CapX2020
Hampton – Rochester – La Crosse 345 kV Project
05-CE-136

Supplemental Need Study
August 2011

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1. INTRODUCTION AND SUMMARY OF RESULTS

1.1 Overall Needs

Demand for electricity in the La Crosse, Wisconsin and Rochester, Minnesota areas has grown over the past decade to the point of approaching the maximum capacity of the existing transmission systems. The existing transmission system serving these areas is comprised of sub-230 kilovolt ("kV") voltage classes not generally used for bulk delivery of the amount of power now needed to serve the current load levels. The 161 kV lines and 69 kV lines serving those areas are reaching the end of their ability to function as those areas' backbone. In addition, there is a lack of high voltage transmission, particularly 345 kV class, between Minnesota and Wisconsin which constrains regional movement of power. This constraint affects the efficiency and reliability of the regional electric transmission system.

Planning engineers evaluated the need for system upgrades and determined that a 345 kV option was the preferred option to reliably serve the La Crosse and Rochester areas for many years into the future and to provide efficient and reliable energy delivery through the regional transmission system. In addition, a higher voltage option aligns with the results of Midwest Independent Transmission System Operator's ("MISO's") Candidate Multi Value Projects ("MVP") Study, which is expected to result in the approval of a 345 kV line from La Crosse to Madison in MISO's Transmission Expansion Plan 2011 ("MTEP11"). As outlined below, the presence of a 345 kV line from Minnesota into La Crosse combined with the expected La Crosse to Madison 345 kV line will provide significant regional benefits that will not be achievable with the completion of an alternative project. More details on the MISO MVP Study is included in Section 2.6.

This report is provided as a supplement to the application for a Certificate of Public Convenience and Necessity ("CPCN") and Transmission Studies Summary Report ("TSSR") document previously submitted by Northern States Power Company, a Wisconsin corporation ("Xcel Energy"), Dairyland Power Cooperative, and Wisconsin Public Power, Inc. (collectively "Applicants"). This study provides additional information and analysis regarding the need for the 345 kV Project for local load serving in the La Crosse and Rochester areas and for regional reliability, including transfer capability.

This report also analyzes and further discusses the alternatives in the context of these overall regional and local needs, including consideration of the Minnesota Public Utilities Commission's ("MPUC") Certificate of Need order.[1] The MPUC determined that a 345 kV transmission line from Hampton to Rochester to a Mississippi River crossing near Kellogg, Minnesota and two 161 kV transmission lines in the Rochester area were needed to meet local and regional needs. Earlier cost and engineering analyses did not uniformly include a 345 kV segment from Hampton to North Rochester Substation and the two Rochester area 161 kV transmission lines. In this report, alternatives to the 345 kV Project include an assessment of these facilities.

1.2 Recommended Project and Supporting Analyses

The recommended option to address local and regional needs is a 345 kV line project between Hampton, Minnesota (southeast of the Twin Cities) and La Crosse, Wisconsin. The proposed CapX2020 Hampton – Rochester – La Crosse 345 kV line and two associated Rochester, Minnesota area 161 kV lines will hereafter be referred to as the 345 kV Project. All project and alternative maps shown in this report are also contained in Appendix A.

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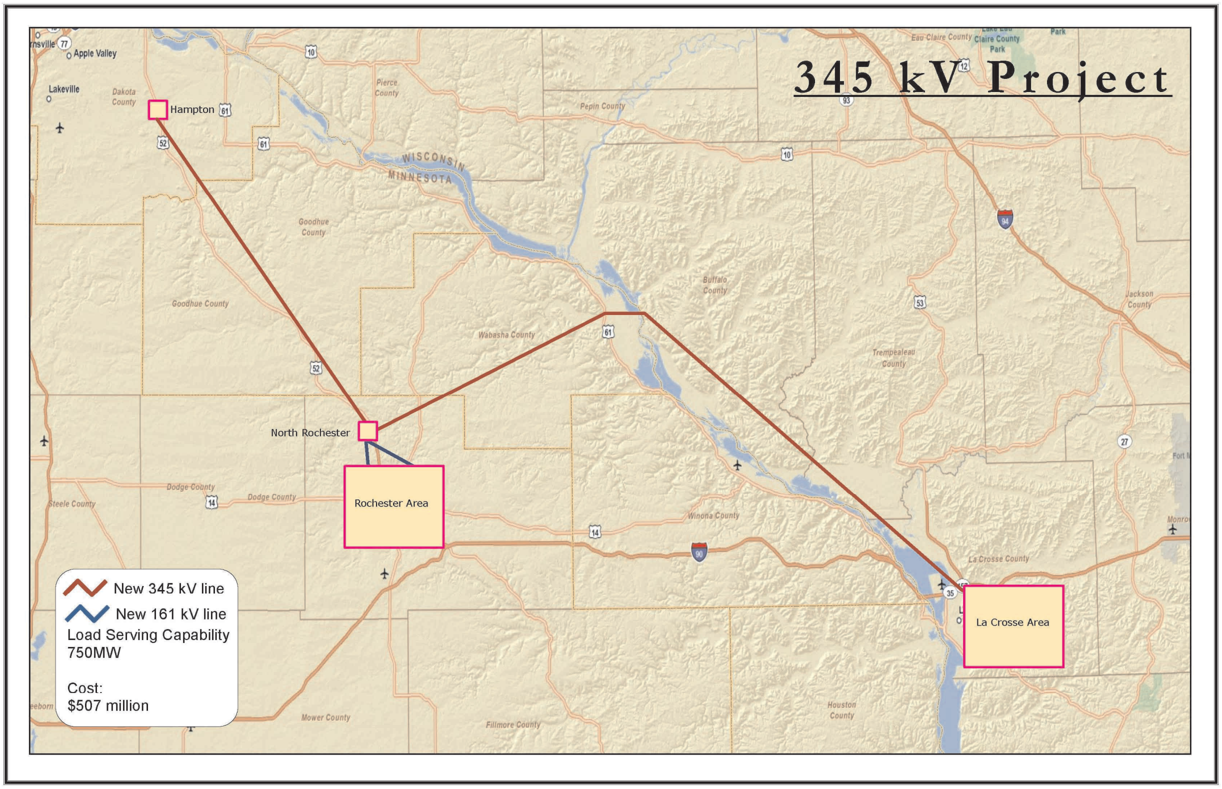
[1] *In the Matter of the Application of Great River Energy, Northern States Power Company (d/b/a Xcel Energy) and others for Certificates of Need for the CapX 345 kV Transmission Projects,* ORDER GRANTING CERTIFICATES OF NEED WITH CONDITIONS, Docket No. ET-2, E-002, et al./CN06-1115 (May 22, 2009, as modified Aug. 10, 2009) (the "Minnesota Certificate of Need Order").

Figure A: 345 kV Project



The 345 kV Project is the best alternative to meet the identified needs based on the following criteria:

Local La Crosse Area Benefits

- La Crosse area load above 430 megawatts ("MW") will be at risk under contingent system situations. When an area generator is off-line (e.g., due to scheduled maintenance, an equipment failure, or generator retirement) and a local 161 kV line has an outage, the La Crosse area experiences low voltages and transmission system overloads. By the time the 345 kV Project can be placed into service (2015), we project that the load at risk will be approximately 85 MW. The 345 kV Project will reliably serve to a load level of 750 MW. Based on the most current load forecasts, which through 2020 are shown in Figure K and discussed in Section 3.1.1, the La Crosse/Winona area will reach the 750 MW load level in approximately 2045. In addition, the 345 kV Project will also reliability serve load in the Rochester area past 2050.

- The 345 kV Project is estimated to cost $507 million and is the most prudent option to address regional and local needs in the La Crosse and Rochester areas. There are two lower voltage alternatives which provide 750 MW to the La Crosse area for lower cost; however , these alternatives do not provide an equivalent level of regional benefits as the 345 kV Project. Addressing the needs of the Rochester and La Crosse areas simultaneously results in more efficient system planning and can avoid duplication or balkanization of transmission facilities. While the resultant project has higher costs than certain lower voltage alternatives, a holistic solution that jointly addresses the needs of both areas as well as the need for future facilities results in the most efficient system development.

Regional System Benefits

- Increased Immediate and Future System Transfer Capability – Transfer limits between Minnesota and Wisconsin affect system operators' ability to move power in response to a critical contingency or shifts in variable resources such as wind generation. Addition of the 345 kV Project or the La Crosse 161 kV Alternative alone adds 700-850 MW of thermal transfer capability between Minnesota and Wisconsin. However, a 345 kV connection is more robust in that it also provides for additional transfer capability as the 345 kV system is extended to the east. Transfer study analysis indicates the additional capacity, depending on the eastern termination, could be as high as 1200 MW over current system levels (depending on the eastern terminus). This 1200 MW increase is not realized if a lower voltage alternative is constructed initially. In fact, the lower voltage alternative followed by a 345 kV line to the east of La Crosse would actually reduce thermal transfer capability *below* current levels. By increasing transfer capability, the 345 kV Project enhances overall regional reliability. This transfer capability analysis is detailed in Section 4.4.

- Reduce Congestion – Congestion limits the ability of system operators to dispatch generation in the most economical manner. In 2009 MISO showed that the 345 kV Project relieved generation trapped in Minnesota that was identified in 2010 and 2014 models. Congestion in Wisconsin expands geographically to the east and to the Upper

Peninsula of Michigan. Reducing congestion results in overall lower energy costs. This is detailed in Section 2.4.1.

- System Losses Benefit – The 345 kV Project presents cost savings and reduced need for new generation capacity over a lower voltage alternative based on system losses. The 345 kV Project provides higher loss savings versus the alternatives, from $5 million up to $36 million depending on the alternative. More detail on system loss calculations is contained in Section 4.2.

- Part of an Approved Regional Plan – The 345 kV Project has been thoroughly evaluated by MISO and was approved in Appendix A of MTEP08. This is further discussed in Section 2 and demonstrates planning collaboration and a regional approach to solving the identified issues.

1.3 Lesser-Performing Alternatives

Five lower voltage alternatives (and two revisions) analyzed through this study process are as follows. Details for each alternative can be found in Section 4.1:

1.3.1 La Crosse 161 kV Alternative[2]

The 161 kV La Crosse Alternative includes 161 kV fixes for the La Crosse area and a 345 kV line from Hampton to North Rochester and two 161 kV lines from North Rochester to the Rochester load serving area. For La Crosse, this includes reconductoring/rebuilding a number of lines in the La Crosse area and building a new 161 kV transmission line across the Mississippi River to connect to the Prairie Island source at Spring Creek Substation. Figure B shows the 161 kV La Crosse Alternative. Full details of this option can be found in Section 4.1.1.2.

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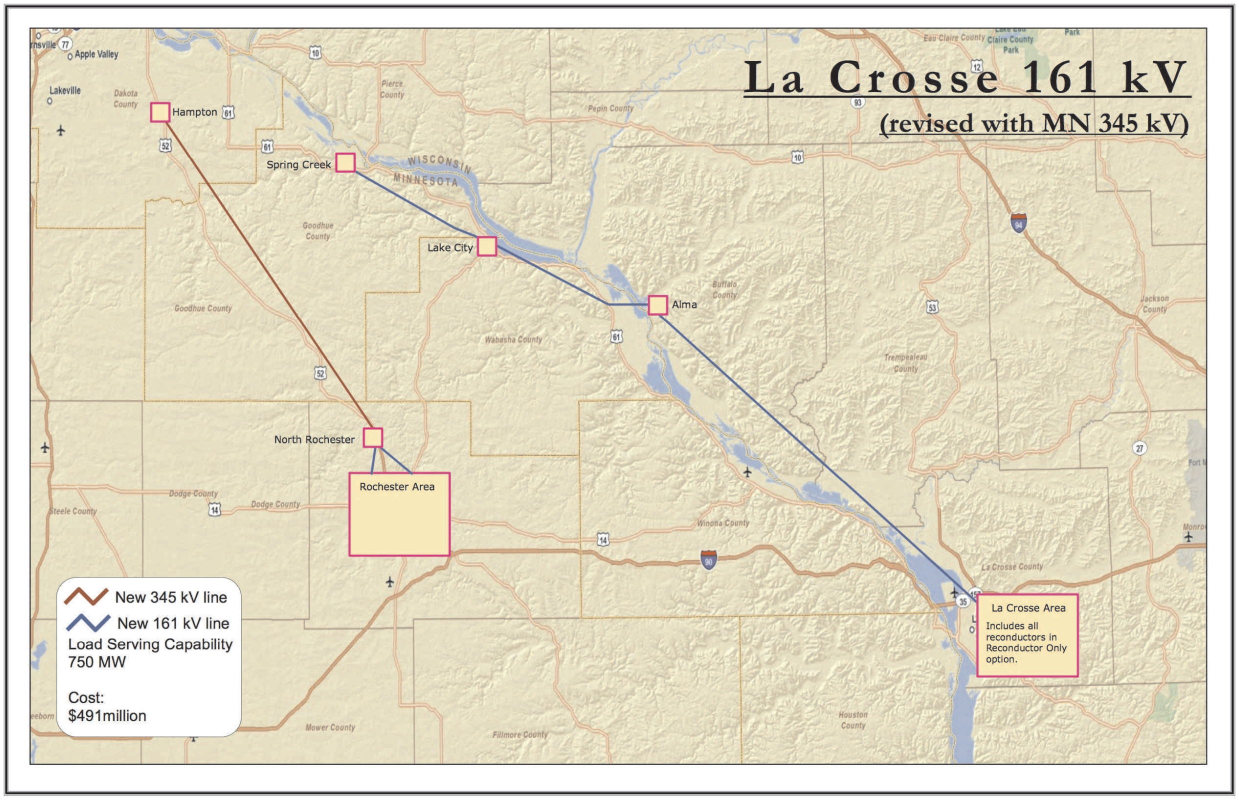
[2] The TSSR reflects a previous version of this alternative (the "2010 La Crosse 161 kV Alternative") which included a 161 kV solution for the Rochester area as opposed to the 345 kV line from Hampton to North Rochester and two 161 kV lines from North Rochester to Rochester area substations.

Figure B: La Crosse 161 kV Alternative



1.3.2 Initial 161 kV North Rochester – Briggs Road Alternative and Revised Alternative

The option which included a 161 kV line from North Rochester to Briggs Road is shown in Figure C below. This option was first introduced in the TSSR and was shown to have a load serving capability of 550 MW. Following the TSSR, planning engineers analyzed what facilities would be necessary to have this alternative serve load to the same level realized by the 345 kV Project and the La Crosse 161 kV Alternative and concluded that to reach 750 MW load level, the alternative needed to tie in at a new substation near Alma and include all the reconductoring associated with the Reconductor Only option described below. The 161 kV North Rochester – Briggs Road (revised to serve 750 MW) Alternative is shown in Figure D. Full details of these alternatives are in Section 4.1.1.3

Figure C: Initial 161 kV North Rochester – Briggs Road Alternative

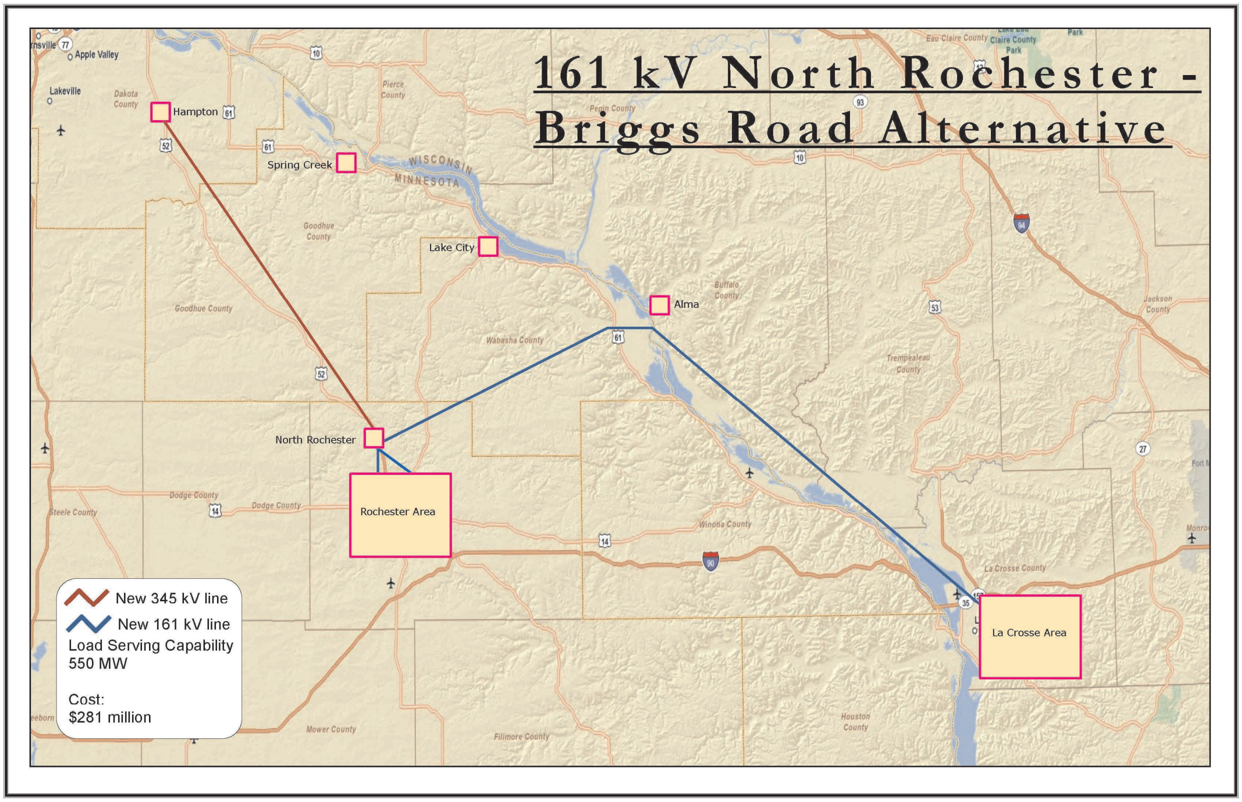
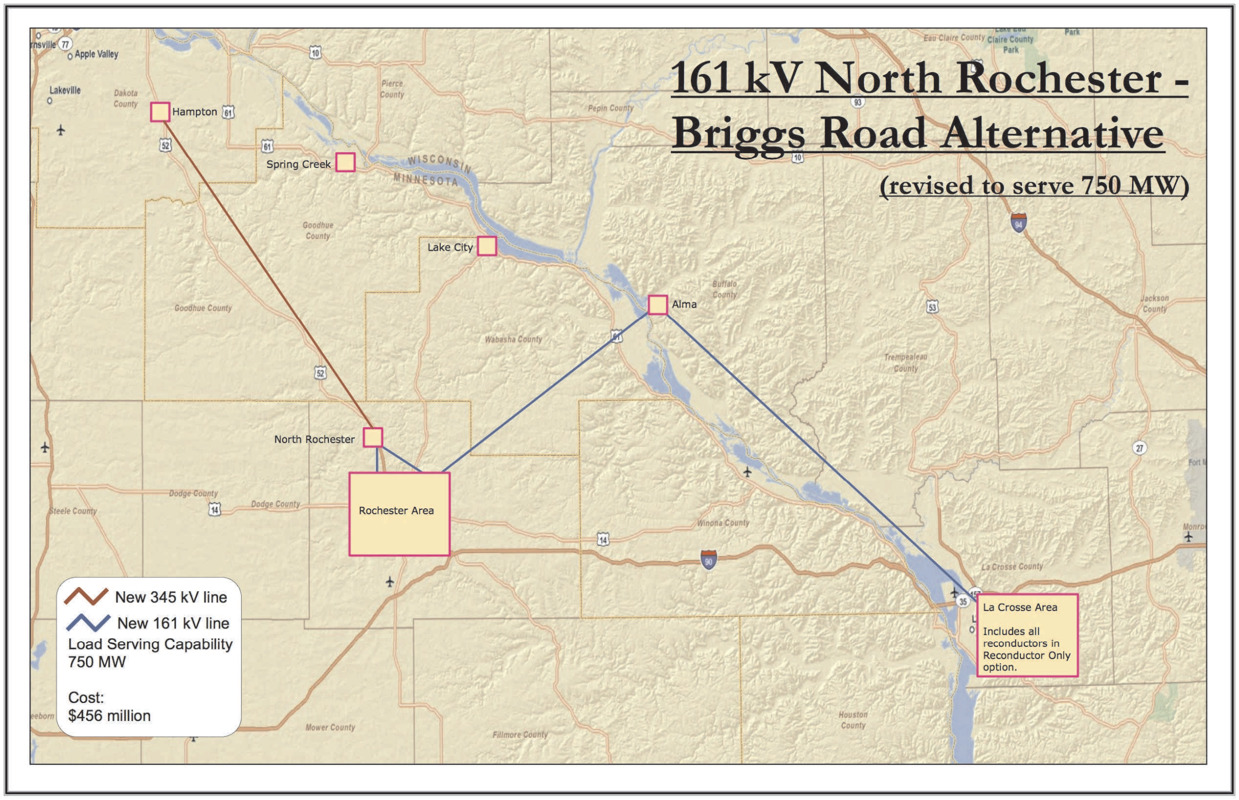


Figure D: 161 kV North Rochester – Briggs Road (revised to serve to 750 MW) Alternative



1.3.3 Reconductor Only Alternative

The Reconductor Only Alternative consists of approximately 200 miles of transmission line reconductors and rebuilds in the city of La Crosse and surrounding area. This option and its revision are detailed in Section 4.1.1.1.

1.3.4 Reconductor Only (revised with 345 kV facilities in Minnesota ("MN 345 kV")) Alternative

The cost of the Reconductor Only Alternative was estimated assuming the lower voltage alternative for the Rochester, Minnesota area. The Reconductor Only (revised with MN 345 kV) Alternative cost estimates includes the cost of the 345 kV connection between Hampton and North Rochester and the 161 kV Rochester connections. This alternative is included in summary table of alternatives serving less than 750 MW of load in Figure U.

1.3.5 Double Circuit 161 kV North Rochester – Briggs Road and 230 kV North Rochester – Briggs Road Alternatives

As with the 161 kV North Rochester – Briggs Road Alternative, the Double Circuit 161 kV North Rochester – Briggs Road and 230 kV North Rochester – Briggs Road aalternatives were introduced in the TSSR. They have load serving capability of 600 MW and 550 MW, respectively. These alternatives are discussed in Section 4.1.1.3.

1.4 Analyses of Lesser-Performing Alternatives

The lower voltage alternatives described above and analyzed through the study process do not meet all of the identified system needs and are inferior to the 345 kV Project based on the following factors:

Load Serving Capability

- With the exception of the La Crosse 161 kV Alternative and the 161 kV North Rochester – Briggs Road (revised to serve 750 MW) Alternative, the lower voltage alternatives provide less load serving capability than the 345 kV Project.

Cost

- The La Crosse 161 kV Alternative and the 161 kV North Rochester – Briggs Road (revised to serve to 750 MW) Alternative cost $491 million and $456 million, respectively, or $16 million and $51 million less than the proposed 345 kV Project, respectively. However, these alternatives do not provide the regional reliability benefits of the 345 kV Project.

Reduced Regional System Benefits

- Addition of the La Crosse 161 kV Alternative alone adds 775 MW of transfer capability between Minnesota and Wisconsin. However, as the 345 kV system expands to the east; whether from La Crosse to Madison or Green Bay or some other location, transfer capability between Minnesota and Wisconsin is degraded to 600-1000 MW lower than today's value, or 1400 to 1800 MW lower than the calculated capability with the 161 kV La Crosse Alternative in service. This is detailed in Section 4.4

System Losses

- Alternatives which do not introduce new 345 kV facilities to the system have more system losses, and therefore incur costs for increased generation to make up for those losses. The cost impacts on each alternative of system losses are detailed in Section 4.2 and included on the summary tables in Section 4.3.

Transmission Upgrades in the City of La Crosse

- 200 miles of existing transmission in and around the city of La Crosse would need to be rebuilt for the Reconductor Only and La Crosse 161 kV Alternatives. These rebuilt lines are shown on an area map in Figure P. In addition, the La Crosse 161 kV Alternative includes a new 100-mile 161 kV line across the Mississippi River to connect to the Prairie Island source at Spring Creek Substation.

Detailed charts along with the detailed analysis of load service capabilities and costs of each option are available in Section 4.3.

2. REGIONAL TRANSMISSION DEVELOPMENT

In addition to the local reliability needs, the 345 kV Project will provide significant regional reliability benefits and generation support. This section describes the CapX2020 initiative, the existing regional bulk transmission system serving Wisconsin, Minnesota, and surrounding states, and the constraints currently limiting transfer capability in that system.

2.1 CapX2020

CapX2020 is a joint initiative of 11 transmission-owning utilities in Wisconsin, Minnesota, and the surrounding region whose goal is to study, develop, permit and construct transmission infrastructure needed to implement long-term and cost-effective solutions for customers to meet the growth in electricity expected in the upcoming decades (the "CapX2020 Initiative"). The 11 utilities currently participating in the CapX2020 Initiative include Applicants, Great River Energy, Central Minnesota Municipal Power Agency, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities ("RPU"), and Southern Minnesota Municipal Power Agency ("SMMPA") (referred to the as the CapX2020 Utilities). The five utilities participating in the 345 kV Project are Applicants, RPU, and SMMPA.

It is both the current and future predicted demand for electricity that drives the CapX2020 Initiative, including the 345 kV Project proposal. The transmission system must have the capacity to meet the peak instantaneous power demands that occur at distribution substations. If maximum instantaneous power demand is met, then it is likely any level of energy consumption over time can be met. By providing a more robust network of high voltage transmission, including 345 kV, the power system can continue to operate reliably while accommodating substantial growth and reducing energy costs.

In the end, customer demand requirements (now and in the future) dictate transmission capacity requirements. The CapX2020 Utilities joined to collaboratively assess the required transmission infrastructure investments needed to meet this growing demand for electricity in Wisconsin, Minnesota and the surrounding region.

The 345 kV Project is one of four transmission projects proposed by the CapX2020 Utilities, collectively referred to as the Group 1 projects. The other Group 1 projects, which are being permitted separately, are identified below.

- Monticello–St. Cloud 345 kV Project and the Fargo–St. Cloud 345 kV Project – jointly, a 345 kV transmission line from Fargo, North Dakota, to Monticello, Minnesota
- Brookings County–Hampton 345 kV Project – 345 kV transmission line between Brookings County, South Dakota, and Hampton, Minnesota
- Bemidji–Grand Rapids 230 kV Project – 230 kV transmission line from Bemidji, Minnesota, to Grand Rapids, Minnesota

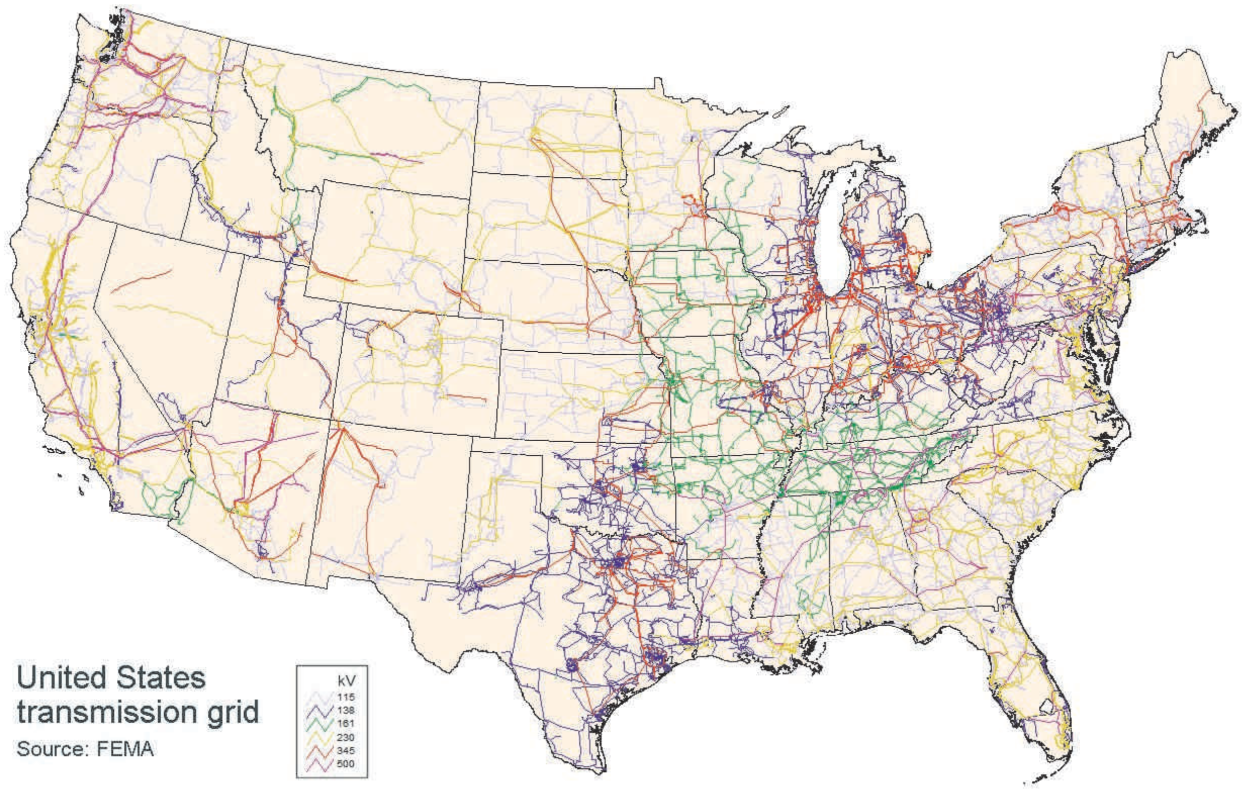
2.2 The Transmission Network

The electric transmission system in the United States is comprised of a highly decentralized interconnected network of generating plants, high voltage transmission lines and distribution facilities. Electricity uses all available paths as it flows from generation to consumers. Since the electricity from all sources is commingled in the transmission system, it is impossible to know exactly where the electric power comes from that lights a room in a home. Designing the transmission system and the proper implementation of new transmission facilities requires complex analysis, including modeling of power system steady-state and dynamic performance.

Today, there are more than 150,000 miles of high voltage transmission lines in the United States transmitting electricity at voltages in excess of 200 kV. There are also many thousands of miles of transmission lines between 100 and 200 kV. These facilities include alternating current lines (“AC”) and direct current lines (“DC”).

A map of the electrical grid in the United States is shown in Figure E.

Figure E: The National Power Grid



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

In Minnesota, there are more than 13,500 miles of AC transmission lines 69 kV and higher voltages, including 870 miles of 345 kV lines, and 340 miles of 500 kV lines. In addition, there are almost 300 miles of DC transmission lines in Minnesota. The Minnesota transmission system connects more than 175 electric generating plants, sized from less than one MW to more than 3,300 MW, including fossil fuel-fired (coal, natural gas, and oil), nuclear, wind, hydro, and biomass plants, located both inside and outside the state, to serve the state's more than five million residents and businesses. The system is also connected to utilities in surrounding states and in Canada.

In Wisconsin, there are approximately 12,000 miles of transmission line facilities. Flows on the system are generally northwest to southeast. As noted by the Public Service Commission of Wisconsin ("PSCW"):

> [T]he western part of Wisconsin is connected by high-voltage lines (161 and 345 kV) primarily from Minnesota. The southeastern part of Wisconsin is connected to northern Illinois by 345 kV high voltage lines. The Wisconsin transmission system can become congested under normal power flow conditions. In addition, there are many transmission lines in Wisconsin that are more than 60 years old, requiring upgrades or replacement. The new Federal Reliability Standards for transmission system design and operation require upgrades to maintain the same performance level. The introduction of renewable power sources such as wind development in Wisconsin and in other Midwest states may require new high and extra high voltage transmission lines.[3]

In addition, Wisconsin contains more than 35 electric generating plants connected to the bulk electric system, sized from less than one MW to more than 1,200 MW. These plants include coal, natural gas, oil, hydroelectric, nuclear, wind, and biomass plants.[4]

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[3] PSCW, Electric Transmission Lines at 7, http://psc.wi.gov/thelibrary/publications/electric/electric09.pdf.

[4] Wisconsin Department of Natural Resources, Power Generation in Wisconsin, http://dnr.wi.gov/org/caer/ce/eek/teacher/Climateguide/pdf/PowerGeneralWisconsin.pdf (accessed Aug. 29, 2011)

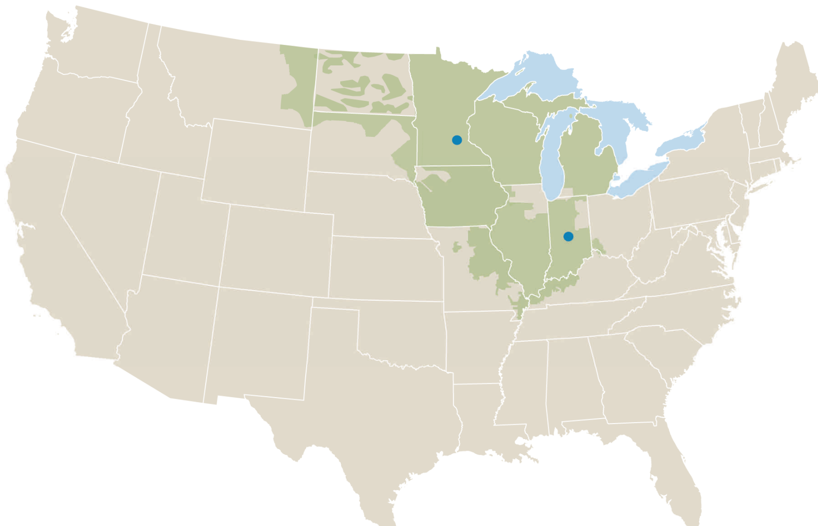
2.2.1 Regional Transmission Planning

MISO is one of several Federal Energy Regulatory Commission ("FERC")-approved Regional Transmission Organizations ("RTO") that oversees and coordinates regional transmission planning and regional transmission service and manages access to the transmission grid to facilitate reliable delivery of power through fair and competitive wholesale electric markets. MISO currently implements an Open Access Transmission and Energy Markets Tariff ("TEMT"), which includes the MISO Day-Ahead, Real-Time, Ancillary Services, and Financial Transmission Rights Markets. Xcel Energy and Dairyland Power Cooperative are transmission-owning members of MISO and both are subject to the terms and conditions of MISO's TEMT.

MISO is a non-profit corporation, comprised of 38 transmission owner members, including the Applicants, and approximately 100 non-transmission owners including municipal utilities, cooperatives and state regulatory authorities. A list of current MISO members can be found at https://www.misoenergy.org/StakeholderCenter/Members/Pages/MembershipList.aspx. The MISO region, or footprint, encompasses all, or portions, of 12 states from Montana to western Ohio. MISO's headquarters are in Carmel, Indiana, with system control centers in Carmel and in Saint Paul, Minnesota.

The MISO members are located in several midwestern states, including Minnesota, Iowa, South Dakota, North Dakota and Wisconsin, along with the Canadian province of Manitoba. MISO's regional system interconnects with the Independent Electricity System Operator of Ontario, the Mid-Continent Area Power Pool, the PJM Interconnection, the Southwest Power Pool and the Tennessee Valley Authority. Figure F is a map of the portion of the MISO footprint contained in the United States. Note that Manitoba is part of MISO but is not included on Figure F.

Figure F: MISO United States Footprint



Source: MISO.

2.2.2 Transmission Constraints

MISO administers and manages the transmission of electricity within its footprint – over 53,000 miles of wires.[5] The dynamics of the electrical system are extremely complicated, and require moment-by-moment matching of generation resources and load requirements at the proper voltage. If the load balance or voltage is disturbed by a sudden change in generation output, transmission line availability, or customer usage, the bulk transmission system provides capacity for other generation to adjust and keep the system in balance. To meet these regional needs, it is essential that power be transferred across states' systems. The greater the transfer capability, the better able MISO is to maintain the system particularly in the case of significant change in variable and intermittent resources such as wind and in the case of catastrophic events.

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[5] *See* MISO, CORPORATE INFORMATION at 1, June 2011, https://www.misoenergy.org/Library/Repository/Communication%20Material/Corporate/Corporate%20Fact%20Sheet.pdf.

MISO is obligated to provide non-discriminatory access to the transmission system in accordance with the TEMT, a tariff on file with FERC. As part of its transmission function, MISO also undertakes studies of the transmission system and recommends proposed transmission projects that are necessary to meet the needs of end use customers and new generators and improve electric power grid performance throughout the Midwest. MISO also undertakes studies of the transmission system and identifies transmission projects that are necessary to meet the needs of end use customers and new generators and improve electric power grid performance throughout the Midwest. MISO then reports on those recommended projects in its annual MTEP report. Transmission owners are contractually obligated to "make a good faith effort to design, certify and build" the facilities included in the MTEP that the MISO Board of Directors approves.[6]

MISO reviewed the 345 kV Project in its 2006 MTEP ("MTEP06") and noted that it "worked closely with [the CapX2020 utilities] during the development of these plans to meet the longer term load serving needs of the area and to coordinate these plans with other expansion concepts underway in Iowa and Wisconsin."[7] In the 2007 MTEP ("MTEP07"), MISO concluded that the project's effectiveness and need for community reliability had been demonstrated and included the project as an "Appendix B" project. The report noted that the 345 kV Project is needed to address North American Reliability Corporation ("NERC") Standard issues in the Rochester and La Crosse areas related to multiple Category B and Category C events.[8]

The 345 kV Project and the Monticello – Fargo 345 kV Project were included in MTEP08 as a "Baseline Reliability" projects, with MISO placing each in Appendix A and approving them for regional cost allocation.[9] (MISO MTEP08, p. 6.) This recognizes MISO's acceptance that these projects were necessary to ensure continued

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[6] MISO, MTEP08 at 25, Nov. 2008, https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=17242.

[7] MISO, MTEP06 at 13, Dec. 2006, https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=17260.

[8] MISO, MTEP07 at 10, Oct. 2007, https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=17199.

[9] MISO, MTEP08 at 6, Nov. 2008, https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=17242.

compliance with NERC reliability standards. The Bemidji – Grand Rapids 230 kV Project had already been included in MTEP06 as a "Baseline Reliability" project. The Brookings – Hampton 345 kV project is included in MISO's MVP study portfolio and has been granted conditional approval for inclusion in MTEP11 as a MVP.[10] Full cost allocation as a MVP will be granted upon MISO's acceptance of the final Candidate MVP Study Report later in 2011.

2.2.3 MISO Market Function

The MISO footprint contains approximately 135,000 MW of electric generating capacity.[11] This generation is used primarily by load-serving entities, such as Applicants, that either own and operate the generators, have long-term bilateral supply arrangements with generators or other utilities, or that purchase short-term energy through MISO's real-time and day-ahead energy markets to serve their native load customer requirements. Under the TEMT, short-term and spot market transactions are available to utilities to acquire energy supply to meet load demands at lower cost than operating their own longer-term resources. Under the MISO TEMT, participating utilities are required to purchase and sell energy within the MISO Day-Ahead and Real-Time markets. MISO works to ensure that this market is a robust and efficient energy market that sends accurate price signals. Pursuant to MISO's TEMT, MISO uses a security constrained economic dispatch that employs Locational Marginal Pricing ("LMP") that is intended to take into account the production costs of resources, transmission losses and capacity limitations (referred to as "congestion") on the transmission system to use the least cost available generation to serve loads on a regional basis within MISO.

LMP is a method of calculating the marginal price for energy and/or transmission which is based on marginal energy price, marginal losses and congestion. Marginal pricing is based upon the theory that the market price of any commodity should be the cost of bringing the last unit of that commodity – the one that balances supply and demand – to the market. In electricity, LMP recognizes that this marginal

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[10] MISO, MISO CANDIDATE MVP PORTFOLIO ANALYSIS INTERIM REPORT at 15, June 2011, https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=1-1-78.

[11] MISO, CORPORATE INFORMATION at 1, June 2011, https://www.misoenergy.org/Library/Repository/Communication%20Material/Corporate/Corporate%20Fact%20Sheet.pdf.

price may vary at different times and locations due to transmission congestion, physical limitations and loss factors. When there is no congestion (*i.e.*, an unconstrained system with no losses), there is only one price: the price bid by the last generator that provides electricity. When there is congestion (*i.e.*, a constrained system with losses), action must be taken to protect the system. Under constrained conditions, LMP dispatch sends a price signal to market participants notifying them that they will have to pay for congestion costs if they want their transactions to continue. The result is that higher cost generation resources are run to reduce congestion and preserve the reliability of the system.

LMP is intended to provide price signals that create market-based solutions to resolve congestion on the transmission system based on generation offers, load bids, and marginal losses.

2.3 Need for Comprehensive Expansion Consistent With Regulatory Requirements

The CapX2020 Utilities are obligated to develop, propose and construct transmission facilities that satisfy all of the various regulatory and mandatory reliability requirements. All of these rules and requirements work together to require that the region's electric transmission system be planned, constructed, operated and maintained in a way that will allow it to operate reliably and in coordination with other interconnected transmission systems throughout the Upper Midwest and the entire Eastern Interconnection.

In Wisconsin, Minnesota, surrounding states, and the country as a whole, transmission system expansion has not kept pace with load and generation growth. Such growth has increasingly used up the capability created by the major transmission expansions in the 1950s, 1960s and 1970s – such as the 345 kV loop around the Twin Cities, the 345 kV interconnections to Chicago, St. Louis and Omaha, and the 230 kV and 500 kV interconnections to Manitoba. For the electrical system to continue to deliver power safely and reliably to consumers and businesses throughout the CapX2020 Utilities' footprints, including territories in both Minnesota and Wisconsin, additional transmission infrastructure must be built across the Upper Midwest region.

One of the main features that sets the CapX2020 Initiative apart is its focus on a long-term view of how to ensure a steady supply of reliable electricity for the upcoming decades, similar to the long-term view that resulted in the large regional interconnections in the 1960s and 1970s. While utilities must continue to develop facilities that meet the immediate needs of customers as well as facilitate environmentally appropriate generation choices, those goals can be accommodated by expanding the overall system in such a way that will benefit Wisconsin and Minnesota consumers and businesses for years and decades to come.

2.3.1 The Transmission System in Minnesota and Western Wisconsin

One important distinction to be made regarding the transmission system in Wisconsin is that it is largely comprised of two systems that behave independently and are only minimally connected. The transmission system in western Wisconsin developed principally as the result of planning and coordination between Xcel Energy; Superior Water Light and Power ("SWLP"); and Dairyland Power Cooperative. The transmission system in eastern Wisconsin, owned by American Transmission Company, LLC ("ATC"), developed separately, preliminarily focusing on the Madison and Milwaukee areas and expanding north into the Upper Peninsula of Michigan. The eastern and western Wisconsin transmission systems have interconnected at only a handful of locations. Specifically, there are two 345 kV connections and one 115 kV connection. As a result, the transmission system in western Wisconsin is currently more closely linked with the transmission system in Minnesota than that in eastern Wisconsin.

2.3.2 Transmission System Development in Minnesota—A Case Study

In the past century, the predecessor company to Xcel Energy and Northern States Power Company - Minnesota has twice embarked on substantial upgrades to its bulk transmission system with a longer planning horizon at the forefront. First, in the early part of the 1900s, planners designed a ring of 115 kV lines around the Twin Cities to reliably deliver electrical power to the growing city populations. Second, in the 1950s and 1960s, a similar overall coordinated system expansion effort was undertaken when (a) the 345 kV ring around the Twin Cities was developed, and (b) the 230, 345 and 500 kV interconnections to neighboring utilities were developed to enhance reliability and facilitate access to additional generation resources.

Minnesota's experiences are highly instructive as it reflects the paradigm underlying the CapX2020 Initiative. That effort will be described in some detail in the next section. Using that historical precedent as a guide, it is recognized that the overall transmission system has nearly reached capacity and, there is once again a need to develop and expand the system beyond modest improvements and to facilitate transmission system expansions that will serve the State and the region for the longer term. The foresight associated with these prior long-range efforts parallels the long-term view underlying the CapX2020 Initiative's efforts.

As electricity use increased through the 1960s and 1970s, planners determined that electricity could be more efficiently generated using much larger (greater than 550 MW in size), more efficient, central station generation facilities. If such large plants were added to the area, the transmission system had to be upgraded so that it could withstand the power fluctuations that would occur if one of the large generators unexpectedly experienced an unplanned outage. The larger facilities would necessitate numerous additions to the electrical system to ensure reliable delivery of the power.

To address the need for transmission, planners looked at continuing with 115 kV additions and the introduction of 230 kV transmission facilities. These lines were studied using power flow modeling on an analog computer. Planners initially settled on constructing a 230 kV transmission line ring around the Twin Cities. Planners, aided by new technology that allowed for digital computerized power flow studies, later determined these voltages would be inadequate in the long term for several reasons. One, they could not adequately support new 550 MW and larger generation plants. For example, if a plant of that size abruptly tripped off-line, the electrical system could fail. Two, the new plants would need to be placed further out from the Twin Cities core to serve city centers and growing suburban areas. Three, lower voltage lines are less efficient because of higher resistance which results in higher electrical losses (and thus lower efficiency). This means that some energy that is generated at the plants does not reach the customer — it is dissipated as heat due to the resistance of the conductor. The higher voltages would yield lower losses and facilitate the interconnection of the larger generators. For example, a heavy-duty 115 kV line could transmit power up to 400 megavolt ampere ("MVA") for several miles, whereas a 345 kV line could transmit as much as 1,200 MVA over hundreds of miles.

Transmission planners evaluated what was required immediately to serve near-term customer needs plus how infrastructure improvements could best meet electricity needs over the coming years and decades. They decided to build the larger

345 kV ring that exists today.[12] At the time of these early studies, Minnesota utilities had no experience with 345 kV. By the early 1960s, however, utilities in the eastern United States were beginning to use the 345 kV voltage, which can carry roughly nine times as much power as a 115 kV line. Based on the east coast experience, the digital powerflow studies and its own research, NSP determined that the 345 kV voltage was a feasible option and necessary for long-term community service reliability. NSP also concluded that a 345 kV voltage was needed to provide robustness to the system in order to withstand the shock of losing a large generator and to enable NSP to replace such lost generation with electric energy from another source (such as from neighboring utilities' generators). Whereas in the past, the system could withstand an outage of a smaller power plant and local generation support was available, once the larger plants came on-line, power would have to be imported from other states in the event that one of the generators went off-line. Additionally, the population was extending toward the Interstate 494/694 loop that circled the Twin Cities suburbs which required additional transmission facilities to deliver power to the more dispersed loads.

In the 1960s and 1970s, NSP embarked on a series of generation and transmission investments that were intended to, and indeed benefited the Minnesota and western Wisconsin transmission system to this day. One of the new transmission facilities was a 345 kV line from the Twin Cities to St. Louis. This project, undertaken by NSP, DPC, and five other utilities, was the first of its size in the Midwest. Two other 345 kV lines, connecting the Twin Cities to Chicago and Omaha were also built.

As explained by NSP President Earl Ewald in 1967, the additions were designed with the long-term view in mind:

> Suddenly the year 2000 doesn't seem too far away.
>
> The Twin Cities metropolitan community, it has been estimated, will then have a population of nearly four million. Babies born in

---

[12] While a second metro ring was contemplated as the subject of a subsequent phase of the CapX2020 Initiative, the 345 kV Twin Cities ring continues to serve customer needs adequately today. In contrast, Colorado during the 1960s constructed a 230 kV transmission ring around Denver, Colorado. Today, current demands have necessitated construction of 345 kV facilities around Denver because the 230 kV lines have reached capacity.

> 1967 will be vigorous young citizens of 33 years when the 21st century arrives.
>
> * * * *
>
> We have been planning for a long time. Ten years ago when NSP's peak electric demand in the four-state area we serve was 1,054,000 kilowatts, our people outlined a construction program that would more than double that electric supply – 2,200,000 kilowatts – in 1966. Their estimate was precisely on the button.
>
> * * * *
>
> Increasingly as the population spreads to the far reaches of a region, a utility must construct longer lines to carry the electricity necessary for homes and industries.
>
> The new 345,000-volt lines connecting us to Chicago, Ill.; St. Louis, Mo., and Omaha, Neb. will bring new economies and added reliability to the supply for the Twin Cities system. Also, since they can carry nine times the power of lower voltage transmission lines, fewer lines will be needed.[13]

Ewald predicted that the transmission and generation additions would meet the Twin Cities' needs for 30 years.

2.4 System Constraints

2.4.1 Congestion

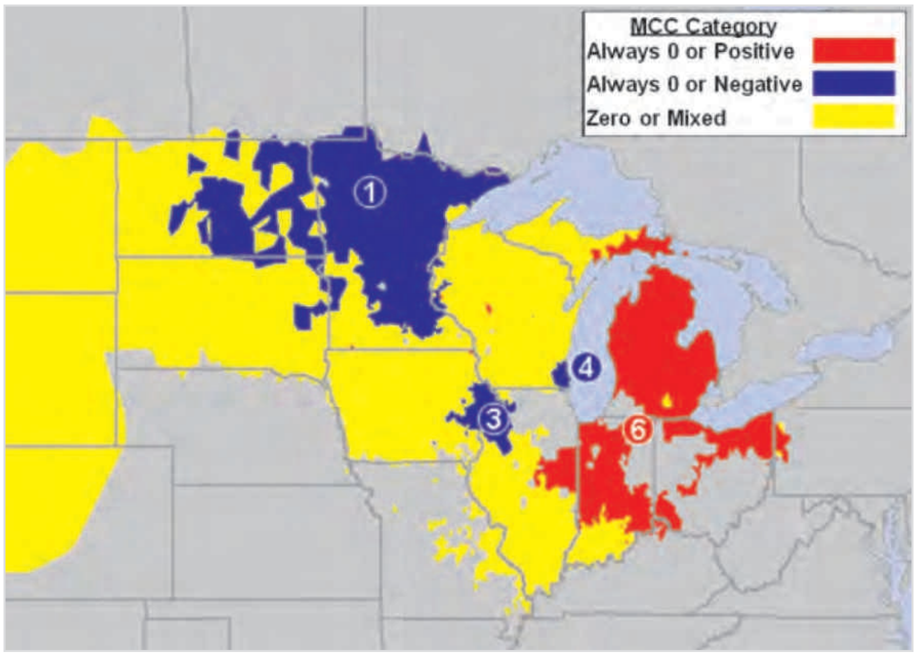
In Wisconsin, Minnesota, and surrounding states, various constraints have been identified that limit the amount of power that can flow across portions of the MISO system. These limitations create market inefficiencies

[13] *NSP Planning for Future Electrical Needs*, MINNEAPOLIS TRIBUNE, May 21, 1967.

MISO Analysis

MISO analyzed congestion in the 2010 MTEP ("MTEP10"). The report included two figures that depict transmission system congestion models. They are shown below:

Figure G: Congestion-Based Zones Modeled in 2014

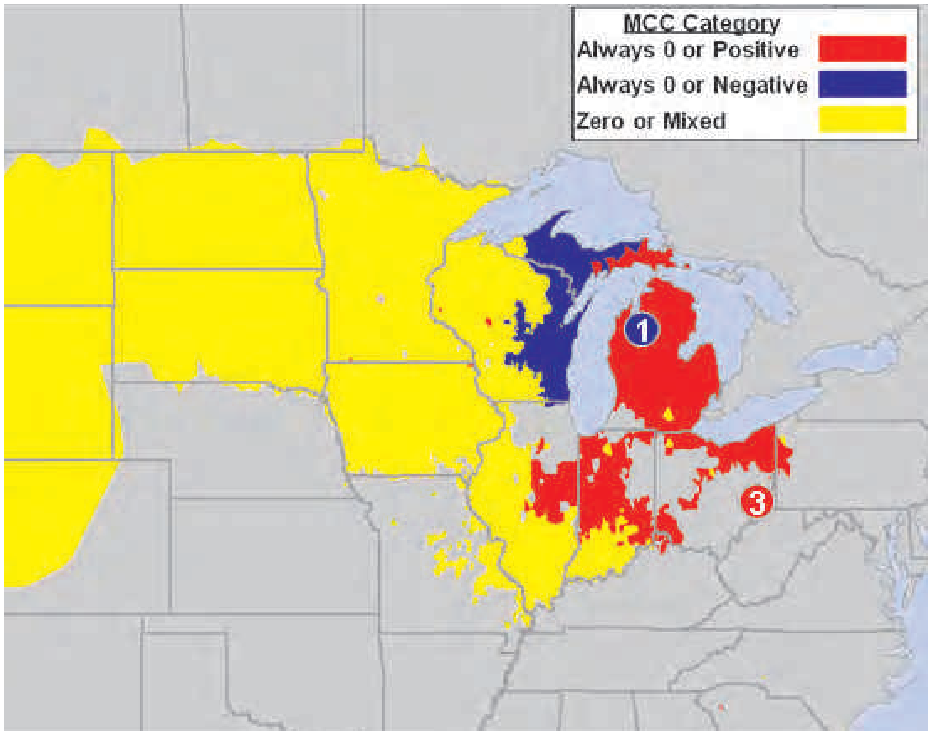


Source: Midwest ISO 2010 Figure 8.3-3.

The blue area represents areas where generation is "bottled up" and "not deliverable to the [MISO] market area on a reliability basis during summer peak load time".[14] Red areas are those that can always be reliably served. Yellow areas are reliably served most of the time. The MISO calculated the deficit in the blue areas as "a shortfall in effectively sharing approximately 443 MW of installed capacity in 2010". In the 2019 model, there is no congestion in Minnesota, which is closely tied to western Wisconsin.

[14] MISO, MTEP10 at 180, November 2010, https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=19942.

Figure H: Congestion-Based Zones Modeled in 2019



Source: Midwest ISO 2010 Figure 8.3-3.

MISO noted the benefits of the proposed project in alleviating congestion in the Minnesota area:

> For 2019, CapX 2020 additions, including the Hampton-Rochester-La Crosse 345 kV transmission project and the Brookings County-Twin Cities 345 kV project, relieve the Minnesota trapped generation identified in the 2010 and 2014 models. Congestion in SE Wisconsin expands geographically to all of eastern Wisconsin and the Upper Peninsula of Michigan.[15]

FERC Designated Narrow Constrained Areas

The existing transmission system in the MISO region has limitations in certain areas that have been specifically designated by FERC. These limitations, or transmission constraints, can result in higher electricity costs to consumers in the

[15] *Id.* at 182.

affected areas under the Day 2 LMP mechanism. There is also concern that transmission constraints could allow power generators in the constrained area that are offering into the MISO Day 2 market to exercise local market power, resulting in inaccurate price signals and excessive payments to generators within the constraint. The constrained transmission lines result in market energy prices in the constrained area to be higher than in neighboring areas not subject to such transmission constraints.

To address this issue, in the orders establishing the MISO Day 2 market, FERC designated Narrow Constrained Areas ("NCAs") for those areas where existing transmission constraints preclude the efficient implementation of the marketplace. A NCA designation alters the operation of the Day Ahead and Real Time energy market in the area from its designed mode. Generators in a NCA face restrictions on their offer price into the MISO energy markets because they can impact the affected transmission constraints in a NCA.

The area of southeast Minnesota, northern Iowa and southwestern Wisconsin has been designated by the MISO Independent Market Monitor ("IMM") as a NCA because the area is chronically constrained, which raises market power concerns for generators in the constrained area making offers into the MISO energy market.[16] The transmission constraints are mainly associated with two dominant parallel electrical paths. The first is a set of 345 kV facilities in western Iowa to the Lakefield, Wilmarth and Blue Lake substations in Minnesota. The second is a set of 345 kV facilities in eastern Iowa to the Adams, Pleasant Valley and Prairie Island substations in Minnesota. Each of the constraints can restrict power flow into Minnesota from the south.

Analysis by the MISO IMM shows that two transmission lines in the Minnesota/Iowa/Wisconsin NCA were constrained for more than 15% of the hours during a one-year period (November 2005 through October 2006). Such constraints mean that actual generation operations patterns had to be altered from optimal economic commitment and dispatch in response to the transmission constraints. The frequency and duration of constraint conditions increased substantially during the fall of 2006, suggesting that at the end of the analysis period the constraints were not

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[16]The MISO IMM is responsible for, among other things, analyzing the MISO market for competitive impacts and potential anti-competitive behavior by market participants.

lessening.[17] The IMM thus concluded that parts of Minnesota, Wisconsin, and areas of surrounding states currently experience periods where certain transmission lines are affected by "pivotal generators" that are necessary to manage congestion in the area and that the condition is likely to persist.[18] In addition, Applicants are aware that, anecdotally, the IMM has declined to reassess the status of the Minnesota/Iowa/Wisconsin NCA because sufficient transmission has not been developed to alleviate the congestion that justified its creation.

Based on MISO's MTEP10 analysis of congestion, the designation of much of Minnesota and southern Wisconsin as a NCA and the State of the Market report support the need for additional transmission to alleviate constrained areas to allow lower cost energy supplies to be delivered. MISO has reviewed the benefits of the Group 1 projects relating to congestion and concluded that the Group 1 projects and four other projects will mitigate the MISO region's "top 10 binding constraints."[19] The MISO noted: "By relieving the most significant points of congestion within Midwest ISO, transmission system performance improves substantially and huge benefit savings are achieved in Midwest ISO west and central regions."[20]

2.4.2 Interstate Transfer Limits

There are two key constrained areas that limit power transfers between Wisconsin and other states that not only affect economic dispatch of energy as discussed above, but create operational limitations. These two constraints, the Minnesota-Wisconsin Export ("MWEX") and the Wisconsin Upper Michigan System ("WUMS") area, affect system operators' ability to move power in response to a critical contingency.

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[17] It should be noted that a wide variety of factors influence the energy market and the commitment and dispatch of generating resources. For example, energy markets in the area analyzed were affected by low precipitation levels in Manitoba in 2005 causing reduced hydroelectric output and the 10-month outage of Xcel Energy's A.S. King plant from Fall 2006 to July 2007 as part of the Metro Emissions Reduction Project.

[18] FERC approved the designation of the Minnesota/Iowa/Wisconsin NCA in *Midwest Independent Transmission System Operator, Inc.*, 118 FERC ¶61,020 (Jan. 18, 2007).

[19] MISO, MTEP08 at 254, Nov. 2008, https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=17242.

[20] *Id.*

In the WUMS area, MISO's 2010 State of the Market Report noted persisting interstate transfer constraints in this area:

> We analyze values for the WUMS Area, the Minnesota Hub, and the Michigan Hub in both peak and off-peak hours. All values in the figures are computed relative to Cinergy Hub, which is the most actively-traded location in MISO. Figure 63 shows the monthly and annual differences for FTRs sourced in WUMS, indicating that for most months in 2010 WUMS was export constrained overall. This is a significant change from years prior to 2008. The direction of congestion in the WUMS region has reversed since 2008 because of: a) transmission upgrades into the area, and b) increased west-to-east power flows associated with increased wind output that has grown rapidly in recent years.[21]

In the eastern Wisconsin/western Minnesota area, transfers across the MWEX interface are limited due to voltage stability and transient voltage recovery limitations. Wind-powered generation concentrated in western Minnesota and the Dakotas affect west to east flows, particularly during off-peak times, and is anticipated to continue to increase to meet renewable requirements, including the Renewable Portfolio Standard requirements in Wisconsin and the Renewable Energy Standard ("RES") in Minnesota. The Minnesota RES studies have concluded that additional transfer capability is needed, particularly in off-peak times, to deliver these renewable resources.

As detailed in Section 4.3, the 345 kV Project will provide the necessary foundational facilities to increase transfers across the MWEX interface. If the 345 kV Project is constructed, any one of several additional 345 kV connections to the east, e.g. Green Bay or Madison, would result in a significant MWEX transfer capability increase. This low impedance path through Wisconsin to Illinois will help off load the upper peninsula of Michigan transmission which is the constraining element for WUMS imports.

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[21] *See Potomac Economics,* 2010 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS at 96, June 2011, https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=102911. It is important to note that, while the *direction* of congestion has reversed between 2008 and 2011, the *presence* of congestion has not diminished.

2.5 Increasing Peak Demand

The demand for power is rising throughout the region. This trend is demonstrated by the new peaks experienced on July 20, 2011 by the MISO states and the utilities serving the Wisconsin, Minnesota areas, including the communities that will benefit from the 345 kV Project.

- In MISO, the demand for power in its 12-state market area, peaked at 103,975 MW, exceeding the prior record of 103,246 MWs set on July 31, 2006.
- Dairyland Power Cooperative exceeded its last peak set in 2010 of 916 MW and reached a new peak demand of 979 MW, a 6.9% increase year-over-year.
- The system operated by Xcel Energy and Northern States Power Company, a Minnesota corporation, over a five-state area (Minnesota, North Dakota, South Dakota, Wisconsin and Michigan) reached a new peak of 9,533 MW of load served, 402 MW above the peak of 9,131 reached in 2010, representing a 4.4% increase.

A robust regional network to interconnect generation, transfer power between states, minimize congestion, reduce system losses, and to source distribution systems will be required to meet the ever increasing demand for power and to reduce overall energy costs. The 345 kV Project will help address all of these needs.

2.6 MISO Multi-Value Projects

Consistent with the MISO TEMT, MISO staff has been conducting a rigorous stakeholder process focused on studying a portfolio of projects that meet MISO's MVP criteria.[22] The analysis began in earnest in September 2010 with a group of 17 projects and has progressed to a final portfolio of 17 projects that will be recommended to the MISO Board of Directors in December 2011 for inclusion in

[22] *See Order Conditionally Accepting Tariff Revisions*, 133 FERC ¶ 61,221 (Dec. 16, 2010). In its December 16, 2010 Order, FERC approved MISO's proposed tariff language, subject to compliance requirements, including the requirement that potential MVPs be evaluated on a portfolio basis.

Appendix A as MVPs.[23] Among the projects that will be recommended for inclusion in Appendix A is a 345 kV line from La Crosse to Madison.

The La Crosse to Madison line has been identified through the study process as being necessary to enable load-serving entities in meeting their state-mandated renewable energy standards. This need alone qualifies it for treatment as a MVP. Simultaneously, MISO staff members have identified a range of benefits to completion of the portfolio.[24] These benefits include production cost benefits, reduction in operating reserves, a reduction in the planning reserve margin, reductions in transmission line losses, and a decrease in the number of new wind turbines necessary to meet renewable energy standards (through accessing more efficient wind resources). In addition, there are a number of qualitative benefits such as flexibility with future generation build-outs. MISO's analysis demonstrates assumption-dependent benefit/cost ratios ranging from a low of 1.6 to a high of 3.3, with all areas of the MISO footprint experiencing benefits in excess of costs.

The inclusion of the La Crosse to Madison line in this portfolio demonstrates the contribution of that facility to the future needs of the region and MISO's independent determination that its completion is necessary in order to pursue its mission of achieving least-cost delivery of reliable electric power. Because MISO has independently verified the need for the 345 kV Project with its Appendix A approval in MTEP08, the 345 kV Project was included in the base case models that were used in the Candidate MVP Study analysis. A central factor in the effectiveness of the La Crosse to Madison line is the presence of a 345 kV connection in the La Crosse area that will enable the efficient transfer of energy between Minnesota, western Wisconsin, and eastern Wisconsin. As detailed in Section 4.4 below, a lower voltage solution for the La Crosse area will result in significantly lower transfer capability than the 345 kV Project. In fact, a lower voltage solution for the La Crosse area will actually degrade the transfer capability of the system if a 345 kV line to Madison were constructed.

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[23] While the number of projects is the same, the final portfolio differs slightly from that which was originally proposed. A project in Illinois (the Sidney – Rising 345 kV line) was inadvertently left out of the original portfolio. In addition, when FirstEnergy exited MISO on June 1, 2011 a project in its Ohio service territory was removed from the portfolio.

[24] *See* MISO, PROPOSED MULTI-VALUE PROJECT PORTFOLIO, Aug. 2011, https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=115189.

3. COMMUNITY RELIABILITY

3.1 Needs for La Crosse

To assess the capabilities and limitations of the electrical system serving La Crosse, planning engineers reviewed historical load data and forecasted future load. The load serving area is defined and shown by substation in section 3.1.1.

Planning engineers found that without further improvements, the existing transmission system would not be able to reliably serve customers under contingency conditions beyond the 430 MW load level without putting load at risk for interruption. (On August 12, 2010, actual flows on the transmission lines serving the La Crosse area reached an all-time coincident peak load of 450 MW.)

La Crosse area load can be further supported by operating the lone operational 70 MW peaking unit at French Island. Relying on a local generator to supplement the transmission system is not a desirable long-term solution because it is less reliable than transmission. Baseload generating plants (such as units at JPM and Genoa near La Crosse) are typically off-line for approximately 20 percent of the time and can be shut down for maintenance without any forewarning. During the time the generator is off-line, the transmission system must maintain reliability. In addition, the energy generated from peaking units or older baseload facilities is normally more expensive than power purchased from units in the MISO energy market. Finally, the number of hours that the French Island unit can run may be restricted by environmental permitting limitations.

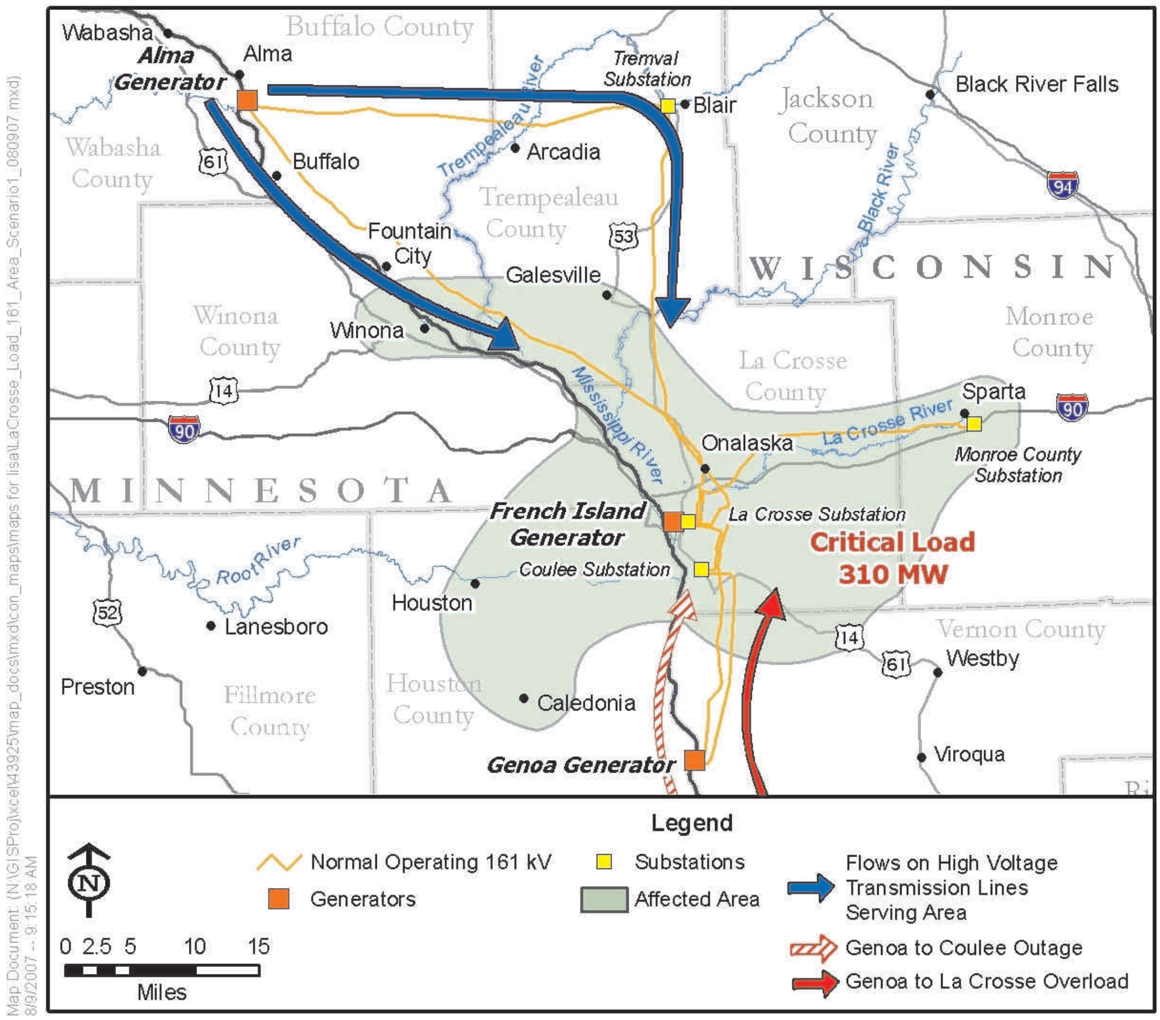
The electrical system's capacity to meet power demands is limited when generation at Alma or Genoa is off-line. If the Genoa generator is off-line and the Alma – Marshland 161 kV transmission line is disconnected, the La Crosse area experiences low voltage conditions at approximately 430 MW of load. Figure I shows the system under this contingency scenario.

Figure I: La Crosse Area Genoa Off-line, Alma – Marshland 161 kV Outage Contingency

Under this contingency, once load reaches 430 MW, the Genoa – Lansing 161 kV transmission line overloads. This level has already been exceeded. On July 17, 2006, actual flows on the transmission lines reached peak load of 447 MW. In addition, flows on the lines reached an all-time coincident peak load of 450 MW on August 12, 2010, with substation loads in the study area reaching 473 MW. If the 70 MW of French Island peaking generation is available and can be used for system support, the maximum capacity of the system reaches 510 MW. While none of these events occurred during the critical contingency, the contingency is nonetheless one the system must be able to withstand; the fact that the system is experiencing loading above 430 MW demonstrates the need for additional transmission infrastructure.

The system capacity is similarly limited if the John P. Madgett generator is off-line, French Island peaking generation is off-line, and the Genoa – Coulee 161 kV transmission line is lost. In this scenario, the Genoa – La Crosse 161 kV transmission line overloads and the electrical system can reliably serve only 310 MW. Figure J illustrates this contingency scenario.

Figure J: La Crosse Area, John P. Madgett and French Island Off-line with Genoa – Coulee 161 kV Line Contingency



As in the other two scenarios, French Island generation can supplement the load-serving capability of the system by 70 MW, up to a total of 380 MW.

3.1.1 Load Forecasts for La Crosse Area

To better understand the timing of the La Crosse area need, planning engineers developed a peak load forecast for substations operating in the affected La Crosse

Winona areas. Planning engineers gathered eight years of historical data and estimates of projected peak load growth. For the forecast, Xcel Energy and Dairyland Power Cooperative provided the actual loads from 2002 to 2010 at each of the substations and then projected loads at each of the substations. This timing analysis was completed using the most current load forecast information available in 2010.

For substations served by Dairyland Power Cooperative's distribution cooperatives, the forecast was estimated by first calculating an average load for years 2004 to 2009 for each substation. To create a forecast to the year 2020, planning engineers then applied a growth rate based on the historical peak growth rates of the distribution cooperatives: Vernon Electric Cooperative at 3.4 percent, Oakdale Electric Cooperative at 2.8 percent, Tri-County Electric Cooperative's growth rate at 1.8 percent and Riverland Energy Cooperative at 1.7 percent.

The 2010–2020 forecast for the Xcel Energy substations was based on an analysis of historical loads and anticipated growth rates. Xcel Energy used the peak demand for 2008 and grew that load by 1.2 percent through the year 2020.[25] Figure K shows the actual non-coincident annual peak demand for power at each substation in 2002, 2006, 2008 and 2010 and provides a forecast of annual peak demand at each greater La Crosse area substation for 2015 and 2020.

Figure K: Actual Loads and Forecast for La Crosse Area

LA CROSSE AREA LOAD SERVING SUBSTATIONS	Actual				Projected	
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2015	Load MW 2020
Bangor	4.08	4.17	3.46	3.3	4.43	4.66
Brice	5.12	6.93	6.36	3.5	3.81	4.15
Caledonia City	3.42	3.9	3.51	3.65	4.06	4.44
Cedar Creek	3.54	5.17	4.93	5	4.94	5.38
Centerville	2.79	3.34	4.2	3.05	3.76	4.09
Coon Valley	4.29	5.22	3.96	3.99	5.58	5.86

25 Actual loads for 2010 were obtained after the analyses were completed. The actual loads rather than forecast loads for 2010 are presented in this figure. The 1.2% growth was based and the corporate forecast rate.

LA CROSSE AREA LOAD SERVING SUBSTATIONS	Actual				Projected	
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2015	Load MW 2020
Coulee	53.5	60.3	52.91	61.44	67.4	71.03
East Winona	8.92	9.47	11.09	7	12.74	14.07
French Island	19.5	29.04	24.06	38.73	37.34	39.35
Galesville	6.91	6.89	5.5	5.79	7.36	7.73
Goodview	31.78	35.33	33.61	31.67	36.14	38.27
Grand Dad Bluff	1.67	1.91	1.63	1.68	1.85	2.01
Greenfield	2.85	3.43	3.06	2.93	3.39	3.69
Holland	-	-	-	4.74	5.16	5.61
Holmen	14.97	13.16	14.91	18.36	15.99	16.8
Houston	3.61	3.78	3.38	3.75	3.88	4.25
Krause	4.12	4.48	4.54	5.02	4.67	5.08
La Crosse	58.43	50.33	46.98	47.63	54.34	57.11
Mayfair	43.9	46.58	45.39	56.45	51.26	54.44
Mound Prairie	2.18	2.02	2.39	2.24	2.49	2.72
Mount La Crosse	1.64	2	2.09	2.15	2.12	2.31
New Amsterdam	3.88	4.66	4.46	3.47	3.78	4.11
Onalaska	11.73	12.93	10.48	13.77	14.54	15.67
Pine Creek	2.03	2.36	1.84	1.93	2.2	2.41
Rockland	4.18	4.14	3.1	3.66	4.15	4.37
Sand Lake Coulee	2.99	2.84	2.59	3.01	2.97	3.24
Sparta	29.65	32.47	31.74	30.9	35.84	38.61
Sparta (Dairyland)	1.15	1.36	1.16	1.14	1.42	1.63
Swift Creek	17.1	24.8	21.83	23.75	29.65	31.17
Trempealeau	4.43	3.94	3.68	2.68	4.2	4.41
West Salem	23.3	24.52	23.97	22.8	27.63	29.41
Wild Turkey	1.17	1.2	1.35	2.69	1.44	1.57
Winona	46.3	51.91	51.19	51.17	55.23	58.77
Total Load MW:	**425.12**	**464.59**	**435.34**	**473.04**	**514.98**	**547.57**
Critical Load Level = 450 MW (With JPM outage and Genoa-Coulee 161 kV outage)						
MW at risk				23.04	64.98	97.57
Critical Load Level = 430 MW (With Genoa outage and Alma-Marshland 161 kV outage)						
MW at risk		34.59	5.34	43.04	84.98	117.57

Load levels for the years 2021 to 2050 were forecasted at the same growth rate (1.24%) as the 2015 to 2020 forecast. Based on that growth the load is forecasted to be 583 MW in 2025, 620 MW in 2030, 711 MW in 2040, 747 MW in 2045 and 795 MW in 2050. As load forecasts for the future vary, these load levels may shift a few years in either direction. Figure L shows how these years may vary with differing forecasts, a lower growth factor of 1% and a higher factor of 2%. This method is also consistent with MISO methods for load forecasts beyond the 10 year planning horizon. MISO asks each transmission owner for the growth factor to apply to that owner's loads for the out years.

Figure L: La Crosse Load Area Growth Post 2020

	1%	**1.24%**	**2%**
2025	576 MW	583 MW	605 MW
2030	605 MW	620 MW	668 MW
2040	669 MW	711 MW	814 MW
2045	703 MW	747 MW	899 MW
2050	739 MW	795 MW	993 MW

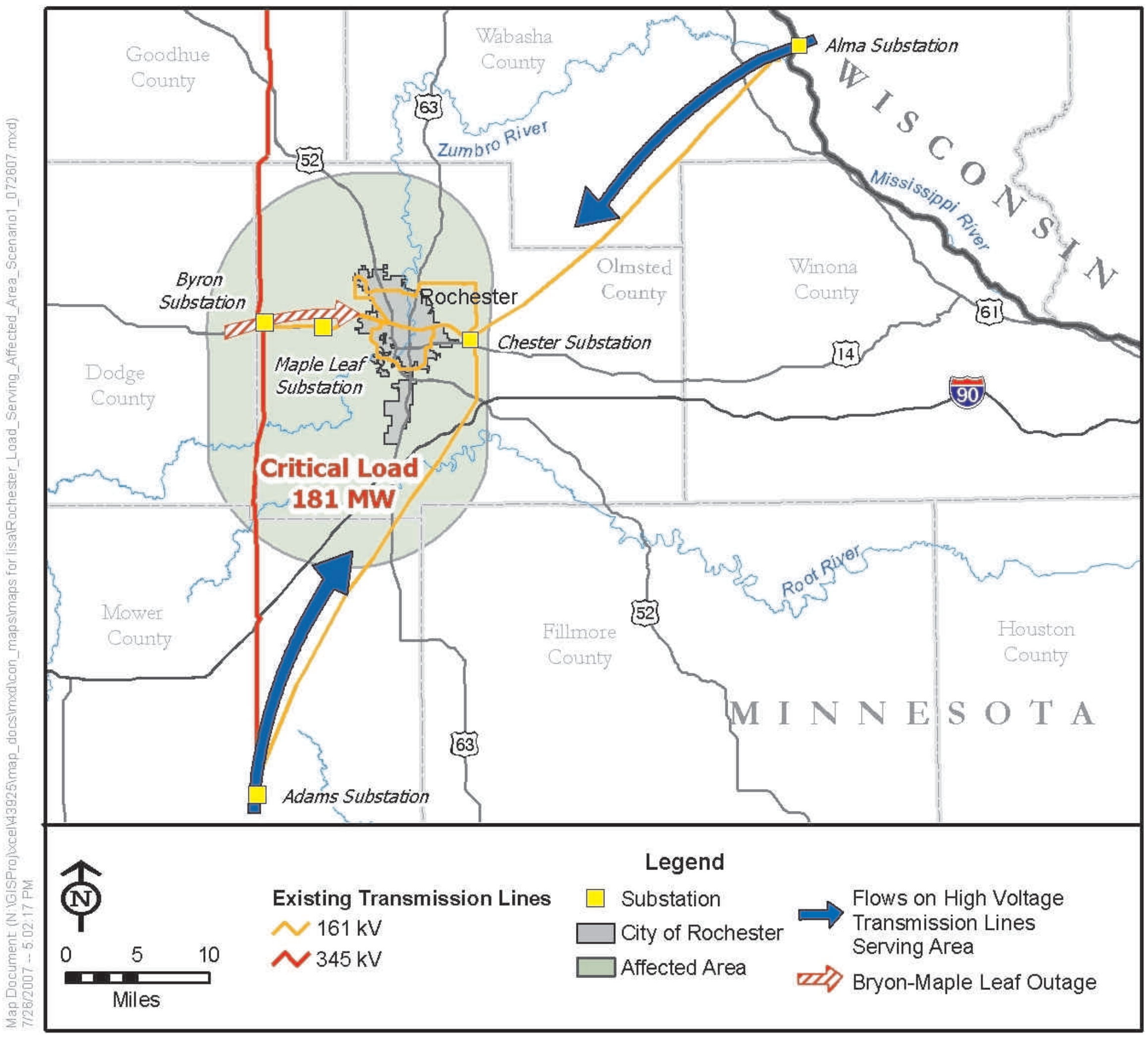
Based on the information in Figure M above, the 345 kV Project, which serves load reliably until 2050, will last until somewhere in the 2030 to post-2050 timeframe, with the exact year dependent on how load growth varies over the next forty years.

3.2 Needs for Rochester

In the Rochester area, electric reliability issues have arisen that are related to population growth and associated increase in electric power demands. The population of the Rochester Metropolitan Statistical Area has grown by 34 percent from 98,400 residents in 1985, to 131,400 residents in 2003. During that same period, peak electric power requirements for RPU increased by 88 percent, from 139 MW to 262 MW, and the peak electric power requirements for Peoples Cooperative Services increased 63 percent, from 22.4 MW to 36.7 MW. When the demand for electrical power exceeds 181 MW in the Rochester area, the failure of a single transmission line could cause service interruptions.

If the double circuit 161 kV transmission line from Byron, Minnesota that interconnects to the Maple Leaf and Cascade Creek substations is out of service, the remaining transmission system can only reliably deliver 181 MW of power to area substations. Figure M shows the system with the outage of the Byron – Maple Leaf/Cascade Creek transmission line and the resulting 181 MW critical load level.

Figure M: Affected Rochester Area Under Contingency



Under this critical contingency, there are only two 161 kV ties remaining to serve customers of RPU and Peoples Cooperative Services, a Dairyland Power Cooperative member cooperative. The two remaining Dairyland Power Cooperative-owned 161 kV lines provide the 181 MW import capability. Due to this limitation, RPU must run local generation when RPU's demand exceeds 145 MW to ensure reliable service to customers should the Byron – Maple Leaf 161 kV line lose service.

In 2005, the demand for power on the RPU system exceeded 145 MW for about 5,400 hours, or more than 61% of the time.

The system peak occurred in 2006 and reached 330 MW, and on August 12, 2010 the system reached 314 MW. With all local generation operating, the system can support up to 362 MW of demand in the Rochester area should a transmission line be out of service. While local generation operated in advance of the next line or power plant outage may support additional demand, running generation for system support to prepare for the next line or power plant to go out of service is not a desirable long-term solution because it is less reliable than transmission. In addition, the energy generated from the older facilities is normally more expensive than power purchased from MISO competitive markets. To address these needs, additional power sources into the Rochester area are needed.

3.2.1 Minnesota PUC Decision for Minnesota Facilities

In early study work, certain lower voltage alternative analysis was undertaken assuming a lower voltage alternative for both the Rochester and La Crosse load areas. However, the Minnesota Certificate of Need Order approved a double-circuit capable 345 kV design from the Hampton Substation to the Alma crossing. It also approved the North Rochester Substation and two 161 kV lines to the City of Rochester.[26] Based on this order, lower voltage alternatives discussed in this report have been amended to include the 345 kV line in Minnesota from Hampton to North Rochester and the 161 kV lines from North Rochester substation to serve the Rochester area loads, and lower voltage alternatives for the La Crosse area.

[26] Minnesota Certificate of Need Order at 18, 43-45.

4. ALTERNATIVES CONSIDERED

4.1 Identified Alternatives to Meet Local Load Serving and Regional Needs Considered Lesser-Performing

Since 2009, five lower voltage alternatives have been studied for the La Crosse area: a reconductor-only option, the 161 kV La Crosse Alternative, and three options for lower voltage lines on the North Rochester to La Crosse segments. These alternatives are discussed in more detail below, with performance and costs including transmission system losses summarized in Figures U and V in Section 4.2. The alternatives as they are described below only include costs for Wisconsin facilities, and do not describe the facilities necessary for Rochester load serving. The summary tables in Figures U and V include total costs for facilities for both load serving areas as well as breakdowns between Minnesota, Wisconsin and costs for transmission system losses.

4.1.1 Reconductor Option

The reconductor alternative would require multiple transmission line upgrades, new transformers and substation expansions. This alternative, as detailed in Figure N, would serve the load in the La Crosse area to the approximately 600 MW load level as compared to 750 MW for the 345 kV Project. In addition, there is less improvement to regional reliability than the 345 Project.

Upgrading these facilities would allow the transmission system to reliably serve load until 600 MW. To improve the load serving capability past the 600 MW load level, the La Crosse area needs a new transmission source. At this point a 345 kV line or yet another 161 kV line could be added as a source.

Figure N: Reconductor Only Alternative, Wisconsin Costs Only

Reconductor alternative - Wisconsin Costs ONLY

Rebuilds	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**69**	**69**
	Genoa - La Crosse Tap	**Coulee - La Crosse**	**Genoa - Coulee**	**Genoa - Lansing**	**Alma - Marshland**	**La Crosse – Mayfair**	**Marshland - La Crosse Tap**	**Tremval - Alma**	**Tremval - Mayfair**	**Coulee - Swift Creek**	**Coulee - Mt. La Crosse**
Length	21	8.5	19.5	20.5	27	4	24	34	31	2	5
Install	$12,500,000	$5,060,000	$11,600,000	$12,200,000	$16,070,000	$2,380,000	$14,280,000	$20,230,000	$18,450,000	$500,000	$1,250,000
ROW	$250,000	$100,000	$240,000	$250,000	$330,000	$50,000	$290,000	$410,000	$380,000	$20,000	$60,000
Overheads		$370,000	$840,000	$880,000	$1,160,000	$170,000	$1,030,000	$1,460,000	$1,340,000	$40,000	$90,000
Removal	$920,000	$370,000	$860,000	$900,000	$1,190,000	$180,000	$1,060,000	$1,500,000	$1,360,000	$78,000	$195,000
Environ fee	$640,000	$260,000	$590,000	$620,000	$820,000	$120,000	$730,000	$1,030,000	$940,000	$0	$0
subtotal	$14,310,000	$6,160,000	$14,130,000	$14,850,000	$19,570,000	$2,900,000	$17,390,000	$24,630,000	$22,470,000	$638,000	$1,595,000
Permitting, contingency	$2,150,000	$920,000	$2,120,000	$2,230,000	$2,940,000	$440,000	$2,610,000	$3,690,000	$3,370,000	$100,000	$240,000
	$16,460,000	$7,080,000	$16,250,000	$17,080,000	$22,510,000	$3,340,000	$20,000,000	$28,320,000	$25,840,000	$738,000	$1,835,000
Per mile	$783,810	$832,941	$833,333	$833,171	$833,704	$835,000	$833,333	$832,941	$833,548	$369,000	$367,000

Substation/Transformers

	Tremval	**La Crosse**	**Coulee**
Install and land	$2,195,000	$4,720,000	$11,033,000
Overheads	$67,826	$145,848	$340,920
Environmental Fee	$109,750	$236,000	$551,650
Subtotal	$2,372,576	$5,101,848	$11,925,570
Permitting, contingency	$355,886	$765,277	$1,788,835
	$2,728,462	$5,867,125	$13,714,405

Total Cost: **$181,762,992**

4.1.2 161 kV La Crosse Alternative (revised with MN 345 kV)

This alternative includes a new approximately 100-mile 161 kV line from Red Wing, Minnesota to La Crosse, Wisconsin with ties at the following substations: Spring Creek, Lake City, Alma, Marshland, Onalaska and La Crosse. In addition, this alternative includes a 345 kV line from Hampton, Minnesota to the North Rochester substation, and two 161 kV ties from North Rochester to the transmission system in the city of Rochester.[27]

The case used in the La Crosse 161 kV Alternative was created using the topology of a 2012 summer peak case and included a baseline load level of 491 MW in the La Crosse area.

In each of the identified contingencies, multiple existing lines needed to be rebuilt to solve the short-term needs and for the long-term needs an additional source needed to be added to the area. The identified new 161 kV source came from the Prairie Island generating plant at the Spring Creek Substation and tied in to the existing sources in the area in an effort to decrease the impact of future outages while increasing system stability at the same time.

This 161 kV source, in addition to the list of system upgrades in the reconductor option, Figure N, could serve load growth in the La Crosse area to the 750 MW load level, or approximately 2045. This is the same load level that the 345 kV Project could serve. This complete alternative is shown in Figure O below.

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[27] The initial 161 kV La Crosse Alternative included a lower voltage solution for Rochester. See Footnote 2.

Figure O: 161 kV La Crosse Alternative, Wisconsin Costs Only

161 kV alternative - Wisconsin costs ONLY

Rebuilds	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**69**	**69**
	Genoa - La Crosse Tap	**Coulee - La Crosse**	**Genoa - Coulee**	**Genoa - Lansing**	**Alma - Marshland**	**La Crosse – Mayfair**	**Marshland - La Crosse Tap**	**Tremval - Alma**	**Tremval - Mayfair**	**Coulee - Swift Creek**	**Coulee - Mt. La Crosse**
Length	21	8.5	19.5	20.5	27	4	24	34	31	2	5
Install	$12,500,000	$5,060,000	$11,600,000	$12,200,000	$16,070,000	$2,380,000	$14,280,000	$20,230,000	$18,450,000	$500,000	$1,250,000
ROW	$250,000	$100,000	$240,000	$250,000	$330,000	$50,000	$290,000	$410,000	$380,000	$20,000	$60,000
Overheads		$370,000	$840,000	$880,000	$1,160,000	$170,000	$1,030,000	$1,460,000	$1,340,000	$40,000	$90,000
Removal	$920,000	$370,000	$860,000	$900,000	$1,190,000	$180,000	$1,060,000	$1,500,000	$1,360,000	$78,000	$195,000
Environ fee	$640,000	$260,000	$590,000	$620,000	$820,000	$120,000	$730,000	$1,030,000	$940,000	$0	$0
subtotal	$14,310,000	$6,160,000	$14,130,000	$14,850,000	$19,570,000	$2,900,000	$17,390,000	$24,630,000	$22,470,000	$638,000	$1,595,000
Permitting, contingency	$2,150,000	$920,000	$2,120,000	$2,230,000	$2,940,000	$440,000	$2,610,000	$3,690,000	$3,370,000	$100,000	$240,000
	$16,460,000	$7,080,000	$16,250,000	$17,080,000	$22,510,000	$3,340,000	$20,000,000	$28,320,000	$25,840,000	$738,000	$1,835,000
Per mile	$783,810	$832,941	$833,333	$833,171	$833,704	$835,000	$833,333	$832,941	$833,548	$369,000	$367,000

New Line	**161**	**161**	**161**	**161**	**161**
	Alma - Marshland #2	**Marshland - Onalaska**	**Onalaska - La Crosse**	**Spring Creek - Lake City**	**Lake City - Alma**
Length	28	26	5	20	22
Install	$16,660,000	$15,470,000	$2,980,000	$11,900,000	$13,090,000
ROW	$1,360,000	$1,260,000	$240,000	$970,000	$1,070,000
Overheads	$1,280,000	$1,190,000	$230,000	$910,000	$1,000,000
Removal	$1,230,000	$1,140,000	$220,000	$880,000	$970,000
Environ fee	$900,000	$840,000	$160,000	n/a	n/a
River Crossing					$10,000,000
subtotal	$21,430,000	$19,900,000	$3,830,000	$14,660,000	$26,130,000
Permitting, contingency	$3,210,000	$2,990,000	$570,000	$2,200,000	$3,920,000
	$24,640,000	$22,890,000	$4,400,000	$16,860,000	$30,050,000
Per mile	$880,000	$880,385	$880,000	$843,000	$1,365,909

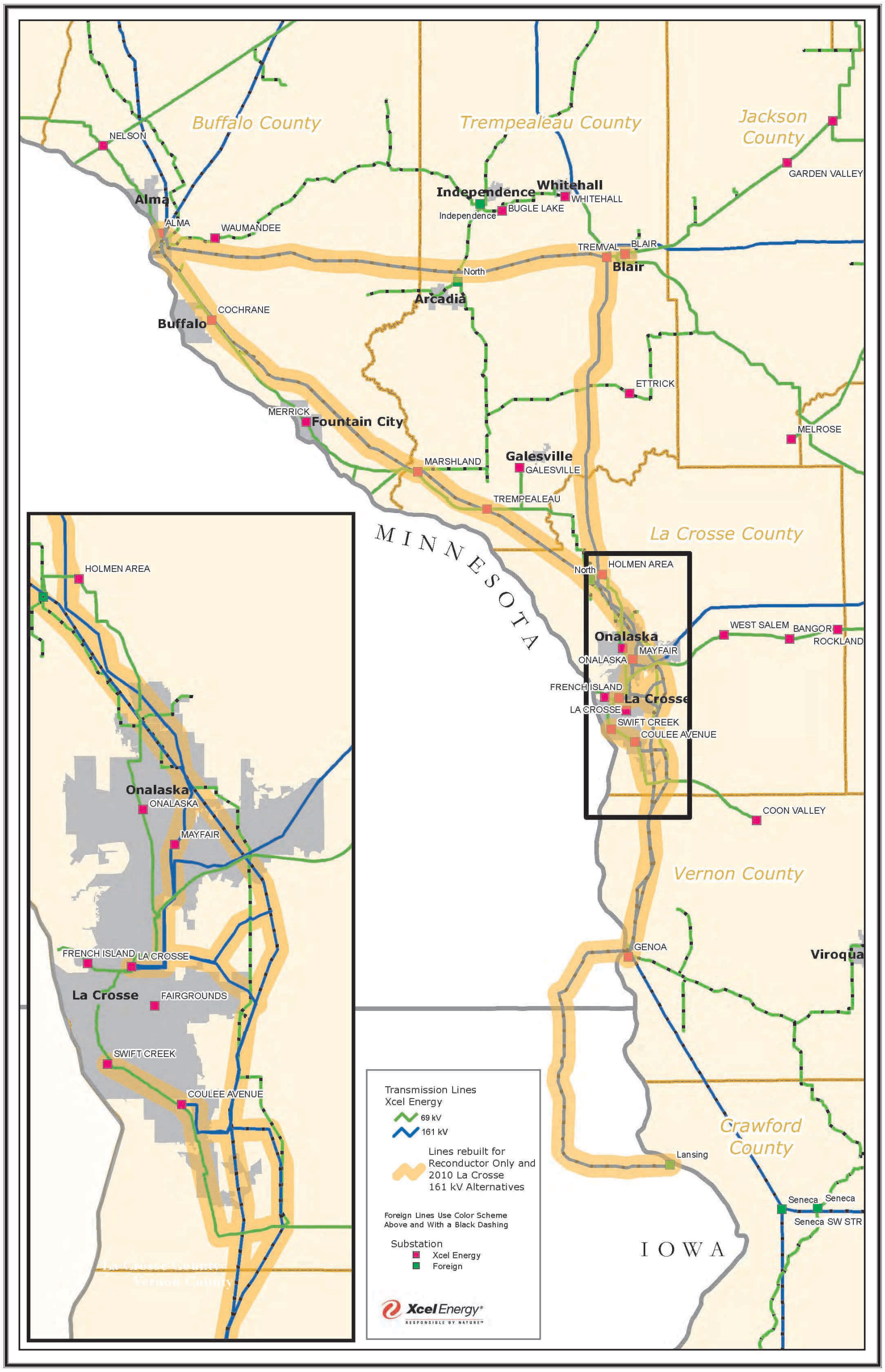
Substation/Transformers

	Tremval	Coulee	Onalaska	Lake City	Spring Creek	Alma	Marshland Termination		
Install and land	$2,195,000	$11,033,000	$13,363,000	$13,363,000	$2,195,000	$13,363,000			
Overheads	$67,826	$340,920	$412,917	$412,917	$67,826	$412,917			
Environmental Fee	$109,750	$551,650	$668,150	$668,150	$109,750	$668,150			
Subtotal	$2,372,576	$11,925,570	$14,444,067	$14,444,067	$2,372,576	$14,444,067		**Total Cost:**	**$332,296,360**
Permitting, contingency	$355,886	$1,788,835	$2,166,610	$2,166,610	$355,886	$2,166,610			
	$2,728,462	$13,714,405	$16,610,677	$16,610,677	$2,728,462	$16,610,677	$5,000,000		

The Reconductor Only Alternative and the 161 kV La Crosse Alternative assume almost 200 miles of transmission reconductors and rebuilds in and around the city of La Crosse. Figure P shows the La Crosse area transmission system with the yellow highlighted lines being the ones assumed to be reconductored or rebuilt for these two options.

The 161 kV North Rochester – Briggs Road (revised to serve 750 MW) Alternative discussed below in Section 4.1.1.3 also includes this set of reconductors/rebuilds as shown in Figure P.

Figure P: La Crosse Area Transmission System, Reconductor Only Alternative



4.1.3 PSCW Alternatives

In 2010 the PSCW requested that the electrical performance of three additional lower voltage alternatives be studied. All three included a 345 kV line from Hampton– North Rochester and the North Rochester substation. The three alternatives also included one of the following:

1. A single 161 kV line from North Rochester Substation to La Crosse
2. A double circuit 161 kV line from North Rochester to La Crosse
3. A single 230 kV line from North Rochester to La Crosse

(i) 161 kV North Rochester – Briggs Road Alternative

Adding a single 161 kV line between North Rochester and Briggs Road 161 kV buses in the powerflow model instead of the proposed 345 kV line was capable of reliably serving load to the 550 MW load level.

At that point multiple bulk system transformers and 161 kV transmission lines in the immediate La Crosse area will overload requiring significant system improvements.

In addition, as discussed in Section 3.2.1, the MPUC considered the 161 kV alternative for Rochester and issued a Certificate of Need Order for a 345 kV transmission line in Minnesota, from Hampton to North Rochester and to the Mississippi River. The load serving performance and cost estimates for these alternatives are included in Figure U.

In the development of this supplemental need report, planning engineers studied what would be necessary to allow the 161 kV North Rochester – Briggs Road Alternative to serve the load level obtainable with the 345 kV Project and the La Crosse 161 kV Alternative. Analysis showed that tapping the line into the existing Alma station and including the 200 miles of reconductors/rebuilds from the Reconductor Only Alternative would allow the alternative to reliably serve 750 MW of load for a cost of $456 million. This alternative, referred to in this report as the 161 kV North Rochester – Briggs Road (revised to serve 750 MW) Alternative, is also included in the summary table in Figure T and detailed cost is shown below in Figure Q.

(ii) Double Circuit 161 kV North Rochester – Briggs Road Alternative

Similar to the 161 kV North Rochester – Briggs Road Alternative, adding a double circuit 161 kV line between North Rochester and Briggs Road 161 kV buses in the powerflow model instead of the 345 kV Project was capable of reliably serving load until the 600 MW load level. Due to the double circuit line being treated as a single transmission element contingency, this provided minimal benefit beyond the 161 kV North Rochester – Briggs Road Alternative.

At the 600 MW level, multiple bulk system transformers and 69 kV and 161 kV transmission lines will overload under contingency.

Also of significance with a double circuit option, the 345 kV Project assumes co-location with existing 161 kV and 69 kV transmission lines for a majority of the route.

(iii) 230 kV North Rochester – Briggs Road Alternative

Planning engineers determined that although a 230 kV North Rochester – Briggs Road Alternative is feasible, past planning efforts for other areas indicated it would provide system benefits comparable to the 161 kV and Double Circuit 161 kV North Rochester - Briggs Road Alternatives for each community (approximately 550 MW), but at a higher cost due to the need for major installations to accommodate the new voltage. There are also other reasons that the study team does not endorse a 230 kV alternative.

The primary reason is that a 230 kV alternative would introduce a new voltage in each of the three areas where the Project connects: SE Twin Cities (Prairie Island/Hampton area), Rochester, and La Crosse. In these areas 345 kV, 161 kV and 69 kV voltages are the primary transmission voltages. When a new voltage is introduced there are significant cost implications to incorporate the nonstandard transformers and substation equipment necessary to transform from 345 kV to 230 kV, and then to the local area lower voltages of 161 kV and 69 kV. Since there were no existing 230 kV lines in the area and no plans in the future, 230 kV was not included. 230/161 kV transformers are not industry standard, and are extremely rare. 25 out of 18,174 transformers, or approximately 0.14%, of the total transformers in the MRO models are 230/161 kV units.

Figure Q: 161 kV North Rochester – Briggs Road (revised to serve 750 MW) Alternative, Wisconsin and Minnesota Costs

			161 kV North Rochester - Briggs Road (revised to serve 750 MW)											
Rebuilds	**345 and 161**	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**69**	**69**	
	Minnesota Costs	**Wisconsin portion of N. Rochester - Briggs Road**	**Genoa - La Crosse Tap**	**Coulee - La Crosse**	**Genoa - Coulee**	**Genoa - Lansing**	**Alma - Marshland**	**La Crosse - Mayfair**	**Marshland - La Crosse Tap**	**Tremval - Alma**	**Tremval - Mayfair**	**Coulee - Swift Creek**	**Coulee - Mt. La Crosse**	**Total**
Length			21	8.5	19.5	20.5	27	4	24	34	31	2	5	197
Install			$12,500,000	$5,060,000	$11,600,000	$12,200,000	$16,070,000	$2,380,000	$14,280,000	$20,230,000	$18,450,000	$500,000	$1,250,000	
ROW			$250,000	$100,000	$240,000	$250,000	$330,000	$50,000	$290,000	$410,000	$380,000	$20,000	$60,000	
Overheads				$370,000	$840,000	$880,000	$1,160,000	$170,000	$1,030,000	$1,460,000	$1,340,000	$40,000	$90,000	
Removal			$920,000	$370,000	$860,000	$900,000	$1,190,000	$180,000	$1,060,000	$1,500,000	$1,360,000	$78,000	$195,000	
Environ fee			$640,000	$260,000	$590,000	$620,000	$820,000	$120,000	$730,000	$1,030,000	$940,000	$0	$0	
subtotal			$14,310,000	$6,160,000	$14,130,000	$14,850,000	$19,570,000	$2,900,000	$17,390,000	$24,630,000	$22,470,000	$638,000	$1,595,000	
Permitting, contingency			$2,150,000	$920,000	$2,120,000	$2,230,000	$2,940,000	$440,000	$2,610,000	$3,690,000	$3,370,000	$100,000	$240,000	
	$179,000,000	$70,000,000	$16,460,000	$7,080,000	$16,250,000	$17,080,000	$22,510,000	$3,340,000	$20,000,000	$28,320,000	$25,840,000	$738,000	$1,835,000	$408,453,000
Per mile			$783,810	$832,941	$833,333	$833,171	$833,704	$835,000	$833,333	$832,941	$833,548	$369,000	$367,000	

Substation/Transformers

	Tremval	**La Crosse**	**Coulee**	**Alma**	
Install and land	$2,195,000	$4,720,000	$11,033,000	$13,363,000	
Overheads	$67,826	$145,848	$340,920	$412,917	
Environmental Fee	$109,750	$236,000	$551,650	$668,150	
Subtotal	$2,372,576	$5,101,848	$11,925,570	$14,444,067	
Permitting, contingency	$355,886	$765,277	$1,788,835	$2,166,610	
	$2,728,462	$5,867,125	$13,714,405	$16,610,677	$38,920,669
					$447,373,669

4.2 Loss Calculations

New transmission lines added to the electric system affect the resistive losses of the system. In turn, the costs for capacity and energy for the system are affected. If adding a new transmission line reduces losses, capacity and energy costs are reduced.

Loss effects have been analyzed for the 345 kV Project and 161 kV alternatives. Based on the spreadsheet in Figure R below, $4,499,904 is the present value of cost of capacity and energy for a 1 MW loss reduction.

Figure R: Computation of Equivalent Capitalized Value for Losses

Computation of Equivalent Capitalized Value for Losses
(based on 1.00 MW loss on -peak)
(pool reserve requirement of x% specified below)

Input Assumptions

Term of loss reduction	40	yrs	Present Value of Annuity factor	11.54	< Losses
Assumed life, xmsn	35	yrs	Present Value of Annuity factor	11.30	< Transmission
Discount rate	8.31	%/yr			
Energy value	$37.15	MWh			
Loss Factor	0.30				
Transmission FCR	0.1403				

Calculation

					Generation FCR	Levelized Annual Revenue Rqmt	Cum PW of Rev Req
Capacity value:	50	% peaking @	$615	/kW	0.1275	$39,218	
	50	% baseload @	$3,370	/kW	0.1275	$214,833	
					$	254,051	$
	15%	reserve requirement:				292,158	3,372,815
Energy Value:	1.00	8760 hr/yr	0.30	$37 /MWh		97,630	$ 1,127,089
				Total annual cost, capacity & energy:	$	389,789	4,499,904

Present Value Annuity factor Losses	11.54
Cum PV Losses $	4,499,904
Equivalent Transmission investment $	**2,838,174**
is Cum PV Losses / FCR trans / PVA trans	

Xcel Energy Services

Figure S below shows the loss performance comparison of the 345 kV Project and lower voltage alternatives for serving La Crosse area load growth. The loss improvements shown are relative to the base model used for the analysis of the 345 kV Project and lower voltage alternatives. The base model does not include any of the facilities proposed in the 345 kV Project or its alternatives. These loss savings are included in the alternative summary charts calculations of total costs in Figures U and V. (Section 4.3)

Figure S: Losses Performance Comparison in 2010 $[28]

Year	Case	System Losses/ MW	System Loss difference from 345-kV case/ MW	Annual energy loss savings/ GWh	Present Value of Capacity and Energy Cost Savings/ M$
2012	Base model as revised	18699.59	-10	-26	-45
2012	345 kV Project	18689.71	0	0	0
2012	La Crosse 161 kV Alternative	18690.59	-1	-3	-5
2012	Reconductor Only	18697.40	-8	-21	-36
2012	230 kV North Rochester – Briggs Road Alternative	18694.12	-4	-11	-18
2012	North Rochester-Briggs Road single 161 kV line	18696.53	-7	-18	-32
2012	161 kV North Rochester-Briggs Road (revised to serve 750 MW)	18691.63	-2	-5	-9
2012	Double Circuit 161 kV North Rochester-Briggs Road Alternative	18695.11	-5	-13	-23

4.3 Summary Tables of Lower Voltage Alternatives

Figures T and U below summarize the performance and cost of all alternatives studied for this project. Included are costs by state, total cost, load serving capability in MW, cost associated with losses on the transmission system, and a summary of reliability and/or right of way issues with the alternative. Figure T compares the

[28] The additional cost for losses is lower for the La Crosse 161 kV Alternative when the addition of the 345 kV facilities from Hampton, Minnesota to Rochester, Minnesota is included in the model. Loss savings are lower for the 345 kV Project when compared to the 161 kV North Rochester – Briggs Road (revised to serve 750 MW) Alternative because of the quantity of rebuilds to lower impedance conductor in the La Crosse area included in the alternative.

alternatives which serve load to the 750 MW load level. Alternatively, Figure U compares the alternatives with a lower load serving capability.

Note that for Figures T and U the following apply:

- 345 kV, 230 kV and 161 kV alternatives all assume the same routes and configurations as proposed in Wisconsin CPCN and Minnesota route permit application, which include plans to double circuit sections with existing transmission facilities (such as Dairyland Power Cooperative's Q3 route in Minnesota and Dairyland Power Cooperative’s Q1 route in Wisconsin).

- Estimates are in 2010 dollars.

- The PSCW requested alterative double circuit 161 kV/161 kV from North Rochester to La Crosse scenario assumes building adjacent to the existing underlying transmission facilities. It is important to note that feasibility of this adjacent configuration has not been investigated. In some places, such as portions of the Q1 route, there is no room for building adjacent to the existing 161 kV line.

Figure T: Performance and Cost Analysis for Alternatives That Serve 750 MW of La Crosse Area Load (approximately 2045)

Option	La Crosse Area Load Serving Capability (MW)	Planning Level Screening Estimates (Excludes escalation, AFUDC, overheads, etc. Includes EIF)	Total Project Cost (escalated to in-service year dollars, includes precertification, overheads, AFUDC, etc.)	Planning Level Screening Estimates (Excludes escalation, AFUDC, overheads, etc. Includes EIF)	Cost of Transmission Losses Relative to the Proposed Project	TOTAL COST OF ALTERNATIVE	Regional System Reliability Issues for Alternatives	Siting and Land Acquisition Issues for Alternatives
		Total Project - Wisconsin + Minnesota	**Minnesota Costs Only**	**Wisconsin Costs Only**		**Total Project - Wisconsin + Minnesota + System Losses**		
345 kV Project	750 MW	$493 million	$292 million	$201 million + $14 million[29]	$0	**$507 million**	Serves as foundational facilities for approximately 1200 MW of future transfer capability between Minnesota and Wisconsin. Approximately 850 MW provided with the 345 kV Project, and an additional 400 MW as the 345 kV system continues East.	Limited new ROW needed, collocating with existing transmission for the majority of the route.
161 kV North Rochester – Briggs Road (revised to serve 750 MW)	750 MW	$447 million	$179 million	$268 million	$9 million	**$456 million**	Does not add necessary foundational facilities to facilitate future transfer capability between Minnesota and Wisconsin – reduces future capability as EHV transmission expands east	200 miles of 161 kV rebuilds in the La Crosse area are necessary for this alternative. Potential for routing hurdles and resulting cost additions
La Crosse 161kV Alternative	750 MW	$488 million	$156 million	$332 million	$3 million	**$491 million**	Does not add necessary foundational facilities to facilitate future transfer capability between Minnesota and Wisconsin – reduces future capability as EHV transmission expands east by approximately 1400 MW	100 miles of new 161 kV ROW and 200 miles of 161 kV rebuilds in the La Crosse area are necessary for this alternative, including a new 161 kV Mississippi River crossing. Major routing hurdles and resulting cost additions expected.

[29] $14 million assumed for 345 kV Project for future rebuild of a 7.5 mile portion of Briggs Road - Mayfair 161 kV line and a 9 mile portion of the Briggs Road – La Crosse Tap 161 kV line

Figure U: Performance and Cost Analysis for Alternatives That Have a Reduced La Crosse Load Serving New Line Capability Below 750 MW

Option	La Crosse Area Load Serving Capability (MW)	Planning Level Screening Estimates (Excludes escalation, AFUDC, overheads, etc. Includes EIF)	Total Project Cost (escalated to in-service year dollars, includes precertification, overheads, AFUDC, etc.)	Planning Level Screening Estimates (Excludes escalation, AFUDC, overheads, etc. Includes EIF)	Cost of Transmission Losses Relative to the Proposed Project	TOTAL COST OF ALTERNATIVE	Regional System Reliability Issues for Alternatives	Siting and Land Acquisition Issues for Alternatives
		Total Project - Wisconsin + Minnesota	**Minnesota Costs Only**	**Wisconsin Costs Only**		**Total Project - Wisconsin + Minnesota + Transmission Losses**		
161 kV North Rochester - Briggs Road Alternative	550 MW	$249 million	$179 million	$70 million	$32 million	**$281 million**	Does not add necessary foundational facilities to facilitate future transfer capability between Minnesota and Wisconsin – reduces future capability as EHV transmission expands east	None
Double Circuit 161 kV North Rochester - Briggs Road Alternative	600 MW	$303 million + significant cost addition for new right of way	$208 million + significant cost addition for new right of way	$95 million + significant cost addition for new right of way	$23 million	**$326 million + significant cost addition for new right of way**	Comparable performance to 161 kV options with higher cost Does not add necessary foundational facilities to facilitate future transfer capability between Minnesota and Wisconsin – reduces future capability as EHV transmission expands east	Double circuit 161 kV requires new ROW and route. Alternative route from existing DPC 161 kV Q1 line would be desired. Likely to require different river crossing. Major routing hurdles expected if not using existing ROW.
La Crosse Reconductor Only Alternative	600 MVA	$229 million	$47 million	$182 million	$36 million	**$265 million**	Does not add necessary foundational facilities to facilitate future transfer capability between Minnesota and Wisconsin.	200 miles of 161 kV rebuilds in the La Crosse area are necessary for this alternative. Potential for routing hurdles and resulting cost additions

Figure U: Performance and Cost Analysis for Alternatives That Have a Reduced La Crosse Load Serving New Line Capability Below 750 MW (continued)

Option	La Crosse Area Load Serving Capability (MW)	Planning Level Screening Estimates (Excludes escalation, AFUDC, overheads, etc. Includes EIF)	Total Project Cost (escalated to in-service year dollars, includes precertification, overheads, AFUDC, etc.)	Planning Level Screening Estimates (Excludes escalation, AFUDC, overheads, etc. Includes EIF)	Cost of Transmission Losses Relative to the Proposed Project	TOTAL COST OF ALTERNATIVE	Regional System Reliability Issues for Alternatives	Siting and Land Acquisition Issues for Alternatives
		Total Project - Wisconsin + Minnesota	Minnesota Costs Only	Wisconsin Costs Only		Total Project - Wisconsin + Minnesota + Transmission Losses		
La Crosse Reconductor Only (revised with MN 345 kV) Alternative	600 MW	$338 million	$156 million	$182 million	$36 million	**$374 million**[30]	Does not add necessary foundational facilities to facilitate future transfer capability between Minnesota and Wisconsin.	200 miles of 161 kV rebuilds in the La Crosse area are necessary for this alternative. Potential for routing hurdles and resulting cost additions.
230 kV North Rochester - Briggs Road Alternative	550 MW	$294 million	$211 million	$83 million	$18 million	**$312 million**	Comparable performance to single 161 kV options with higher cost New voltage introduced into both Rochester and La Crosse area. Non-standard 230/161 kV transformers (0.14% of transformers on MRO model)	None

[30] Total cost of the La Crosse Reconductor Only (revised with MN 345 kV) Alternative becomes $510 million ($292 million Minnesota costs) if the 345 kV line from North Rochester to the Mississippi River is included. The load serving capability does not change, and remains at 600 MW.

4.4 Transfer Analysis

In addition to the factors summarized in Figures U and V, thermal transfer capability between Minnesota and Wisconsin was also analyzed for the 345 kV Project and compared to the La Crosse 161 kV Alternative. The transfer capability of the reconductor only option was not studied as it does not add a new facility across the existing transmission constraint. The other alternatives were excluded because they did not provide 750 MW of load serving capability in the La Crosse area.

Xcel Energy and ATC have recently studied a 345 kV line connecting the La Crosse area to potential endpoints to the south and east (La Crosse - Madison 345 kV Project). The Xcel Energy/ATC anticipated La Crosse – SE Wisconsin line is an independent project. Nevertheless, it is slated to be approved in MISO's MTEP Appendix A as a MVP in late 2011.

The 345 kV Project is needed to meet the identified local and regional needs regardless of whether additional facilities are constructed to the east. However, it is recognized that additional high voltage connections to La Crosse will provide additional electrical system benefits. The 345 kV Project would enhance those system benefits.

As shown in Figure V and discussed below, the 345 kV Project from Hampton to La Crosse acts as a first step towards increased regional transfer capability. Alternatively, if a lower voltage alternative were constructed to serve the La Crosse area load, future transfer capability is limited, and in fact reduced below today's values, as future 345 kV facilities to the east, such as La Crosse - Madison, are added to the transmission system. Under these conditions, a 345 kV line would need to be constructed in the future between the Minnesota and Wisconsin 345 kV systems to alleviate the limitations as shown in Figure V below when there are 345 kV facilities from Minnesota to the 345 kV system in the Madison or Appleton, Wisconsin areas.

In the transfer analysis, four conditions were picked for both the La Crosse 161 kV and a 345 kV option in La Crosse. The four conditions studied for each voltage option were:

1. The system without the 345 kV Project. This case was set as the base case, with all options showing either a positive or negative impact on transfer capability between Minnesota and Wisconsin in comparison to this base case.

2. The system with either the 345 kV Project or the 161 kV Alternative alone
3. The system with the 345 kV Project plus a 345 kV line to Madison, WI
4. The system with the 345 kV Project plus a 345 kV to Appleton, WI.

The transfer capability analysis here is presented to provide information about the immediate comparative capability of the alternatives as well as the future comparative capability of the alternatives based on a future 345 kV connection further to the east. The analysis does not prejudge the probability of an eastern 345 kV connection, but instead merely considers the high probability that MISO will approve a 345 kV connection between La Crosse and Madison in late 2011. See Section 2.6 above for additional discussion of the MISO Candidate MVP study and anticipated approval.

If it is assumed that the Eau Claire – Arpin special protection system ("SPS") will not be retired in the future, the chart below shows that either voltage works well in the near term. However, as soon as a 345 kV line to the east is built, the 345 kV Project adds considerable transfer capability to the system.

Although it is not the intent today of the 345 kV Project to retire the Eau Claire – Arpin SPS, it is a possibility that a 345 kV line to the east could eliminate the need for this SPS, and the second chart on Figure V shows the transfer results following that potential retirement.

Figure V: Transfer Capability for the 345 kV Project vs. 161 kV Alternative[31]

Source (MN): Great River Energy, Minnesota Power, Otter Tail Power Co, and Xcel Energy - MN

Sink (WI): Alliant Energy East, Madison Gas and Electric Co, Upper Peninsula Power Co, and Wisconsin Energy Corp

KEEPING Eau Claire - Arpin SPS

Transfer Analysis	Before CAPX	Plus La Crosse Project	Plus 345 kV line to Madison, WI	Plus 345 kV line to North Appleton, WI
CAPX La Crosse 345 kV Line	0	838	1236	1144
161 kV Alternative Option	0	775	-692	-636

RETIRING Eau Claire - Arpin SPS

Transfer Analysis	Before CAPX	Plus La Crosse Project	Plus 345 kV line to Madison, WI	Plus 345 kV line to North Appleton, WI
CAPX La Crosse 345 kV Line	0	370	663	794
161 kV Alternative Option	0	-944	-1168	-1043

The powerflow case used for the transfer analysis and the applicable idev files will be supplied to the PSCW upon request.

[31] Transfer analysis is stated for thermal limitations only and does not serve as a redefinition of the existing MWEX interface, but rather shows that the 345 kV Project will provide necessary foundational facilities to increase transfers across MWEX.

5. CONCLUSION

It has been nearly three decades since the electrical network serving Minnesota and western Wisconsin, has been expanded to any significant degree. At the same time, the demand for power has continued to grow.

Forecast information shows that the La Crosse area began exceeding the ability of the system to provide power during certain contingent conditions in 2006. In the event of a critical transmission line failure during at time when existing generation is not available, outage load levels in excess of 430 MW will not be able to be served. The local system relies heavily on generation at Genoa and Alma to maintain the reliability of service to the area. If a transmission line should fail, the outage of either of those plants severely restricts the amount of power that can be delivered, even with the French Island peaking generator on.

Load data also shows that demand in the Rochester area currently exceeds the level at which the electrical system can reliably serve customers. As growth continues, this deficit will increase.

The 345 kV Project is the most prudent alternative because it best addresses the regional as well as the local area needs. The 345 kV Project as well as several of the lower voltage alternatives will provide community support for the La Crosse and Rochester areas until mid-century based on current projections. However, the 345 kV Project will help strengthen the 345 kV backbone regional transmission system and provide foundational facilities for up to 1200 MW of additional transfer capability. It will also reduce MISO-identified congestion constraints between Minnesota and Wisconsin. The 345 kV Project will be a critical component, along with the other CapX2020 projects, necessary to strengthen the transmission network to meet future demand for electrical power anticipated in Minnesota, Wisconsin and parts of surrounding states while creating flexibility to accommodate multiple future bulk transmission system build-outs.

6. APPENDIX A: PROJECT AND ALTERNATIVE GRAPHICS

Figure A: 345 kV Project

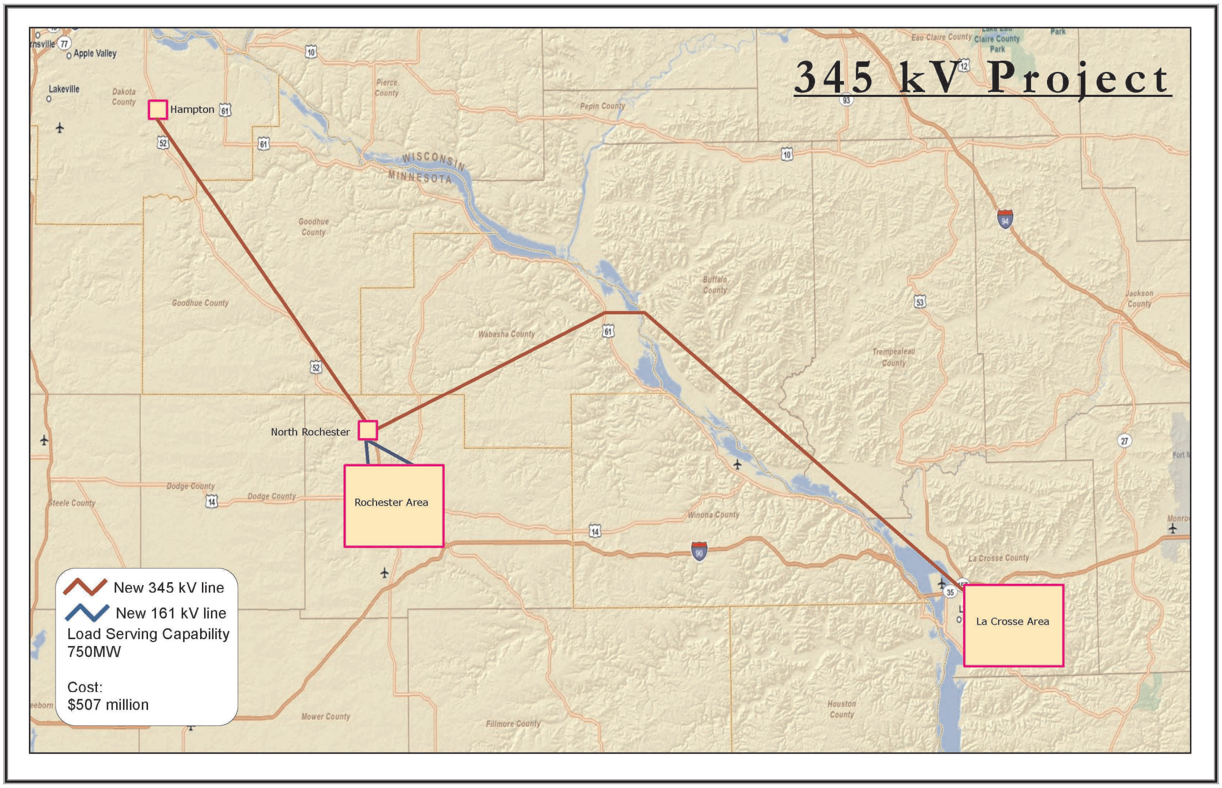


Figure B: La Crosse 161 kV Alternative

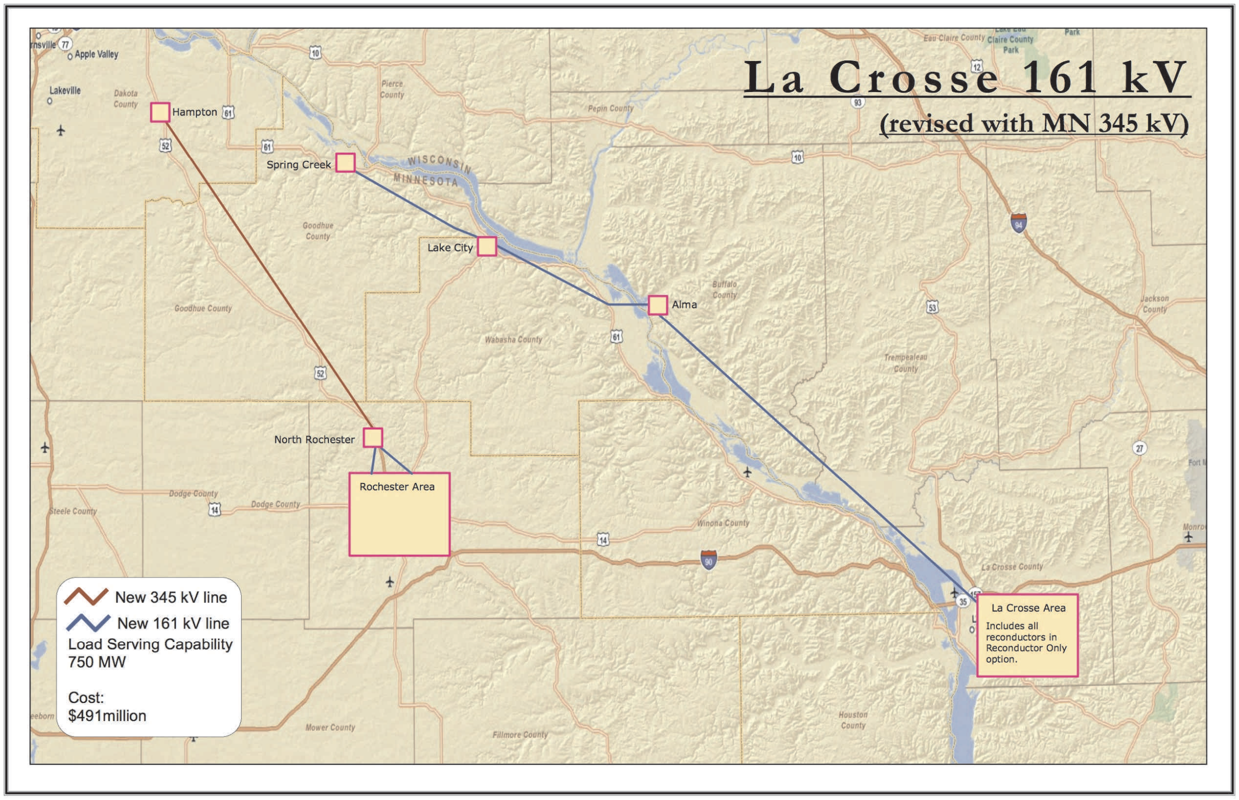


Figure C: Initial 161 kV North Rochester – Briggs Road Alternative

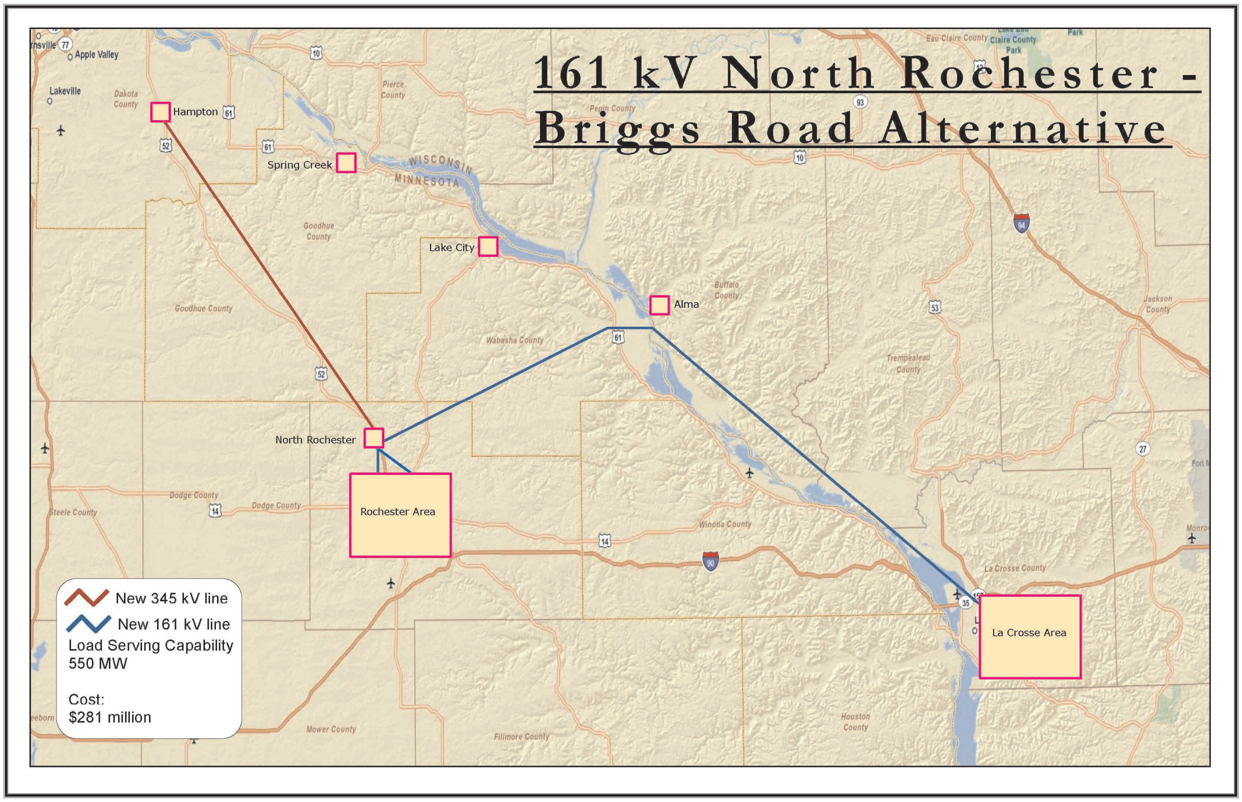


Figure D: 161 kV North Rochester – Briggs Road (revised to serve to 750 MW) Alternative

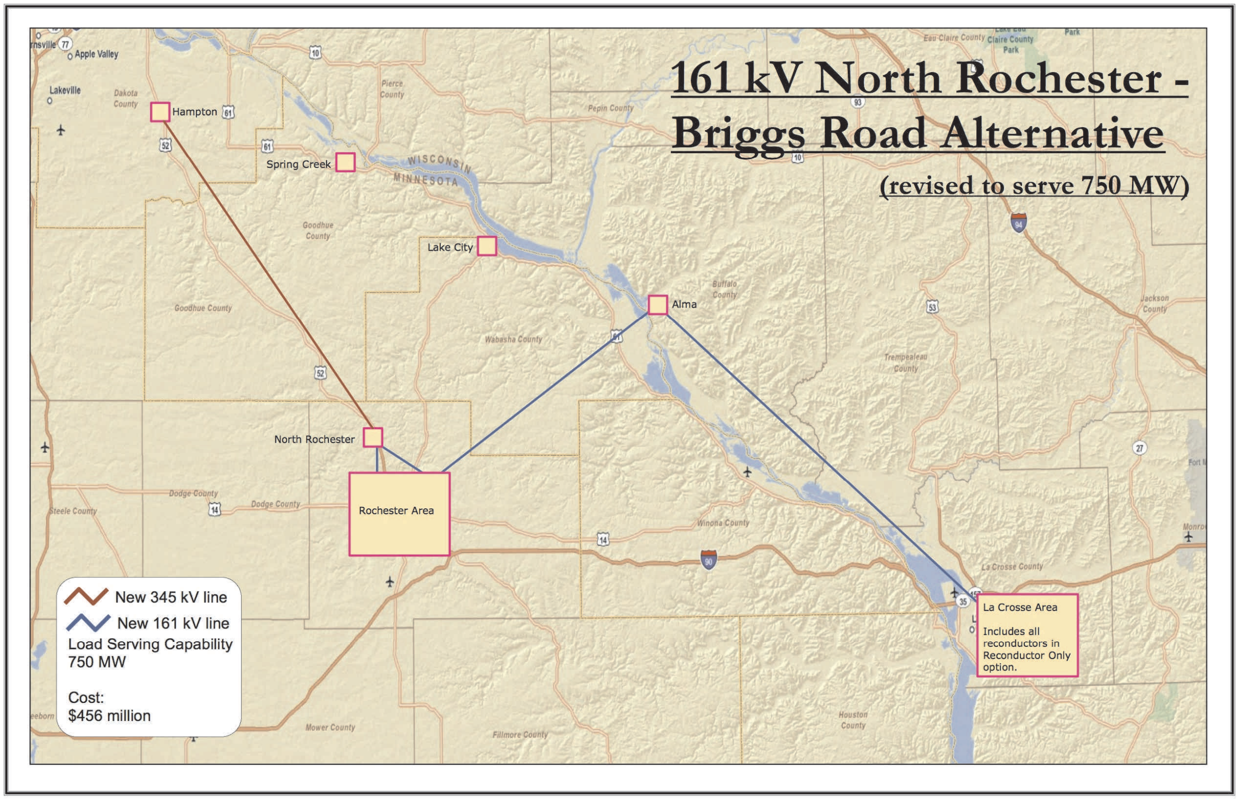


Figure P: La Crosse Area Transmission System, Reconductor Only Alternative