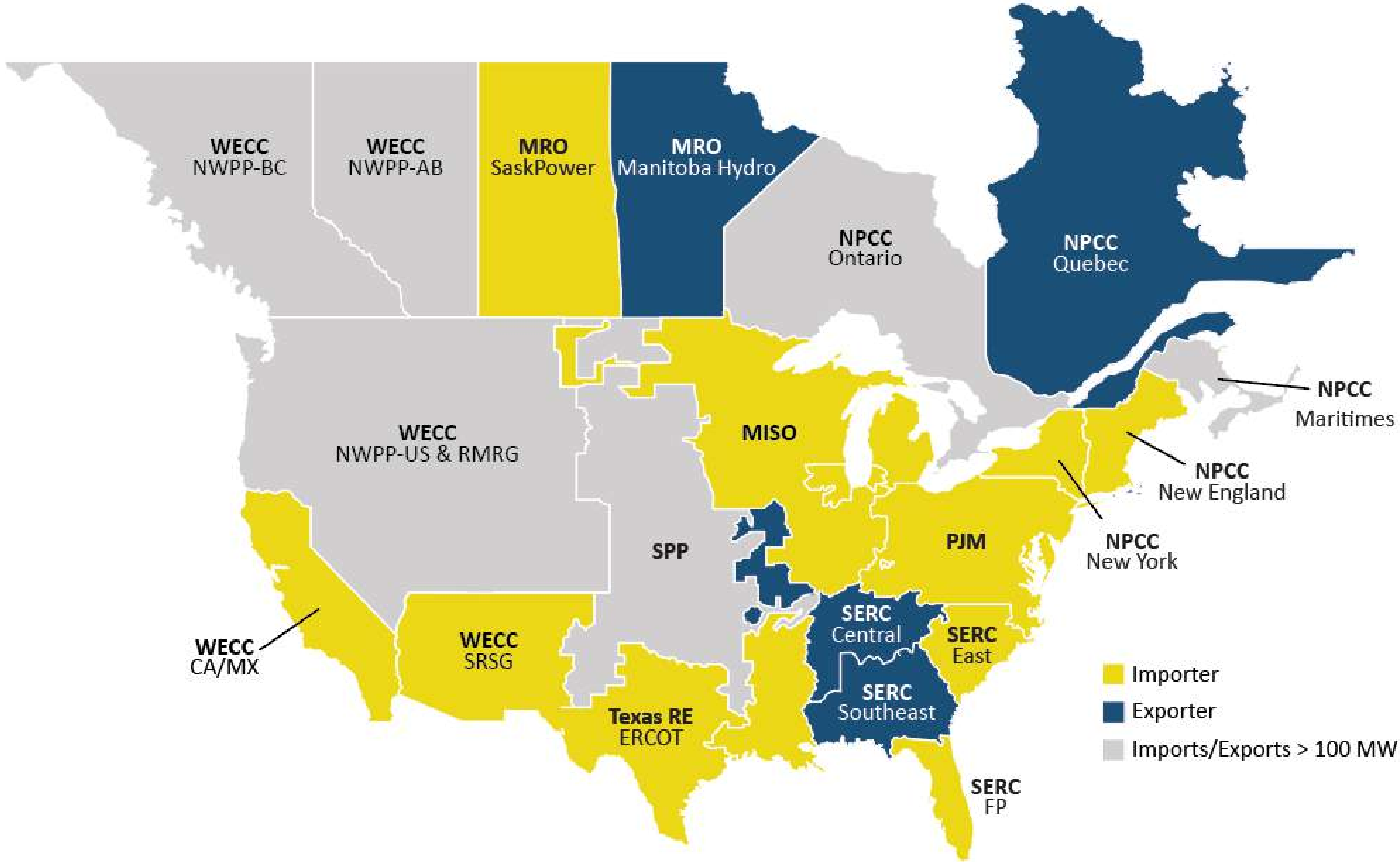


Figure 40: Net Capacity Transfers for Year 2021

Table 11 shows the percent of the reserve margin that is supported by net capacity transfers. If an assessment area has a positive percentage, it is a net importer. Conversely, if an assessment area has a negative percentage, it is a net exporter.

Table 11: Year 2021 Net Capacity Transfers by Assessment Area					
Assessment Area	**Peak Demand (MW)**	**Firm Net Transfers (MW)**	**Reserve Margin (MW)**	**Percent of Reserve Margin**	**Anticipated Capacity Resources**
MISO	118,684	2,545	27,364	9.3%	146,048
MRO-Manitoba Hydro	4,667	-447	923	-48.4%	5,591
MRO-SaskPower	3,516	-66	1,205	-5.5%	4,721
NPCC-Maritimes	5,422	153	1,170	13.1%	6,591
NPCC-New England	24,327	1,305	7,526	17.3%	31,852
NPCC-New York	31,253	1,812	6,064	29.9%	37,317
NPCC-Ontario	21,635	0	5,139	0.0%	26,774
NPCC-Quebec	36,743	-499	4,830	-10.3%	41,610
PJM	140,661	1,460	54,988	2.7%	195,649
SERC North	39,628	-630	11,623	-5.4%	51,251
SERC-East	45,000	605	10,206	5.9%	55,206
SERC-FP	46,075	872	10,275	8.5%	56,350
SERC-Southeast	45,394	-1,016	15,506	-6.6%	60,900
SPP	51,643	-4	15,215	0.0%	66,859
TRE-ERCOT	76,045	210	12,354	1.7%	88,399
WECC-AB	12,329	0	2,784	0.0%	15,113
WECC-BC	11,077	0	2,368	0.0%	13,445
WECC-CAMX	54,713	4,224	11,704	36.1%	66,417
WECC-NWPP US and RMRG	63,096	0	16,337	0.0%	79,433
WECC-SRSG	25,590	865	4,634	18.7%	30,224

Regional Assessments

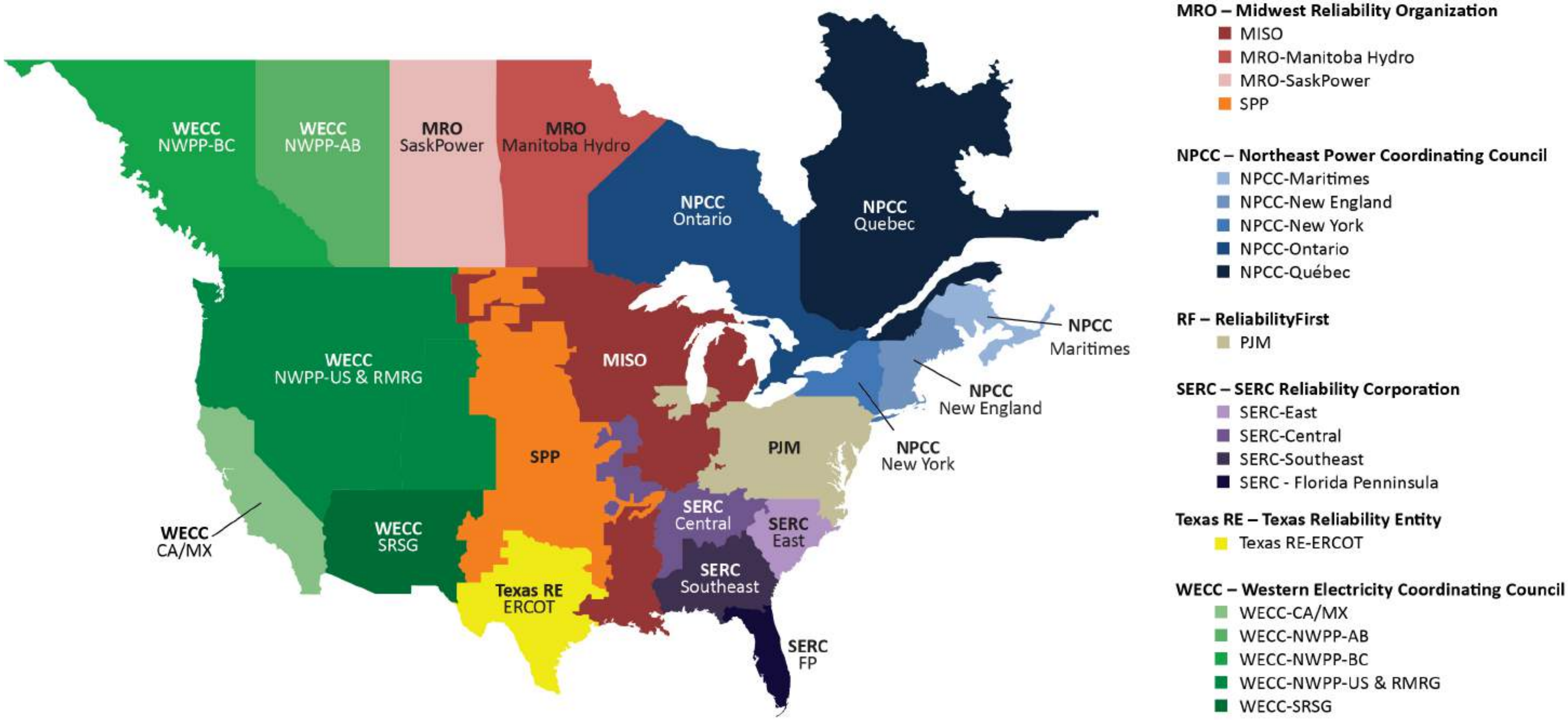
The following regional assessments were developed based on data and narrative information collected by NERC from the REs on an assessment area basis. The RAS, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information. A summary of the key data is provided in Table 12.

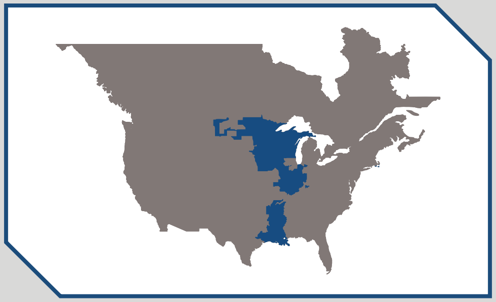
Table 12: Summary of 2025 Peak Projections by Assessment Area and Interconnection

Area	Net Internal Demand (MW)	Annual Net Energy for Load (GWh)	Net Transfers (MW)	Anticipated Capacity Resources	Anticipated Reserve Margin
MISO	121,303	743,628	1,840	141,976	17.0%
MRO-Manitoba	4,780	25,293	-614	5,423	13.5%
MRO-SaskPower	3,622	24,967	290	4,762	31.5%
NPCC-Maritimes	5,500	28,509	0	6,636	20.7%
NPCC-New England	24,065	124,678	14	30,061	19.0%
NPCC-New York	30,835	149,167	1,954	36,121	17.1%
NPCC-Ontario	23,238	137,836	0	23,703	2.0%
NPCC-Quebec	37,238	196,571	-145	42,263	13.5%
PJM	144,143	817,966	0	203,332	41.1%
SERC-C	40,202	219,331	-701	49,701	23.6%
SERC-E	45,686	221,114	605	58,206	27.4%
SERC-FP	47,961	242,993	498	58,594	22.2%
SERC-SE	45,894	253,032	-1,086	64,685	40.9%
SPP	54,399	297,456	183	67,118	23.4%
TRE-ERCOT	81,992	458,263	210	93,678	14.3%
WECC-AB	12,725	92,118	0	15,727	23.6%
WECC-BC	11,572	62,555	0	14,364	24.1%
WECC-CAMX	53,770	273,398	3,571	65,875	22.5%
WECC-NWPP US and RMRG	65,319	402,067	0	78,906	20.8%
WECC-SRSG	27,396	111,018	2,220	31,637	15.5%
EASTERN INTERCONNECTION	591,628	3,285,970	2,983	749,489	26.7%
QUEBEC INTERCONNECTION	37,238	196,571	-145	42,263	13.5%
TEXAS INTERCONNECTION	81,992	458,263	210	93,678	14.3%
WESTERN INTERCONNECTION	162,853	941,156	2,628	208,390	28.0%

NERC Assessment Areas

In order to conduct NERC reliability assessments, NERC further divides the REs into 20 assessment areas, shown below. This level of granularity allows NERC to better evaluate resource adequacy and ensure deliverability constraints between and among assessment areas are accounted for.

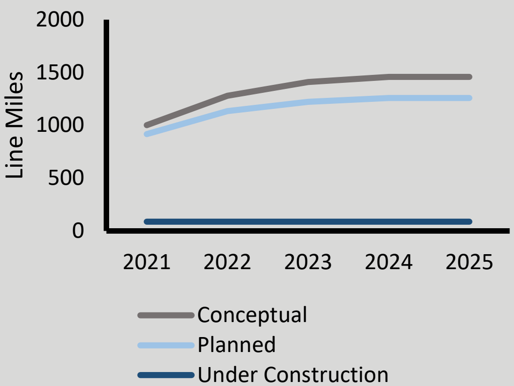




MISO

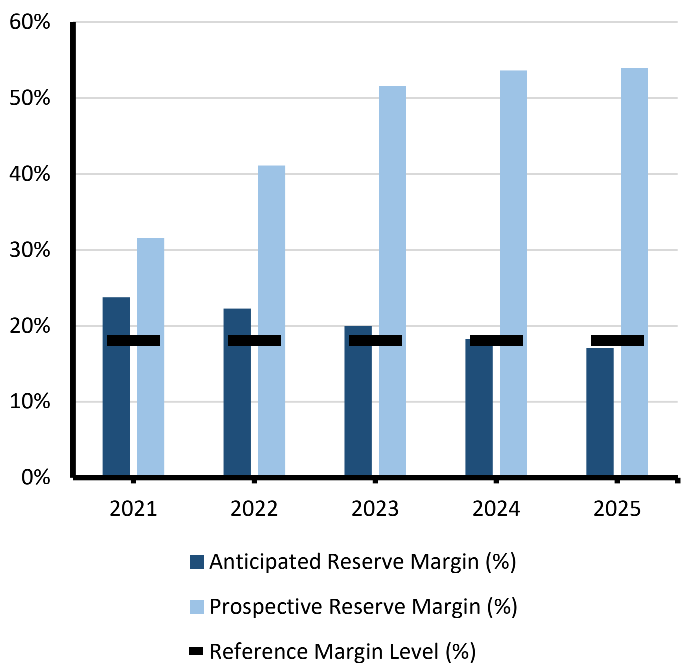
MISO is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities (BAs) and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC REs, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

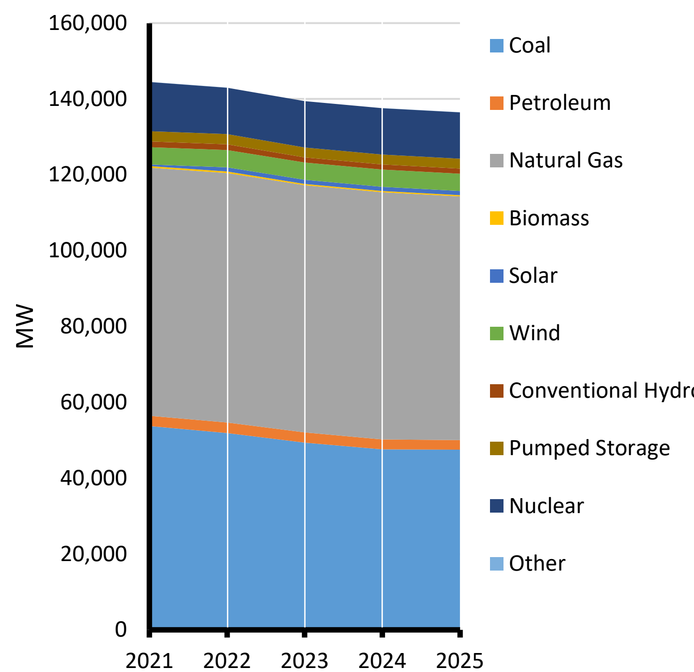


Projected Transmission Circuit Miles

Demand, Resources, and Reserve Margins (MW)										
Quantity	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Internal Demand	124,485	125,913	126,237	126,612	127,029	127,195	127,618	128,004	128,324	128,672
Demand Response	5,801	5,760	5,726	5,726	5,726	5,726	5,726	5,726	5,726	5,726
Net Internal Demand	118,684	120,152	120,511	120,886	121,303	121,469	121,892	122,277	122,598	122,946
Additions: Tier 1	2,964	4,634	4,634	4,634	4,634	4,634	4,634	4,634	4,634	4,634
Additions: Tier 2	3,214	16,615	32,360	36,993	38,993	38,993	38,993	38,993	38,993	38,993
Additions: Tier 3	1,456	3,524	5,279	6,495	8,592	8,666	9,947	10,419	11,477	11,477
Net Firm Capacity Transfers	2,545	2,550	2,555	2,560	1,840	1,840	1,745	1,750	1,755	1,755
Existing-Certain and Net Firm Transfers	143,913	142,265	139,905	138,360	137,342	136,238	136,032	135,093	133,904	134,280
Anticipated Reserve Margin (%)	23.8%	22.3%	19.9%	18.3%	17.0%	16.0%	15.4%	14.3%	13.0%	13.0%
Prospective Reserve Margin (%)	31.6%	41.1%	51.6%	53.7%	53.9%	52.7%	52.0%	50.7%	49.4%	49.2%
Reference Margin Level (%)	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- The MISO area will have adequate but tighter reserve margins for 2021, and continued action will be critical to ensure resource adequacy into the future. For 2021, MISO will have surplus resources to meet the regional resource requirement. In most of the MISO area, load-serving entities with oversight by the applicable state or local jurisdiction are responsible for resource adequacy. Though the 2021 peak demand forecast decreased 300 MWs from last year's survey, the five-year regional demand growth rate is up from 0.2% to just under 0.35% this year. On the supply side, the survey indicates that increasing resource adequacy risk can be avoided by firming up the commitments of additional potential resources.
- The potential for significant generation fleet transformation has prompted MISO to evaluate how system needs will change and how MISO might adapt its planning, markets, and operations to maintain reliability with aging and retiring units, higher penetration of intermittent resources, and new load consumption patterns.
- Resource adequacy planning that focuses on summer peak alone will no longer suffice. Resource adequacy analysis will likely need to reflect patterns across the year in order to capture the magnitude of risks.
- Effective dialogue amongst stakeholders will be key to this transformation; this will help identify needs and allow MISO to develop solutions that work across the footprint. MISO will leverage the forums where discussions are already underway on transmission planning, MISO's resource adequacy construct, and pricing enhancements.
- As the MISO fleet continues to evolve, ongoing comprehensive analysis is needed to detail risks; inform change in MISO's planning, markets, and operations processes; and iterate based on continued change in stakeholders' plans.

MISO Fuel Composition										
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	53,771	51,948	49,401	47,595	47,516	46,296	46,362	45,362	43,866	43,866
Petroleum	2,737	2,737	2,652	2,652	2,507	2,507	2,507	2,507	2,507	2,507
Natural Gas	65,396	65,787	65,162	65,142	64,278	62,631	62,387	62,300	60,802	60,802
Biomass	438	420	397	372	372	372	300	300	297	297
Solar	385	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089
Wind	4,558	4,569	4,555	4,550	4,542	4,541	4,519	4,489	4,464	4,464
Conventional Hydro	1,539	1,539	1,333	1,333	1,331	1,331	1,331	1,331	1,331	1,331
Pumped Storage	2,686	2,686	2,654	2,654	2,654	2,654	2,654	2,654	2,654	2,654
Nuclear	12,982	12,169	12,169	12,169	12,169	12,169	12,169	12,169	12,169	12,169
Other	35	35	35	35	35	35	35	35	35	35
Total MW	144,527	142,978	139,446	137,591	136,492	133,624	133,352	132,235	129,213	129,213

MISO Assessment

PRM

MISO projects a regional surplus for the summer of 2021 and possibly 2022 and then falling near or below the RML in 2023–2024, sooner than the last LTRA. These results are driven by a number of factors: an increase in load forecast, an increase in reserve requirement due to changes in load shape and fleet make-up, and a decrease in load modifying resources. New resources effectively made up for retirements since 2019.

This *2020 LTRA's* results represent a point in time forecast, and MISO expects PRMs will change as future capacity plans are solidified by LSEs and states. There are enough resources in Tier 2 and 3 to mitigate any long-term resource shortfalls.

Demand

MISO does not forecast load for the seasonal resource assessments. Instead, LSEs report load projections under the Resource Adequacy Requirements section (Module E-1) of the MISO tariff. LSEs report their annual load projections on a MISO-coincident basis as well as their noncoincident load projections for the next 10 years, monthly for the first 2 years, and seasonally for the remaining 8 years. MISO LSEs have the best information of their load, so MISO relies on them for their 50/50 load forecast information.

The MISO coincident total internal demand peak forecast was 124,148 MW during the 2020 summer season, around an 850 MW decrease from last year's projection. MISO members project the summer coincident peak demand is expected to grow at an average annual rate of 0.34% over the next five-year period, up from 0.2% seen in last year's forecasts. Drivers for an increase in the annual growth rate are unknown but not surprising as 0.2% last year was very low and, compared with historical forecast growth rates, 0.34% is still very low. Electrification of transportation, heating, and other loads traditionally served by other sources are anticipated, so future growth is not unexpected. These projections were largely submitted to MISO before any observed or forecasted impacts due to COVID-19.

Demand Side Management

MISO currently separates demand response resources into two categories: Direct Control Load Management and Interruptible Load. Direct Control Load Management is the magnitude of customer service (usually residential). During times of peak conditions, or when MISO otherwise forecasts the potential for maximum generation conditions, MISO surveys local BAs to obtain the amount of their demand. For this assessment, MISO uses the registered amount of DSM that is procured and cleared through the annual planning resource auction.

MISO forecasts 7,557 MW of Direct Control Load Management and Interruptible Load to be available for the assessment period. MISO also forecasts at least 4,793 MW of BTM generation to be available for assessment period. This year's 2020 OMS-MISO survey responses indicate declining DR. The driver for this is unclear, but it may be due to respondents only entering current capacity contracts and not anticipated contract renewals.

Distributed Energy Resources

MISO has not experienced any operational challenges yet due to DERs and will continue to monitor as programs grow and visibility increases in the future. As of right now, the main method of collecting DER information is through an organization of MISO states DER survey that, to-date, has just tracked current installation levels, not future forecasts. This will be the third iteration that informs responses in the LTRA, and MISO will begin to get a better sense of future impacts to the system from DERs as this process matures or other efforts are undertaken to better assess DERs.

Generation

Though MISO does not have any authority to direct any member to construct new generation, MISO continuously seeks to improve the generator interconnection process, enabling more seamless resource integration and resource adequacy assessments; this ensures all utilities and state regulators with the authority to direct to build new generation are aware of the state of resource adequacy in MISO and its corresponding resource zones.

MISO allows units to participate in the MISO capacity auction only to the level of interconnection service they have. If a unit has transmission interconnection service less than their nameplate rating, that unit is only eligible for the level of transmission service in the capacity auction. If future projects increase the level of transmission service, that unit may then qualify for up to the rated uniformed capacity in the capacity market.

Capacity Transfers

Interregional planning is critical to maximize the overall value of the transmission system and deliver savings for customers. Interregional studies conducted jointly with MISO's neighboring planning areas are based on an annual review of transmission issues at the seams. Depending on the outcome of those reviews, studies are scoped out and performed.

MISO and SPP completed their second coordinated system plan study. The study identified one potential interregional project for further evaluation within each area whereby MISO's regional analyses determined there existed more cost-effective and efficient regional alternatives. MISO and SPP will be exploring process improvements to allow both RTOs to align more closely how each addresses future interregional system planning needs that stem from a dramatically changing future energy landscape expected to impact both RTOs.

Transmission

As a part of MISO's annual planning process, MISO performs extreme event analysis to evaluate system performance of a large variety of extreme events developed collaboratively by MISO and the Transmission Planners within the MISO footprint.

The following analyses are performed annually as part of the *MISO Transmission Expansion Plan* reliability assessment, and the results of these analyses are documented in *MISO Transmission Expansion Plan* report for future NERC compliance:[50]

- Steady State Analysis (including the simulation of documented remedial action schemes)
- Planning Horizon Transfer Analysis
- Transient Stability Analysis
- Voltage Stability Analysis

Together, these analyses address the impacts to transmission limitations, transmission constraints, dynamic and steady state reactive-power limited areas, and remedial action schemes.

50 MISO Transmission Expansion Plan information: https://www.misoenergy.org/planning/planning

Probabilistic Assessment Overview

- **General Overview:** MISO is a summer-peaking system that spans 15 states and consists of 36 Local BAs that are grouped into 10 local resource zones. For the ProbA, MISO utilized a multiarea modeling technique for the 10 local resource zones internal to MISO. Firm external imports as well as nonfirm imports are also modeled. This model and accompanying methodology has been thoroughly vetted through MISO's stakeholder process.
- **Modeling:** Each local resource zone was modeled with an import and export limit based on power flow transfer analysis. In addition to the zone-specific import and export limits, a regional directional limit was modeled, limiting the North/Central (LRZs 1–7) to South (LRZs 8–10) flow to 3,000 MWs and South to North/Central to 2,500 MWs. Specific modeling details include the following:
  - Annual peak demand in MISO varies by about ±5% of forecasted MISO demand based upon the 90/10% points of load forecast uncertainty (LFU) distributions.
  - Thermal units in MISO follow a two-state on-or-off sequence based on Monte-Carlo simulations, which utilize equivalent forced outage rate demand (EFORd). EFORd is, on average, equivalent to derating MISO thermal generating resources by ~9.36%.
  - Hydro units in MISO are modeled as resources with an EFORd except for run-of-river units. These are modeled at their individual capacity credit that is determined by the resource's historic performance during peak hours.
  - Variable energy resources (wind and solar) in MISO are load modifiers. Wind resources are modeled with varying monthly capacity values that were determined by a monthly effective load-carrying capability (ELCC) analysis. Solar resources are modeled at their individual capacity credit that is determined by the resource's historic performance during peak hours. The average capacity value is 16.6% for wind and assumed at 50% for solar initially and until enough solar exists on the system for a solar ELCC analysis to be performed.
- **Probabilistic vs. Deterministic Assessments:** The LTRA deterministic reserve margins decrement the capacity constrained within MISO south due to the 2,500 MW limit that reflects a decrease in reserve margin. The constraint was explicitly modeled for the probabilistic analysis to determine if sufficient capacity was available to transfer from south to north and vice versa. The modeling of this limitation results in a higher ProbA forecast PRM. The following describes differences and other details:
  - The ProbA utilized demand forecasts based on the average annual peak of 30 weather years developed as part of MISO's annual LOLE analysis. The 30 weather year load shapes are then scaled to match the LSE's monthly forecasted peaks. The LTRA relies on 50/50 out-year forecasts from LSE's.
  - The ProbA applies monthly ELCC values to wind resources where the LTRA counts wind at their annual capacity credit values.
  - DR is treated as a dispatchable call-limited resource in the ProbA. In the LTRA, NERC nets DR from the load.
  - The ProbA accounted for zonal transmission constraints whereas the LTRA only considers regional (north/south) constraints. The LTRA reduces the reserve margin according to capacity that is trapped behind constraints, but the ProbA does not. Instead, the constraints are modeled, and trapped capacity is probabilistically determined (this is reflected in the risk results).

Base Case Study

- The forecast operable reserve margin decreases slightly from 2022 to 2024. However, because of additional resources in import-constrained zones, the LOLH and EUE risk decreases.
- The magnitude of EUE decreased slightly from the 2018 ProbA, but EUE increased in PPM due to a reduced energy forecast. There was also a slight increase in LOLH. The increases in risk were driven by reduced import limits in some zones.

Probabilistic Base Case Results Outside of the On-Peak Hour

- Month of LOL occurrences and/or contributing factors:
  - Since MISO is a summer-peaking system, most of the LOLH occurs during the summer months (June–September) as expected. However, there are cases where LOLH occurs during off-peak periods.
- Time of day of occurrence(s) and/or contributing factors (e.g., morning, afternoon, evening, overnight):
  - LOLH typically happens in the morning during the winter and afternoon during the spring/fall. Winter LOLH is confined to MISO south where peak loads occur in the morning.
- Any reliability factors or reliability risk drivers that created additional LOL or resource adequacy risk at the nonpeak hours:
  - LOLH during nonpeak hours was the result of certain zones being import limited during shoulder seasons when seasonal planned outages are occurring or there is high seasonal load, as seen in MISO south during the winter.

Base Case Summary of Results			
Reserve Margin (RM) %			
	2022*	**2022**	**2024**
Anticipated	18.9%	21.6%	17.6%
Reference	17.1%	18.0%	18.0%
ProbA Forecast Operable	13.7%	17.9%	17.8%
Annual Probabilistic Indices			
	2022*	**2022**	**2024**
EUE (MWh)	31.6	27.3	14.3
EUE (ppm)	0.019	0.038	0.020
LOLH (hours/year)	0.108	0.196	0.085

*Represents the 2018 ProbA results for 2022.

Probabilistic Base Case results of EUE

- Month, magnitude, duration, time of day of occurrence(s) and/or contributing factors (e.g., morning, afternoon, evening, overnight):
  - EUE is observed in all months with the majority occurring in the summer during the afternoon peak hours. The average duration of EUE events is about two hours. EUE during the summer is driven primarily by high load and high forced outages.
- Any reliability factors or reliability risk drivers that created additional LOL or resource adequacy risk at the nonpeak hours:
  - There are cases where EUE occurs during nonpeak hours when high planned outages overlap with unseasonably high load. This is magnified in zones that are transmission constrained when the zone is unable to import enough energy to meet peak demand.

- Any proposed resource, system changes, or planning strategy that may help mitigate LOL or resource adequacy risks. These could be based on LTRA or ProbA Base Case results:
    - MISO's Resource Availability and Need initiative is analyzing off-peak risks and working with stakeholders on how to best address these issues. As a result of the Resource Availability and Need initiative, MISO has made changes to the annual LOLE study to better reflect unit availability, including modeling planned outages more realistically and modeling wind with monthly variation. Future improvements that are being considered include changes to resource accreditation, sub-annual resource adequacy requirements, and modeling hourly wind profiles in LOLE studies.

Key methods and assumption differences between this *2020 LTRA* and ProbA assessments

The ProbA analyzes all hours of the year while the LTRA is only looking at 10-year summer/winter peak forecasts. As a result, the ProbA provides more insight into intra-yearly system risks that may occur during nonpeak periods, and the LTRA highlights longer-term resource adequacy planning concerns.

Probabilistic resource adequacy studies conducted that address area reliability risk drivers

MISO conducts a LOLE analysis on an annual basis that sets the PRM and local reliability requirements for market participants. The requirements serve as inputs to MISO's annual planning resource auction, where resources are cleared in the auction up to the requirements in order to maintain an LOLE of one day-per-year. The LOLE study[51] is similar to the ProbA in that both are probabilistic Monte-Carlo simulations that analyze the entire year. However, the LOLE study does not explicitly model transmission constraints. Instead, the local resource zones (LRZs) are analyzed as though they are isolated from the rest of the system to determine local requirements while the MISO system is modeled as a "copper sheet" to determine the PRM.

Regional Risk Scenario

For the 2020 ProbaA risk scenario sensitivity, MISO chose to investigate how the risk changes as a result of increasing DR. Over the last several years, DR in MISO has steadily increased and has made up a larger percentage of reserves. However, these resources are limited in the number of times they can be deployed each year, increasing risk as their calls are depleted. Currently in MISO, DR is required to be available at a minimum of five calls per year and four hours per call.

For this analysis, MISO will increase DR as a percentage of the overall resource mix in increments of 1,000 MW. This will be done by adding 100 MW DR resources to each of the 10 LRZ's as well as a 100 MW negative unit, which is equivalent to adding 100 MW of peak demand. Adding a negative unit (instead of removing units when DR is added) allows MISO to isolate the effect that increasing DR has on reliability since removing units would have its own effect on reliability depending on which units were removed. This analysis will be performed on year four. Since that year is starting from a lower LOLH value, it should be easier to see any risk that is introduced as a result of increasing DR.

51 https://www.misoenergy.org/planning/resource-adequacy/#nt=%2Fplanningdoctype%3APRA%20Document&t=10&p=0&s=&sd=