MINNESOTA TRANSMISSION OWNERS

October 31, 2017

Re: 2017 Biennial Transmission Projects Report

Dear Recipient:

Enclosed is a CD containing the 2017 Minnesota Biennial Transmission Projects Report prepared by the Minnesota Transmission Owners, a group of sixteen utilities that own transmission lines in Minnesota.

The Transmission Projects Report summarizes the transmission needs that Minnesota utilities foresee for the near future. Utilities are required by state law (Minnesota Statutes § 216B.2425) to file this Report with the Minnesota Public Utilities Commission by November 1 of each odd-numbered year.

You are receiving a copy of this Report because your name or your organization's name appears on a service list for this matter. The Commission's rule identifying the individuals and organizations who are to receive a copy is Minnesota Rules part 7848.1800. If you are a county government or a library, we request that you make the CD available to members of the public who request to review it.

The Minnesota Public Utilities Commission has assigned Docket Number E-999/M-17-377 to this matter. The Public Utilities Commission will be soliciting public comments on the Reports over the next few weeks. Persons interested in participating in this matter can find various documents related to the Biennial Report by entering the 17-377 number into the PUC's efiling webpage at

https://www.edockets.state.mn.us/EFiling/search.jsp

The 2017 Report and previous years Reports are also available on the Internet at:

www.minnelectrans.com

If you have any questions or would like to request a printed copy of the Biennial Report, you can send an e-mail to: Jason.t.standing@xcelenergy.com A free printed copy of the Report will be provided to those on the service list upon request.

Thank you.

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2017 Biennial Transmission Projects Report

American Transmission Company, LLC
Dairyland Power Cooperative
East River Electric Power Cooperative
Great River Energy
Hutchinson Utilities Commission
ITC Midwest LLC
L&O Power Cooperative
Marshall Municipal Utilities
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
Willmar Municipal Utilities

November 1, 2017
MPUC Docket No. E999/M-17-377

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1.0 Executive Summary

The 2017 Biennial Transmission Projects Report is the ninth 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 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 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 2017 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 2017 Biennial Report is a joint effort of the Minnesota Transmission Owners – those utilities that own or operate high voltage transmission lines in the state of Minnesota. These utilities include the following:

American Transmission Company, LLC	Dairyland Power Cooperative
East River Electric Power Cooperative	Great River Energy
Hutchinson Utilities Commission	ITC Midwest LLC
L&O Power Cooperative	Marshall Municipal Utilities
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	Willmar Municipal Utilities

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

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 deadlines.

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 Minnesota Public Utilities Commission in separate dockets.

The following is a summary of each subsequent chapter of the 2017 Biennial Report.

Chapter 2 describes the biennial reporting requirements. This includes a discussion of the specific information the Public Utilities Commission directed the utilities to include in the 2017 Biennial Report.

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 the Midcontinent Independent Transmission System Operator (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 Minnesota Transmission Owners maintain (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 over 90 separate transmission inadequacies across the state, including 50 new ones identified in the 2017 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 MISO Transmission Expansion Plan (MTEP) Report. The 2017 MTEP Report, for example, would be called MTEP17. 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 on the Internet the appropriate MTEP Report containing the desired information. The utilities have also attempted to indicate whether a

Certificate of Need (CON) from the Public Utilities Commission might be required for a particular project selected to address a named inadequacy.

Certain projects have been completed since the 2015 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 16 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 2020, 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.

MPUC Process. Upon receipt of this Report, the Minnesota Public Utilities 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 Public Utilities Commission. The Docket Number is E999/M-17-377. The precise schedule for filing comments is established by the MPUC rules relating to the biennial reporting process. Minn. Rule Chapter 7848. It is anticipated that the MPUC will make a final decision on the 2017 Biennial Transmission Projects Report in May 2018.

2.0 Biennial Report Requirements

2.1 Generally

This is the ninth 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 eight reports are all available on the Minnesota Public Utilities Commission's eDockets webpage using the Docket Number from the table below. The past six reports are also available on the webpage maintained by the utilities: http://www.minnelectrans.com/. The 2017 Report will also be posted on that webpage.

Biennial Report	**MPUC Docket Number**	**MPUC Order**
2017	E999/M-17-377	
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 the Midcontinent Independent Transmission System Operator (MISO). MISO prepares a report each year, called the MISO Transmission Expansion Plan (MTEP) Report. MISO transmission planning is conducted in public forums and the MTEP Report is publically 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 three biennial reports – 2011, 2013 and 2015 – the Minnesota Public Utilities Commission has allowed the utilities to reference the latest MTEP Report to provide information about the identified inadequacies in Minnesota. The 2017 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 2017, 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 May 27, 2016, Order accepting the 2015 Biennial Report, the Commission said that the MTO shall "file the 2017 Report with content similar to the 2015 Report." Consequently, the 2017 Report closely tracks the 2015 Report and contains information similar to what was included and accepted in the 2015 Report and in previous reports.

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 Minnesota Transmission Owners (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
Dairyland Power Cooperative
East River Electric Power Cooperative (will become part of Southwest Power Pool October 1, 2015)
Great River Energy
Hutchinson Utilities Commission
ITC Midwest LLC
L&O Power Cooperative
Marshall Municipal Utilities
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
Willmar Municipal Utilities

Of the above utilities, East River Electric Power Cooperative, L&O Power Cooperative, Marshall Municipal Utilities, Minnkota Power Cooperative, Rochester Public Utilities and Willmar Municipal Utilities are not members of MISO; all the others are. Only Minnkota Power Cooperative reports any new transmission projects in this 2017 Biennial Report. However, 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 Certificate of Need (CON) under Minn. Stat. § 216B.243 is not required.

On June 1, 2017, the MTO filed a letter to the Commission in the instant docket that there would be no certification requests included with the 2017 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 Public Utilities 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 of all, 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 not able to identify possible alternatives, let alone 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 looming 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, and that is what the utilities have done here.

Thus, it is not possible for the utilities to provide specific discussion of potential impacts for each and every Tracking Number that is identified in this Biennial Report. There are over 100 separate Tracking Numbers, for one thing. 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, they know that a transmission line may cross a wetland, or run through an agricultural field, or follow a residential street. They are well versed that a new generating plant has a certain footprint, and may result in the emission of various pollutants, and may require the transport of fuel. The utilities are aware that a large energy project has tax consequences for local government. They know that jobs will be created by the construction of a new facility and that 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.

The time to provide an in-depth analysis of potential impacts of a proposed project and the identified alternatives is 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 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 Certificate of Need 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 ample 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. When a project is far enough along that a specific project has been identified and alternatives considered, a more detailed discussion is possible but that discussion more appropriately belongs in the docket for the permits required for the project.

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 on its

> *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 new reporting requirement is often referred to as the Grid Modernization Report. The PUC in May 2015 opened a separate docket for consideration of efforts related to modernization of the transmission and distribution grid. Docket Number 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.*

On October 30, 2015, Xcel Energy filed its 2015 Biennial Distribution-Grid Modernization Report under Minn. Stat. § 216B.2425. The PUC assigned a separate docket number to the Report. Docket Number E002/M-15-962. On June 28, 2016, in that docket, the PUC accepted the Grid Modernization part of the Report and directed Xcel Energy to file a separate Distribution System Study by December 1, 2016, which Xcel Energy did.

As mentioned above, 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. Accordingly, Xcel Energy has submitted its Grid Modernization Report and its Hosting Capacity/Distribution Study Report under separate cover for PUC consideration in two separate dockets.

3.0 Transmission Studies

3.1 Introduction

The Minnesota Public Utilities 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. Rules 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 2017 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 in the upper Midwest. Section 3.4 focuses on ongoing load serving studies that are attempting to resolve local inadequacy issues. Section 3.6 is a new section describing certain studies at the national level that are underway.

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 November 2015. 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
Interconnection System Impact Study of MPC02100	2015	MPC	Minnkota performed the Interconnection System Impact Study of MPC02100. It was completed on December 29, 2015. Most impacts required minor upgrades, but a substation on Center – Mandan 230 kV (called Roughrider) and an uprate from Roughrider to Mandan 230 kV were required. The System Impact Study is posted on OASIS.

Study Title	Year Completed	Utility Lead	Description
System Impact Study of Minnkota Power Cooperative Generation to Native Load – Appendix I Update for Approvals and Contingent Items	2015	MPC	Minnkota updated Appendix I (“Study Approval and Discussion of Contingent Items”) in the previous System Impact Study of Minnkota Power Generation to Native Load. This study focused on securing Transmission Service on Minnkota Power Cooperative’s system for Langdon Wind, Ashtabula Wind, and Young 2 (specifically for moving it off of the DC system, and onto the AC system for the duration of ownership transfers between MPC and MP). The System Impact Study is posted on OASIS.
System Impact Study of Minnkota Power Cooperative Generation to the MISO Border	2015	MPC	Minnkota performed the System Impact Study for Minnkota Power Generation to the MISO Border. It was completed on August 26, 2015. Only two transmission lines were impacted in the study and uprates were already planned, and those lines were in North Dakota. Transmission Service has been granted with uprates in-service. The System Impact Study is posted on OASIS.
System Impact Study for MPC02100 Network Service and Service to the MISO Border	2016	MPC	Minnkota performed the System Impact Study for MPC02100 Network Service and Service to the MISO Border. It was completed on February 11, 2016. Two Minnkota transmission lines were impacted in the study and must be uprated in order to grant the requested Transmission Service, including the Jamestown-Buffalo 345 kV line and the Roughrider-Mandan 230 kV line. The Jamestown-Buffalo 345 kV line uprate was already planned for TSR #81607456 (previously #81022904), so that upgrade was already put through Facility Study and uprated. A Facility Study was performed for the Roughrider-Mandan 230 kV line, and it was uprated also. The System Impact Study is posted on OASIS.
GNTL Short Circuit Study	2015	MP	Assessment of breaker interrupting capability for post-GNTL short circuit levels; Blackberry Breaker Replacements (2017-NE-N22)

Study Title	Year Completed	Utility Lead	Description
North Shore Loop Comprehensive Plan	2015	MP	Develop a comprehensive plan and staged approach for transmission expansion in the area between Duluth, Taconite Harbor, and Hoyt Lakes in light of future changes in generation and load; Dunka Road Substation (2011-NE-N5), Laskin-Taconite Harbor Voltage Conversion (2017-NE-N2), Babbitt Capacitor Bank (2017-NE-N8), ETCO Capacitor Bank (2017-NE-N9), Hoyt Lakes 115 kV Project (2017-NE-N23)
Bear Creek 69/46 kV Transformer Addition	2016	MP	System impact of retiring Sandstone 69/46 kV source and establishing new Bear Creek 69/46 kV source; Bear Creek 69/46 kV Transformer (2015-NE-N13)
Shutdown of Boswell Units 1 & 2 System Impact Study	2016	MP	System impact of shutting down Boswell Units 1 & 2 and evaluation of solutions for maintaining system reliability should it become necessary or preferable to shut down Boswell Units 1 & 2; Boswell 230/115 kV Transformer (2017-NE-N13)
North Shore Loop Transmission Study	2017	MP	System impact of transitional changes between Duluth, Silver Bay, Taconite Harbor, and Hoyt Lakes due to conversion, idling, or retirement of local baseload coal-fired generators; North Shore Switching Station & Cap Banks (2017-NE-N7), Forbes 3T Breaker Replacement (2017-NE-N10), North Shore Dynamic Reactive Device (2017-NE-N15), 18 Line Upgrade (2017-NE-N17), North Shore Transmission Line Upgrades (2017-NE-N19), Two Harbors 115 kV Project (2017-NE-N2), Laskin-Tac Harbor Line Upgrades (2017-NE-N21)
868 Line Power Guardian Solution Study	2017	MP	Evaluate Smart Wires Power Guardian solution as an alternative to reconductoring the Little Falls – St. Stephen Tap 115 kV Line; 868 Line Upgrade (2015-NE-N2)
Cass Lake - Donaldson Capacitor Study	2017	OTP	This study aimed to determine the usefulness of the 115 kV capacitors installed at Cass Lake. If removing these capacitors causes no issues in the Cass Lake area, the capacitors could be moved to Donaldson where the system has a greater need for reactive support.

Study Title	Year Completed	Utility Lead	Description
Minnesota Transmission Assessment and Compliance Team 2016 Transmission Assessment (2016 – 2026)	2016	MTO	This report is an annual transmission assessment investigating near-term, mid-term, and long-term transmission conditions. This purpose of this study is to develop an understanding of the transmission system topology, behavior, and operations to determine if existing and planned facility improvements meet NERC Transmission Planning Standard TPL-001-4.

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. Many of these studies are especially important for focusing on transmission needs for complying with upcoming Renewable Energy Standards.

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

The Midcontinent Independent System Operator (MISO) engages in annual regional transmission planning and documents the results of its planning activities in the MISO Transmission Expansion Plan (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."

MTEP16 Report

The 2016 MTEP report was the 13th edition of the publication. The MTEP16 report identified projects required to maintain reliability for the ten year period through the year 2024 and provides a preliminary evaluation of projects that may be required for economic benefit up to twenty years in the future.

According to the MTEP16 Executive Summary of the report, MISO staff is recommending approval of approximately $2.7 billion in new transmission infrastructure investment. Of the $2.7 billion, $691.1 million is new Baseline Reliability Projects, $142.7 million is Generation Interconnection Projects, $108 million for Market Efficiency, and the remainder falls into the Other category.

MTEP17 Report

The 2017 MTEP report will be the 14th edition of the publication. The report exists in draft form for now, but should be formally approved by MISO by the end of the calendar year.

According to the MTEP17 Executive Summary, the MISO staff is recommending approval of approximately $2.47 billion in new transmission infrastructure investment. Of the $2.47 billion, $1.01 billion is new Baseline Reliability Projects, $197.15 million is Generation Interconnection Projects, and the remainder falls into the Other category.

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	2017	NSP	Develop a comprehensive plan to serve the growing load around the City of Woodbury in eastern Twin Cities Area.
Owatonna Area Study	2018	NSP/ GRE	Owatonna Area Study. This study is to evaluate the need for more voltage support under contingency. The early results are indicating an additional 161 kV line into the Owatonna area. This study is still ongoing.
Grand Rapids Long-Term Analysis	2018	MP	Continued analysis of the Grand Rapids area in the post-2020 timeframe following shutdown of Boswell Units 1 & 2, interconnection of the Great Northern Transmission Line, potential mining expansion, and general load growth; Projects *TBD*

Study Title	Anticipated completion	Utility lead for Study	Description
North Shore Loop Alternatives Analysis	2018	MP	Continued analysis of the North Shore Loop in the post-2020 timeframe following completion of the transition away from local baseload generators, potential mining expansion, and general load growth; Projects *TBD*

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 May 27, 2016, 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 Midcontinent Independent Transmission System Operator (MISO). MISO provides all kinds of 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 Minnesota Transmission Owners 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 Minnesota Transmission Owners 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 well 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 esoteric transmission planning activities but it surely wants to be aware of projects that are under consideration in its 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 Minnesota Public Utilities 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 the Company 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 the Company'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 the Company'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 the Company's website to many of the questions that were received.

As explained in section 6.6.1 for Tracking Number 2017-TC-N6, the alternative that was selected was Alternative C. Xcel Energy will continue to keep landowners and the city and the general public informed of developments.

4.4.2 Menahga Area 115 kV Project MPUC Tracking Number 2013-NE-N21

In January 2015, Great River Energy applied for a Certificate of Need and a Route Permit for a new 115 kV transmission line in Hubbard, Wadena and Becker Counties. In its application, at page 1-10, GRE explained that it contacted several local governmental bodies and invited them to meet prior to submitting the application. As part of its application, at page 2-4, GRE explained that pursuant to Minn. Stat. § 216B.03, subds. 3a and 3b, the following efforts were undertaken to inform the public about this project:

> Great River Energy held a public open house informational meeting on September 30, 2014, at the Menahga Senior Center in Menahga, MN to provide information about the Project to the public. Great River Energy sent post card open house invitations to 141 landowners within the 1000-foot notice corridor. Great River Energy also mailed notice of the Project and open house to 93 agencies, elected officials, and local governmental units, including tribal representatives (White Earth Band of Ojibwe and Leech Lake Band of Ojibwe). Newspaper notices announcing the open house were also placed in four local newspapers approximately a week before the open house.
>
> Approximately 30 members of the public attended the open house.
>
> The meeting was publicized in several local papers approximately one week prior to the open house, and landowners potentially impacted received a post card invitation. Tribal and local government officials and resource agencies were also invited by letter (Minn. Stat. § 216E.03, subd. 3a). Large aerial maps of the proposed Project, photos of proposed transmission structures, fact sheets, information on the permitting process and need for the Project, ROW information, and a post card for questions or comments were available at the open house.

4.4.3 Motley Area 115 kV Project MPUC Tracking Number 2015-NE-N6

In March 2015, Great River Energy applied for a Certificate of Need and a Route Permit for a new 115 kV transmission line in Morrison, Cass and Todd Counties. In its application, at page 1-10, GRE explained that it contacted several local governmental bodies and invited them to meet prior to submitting the application. As part of its application, at pages 2-4 and 2-5, GRE explained that pursuant to Minn. Stat. § 216B.03, subds. 3a and 3b, the following efforts were undertaken to inform the public about this project:

> Great River Energy held a public open house informational meeting on September 23, 2014, at the Motley United Methodist Church located in Motley, MN to provide information about the Project to the public. Great River Energy sent 172 post card invitations (copy included in Appendix A) announcing the open house to all landowners within 1,000 feet of a preliminary route for the project, which did

> not include the East Route Option for the proposed 115 kV transmission line segment between Minnesota Power's "24 Line" transmission line and the March 2015 Motley Area 115 kV Project 1-11 existing Crow Wing Power Motley Substation. Great River Energy also mailed 73 letters and project fact sheets (an example letter is provided in Appendix A) providing details of the Project and open house meeting to agencies, elected officials, and local governmental units (LGUs).
>
> Approximately 20 members of the public attended the open house meeting on September 23, 2014.

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 Minnesota Public Utilities Commission.

5.0 Transmission Planning Zones

5.1 Introduction

The Minnesota Public Utilities 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 of the 2017 Report 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.

Continued load growth in the northern part of this zone has led to the development of plans for a new 230 kV line from Winger to Thief River Falls. This line is reported under Tracking Number 2007-NW-N3.

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. 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 between the Bemidji area in the Northwest

Zone and the Grand Rapids area in the Northeast Zone (the CapX2020 Bemidji-Grand Rapids project) has been completed. 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.

The new Great Northern Transmission Line Project will build approximately 220 miles of new 500 kV coming from Manitoba Hydro to the Grand Rapids, Minnesota area. This project will increase the amount of hydro renewables that can be imported to the state of Minnesota. This line is reported under Tracking Number 2013-NE-N13.

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.

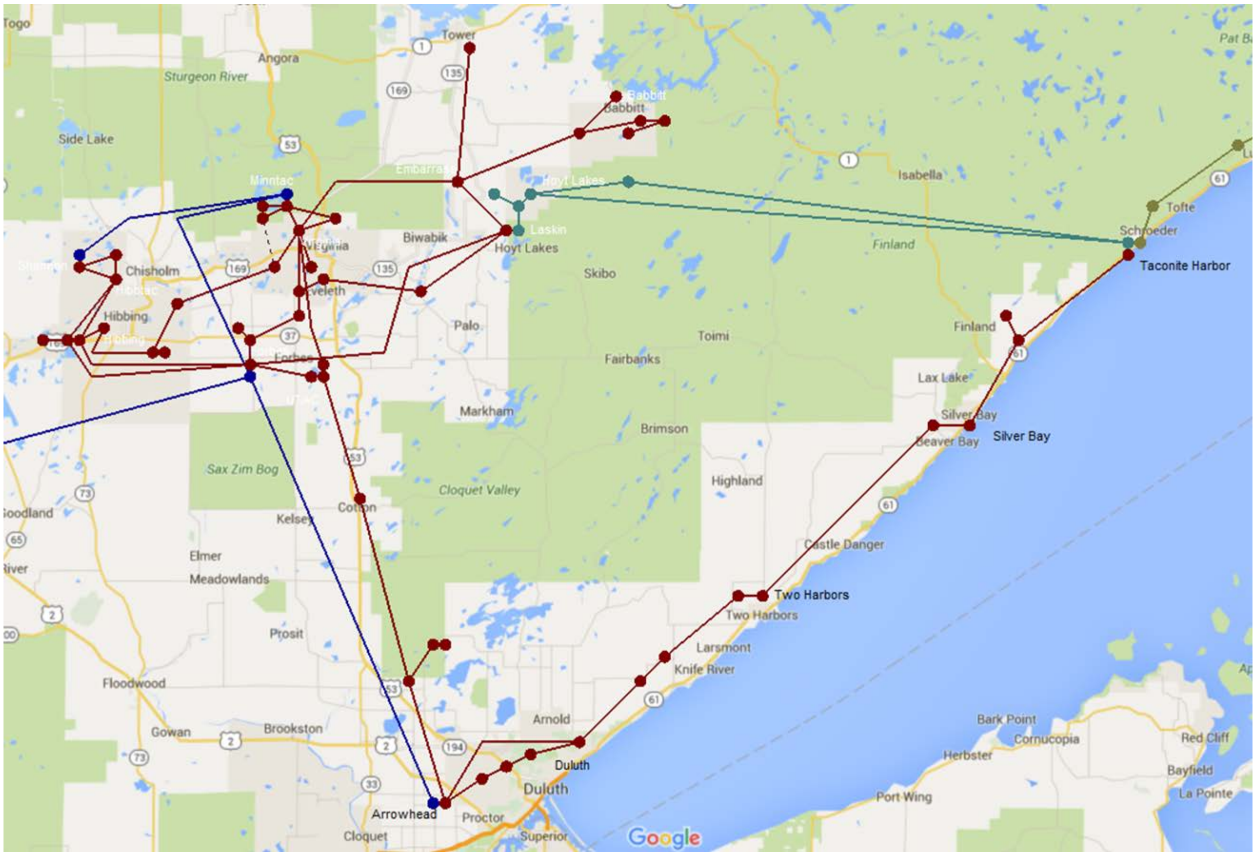

Figure 1: North Shore Loop Transmission System Geographical Representation

Over a span of approximately five years beginning in 2015, all seven of the coal-fired generating units located at these three sites are being 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. By the end of 2019 both Silver Bay units will be idled, leaving no baseload generators normally online in the North Shore Loop.

This transition away from local coal-fired baseload generation in the North Shore Loop has necessitated an evaluation of the transmission system in the area to ensure that it may operate reliably and with sufficient load-serving capacity without the power and voltage support previously provided by the generators. While evaluation of the long-term impacts of these changes is ongoing, several necessary transmission improvements have already been identified and are in various stages of project development and execution. Projects located in the North Shore Loop or related to the transitional changes in the North Shore Loop include: Minntac 230 kV Bus Reconfiguration (Tracking Number 2015-NE-N10), Forbes 230/115 kV Transformer Addition (Tracking Number 2015-NE-N11), Laskin-Taconite Harbor Voltage Conversion (Tracking Number 2017-NE-N2), North Shore Switching Station & Cap Banks (Tracking Number 2017-NE-N7), Babbitt Capacitor Bank (Tracking Number 2017-NE-N8), ETCO

Capacitor Bank (Tracking Number 2017-NE-N9), Forbes 3T Breaker Replacement (Tracking Number 2017-NE-N10), North Shore Dynamic Reactive Device (Tracking Number 2017-NE-N15), 18 Line Upgrade (Tracking Number 2017-NE-N17), North Shore Transmission Line Upgrades (Tracking Number 2017-NE-N19), Two Harbors 115 kV Project (Tracking Number 2017-NE-N20), Laskin-Tac Harbor Transmission Line Upgrades (Tracking Number 2017-NE-N21), and Hoyt Lakes 115 kV Project (Tracking Number 2017-NE-N23).

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
- Hutchinson Utilities Commission
- Missouri River Energy Services
- Otter Tail Power Company
- Southern Minnesota Municipal Power Agency
- Willmar Municipal Utilities
- 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 will transfer 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.

Some of the 69 kV network is becoming inadequate for supporting the growing load in the area. Solutions to the 69 kV transmission inadequacies may involve construction of new 115 kV transmission lines. Therefore, any discussion about the inadequacy of the existing system must include an analysis of parts of the existing 69 kV transmission 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 Minnesota Public Utilities 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 will transfer 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
- Marshall Municipal Utilities
- 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 two 345 kV transmission lines, one beginning at Split Rock Substation near Sioux Falls and traveling to Lakefield Junction and the second traveling from Mankato, through Lakefield Junction and south into Iowa. Lakefield Junction 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 will soon be enhanced by the addition of the Twin Cities-Brookings 345 kV transmission line to provide additional outlet for the wind generation in the Southwest Zone which is scheduled to be completed by the end of 2015. 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.

The CapX Brookings, South Dakota-Twin Cities 345 kV project was completed in 2015.

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 change in the Southeast Planning Zone is the completion of the CapX 345 kV line from the Hampton Substation to LaCrosse, Wisconsin. This line will help increase local reliability along with helping increase renewable generation transfer to the east.

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?	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 MISO Transmission Expansion Plan (MTEP) Report and an Appendix in the report. The MTEP Report is prepared annually by the Midcontinent Independent System Operator (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 MTEP17, 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 Midcontinent Independent Transmission System Operator (MISO) for each project. This Project Number is important for finding a particular project in the appropriate MISO Transmission Expansion Plan (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), Hutchinson Utilities Commission (HUC), L&O Power Cooperative (L&O), Marshall Municipal Utilities (MMU), and Willmar Municipal Utilities (WMU), 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 assumed many of the planning functions for Minnkota Power Cooperative once 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, including Minnkota. Minnkota does do some of its own planning though, as shown in table 6.3.1 where no MTEP Project Number is shown for some Minnkota projects.

CON

The MPUC rules (Minn. Rules part 7848.1300, item M) state that the biennial report shall contain an approximate timeframe for filing a certificate of need application for any projects identified that are large enough to require a certificate of need. This column provides a simple "Yes" or "No" indication of whether a CON is required. If a certificate of need 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.

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 Minnesota Public Utilities 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 the Midcontinent Independent Transmission System Operator (MISO), this subsection is provided to assist the reader in finding information about the MISO planning process and the annual MISO Transmission Expansion Plan (MTEP) Report that is prepared each year. Much of the information provided in this subsection was also available in the 2013 and 2015 Biennial Reports.

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

http://www.misoenergy.org (Click on "Planning.")

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 MTEP17 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 2017-TC-N5 is used for illustrative purposes):

MPUC Tracking Number	**MISO Project Name**	**MTEP Year/App**	**MTEP Project Number**	**CON?**	**Utility**
2017-TC-N5	Wilson Substation	2017/C>A	4695	No	XEL

MPUC Tracking Number 2017-TC-N5 is the Wilson Substation Project in Bloomington, MN. The project can be found in Appendix A of the MTEP17 Report (the MTEP17 Report will be finalized in late 2017) 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. Then click on the link on the left side of the page entitled "MISO Transmission Planning Expansion (MTEP)."

Step 3. Click on the link for the MTEP17 Report.

Step 4. Click on the "MTEP17 Appendices AB."

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 4695, 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, B and C 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 “4695” 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 4695 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 D1 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 D1 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 Wilson Substation, Tracking Number 2017-TC-N5, which is an approved Appendix A project, this additional information can be found by going to Appendix D1 through the following steps.

Step 1. After following the first three steps described above to get to the appropriate MTEP report, click on the MTEP17 Appendices link.

Step 2. Select MTEP17 Appendix D1 West.

Step 3. Once the desired Appendix D1 is downloaded, use the .pdf search tool to find Project Number 4695 and 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 MTEP17.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Utility
2007-NW-N3	Winger-Thief River Falls 230 kV Line	2014/B	4232	Yes	OTP/ MPC
2009-NW-N2	Frazee-Perham-Rush Lake Area	2010/A	2670	No	GRE

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Utility
2015-NW-N1	Clearbrook 115 kV-Bagley West 230 kV	2015/B		Yes	OTP/ MPC
2015-NW-N2	Donaldson 115 kV Breaker	2015/A	8281	No	OTP
2015-NW-N3	Bagley North 115 kV Ring Bus	2015/B	4813	No	OTP/ MPC
2015-NW-N4	Moranville 230/69 kV Transformer Replacement	Non-MISO		No	MPC
2015-NW-N5	Ulrich 115/69 kV Transformer Replacement	Non-MISO	9652	No	MPC
2015-NW-N7	Richwood-Oakland 69 kV and Audubon-Erie Junction 41.6 kV Lines (Load Transfers)	Non-MISO		No	MPC
2015-NW-N8	Thief River Falls 115 kV Capacitor Bank Addition	Non-MISO		No	MPC
2017-NW-N1	Lake Park Substation	Non-MISO	11444	No	MPC
2017-NW-N2	Itasca-MPL Laporte 115 kV Line (and Northwoods Circuit Breaker Addition)	Non-MISO	11263	No	MPC
2017-NW-N3	Thief River Falls-Plummer Pipe 115 kV Line Uprate	Non-MISO	12683	No	MPC
2017-NW-N4	Donaldson 115 kV Capacitor Bank Addition	2017/A	13043	No	OTP

Winger-Thief River Falls 230 kV Line

MPUC Tracking Number: 2007-NW-N3

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

Project Description: The Winger-Thief River Falls 230 kV Line Project consists of a Winger substation expansion, a Thief River Falls substation expansion, a new 47 mile 230 kV transmission line between Winger and Thief River Falls and a new 230/115 kV transformer at Thief River Falls.

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.

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 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 a new Winger-Thief River Falls 230 kV line (and the associated Thief River Substation), and it was determined that the benefits of such a project are more robust and cost effective than the other options that were considered.

Analysis: Reliability improvements from the previously mentioned projects were evaluated in the "High Voltage Study," which was performed by OTP with support from MPC. The study showed that a fault on and 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 a new 230 kV source at Thief River Falls to be completed by 2023.

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 2024. 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 is expected to be completed by early 2018 to determine a more definitive mitigation plan and schedule. Upon completion of this study, Certificate of Need and other filing processes can begin.

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 of 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 importance of an improved system.

Frazee-Perham-Rush Lake Area

MPUC Tracking Number: 2009-NW-N2

Utility: Great River Energy (GRE)

Project Description: Voltage problems in the Frazee area are planned to be addressed by the addition of a new Schuster Lake 115/41.6 kV Substation near Frazee in Otter Tail County to support the 41.6 kV system in this area.

Need Driver: This area is served by two 115/41.6 kV sources from Frazee and Rush Lake. The loss of the Frazee 115/41.6 kV transformer or Frazee to Perham 41.6 kV line causes low voltage issues at multiple substations in the area including LREC's Dent and Dora distribution substations.

There are eight GRE-LREC distribution substations and four OTP distribution substations served in the area between Frazee and Rush Lake. The loss the Frazee 115/41.6 kV transformer causes low voltage problems at the Dora and Dent distribution substation.

Alternatives: Leaving the transmission system in the Frazee to Rush Lake area as it is now presents severe undervoltage problems at LREC's distribution substation. The transmission line overload problems will continue to be critical in the area. Two other alternatives were considered to address the voltage and loading issues in the area. One of the alternatives recommends adding a second transformer at Frazee and rebuilding the 9 mile, 2/0 A Tap line to Dent Sub with 477 ACSR conductor. The other alternative converts 41.6 kV loads to 115 kV system in the near term and establishes a 115/41.6 kV source at the North Perham Junction in the long term. These alternatives were not found being the least cost plan to address the needs of the area for a long term.

Analysis: The Shuster Lake Substation, at system intact, will serve the Dent and Perham loads which are now served from the Frazee and Rush Lake sources, respectively. The project is the least cost plan that will address the low voltage problems in the 41.6 kV system during critical contingencies in the system, the loss of the Frazee 115/41.6 kV system and loss of the Frazee to Perham 41.6 kV line. It also ensures a better load serving reliability in the area as it will provide contingency back up to the Frazee and Rush Lake sources in the area while increasing capacity in the system to serve future load growth in the transmission system.

Schedule: The Schuster Lake Project is currently planned for a fall 2019 completion.

General Impacts: Installation of a new transformer at an existing substation is not expected to have any significant effects.

Clearbrook 115 kV-Bagley West 230 kV

MPUC Tracking Number: 2015-NW-N1

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

Project Description: The name of this project has been changed slightly from the 2015 Report, when it was called Clearbrook West, simply to more accurately reflect the location of the project. This project is related, however, to the new 115 kV ring bus to be installed at the existing Bagley Junction switch. (Tracking Number 2015-NW-N3). The option selected from the Coordinated Clearbrook Looped Service Study (performed primarily by OTP) was to develop a substation near Bagley (about 4.5 miles southwest) that taps the Winger to Wilton 230 kV line, as well as a 22 mile line from the newly developed substation to the Clearbrook 115 kV Substation.

Need Driver: The Clearbrook 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 two 230 kV sources at Wilton and Winger. Loss of any one source forces the load to be served from a single source. Additionally, loss of any transmission between Bagley and Clearbrook threatens a substantial amount of existing and future load service. The proposed transmission facilities include a 22 mile transmission line and a new substation.

Alternatives: Several different transmission alternatives were developed as part of a Clearbrook Looped Service Study to assess the ability of the transmission system to serve the anticipated load increase for the Clearbrook area. These included:

- a new Clearbrook-Solway 115 kV line,
- a new Clearbrook-Plummer 115 kV line, or
- a capacitor bank / system rebuild alternative.

The options above have been considered and compared with a new 230 kV / 115 kV tap line, and it was determined that the benefits of such a project heavily out-weight the added investment (determined in coordinated efforts that followed the initial report).

Analysis: The option selected from the Coordinated Clearbrook Looped Service Study was to develop a substation near Bagley (about 4.5 miles southwest) that taps the Winger to Wilton 230 kV line, as well as a 26 mile line from the newly developed substation to the Clearbrook 115 kV Substation. The newly developed substation, referred to as Bagley West, has a 230/115 kV transformer, breakers for the high and low side of the transformer, switches, relaying, and all other associated bus work. The Bagley West 230/115 kV transformer was identified as an equivalent replacement for the previously repurposed Wilton transformer #1 (OTP), with the recognition that the Wilton 230/115 kV transformer would have needed to be replaced.

Looped service for the Clearbrook area loads was evaluated in the “Coordinated Clearbrook Looped Service Study.” Of the options analyzed, the Clearbrook West 115 kV to Bagley West 230 kV option provided the best option to meet our transmission planning requirements. The study demonstrated a final upgrade requirement of looped service, to be completed by 2026.

Schedule: The study efforts mentioned above determined that an upgrade to mitigate post-contingent service issues on the Clearbrook area transmission must be completed by the winter of 2026. The project was listed as having an in-service date of 2018 in the previous report. This date has now been pushed out significantly because of the cancellation of proposed loads in the area. A schedule will be developed as definite mitigation plans are determined.

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 814 acres, only 69 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.

Donaldson 115 kV Breaker

MPUC Tracking Number: 2015-NW-N2

Utility: Otter Tail Power Company (OTP)

Project Description: The Donaldson 115 kV Breaker Project consists of adding a new 115 kV breaker at Donaldson on the Donaldson to Drayton 115 kV line to improve reliability of area loads.

Need Driver: The addition of a new breaker at the Donaldson 115 kV Substation on the Donaldson-Drayton 115 kV line will improve reliability in the area. This breaker will reduce fault exposure to Donaldson loads over 17 miles of transmission, improve operations, maintenance, and relaying flexibility at Donaldson.

Alternatives: Due to the low cost and benefits provided by the addition of the Donaldson breaker no other alternatives were considered.

Analysis: The addition of the breaker at Donaldson reduces fault exposure, improves operations and maintenance, and provides relaying flexibility at Donaldson. This breaker improves reliability to sensitive loads in the Donaldson area.

Schedule: The addition of the Donaldson 115 kV breaker is currently scheduled for December 2018. The July 2016 timeline listed in the previous report was pushed out to this 2018 date due to a lack of internal resources at OTP.

General Impacts: The addition of the Donaldson 115 kV breaker will reduce fault exposure to Donaldson while improving operations, maintenance and relaying flexibility at the Donaldson Substation. This project is the most cost-effective and environmentally responsible project to address the reliability concerns in the area.

Bagley North 115 kV Ring Bus

MPUC Tracking Number: 2015-NW-N3

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

Project Description: The name of this project has been changed from the 2015 Report, when it was called the Clearbrook-Clearbrook West 115 kV line (Load Interconnect), in order to more accurately describe it and to distinguish it from Tracking Number 2015-NW-N1 (Clearbrook 115 kV-Bagley West 230 kV). A new 115 kV ring bus is planned at the existing Bagley Junction switch. This will reduce fault exposure for area loads and improve operations and maintenance flexibility in the area.

Need Driver: The Clearbrook area is a developing hub of crude oil pipelines, and those pipelines require pumping stations. The Clearbrook pumping station has a large amount of exposure due to a lack of breakers in the area. Adding this breaker station not only reduces exposure for the pumping station, but reduces exposure for other area loads as well as improving operations and maintenance flexibility.

Alternatives: Several different transmission alternatives were developed as part of a Clearbrook Looped Service Study developed primarily by Otter Tail Power to assess the ability of the transmission system to serve the anticipated load increase for the Clearbrook area. These included:

- a new Clearbrook-Solway 115 kV line,
- a new Clearbrook-Plummer 115 kV line, or
- a capacitor bank / system rebuild alternative.

The options above have been considered and compared with a new 230 kV / 115 kV tap line and Bagley 115 kV Ring Bus option, and it was determined that the benefits of such a project heavily out-weigh the added investment (determined in coordinated efforts that followed the initial report). This breaker station was considered as part of that study.

Analysis: The option selected from the Coordinated Clearbrook Looped Service Study was to develop a substation near Bagley (about 4.5 miles southwest) that taps the Winger to Wilton 230 kV line, as well as a 22 mile line from the newly developed substation to the Clearbrook 115 kV Substation. This breaker station was considered as part of this study.

Schedule: The new ring bus is planned to be in service by the end of 2018.

General Impacts: The addition of the Bagley 115 kV breaker station will reduce fault exposure to Clearbrook by 50% while improving operations and maintenance flexibility along the Winger-Solway 115 kV transmission line. This project is the most cost-effective and environmentally responsible project to address the reliability concerns in the area.

The economic and social impacts from this project will likely be minimal. 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.

Moranville 230/69 kV Transformer Replacement

MPUC Tracking Number: 2015-NW-N4

Utility: Minnkota Power Cooperative (MPC)

Project Description: To keep up with the customer's growing demand, a new 230/69 kV transformer, along with the corresponding breakers, is planned for installation at the Moranville Substation.

Need Driver: Moranville area load is approaching the thermal limitations of the existing transformer. The existing transformer is also approaching its appropriate retirement age, and it has shown signs of slight deterioration.

Alternatives: There are two transformers at the Moranville Substation (comprised of two transformer pairs), however, thermal limitations on alternate service lines and the transformers prevent the current configuration from being fully effective during peak conditions following a contingency. An extensive uprate to the surrounding 69 kV system could serve as an alternative to the transformer replacement, but it would be a far more expensive approach to serving this load during a contingency. The transformer replacement is also a more robust and energy efficient option.

Analysis: There are not any negative reliability impacts due to the transformer and breaker replacements. This is primarily a capacity uprate.

Schedule: The study efforts mentioned above determined that the transformer replacement should be completed by the winter of 2017-2018. Delays have occurred due to budgeting and more important projects taking higher priority. The project is soon to be underway, and should be complete sometime fall 2017.

General Impacts: This project is entirely at the Moranville Substation location. There is no new transmission area for this project. No notable sites or locations are near the site of this project. This project is nearing construction, so all of these details are already approved in terms of impacts to the nearby area and environment.

This project will require a short-term project crew. This will bring some business to the area in the form of room and/or board. In terms of local government benefits, little is expected as a result of the substation modifications.

This project is the result of update requirements and capacity needs, and it will probably not have an impact on the community in terms of population or other social characteristics.

Ulrich 115/69 kV Transformer Replacement

MPUC Tracking Number: 2015-NW-N5

Utility: Minnkota Power Cooperative (MPC)

Project Description: A new 115/69 kV transformer is being proposed for installation at the Ulrich Substation. Capacitors mentioned in the 2015 Report as part of this project are no longer required due to the Lake Park 230/69 kV Substation (Tracking Number 2017-NW-N1) providing sufficient support during outage of the Ulrich transformer.

Need Driver: The Ulrich area load is approaching the thermal limitations of the existing transformer. In addition to the existing load topology, a couple of loads that are currently served by a neighboring utility will soon be transferred to the Ulrich source.

Alternatives: There is a single transformer at Ulrich that serves two 69 kV transmission lines. These lines are well loaded under peak conditions, and alternate service is somewhat restricted to these transmission lines due to radial configuration or thermal limitations during peak conditions following a contingency. Ensuing load transfers also create some concerns during system intact conditions. A new 230/69 kV substation is being built nearby (Lake Park, MN) to provide some alternate service, see Tracking Number 2017-NW-N1, but there are still some thermal limitations. An extensive uprate to the surrounding 69 kV system or further load transfers could serve as an alternative to the transformer replacement, but uprates would be a far more expensive approach. Load transfers are being investigated as another project is being studied (near White Earth, MN). The transformer replacement is a robust and energy efficient option, and is preferred for now.

Analysis: There are not any negative reliability impacts due to the transformer replacement. This is primarily a capacity uprate.

Schedule: The study efforts mentioned above determined that the transformer replacement must be completed by the winter of 2019-2020, however, the ultimate schedule and scope of this project will be determined by the outcome of Tracking Number 2009-NW-N2. A schedule will be developed as that timeframe approaches.

General Impacts: This project is entirely at the Ulrich Substation location. There is no new transmission area for 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, little is expected as a result of the substation modifications.

This project is the result of update requirements and capacity needs, and it will probably not have an impact on the community in terms of population or other social characteristics.

Richwood-Oakland 69 and Audubon-Erie Junction 41.6 kV Lines (Load Transfers)

MPUC Tracking Number: 2015-NW-N7

Utility: Minnkota Power Cooperative (MPC)

Project Description: Referred to as "Mahnomen/Ulrich Tap-Existing White Earth Substation 115 kV Line (Load Tap/Transfer)" in the 2015 Biennial Report. 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. The proposed project includes 20.0 miles of transmission line work (all new line).

A new 41.6 kV line from Audubon Distribution Substation to Erie Junction (with conversion of Audubon Distribution Substation onto the 41.6 kV system) has also been deemed necessary. The proposed project includes 4.0-7.5 miles of transmission line work (2.5 miles of it will be completely new). 1.5-5.0 miles of the transmission line work will be rebuilt transmission (1.5 miles will be double circuit). This will also require some substation expansion at the Ulrich 115/69/41.6 kV Substation.

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 Erie Substation. The intent is to transfer load off a neighboring system for primary service and continue to use the neighboring system for back-up service.

According to these requests, existing sources (via the neighboring system or distribution backfeeding) are insufficient for the customer's demand during a contingency. As a result, new transmission has been deemed necessary. The proposed transmission facilities include a 24.0-27.5 miles of transmission line work (22.5 miles of it will be completely new), substation conversions (White Earth and Erie dist. substations), and expansion of the Ulrich 115/69/41.6 kV Substation.

Alternatives: There are several transmission alternatives being considered as part of these load transfers. In the 2015 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) and a neighboring system's project near Audubon 230/115/41.6 kV Substation. Investigations are ongoing, and these alternatives will be compared with the proposed transmission line options. 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 TPL assessments (in terms of forecasting the existing White Earth and Erie area loads). 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. This will occur after final scope and schedule of the Frazee-Perham-Rush Lake Area (Tracking Number 2009-NW-N2) is finalized.

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 sites or locations are near the site of this project. 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 population or other social characteristics. It will likely impact some farmland; however, it should only amount to about 15 acres, as stated in the environmental considerations.

Thief River Falls 115 kV Capacitor Bank Addition

MPUC Tracking Number: 2015-NW-N8

Utility: Minnkota Power Cooperative (MPC)

Project Description: An additional capacitor in the existing capacitor bank is being proposed for the Thief River Falls Substation. Due to the steady growth of area loads, some voltage support to the system has been deemed necessary. The proposed capacitor addition includes 14.96 MVAR of capacitors and any necessary modifications to the existing Thief River Falls Substation.

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. To sustain reliability in years leading to new transmission upgrades, a new capacitor bank addition is being proposed for the Thief River Falls Substation in cooperation with Otter Tail Power, as they have agreed to their own capacitor addition at Donaldson Substation. Tracking Number 2017-NW-N4.

Alternatives: In years prior to 2021, automatic undervoltage load shedding has been identified as the most cost effective mitigation for voltage violations following a contingency. However, new compliance standards come into effect after that time, and non-consequential load loss is no longer permitted. That led to the proposed capacitor bank additions at Thief River Falls (14.96 MVAR) and Donaldson (30.00 MVAR). This will sufficiently support the system until the in-service date of the Winger-Thief River Falls 230 kV line (winter of 2023-2024).

Analysis: Reliability improvements from the previously mentioned projects were evaluated in the "High Voltage Study," which was performed by OTP with support from MPC. The study showed that a fault on and 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 a new 230 kV source at Thief River Falls to be completed by 2024. However, the timeframe between 2021 and 2023 required further mitigations for the loss of automatic undervoltage load shedding (per TPL-001-4). To mitigate the resulting voltage violations, Thief River Falls capacitor bank and Donaldson capacitor additions have been proposed (2019-2020).

Schedule: The study efforts mentioned above determined that an upgrade to mitigate post-contingent service issues to the Northwest Minnesota area transmission must be completed by the winter of 2023-2024. 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." The date change is due to actual vs. projected load increases and recent changes to interpretations of NERC TPL standards. A schedule will be developed as definite mitigation plans are determined. A study effort will soon be underway to re-evaluate the Northwestern Minnesota load service and project options.

General Impacts: This project is entirely at the Thief River Falls Substation location. There is no new transmission area for 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, little is expected as a result of the substation modifications.

This project is the result of update requirements, and it will probably not have an impact on the community in terms of population or other social characteristics.

Lake Park Substation

MPUC Tracking Number: 2017-NW-N1

Utility: Minnkota Power Cooperative (MPC)

Project Description: A new 230/69 kV substation is planned for construction near Lake Park, MN.

Need Driver: The Ulrich area load is approaching the thermal limitations of the existing transformer. In addition to the existing load topology, a couple of loads that are currently served by a neighboring utility will soon be transferred to the Ulrich source. The new substation is required to keep up with the changes in the demand near Hawley, MN and to provide alternate service to a radial transmission system.

Alternatives: There is a single transformer at Ulrich that serves two 69 kV transmission lines. These lines are well loaded under peak conditions, and alternate service is somewhat restricted to these transmission lines due to radial configuration or thermal limitations during peak conditions following a contingency. Ensuing load transfers also create some concerns during system intact conditions. An early alternative (to this new 230/69 kV substation being built at Lake Park) was a new 69 kV transmission line between Audubon and Hal Christensen distribution substations. This transmission line was going to provide some alternate service, but there would have still been some thermal limitations, for system intact and alternate service. An extensive uprate to the surrounding 69 kV system and a second transformer at Ulrich Substation could have been an alternative to this new Lake Park Substation, but the uprates and Ulrich Substation expansion would have been a more expensive approach. The Lake Park substation is a robust and energy efficient option, and will be in-service this winter.

Analysis: There are not any negative long-term reliability impacts due to the new substation. The only reliability issue is the short-term construction outage on radial transmission. Otherwise, it will provide more sources of power and higher capacity to Hawley, MN and the surrounding area.

Schedule: The alternate service issues and ensuing load transfers mentioned above determined that the substation was critical. The project is underway, and will be complete by winter 2017-2018.

General Impacts: This project is entirely at the new Lake Park Substation location (Section 30, Township139N, Range 43W, Becker County). There is no new transmission area required for this project. No notable sites or locations are near the site of this project. This project is nearing construction, so all of these details are already approved by the Rural Utility Service (RUS)—no impacts to the nearby area and environment.

This project will require a short-term project crew. This will bring some business to the area in the form of room and/or board. In terms of local government benefits, little is expected as a result of the new substation. Also, a landowner has received income as a result of this project, and the income will be taxable.

This project is the result of alternate service and capacity needs, and it will probably not have an impact on the community in terms of population or other social characteristics.

Itasca-MPL Laporte 115 kV Line (and Northwoods Circuit Breaker Addition)

MPUC Tracking Number: 2017-NW-N2

MPUC Docket Number: ET-6/TL-16-327

Utility: Minnkota Power Cooperative (MPC)

Project Description: The project consists of a new 9.4 mile-long 115 kV HVTL and 115/4.16 kV substation.

Need Driver: The Clearbrook and Itasca areas are developing hubs of crude oil pipelines, and those pipelines require pumping stations. A new pumping station is developing south of Itasca, and the existing transmission/distribution system is insufficient for the customer's expected demand. As a result, a new load interconnection on the 115 kV system has been deemed necessary. The proposed interconnection facilities include a 9-mile transmission line and a new substation. As a result of the system impact study, a breaker addition at the existing Northwoods Substation (located roughly 25 miles north of the MPL Laporte site) is a required interconnection facility also.

Alternatives: There was really only one feasible option for this load interconnection, due to the absence of both transmission and distribution that would sufficiently serve a load of this size. The next most feasible option would have been an 18-mile line (twice the length of this project's line) to Minnkota's Nary 115 kV Substation.

Analysis: Due to the development of a new pump station load near Itasca, a new load service needed to be established. Since the forecast provided by the customer was beyond the availability of existing member distribution cooperative facilities, and there are no existing Minnkota transmission facilities near the site, the load service was specified for 115 kV. This required a new transmission line from a nearby 115 kV substation at Itasca (about 9 miles of line to the north), as well as a newly developed substation for service to the MPL Laporte pump station load. Since the 115 kV line and load are to be interconnected with a neighboring transmission system, a system impact study was done, and protection upgrades were necessary due to the extension of this radial 115 kV system. The miles of exposure on this radial 115 kV system was already around 18 miles (putting strain on the typical protection specifications used on a 115 kV loop). The additional 9 miles of radial exposure (total of 27 miles) would have made it difficult to coordinate proper breaker operation for faults that occur on the far outreaches of that radial system. To mitigate the issue, a breaker addition at the existing Northwoods Substation (about 25 miles north of the MPL Laporte pump station load site) was selected for facilitating the interconnection.

Schedule: The customer's latest in-service date determined that the load interconnection must be completed by the winter of 2017-2018. The project is underway and will be completed by that time. A route permit was issued for the line by the Public Utilities Commission on June 21, 2017. MPUC Docket No. ET-6/Tl-16-327.

General Impacts: This project is primarily rural in location. The route will have to navigate around some lakes within the area. Assuming a one hundred foot right-of-way, the project area will be nearly 110 acres, but the affected farmland should only be about 6 acres, assuming some general estimates on electrical poles and farmland equipment navigation. The project follows around Itasca State Park, some nearby roads, and some farmsteads. It also has one crossing at La Salle Creek. This project is nearing approval and construction, so all of these details are already approved—no impacts to the nearby area and environment.

This project will require a temporary project crew. This will bring some business to the area in the form of room and board. In terms of local government benefits, permit costs have been enforced on this project, and that was determined by the scope of this project. Also, some landowners have received income as a result of this project, and the income will be taxable.

This project is the result of a new pump station development, but it will probably not have a substantial or lasting impact on the community in terms of population or other social characteristics. It will likely impact some farmland; however, it should only amount to about 6 acres, as stated in the environmental considerations.

Thief River Falls-Plummer Pipe 115 kV Line Uprate

MPUC Tracking Number: 2017-NW-N3

Utility: Minnkota Power Cooperative (MPC)

Project Description: A capacity uprate is being proposed for the existing Thief River Falls-Plummer Pipe 115 kV line.

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. A specific contingency forces a heavy share of this load to be served from only one 115 kV line. Additionally, other contingencies involving the loss of two transmission facilities between Drayton and Grand Forks can also cause the same capacity issue. Due to the nature of the contingencies, non-consequential load loss is permissible.

Alternatives: The uprate is a relatively low-cost improvement, and is only questionable on the basis that such an improvement could be deferred with a temporary use of non-consequential load loss, and a later project in Winger-Thief River Falls 230 kV line.

Analysis: Due to steady growth of area loads and new contingencies added to regular MTEP (transmission planning) analyses, some additional capacity to the system has been deemed necessary. The proposed uprate includes some analysis, design, and probably the raising of 3 or 4 structures (or potentially, structure replacements). Since there is new transmission being proposed in the area (Winger-Thief River Falls 230 kV), this uprate could be deferred by non-consequential load loss. A final determination hasn't been reached, but this is the preferred option.

Schedule: The need for in-service is tentatively summer of 2019. A study effort will soon be underway to re-evaluate the Northwestern Minnesota load service and related project options.

General Impacts: This project is primarily rural in location and slight in scope. Since it is an uprate to an existing 115 kV line, no environmental impacts are anticipated.

This project may require a temporary project crew. If so, that may bring some business to the area in the form of room and board. In terms of local government benefits, little is expected as a result of the transmission uprate.

This project is the result of capacity needs, and it will probably not have an impact on the community in terms of population or other social characteristics.

Donaldson 115 kV Capacitor Bank Addition

MPUC Tracking Number: 2017-NW-N4

Utility: Otter Tail Power Company (OTP)

Project Description: A new capacitor bank is being proposed for the Donaldson Substation. Growth of industrial loads in the area has caused a need for more voltage support. A total of 30

MVAR of capacitors in two 15 MVAR stages is proposed, along with any necessary modifications to the existing Donaldson Substation.

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. To sustain reliability in years leading to new transmission upgrades, a new capacitor bank addition is being proposed for the Donaldson Substation (in cooperation with Minnkota Power Cooperative, as they have agreed to their own capacitor addition at the Thief River Falls Substation).

Alternatives: In years prior to 2021, automatic undervoltage load shedding has been identified as the most cost effective mitigation for voltage violations following a contingency. However, new compliance standards come into effect after that time, and non-consequential load loss is no longer permitted. That led to the proposed capacitor bank additions at Thief River Falls (14.96 MVAR) and Donaldson (30.00 MVAR). This will sufficiently support the system until the in-service date of the Winger-Thief River Falls 230 kV line (winter of 2023-2024).

Analysis: Reliability improvements from the previously mentioned projects were evaluated in the "High Voltage Study," which was performed by OTP with support from MPC. The study showed that a fault on and 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 a new 230 kV source at Thief River Falls to be completed by 2024. However, the timeframe between 2021 and 2023 required further mitigation for the loss of automatic undervoltage load shedding (per TPL-001-4). To mitigate the resulting voltage violations, Thief River Falls capacitor bank and Donaldson capacitor additions have been proposed (2018-2020).

Schedule: The study efforts mentioned above determined that an upgrade to mitigate post-contingent service issues to the Northwest Minnesota area transmission must be completed by the winter of 2023-2024 (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 schedule will be developed as definite mitigation plans are determined. A study effort is underway to re-evaluate the Northwestern Minnesota load service and project options.

General Impacts: This project is entirely at the Donaldson Substation location. There is no new transmission area for 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.

This project is the result of updated requirements, and it's unlikely it will have a noticeable impact on the community in terms of population or other social characteristics.

6.3.2 Completed Projects

The table below identifies one project in the Northwest Zone that was listed as an ongoing project in the 2015 Biennial Report but has since been determined to not be necessary. More information about Tracking Number 2015-NW-N6 can be found in the 2015 Report. Should the project once again become necessary, it will be assigned a new Tracking Number.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2015-NW-N6	Anderson/Thief River Falls Tap-New Thief River Falls Substation 115 kV Line (Load Tap/Transfer)	Not Required	MPC	Withdrawn 2017

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 ?	Utility
2007-NE-N1	Duluth Area 230 kV	2014/B	2548	Yes	MP
2007-NE-N6	Onigum Area	2012/B	2632	No	GRE
2011-NE-N2	15 Line Upgrade	2016/A	7996	No	MP
2011-NE-N5	Dunka Road Substation	2010/A	2761	No	MP
2011-NE-N12	Wrenshall Substation	2013/B	3756	No	MP
2013-NE-N13	Great Northern Transmission Line	2014/A	3831	Yes	MP
2013-NE-N16	HVDC Valve Hall Replacement	2013/B	4295	No	MP
2013-NE-N17	HVDC 750 MW Upgrade	2014/B	3856	No	MP
2013-NE-N22	Elisha 115/34.5 kV Project	2018/A	8920	No	GRE
2015-NE-N1	5 Line Upgrade	2016/A	7910	No	MP
2015-NE-N2	868 Line Upgrade	2015/B	7913	No	MP
2015-NE-N4	15th Avenue West Modernization	2016/A	7997	No	MP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON ?	Utility
2015-NE-N5	16 Line Relocation	2015/A	8000	No	MP
2015-NE-N12	Iron Range-Arrowhead 345 kV Project	2014/B	3832	Yes	MP
2015-NE-N13	Bear Creek 69/46 kV Transformer	2016/A	9624	No	MP
2015-NE-N14	83 Line Upgrade	2016/A	9622	No	MP
2015-NE-N15	95 Line Upgrade	2016/A	9623	No	MP
2015-NE-N16	Two Inlets Pumping Station (X1A)	2016/B	9200	No	GRE
2015-NE-N17	Backus Pumping Station (X2A)	2016/B	9201	No	GRE
2015-NE-N18	Palisade Pumping Station (X3A)	2016/B	9202	Yes	GRE
2015-NE-N19	Cromwell Pumping Station (X4A)	2016/B	9203	No	GRE
2017-NE-N1	28 Line Upgrade	2016/A	10284	No	MP
2017-NE-N2	Laskin-Tac Harbor Voltage Conversion	2016/A	10383	No	MP
2017-NE-N3	Little Falls Voltage	2016/B	9643	No	MP
2017-NE-N4	Nashwauk 14 Line Upgrade	2018/A	9646	No	MP
2017-NE-N5	53 Line Upgrade	2018/A	9647	No	MP
2017-NE-N6	Forbes 38-44 MW Breaker Failure	2016/B	10285	No	MP
2017-NE-N7	North Shore Switching Station & Cap Banks	2017/A	11503	No	MP
2017-NE-N8	Babbitt Capacitor Bank	2017/A	11930	No	MP
2017-NE-N9	ETCO Capacitor Bank	2017/A	11931	No	MP
2017-NE-N10	Forbes 3T Breaker Replacement	2017/A	11932	No	MP
2017-NE-N11	LSPI 10K Breaker Addition	2017/A	11934	No	MP
2017-NE-N12	93 Line Upgrade	2017/A	12323	No	MP
2017-NE-N13	Boswell 230/115 kV Transformer	2017/A	12563	No	MP
2017-NE-N14	76 Line Upgrade	2017/A	12583	No	MP
2017-NE-N15	North Shore Dynamic Reactive Device	2017/A	12644	No	MP
2017-NE-N16	51 Line Upgrade	2017/B	12564	No	MP
2017-NE-N17	18 Line Upgrade	2018/A	13143	No	MP
2017-NE-N18	Tioga 115/23 kV Substation	2018/A	13526	No	MP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON ?	Utility
2017-NE-N19	North Shore Transmission Line Upgrades	2018/A	13364	No	MP
2017-NE-N20	Two Harbors 115 kV Project	2018/A	13484	No	MP/GRE
2017-NE-N21	Laskin-Tac Harbor Transmission Line Upgrades	2018/A	13504	No	MP
2017-NE-N22	Blackberry Breaker Replacements	2018/A	13527	No	MP
2017-NE-N23	Hoyt Lakes 115 kV Project	2018/B	13485	No	MP
2017-NE-N24	Knife Falls Distribution Substation	2017/A	12122	No	GRE
2017-NE-N25	Boswell 230 kV Fast-Switched Capacitor Bank	2017/B	12684	No	MP

Duluth 230 kV Project

MPUC Tracking Number: 2007-NE-N1

Utility: Minnesota Power (MP)

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

Need Driver: Reliability and load growth in the Duluth area. 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: Build a new 230/115 kV substation in the Duluth area.

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 and anticipated need to provide a second 230 kV source to the Hilltop

Substation, no other alternative to this project will provide a cost effective or reasonable solution to this pending inadequacy. Other transmission alternatives would require longer 230 kV line construction and increase both social and economic impacts associated with construction of such a line, and distributed generation is not preferable from either a cost or operational standpoint to the project.

Minnesota Power is continuing to monitor line loading, voltage support and load growth in the Duluth area to better understand when to move ahead with the Duluth 230 kV Project.

Schedule: Slower than anticipated load growth and external system improvements such as the Arrowhead-Stone Lake-Gardner Park 345 kV Line delayed the need for the Duluth 230 kV Project for many years. Recent studies indicate that this project may become needed in the early 2020s. The underlying system drivers behind this potential update in the timing of the project are related to the impact of a number of transitional changes in the nearby North Shore Loop transmission system as well as large load additions and changing transfer assumptions on the Minnesota Power system. The earliest that Minnesota Power currently anticipates initiating public outreach or permitting activities for this project would be in 2019. Further study is required to determine if the Duluth 230 kV Project remains the best technical solution to the issues being identified in the out-year cases and when the project is needed.

General Impacts: When it becomes needed, the Duluth 230 kV Project will make optimal use of existing transmission infrastructure in the area to provide the needed system improvements, supporting load growth, economic development, and the transition away from small coal units on the Minnesota Power system in the most cost-effective and least environmentally impactful manner possible by utilizing existing utility infrastructure to the greatest extent possible.

Onigum 115 kV Conversion

MPUC Tracking Number: 2007-NE-N6

Utility: Great River Energy (GRE)

Project Description: Construct a new, 115 kV line from Great River Energy's (GRE) existing Birch Lake Substation to Lake Country Power's (LCP) Onigum Substation. LCP will rebuild their substation adjacent to the existing site to receive 115 kV electric service.

Need Driver: LCP's Onigum Substation is served by a 34.5 kV system that is sourced by the 115/69/34.5 kV Birch Lake Substation and the 115/34.5 kV Akeley substation. Due to the aging condition and lack of capacity, GRE is planning to rebuild the existing 34.5 kV to 115 kV.

Alternatives: An alternative considered was rebuilding the 34.5 kV system with a like-for-like replacement.

Analysis: The 2008 GRE Long Range Plan indicated that the conversion of the Onigum Substation to 115 kV operation will unload the 34.5 kV service and extend the useful life of this system. MP and GRE will need to monitor the growth of the Walker area electric system to see when further conversion may be required.

Schedule: The timing of the Onigum conversion will be driven by the anticipated load growth in the area or if structural issues arise.

General Impacts: The Onigum 115 kV Conversion Project is the most efficient and least environmentally impactful viable solution for meeting the near term and long term needs in the Onigum area. The Onigum area will be served by a transmission grade source that will have less disruption resulting in greater reliability and also will also have less system losses.

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15 Line Upgrade

MPUC Tracking Number: 2011-NE-N2

Utility: Minnesota Power (MP)

Project Description: Rebuild and reconductor existing Fond du Lac-Hibbard 115 kV Line (MP "15 Line").

Need Driver: The existing Fond du Lac-Hibbard 115 kV Line needs to be rebuilt with a larger conductor due to its age and condition, lack of shield wire resulting in elevated risk to nearby sensitive industrial loads, and identified pre- and post-contingent overloads on the line.

Alternatives: A previously-preferred alternative (MISO MTEP Project #2549) involved reconfiguring 15 Line with an existing 115 kV line and substation to allow for removal of approximately half of the 11-mile line. Further analysis of constructability, particularly with regard to the location where 15 Line would be reconfigured to interconnect with the existing 115 kV line, as well as further analysis of the long-term transmission system needs in the area identified that an in-place rebuild of 15 Line was a preferable solution.

Analysis: Reconductoring 15 Line provides the best solution for maintaining the reliability of the Duluth-area 115 kV system in view of current needs (to deliver hydroelectric generation from Thomson and Fond du Lac, to support current load levels) and long-term needs (projected load growth and transmission system modifications such as the Duluth 230 kV Project). While recent analysis has shown that it would be prohibitively expensive to reconductor a portion of existing conductor on lattice towers, new line ratings will still be sufficient to mitigate identified overloads on the line.

Schedule: MISO and Minnesota Power studies indicate that a need for the 15 Line Upgrade develops in 2017. Since construction will not be completed in 2017, an operating guide is in place to mitigate overloading until the project can be completed. The project was broken into two phases, with Phase 1 construction taking place in 2017 and Phase 2 construction (and project completion) taking place in 2018.

General Impacts: The 15 Line Upgrade project will provide necessary system improvements in the Duluth area without requiring the establishment of additional transmission line corridors, which will minimize any potential environmental impacts.

Dunka Road Substation

MPUC Tracking Number: 2011-NE-N5

Utility: Minnesota Power (MP)

Project Description: Add a new 115/13.8 kV substation interconnected to the Taconite Harbor-Hoyt Lakes 115 kV Line (MP "1 Line"). A mechanically switched capacitor bank will also be included to provide necessary voltage support to the area between Hoyt Lakes and Taconite Harbor.

Need Driver: Development of the proposed Polymet mine.

Alternatives: There are no viable alternatives to this project since the project is needed to provide transmission-level electric service at a specific proposed mine site.

Analysis: The Dunka Road Substation will be designed to provide redundant electric service and meet the projected near-term and long-term needs of the proposed Polymet mine site and the surrounding transmission system.

Schedule: The schedule for construction of the Dunka Road Substation is dependent on the schedule for the development of the Polymet mine. Construction of the Dunka Road Substation also needs to be coordinated with the completion of the Laskin-Taconite Harbor Voltage Conversion Project (Tracking Number 2017-NE-N2) to ensure that the legacy 138 kV system has been converted to 115 kV prior to energization of the new Dunka Road Substation.

General Impacts: The Dunka Road Substation is the most efficient and least environmentally impactful viable solution for meeting the near-term and long-term needs at the new mine site. The project supports industrial expansion in northeastern Minnesota and the attendant social and economic benefits that such expansion brings to the local area and the State. As part of enabling service to the new industrial load, the inclusion of a switched capacitor bank at the Dunka Road Substation 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 enables the realization of significant economic and environmental benefits from transitioning away from these units.

Wrenshall Substation

MPUC Tracking Number: 2011-NE-N12

Utility: Minnesota Power (MP)

Project Description: Rebuild existing Wrenshall 115/14kV Distribution Substation and extend new feeder to Military Road.

Need Driver: Retirement of existing 46 kV line and equipment at Thomson Substation due to age and condition. Additionally, the assets at the existing Wrenshall Substation are near end of life.

Alternatives: Rebuild existing radial 46 kV circuit from Thomson to Military Road.

Analysis: Rebuilding the existing Wrenshall Substation and extending a new feeder to the Military Road area will allow for continued service to Minnesota Power customers in the Wrenshall area and allow for Minnesota Power to retire 46 kV line assets and equipment at Thomson Substation.

Schedule: The Wrenshall Substation Project is expected to be in service in late 2020.

General Impacts: The Wrenshall Substation Project will ensure a continuous and reliable power supply to Wrenshall and the surrounding area, while eliminating an aged segment of 46 kV line that is difficult and expensive to maintain due to its location and the surrounding terrain.

Great Northern Transmission Line

MPUC Tracking Number: 2013-NE-N13

MPUC Docket Numbers: E015/CN-12-1163 and E015/TL-14-21

Utility: Minnesota Power (MP)

Project Description: The Great Northern Transmission Line Project includes approximately 225 miles of 500 kV transmission line between a point on the Minnesota-Manitoba border northwest of Roseau, MN, and Minnesota Power's existing Blackberry Substation near Grand Rapids, MN. The project also includes the development of a new substation (Iron Range 500/230 kV Substation) located on the same site as the existing Blackberry Substation as well as a 500 kV midline series compensation station (Warroad River Series Compensation Station) located near Warroad, MN.

Need Driver: The purpose of the Great Northern Transmission Line Project is to efficiently provide Minnesota Power's customers and the Midwest region with clean, emission-free energy that will help meet the region's growing long-term energy demands, advance Minnesota Power's Energy*Forward* strategy to increase its generation diversity and renewable portfolio, strengthen system reliability, and fulfill Minnesota Power's obligations under its power purchase agreements with Manitoba Hydro, all in a manner that is consistent with Minnesota Power's commitment to making a positive impact on the communities where it does business.

Alternatives: Riel-Shannon 230 kV Line.

Analysis: The Great Northern Transmission Line provides the most effective and efficient long-term solution for supporting incremental power transfers on the Manitoba-United States interface.

Schedule: In anticipation of the Great Northern Transmission Line Project's aggressive schedule and needing to meet a June 1, 2020, in-service date, Minnesota Power initiated a proactive public outreach program to key agency stakeholders and the public that started in August 2012 and continued through May 2015. Through this program, thousands of landowners, the public, and federal, state, and local agency stakeholders were engaged through a variety of means, including five rounds of voluntary public open house meetings held throughout the project area.

On September 23, 2014, Minnesota Power, Manitoba Hydro, and the Midcontinent Independent System Operator (MISO) executed a Facilities Construction Agreement (FCA) for the Great Northern Transmission Line Project, setting forth the ownership and financial responsibilities for the project, among other terms. Upon approval of the FCA by the Federal Energy Regulatory Commission (FERC) on November 25, 2014, MISO considered the project an approved project under the MISO tariff and moved the Great Northern Transmission Line Project to Appendix A of the MISO Transmission Expansion Plan 2014 (MTEP14). Subsequently, the Minnesota Public Utilities Commission granted Minnesota Power a Certificate of Need (MPUC Docket No. E015/CN-12-1163) and Route Permit (MPUC Docket No. E015/TL-14-21) for the Great Northern Transmission Line on May 14, 2015, and February 26, 2016, respectively. The final major approval – the United States Presidential Permit granting approval of the border crossing (DOE Docket No. PP-398) – was received from the United States Department of Energy on November 16, 2016. Following receipt of the Presidential Permit, Minnesota Power began construction of the project in early 2017 and is continuing to execute the project construction schedule in order to meet the required in-service date of June 1, 2020 in satisfaction of the contractual agreements between Minnesota Power and Manitoba Hydro.

General Impacts: The Manitoba Hydro hydropower purchases made possible by the Great Northern Transmission Line will provide Minnesota Power and other utilities in the Upper Midwest access to a predominantly emission-free energy supply that has a unique combination of baseload supply characteristics, price certainty, and resource optimization flexibility not available in comparable alternatives for meeting customer requirements. Minnesota Power has maintained its commitment to making a positive impact in the communities throughout the project area through a multiyear proactive public outreach program and through designing its routes to utilize existing transmission line corridors to the greatest reasonable extent when considering all human, environmental, and engineering constraints. The project is also expected to have a significant impact on local property taxes in the counties where it will be located.

HVDC Valve Hall Replacement

MPUC Tracking Number: 2013-NE-N16

Utility: Minnesota Power (MP)

Project Description: Replace thyristor valve halls with modern equipment on Square Butte – Arrowhead HVDC line.

Need Driver: The HVDC terminals were designed by General Electric (GE) for a 30 year operating lifetime and as of 2017 they have been operating reliably for over 40 years. The main components of the HVDC terminals include the thyristor valves and cooling, converter transformers, and smoothing reactors to complete the energy conversion. The original vendor, GE, left the HVDC business in the 1980s and over the past few years it has been increasingly difficult to procure spare parts 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 HVDC system remain limited. By taking action to modernize the thyristor equipment, Minnesota Power will greatly reduce the likelihood of a line failure. Minnesota Power is evaluating a series of modernization activities for each of the major components of the HVDC system. Along with the thyristor valves, Minnesota Power can reduce the likelihood of forced outages of the 465 mile transmission line by planning replacement of transformers and smoothing reactors. Minnesota Power continues to evaluate the timing and priority for modernizing each of these components.

Alternatives: There are two alternatives. “Do Nothing” (risk of extended outage due to equipment failure) or implement the HVDC 750 MW Upgrade (Tracking Number 2013-NE-N17).

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: The timing of the HVDC Valve Hall Replacement Project will be identified based on Minnesota Power’s reliability and economic evaluations. Minnesota Power is actively monitoring the project and looking for an opportunity to execute it while balancing system reliability needs with costs to customers and prioritization of all capital projects. Following detailed specification and competitive bidding of the project, the earliest expected in-service date for the project is 2023. The delay is due to manufacturer lead times and Minnesota Power budgetary restrictions.

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.

HVDC 750 MW Upgrade

MPUC Tracking Number: 2013-NE-N17

Utility: Minnesota Power (MP)

Project Description: Upgrade existing Square Butte-Arrowhead HVDC line and terminal equipment to 750 MW capacity.

Need Driver: With new equipment such as what would be necessary to complete the HVDC Valve Hall Replacement Project (Tracking Number 2013-NE-N16) there is opportunity to consider new designs, technology capabilities and system enhancements. Specifically with the thyristor valves, Minnesota Power has the opportunity to design a system capable for up to 750 MW while utilizing the existing building and real estate. The new valves provide advantages of life extension (of at least 30 years) and the option to allow energy to flow in both west to east and east to west directions that would add a new and positive dynamic to the regional transmission system. Additional equipment upgrades beyond replacement of the thyristor valves would be necessary to upgrade the capacity of the HVDC line to 750 MW. The converter transformers, AC filter banks, and transmission line capability would all need to be studied and either replaced or increased in size. The 230 kV system connecting the Arrowhead Substation to power sources on the Iron Range would also need to be evaluated to determine if additional 230 kV transmission line capacity would be necessary to enable east to west scheduling of the HVDC line. The decision to size the system for 750 MW operation will need additional study and be determined during the final design phase for the modernization activities.

Alternatives: HVDC Valve Hall Replacement (Tracking Number 2013-NE-N16).

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. Additional modifications to the HVDC system enabling higher transfer capability on the line would potentially provide an even better long-term solution, assuming that the additional costs can be justified.

Schedule: The timing of the HVDC 750 MW Upgrade Project will be identified based on Minnesota Power's reliability and economic evaluations. Minnesota Power is actively monitoring the project and looking for an opportunity to execute it while balancing system reliability needs with costs to customers and prioritization of all capital projects. Following detailed specification and competitive bidding of the HVDC Valve Hall Replacement Project (Tracking Number 2013-NE-N16), the earliest expected in-service date for any HVDC upgrade is 2023. The delay is due to manufacturer lead times and Minnesota Power budgetary restrictions.

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 HVDC 750 MW 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.

Elisha 115/34.5 kV Project

MPUC Tracking Number: 2013-NE-N22

Utility: Great River Energy (GRE)

Project Description: Construct a new 115/34.5 kV substation to be named Elisha, build approximately 2.0 miles of 115 kV transmission to interconnect Elisha to the Itasca Mantrap's Potato Lake Substation, and build approximately 12.0 miles of 69 kV transmission, to be operated at 34.5 kV, to interconnect to Itasca Mantrap's Pine Point Substation. The 230/115/34.5 kV Hubbard Substation will retire all of its 34.5 kV assets and the Elisha Substation will utilize the remaining 115/34.5 kV transformer at Hubbard. The newly established 34.5 kV loop served by Elisha and Long Lake will have a normally open point at the Osage Substation.

Need Driver: Provide a redundant, stronger source to the Osage load pocket to alleviate low voltage seen on the 12.47 kV end. Minimize the radial MW-Mile exposure on the Hubbard-Osage-Shell Lake-Pine Point 34.5 kV line.

Alternatives: Development of a 115/34.5 kV substation near Potato Lake and build a 34.5 kV line from the new substation to the Osage Substation.

Analysis: The Elisha Substation will serve the Osage, Pine Point, and Shell Lake substations system intact while Long Lake will act as a backup source to these loads. The voltage profile in the Osage area will increase significantly with the proposed Elisha Substation.

Schedule: GRE anticipates initiating the project development in 2018. The timing of this project is dependent on the Enbridge Pipeline construction schedule.

General Impacts: The Elisha 115 kV Project is the most efficient and least environmentally impactful viable solution for meeting the near term and long term needs in the Osage area. The Osage area will be served by a transmission grade source that will have less disruption resulting in greater reliability and also will also have less system losses.

5 Line Upgrade

MPUC Tracking Number: 2015-NE-N1

Utility: Minnesota Power (MP)

Project Description: Reconductor existing Brainerd-Mud Lake 115 kV Line (MP "5 Line") and replace limiting substation terminal equipment.

Need Driver: Post-contingent overload following loss of parallel 230 kV line.

Alternatives: Build a new 115 kV or 230 kV line between Mud Lake and Riverton.

Analysis: Reconductoring 5 Line provides the best solution for maintaining the reliability of the Brainerd-area 115 kV system in view of currently-identified needs, and should defer or eliminate the need for additional transmission line development in the area based on current projections.

Schedule: MISO and Minnesota Power studies first indicate a need for the 5 Line Upgrade prior to the 2019-2020 winter season. The earliest MP anticipates being able to begin construction of the project would be in 2019.

General Impacts: The 5 Line Upgrade Project will provide necessary system improvements in the Brainerd area without requiring the establishment of additional transmission line corridors.

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868 Line Upgrade

MPUC Tracking Number: 2015-NE-N2

Utility: Minnesota Power (MP)

Project Description: Reconductor existing Little Falls-Langola Tap-St. Stephen Tap 115 kV Line (MP "868 Line") and replace limiting substation terminal equipment.

Need Driver: Post contingent overload following loss of parallel 230 kV, 345 kV, or 500 kV lines.

Alternatives: Build a new 115 kV or 230 kV line between Mud Lake and the St. Cloud area; thermal upgrade of existing conductor paired with deployment of Smart Wires power flow control devices to reduce power flow to within capability of existing conductor.

Analysis: Minnesota Power is continuing to evaluate the reconductor solution against the Smart Wires solution to determine which solution presents the best long-term value. Either solution should be sufficient for maintaining the reliability of the Little Falls-area 115 kV system in view of currently-identified needs, and should defer or eliminate the need for additional transmission line development in the area based on current projections.

Schedule: MISO and Minnesota Power studies first indicated a need for the 868 Line Upgrade prior to the 2019-2020 winter season. The earliest MP anticipates being able to begin construction of the project would be in 2019.

General Impacts: The 868 Line Upgrade Project will provide necessary system improvements in the area between Little Falls and St. Cloud without requiring the establishment of additional transmission line corridors.

15th Avenue West Substation Modernization

MPUC Tracking Number: 2015-NE-N4

Utility: Minnesota Power (MP)

Project Description: Rebuild & modernize existing 15th Avenue West Substation, including new 14 kV switchgear on adjacent property, one new 115/14 kV transformer, replacement of three 115 kV breakers and other 115 kV equipment, and miscellaneous site improvements.

Need Driver: The 15th Avenue West Substation is the largest single load-serving distribution substation in the Duluth area by total load, and serves one of Minnesota Power's most high profile load pockets: downtown and central Duluth. Many of the assets within the substation are nearing the end of their useful life, including particularly the 14 kV switchgear and some of the foundations. In addition to the risks posed by the possible failures of end-of-life equipment, there are parts of the substation that do not meet modern design and safety standards, causing safety concerns and limiting accessibility within the substation. The purpose of the 15th Avenue West Substation Modernization Project is to address aging equipment, potential reliability and safety concerns, and long-term system needs at the 15th Avenue West Substation.

Alternatives: Development of a new 115/14 kV substation in downtown Duluth and retirement of the existing 15th Avenue West Substation; utilization of gas insulated substation (GIS) equipment to minimize project footprint.

Analysis: Much of the existing equipment in the 15th Avenue West Substation is at end-of-life, and its replacement is a prudent and necessary step in maintaining reliable electric service for the downtown and central Duluth area. The cost associated with the development of an entirely new 115/13.8 kV substation adjacent to the existing site – and subsequent retirement of the existing site – was not justified based on the fact that the reliability, accessibility, and safety needs on the site could largely be addressed by relocation the distribution equipment and remaining equipment on the site as necessary.

Schedule: Construction of the 15th Avenue West Substation Modernization Project began in 2017 and will continue in stages through 2018.

General Impacts: The 15th Avenue West Substation Modernization Project will ensure a continuous and reliable power supply for the downtown and central Duluth area in the most cost-effective and least environmentally impactful manner possible.

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16 Line Relocation

MPUC Tracking Number: 2015-NE-N5

MPUC Docket Numbers: E015/TL-14-977

Utility: Minnesota Power (MP)

Project Description: Reroute a segment of the existing Arrowhead-16 Line Tap 115 kV Line around a proposed United Taconite tailings basin expansion.

Need Driver: United Taconite tailings basin expansion.

Alternatives: Remove the segment of existing line without rebuilding it.

Analysis: A fully-intact connection between Arrowhead and the 16 Line Tap is necessary for providing reliable electric service to the area between Duluth and Eveleth. Removal of the line off the proposed tailings basin expansion site without re-establishing this connection is not a viable solution.

Schedule: The 16 Line Relocation Project is expected to be completed by May of 2020 to meet United Taconite's schedule for the planned tailings basin expansion. Since the 2015 Report, a two year delay of the project was agreed to with United Taconite to better align the timing of the project with the scheduled expansion of the tailings basin.

General Impacts: The 16 Line Relocation Project maintains an important source of power for the area between Virginia and Duluth while also enabling industrial expansion on the Iron Range.

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 have since been 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, 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 currently-desired incremental export capability from Manitoba to the United States and the majority of the benefits of wind and hydro synergy can be realized by the development of the Great Northern Transmission Line Project alone, without a 345 kV extension to Arrowhead. Because there are not sufficient transmission service requests to justify the 345 kV connection to Arrowhead at this time, Minnesota Power has determined that it will 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, it will be advanced at that time based on its own merits apart from the Great Northern Transmission Line Project.

Alternatives: No other alternatives are currently being considered.

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 is not needed or economically justified at this level of Manitoba Hydro export. MISO studies have confirmed this finding.

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 has 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.

Bear Creek 69/46 kV Transformer

MPUC Tracking Number: 2015-NE-N13

Utility: Minnesota Power (MP)

Project Description: Install new 69/46 kV transformer at Great River Energy's existing Bear Creek Substation and remove existing Sandstone 69/46 kV distribution station.

Need Driver: Age and condition of Sandstone distribution station, as well as environmental concerns with the location of the Sandstone distribution station adjacent to the Kettle River.

Alternatives: Rebuild Sandstone Substation at the existing site.

Analysis: Relocating the 69/46 kV source from Sandstone to the nearby Bear Creek Substation will improve redundancy for Minnesota Power's customers while also utilizing an already-developed substation site in a more accessible and environmentally favorable location.

Schedule: Expected to be placed in-service in early 2018 following a minor delay due to engineering resource constraints.

General Impacts: The Bear Creek 69/46 kV Transformer Project will replace end-of-life equipment and provide increased load-serving capacity and reliability for Minnesota Power's customers along the Interstate 35 Corridor south of Duluth. Utilizing the existing Bear Creek Substation for the new 69/46 kV transformer and retiring the existing Sandstone distribution station site meets these needs in the most cost-effective and least environmentally impactful manner possible.

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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: Build a third Boswell-Blackberry 230 kV Line.

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, 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.

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95 Line Upgrade

MPUC Tracking Number: 2015-NE-N15

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 95 Line Upgrade Project restores the capacity of 95 Line, a critical outlet for Boswell generation, to its original capacity.

Alternatives: Build a third Boswell-Blackberry 230 kV Line.

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, and post-contingent overloads of 95 Line at its new lower rating were identified in the MTEP15 assessment as well as Minnesota Power's own internal studies. The project is expected to be placed in-service in October 2017.

General Impacts: The 95 Line Upgrade Project will restore critical transmission outlet capability for the Boswell Energy Center without requiring the establishment of additional transmission line corridors.

Two Inlets Pumping Station (X1A)

MPUC Tracking Number: 2015-NE-N16

Utility: Great River Energy (GRE)

Project Description: Tap the Mantrap to Potato Lake line near Potato Lake Substation and build approximately 7.5 miles of 115 kV transmission line to connect the future Two Inlets Substation. The substation will supply power to the Enbridge Two Inlets pump station.

Need Driver: Enbridge Pipeline has proposed a new pumping station about 12 miles northwest of Park Rapids.

Alternatives: The nearby distribution systems would not support the large pumping station load. Other alternatives would require longer 115 kV or higher voltage transmission lines.

Analysis: Large pumping stations with large electric motors require a robust voltage like 115 kV. The nearest 115 kV source is the Potato Lake Substation. A short, radial tap from the Potato Lake Substation to the new Two Inlets Substation will be constructed to provide electric service.

Schedule: The project is planned to be in-service by July 2019. The timing of this project is dependent on the Enbridge Pipeline construction schedule.

General Impacts: The Two Inlets Pumping Station Project is the most efficient and least environmentally impactful viable solution to serve the new pumping station load.

Backus Pumping Station (X2A)

MPUC Tracking Number: 2015-NE-N17

Utility: Great River Energy (GRE)

Project Description: Build an approximately 2.5 mile 115 kV transmission line from a new interconnection to the Minnesota Power 115 kV #142 line (Badoura to Pine River) to the Backus Pumping Station.

Need Driver: Enbridge Pipeline has proposed a new pumping station about 3 miles south of Backus.

Alternatives: The nearby distribution systems would not support the large pumping station load. Other alternatives would require longer 115 kV or higher transmission lines.

Analysis: Large pumping stations with large electric motors require a robust voltage like 115 kV. The nearest 115 kV source is the Badoura-Pine River (142 Line) 115 kV line. A short, radial tap from the 142 Line to the new Backus Pumping Station Substation will be constructed to provide electric service.

Schedule: The project is planned to be in-service by July 2019. The timing of this project is dependent on the Enbridge Pipeline construction schedule.

General Impacts: The Backus Pumping Station Project is the most efficient and least environmentally impactful viable solution to serve the new pumping station load.

Palisade Pumping Station (X3A)

MPUC Tracking Number: 2015-NE-N18

MPUC Docket Number: ET2/TL-15-423

Utility: Great River Energy (GRE)

Project Description: Build an approximately 13 mile 115 kV transmission line from MP's 115 kV #13 line to the Enbridge Palisade Pumping Station.

Need Driver: Enbridge Pipeline has proposed a new pumping station about 5.5 miles northwest of the City of Palisade.

Alternatives: The nearby distribution systems would not support the large pumping station load. Other alternatives would require longer 115 kV or higher transmission lines.

Analysis: Large pumping stations with large electric motors require a robust voltage like 115 kV. The nearest 115 kV source is the Riverton-Cromwell (13 Line) 115 kV line. A radial tap from the 13 Line to the new Palisade Pumping Station Substation will be constructed to provide electric service.

Schedule: The project is planned to be in-service by July 2019. The timing of this project is dependent on the Enbridge Pipeline construction schedule.

General Impacts: The Palisade Pumping Station Project is the most efficient and least environmentally impactful viable solution to serve the new pumping station load.

Cromwell Pumping Station (X4A)

MPUC Tracking Number: 2015-NE-N19

Utility: Great River Energy (GRE)

Project Description: Build an approximately 0.5 mile long 115 kV line from Cromwell City line to the Cromwell Pumping Station.

Need Driver: Enbridge Pipeline has proposed a new pumping station about 5.5 miles south of the City of Cromwell.

Alternatives: The nearby distribution systems would not support the large pumping station load. Other alternatives would require longer 115 kV or higher transmission lines.

Analysis: Large pumping stations with large electric motors require a robust voltage like 115 kV. The nearest 115 kV source is the Cromwell-Savanna (156 Line) 115 kV line. A short, radial tap from the 156 Line to the new Cromwell Pumping Station Substation will be constructed to provide electric service.

Schedule: The project is planned to be in-service by July 2019. The timing of this project is dependent on the Enbridge Pipeline construction schedule.

General Impacts: The Cromwell Pumping Station Project is the most efficient and least environmentally impactful viable solution to serve the new pumping station load.

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28 Line Upgrade

MPUC Tracking Number: 2017-NE-N1

Utility: Minnesota Power (MP)

Project Description: Thermal upgrade of the Boswell-Canisteo 115 kV Line (MP "28 Line") and replacement of limiting 115 kV terminal equipment at the Boswell Substation to increase capacity.

Need Driver: Post-contingent overload following loss of parallel 115 kV connections.

Alternatives: Build an additional 115 kV transmission line out of the Boswell 115 kV Substation.

Analysis: This issue was first identified in the MTEP15 assessment near-term models. Increasing the transmission line capacity provides the best solution for maintaining the reliability of the transmission system in the Grand Rapids area.

Schedule: The project was completed May 2017.

General Impacts: The 28 Line Upgrade Project will provide necessary system improvements on Minnesota Power's 115 kV system in the Grand Rapids area without requiring the establishment of additional transmission line corridors or removal of the existing conductor.

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. At the Hoyt Lakes Substation, the existing bus will also be expanded to include two 20 MVAR capacitor banks, a bus-tie breaker, and an open dead end structure to connect a future transmission line to the Hoyt Lakes Substation.

Need Driver: Age and condition, removal of single points of failure, standardization of equipment, and voltage support concerns following conversion, idling, or retirement of coal-fired generators in the North Shore Loop.

Alternatives: Continue to operate at 138 kV.

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 ongoing 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 leadtimes (138/115 kV transformers), providing a more redundant and reliable transmission connection for the North Shore Loop. The project also incorporates the establishment of two 20 MVAR capacitor banks at the Hoyt Lakes Substation to replace voltage support historically provided by local baseload generators. 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 future transmission expansion, should it become necessary to further interconnect and enhance redundancy to the area. The establishment of a future 115 kV transmission line bay at the Hoyt Lakes Substation provides a place to connect the Hoyt Lakes

115 kV Project (Tracking Number 2017-NE-N23), should it become needed. Continued operation of the Laskin-Tac Harbor system at 138 kV would significantly increase the cost and complexity of making this future transmission connection into the area.

Schedule: The project is expected to be in service by the end of 2019.

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 Voltage

MPUC Tracking Number: 2017-NE-N3

Utility: Minnesota Power (MP)

Project Description: Reconfigure Little Falls 115 kV bus and add a tie breaker.

Need Driver: Low voltage was identified at the Pepin Lake, Blanchard, Bellevue, and Little Falls Substations following contingency events involving the Little Falls 115 kV Bus.

Alternatives: Add another 115 kV capacitor bank in the area.

Analysis: This issue was first identified in the MTEP15 assessment and is being monitored. The addition of a bus tie breaker at the Little Falls Substation was submitted as a potential Corrective Action Plan. Depending on if and how the issue shows up in subsequent assessments, further analysis will be done to clarify the critical load level at which post-contingent voltage becomes a problem and determine what the most appropriate solution is.

Schedule: This issue was first identified in the MTEP15 2019 Winter Peak case. Minnesota Power is monitoring MTEP reliability assessment results and analyzing the load level in the area 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 MTEP15 assessment.

Nashwauk 14 Line Upgrade

MPUC Tracking Number: 2017-NE-N4

Utility: Minnesota Power (MP)

Project Description: Increase capacity of Nashwauk-14 Line Tap 115 kV Line (MP "Nashwauk 14 Line").

Need Driver: Post-contingent overload following loss of parallel line.

Alternatives: Reconductor existing line, build new parallel line.

Analysis: This issue was first identified in the MTEP15 assessment and is being monitored. The capacity upgrade project was proposed as the most straightforward and likely Corrective Action Plan should the post-contingent overloads first observed in the MTEP15 assessment continue to show up in subsequent study results. The same issue was identified in the MTEP17 assessment, and based on those results the project will be moved to Appendix A in MTEP18.

Schedule: This issue was first identified in the MTEP15 2020 Shoulder (off-peak) case, and subsequently showed up in a similar MTEP17 2022 Summer Peak case. Based on the MTEP15 results, the project is targeted for an in-serviced date prior to May 1, 2020.

General Impacts: The Nashwauk 14 Line Upgrade Project will provide necessary system improvements on Minnesota Power's 115 kV system without requiring the establishment of additional transmission line corridors.

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53 Line Upgrade

MPUC Tracking Number: 2017-NE-N5

Utility: Minnesota Power (MP)

Project Description: Increase capacity of Nashwauk-National 115 kV Line (MP "53 Line").

Need Driver: Post-contingent overload following loss of parallel line.

Alternatives: Reconductor existing line, build new parallel line.

Analysis: This issue was first identified in the MTEP15 assessment and is being monitored. The capacity upgrade project was proposed as the most straightforward and likely Corrective Action Plan should the post-contingent overloads first observed in the MTEP15 assessment continue to show up in subsequent study results. A similar issue was identified in the MTEP17 assessment, and based on those results the project will be moved to Appendix A in MTEP18.

Schedule: This issue was first identified in the MTEP15 2020 Shoulder (off-peak) case, and subsequently showed up in a similar MTEP17 case. Based on the MTEP15 results, the project is targeted for an in-serviced date prior to May 1, 2020.

General Impacts: The 53 Line Upgrade Project will provide necessary system improvements on Minnesota Power's 115 kV system without requiring the establishment of additional transmission line corridors.

Forbes 38-44 MW Breaker Failure

MPUC Tracking Number: 2017-NE-N6

Utility: Minnesota Power (MP)

Project Description: Install breaker failure relay on Forbes 38-44 MW 115 kV bus tie breaker.

Need Driver: Bus fault followed by failure of breaker to operate causes overloading on area transmission lines. Breaker failure relay will keep post-contingent loading within the present capacity of the system.

Alternatives: Add redundant bus tie breaker.

Analysis: This issue was first identified in the MTEP15 reliability assessment and is being monitored. The addition of a breaker failure relay was submitted as a potential Corrective Action Plan. Further internal Minnesota Power studies have identified potential for additional issues associated with internal fault or failure of the Forbes tie breaker that may drive a need to add a redundant bus tie breaker rather than just a breaker failure relay. Further analysis is necessary to determine the most appropriate long-term solution.

Schedule: This issue was first identified in the MTEP15 2020 Shoulder (off-peak) case. Minnesota Power is monitoring the MTEP reliability assessment results, as well as its own internal study 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, 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.

North Shore Switching Station & Cap Banks

MPUC Tracking Number: 2017-NE-N7

Utility: Minnesota Power (MP)

Project Description: A new substation called the North Shore Switching Station will be constructed. The North Shore Switching Station involves the development of a 6 position ring bus in the Silver Bay-Taconite Harbor 115 kV Line approximately one mile northeast of the existing Silver Bay 115 kV Substation, as well as approximately one mile of double circuit 115 kV line from the new switching station along the existing transmission line corridor to the Silver Bay-Two Harbors 115 kV Line just outside the Silver Bay Substation. Two 20 MVAR switched capacitor banks and two 40 MVAR fast-switched capacitor banks will be established in the new switching station.

Need Driver: Voltage violations and voltage stability concerns in the North Shore Loop transmission system following conversion, idling, or retirement of local coal-fired generators.

Alternatives: Re-establish existing Silver Bay capacitor banks and load shedding scheme.

Analysis: Because of the rapid rate of change in the North Shore Loop transmission system, Minnesota Power has effected the re-establishment of several decommissioned (and deteriorating) capacitor banks at the Silver Bay Substation as well as a previously-retired automatic load shedding scheme at a large industrial plant in Silver Bay as interim solutions until the North Shore Switching Station can be constructed and placed in service. The North Shore Switching Station is a superior long-term solution for the voltage stability and performance issues in the Silver Bay area because it provides the necessary voltage support from reliable switched capacitor banks, further sectionalizes the North Shore Loop to eliminate some of the most severe contingency events, and provides fast-switched capacitor banks to eliminate dependence on a very simplistic customer-owned auto load shedding scheme. The North Shore Switching Station also provides a ready location for the establishment of the North Shore Dynamic Reactive Device (Tracking Number 2017-NE-N15) when that project becomes necessary.

Schedule: With the majority of generator transition already having taken place in 2015 and 2016, the North Shore Switching Station needs to be placed in service as soon as possible. Currently, the targeted in-service date is November 2017.

General Impacts: The North Shore Switching Station is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. The establishment of new capacitor banks begins the process of replacing the voltage support previously provided by baseload coal units in the area, enabling the realization of significant economic and environmental benefits from transitioning away from these units. The location of the switching station and transmission line upgrades within the boundaries of a large industrial facility further limits human and environmental impacts from the project.

Babbitt Capacitor Bank

MPUC Tracking Number: 2017-NE-N8

Utility: Minnesota Power (MP)

Project Description: Add a 12 MVAR capacitor bank to the existing Babbitt 115 kV Substation.

Need Driver: Voltage violations following conversion, idling, or retirement of North Shore Loop coal-fired generators.

Alternatives: There is no more economical or less impactful solution than adding a capacitor bank to an existing substation to provide the necessary voltage support.

Analysis: Minnesota Power internal analysis of the impact of transitioning away from local baseload coal-fired generators in the North Shore Loop identified low voltage violations in the Babbitt area. The Babbitt Capacitor Bank Project will replace the voltage support previously provided by the local generators, allowing for continued reliable operation of the system in the North Shore Loop and the surrounding area in their absence.

Schedule: The project was completed and placed in service in September 2017.

General Impacts: The Babbitt Capacitor Bank is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. The establishment of new capacitor banks begins the process of replacing the voltage support previously provided by baseload coal units in the area, enabling the realization of significant economic and environmental benefits from transitioning away from these units. The location of the Babbitt Capacitor Bank at an existing substation considerably limits human and environmental impacts from the project.

ETCO Capacitor Bank

MPUC Tracking Number: 2017-NE-N9

Utility: Minnesota Power (MP)

Project Description: Add a 20 MVAR capacitor bank and replace a broken 115 kV switch at the existing ETCO 115 kV Substation.

Need Driver: Voltage violations following conversion, idling, or retirement of North Shore Loop coal-fired generators.

Alternatives: There is no more economical or less impactful solution than adding a capacitor bank to an existing substation to provide the necessary voltage support.

Analysis: Minnesota Power internal analysis of the impact of transitioning away from local baseload coal-fired generators in the North Shore Loop identified low voltage violations in the ETCO Substation area. The ETCO Capacitor Bank Project will replace the voltage support previously provided by the local generators, allowing for continued reliable operation of the system in the North Shore Loop and the surrounding area in their absence.

Schedule: The project was completed in August 2017.

General Impacts: The ETCO Capacitor Bank is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. The establishment of new capacitor banks begins the process of replacing the voltage support previously provided by baseload coal units in the area, enabling the realization of significant economic and environmental benefits from transitioning away from these units. The location of the ETCO Capacitor Bank at an existing substation considerably limits human and environmental impacts from the project.

Forbes 3T Breaker Replacement

MPUC Tracking Number: 2017-NE-N10

Utility: Minnesota Power (MP)

Project Description: The Forbes 3T Breaker Replacement Project involves replacing a 115 kV circuit breaker on the secondary side of the Forbes 230/115 kV Transformer #3. The project also includes replacement of two 115 kV switches and any limiting power wiring between the transformer and the 115 kV bus. Replaced equipment will be seized appropriately to achieve the full emergency rating of the transformer. At the same time the breaker is replaced, the relay panel will be updated to include breaker failure functionality.

Need Driver: Updating the relay panel to include a breaker failure relay is necessary to address voltage stability concerns following a breaker failure event. The Forbes 3T breaker is also aging and due to be replaced as part of Minnesota Power's ongoing asset renewal program, and much of the existing equipment and power wiring limits the emergency capacity available from the transformer.

Alternatives: There is no more economical or less impactful solution than replacing existing equipment and relaying to mitigate the identified issues.

Analysis: Minnesota Power internal analysis of the impact of transitioning away from local baseload coal-fired generators in the North Shore Loop identified widespread voltage stability concerns following breaker failure events involving the Forbes 3T breaker. The addition of a breaker failure relay would enable fault isolation to occur locally, limiting the impact of the event and mitigating the voltage stability concerns present without the North Shore Loop generators online. Replacement of the Forbes 3T breaker at the same time reduces the likelihood of breaker failure by replacing an aging oil-filled circuit breaker. Replacement of limiting terminal equipment on the secondary side of the transformer allows for better utilization of the existing Forbes transformer to deliver power to the area during system outages.

Schedule: The project will be completed by the end of 2017.

General Impacts: The Forbes 3T Breaker Replacement is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. The addition of a breaker failure relay mitigates voltage stability concerns present without the North Shore Loop generators online, preventing equipment damage and other adverse system impacts of a potentially widespread event. Replacement of the Forbes 3T breaker and other equipment in addition to adding a breaker failure relay provides for aging equipment to be replaced and for the full rating of the transformer to be realized. Accomplishing all of this within the footprint of an existing substation considerably limits human and environmental impacts from the project.

LSPI 10K Breaker Addition

MPUC Tracking Number: 2017-NE-N11

Utility: Minnesota Power (MP)

Project Description: Add a circuit breaker to the existing LSPI 10K capacitor bank.

Need Driver: Improve capacitor bank and bus protection.

Alternatives: “Do nothing” – leave capacitor bank and bus protection as-is.

Analysis: Capacitor bank faults cause the entire LSPI 115 kV bus, including load and networked 115 kV lines, to trip. Adding the breaker prevents the bus from tripping for capacitor bank faults.

Schedule: The LSPI 10K breaker addition was completed in June 2017.

General Impacts: This project improves reliability for a large area of western Duluth at a relatively minimal cost, making optimal use of existing assets and space at the LSPI Substation.

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93 Line Upgrade

MPUC Tracking Number: 2017-NE-N12

Utility: Minnesota Power (MP)

Project Description: Thermal upgrade of the Blackberry-Forbes 230 kV Line (MP "93 Line") to increase summer normal/emergency ratings to 470/517 MVA.

Need Driver: Post-contingent overloads during high export conditions identified in Minnesota Power internal studies and confirmed by MISO in MTEP17.

Alternatives: Reconductor 93 Line.

Analysis: Post-contingent overloads on the Blackberry-Forbes 230 kV Line were first identified in summer 2020 models including high regional export levels. High regional export levels put stress on the Minnesota Power system, including causing this overload. Sufficient capacity can be achieved without replacing the existing conductor or building new transmission lines by increasing the thermal operating temperature of the line from 75 degrees Celsius to 100 degrees Celsius.

Schedule: The targeted in-service date for the 93 Line Upgrade Project is May 1, 2020.

General Impacts: The 93 Line Upgrade Project will provide necessary system improvements on Minnesota Power's 230 kV system without requiring the establishment of additional transmission line corridors or removal of the existing conductor.

Boswell 230/115 kV Transformer

MPUC Tracking Number: 2017-NE-N13

Utility: Minnesota Power (MP)

Project Description: The Boswell 230/115 kV Transformer Project involves adding a new 230/115 kV transformer to the existing Boswell 230 kV Substation, expanding the existing Boswell 230 kV Substation yard to include a new 115 kV yard in a breaker-and-½ configuration, and reconfiguring the existing 115 kV transmission lines in the area to terminate at the new 115 kV yard.

Need Driver: Voltage violations following retirement of Boswell Units 1 & 2 coal-fired generators.

Alternatives: Build new transmission line or add additional reactive devices to provide voltage support to the Grand Rapids area. Re-establish baseload generation in the Grand Rapids area.

Analysis: Minnesota Power internal analysis of the impact of transitioning away from Boswell Units 1 & 2 identified low voltage violations on the Grand Rapids 115 kV system without the local baseload generators online. Establishment of a new 230/115 kV source from the Boswell 230 kV Substation (which is not presently connected to the local 115 kV system) will replace the power and voltage support previously provided to the Grand Rapids-area 115 kV transmission system by Boswell Units 1 & 2.

Schedule: The project is planned to be in service by December 31, 2018, consistent with the planned retirement of Boswell Units 1 & 2.

General Impacts: The Boswell 230/115 kV Transformer Project is a critical component to maintaining a reliable system following the planned shutdown of Boswell Units 1 & 2. Establishing a new 230/115 kV connection will provide a new 230 kV source to the Grand Rapids area 115 kV system, allowing for the continued reliable delivery of power and voltage support to the area following the transition away from local baseload coal units and enabling the full realization of significant economic and environmental benefits from transitioning away from these units.

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76 Line Upgrade

MPUC Tracking Number: 2017-NE-N14

Utility: Minnesota Power (MP)

Project Description: Replacement of end of life oil circuit breaker at the Hibbard Substation in addition to terminal equipment upgrades to increase rating of Hibbard-Winter St.115 kV Line (MP "76 Line"). The Hibbard-Winter St. 115 kV Line is an important transmission connection between Duluth and Superior.

Need Driver: The MISO MTEP16 study results show potential thermal overloading of 76 Line as early as summer 2018 for certain contingencies. Replacing the end of life circuit breaker and upgrading the limiting terminal equipment will eliminate the risk of potential thermal overloads.

Alternatives: Build a new 115 kV line between Duluth and Superior.

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

Schedule: Upgrades will be completed in early 2018.

General Impacts: The 76 Line Upgrade Project is the most cost-effective solution to maintain baseline reliability without requiring the establishment of additional transmission line corridors across state lines.

North Shore Dynamic Reactive Device

MPUC Tracking Number: 2017-NE-N15

Utility: Minnesota Power (MP)

Project Description: Install a new Static VAR Compensator (SVC) or Static Synchronous Compensator (STATCOM) system at the planned North Shore Switching Station in Silver Bay, MN. The SVC or STATCOM will control local mechanically switched capacitors (MSCs) at the North Shore Switching Station as part of an integrated Static VAR System (SVS).

Need Driver: Voltage and transient stability concerns in the North Shore Loop transmission system following conversion, idling, or retirement of coal-fired generators.

Alternatives: Large new transmission line(s) into the Silver Bay area, replacement dispatchable baseload generation in the Silver Bay area.

Analysis: Following transition of the last baseload coal-fired generator in the North Shore Loop, the dynamic reactive support formerly provided by local generators must be replaced to ensure continued reliable service to all customers in the North Shore Loop. Establishment of a new SVC or STATCOM system at the North Shore Switching Station is a low-impact, relatively low-cost solution compared to the alternatives, which involve building large new transmission from the Duluth area or the Iron Range to the Silver Bay area, or establishing replacement dispatchable baseload generation in the Silver Bay area. The North Shore SVC or STATCOM will also build upon the planned establishment of the North Shore Switching Station and capacitor banks, making good use of the site and the assets located there. The specific technology employed (SVC or STATCOM) will be determined following a competitive bidding process for the project based on the proposals received from the manufacturers.

Schedule: The targeted in-service date for the North Shore SVC or STATCOM is September 1, 2019, to ensure that the system is fully operational by the end of 2019.

General Impacts: The North Shore SVC/STATCOM is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. The addition of the SVC/STATCOM to the planned capacitor banks at the North Shore Switching Stations completes the replacement of voltage support previously provided by baseload coal units in the area, enabling the full realization of significant economic and environmental benefits from transitioning away from these units. Locating the new SVC/STATCOM adjacent to the North Shore Switching Station within the boundaries of a large industrial facility greatly minimizes the human and environmental impacts from the project, especially compared to potentially routing large new transmission lines through highly-valued natural and recreational resources into the Silver Bay area or establishing new baseload generation in the area.

51 Line Upgrade

MPUC Tracking Number: 2017-NE-N16

Utility: Minnesota Power (MP)

Project Description: Thermal upgrade of the Riverton-Pequot Lakes 115 kV Line (MP "51 Line").

Need Driver: Post-contingent overload following loss of parallel 230 kV connections.

Alternatives: Reconductor, establish new transmission.

Analysis: Post-contingent overloads on the Riverton-Pequot Lakes 115 kV Line were first identified in the MTEP16 2021 Winter Peak case and are being monitored. A modest 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. 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 MTEP16 2021 Winter Peak case. 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 MTEP16 assessment.

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18 Line Upgrade

MPUC Tracking Number: 2017-NE-N17

Utility: Minnesota Power (MP)

Project Description: Reconductor existing ETCO-Forbes 115 kV Line (MP "18 Line").

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

Alternatives: Build a new 115 kV line parallel to 18 Line.

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 transmission lines, including 18 Line, which also carries power to serve loads on the eastern part of the Iron Range. Reconductoring 18 Line provides the needed capacity to ensure continued reliable delivery of power in the eastern part of the Iron Range and into the North Shore Loop following transition away from the local generation.

Schedule: Minnesota Power studies indicate that the 18 Line Upgrade is needed by the end of 2019. The targeted in-service date for the project is fall 2018.

General Impacts: The 18 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 the 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 18 Line Upgrade Project will provide necessary system improvements on the 115 kV system without requiring the establishment of additional transmission line corridors, which will minimize any potential environmental impacts.

Tioga 115/23 kV Substation

MPUC Tracking Number: 2017-NE-N18

Utilities: Minnesota Power (MP) & Grand Rapids Public Utility Commission (GRPUC)

Project Description: Minnesota Power will extend an existing 115 kV tap from the Boswell-Blandin 115 kV Line (MP "27 Line") to a new GRPUC "Tioga" Substation. GRPUC will construct the new 115/23kV substation and connect to existing distribution.

Need Driver: GRPUC desires a backup substation that is capable of providing redundancy for their distribution system in addition to enabling future load growth.

Alternatives: Build a new 115 kV transmission extension to a different substation site.

Analysis: Since this project is utilizing an existing transmission line asset, it is the least-cost option for meeting GRPUC's needs. Furthermore, the substation will be strategically located in an industrial park area that has potential for future commercial or industrial development.

Schedule: Project in-service date is projected to be late 2018.

General Impacts: Establishing a new distribution substation will provide reliability benefits to the Grand Rapids area as well as enable economic development in the project area. Location of the new substation near an existing transmission line eliminates the need to establish an additional transmission line corridor in the Grand Rapids area, providing a low-cost, low-environmental impact solution.

North Shore Transmission Line Upgrades

MPUC Tracking Number: 2017-NE-N19

Utility: Minnesota Power (MP)

Project Description: Replace limiting substation equipment on the Ridgeview-Colbyville 115 kV Line (MP "56 Line"). Replace limiting substation equipment and complete a thermal upgrade on the Arrowhead-Colbyville 115 kV Line (MP "57 Line"). Replace limiting substation equipment and complete a thermal upgrade on the Arrowhead-Haines Road 115 kV Line (MP "58 Line"). Replace limiting substation equipment and reconductor 1.9 miles of the existing Colbyville-Two Harbors 115 kV Line (MP "145 Line").

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

Alternatives: Build a new 115 kV line between Arrowhead and Two Harbors.

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 transmission lines, including 56 Line, 57 Line, 58 Line, and 145 Line. The coordinated upgrade of these four transmission lines via replacement of limiting substation equipment, thermal upgrades of existing conductors, and replacement of a small segment of conductor provides the needed capacity to ensure reliable delivery of power into the North Shore Loop following transition away from the local generation.

Schedule: Minnesota Power studies indicate that the North Shore Transmission Line Upgrades are needed by the end of 2019. The project will take place in stages between 2018 and 2019, with a targeted in-service date in fall 2019.

General Impacts: The North Shore 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.

Two Harbors 115 kV Project

MPUC Tracking Number: 2017-NE-N20

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

Project Description: Expand and reconfigure existing Two Harbors Switching Station to accommodate relocation of existing Great River Energy Waldo load-serving tap from Two Harbors-North Shore 115 kV Line (MP "42 Line") onto a dedicated source from the Two Harbors Switching Station three spans away. Complete a thermal upgrade of existing 42 Line conductor to provide increased transmission line capacity.

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

Alternatives: Reconductor 42 Line (30 miles) without relocating Waldo tap.

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 transmission lines, including 42 Line. Analysis of potential upgrade options for 42 Line determined that a costly reconductor of the line could be deferred – and potentially avoided completely – by shifting the Great River Energy Waldo load-serving tap from this line to a dedicated source from the nearby Two Harbors Switching Station and completing a thermal upgrade of the existing 42 Line conductor.

Schedule: Minnesota Power studies indicate that the Two Harbors 115 kV Project needs to be completed by the end of 2019. The targeted in-service date for the project is December 2019.

General Impacts: The Two Harbors 115 kV Project is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. Increasing the available capacity of 42 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 while minimizing additional transmission line construction and maximizing the optimal use of existing transmission facilities.

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").

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

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

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 transmission lines, including 43 Line, 1 Line, and 2 Line. The coordinated upgrade of these three transmission lines via thermal upgrades of existing conductors and minor modification of existing structures provides the needed capacity to ensure reliable delivery of power into the North Shore Loop following transition away from the local generation.

Schedule: Minnesota Power studies indicate that the Laskin-Tac Harbor Line Upgrades are needed by the end of 2019. Construction of the project is expected to take place at the same time as the Laskin-Tac Harbor Voltage Conversion (2017-NE-N2) to utilize the same outage dates.

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.

Blackberry Breaker Replacements

MPUC Tracking Number: 2017-NE-N22

Utility: Minnesota Power (MP)

Project Description: Replace three 115 kV circuit breakers at the Blackberry Substation due to age and condition and fault current projected to be over the breaker interrupting capability. Replace three additional 230 kV circuit breakers at the Blackberry Substation due to age and condition.

Need Driver: The six circuit breakers being replaced are older oil-filled circuit breakers. Three of those breakers will be over-dutied by increased fault currents in the 2020 timeframe. The other three will be replaced for asset renewal due to their age and condition.

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

The breakers were also identified to be replaced as part of MP's asset renewal program due to the age and maintenance required for the existing circuit breakers.

Analysis: Minnesota Power internal analysis identified that an increase in fault current in the 2020 timeframe, corresponding to the in-service date for the Great Northern Transmission Line (Tracking Number 2013-NE-N13), causes three 115 kV circuit breakers at the Blackberry Substation to exceed their interrupting capability. These three breakers are approximately 40-year old oil-filled circuit breakers that were scheduled to be replaced as part of Minnesota Power's ongoing asset renewal program. Three additional oil-filled 230 kV circuit breakers of a similar vintage will also be replaced at the same time to take advantage of the efficiencies of bundling the work.

Schedule: The project is planned to be in service by June 2020.

General Impacts: Replacing the circuit breakers will accommodate increased fault current due to changing system topology in the area. Accomplishing this within the footprint of an existing substation considerably limits human and environmental impacts from the project.

Hoyt Lakes 115 kV Project

MPUC Tracking Number: 2017-NE-N23

Utility: Minnesota Power (MP)

Project Description: Extend the existing Forbes-Laskin 115 kV Line (MP "38 Line") approximately 7 miles into the Hoyt Lakes Substation along the same corridor as the existing Laskin-Hoyt Lakes transmission line. Eliminate the existing connection to the Laskin Substation.

Need Driver: Voltage stability concerns in the Hoyt Lakes area following conversion, idling, or retirement of North Shore Loop coal-fired generators and expected industrial customer expansion at the Hoyt Lakes Substation.

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

Analysis: The Hoyt Lakes 115 kV Project provides needed redundancy for the northern end of the North Shore Loop, enabling industrial customer expansion in the area without the benefits of voltage support historically provided by local coal-fired baseload generators. Reconfiguring and extending the existing Forbes-Laskin 115 kV Line into the Hoyt Lakes Substation avoids a costly overhaul of the existing Laskin Substation or many miles of additional transmission line construction to establish fully redundant transmission sources.

Schedule: Minnesota Power studies indicate that a need for the Hoyt Lakes 115 kV Project develops when future industrial load at the Hoyt Lakes substation comes online. Therefore, Minnesota Power will initiate development of the Hoyt Lakes 115 kV Project only when – and if – the schedule for industrial customer expansion requires it.

General Impacts: The Hoyt Lakes 115 kV Project is a critical component to maintaining a reliable system in the face of significant changes and anticipated load growth in the North Shore Loop. When it becomes needed, the Hoyt Lakes 115 kV Project will make optimal use of existing transmission corridors in the area to provide the needed system improvements, supporting load growth and economic development in the Hoyt Lakes area in the most cost-effective and least environmentally impactful manner possible by utilizing existing utility infrastructure and transmission line corridors to the greatest extent possible.

Knife Falls Distribution Substation

MPUC Tracking Number: 2017-NE-N24

Utility: Great River Energy (GRE)

Project Description: Great River Energy (GRE) will build a 0.2 mile, 115 kV tap line that will interconnect to Minnesota Power's (MP) 115 kV 9 Line near the intersection of St. Louis River Road and Crosby Road in the Cloquet area via 3-way switch with motor operators in order to provide 115 kV electric service to Lake Country Power's (LCP) new Knife Falls Distribution Substation. The Knife Falls Substation will serve existing system load that is currently served by LCP's Solway and Grand Lake substations.

Need Driver: The Cloquet load pocket has been growing and Lake Country Power wants to upgrade the service they are providing to this area. At the moment Solway and Grand Lake substations provide ANSI B voltage to the Cloquet load pocket using two stages of regulation and a cap bank. The installation of the new Knife Falls Substation will allow for ANSI A voltage service to the aforementioned load pocket. LCP is planning to use a 7.5/10.5 MVA transformer that is protected by a transrupter. Knife Falls will serve 0.5 MVA and 2.0 MVA from the Solway and Grand Lake substations respectively.

Alternatives: The alternative to the Knife Falls Distribution Substation would be to continue serving load in the area with the existing distribution substations in the area. However, load growth in the area has reached a level that makes this not feasible. Stepping up the 12.5 kV to 25 kV and then stepping back down could alleviate the issues in the short term but would not be the least cost plan overall and would introduce a new voltage to the area. The best value plan to reliably serve customers in the area is to establish the Knife Falls Distribution Substation.

Analysis: Establishing a new 115/12.5 kV source near Cloquet alleviated the low voltage issues seen on the feeders from Solway and Grand Lake also providing redundancy to this load pocket between Cloquet and the Solway and Grand Lake substations.

Schedule:
Siting and Routing complete.. Feb 2017
ROW Easement Acquisition underway.. June 2017 – June 2018
Project Construction... June 2018 – Sept 2018
Project In-service.. Sept 2018

General Impacts: The new Knife Falls Distribution Substation will be the most efficient (lowest system losses) and have the least impact on the environment for meeting the near-term low voltage needs and also meeting long term loading needs in the Cloquet area going into the future. The Knife Falls Substation will support the growing needs along Highway 33.

Boswell 230 kV Fast-Switched Capacitor Bank

MPUC Tracking Number: 2017-NE-N25

Utility: Minnesota Power (MP)

Project Description: Add fast-switched capacitor bank at Boswell 230 kV Substation in a size to be determined.

Need Driver: Transient voltage violations following local three-phase fault events.

Alternatives: No alternatives are currently being considered.

Analysis: Transient voltage violations in the Boswell 230 kV Substation area were first identified in the MTEP16 stability assessment and are being monitored. A conceptual fast-switched capacitor bank was submitted as a potential Corrective Action Plan based on the limited information about the issue known at the time. 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 MTEP16 stability assessment. 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 MTEP16 assessment.

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 2015 Biennial Report but have been completed or withdrawn since the 2015 Report was filed with the Minnesota Public Utilities Commission in November 2015. 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 2015 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
2003-NE-N2	Cromwell-Wrenshall-Mahtowa-Floodwood Area	E015/CN-10-973 and E015/TL-10-1307	GRE/ MP	March 2016
2007-NE-N2	Essar 230 kV Project	E280/TL-09-512	MP	Phase 1 of project completed in April 2013. Phase 2 of project cancelled due to lower industrial load.
2009-NE-N2	Deer River Area	E015/TL-13-68	MP	November 2016
2011-NE-N10	Laskin Transformer	Not Required	MP	Cancelled while MP evaluates the future of 46 kV at Laskin.
2013-NE-N7	Canosia Road Substation	Not Required	MP	December 2016
2013-NE-N8	Embarrass Transformer	Not Required	MP	November 2016
2013-NE-N19	Hoyt Lakes Sub Modernization	Not Required	MP	Cancelled and incorporated into Project #10383. Tracking Number 2017-NE-N2.
2013-NE-N21	Menahga Area 115 kV Project	E015/CN-14-787 and E015/TL-14-797	GRE/ MP	October 2017
2015-NE-N3	Maturi 115/23 kV Transformer	Not Required	MP	January 2016

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2015-NE-N6	Motley Area 115 kV Project	E015/CN-14-853 and E015/TL-15-204	GRE/ MP	September 2017
2015-NE-N7	Maturi 115/34.5 kV Transformer Replacement	Not Required	MP	Cancelled due to industrial customer shutdown.
2015-NE-N8	Hat Trick 115 kV Project	Not Required	MP	June 2017
2015-NE-N9	Arrowhead 115 kV Bus Reconfiguration	Not Required	MP	August 2017
2015-NE-N10	Minntac 230 kV Bus Reconfiguration	Not Required	MP	September 2016
2015-NE-N11	Forbes 230/115 kV Transformer Addition	Not Required	MP	September 2016

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?	Utility
2003-WC-N7	Panther Area	N/A	N/A	Yes	GRE
2009-WC-N6	Elk River-Becker Area	2012/C	2691	No	GRE
2013-WC-N3	Priam Substation	2014/A	4380	No	WMU/GRE
2015-WC-N3	Ortonville 115/41.6 kV Transformer	2015/B	4236	No	OTP
2015-WC-N4	Riverview Road 345/115/69 kV Project	2016/A	7884	No	GRE
2017-WC-N1	Benson 14.4 MVAR Capacitor Bank	2018/C>A	12206	No	GRE

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Utility
2017-WC-N2	Brooks Lake Distribution Substation	2018/C>A	13464	No	GRE
2017-WC-N3	Cashel West 115 kV Distribution Substation	2019/C>A	14364	No	GRE
2017-WC-N4	Cashel East 115 kV Distribution Substation	2019/C>A	14365	No	GRE
2017-WC-N5	DS Line Rebuild Project	2019/C>A	14366	No	GRE

Panther Area

MPUC Tracking Number: 2003-WC-N7

Utility: Great River Energy (GRE)

Project Description: Construct a 115 kV line from Brownton to McLeod 115 kV.

Need Driver: The Panther area is characterized by long 69 kV transmission lines from remote 115/69 kV sources with one 230/69 kV source (Panther) in the middle of the system. Although load growth in this area is slow, several relatively large spot loads are present (near Danube and Olivia). During the loss of the Panther 230/69 kV source or one of the 69 kV lines emanating from Panther, bus low voltage and line overloads occur.

The following are typical of the deficiencies in this area that could be expected based on the summer peak conditions.

- 2021: Hector bus voltage at 87.3% for the outage of the Bird Island-Hector 69 kV line
- 2021: Panther 230/69 kV transformer loading at 103% during system intact
- 2021: Panther 230/69 kV transformer loading at 123% for the outage of the Birch-Franklin 69 kV line (could be reduced by switching)
- 2021: Melville Tap-Panther 69 kV line at 103%

Alternatives: The following two alternatives were considered to address the low voltage and overload concerns in the area:

- Alternative 1: Install a second 230/69 kV transformer at Panther.

- Alternative 2: Construct a 115 kV line from McLeod to Brownton and establish a 115/69 kV source at Brownton.

The first alternative will address the transformer overload concern, but will not address the low voltage problems at Hector. Alternative 2 is the preferred plan to address both the low voltage and overload concerns in the Panther area for a long-term.

Analysis: Doubling the Panther 230/69 kV transformer will only address the transformer overload, but it will not address low voltage problems. The Brownton 115/69 kV source instead will provide significant load serving reliability improvement by addressing both low voltage and overload problems in the system. It will also relieve loading from the Panther 230/69 kV and Franklin 115/69 kV transformers, sectionalize the extensive 69 kV system and make capacity available for future load growth in the 69 kV system.

Schedule: This project has been delayed indefinitely due to a drop in load growth. GRE continues to monitor the situation but there have not been any changes that would warrant proceeding with the project at this time.

General Impacts: The Panther Area Project is the most efficient solution that will address both the low voltage and transformer overload concerns in the area. The project also increases the overall load serving reliability of the 69 kV system.

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 Liberty & Enterprise Park.

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

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 project is expected to be completed in 2023.

General Impacts: The Elk River-Becker Area Project is the most efficient and least environmentally impactful viable solution for meeting the near term and long term needs in the area.

Priam Substation

MPUC Tracking Number: 2013-WC-N3

Utility: Great River Energy (GRE)

Project Description: Build a 115/69 kV substation to be named Priam three miles west of Willmar. Move the existing Willmar 115/69 kV transformer to the new Priam Substation.

Need Driver: This project provides a second delivery location to the City of Willmar.

Alternatives:

- Alternative 1: Establish a new 230/69 kV substation in the Spicer area and construct about 1 mile double circuit 69kV line from the substation to the Kandiyohi to Green Lake 69 kV line.

- Alternative 2: Establish a new 115/69 kV substation at Kerkhoven Tap by moving the Willmar 115/69 kV transformer to the new substation and convert the Kerkhoven Tap to Willmar 115 kV line to 69 kV.

These two options were not found to be the best value plan to Priam Substation plan.

Analysis: The project will move 115/69 kV transformer from the Willmar Substation to a new substation location about 3 miles west of Willmar, at the Priam Substation. The transformer will serve the same load that it now serves while at the Willmar Substation site. The separation of the two substations, however, provides better reliability to the system in such a way that a major outage causing event at Willmar Sub will not put both the 230/69 kV and 115/69 kV transformer out-of-service.

Schedule: This project is expected to be complete by summer 2019. The project schedule is being driven by land acquisition delays.

General Impacts: This project is the best value plan that will increase the reliability of the area served currently from the Willmar Substation.

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 will cause the current 115/41.6 kV Ortonville transformer to become overloaded and created reliability concerns.

Alternatives: Due to the small size of the project, little impact and low cost no alternatives were considered.

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: Currently the new Ortonville 115/41.6 kV transformer is scheduled to be replaced in the year 2020. However, faster or slower load growth could cause the date of the project to change.

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.

Riverview Road 345/115/69 kV Project

MPUC Tracking Number: 2015-WC-N4

Utility: Great River Energy (GRE)

Project Description: Build a new 345/115/69 kV substation near Melrose, MN.

Need Driver: This project is needed to address contingency low voltage issues as well as transformer and 69 kV line overload concerns in the system.

Alternatives: The following are the alternatives considered in the study of this matter:

1. Replace West St. Cloud transformer and rebuild overloaded lines,
2. Roscoe to Millwood 69 kV line with new West St. Cloud transformer,
3. St. Stephen to Albany 115 kV line with Albany 115/69 kV Substation,
4. Rockville to Albany 115 kV line with Albany 115/69 kV Substation,
5. Riverview Road 345/115/69 kV station with Millwood to Melrose 69 kV line rebuild,
6. Rockville to Millwood 115 kV transmission line with Riverview Road 115/69 kV Substation,
7. Munson to Albany 115 kV line and Roscoe to Albany 69 kV line with Albany 115/69 kV Substation.

Analysis: The Riverview Road Substation will relieve system intact and contingency overloads in the 69 kV system. The project also addresses low voltage problems during critical contingencies in the system. As the project relieves loading from the Douglas County, Wakefield, Paynesville and West St. Cloud 115/69 kV transformers and it is directly sourced from a stiff 345 kV system, additional capacity will be available for reliable service to future load growth in the system.

Schedule: This project is expected to be complete by winter 2018. The project schedule is being driven by land acquisition delays.

General Impacts: The Riverview Road 345/115/69 kV Substation Project is the best value plan that will address the load serving problems in the 69 kV systems (bounded by Douglas County, Paynesville, Wakefield and West St. Cloud) for the long-term.

Benson 14.4 MVAR Capacitor Bank

MPUC Tracking Number: 2017-WC-N1

Utility: Great River Energy (GRE)

Project Description: Install 14.4 MVAR capacitor bank at GRE's Benson Substation.

Need Driver: Contingencies in the transmission system while Benson Power is offline cause low voltage problems at multiple substation that are served from the Morris to Benson 115 kV transmission line. The capacitor bank is needed to alleviate the low voltage problems.

Alternatives: The first alternative is the Do Nothing Option. This option involves transferring of load to adjacent sources and shedding off load in the system for some transmission events. Load shedding is a violation of the NERC criteria for this outage scenario; therefore, this option wasn't considered further. Installing SVC, synchronous condenser, a 230/115 kV substation by Benson and bringing 115 kV line from Paynesville, Appleton, or Alexandria were considered as alternatives. These alternates were not considered as they are costly and can't be put in place in relatively short period to time.

Analysis: The simulation results show that the preferred capacitor bank size that can be switched in with a capacitor-switcher is 14.4 MVAR. Switching this capacitor bank requires a cap-switcher with 250Ω pre-insertion resistor. The cap-switcher manufacturer should review the resistor value to determine the optimum resistor size.

Schedule: The Benson capacitor bank is scheduled to be in-service in December 2017.

General Impacts: The Benson Capacitor Bank Project is the best value plan that will address the low voltage problems in the Benson area.

Brooks Lake 115 kV Distribution Substation

MPUC Tracking Number: 2017-WC-N2

Utility: Great River Energy (GRE)

Project Description: Construct 0.2 mile, in/out, 115 kV line from NSP's Big Swan to Crow River 115 kV line with 795 ACSS conductor to interconnect Wright-Hennepin Cooperative Electric Association's (WHECA) Brooks Lake Distribution Substation. GRE will construct the high side, and install two 2000A, 115 kV load break switches and metering equipment at WHECA's Brooks Lake Substation.

Need Driver: Existing substations are determined not capable of serving growing load in the Brooks Lake area including the expected expansion of WHECA's largest load customer in the area. The Brooks Lake Distribution Substation will serve growing loads in the Brooks Lake area and unload nearby distribution substations that are reaching capacity. Brooks Lake will also provide contingency back-feed to nearby substations.

Alternatives: WHECA considered upgrading existing feeders to provide service to growing loads in the Brooks Lake area. This option, however, is not chosen as the expected load growth is too large to serve with upgraded feeders.

Analysis: The magnitude of the local load growth requires a new distribution substation.

Schedule: The Brooks Lake 115 kV Distribution Substation Project is scheduled to be in service by summer 2019.

General Impacts: The Brooks Lake 115 kV Distribution Substation Project is the least impact solution to serving the local area load reliably.

Cashel West 115 kV Distribution Substation

MPUC Tracking Number: 2017-WC-N3

Utility: Great River Energy (GRE)

Project Description: Install a 3-way, 115 kV switch on GRE's AG-BK line and construct about 3 mile of 115 kV line with 477 ACSR conductor from the new 3-way switch to Agralite Electric Cooperative (AEC) Cashel West Distribution Substation.

Need Driver: AEC needs Cashel West Substation to serve a new spot load of 2 MW and pick up additional load that is now served from the Cashel Substation.

Alternatives: AEC examined the possibility of upgrading the Cashel Substation as opposed to building a new one, but it was quickly ruled out. The Cashel Substation is an all wood structure substation that was built in 1958. The largest obstacle to upgrading or keeping this substation in the location where it is situated is its proximity to a river. Cashel Substation sits in a low spot approximately 200 feet from a creek. AEC has experienced flooding in this substation from this creek before. AEC also has concerns in regard to environmental issues related to oil spills given the close proximity of the creek. The elevation difference between the substation surface and the road makes it extremely difficult to safely move heavy equipment in an out of the substation. An upgrade to this substation would involve a new transformer, bus upgrades, regulators upgrades, new recloser, and a feeder upgrade. Given the aforementioned issues, AEC does not feel upgrading this substation in its current location is a good investment of funds.

Analysis: A new spot load in the area requires electric service from an existing substation, or a new substation, the Cashel Substation that exists in the area doesn't have capacity to serve the 2 MW spot load in the area. In addition, the existing substation is scheduled for retirement in 2019 due to age and condition of the substation. A new substation has to be constructed in the area to serve the 2 MW spot load in the Cashel West area.

Schedule: This project is planned to be in-service in November 2018.

General Impacts: The Cashel West Distribution Substation will have sufficient capacity to serve the spot load and growing loads in the area reliably. This substation facilitates the retirement of the existing Cashel Substation that has had reliability concerns. It is also the least environmentally impactful solution to serve the new load and address concerns related to the Cashel Substation.

Cashel East 115 kV Distribution Substation

MPUC Tracking Number: 2017-WC-N4

Utility: Great River Energy (GRE)

Project Description: Install a 3-way 115 kV switch on GRE's AG-BK line, and construct about one span of 115 kV line with 477 ACSR conductor from the new 3-way switch to Agralite Electric Cooperative (AEC) Cashel East Distribution Substation.

Need Driver: AEC needs to construct the Cashel East Substation to serve all the Cashel Substation load that will not be served from Cashel West Substation, provide contingency back to the Cashel West Substation, and facilitate the retirement of the Cashel Substation. Cashel Substation will be retired due to age and condition.

Alternative: The alternative to keep the Cashel Substation instead of constructing a new substation was not considered further as the existing Cashel Substation is deemed not reliable due to its age and condition. In addition, AEC has concerns in regard to environmental issues related to oil spills given the close proximity of the creek to the substation.

Analysis: The Cashel East Substation will increase load serving reliability in the area. As it facilitates the retirement of the existing Cashel Substation, it addresses environmental concerns that is related to the Cashel Substation.

Schedule: This project is planned to be in-service in December 2019.

General Impact: The Cashel East Substation will provide a reliable electric service to the area that is now served from the Cashel Substation. Contingency back feed between Cashel East and Cashel West Substation will bring better service reliability than that currently exists.

DS Line Rebuild Project

MPUC Tracking Number: 2017-WC-N5

Utility: Great River Energy (GRE)

Project Description: Rebuild GRE's existing 69 kV transmission line from Willmar to Litchfield Muni Tap to 115 kV standard with 795 ACSR conductor for continues operation at 69 kV.

Need Driver: GRE's Willmar to Litchfield Muni Tap 69 kV line (DS line) is one of the oldest 69 kV transmission lines in the area. It is in need of a replacement due its age and condition. In addition, this transmission line provides support to a large load center at Litchfield Muni. System analysis shows the existing transmission system doesn't have margin to serve new or growing loads in the Litchfield area within the required voltage criteria. In order to improve system voltage, and address reliability concerns due to the transmission line age and condition, GRE will rebuild the transmission line. Better system reliability and load serving performance will be gained in this area with 115 kV transmission line that extends between Willmar and Big Swan area. As a result, GRE will rebuild the DS line to 115 kV standard, but will continue to operate the line at 69 kV until the need to operate the transmission line at 115 kV is justifiable in the future.

Alternative: The driver for the line rebuild is mostly age and condition of the transmission line. GRE could rebuild the transmission line to 69 kV standard, but this will limit the load serving capacity of the transmission system in the Litchfield area. Rebuilding the line to 115 kV at a later date will also be costly.

Analysis: The DS Line Rebuild Project brings efficiency improvement as there will be less power loss on the transmission line. It also provide better load serving reliability as it will be new, and construction of the line will be done to the 115 kV standard. The line rebuild makes capacity available in the transmission system for a new load that may come to the areas that are served from the DS line.

Schedule: The schedule for the line rebuild is currently unknown. GRE is in the process of getting this project scheduled.

General Impact: The DS Line Rebuild Project reduces power loss on the transmission system and fosters economic development. It is also the least environmentally impactful viable solution to address age and condition the DS line.

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 2015 Biennial Report but have been completed or withdrawn since the 2015 Report was filed with the Minnesota Public Utilities Commission in November 2015. 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 2015 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
2009 WC-N4	Five Points Distribution Substation (formerly Sartell)	Not Required	GRE	2017
2013-WC-N1	Upgrade St. Stephen Substation	Not Required	GRE	2016
2013-WC-N2	Quarry-West St. Cloud 115 kV line	Not Required	GRE	2017
2015-WC-N1	Quarry Breaker-and-½ expansion	Not Required	XEL	2017
2015-WC-N2	Douglas County-West Union 69 kV Line rebuild	Not Required	XEL	2017

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2015-WC-N5	Stockade Pumping Station	Not Required	GRE	2017

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?	Utility
2017-TC-N1	Airport-Rogers Lake 115 kV Rebuild	2016/B>A	10074	No	XEL
2017-TC-N2	City of Chaska Interconnection	2016/B>A	10045	No	XEL
2017-TC-N3	Southtown Area Upgrades	2016/B>A	10066	No	XEL
2017-TC-N4	Black Dog-Wilson 115 kV Uprate	2017/C>A	11993	No	XEL
2017-TC-N5	Wilson Substation	2017/C>A	4695	No	XEL
2017-TC-N6	Plymouth-Area Power Upgrade	2018/C>A	14054	No	XEL
2017-TC-N7	Lebanon Hills 115 kV	2018/C>A	12211	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: 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.

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

Schedule: The project is planned to be in-service by December 2020.

General Impacts: This line crosses the Mississippi River, multiple lakes, two cemeteries, three highways, and an interstate, so the permitting process is expected to be very involved and time consuming. Otherwise, this project is a replacement of what exists today.

City of Chaska Interconnection (Lake Hazeltine)

MPUC Tracking Number: 2017-TC-N2

Utility: Xcel Energy (XEL)

Project Description: The City of Chaska will build a new distribution substation tapping Xcel Energy's 115 kV line from Bluff Creek and Scott County. Xcel Energy will build and own the 115 kV side of the new substation.

Need Driver: City of Chaska Interconnection request.

Alternatives: A radial tap from Bluff Creek to new Chaska Substation.

Analysis: The City of Chaska is planning on serving their complete load from the new substation. This substation will also accommodate future load growth in the City of Chaska.

Schedule: The project is planned to be in-service by summer of 2018.

General Impacts: The project is expected to cost $3.2M and be in-service in 2018.

Southtown Area Upgrades

MPUC Tracking Number: 2017-TC-N3

Utility: Xcel Energy (XEL)

Project Description: Upgrade the Southtown-Cedarvale 115 kV line to a minimum of 290 MVA emergency rating. Upgrade the Southtown-Shepard 115 kV line to a minimum of 270 MVA emergency rating. Add an 80 MVAR cap to the Hiawatha Substation.

Need Driver: Local load growth in the southeast Minneapolis area causes thermal overloads and voltage violations under certain contingencies.

Alternatives: Bring a new 115 kV line into the new Midtown Substation from western Twin Cities.

Analysis: This project is needed due to the load growth in the area under certain contingencies causing thermal overloads and voltage issues. These projects will address all the thermal and voltage issues in the area.

Schedule: The majority of this project is already complete with the remainder being completed by the end of 2017. The work took approximately two years to complete and used Xcel Energy employees.

General Impacts: This project will use existing right of way and substation land. The cost estimate is approximately $3.2M and has a targeted in-service date end of 2017.

Black Dog-Wilson 115 kV Uprates

MPUC Tracking Number: 2017-TC-N4

Utility: Xcel Energy (XEL)

Project Description: This project is to uprate the existing 115 kV lines from the Black Dog Substation to the Wilson Substation.

Need Driver: Load has continued to grow in the southern metro area putting additional pressure on the existing facilities to continue to serve the load reliably. Under certain conditions the existing 115 kV lines from Black Dog-Wilson #1 and #3 are likely to be overloaded in the 2020 summer peak cases.

Alternatives: Alternative 1 was to build a 4th 115 kV line from Black Dog-Wilson. This option was shown infeasible due to a new river crossing and the difficulty in getting into the Wilson Substation due to the line congestion and the location of the substation.

Alternative 2 was to convert the Black Dog Substation to breaker-and-½. This option was shown to be a very expensive solution as most of the existing Black Dog Substation would have to be rebuilt to accommodate this solution.

Analysis: This project is needed due to the load growth in the area under certain contingencies causing thermal overloads. Under certain contingencies Black Dog generation would have to be reduced to prevent overloading the 115 kV lines feeding the Bloomington/494 area.

Schedule: The work will take approximately two years to complete and used Xcel Energy employees.

General Impacts: This project will use existing right of way and substation land. The cost estimate is approximately $4.2M and has a targeted in-service date of summer 2019.

Wilson Substation

MPUC Tracking Number: 2017-TC-N5

Utility: Xcel Energy (XEL)

Project Description: Convert the existing Wilson Substation from a straight bus configuration to a breaker-and-½ configuration.

Need Driver: This project is needed to interconnect a 4th distribution transformer at Wilson Substation, remove a three terminal line, and add flexibility for real time operations and maintenance.

Alternatives: An alternative to this project is a new substation in the area and new transmission lines to the new substation. This area is already very congested and routing new transmission lines would be very difficult.

Analysis: This project is needed due to the load growth in the area and to address the lack of load serving flexibility in the area. This substation is one of the largest substations on the Xcel Energy system with a straight bus design; the breaker-and-½ design will address load serving concerns in this area.

Schedule: The work will take approximately two years to complete and use Xcel Energy employees.

General Impacts: This project will use existing substation land. The cost estimate is approximately $17M and has a targeted in-service date of summer 2020.

Plymouth-Area Power Upgrade

MPUC Tracking Number: 2017-TC-N6

Utility: Xcel Energy (XEL)

Project Description: This project includes the rebuild of the existing Parkers Lake to Gleason Lake 115 kV double circuit line into two single circuit lines in the same right of way and installation of a 40 MVAR capacitor bank at Gleason Lake. Additionally, this project constructs a new substation called Pomerleau Lake, located on the Parkers Lake to Plymouth 115 kV line, re-energizes the existing Hollydale to Plymouth 69 kV line, and re-terminate that 69 kV line into Pomerleau Lake Substation. Finally, the Hollydale Substation will be expanded to accommodate serving load from 69 kV on a permanent basis.

Need Driver: Regular load growth in the area in and around Plymouth has required the need for the project. The City of Plymouth asked for a long term solution in this area after extensive public input. This set of projects was the result of this public input.

Alternatives: This project has gone through many years of public involvement and included many alternatives. The project listed above is the project that came out of all of this public involvement.

Analysis: This project is needed due to the load growth in the area under certain contingencies causing voltage and thermal violations. Assuming normal load growth in the Plymouth area, the project as listed above should mitigate these load serving violations for at least the next 20 years.

Schedule: While this project will occur in phases, the entire project is planned to be in-service by summer of 2020.

General Impacts: The public process that was followed to establish this as the preferred project considered various potential impacts of various alternatives, and this was the preferred project.

Lebanon Hills 115 kV

MPUC Tracking Number: 2017-TC-N7

Utility: Great River Energy (GRE)

Project Description: Build 1.25 miles of double circuit 115 kV transmission line to the Dakota Electric Association Lebanon Hills Substation.

Need Driver: The Lebanon Hills Distribution Substation is served on the 69 kV system from Inver Grove source with a contingency back up from the Pilot Knob Substation. The future plan of the area involves reconfiguration of the Pilot Knob Substation and the transmission system in the area. The Pilot Knob Substation will be reconfigured in such a way that the 115 kV side will have a breaker-and-½ design and the 69 kV side is a simpler straight bus configuration. The transmission system reconfiguration involves overheading the underground cables towards Deerwood and Lemay Lake and retirements of the DA-PKX, DA-RE, DA-LE, DA-LEX and DA-LK lines. With this future plan, the Lebanon Hills Substation will be better served from the 115 kV system in the area.

The Pilot Knob Substation consists of breakers and transformers that are old and have been failing. Breaker and underground cable pot head replacement projects were done in the past. Remaining breakers and pot heads will continue to be sources of failure that could cause outages in area. In additions, the transformers are old and are likely to fail causing extended outage at the substation. Replacements of these equipment at Pilot Knob Substation are efficient as the substation can be reconfigured in to a more reliable configuration that is up to GRE's current substation design standard. This proposed Pilot Knob reconfiguration project, in a long run, saves on cost of equipment replacement and frequent maintenance while resulting in a more reliable transmission system in the area. The Lebanon Hills Substation conversion to the 115 kV system is among few projects that need to be completed before the start of Pilot Knob reconfiguration project.

Alternative: Continued 69 kV service for Lebanon Hills-this option makes service to Lebanon Hills unreliable after the proposed configuration of the Pilot Knob Substation. The proposed configuration will retire the underground 69 kV line out of Pilot Knob to Pilot Knob Tap and the line from Pilot Knob Tap that connects to Lebanon Hills. Therefore, Lebanon Hills will depend on service from Chub Lake during contingencies along the Inver Grove to Lebanon Hills 69 kV line. This causes low voltage at Lebanon Hills.

Keep the underground 69 kV line from Pilot Knob to Pilot Knob Tap and use it for contingency backup for Lebanon Hills. The underground 69 kV lines out of Pilot Knob that connects to Pilot Knob Tap have had historical reliability concerns related to the underground cable pot head failures. The line termination breakers are also old and there is not much service life left in them. In addition, part of Pilot Knob Substation reconfiguration plan involves elimination of these underground cables and line termination breakers. Therefore this option wasn't considered further as these lines won't be available when the Pilot Knob area is reconfigured. This is also inefficient and costly in a long run in terms of reliability and replacement cost of pot heads.

Analysis: The 69 kV transmission system that serves the Lebanon Hills Substation consists of high impedance conductors. As a result, power loss on the 69 kV system is significant with Lebanon Hills served from the 69 kV system. In addition to the added reliability improvement from serving Lebanon Hills on the stronger 115 kV system, conversion of the Lebanon Hills to the 115 kV system will have financial benefit in relation to loss saving in a long run.

Schedule: The Lebanon Hills 115 kV Project is scheduled to be in service by summer 2020.

General Impact: The Lebanon Hills 115 kV Project is the least impact solution to serving the local area load reliably.

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 2015 Biennial Report but have been completed or withdrawn since the 2015 Report was filed with the Public Utilities Commission in November 2015. 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 2015 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
2009-TC-N2	New Market & Cleary Lake Area Projects	ET2/CN-12-1235 and ET2/TL-12-1245	GRE	2016
2015-TC-N1	Bailey Road Substation	Not Required	XEL	Restudying
2015-TC-N2	Cedar Lake Pumping Station	Not Required	GRE	2017
2015-TC-N3	SW Twin Cities Project	Not Required	XEL	2016

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?	Utility
2013-SW-N1	Heron Lake Capacitors	2012/A	3528	No	ITCM
2013-SW-N4	MVP #3	2011/A	3205	Yes	ITCM 2017 In Service
2015-SW-N3	Buffalo Ridge Cutover	2015/A	8017	No	XEL
2017-SW-N1	Summit to Dovray 69 kV Rebuild	2016/A	9907	No	ITCM

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Utility
2017-SW-N2	Dovray to Fulda 69 kV Rebuild	2016/A	9908	No	ITCM
2017-SW-N3	Fulda to Heron Lake 69 kV Rebuild	2016/A	9910	No	ITCM

Heron Lake Capacitors

MPUC Tracking Number: 2013-SW-N1

Utility: ITC Midwest (ITCM)

Project Description: Heron Lake 161 kV Capacitor Banks.

Need Driver: Low voltage in the Heron Lake area requires the addition of a 42 MVAR capacitor bank at the Heron Lake 161 kV Substation. The addition of the capacitor bank will require rebuild of Heron Lake Substation to a breaker-and-½ configuration.

Alternatives Considered: The capacitor bank was the only alternative evaluated. Expansion of the transmission system in the area would have been a more costly alternative.

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. The capacitor bank will help support system voltage. The existing facility is not able to accommodate the capacitor bank. The 161 kV substation will be constructed in a breaker-and-½ configuration, which will require expansion of the existing facility.

Schedule: It is expected that the project would be complete by December 2022.

General Impacts: The capacitor bank addition will increase reliability by adding voltage support for the area. Site expansion will be coordinated with local authorities and landowners to minimize impacts.

MVP #3

MPUC Tracking Number: 2013-SW-N4

Utility: ITC Midwest (ITCM)

MPUC Docket Number: ET-6675/CN-12-1053

Project Description: MVP #3 is a new 345 kV path from that will begin at Lakefield Junction in Jackson County and continue through Martin County to Faribault County near Winnebago Junction, then continue south into Iowa. In conjunction with MVP #4, a new 345 kV network will connect Lakefield Junction to multiple points on the existing 345 kV system in Iowa.

Need Driver: MVP #3 is part of a portfolio of transmission expansion projects that were developed to address public policy while also addressing reliability and economic needs of the system. The portfolio of projects was approved by MISO in 2011, and triennial reviews have occurred in 2014 and 2017. The 2017 triennial review estimated a benefit to cost ratio of 2.2 to 3.4, identified $12-$52.6 billion in net benefits over the next 20 to 40 years and also identified enablement of 52.8 million MWh of wind energy to meet renewable energy mandates and goals through year 2031. The MVP analysis and triennial review reports can be found at https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MVPAnalysis.aspx.

Analysis: MVP #3 is a portion of multiple high voltage projects that were developed through multiple years of analysis with the cooperation of MISO and Transmission Planning personnel from utilities across the MISO footprint. Details of the analysis can be found in the MTEP11 report. Triennial reviews of the MVPs are also provided as part of the MTEP14 and MTEP17 reports.

Schedule: Project is currently under construction.

General Impacts: The Department of Commerce prepared an Environmental Impact Statement on this project, which was finalized on July 11, 2014. The Public Utilities Commission found, on November 25, 2014, that the EIS and the record in the matter were adequate, and that the project would provide benefits to society in a manner compatible with protecting natural and socioeconomic environments, including human health.

Buffalo Ridge Cutover

MPUC Tracking Number: 2015-SW-N3

Utility: Xcel Energy (XEL)

Project Description: Plan is to cutover the existing Buffalo Ridge feeder 321 to Yankee by building 2 miles of new 34.5 kV line. Will require installation of a 3rd 115/34.5 kV transformer and 115 kV breaker addition/s at Yankee.

Need Driver: Existing Feeder 321 is susceptible to voltage instability during high wind output from the Alpha and Zulu wind farms. Additionally the Buffalo Ridge 115/34.5 kV transformer #2 could overload during high wind conditions under contingency.

Alternatives: An alternative proposal was to install a 25 MVAR STATCOM at the end of the 321 feeder and curtail wind under contingency.

Analysis: This project will decrease the wind farm feeder length from approximately twenty miles to approximately seven miles by tying into the Yankee Substation. Shortening the feeder length will correct the voltage instability issue at the Alpha and Zulu wind farms and the reduction of wind output on the Buffalo Ridge feeders will fix the overloading issue. This project will likely be constructed by Xcel Energy employees.

Schedule: This project is scheduled to begin in 2019 with a completion date of early 2020.

General Impacts: The substation portion of the project will be contained in the existing Yankee Substation and will not require expanding the substation site. This project will require some new 34.5 kV line extension to complete the cutover to from Buffalo Ridge to Yankee. Xcel Energy construction crews are expected to perform the work.

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: 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.

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 2019.

General Impacts: The rebuild will occur on existing right of way in order to minimize impacts. 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: 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.

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 2019.

General Impacts: The rebuild will occur on existing right of way in order to minimize impacts. 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: 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.

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 2020.

General Impacts: The rebuild will occur on existing right of way in order to minimize impacts. 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 2015 Biennial Report but have been completed or withdrawn since the 2015 Report was filed with the Minnesota Public Utilities Commission in November 2015. 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 2015 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-N1	25 MVAR Reactor at Yankee Substation	Not Required	XEL	2017
2015-SW-N2	Fenton Reactor	Not Required	XEL	2017

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?	Utility
2011-SE-N5	Arlington-Green Isle 69 kV	2012/A		No	XEL
2015-SE-N1	Lake Bavaria	2015/C	8075	No	XEL
2015-SE-N4	Line 0714 Rebuild	2015/A	8079	No	XEL
2015-SE-N5	Alden-Mansfield 69 kV Rebuild	N/A	N/A	No	DPC
2015-SE-N6	Waseca Junction to Montgomery 69 kV rebuild	2013/A	4101	No	ITCM

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Utility
2015-SE-N7	Ellendale to Owatonna 69 kV Rebuild	2013/A	4108	No	ITCM
2017-SE-N1	Huntley to Wilmarth 345 kV MEP Project	2016/A	11883	Yes	XEL/ITCM
2017-SE-N2	Bluff Siding Area Reconfiguration	2017/C	12011	No	XEL
2017-SE-N3	Rochester to Wabaco 161 kV Rebuild	2018/C (Target A)	13486	No	DPC
2017-SE-N4	Walters 161/69 kV Substation Expansion	2018/C	13888	No	ITCM
2017-SE-N5	Huntley 69 kV Maintenance	2016/A	9706	No	ITCM
2017-SW-N6	J407 Interconnection at Glenworth 161 kV	2018/A	14030	No	ITCM

Arlington-Green Isle 69 kV

MPUC Tracking Number: 2011-SE-N5

Utility: Xcel Energy (XEL)

Project Description: Re-build 13 miles of 69 kV line from Arlington-Green Isle in existing right of way.

Need Driver: This line was flagged during the CapX study as an underlying facility that needed upgrading. With the loss of the CapX lines under high transfers this 69 kV line will overload.

Alternatives: Adding additional transmission lines would mitigate this issue but would require far greater cost and land usage.

Analysis: This project will have the associated construction projects by Xcel Energy employees. This project will help maintain local reliability and uses existing right of way to minimize impact.

Schedule: The line rebuild was not a part of the 2015, five-year budget. The rebuild of the line expected to occur within approximately 6-7 years.

General Impacts: Replacement of the line will provide for additional system capacity and reduce maintenance cost on the existing, aging infrastructure.

Lake Bavaria

MPUC Tracking Number: 2015-SE-N1

Utility: Xcel Energy (XEL)

Project Description: Build new substations to feed load growth in the Victoria/Chaska area. A single distribution transformer will be installed with an "in and out" configuration on the 115 kV.

Need Driver: This is a distribution driven project. The existing distribution system in the area has reached its limits and requires an additional source. This new substation will offload West Waconia and Westgate substations.

Alternatives: Many locations were considered for this new substation. Adding this load onto the existing 69 kV in the area will not work as the line cannot handle that amount of load growth. Additional 115 kV locations were found to work from a transmission perspective, but the selected location minimizes feeder lengths.

Analysis: This project will have the associated construction projects by Xcel Energy and GRE employees. This will help enable local load growth. Our team worked closely with local community to minimize substation footprint.

Schedule: Planned in service date will be end of 2017.

General Impacts: This project will have the associated construction conducted by Xcel Energy and GRE employees. This will help enable local load growth. The team will work closely with local community to minimize substation footprint.

0714 Line Rebuild

MPUC Tracking Number: 2015-SE-N4

Utility: Xcel Energy (XEL)

Project Description: Rebuild 3.6 miles of 0714 69 kV line from Madelia Switching Station to Village of Madelia to 336 ACSR.

Need Driver: With the loss of both 345 kV lines heading into Wilmarth, this line will overload. Rebuilding it to a higher ampacity mitigates the issue.

Alternatives: Alternatives would have been more costly and environmentally impactful. Such alternatives include construction of a new transmission line which would have required additional land and right of way.

Analysis: This project will have associated construction jobs. This project will help maintain local reliability and uses existing right of way to minimize impact.

Schedule: Project is currently underway. Construction began in 2015 and should be completed by June 1, 2019.

General Impacts: This project will have associated construction jobs. This project will help maintain local reliability and uses existing right of way to minimize impact.

Alden-Mansfield 69 kV Rebuild

MPUC Tracking Number: 2015-SE-N5

Utility: Dairyland Power Cooperative (DPC)

Project Description: Rebuild 5.3 miles of DPC's Twin Lakes-Freeborn 69 kV line between DPC's Alden and Mansfield distribution substations, improving reliability to all three distribution substations on this line which was originally constructed in 1951.

Need Driver: This 69 kV line was built in 1951 and increased maintenance costs have required that this line be rebuilt due to age and condition. The line also has some long spans that can be prone to galloping due to high winds.

Alternatives: The primary need driver is age and condition issues resulting in reliability concerns. Because of this need, the only alternative that was considered is a rebuild of the existing line. An alternative on new right-of-way was not considered as this line serves several distribution substations and new right-of-way would present routing difficulties and a higher cost.

Analysis: The plan to replace the existing 64-year-old transmission line with new poles, conductor and shield wire will solve the reliability concern caused be the age and condition of the existing transmission line serving Mansfield, Alden and Freeborn distribution substations. The estimated cost is approximately $1.5M and has a targeted in-service date of 2018.

Schedule: Construction would occur September-November 2018.

General Impacts: Dairyland construction crews will rebuild this line in 2018 requiring approximately ten weeks to construct. This 69 kV line follows a road, resulting in minimal impacts to the local right-of-way.

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: A rebuild on existing ROW was the sole alternative considered to solve the age and condition issue.

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. 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 2019.

General Impacts: The line is near the end of its useful life. The capacity of the line will be increased to approximately 77 MVA with the rebuild.

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: Rebuilding the line to a greater capacity on existing ROW was the sole alternative considered to alleviate the system capacity constraint.

Analysis: 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.

Schedule: The rebuild of the line is expected to occur within approximately 5-6 years.

General Impacts: Replacement of the line will provide for additional system capacity and reduce maintenance cost on the existing, aging infrastructure.

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: 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.

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. Further, MISO has found that this project does create unintended reliability issues for the transmission system.

Schedule: Planned in service date is 2022. A certificate of need application is anticipated for early 2018.

General Impacts: This project will utilize the existing Wilmarth and Huntley substations. New 345 kV right will need to be acquired to construct the new 345 kV circuit. Siting will be coordinated with the appropriate landowners, local, state, and federal authorities.

Bluff Siding Area Reconfiguration

MPUC Tracking Number: 2015-SE-N2

Utility: Xcel Energy (XEL)

Project Description: Upgrade Winona and Goodview bus. Reconfigure normally open from Merrick to Goodview, normally open from Goodview 1 to Goodview 2, normally closed from Winona Tap to Goodview Tap. Install remote operators at Winona Tap.

Need Driver: With the loss of both 161 kV lines heading into Marshland, potential voltage collapse will occur in the Bluff Siding area including Goodview and Winona.

Alternatives: Alternatives would have been more costly and environmentally impactful. Such alternatives include construction of a new transmission line which would have required expanding existing right of way and a new breaker station at existing Winona Tap.

Analysis: This project will have associated construction jobs. This project will help maintain local reliability and uses existing facilities to minimize impact.

Schedule: Planned in service date is 2020.

General Impacts: This project will have associated construction jobs. This project will help maintain local reliability and uses existing facilities to minimize impact.

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 constraint as part of the MISO generation interconnection queue process. MISO studied the interconnection of a 202 MW wind farm in Mitchell County, Iowa with MISO queue number J449. The study identified the Rochester-Wabaco 161 kV line as requiring a higher capacity in order to allow the wind farm to connect to the transmission system.

Alternatives: 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.

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 capacity issues as determined by MISO. This will allow for the connection of a new 202 MW wind farm to the transmission system. The wind farm will fund the upgrade and it has a targeted in-service date of October 2018.

Schedule: Construction is scheduled to occur July to October 2018.

General Impacts: Dairyland construction crews will rebuild this line in 2018 requiring approximately sixteen weeks to construct. The upgraded line will add to the capacity of the transmission system allowing a new wind farm to connect to the transmission system.

Walters 161/69 kV Substation Expansion

MPUC Tracking Number: 2017-SE-N4

Utility: ITC Midwest (ITCM)

Project Description: The project calls for the Huntley to Freeborn 161 kV line to be tapped approximately 14 miles west of Freeborn and an approximately 7 miles-long 161 kV line to be routed to the Walters Substation. The Walters Substation would be expanded and upgraded in order 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: 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.

Analysis: The new substation at Walters 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 Walters 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 the end of December 2018.

General Impacts: The seven mile long 169 kV line will seek to utilize existing rights of way, and the upgrade will help support area voltage and provide a new 161 kV source for future needs. Line routing and facilities siting will be coordinated with necessary local, state and federal authorities.

Huntley 69 kV Maintenance

MPUC Tracking Number: 2017-SW-N5

Utility: ITC Midwest (ITCM)

Project Description: The Winnebago Junction 69 kV Substation facilities are being relocated to Huntley 69 kV Substation in conjunction with construction of the Huntley 345/161 kV Substation for MVP #3 (Tracking Number 2013-SW-N4). One of the two transformers at Winnebago Junction will be relocated to Huntley, and one of the 161/69 kV transformers will not. One of the two transformers is being replaced by a 75 MVA unit that was previously replaced at Adams Substation. Winnebago Junction Substation will be retired after Huntley is placed in service.

Need Driver: The Winnebago Junction 69 kV facilities' age and condition and increased maintenance costs warranted relocation of the 69 kV facilities to the new Huntley Substation, which is being constructed under the scope of work for MVP #3 (Tracking Number 2013-SW-N4). One of the 161/69 kV transformers is in poor condition, and it will be replaced with a unit previously in service at Adams Substation.

Alternatives: Rebuilding facilities at the existing Winnebago Junction was considered, but relocating the 69 kV to new facilities was the preferred solution.

Analysis: Rebuilding 69 kV facilities at the existing Winnebago Junction site after retirement of 161 kV facilities would require extensive work and outages, and costs for maintaining facilities at Winnebago Junction warranted the establishment of new 69 kV facilities at the new Huntley Substation.

Schedule: Construction and relocation of facilities is expected to be completed by the end of 2017.

General Impacts: Existing facilities and rights of way were utilized for new facilities to the extent practical, and construction of new facilities is being coordinated with local, state, and federal authorities and with the cooperation of landowners.

J407 Interconnection at Glenworth 161 kV

MPUC Tracking Number: 2017-SE-N6

Utility: ITC Midwest (ITCM)

Project Description: Expand the 161 kV ring bus at Glenworth by adding a 161 kV breaker and new terminal for the interconnection of a 200 MW wind-powered generating facility and replace the existing 100 MVA, 161/69 kV transformer with an 150 MVA unit.

Need Driver: The expansion of Glenworth and the replacement of the existing 100 MVA transformer with a 150 MVA unit are required for the Interconnection Service for project J407 under the MISO Tariff.

Alternatives: The interconnection was evaluated under the MISO's DPP February 2015 system impact study. No alternatives for the interconnection or the overload of the transformer were identified.

Analysis: The interconnection of project J407 was evaluated as part of the MISO February 2015 system impact study. The expansion of facilities at Glenworth are required to provide a point of interconnection for project J407, and the transformer was shown to overload under contingency with the interconnection of project J407 to Glenworth.

Schedule: The in service date for the project is August 2020.

General Impacts: The upgrades will occur within the existing Glenworth 161 kV Substation. Termination of the J407 generator tie line will be coordinated with the interconnection customer and necessary authorities.

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 2015 Biennial Report but have been completed or withdrawn since the 2015 Report was filed with the Minnesota Public Utilities Commission in November 2015. 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 2015 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-SE-N2	Vesili Substation	Not Required	XEL	2015
2915-SE-N3	Jordan Substation	Not Required	XEL	2015

7.0 Transmission-Owning Utilities

7.1 Introduction

In this chapter in the 2017 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 2015 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, and 2015 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
Dairyland Power Cooperative	423.8	152.75	0	8.88	0
East River Electric Power Cooperative	170	46	0	0	0
Great River Energy	3,073	574	524	145	436
Hutchinson Utilities Commission	8	9	0	0	0
ITC Midwest LLC	688.6	307.9	0	19.9	0
L&O Power Cooperative	44.52	8.32	0	0	0
Marshall Municipal Utilities	0	18.1	0	0	0
Minnesota Power	0.22	1,326.72	617.01	43.34	231.6
Minnkota Power Cooperative	998.16	143.90	268.09	0	0

Utility	<100 kV	100-199 kV	200-299 kV	> 300 kV	DC
Missouri River Energy Services	0	212.22	10.97	47	0
Northern States Power Company d/b/a Xcel Energy	1,667.19	1,757.92	436.96	1,763.55	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	149.35	135.48	17.09	0	0
Willmar Municipal Utilities	24.16	0	13.05	0	0
Totals:	8,547.99	5,275.68	2,068.35	2,658.69	667.6

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, with more than 600 employees working in Wisconsin and Michigan.

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 9,480 circuit miles of transmission lines and 529 substations in Wisconsin, Michigan, Illinois, and Minnesota. ATC has $3.3 billion in total assets.

ATC is a transmission-owning member of the Midcontinent Independent System Operator 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:

Joel Berry
Transmission Planning Engineer
American Transmission Co.
P.O. Box 47
Waukesha, WI 53187-0047
Phone: (262) 506-6700
e-mail: jberry@atcllc.com

Transmission lines. ATC owns more than 9,480 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 capacity 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.

7.3 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, wind, natural gas, landfill gas and animal waste. In 2010, Dairyland Power Cooperative joined a larger regional transmission organization called the Midcontinent Independent System Operator (MISO).

More information about Dairyland Power Cooperative is available at:

http://www.dairylandpower.com

Contact Person: Steve Porter
Planning Engineer III
Dairyland Power Cooperative
3200 East Avenue South
La Crosse, WI 54601
Phone: (608) 787-1227
Fax: (608) 787-1475
e-mail: steve.porter@dairylandpower.com

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

7.4 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 nineteen member systems have service areas entirely in eastern South Dakota.

More information about East River Electric Power Cooperative is available at:

http://www.eastriver.coop

Contact Person: Mark Hoffman
Engineering Services Manager
East River Electric Power Cooperative
P.O. Box 227
211 South Harth Avenue
Madison, SD 57042
Phone: (605) 256-4536
Fax: (605) 256-8058
e-mail: mhoffman@eastriver.coop

Transmission Lines. East River delivers electricity via approximately 2,900 miles of transmission lines and 213 substations located throughout the system's 36,000 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
170	46	0	0	0

7.5 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 125,000 member-consumers, while the smallest serves approximately 2,500. Collectively, Great River Energy's member cooperatives distribute electricity to approximately 655,000 member accounts, or about 1.7 million people. In addition, Great River Energy is part of a larger regional transmission organization called the Midcontinent Independent System Operator (MISO).

More information about Great River Energy is available at:

http://www.greatriverenergy.com

Contact Person: Gordon Pietsch
Director, Transmission Planning & Operations
Great River Energy
12300 Elm Creek Blvd
Maple Grove, MN 55369-4718
Ph: (888) 521-0130, ext. (763) 445-5050
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
3,073	574	524	145	436

7.6 Hutchinson Utilities Commission

Background Information. The City of Hutchinson is located 55 miles west of Minneapolis in McLeod County and has a population of approximately 14,000 people. The area is expected to continue to grow over the next decade. The Hutchinson Utilities Commission (HUC) was established in 1936 by the City of Hutchinson as a municipal public utilities commission under Minn. Stat. § 412.321 et seq., and added a municipal natural gas operation in 1960. HUC provides electricity and natural-gas services to commercial and residential customers in Hutchinson. Its largest commercial customers are 3M and Hutchinson Technologies, Inc. HUC transmission facilities are under the functional control of the Midcontinent Independent System Operator (MISO).

Additional information is available at:

http://www.hutchinsonutilities.com/about-huc/

Contact Person:

Jeremy Carter
Hutchinson Utilities Commission
225 Michigan Street SE
Hutchinson, MN 55350
Phone: (320) 587-4746
Fax: (320) 587-4721
e-mail: jcarter@ci.hutchinson.mn.us

Transmission Lines. Hutchinson Utilities Commission owns 8 miles of a 69 kV transmission line and 9 miles of a 115 kV line in McLeod County.

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 Minnesota Public Utilities 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 a larger regional transmission system called the Midcontinent Independent System Operator (MISO.)

More information about ITC Midwest and ITC Holdings Corp. can be found at:

http://www.itctransco.com

Contact Person: David Grover
Director, RTO Affairs
ITC Midwest, LLC
901 Marquette Avenue, Suite 1950
Minneapolis, MN 55402
Phone: 612-332-2511
Fax: 612-332-2544
e-mail: DGrover@itctransco.com

Transmission Lines. The ITC Midwest system includes approximately 6,600 miles of transmission lines, operating at voltages from 34.5 kV to 345 kV in Minnesota, Iowa, Illinois, and Missouri.

ITC Midwest owns approximately 1,023 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	19.9	0

7.8 L&O Power Cooperative

Background Information. L & O Power Cooperative (L&O), headquartered in Rock Rapids, Iowa, is a wholesale electric power supply and transmission cooperative serving three rural distribution electric cooperatives. These member cooperatives in turn serve more than 5,600 homes and businesses across Rock and Pipestone counties in southwest Minnesota, and Lyon and Osceola counties in northwest Iowa. Approximately 2,700 of the total 5,600 total consumers served are located in Minnesota.

Additional information about L&O is available at:

http://www.landopowercoop.com

Contact Person: Curt Dieren
Manager
L&O Power Cooperative
P.O. Box 511
1302 S. Union Street
Rock Rapids, IA 51246
Phone: (712) 472-2556
Fax: (712) 472-2710
e-mail: CDieren@dgrnet.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
44.52	8.32	0	0	0

7.9 Marshall Municipal Utilities

Background Information. Marshall Municipal Utilities (MMU) has been providing electric and water utility services to the City of Marshall for over 120 years. Marshall is a community of approximately 13,680 people located in Lyon County in Southwest Minnesota approximately 30 miles east of the South Dakota border and 50 miles north of the Iowa border. MMU is the second largest municipal utility in the state in terms of retail energy sales at over 580,420 kWh sold in 2015. MMU serves over 6,500 customers and has a peak demand of just under 85 megawatts.

More information about MMU is available at:

http://www.marshallutilities.com/about

Contact Person: Brad Roos
Marshall Municipal Utilities
113 4th Street South
Marshall, MN 56258-1223
Phone: (507) 537-7005
Fax: (507) 537-6836
e-mail: bradr@marshallutilities.com

Transmission Lines. Marshall Municipal Utilities owns 18.1 miles of 115 kV transmission line.

7.10 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, 16 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 a larger regional transmission organization called the Midcontinent Independent System Operator (MISO).

More information is available on the company's web page at:

http://www.mnpower.com

Contact Person: Christian Winter
Minnesota Power
30 West Superior Street
Duluth, MN 55802
Phone: (218) 355-2908
e-mail: cwinter@mnpower.com

Transmission Lines. The number of miles of transmission in Minnesota owned by Minnesota Power is shown in the following table.

Minnesota Power Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
0.22	1,326.72	617.01	43.34	231.56

7.11 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 150,000 consumers.

Additional information about Minnkota is available at:

http://www.minnkota.com

Contact Person: Tim Bartel
Power Delivery Business Administrator
Minnkota Power Cooperative, Inc.
5301 32nd Avenue South
Grand Forks, ND 58208-3201
Phone: (701) 795-4314
Fax: (701) 795-4333
e-mail: tbartel@minnkota.com

Transmission Lines. The Joint System owns 1,410.15 miles of transmission line in Minnesota and 1930.27 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
998.16	143.90	268.09	0	0

7.12 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 60 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 23 municipalities located in Minnesota, each of which owns and operates a utility for the local distribution of electricity. In addition, MRES is part of a larger regional transmission organization called the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP).

More information about Minnesota River Energy can be found at:

http://www.mrenergy.com

Contact Person:
Brian Zavesky
Missouri River Energy Services
3724 West Avera Drive
P.O. Box 88920
Sioux Falls, SD 57108-8920
Phone: (605) 330-6986
Fax: (605) 978-9396
e-mail: brianz@mrenergy.com

Transmission Lines. Missouri River Energy Services has 212.22 miles of 115 kV transmission line, 10.97 miles of 230 kV transmission line and 47 miles of 345 kV transmission line in Minnesota.

7.13 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 New York Stock Exchange. 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 a larger regional transmission organization called the Midcontinent Independent System Operator (MISO).

More information can be found on Xcel Energy's web page at:

http://www.xcelenergy.com

Contact Person: Jason Standing
Principal Engineer
414 Nicollet Mall
Minneapolis, MN 55401
Phone: (612) 330-7768
Fax: (612) 330-6357
e-mail: jason.t.standing@xcelenergy.com

Transmission Lines. Northern States Power Company owns about 5,600 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
1,667.19	1,757.92	436.96	1,763.55	0

7.14 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 a larger regional transmission organization called the Midcontinent Independent System Operator (MISO).

To learn more about Otter Tail Power Company visit www.otpco.com. To learn more about Otter Tail Corporation visit www.ottertail.com.

Contact Person: Jesse Tomford
Supervisor, Delivery Studies
Otter Tail Power Company
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone: (218) 739-8200
Fax: (218) 739-8442
e-mail: JTomford@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

7.15 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 the Midwest Independent Transmission System Operator (MISO) through its market function. RPU's Planning Coordinator for transmission is the Mid-Continent Area Power Pool (MAPP). MISO is RPU's Reliability Coordinator via contract.

More information about Rochester Public Utilities is available at:

http://www.rpu.org/about

Contact Person: Scott Nickels
Manager of System Operations/Reliability
Rochester Public Utilities
4000 East River Road NE
Rochester, MN 55906
Phone: (507) 280-1585
Fax: (507) 280-1542
e-mail: snickels@rpu.org

Transmission Lines. 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.

7.16 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 a larger regional transmission organization called the Midcontinent Independent System Operator (MISO).

More information about SMMPA is available at:

http://www.smmpa.com

Contact Person: Richard Hettwer
PE, MBA
Manager of Power Delivery
Southern Minnesota Municipal Power Agency
500 First Avenue Southwest
Rochester, MN 55902-3303
Phone: (507) 292-6451
e-mail: rj.hettwer@smmpa.org

Transmission Lines. Southern Minnesota Municipal Power Agency has the following transmission lines in Minnesota:

SMMPA Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
149.3	135.48	17.09	0	0

7.17 Willmar Municipal Utilities

Background Information. Willmar, a regional center for West Central Minnesota, is located 100 miles west of the Twin Cities. It is the Kandiyohi County Seat with a population of 19,000. Willmar Municipal Utilities maintains an electric system that currently has five distribution substations with 226 miles of distribution lines and 35 miles of transmission lines.

Additional information is available at:

http://wmu.willmar.mn.us

Contact Person: John Harren
General Manager
P.O. Box 937
700 Litchfield Avenue SW
Willmar, MN 56201
Phone: (320) 235-4422
Fax: (320) 235-3980
e-mail: wmu@wmu.willmar.mn.us

Transmission Lines. Willmar Municipal Utilities owns 24.16 miles of 69 kV transmission line and 13.05 miles of 230 kV transmission line.

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 May 27, 2016, Order approving the 2015 Report, the Commission said that the 2017 Report should include content similar to the 2015 Report.

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 identical in many respects to the narrative and explanations provided in the 2015 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 2017 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

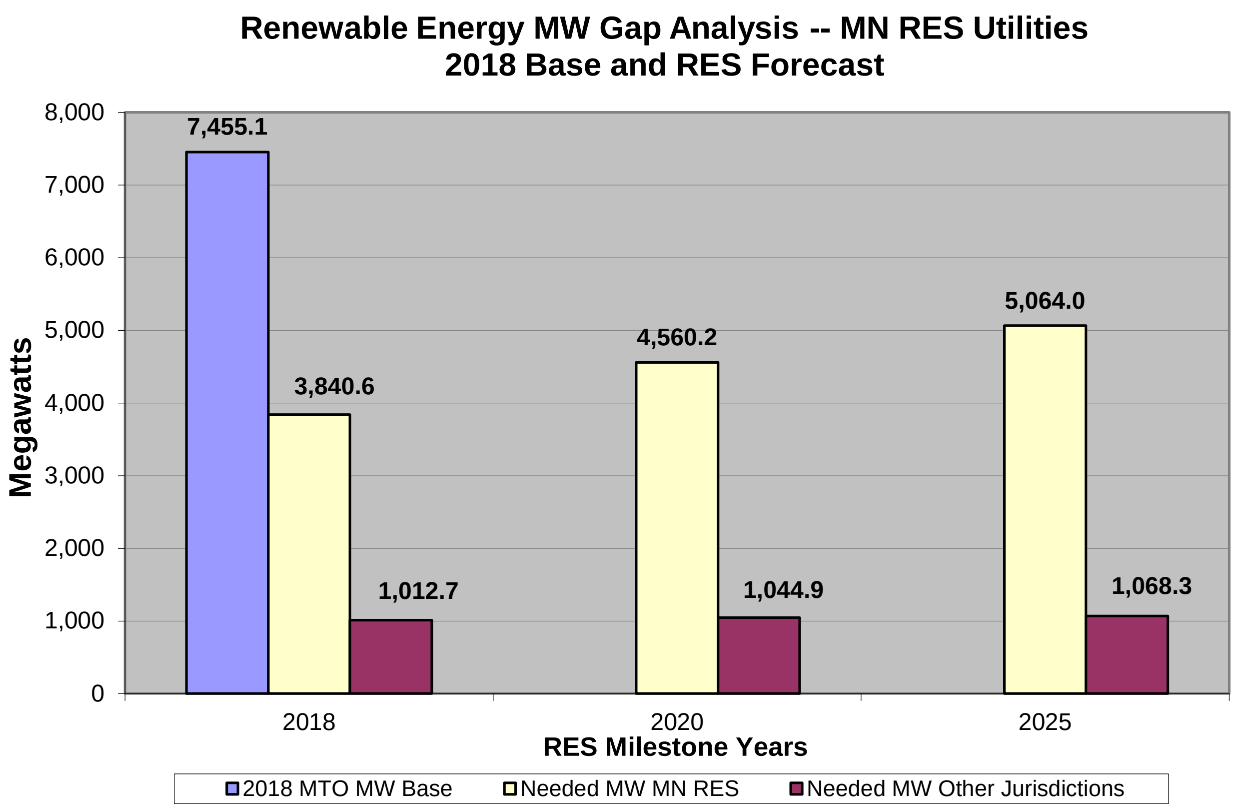
The utilities have continued to make substantial progress with respect to meeting future RES milestones. The RES milestone for 2016 – 17% renewables for all utilities except Xcel Energy, for which the standard is 25% - was achieved and is presently being achieved. The CapX Group 1 projects were crucial to meeting the 2016 Minnesota RES and non-Minnesota RES milestones. The utilities recognize that additional transmission and generation will be necessary for 2020 and beyond in Minnesota, and that other demands for renewable energy will impact Minnesota's compliance status. In addition, the utilities have provided a Gap Analysis regarding compliance with the upcoming 2020 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 sixth time the utilities have prepared a Gap Analysis; a Gap Analysis was prepared for the 2007, 2009, 2011, 2013 and 2015 Biennial Reports also.

8.5 Base Capacity and RES/REO Forecast

The chart below presents a system-wide overview of existing capacity in 2017 (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) using the most appropriate capacity factors unique to their specific generating resources.



2018 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]

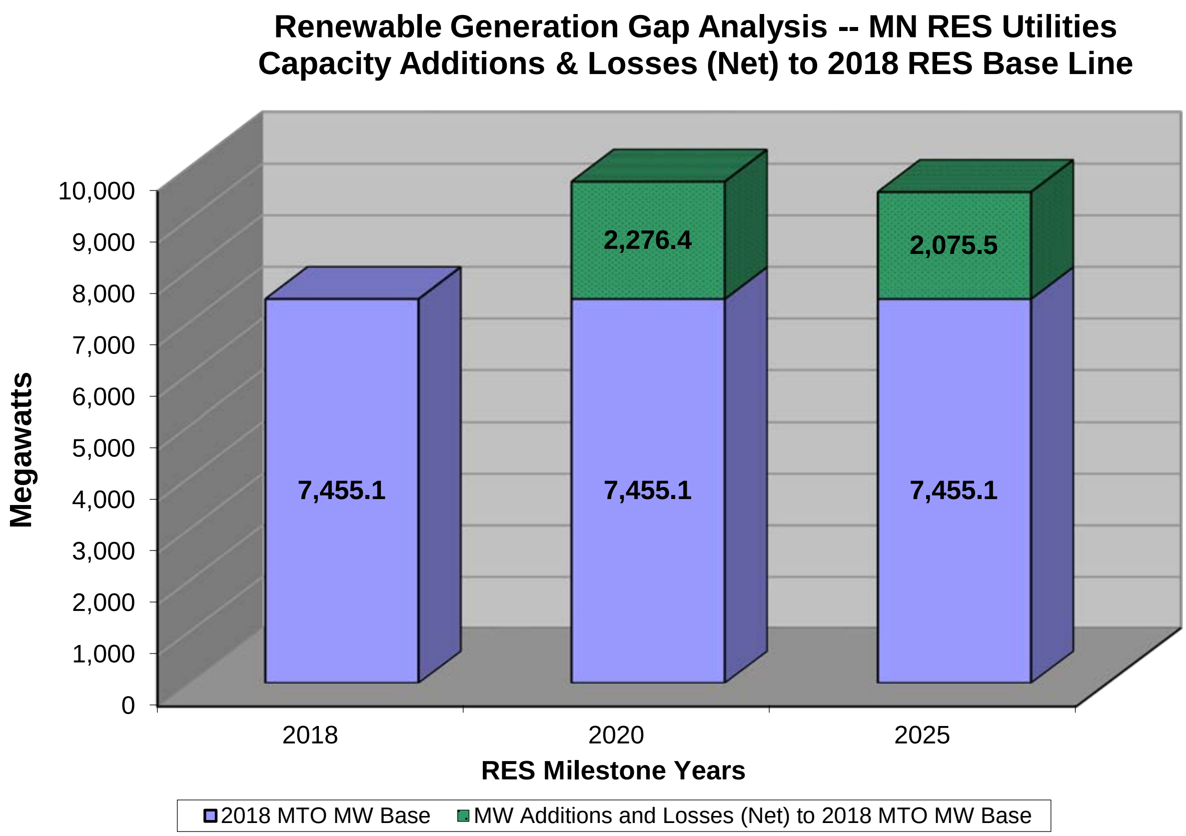
Utility	2018		2020		2025	
	MN RES	Non-MN RES	MN RES	Non-MN RES	MN RES	Non-MN RES
Basin Electric[2]	75.2	382.2	92.1	404.8	132.1	430.4
CMMPA	18.0	-	26.0	-	35.0	-
Dairyland	41.5	79.5	49.5	80.7	76.0	83.6
GRE	566.0	1.8	630.0	1.8	781.0	1.8
Heartland	4.0	7.7	4.9	7.9	6.6	8.4
Minnkota	104.5	78.8	124.8	81.6	162.7	88.9
MMPA	77.4	-	106.3	-	140.1	-
MN Power	494.4	19.8	573.6	20.5	742.8	22.1
Otter Tail	135.0	66.2	154.7	67.1	222.0	68.8
SMMPA	155.0	-	186.0	-	243.0	-
WMMPA/MRES	82.0	23.4	99.7	23.6	130.2	24.0
Xcel Energy	2,087.5	353.4	2,512.6	357.0	2,392.5	340.4
TOTAL	3,840.6	1,012.70	4,560.2	1,044.9	5,064.0	1,068.3

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.

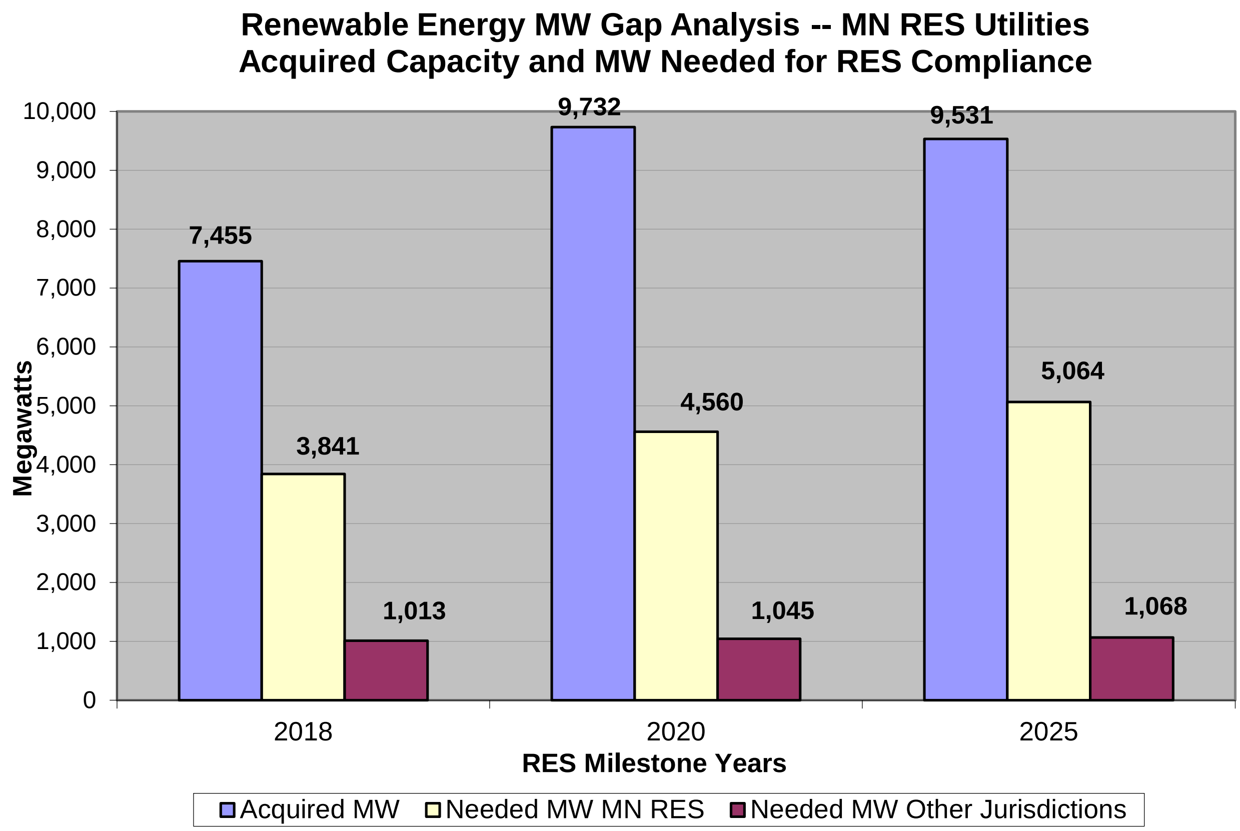
8.5.1 Capacity Acquisitions & Expirations

This chart presents a system-wide overview of additional renewable capacity that will be acquired by individual utilities beginning in 2018 and capacity that will expire between 2020 and 2025. 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 2018 and 2025, as well as the total Minnesota RES and non-Minnesota RES/REO needs between 2018 and 2025.



As can be seen, the Minnesota RES utilities have sufficient capacity acquired to meet the Minnesota RES needs through 2025. When considering the RES needs, including other jurisdictions outside of Minnesota, the Minnesota RES utilities have enough capacity to meet RES needs beyond 2020. 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	2018		2020		2025	
	RES Cap Acq.	MN RES Net	RES Cap Acq.	MN RES Net	RES Cap Acq.	MN RES Net
Basin Electric [2]	1,360.6	-	1,560.6	-	1,531.6	-
CMMPA	32.0	-	32.0	-	26.0	9.0
Dairyland	287.0	-	287.0	-	287.0	-
GRE	502.0	-	788.0	-	786.0	-
Heartland	31.0	-	30.0	-	30.0	-
Minnkota	458.1	-	458.1	-	458.1	-
MMPA	325.0	-	391.0	-	468.9	-
MN Power	833.3	-	1,083.3	-	1,083.3	-
Otter Tail	254.0	-	254.0	-	254.0	-
SMMPA	121.0	-	224.0	-	224.0	-
WMMPA/ MRES	86.7	17.3	141.7	0.2	141.7	8.4
Xcel Energy	3,164.6	-	4,481.9	-	4,240.1	-
TOTAL[3]	7,455.1	17.3	9,731.5	0.2	9,530.7	17.4

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.
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 (a negative value means the utility has a surplus of RES capacity). 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). That statute requires public utilities subject to the solar standard to report to the Public Utilities 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 Public Utilities 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 Solar Energy Standard.

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 2020 Solar Energy Standard is included below. Utilities will continue to file annual reports until 2020 as required by the statute and directed by the Commission.

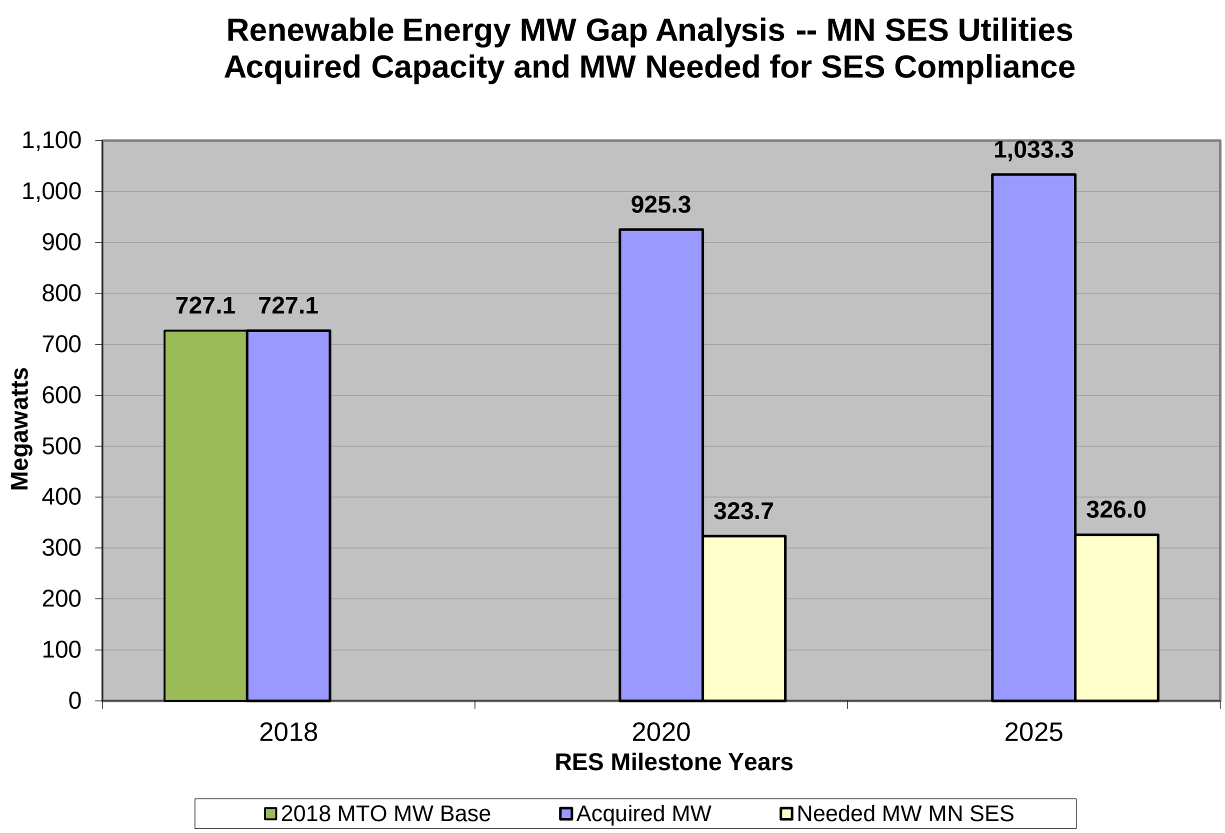


Table 3 shows a more specific breakdown of each utility's Minnesota SES and non-Minnesota SES needed capacity forecast.

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

Utility	2018		2020		2025	
	MN SES	Non-MN SES	MN SES	Non-MN SES	MN SES	Non-MN SES
Heartland	-	-	0.3	-	0.3	-
Minnesota Power	-	-	30.0	-	30.0	-
Otter Tail Power	-	-	30.0	-	30.0	-
Xcel Energy	-	-	263.4	-	265.7	-
TOTAL	-	-	323.7	-	326.0	-

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 2018 and capacity that will expire between 2020 and 2025. Such losses are attributable primarily to the expiration of various power purchase agreements for renewable energy generation.

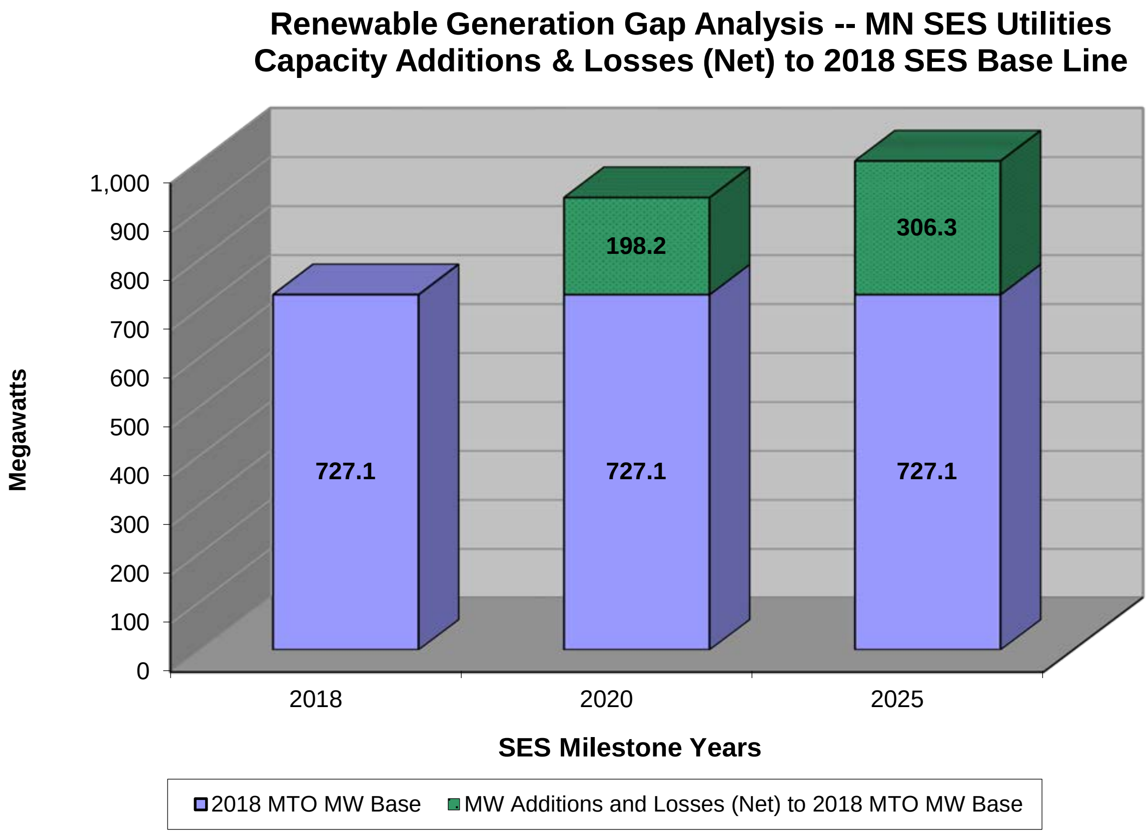


Table 4 below Provides MN Utilities planned level of solar capacity additions.

Table 4. SES Capacity Acquired & Net MN SES Capacity Need (MW)

Utility	2018		2020		2025	
	SES Cap Acq.	MN SES Net	SES Cap Acq.	MN SES Net	SES Cap Acq.	MN SES Net
Dairyland	21.5	-	21.5	-	21.5	-
Heartland	-	-	-	0.3	-	0.3
Minnesota Power	11.0	-	21.0	8.9	33.0	-
Otter Tail Power	-	-	-	30.0	-	30.0
SMMPA	5.0	-	8.0	-	8.0	-
WMMPA/ MRES	1.0	-	1.0	-	1.0	-
Xcel Energy	688.6	-	873.8	-	969.8	-
TOTAL	727.1	-	925.3	39.2	1,033.3	30.3

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