APPLICATION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR A CERTIFICATE OF NEED FOR THE HUNTLEY-WILMARTH 345 KV TRANSMISSION LINE PROJECT

MPUC Docket No. E-002, ET6675/CN-17-184

January 17, 2018

Submitted by
Northern States Power Company and ITC Midwest LLC

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APPENDICES

[1] This spreadsheet is used by ITC Midwest to evaluate alternatives in a Certificate of Need proceeding before the Minnesota Public Utilities Commission. The spreadsheet was created pursuant to the Commission's November 25, 2014 order in Docket No. ET6675/CN-12-1053 for ITC Midwest to develop a spreadsheet to calculate the cost of alternatives, including the Commission's CO2 internal cost and externality values.

1. EXECUTIVE SUMMARY

1.1 Introduction

Northern States Power Company, doing business as Xcel Energy, and ITC Midwest LLC (ITC Midwest) (collectively, the Applicants) request a Certificate of Need from the Minnesota Public Utilities Commission (Commission) to construct an approximately 50-mile 345 kilovolt (kV) transmission line between Xcel Energy's existing Wilmarth Substation north of Mankato, Minnesota, and ITC Midwest's Huntley Substation south of Winnebago, Minnesota (Project or Huntley-Wilmarth Project).

The Huntley-Wilmarth Project was studied, reviewed, and approved by the Midcontinent Independent System Operator, Inc.'s (MISO) Board of Directors as a Market Efficiency Project (MEP) in December 2016 in its annual Transmission Expansion Plan (MTEP16) report.

This Project is the first MEP brought forward for Commission approval in this state. As an MEP, the primary need for this Project is different than other transmission projects in Minnesota which have been reliability or generation outlet projects. An MEP is needed to reduce transmission system congestion which will improve the efficiency of MISO's energy market resulting in lower wholesale energy costs.

Congestion on the electrical system is like a traffic jam along a highway in that when the generators and consumers of electricity want to produce and consume more energy than the transmission system has the ability to carry at that time, the result is that the energy is unable to travel along the congested path. The Minnesota/Iowa border is one of the most congested areas in the region's electric transmission system. Without a solution, additional wind facilities constructed along the border will worsen congestion. The Project is needed to relieve the transmission congestion in this area and increase market access to lower cost generation, thereby providing economic benefits through reduced wholesale energy costs. The Project will also strengthen the resiliency of the regional grid and improve the deliverability of energy by reducing curtailments of wind generators. In addition, the Project will make the Minnesota transmission system more robust because, under a variety of future scenarios, it will increase deliverability of energy, improve the ability of the transmission system to respond to different contingencies, and provide economic benefits.

In its MTEP16 analyses, MISO found that the Project will provide net economic benefits and fully relieve congestion on the transmission system along the Minnesota/Iowa border. The Applicants' analyses using MTEP17 models and Futures[2] show increased economic benefits and congestion relief that go beyond MISO's initial projections as set forth in its MTEP16 analyses.

The Applicants submit this Certificate of Need Application (Application) to the Commission pursuant to Minn. Stat. § 216B.243 and Minn. R. Ch. 7849. To facilitate review, a completeness checklist is included as Appendix A which provides a roadmap identifying where in this Application information required by Minnesota statutes and rules can be found.

The Applicants will also apply for a Route Permit for the Project (Docket No. E002, ET6675/TL-17-185) as required by Minn. Stat. § 216E03. The Applicants request that the Commission order that the two proceedings be coordinated pursuant to Minn. Stat. § 216B.243, subd. 4 and Minn. R. 7849.1900, subp. 4.

1.2 Project Description and Ownership

The Huntley – Wilmarth Project consists of a new 345 kV transmission line connecting Xcel Energy's existing Wilmarth Substation north of Mankato, Minnesota, with ITC Midwest's Huntley Substation, south of Winnebago, Minnesota. Route alternatives for the proposed transmission line traverse Blue Earth, Faribault, Martin, and Nicollet counties in Minnesota. The Applicants also propose to make the necessary modifications to the existing Wilmarth and Huntley substations to accommodate this new 345 kV transmission line.

Xcel Energy and ITC Midwest will own the transmission line proposed in this Application jointly as tenants in common. The equipment and improvements inside the Wilmarth Substation will be owned solely by Xcel Energy. The equipment and

[2] As part of its annual transmission planning process, MISO, in coordination with stakeholders, develop a variety of future scenarios or "Futures" under which to study potential transmission projects. These Futures are discussed in more detail in Chapter 4.

improvements inside the Huntley Substation will be owned solely by ITC Midwest. As the Project Manager, Xcel Energy will be responsible for the construction and maintenance of the proposed 345 kV transmission line. Each party will be responsible for the construction and maintenance of its substation.

Northern States Power Company, doing business as Xcel Energy, is a Minnesota corporation headquartered in Minneapolis, Minnesota, that is engaged in the business of generating, transmitting, distributing, and selling electric power and energy and related services in the states of Minnesota, North Dakota, and South Dakota. In Minnesota, Xcel Energy provides electric service to 1.3 million customers. Xcel Energy is a wholly-owned utility operating company subsidiary of Xcel Energy Inc. and operates its transmission and generation system as a single integrated system with its sister company, Northern States Power Company, a Wisconsin corporation, known together as the NSP Companies. The NSP Companies are vertically integrated transmission-owning members of MISO. Together, the NSP Companies are among the largest transmission-owning members of MISO with over 8,000 miles of transmission lines and approximately 550 transmission and distribution substations.

ITC Midwest is a transmission-only utility that owns approximately 6,600 circuit miles of transmission lines and more than 200 transmission substations in Minnesota, Iowa, Illinois, and Missouri. ITC Midwest is a "transmission company" pursuant to Minn. Stat. § 216B.02, subd. 10. ITC Midwest is a public utility under Section 203 of the Federal Power Act. As such, ITC Midwest is subject to rate and other regulatory oversight by the Federal Energy Regulatory Commission (FERC). ITC Midwest is part of ITC Holdings Corp., the largest independent transmission company in the United States with ITC Holdings Corp., the sole member of ITC Midwest, headquartered in Novi, Michigan, and ITC Midwest's headquarters in Cedar Rapids, Iowa.

In evaluating the economic benefits of the Huntley – Wilmarth Project, the key indicator is its benefit-to-cost ratio. This ratio is dependent on the total cost of the Project compared to the total adjusted production cost (APC) savings[3] that the

[3] APC savings are utilized to measure the economic benefits of proposed transmission projects. These savings are calculated as the difference in total production costs of energy for a generation fleet adjusted for import costs and export revenues with and without the proposed transmission project.

Project will provide over time. Accordingly, cost will be an important consideration in selecting the route and design for the Project.

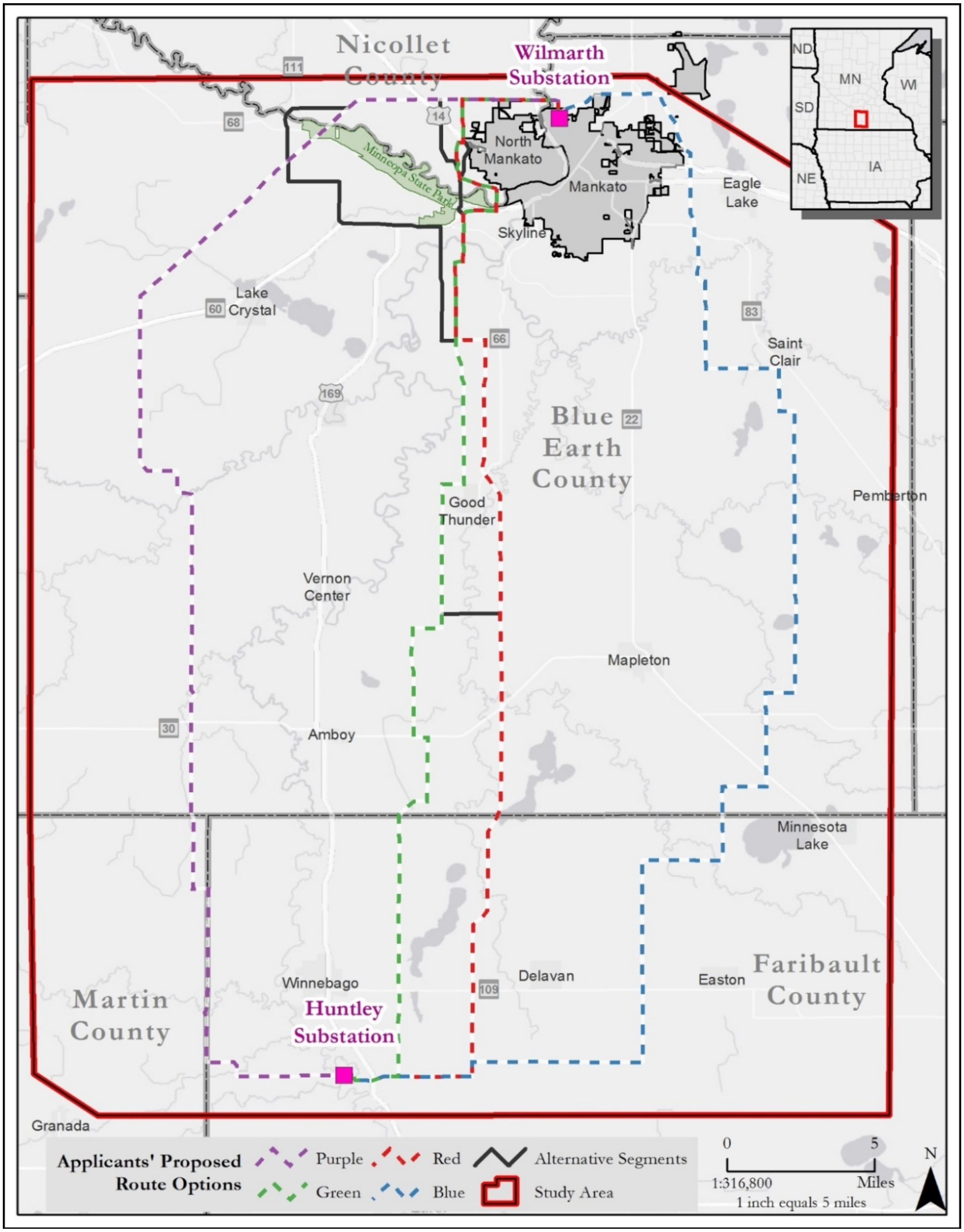
Given the unique nature of this Project, Applicants are proposing four route alternatives and several design options that result in nine distinct route/design combinations. These route/design options have total costs ranging from $105.8 million to $138.0 million (2016$).[4] Applicants are providing these different design and route options to enable the Commission to select an option that provides the appropriate balance between the economic-based need for the Project while minimizing the Project's potential impacts. For instance, certain design options, such as single circuit H-frame structures parallel to an existing transmission line, have lower costs and thus higher net economic benefits, but have greater potential impacts to the human and natural environments. Likewise, other design options, such as a double-circuit monopole structure, have higher costs and slightly lower net economic benefits, but may reduce human and natural impacts.

The Commission's final route selection will require an analysis of all routing criteria along with the tradeoffs of impacts and costs. To aid the Commission in this analysis, the Applicants have undertaken a more thorough cost estimation process than is typically performed during the permitting phase and have fully evaluated the expected energy production cost savings the Project will provide. Based on that analysis, the Applicants have demonstrated that the Project's benefits exceed its costs if any one of the routes/designs proposed in this Application is selected by the Commission.

The four routes proposed for consideration in the Route Permit Application (west to east) are: the Purple Route, the Green Route, the Red Route, and the Blue Route. In addition to the four main routes, six alternative segments are included to provide routing options related to the area west of the City of North Mankato and Minneopa State Park. These six alternative segments also provide options to connect portions of the Purple, Green, and Red routes. An overview map of the Applicants' four proposed route alternatives and six alternative segments are shown in **Figure 1**. More detailed maps of these routes can be found in the Route Permit Application (Docket No. E002, ET6675/TL-17-185).

[4] The Project was approved in 2016 by MISO using 2016$. For ease of comparison, the majority of costs in this Application are provided in 2016$ as well.

Figure 1
The Huntley - Wilmarth Project



1.3 Need for the Project

Congestion on the transmission system affects both the cost of energy, deliverability of energy, and the efficiency of the system. Transmission lines serve as the highways of the electric grid in that they facilitate the movement of large volumes of energy from where it is generated, such as wind turbines or coal or natural gas-fired generation stations, to where it is needed. There are limits to the amount of energy that can be transmitted on a particular transmission line at a given point in time. These limits take different forms such as thermal limits, voltage limits, and stability limits.

With zero congestion, the lowest-priced generators, often wind generation, are first used to meet the needs or demands of the electrical customers. When there is congestion on the transmission system, however, the lowest-priced energy cannot flow freely across the electrical system. As a result, more expensive generators are ordered to operate or increase output (dispatched) to replace the wind energy that could not be delivered to the end user. Predictably, this re-dispatch to avoid congestion increases the price of electricity for both wholesale and retail customers.

As early as 2008, transmission planners documented congestion on the transmission system along the Minnesota/Iowa border. Since that time, despite other transmission line additions, congestion in this area has progressively worsened. Accordingly, MISO turned its attention to this area of the transmission system and, ultimately, the MISO Board of Directors studied, reviewed, and approved the Project as an MEP.

To qualify as an MEP, a transmission project must meet the following three criteria: (1) Greater than 50 percent of the total cost of the candidate project must be attributed to facilities that operate at a 345 kV voltage level or higher; (2) The benefit to cost ratio of the candidate project must meet or exceed 1.25; and (3) The total project costs must exceed $5 million. MISO selected the 1.25 threshold as the appropriate ratio to capture the uncertainties associated with calculating future economic benefits of a transmission project while not setting the thresholds so high that projects with net benefits are not approved.[5]

MISO's MTEP report is the culmination of more than 18 months of study and analysis of transmission system issues as well as the development and evaluation of alternatives to determine the most effective transmission solutions to address the identified issues. One of the goals of the MTEP process is to reduce the wholesale cost of energy delivery for the consumer by identifying transmission projects that enable access to generation at the lowest total electric system cost under a variety of possible future scenarios. MISO found, using its MTEP16 models and Futures' assumptions, that the Huntley – Wilmarth Project would provide $210 million (2016$) in APC benefits on a net present value (NPV) basis over 20 years and had a weighted benefit-to-cost ratio of 1.51 to 1.86.

The Applicants have also evaluated the economic benefits of the Project under the most recent system models and MISO Futures prepared for MTEP17 and the Applicants' cost estimates for the Project presented in this Application. This analysis shows that the projected economic benefits of the Project are even higher than MISO predicted in its MTEP16 analysis. The economic benefits of this Project are tied to the fact that the Project reduces transmission system congestion thus allowing lower cost generation to be used to meet customer demands and as a result, reducing the overall energy production costs. Specifically, the MTEP17 analysis shows that the Project would provide $246.3 million (2016$) in APC saving benefits on a present value basis over 20 years and will have a weighted benefit-to-cost ratio of 1.64 to 2.14, dependent on route/design selected. The reasons for the increased economic benefits are due, in part, to the increased amount of low-cost wind generation present in the MTEP17 Futures that is enabled by this Project.

The Project will also improve the deliverability of wind generation as it will reduce curtailments, allowing the maximum amount of this low-cost renewable generation to meet customer demands. Reducing curtailments improves energy delivery, reduces

[5] *Midcontinent Indep. Transmission Sys. Operator, Inc.'s Section 205 Filing to Revise the Open Access Transmission, Energy and Operating Reserve Markets Tariff Provisions Regarding Market Efficiency Projects*, FERC Docket No. ER12-1577-000 at 4-5 (Apr. 19, 2012).

system generation costs, and provides environmental benefits in the form of lower carbon emissions.

Finally, the Project will improve the robustness of the regional backbone transmission system by improving the efficient delivery of energy and enabling the system to better withstand contingencies under multiple future scenarios. A robust transmission system is better positioned to deal with unplanned system outages. A robust regional transmission system is also key to enabling access to a diverse mix of generation resources, which in turn allows customers to access the least expensive power available at any given time.

1.4 Project Costs and Schedule

For purposes of this Application, the Applicants developed route- and design-specific cost estimates for the Project. These cost estimates were developed to allow the Commission to evaluate each of the route and design options for the Project in terms of how these selections impact the projected benefit-to-cost ratio of the Project. Depending on the route and design selected for the Project, Applicants estimate that the total costs for the Project range from $105.8 million to $138.0 million (2016$). Additional details regarding the Project costs are provided in **Chapter 2**.

Construction of the Project is anticipated to commence in 2020, and the Project is expected to be in-service by the end of 2021.

1.5 Potential Environmental Impacts

Chapter 8 of this Application provides a discussion of the natural environment and land use features in the area reviewed for the Project (Project Study Area), which is shown in **Figure 1** above. The Project Study Area consists primarily of agricultural land. It is not anticipated that any homes or businesses will be displaced by the Project. The Applicants have not identified any potential environmental impacts that would preclude construction of the Project.

1.6 Public Input and Involvement

The public can review this Application and submit comments on the Project to the Commission. A copy of the Application is available at the Commission's website:

https://mn.gov/puc/. On the Commission's homepage, click on the eDockets link near the top right-hand side, and then enter the docket number "17-184" in the "Docket Lookup" section. A copy of the Application is also available on the Project website: http://www.huntleywilmarth.com/.

To subscribe to the Project's Certificate of Need docket and to receive email notifications when information is filed in that docket, visit the Commission's website: www.puc.state.mn.us, click on the "Subscribe to a Docket" button, enter your email address and select "Docket Number" from the Type of Subscriptions dropdown box, then select "17" from the first Docket number drop down box and enter "184" in the second box before clicking on the "Add to List" button. You must then click the "Save" button at the bottom of the page to confirm your subscription to the Project's Certificate of Need docket. These same steps can be followed to subscribe to the Project Route Permit docket (TL-17-185).

If you would like to have your name added to the Certificate of Need or Route Permit mailing list send an email to docketing.puc@state.mn.us or call (651) 201-2204 (800-657-3782). If you send an email or leave a phone message, please include: (1) how you would like to receive mail (regular mail or email) and (2) the docket number (CN-17-184 or TL-17-185), your name, and your complete mailing address or email address.

If you have questions about the state regulatory process, you may contact the Minnesota state regulatory staff listed below:

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1.7 Project Meets Certificate of Need Criteria

Minnesota rules and statutes specify the criteria the Commission should apply in determining whether to grant a Certificate of Need. While this Project is the first MEP to seek a Certificate of Need in Minnesota, Minnesota statutes and rules governing this approval contemplate the need for a transmission project that improves the robustness of the transmission system and provides economic benefits as a result.

Specifically, Minn. Stat. § 216B.243, subd. 9 provides that in assessing whether to grant a Certificate of Need the Commission shall evaluate:

> [t]he benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota.

As an MEP, MISO designed the Project to relieve congestion on the transmission system along the Minnesota/Iowa border and lower wholesale energy costs by improving the access and deliverability of low-cost wind generation by reducing system congestion. Construction of the Huntley – Wilmarth Project will also reduce curtailments of wind generation, and enhance the robustness of the high voltage transmission system by improving the efficient delivery of energy. This Project will enable the transmission system to better withstand contingencies under multiple future scenarios.

In addition, Minnesota Rule 7849.0120 provides that the Commission shall grant a Certificate of Need if the Commission determines that:

(A) The probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states;

(B) A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record;

(C) By a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health; and

(D) The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

Applicants' proposal satisfies these four criteria as discussed below.

(A) Probable result of denial of the Project would have an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the Applicants' customers

Denial of a Certificate of Need for this Project would result in adverse effects upon the present and future efficiency of energy supply to the Minnesota electric customers and other end users. This Project is designed to improve the efficiency of the regional transmission system under a range of future scenarios by relieving one of the most congested areas in the MISO electric transmission system, along the Minnesota/Iowa border. Relieving this congestion will improve deliverability and allow customers greater access to low-cost renewable energy and result in lower wholesale energy costs.

(B) A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence

A more reasonable and prudent alternative was not demonstrated in MISO's MTEP16 analysis or as part of the additional study work conducted by the Applicants.

MISO staff and stakeholders developed more than 20 different transmission solutions to alleviate the congestion along the Minnesota/Iowa border. These solutions were tested for their ability to address this congestion under five Future scenarios. Following this rigorous analysis, the proposed Project consisting of a new 345 kV circuit between the Huntley and Wilmarth substations provides 100 percent congestion relief throughout the study period with a high benefit-to-cost ratio under the various Futures studied. The Project also enhances the regional transmission system with a new 345 kV connection to strengthen the region's high-voltage power delivery system.

In addition to the study work conducted by MISO, Applicants considered multiple alternatives including: (i) size alternatives (different voltages or conductor arrays, alternating current (AC)/direct current (DC), and double-circuit); (ii) generation alternatives; and (iii) no build alternative (including Demand-Side Management). After reviewing these alternatives, the Applicants concluded that none is a more reasonable and prudent alternative to the Project.

(C) The proposed transmission lines will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments

The proposed Project will reduce congestion and allow the transmission system to operate more efficiently and more cost-effectively, and pursuant to the Commission's routing criteria will be routed in a manner compatible with protecting the natural and socioeconomic environments.

(D) The proposed transmission lines will comply with relevant policies, rules, and regulations of other state and federal agencies and local governments

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

1.8 Socioeconomic Considerations

Minnesota Rule 7849.0240, subpart 2 requires the applicant for a Certificate of Need to address the socially beneficial uses of the facility output, promotional activities that may have given rise to the demand, and effects of the facility in inducing future development. Following is a discussion of each consideration:

1.8.1 Socially Beneficial Uses of Facility Output

As an MEP, this Project is designed to reduce wholesale energy costs by addressing one of the most congested areas in the MISO electric transmission system, along the Minnesota/Iowa border. The Project will relieve the current transmission congestion in this area, increase market access to lower cost wind generation, provide economic benefits in terms of reduced wholesale energy costs, increase the robustness of the regional grid, and supports future wind generation facilities in Minnesota and Iowa.

1.8.2 Promotional Activities

Neither Xcel Energy nor ITC Midwest has conducted any promotional activities or events that have triggered the need for the Project. The Project is needed due to the large amount of wind capacity in southern Minnesota and northern Iowa coupled with transmission constraints, causing congestion on this part of the transmission system. This congestion is projected to worsen over the next 15 years as more wind facilities come on line in this area. Further, the expected coal generation retirements north of the Minneapolis/St. Paul area, such as Sherco 1, Sherco 2, and Clay Boswell Units 1&2, increase the need for power to flow from northern Iowa to the Twin Cities on the currently congested Huntley – Blue Earth 161 kV line.

1.8.3 Effect in Inducing Future Development

The Project is not necessarily intended to induce future development, but it will support future economic development (for example, additional wind generation in the area).

1.9 Request for Joint Proceeding with Route Permit Application

Applicants are also applying for a Route Permit for the Project. Minnesota Rule 7849.1900, subpart 2 permits the Department of Commerce to elect to prepare an environmental impact statement (EIS) in lieu of an environmental report required under part 7849.1200 in certain circumstances. Further, Minn. Stat. § 216B.243, subd. 4 and Minn. R. 7849.1900, subp. 4 permit the Commission to hold joint proceedings for the Certificate of Need and Route Permit in circumstances where a joint hearing is feasible, more efficient, and may further the public interest.

Applicants respectfully request that the Commission find that this Certificate of Need Application is complete, that the Department of Commerce prepare an EIS rather than an environmental report, and commence a joint regulatory review process for the Certificate of Need and Route Permit Applications. Given that the route and design selected by the Commission in the Route Permit proceeding will impact the projected economic benefits derived from the Project, a joint proceeding will further the public interest by allowing these intertwined issues to be fully examined in a singular proceeding.

1.10 Application Organization

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

- Chapter 2 – Project Description
- Chapter 3 – Electrical System and Changing Generation Portfolio Overview
- Chapter 4 – Need Analysis
- Chapter 5 – Alternatives Analysis
- Chapter 6 – Transmission Line Operating Characteristics
- Chapter 7 – Transmission Line Construction and Maintenance
- Chapter 8 – Environmental Information

1.11 Applicants' Request and Contact Information

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

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2. PROJECT DESCRIPTION

In Chapter 2, we will describe the specifics of the Project including the types of structures that we propose to use to support the new 345 kV transmission line, the required right-of-way, the routes being considered for the Project, the cost of the Project, and the anticipated Project schedule. We will also describe the proposed modifications to the existing Wilmarth and Huntley substations to accommodate the new 345 kV transmission line.

Key Terms:

- ***Allowance for Funds Used During Construction (AFUDC)*** – accounting mechanism used to account for the cost of financing a capital project during construction.

- ***Double-circuit*** – transmission line design which uses a single structure to carry two circuits, each made up of three phases, or six phases in total.

- ***Easement*** – permanent right authorizing a person or party to use the land or property of another for a particular purpose. In the case of this Project, this means acquiring certain rights to construct, operate, and maintain a transmission line safely and reliably. Landowners are paid a fair market price for the easement and can continue to use the land for most purposes, although some restrictions are included in the easement agreement.

- ***Kilovolt (kV)*** – equal to one thousand volts.

- ***National Electric Safety Code (NESC)*** – the standards in the United States for the safe installation, operation, and maintenance of electric power facilities.

- ***Route*** – location of a high voltage transmission line between two end points. Minnesota rules allow for a route to have a variable width of up to 1.25 miles within which the right-of-way for a high voltage transmission line can be located.

- ***Right-of-Way*** – land area legally acquired for a specific purpose, such as the construction, operation, and maintenance of transmission facilities and for maintenance.

- ***Single-circuit*** – transmission line design that uses one structure to carry one circuit made up of three phases.

- ***Structures*** – towers or poles that support transmission lines.

- ***Substation*** – facility that monitors and controls electrical power flows, uses high voltage circuit breakers to protect power lines, and transforms voltage levels to meet the needs of end users.

- ***Transformers*** – devices that step-up or step-down voltage between two voltage systems.

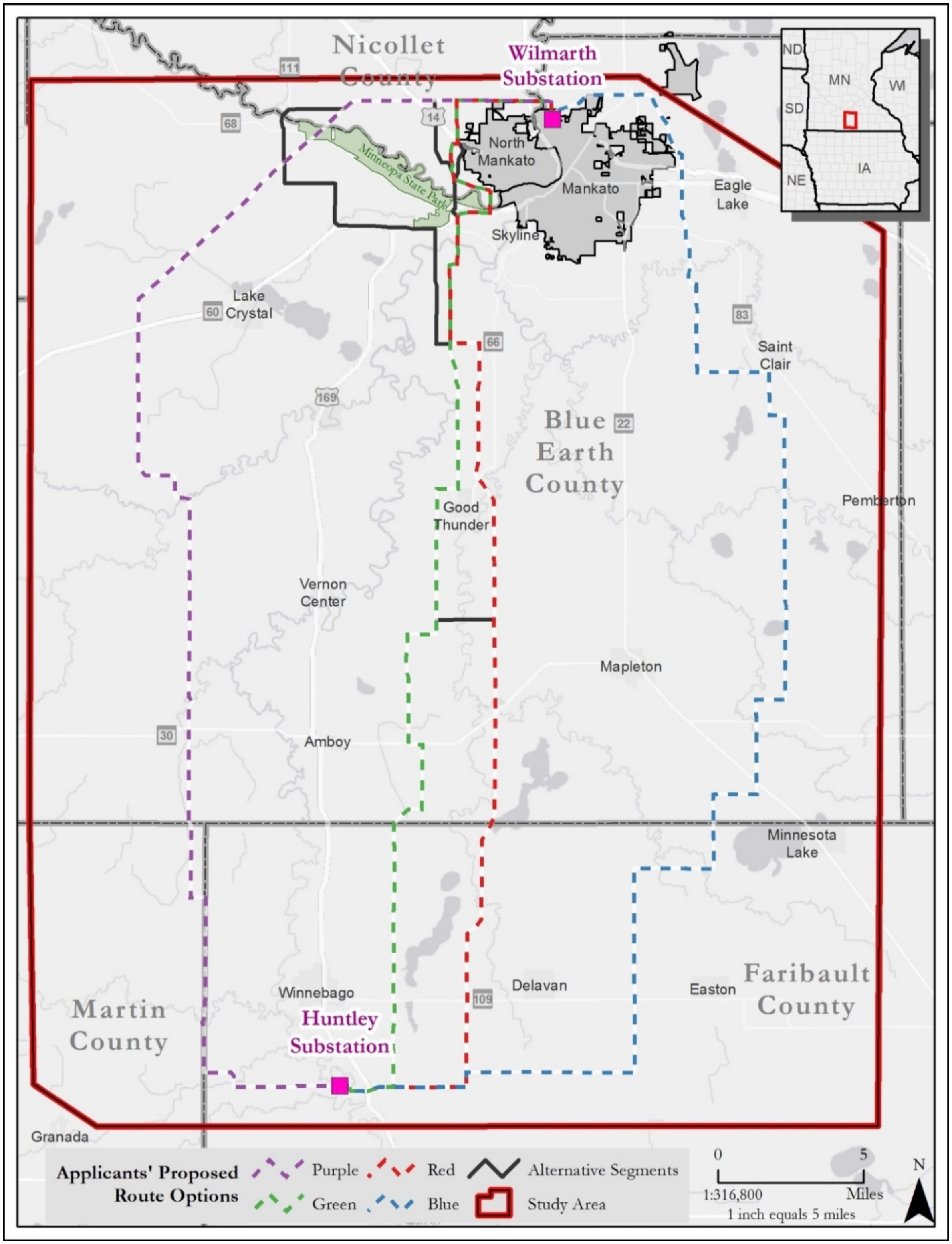
- ***Transmission System*** – interconnected group of lines and equipment for transporting electric energy in bulk between power sources (e.g., power plants) and major substations where the voltage is 'stepped down' for distribution to customers. Transmission is considered to end where the line connects to a distribution substation.

2.1 Project Description

The Applicants propose to construct an approximately 50-mile new 345 kV transmission line connecting Xcel Energy's existing Wilmarth Substation north of Mankato, Minnesota, with ITC Midwest's Huntley Substation, south of Winnebago, Minnesota. The Applicants also propose to make the necessary modifications to the Wilmarth and Huntley substations to accommodate this new 345 kV transmission line. These two substations currently connect to other regional and local 345 kV, 161 kV, 115 kV, and 69 kV transmission infrastructure.

In the Route Permit Application, Docket No. E002, ET6675/TL-17-185, Applicants will propose four different routes for the Project between the two endpoints, the Wilmarth and Huntley substations. These routes, from westernmost to easternmost, are: the Purple Route, Green Route, Red Route, and Blue Route. To provide the ability to connect different routes to create other combinations, the Applicants also developed several alternative segments. An overview map of these four routes and alternative segments is shown in **Figure 2**.

Figure 2
Project Overview Map



2.1.1 345 kV Transmission Line and Structures

The new 345 kV transmission line would be constructed of steel pole structures in either single (monopole) or two-pole H-frame configuration except in certain locations, such as angles, along highways, or environmentally-sensitive areas, where multiple pole or other specialty structures may be required. These multiple pole structures include three-pole structures that may be used on all routes to accommodate large angles where the transmission line route changes direction. The single-pole transmission structures will either be a single-circuit design to accommodate only the new 345 kV transmission line or a double-circuit design to accommodate both the new 345 kV line and an existing transmission line on the same structure. The H-frame structures will only be a single-circuit design. The new 345 kV line would have a right-of-way of 150 feet.

The proposed structures will typically range in height from approximately 75 feet to 170 feet tall. The typical spans between structures will be about 1,000 feet. A single pole structure is typically installed on a concrete foundation while an H-frame and 3-pole structure can either be installed on two concrete foundations or embedded in steel culverts.

Figure 3 provides photos of typical single-circuit and double-circuit structures that Applicants propose to use for this Project. Technical diagrams of these three proposed structure types are included in **Appendix L**.

Figure 3
Photos of Typical 345 kV Structures

		
345 kV Steel Single-Circuit Monopole Structure	**345 kV Steel Single-Circuit H-Frame Structure**	**345 kV/345 kV Steel Double-Circuit Monopole Structure**[6]

[6] If the new 345 kV transmission line is constructed on double-circuit monopole structures with a 345 kV, 161 kV, or 115 kV transmission line, the structure will look similar to this structure.

Table 1 summarizes the three typical structure design details for the Project.

Table 1
Typical Structure Design Summary

Line Type	Structure Type	Structure Material	Typical Right-of-way Width (feet)	Typical Structure Height (feet)	Structure Base Diameter (inches)	Foundation Diameter (feet)	Average Span Between Structures (feet)
345 kV Single-Circuit	H-Frame	Weathering Steel	150	75-150	30	4 (culvert diameter) 7-10 (concrete foundations)	1,000
345 kV Single-Circuit	Monopole w/ Davit Arms	Weathering Steel	150	90-150	48-62	7-12	1,000
345 kV Double-Circuit[7]	Monopole w/ Davit Arms	Weathering Steel	150	100-170	54-67	7-12	1,000

The conductors for the 345 kV transmission line will consist of double bundled, twisted pair Dove (2-556.5 kcmil) Aluminum Conductor Steel Reinforced (ACSR) cables, or cables with comparable capacity. The 345 kV twisted pair conductors will have a capacity equal to or greater than 3,000 amps. In locations where the new 345 kV line is proposed to be built as a double-circuit line with an existing transmission line, the conductor for the existing line will be sized appropriately for new construction at that voltage. Twisted pair conductors may be used instead of the existing round wire to minimize the potential conductor movement caused by "galloping."[8]

[7] One circuit would be 345 kV while the other circuit would be 345 kV, 161 kV, or 115 kV, depending on the specific design criteria and existing transmission lines along the selected route.

[8] Galloping is the motion of conductors that can occur due to wind acting on conductors that are coated with a layer of ice or wet snow. Under certain wind conditions, the asymmetrical profile caused by ice can act like an airfoil causing the conductors to move significantly, usually vertically. If the galloping action is significant, it can cause phase-to-phase and phase-to-ground faults. Galloping can also produce mechanical loads sufficient to damage hardware and structure components.

The proposed transmission line will be designed to meet or surpass relevant local and state codes including NESC and Xcel Energy standards. Applicable standards will be met for construction and installation, and applicable safety procedures will be followed during design, construction, and after installation.

2.1.2 Associated Facilities

2.1.2.1 Wilmarth Substation Modifications

The existing Wilmarth Substation, owned by Xcel Energy, is the northern endpoint of the proposed 345 kV transmission line. This substation is located on the northern edge of the City of Mankato, adjacent to Xcel Energy's refuse derived fuel plant, just east of the Minnesota River.

New substation equipment necessary to accommodate the proposed 345 kV transmission line will be installed at the Wilmarth Substation. No expansion of the current fenced area will be required to accommodate this new substation equipment.

2.1.2.2 Huntley Substation Modifications

The Huntley Substation is the southern endpoint of the Project and was recently constructed by ITC Midwest as part of its Minnesota – Iowa 345 kV Transmission Project.[9] This substation is located approximately three miles south of the City of Winnebago, approximately one mile north of Interstate 90, and just west of Highway 169.

New substation equipment necessary to accommodate the new 345 kV transmission line will be installed at the Huntley Substation. The Huntley Substation was constructed in 2017 to accommodate future 345 kV bays within the substation fenced area and as a result, this Project will not require expansion of the fenced area.

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[9] ITC Midwest's Minnesota –Iowa 345 kV Transmission Line Project, also known as "MVP3," received a Certificate of Need and Route Permit from the Commission in 2014. *See In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minn.-Iowa 345kV Transmission Line Project in Jackson, Martin, and Faribault Counties*, Docket No. ET6675/CN-12-1053, ORDER GRANTING CERTIFICATE OF NEED WITH CONDITIONS (Nov. 25, 2014); *In the Matter of the Application of ITC Midwest LLC for a Route Permit for the Minn.-Iowa 345 kV Transmission Line Project in Jackson, Martin, and Faribault Counties*, Docket No. ET6675/TL-12-1337, ORDER ISSUING ROUTE PERMIT (Nov. 25, 2014).

At this time, Applicants do not anticipate any construction or relocation will be necessary on existing transmission lines at either substation to accommodate the new 345 kV transmission line. Additionally, the Applicants do not anticipate that any construction or relocation will be necessary on any existing transmission lines crossed by the new 345 kV transmission line. At the time of final design of the Project, however, Applicants may determine that short segments of existing transmission lines crossed by the new 345 kV transmission line or at either substation may need to be relocated or reconstructed to ensure NESC and Xcel Energy design criteria and clearances are maintained.

2.2 Applicants' Proposed Routes

Applicants are proposing four routes for the Project which are shown in **Figure 2** above. A written description of each of the Applicants' proposed routes is provided below. Additional information and detailed maps for these proposed routes will be provided in the Route Permit Application for this Project (Docket No. E002, ET6675/TL-17-185). **Figure 4**, following these descriptions, illustrates the co-location alternatives for these routes.

2.2.1 Purple Route

The Purple Route is the westernmost route that Applicants are proposing for the Project and is approximately 52 miles long. From the Wilmarth Substation, the Purple Route follows the existing Lakefield Junction – Wilmarth 345 kV line (Lakefield Junction – Wilmarth Line) to the west across the Minnesota River and north of the City of North Mankato, turning southwest crossing the Minnesota River and Minneopa State Park (Minneopa State Park or Park) (within an existing transmission line easement) and then turns south. When the Lakefield Junction – Wilmarth Line heads west to the Lakefield Junction Substation, the Purple Route continues south, generally following existing linear features (e.g., roads and property lines) to the Project's southern endpoint, the Huntley Substation.

For the approximately 23 miles, from US Highway 169 in Nicollet County to 3.5 miles south of Highway 60 near Lake Crystal, the new 345 kV transmission line would be constructed adjacent to the existing line in a single-circuit design or built as a double-circuit design with the Lakefield Junction – Wilmarth Line. If built using single-circuit design, co-location would be proposed in two areas along the route where Xcel Energy has existing land rights for transmission facilities that can accommodate the new 345 kV line: (1) Minneopa State Park crossing and (2) a federal Waterfowl Production Area (WPA) located in Lake Crystal. For the double-circuit design, the Applicants propose to build the new 345/345 kV line adjacent to the existing line (in most areas) to allow the existing line to remain in service during construction. The new 345 kV line would be offset approximately 100 feet from the existing line, measured from centerline to centerline. The existing line would then be removed when the new line is completed. Since the existing Lakefield Junction – Wilmarth Line is built cross-country in the middle of agricultural fields, constructing the new 345 kV line adjacent to the existing line (and then removing the old line) will not result in additional permanent agricultural impacts.

2.2.2 Green Route

The Green Route is approximately 45 miles long and follows a relatively direct path to the Huntley Substation, generally following property lines through farmland and an existing transmission line. Starting from the Wilmarth Substation, the Green Route follows the Lakefield Junction – Wilmarth Line for 4.5 miles north and west. Applicants propose to construct the Green Route on either single-circuit H-frame or single-circuit monopole structures adjacent to the existing 345 kV line. The new 345 kV line would be offset approximately 100 feet from the existing line, measured from centerline to centerline. The Green Route departs from the existing 345 kV transmission line in Belgrade Township and heads south along property lines through agricultural and low density residential areas crossing three wooded ravines on upper and middle terraces of the Minnesota River Valley. The Green Route bypasses Minneopa State Park by heading east between the Minnesota River and North Mankato to an existing 115 kV transmission line crossing of the Minnesota River bottom land and river channel. In this one-mile segment of the Green Route, the new 345 kV circuit is proposed to be constructed on double-circuit structures, allowing co-location of the new 345 kV transmission line with the existing 115 kV transmission line at the river crossing.

Once across the Minnesota River, the route heads west along Highway 169 for one mile where it turns south. After departing from Highway 169, the Green Route takes a relatively direct route south for 30 miles to the Huntley Substation, generally along field divisions and roads with a few deviations from these features to avoid homes.

2.2.3 Red Route

The Red Route is approximately 46.5 miles long and shares the same route as the Green Route for its northernmost 12.5 miles. Leaving the Wilmarth Substation, the Red Route follows the Lakefield Junction – Wilmarth Line for 4.5 miles north and west. West of Highway 169 in Nicollet County, Applicants propose to construct three miles of the Red Route as a double-circuit line with the existing 345 kV line. Applicants propose to build the new 345/345 kV line adjacent to the existing line (in most areas) to allow the existing line to remain in service during construction. The new 345 kV line would be offset approximately 100 feet from the existing line, measured from centerline to centerline. The existing line would then be removed when the new line is completed. The Red Route deviates from the Green Route near Rapidan Township where it will be double-circuited with the existing Huntley – South Bend 161 kV line for approximately 24 miles. The Red Route would be constructed on or near the same alignment as the existing 161 kV line. The southernmost six miles of the Red Route generally follows field divisions and roads to the south and west to the Huntley Substation.

2.2.4 Blue Route

The Blue Route is approximately 57 miles long and is the easternmost route. The Blue Route exits the Wilmarth Substation following the existing Xcel Energy 115 kV Wilmarth – Dome Pipeline transmission line to the east. In this segment of the Blue Route, Applicants propose that the new 345 kV line be constructed on double-circuit structures, allowing co-location of the new 345 kV transmission line and the existing 115 kV transmission line. The Blue Route then turns south away from the existing line on the northern edge of the City of Mankato, and then travels further east near the City of St. Clair. The Blue Route continues south along agricultural field lines and roads where practicable, working back to the west eventually meeting with the Red and Green Routes into the Huntley Substation.

In Barber Township, the Blue Route joins and follows an existing 161 kV line, continuing west for approximately six miles. This six-mile segment of new 345 kV transmission line is proposed to be constructed on double-circuit monopole structures, allowing co-location of the new 345 kV transmission line and the existing 161 kV transmission line. The last five miles of the Blue Route are shared with the Red Route and follows 160th Street to the Huntley Substation.

2.3 Design Alternatives

Applicants are proposing several structure design options for each route design to enable the Commission to select an option that provides the appropriate balance between the economic-based need for the Project while minimizing the Project's potential impacts.

For the Purple Route, Applicants propose three different design options: (1) a single-circuit H-frame; (2) a single-circuit monopole; and (3) a double-circuit monopole. Both single-circuit designs will be constructed next to the existing transmission lines but, as noted above, will be constructed as double-circuit within Minneopa State Park and the federal WPA.

The double-circuit design will be constructed on a monopole structure with existing transmission lines in those areas where the route follows existing transmission line corridors. For the double-circuit design, in areas where the transmission line does not follow an existing transmission line corridor, the Applicants propose single-circuit monopole structures.

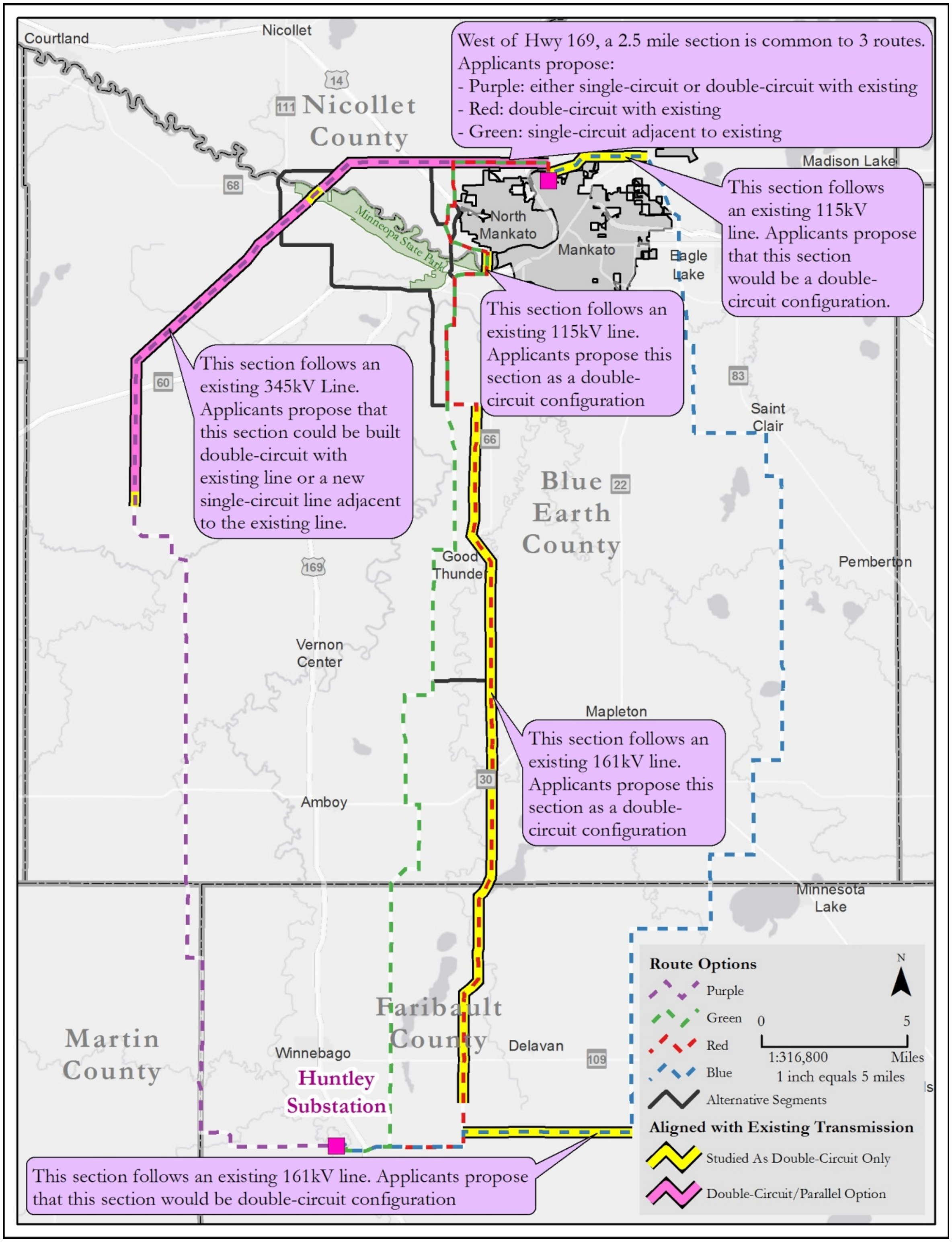
For the Green Route, Applicants are proposing two design options: (1) single-circuit H-frame structures; or (2) single-circuit monopole structures. The Green Route follows the existing Lakefield Junction – Wilmarth Line leaving the Wilmarth Substation but Applicants propose to construct this segment as a single-circuit design adjacent to the existing line. The only location where Applicants propose to double-circuit the Green Route with an existing line is for a one-mile segment across the Minnesota River.

For the Red Route, Applicants are proposing to double-circuit the 345 kV line in all areas where these routes follow existing transmission line corridors. In the areas where these routes do not follow existing transmission line corridors, the Applicants propose either: (1) single-circuit H-frame structures; or (2) single-circuit monopole structures.

For the Blue Route, Applicants propose two different design options: (1) a single-circuit H-frame; and (2) a single-circuit monopole. As discussed in Section 2.2.4, a segment near the Wilmarth Substation and a segment east of the Huntley Substation will be constructed as double-circuit monopole.

Figure 4 outlines the co-location design alternatives for each route.

Figure 4
Project Design Alternatives



2.4 Project Costs

2.4.1 MISO's Estimated Project Costs

Project costs are a key input in evaluating the need for this Project. Specifically, in approving the Huntley – Wilmarth Project as an MEP, MISO evaluated the 20-year NPV of the APC savings of the Project under the MTEP16 Future scenarios as compared to the estimated capital project costs in the same year dollars. To qualify as an MEP, a project must provide APC savings in excess of its estimated costs by a factor of 1.25 or greater. MISO's analysis in MTEP16 determined that the Project would provide a benefit-to-cost ratio of 1.51 to 1.86.

To facilitate the benefit-to-cost analysis for MTEP16, MISO developed what it terms a "scoping level" cost estimate for the 345 kV line between the Wilmarth and Huntley substations and the associated substation modifications.[10] The process used to develop the scoping level cost estimate is outlined in MISO's Transmission and Substation Project Cost Estimation Data document.[11] MISO established a scoping level cost estimate of $80.9 million (2016$), which included $75.9 million for the 345 kV line and $2.47 million for each substation modification. The scoping level cost estimate assumed single-circuit, tubular steel structures and double bundled, twisted pair (T-2) conductors. Right-of-way costs were calculated on a per mile basis with costs based on United States Department of Agriculture (USDA) pasture land prices. The scoping level cost estimates also include AFUDC of 7.5 percent of the construction cost estimate, overhead costs of 10 percent of the construction cost estimate to account for non-material costs such as engineering, permitting, and regulatory costs, as well as a contingency addition of 15 percent of the construction cost estimate. MISO then assumed standard costs, outlined in the MISO

[10] MISO defines a "scoping-level" cost estimate as "based on a more detailed scope definition when compared to Planning-Level Estimates. MISO uses Google Earth program for potential route identification for the proposed transmission line project following existing overhead line corridors between two substations. MISO's potential route assumed in the scoping level is not a recommended or preferred route and it is only used for the indicative cost estimation purpose." *See* MISO Transmission and Substation Project Cost Estimation Data available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2017/20170213/20170213%20EPUG%20Item%2004%20MISO%20Cost%20Estimation%20Data.pdf.

[11] A copy of the 2017 version of this document is available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2017/20170213/20170213%20EPUG%20Item%2004%20MISO%20Cost%20Estimation%20Data.pdf.

Transmission and Substation Project Cost Estimation Data document to accommodate this new 345 kV line at both the Huntley and Wilmarth substations.

The initial route developed by MISO for the scoping level estimate was for a parallel, single-circuit configuration that utilized the existing transmission right-of-way of the Wilmarth – South Bend 115 kV line that runs through the City of Mankato as well as the existing South Bend – Winnebago 161 kV line. While this route is relatively short (38.5 miles) and utilizes an existing corridor, Xcel Energy notified MISO of concerns that the existing 115 kV right-of-way through Mankato would not be able to accommodate the clearance requirements for a new 345 kV transmission line and that this right-of-way could not be expanded.

Based on this information, MISO coordinated with Xcel Energy to determine a more reasonable line length based on potential alternate routes for the Project, which resulted in MISO selecting a longer route length. MISO then revised its cost estimate for this longer length resulting in a range of estimated transmission line costs from $83 million to $103 million. MISO then applied the previously developed substation cost estimates. This resulted in a revised total cost estimate of $88 million to $108 million (2016$) which MISO used for MTEP16. Under the MTEP16 Future scenarios, these revised cost estimates would provide a benefit-to-cost ratio of 1.51 to 1.86. Appendix A of MTEP16 lists the estimated Project costs as $108.0 million.[12]

2.4.2 Applicants' Estimated Project Costs

For purposes of this Application, Applicants developed route and structure design-specific cost estimates for the Project. These nine design alternatives have varying costs and varying impacts to the human and natural environments. These cost estimates were developed to allow the Commission to evaluate each route and design option for the Project in terms of how the costs for each of these choices impact the projected benefit-to-cost ratio of the Project.

Due to the importance of costs in determining the need for this Project, Applicants deployed a more thorough cost estimation process for this Project than what is typically employed prior to submitting a Certificate of Need application to the

[12] A copy of the relevant portion of Appendix A is included in Appendix F to this Application.

Commission. As Applicants have extensive recent experience constructing high voltage transmission infrastructure in the Midwest region, they were able to draw upon that experience, lessons learned, and cost information from these prior projects to develop the cost estimates for this Project.

There are several main components of the cost of a new transmission line project. These main components are the costs of: (1) transmission line structures and materials; (2) transmission line construction and restoration; (3) transmission line permitting and design; (4) transmission line right-of-way acquisition; and (5) substation materials, permitting, design, and construction.

The cost estimation process for this Project began with the selection of Applicants' proposed routes for the Project. As described in detail in the Route Permit Application, Applicants' four proposed routes were developed based on the Project need, a comprehensive examination of human and environmental impacts and consideration of landowner, stakeholder, and local government feedback.

2.4.2.1 Transmission Line Structure and Materials Costs

After selecting four proposed route alternatives, Applicants obtained publicly-available LiDAR[13] survey data for each route. This survey data provided information on the approximate elevation and grading for each route. Applicants also gathered publicly-available geographic information system (GIS) data to identify wetlands, rivers, and buildings for purposes of locating structures for each route.

Applicants loaded the survey and GIS information into PLS-CADD, a transmission line design software. The Project engineer uses this software to produce a detailed preliminary design that includes specific structure placements that account for terrain- and location-specific constraints. These preliminary designs allowed Applicants to obtain structure counts, weights, heights, and diameters for each of the nine designs along the four routes. Applicants also used available soil borings and other geotechnical information to develop preliminary foundation designs. Based on these

[13] LiDAR, which stands for Light Detection and Ranging, is a remote sensing method that uses light in the form of a pulsed laser to measure ranges (distances) to the Earth.

preliminary designs, Applicants obtained updated pricing from structure and conductor suppliers.

2.4.2.2 Transmission Line Construction and Restoration Costs

To develop the construction cost estimates, Applicants provided the preliminary designs and construction specifications to several construction contractors and requested cost estimates to construct foundations and the transmission line. These contractor estimates were compared to Xcel Energy's internal estimates to validate the reasonableness of the estimates for each of the nine designs.

2.4.2.3 Transmission Line Permitting and Design Costs

To estimate the permitting and design costs for the Project, each department within Xcel Energy that assists with these tasks provided estimated hours and costs to accomplish the required work. These departments included: Engineering, Project Management, Siting and Permitting, Construction Management, and Real Estate, among others. These departments estimated their projected hours and costs based on work on prior similar transmission line projects.

2.4.2.4 Right-of-Way Costs

Applicants also estimated right-of-way acquisition costs for each route by classifying the land types crossed by each of the proposed routes (i.e., agricultural, residential, commercial). Applicants then estimated the right-of-way cost for each land type by analyzing and applying general market value data for each property type in the Project area. Applicants then determined a right-of-way acquisition cost based on this data and the potential impact to the property for the particular route and design proposed. Applicants' right-of-way costs also account for possible condemnation based on prior transmission line projects.

2.4.2.5 Substation Costs

To estimate the costs of the substation upgrades required at the Huntley and Wilmarth substations, Applicants developed a preliminary design for the improvements to each substation. Applicants then estimated material, construction, design, and permitting costs based on cost estimates for these items from prior substation improvement projects.

2.4.2.6 Risk Assessment Contingencies

Applicants also identified potential risks that could result in additional costs. These risks include unexpected weather conditions, route changes, poor soil conditions in areas where no soil data was obtained, transmission line outage constraints, or labor shortages. Applicants then developed an appropriate cost contingency for each of these risks.

The five cost components identified above as well as the risk assessment contingencies were combined to create the total Project costs.

2.4.3 Total Project Costs

Table 2 and **Table 3** below provide total Project Costs for each of Applicants' proposed routes and design alternatives. These costs include all transmission line costs (including materials, associated construction, permitting and design costs, and risk assessment contingencies), substation modification costs (including materials, construction, permitting and design costs, and risk contingencies), AFUDC, and right-of-way costs.

Table 2 provides 2016 dollar costs and the costs in **Table 3** have been escalated to the year a particular cost is anticipated to be incurred.

Table 2
Total Project Costs (2016$)

Design Option	Route Option			
	Purple Route (West Route) ($Millions)	Green Route (Middle Route) ($Millions)	Red Route (Middle Route) ($Millions)	Blue Route (East Route) ($Millions)
Single-Circuit H-Frame		$109.0		
Single-Circuit Monopole		$121.3		
Single-Circuit Parallel H-frame	$105.8			
Single-Circuit Parallel Monopole	$121.7			
Double-Circuit Monopole and Single-Circuit H-Frame			$135.2	$123.7
Double-Circuit Monopole and Single-Circuit Monopole	$137.9		$138.0	$135.8

Table 3
Total Project Costs ($ escalated to anticipated year spend)

Design Option	Route Option			
	Purple Route (West Route) ($Millions)	Green Route (Middle Route) ($Millions)	Red Route (Middle Route) ($Millions)	Blue Route (East Route) ($Millions)
Single-Circuit H-Frame		$121.2		
Single-Circuit Monopole		$134.9		
Single-Circuit Parallel H-frame	$117.6			
Single-Circuit Parallel Monopole	$135.4			
Double-Circuit Monopole and Single-Circuit H-Frame			$150.5	$137.5
Double-Circuit Monopole and Single-Circuit Monopole	$153.3		$153.5	$151.0

Two of the route/design options proposed by the Applicants are below or close to MISO's cost estimate of $108 million (2016$). These include the Purple Route with a single-circuit H-frame design ($105 million, 2016$) and the Green Route with a single-circuit H-frame design ($109.0 million, 2016$). Other route/design options proposed by Applicants are higher than MISO's cost estimates. Applicants' costs estimates are higher in certain instances than MISO's cost estimates due to differences between the cost estimation process employed as well as differences in the route and design assumptions used by the parties.

As evidenced by the discussion above, MISO's and the Applicants' cost estimation processes are different. Whereas MISO employs a standard set of costs to compile its estimate, Applicants relied on site specific cost information as well as cost information gathered from recent transmission projects. For instance, MISO's right-of-way costs were calculated on a per-mile basis with costs based on USDA pasture land prices. In contrast, Applicants estimated right-of-way costs for each route by classifying the property types crossed by each of the proposed routes and then analyzing and applying general market value data for each property type in the Project area.

Another reason that Applicants' costs are higher than MISO's cost estimate is because Applicants sought to identify route and design alternatives to minimize impacts to the human and natural environment consistent with Minnesota routing criteria. Minnesota Statutes section 216E.03, subdivision 7(a) provides that the Commission's route permit determinations "must be guided by the state's goals to conserve resources, minimize environmental impacts, minimize human settlement and other land use conflicts, and ensure the state's electric energy security through efficient, cost-effective power supply and electric transmission infrastructure." In developing routes/designs for the Project, Applicants worked to minimize impacts to the human and natural environment by proposing longer route options in certain instances to avoid populated areas, state parks, or wetlands. This additional route length for certain routes resulted in increased costs. Applicants also sought to minimize impacts by proposing different design options such as double-circuit structures that allow the new 345 kV line to be co-located with existing lines. Double-circuit structures are, however, more expensive than single-circuit structures and thus resulted in increased cost as compared to MISO's estimate.

2.4.4 Cost Allocation under MISO/Rate Impact

Under Attachment FF of the MISO Tariff, recovery of the Project costs will be governed by Attachment GG and Schedules 26 of the MISO Tariff. The MISO Tariff provides that 20 percent of the Project costs for an MEP are allocated to each pricing zone in MISO Classic[14] based on load ratio share (LRS). The remaining 80 percent of the costs of an MEP are allocated to pricing zones based on the distribution of positive APC savings to the Local Resource Zones.[15]

Table 4 provides the allocation of the Project's costs to each pricing zone in MISO.

[14] Generally speaking, the MISO Classic area is comprised of the utilities identified in Table 4.

[15] A map showing the Local Resource Zone boundaries is provided in Attachment WW of the MISO Tariff.

Table 4
Pricing Zone Allocations for the Project based on Attachment FF of the Tariff

Pricing Zone	Local Resource Zone	Local Resource Zone Distribution of Benefits	MISO N/C Load Ratio Share	Pricing Zone Load Ratio Share of Local Resources Zone	20% Postage Stamp Component	80% Local Resource Zone Component	Pricing Zone Allocation Total (%)
[1]	[2]	[3]	[4]	See Note 1 [5]	[6]=20%*[4]	[7]=80%*[3]*[5]	[8]=[6]+[7]
DEI	6	0.0%	8.2%	42.7%	1.6%	0.0%	1.6%
NIPS	6	0.0%	4.0%	20.6%	0.8%	0.0%	0.8%
IPL	6	0.0%	3.1%	16.0%	0.6%	0.0%	0.6%
ATC	2	0.0%	12.8%	100%	2.6%	0.0%	2.6%
ITC	7	0.0%	11.4%	54.3%	2.3%	0.0%	2.3%
BREC	6	0.0%	1.9%	9.7%	0.4%	0.0%	0.4%
NSP	1	38.4%	10.4%	57.8%	2.1%	17.7%	19.8%
METC	7	0.0%	8.8%	41.9%	1.8%	0.0%	1.8%
VECT	6	0.0%	1.3%	7.0%	0.3%	0.0%	0.3%
MEC	3	60.8%	5.7%	58.3%	1.1%	28.4%	29.5%
ITCM	3	60.8%	3.9%	40.0%	0.8%	19.5%	20.3%
HE	6	0.0%	0.8%	3.9%	0.2%	0.0%	0.2%
AMIL	4	0.8%	9.4%	90.7%	1.9%	0.6%	2.5%
AMMO	5	0.0%	8.6%	95.4%	1.7%	0.0%	1.7%
MP	1	38.4%	2.2%	12.2%	0.4%	3.8%	4.2%
GRE	1	38.4%	1.4%	7.9%	0.3%	2.4%	2.7%
OTP	1	38.4%	1.7%	9.7%	0.3%	3.0%	3.3%
DPC	1	38.4%	1.2%	6.5%	0.2%	2.0%	2.2%
MICH13A	7	0.0%	0.8%	3.8%	0.2%	0.0%	0.2%
MDU	1	38.4%	0.7%	4.0%	0.1%	1.2%	1.4%
SMMPA	1	38.4%	0.4%	2.0%	0.1%	0.6%	0.7%
SIPC	4	0.8%	0.6%	5.9%	0.1%	0.0%	0.2%
MPC	3	60.8%	0.2%	1.7%	0.0%	0.8%	0.8%
CWLP	4	0.8%	0.4%	3.4%	0.1%	0.0%	0.1%
CWLD	5	0.0%	0.4%	4.6%	0.1%	0.0%	0.1%

The NSP Companies have load in multiple pricing zones, including: ITCM, DPC, GRE, MP, NSP and OTP.[16] To calculate the impact to customer rates for the NSP Companies, an Annual Transmission Revenue Requirement was calculated for the Project, as shown in **Appendix J**. This total Annual Transmission Revenue Requirement was then multiplied by the LRS of the NSP Companies load in each pricing zone. The NSP Companies load, using the 2016 12CP Average Load, will be allocated 16.96 percent of the Project costs as shown in **Table 5**. This means NSP

[16] DPC: Dairyland Power Cooperative; GRE: Great River Energy; MP: Minnesota Power; OTP: Otter Tail Power Company.

Companies' load will only pay 16.96 percent of the total costs for the Project with the rest of the costs being paid for by the other load that also benefits from the Project being placed into service.

Table 5
NSP Companies' Share of Allocated Costs

Pricing Zone	Huntley Wilmarth Pricing Zone Allocation %	NSP Sch 26 Pricing Zone Load Ratio Share	NSP Share of Pricing Zone Allocated Costs
ITCM	20.30 %	0.19 %	0.04 %
DPC	2.20 %	13.07 %	0.29 %
GRE	2.70 %	5.51 %	0.15 %
MP	4.20 %	0.03 %	0.00 %
NSP	19.80 %	79.56 %	15.75 %
OTP	3.30 %	22.26 %	0.73 %
NSP Companies' Retail Load			**16.96 %**

Appendix J provides the NSP Companies' Minnesota jurisdictional revenue requirement calculation for Xcel Energy's investment in the Project, the MISO Attachment GG revenue requirements for ITC Midwest and the NSP Companies, estimated Attachment GG revenue requirement allocations for the Project to all MISO Network Load in Minnesota, and Xcel Energy's rate impact calculation for the NSP System and for Xcel Energy's Minnesota jurisdiction utilizing the currently available public data. These calculations are shown for the first year the Project is placed in service; the annual revenue requirements will decline ratably over the life of the Project and are calculated using 2016$.

2.5 Project Schedule

Table 6 provides the permitting and construction schedule currently anticipated for the Project. This schedule is based on information known as of the date of filing and may be subject to change as further information develops or if there are delays in obtaining the necessary federal, state, or local approvals that are required prior to construction.

Table 6
Anticipated Project Schedule

Activity	Estimated Dates
Minnesota Certificate of Need and Route Permit Issued	Second Quarter, 2019
Land Acquisition Begins	Third Quarter, 2019
Survey and Transmission Line Design Begins	Second Quarter, 2019
Other Federal, State, and Local Permits Issued	First Quarter, 2020
Start Right-of-Way Clearing	Second Quarter, 2020
Start Project Construction	Second Quarter, 2020
Project In-Service	December 2021

3. ELECTRICAL SYSTEM AND CHANGING GENERATION PORTFOLIO OVERVIEW

In Chapter 3 we explain how the electrical system works, from generation resources, to transmission lines and other infrastructure, to distribution substations, lines, and transformers, and, finally, to the point of delivery in a customer's home or business. In planning for and designing the transmission and distribution systems, both customer needs and the portfolio of generation resources must be considered. We also provide information on how state and federal regulatory requirements and incentives are changing the generation portfolio in Minnesota and our surrounding region. These changes, in turn, have required and will require additional transmission infrastructure to deliver a diverse mix of types of generation to customers.

Key Terms:

- ***Business Energy Investment Tax Credit*** – provides a federal tax credit based on the amount of expenditures invested in eligible renewable technologies.

- ***Generation Capacity Factor*** – is the measurement of the amount of actual energy generated by a generation resource over a given period of time as a ratio when compared to the maximum possible energy output the generation resource is capable of producing over the same period of time.

- ***Production Tax Credit (PTC)*** – provides a federal tax credit based on the amount of electricity generated by a qualified energy resource during the taxable year.

- ***Renewable Energy Objective (REO)*** – was enacted as Minnesota law in 2001, directing all electric utilities in the state to "make a good faith effort" to obtain one percent of their Minnesota retail energy sales from renewable energy resources in 2005, increasing annually to ten percent by 2015.

- ***Renewable Energy Standard (RES)*** – was enacted in 2007 to require public utilities, generation and transmission electric cooperatives, municipal power agencies, and power districts operating in the state to have at least 25 percent of retail electricity sales be generated or procured using eligible renewable sources by 2025. For Xcel Energy, the target was set at 30 percent.

3.1 Electrical System Overview

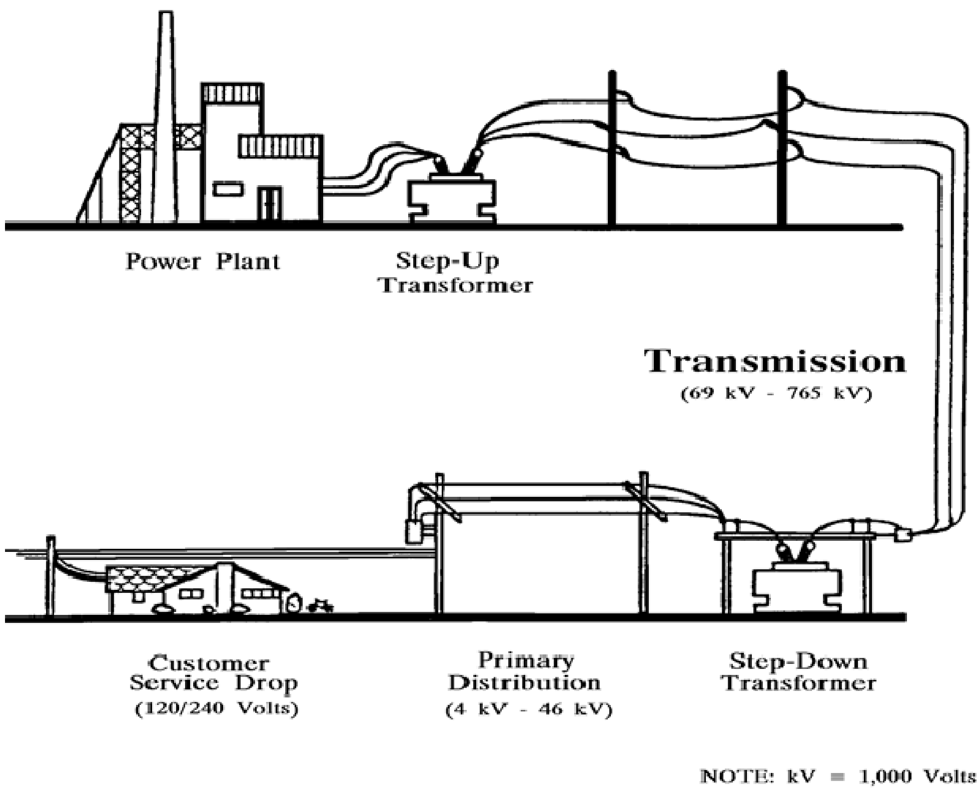
When a customer turns on a light switch, a circuit is completed that connects the light with the wires that serve the customer's building. The building wires are connected to a transformer and a distribution line outside of the building. The distribution lines, in turn, are connected to substations and through larger transformers to transmission lines, which are connected to the bulk-power system that carries electricity from electric generating facilities.

Electricity is produced at both large and small generating facilities. Electricity can be generated using a variety of sources or fuels, including solar, wind, and hydro; internal and external combustion of biomass, biofuels, natural gas, and coal; and heat and steam created through nuclear fission. Electric energy is generated at a specific voltage and frequency. For it to be useful, electricity must be transmitted from the generation source to substations with transformers and then to consumers at consistent voltages. Unlike other consumables, where excess product can be easily and economically stored for future use, electricity must largely be generated simultaneously with its consumption, so generators connected to the system and substations within the system, which are responsible for directing the flow of electric energy, must instantaneously adjust their electric output to respond to changes in customer demand.

Typically, the voltage of electricity generated in a power plant is increased (stepped-up) by transformers installed close to the generating plant. The electricity is then transported over transmission lines, often at voltages in excess of one hundred thousand volts (e.g., 115 kV, 230 kV, 345 kV). One kV equals 1,000 volts. Voltage is stepped-up because it is more efficient to move electricity over longer distances at higher voltages because the system experiences less electrical losses. Once the electricity reaches the locality where it will be consumed, the transmission voltage (e.g., 115 kV and higher) is reduced (stepped-down) by transformers at a distribution substation facility to voltages appropriate for distribution to end use customers. The electricity is then further transformed and distributed at distribution "primary" voltages (e.g., 13.8 kV) within communities by the distribution system which delivers power for individual customer use to the end location where it is stepped-down further to, most commonly, 240 V or 120 V.

A diagram showing the transfer of electricity from generator to consumer is shown below in **Figure 5**.[17]

Figure 5
Electrical System



Note that **Figure 5** is an artistic portrayal of an electrical system and is not a true representation of all actual electrical system components.

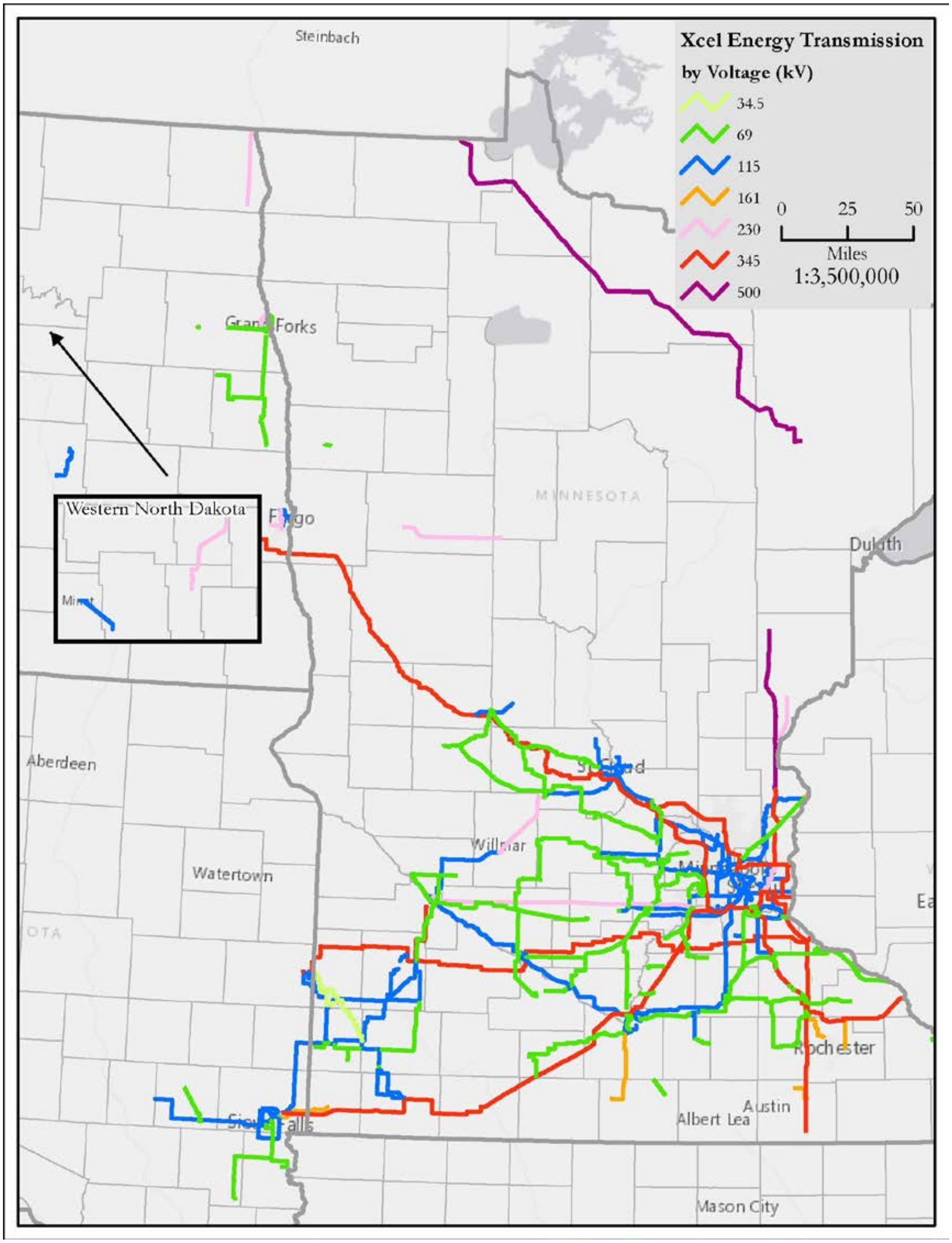
3.2 Transmission System Overview

The transmission system is made up of high voltage transmission lines which can carry electricity long distances and deliver power to distribution systems to meet

[17] Pub. Serv. Comm'n of Wis., *Electric Transmission Lines* at 2 (Oct. 2013), *available at* https://psc.wi.gov/Documents/Electric%20Transmission.pdf.

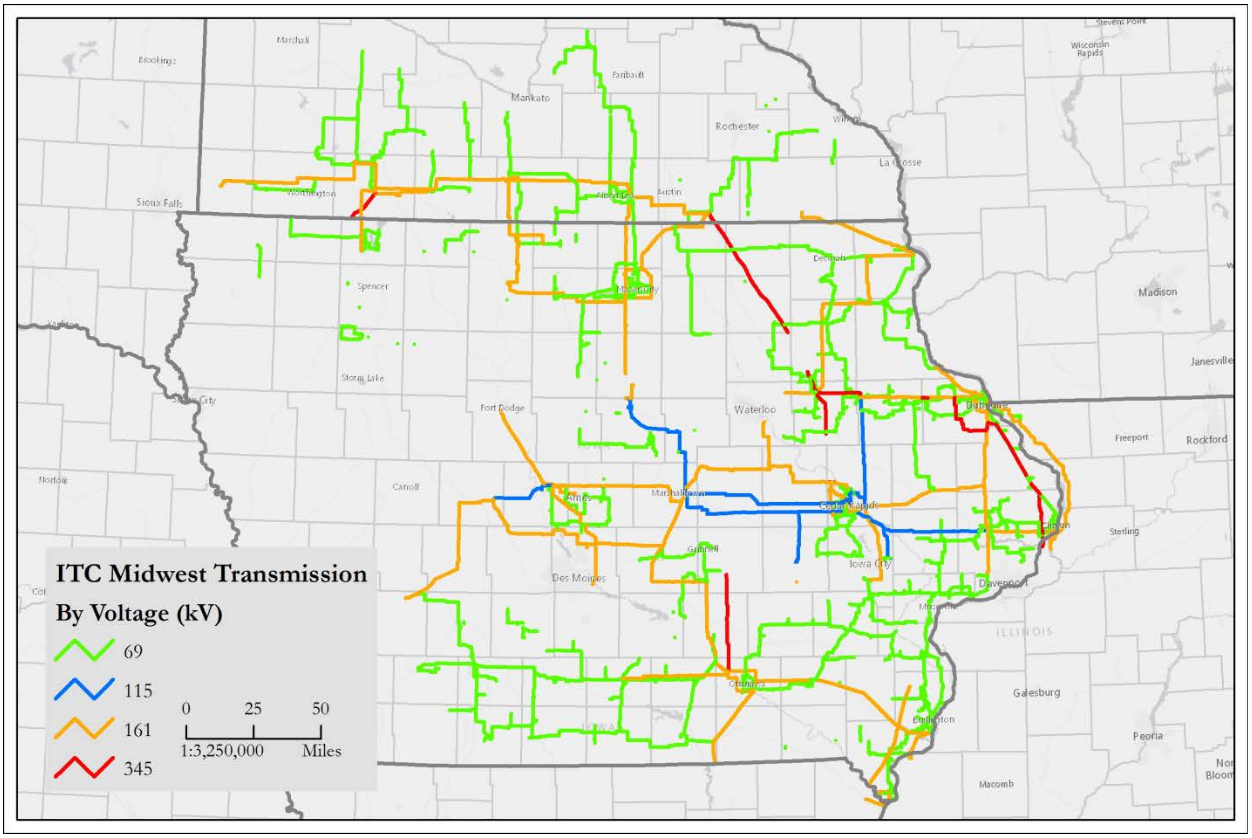
customer needs in specific locations. The transmission system is designed to be an integrated system that is able to withstand the outage of a single transmission line without major disruption to the overall power supply. The majority of the bulk transmission facilities consist of transmission lines and bulk transformers at 100 kV and above. Xcel Energy's transmission system in Minnesota and portions of North Dakota and South Dakota is depicted below in **Figure 6**. ITC Midwest's transmission system in Minnesota and Iowa is shown in **Figure 7**.

Figure 6
Xcel Energy's Transmission System in Minnesota, North Dakota, and South Dakota [18]



[18] Current as of December 2017. Portions of the lines depicted above are transmission facilities that Xcel Energy owns with other utilities.

Figure 7
ITC Midwest's Transmission System in Minnesota and Iowa [19]



3.2.1 High Voltage Transmission Lines

Transmission lines are made up of conductors which complete a three phase circuit and are usually accompanied by a shield wire that provides protection from lighting strikes. These conductors are groups of wires, usually made from copper or aluminum, and most commonly held up by poles or towers that are made from wood or steel.

Transmission lines carry electricity from the generation source to the area where the power is needed. The rate at which electric charge moves through a wire is called current and is measured in amperes (amps). The force that moves the electricity

[19] Current as of 2011. Does not reflect completion of MVP 3 & 4, which have all obtained regulatory approval and are in various stages of construction.

through the wire is called voltage (V). Voltage is measured in terms of V or kV. The wire conducting the current offers resistance to its movement. This resistance is measured in a unit called Ohms. The wires used by utilities to conduct electricity are usually made of copper or aluminum, which conduct electricity with relatively little resistance.

3.2.2 Substations

Electrical substations are a part of the electrical generation, transmission, and distribution system and contain high-voltage electric equipment to monitor, regulate, and distribute electrical energy. Generally, substations allow transmission lines to connect with one another, or allow power to be transformed from a higher transmission voltage to a lower voltage for distribution, typically below 69 kV.

Substation property dimensions depend on the ultimate planned design foreseen for the substation and physical characteristics of the site, such as shape, elevation, above and below ground geographical characteristics, and proximity of the site to transmission lines. Substation sites need to be large enough to accommodate both the planned ultimate fenced area and the required surrounding areas. The required surrounding areas, include applicable setbacks, storm water ponds, wetlands, grading, access road, and new transmission line right-of-ways. Depending on the timing of future load growth and electrical system needs, the configuration of a substation may change over time resulting in multiple construction stages over an extended period of years.

3.3 Minnesota's Changing Generation Portfolio

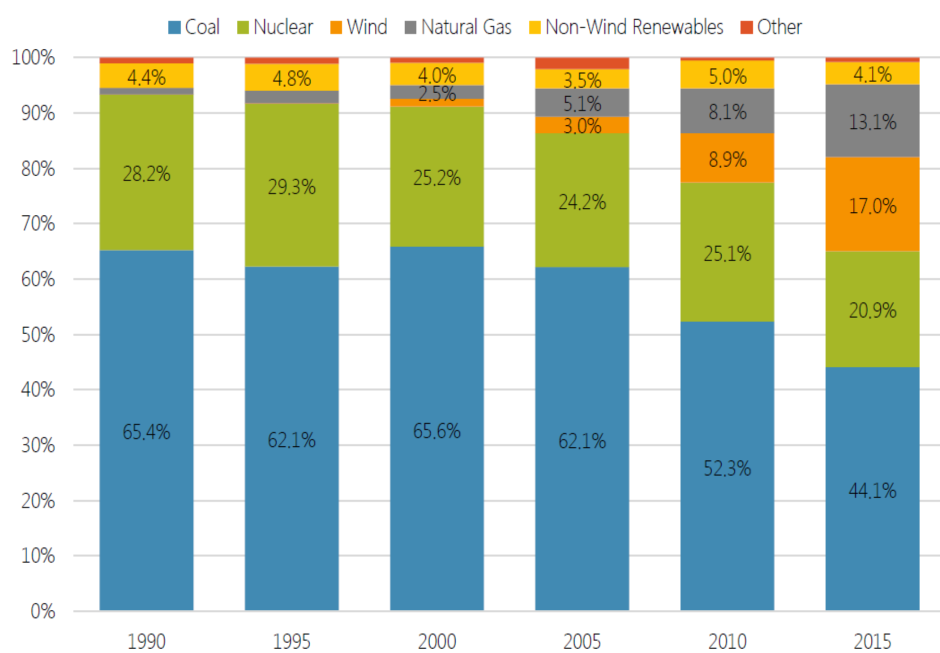
Over the course of the past 20 years, the generation mix in Minnesota and surrounding states has dramatically shifted from relying primarily on coal and nuclear generation resources to a more diverse generation mix that includes increasing amounts of renewable energy, in particular, wind generation. These changes in the generation portfolio in Minnesota require additions and changes to the electrical system in the region to ensure that the added generation can be efficiently and economically delivered to load centers.

The following sections discuss the exceptional growth in wind energy in Minnesota, the conditions that have supported this transformation, and the signs of continued expansion of wind energy along the Minnesota/Iowa border.

3.3.1 Overview of Growth in Wind Generation

Since 2000, Minnesota has experienced a dramatic transformation in its energy production towards more renewable energy resources, especially wind-based generation. As depicted in **Figure 8** and **Figure 9**, wind generation has increased from approximately one percent in 2000[20] to 18 percent in 2016. At the same time, the state's percentage of generation from coal-fired resources has dropped from approximately 66 percent to 39 percent and natural gas generation has increased from approximately three percent to 15 percent.

Figure 8
Minnesota's Electricity Generation Mix 1990-2015, Percentage of Total MWh[21]



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[20] NAT'L RENEWABLE ENERGY LAB., *Wind Powering America: Clean Energy for the 21st Century - Minnesota* (last visited Dec. 14, 2017), *available at* https://www.nrel.gov/docs/fy00osti/28082.pdf.

[21] UNIVERSITY OF MINN. ENERGY TRANSITION LAB, *Minn. Clean Energy: Economic Impacts & Policy Drivers* at 5 (Nov. 2016), *available at* http://energytransition.umn.edu/wp-content/uploads/2015/08/ITC-PTC-Report-FINAL-11.14.pdf.

Figure 9
Minnesota Electricity Generation in 2016[22]

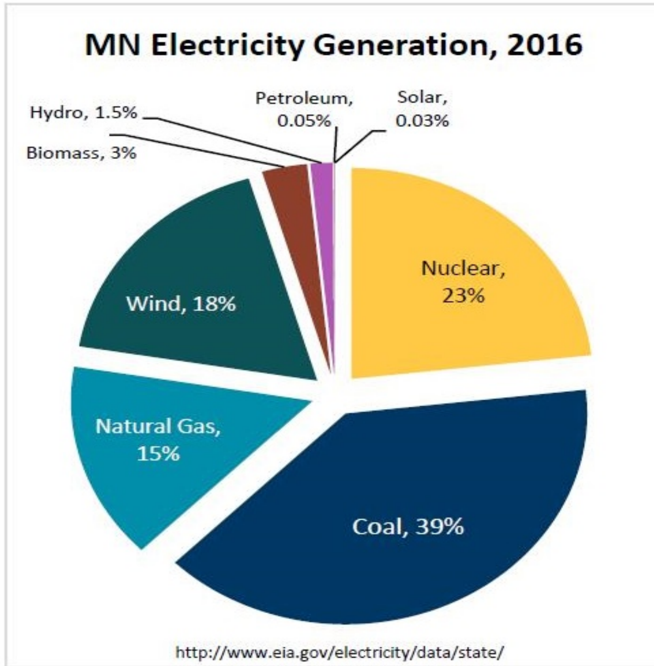
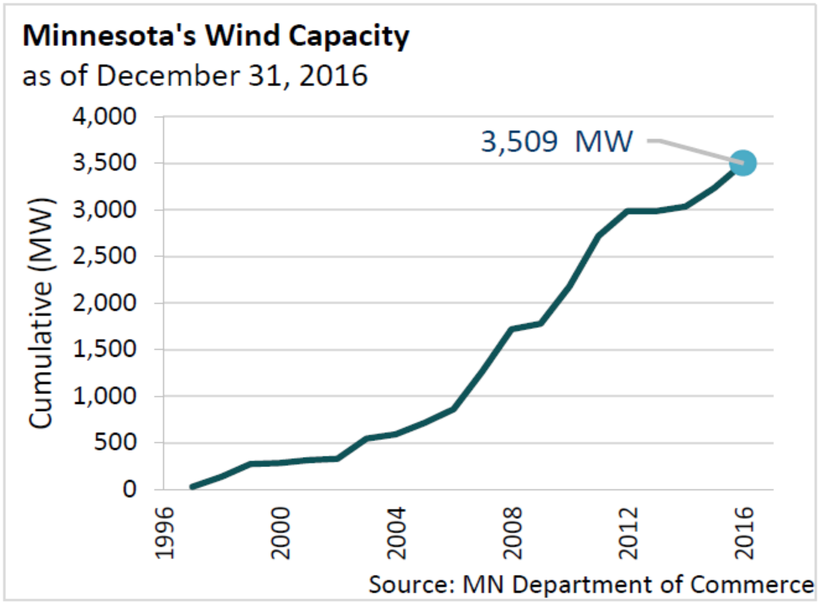


Figure 10 shows the overall increase in Minnesota's wind capacity, in MW, from the mid-1990s to 2016.

[22] MINN. DEP'T OF COMMERCE, *Minn. Renewable Energy Year in Review 2016* at 3 (last modified May 31, 2017), *available at* http://mn.gov/commerce-stat/pdfs/2016-renewable-energy-update.pdf.

Figure 10
Minnesota's Wind Capacity 1996-2016[23]



The expansion of wind generation in Minnesota has been the result of various overlapping factors: state and federal policies, favorable geographic conditions, technological improvements, and economics. Together, these factors have made wind power the most economical option to generate electricity in Minnesota today. This increase has also been accompanied by a decrease in coal generation. This shift has required additional investments in transmission infrastructure to support the movement of this electric energy from generation areas to load centers.

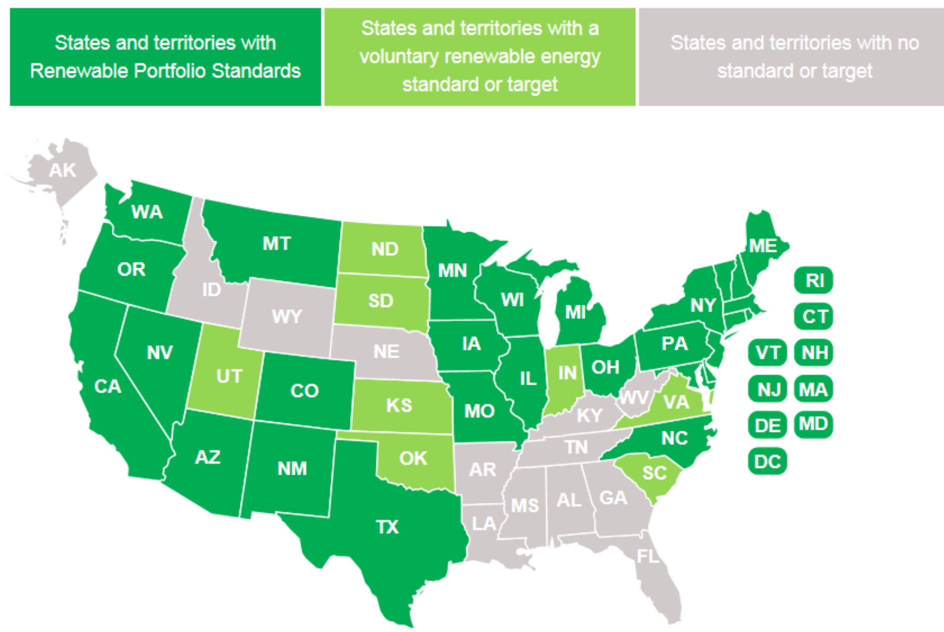
The following sections discuss in detail how these factors have contributed to the increase in wind generation experienced over the past several decades as well as how some of these factors will continue to drive further wind expansion in the future.

[23] MINN. DEP'T OF COMMERCE, *Minn. Renewable Energy Year in Review 2016* at 7 (last modified May 31, 2017), *available at* http://mn.gov/commerce-stat/pdfs/2016-renewable-energy-update.pdf.

3.3.2 State Policies on Renewable Energy

Minnesota and its neighboring states have either established renewable portfolio standards (RPS) or have voluntary renewable energy goals, as shown in **Figure 11.**[24]

Figure 11
States with Renewable Energy Standards or Goals, 2017[25]



In 2001, Minnesota adopted an REO, which directed all electric utilities in the state to "make a good faith effort" to obtain one percent of their Minnesota retail energy sales from renewable energy resources in 2005, increasing annually to ten percent by 2015.

In 2007, as part of the Next Generation Energy Act, Minnesota legislation modified the state's mostly-voluntary REO[26] to create a mandatory RES and also directed the Commission to establish a trading system for renewable credits.[27] Under this RES,

[24] This data is current as of August 1, 2017.

[25] Jocelyn Durkay, *State Renewable Portfolio Standards and Goals*, NAT'L CONFERENCE OF STATE LEGISLATURES (Aug. 1, 2017), *available at* http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

[26] Xcel Energy was explicitly mandated to meet the REO goals.

[27] The RES requirements are codified in Minn. Stat. § 216B.1691. The Commission selected the Midwest Renewable Energy Tracking System (M-RETS) for tracking tradable Renewable Energy Credits (RECs), adopted a four-year shelf life for RECs, and created procedures for mandatory retirement of RECs.

public utilities, generation and transmission electric cooperatives, municipal power agencies, and power districts operating in the state are required to have at least 25 percent of retail electricity sales be generated or procured using eligible renewable sources by 2025. For Minnesota's nuclear utility, Xcel Energy, the RES is higher and must be met earlier than other utilities at 30 percent by 2020.[28]

The legislature also established interim standards, which are separate for other electric utilities and Xcel Energy, as shown in **Table 7**.

Table 7
Minnesota RES Targets by Year

Year	Targets for Other Utilities	Targets for Xcel Energy
2010	*N/A*	15 percent
2012	12 percent	18 percent
2016	17 percent	25 percent
2020	20 percent	30 percent
2025	25 percent	*N/A*

All Minnesota electric utilities are required to report at least every two years to the Commission on their compliance with the RES statute.[29] Thus far, the Commission has found that the 16 utilities subject to the RES have fulfilled the reporting requirements and met the RES targets in each year. The most recent compliance reports were filed in June 2016, covering the 2014-2015 obligations of 12 percent for other utilities and 18 percent for Xcel Energy.[30]

At the time of filing its latest Integrated Resource Plan in 2015, Xcel Energy estimated that it would have sufficient renewable resources to comply with the RES through 2030 without securing additional renewable resources. Specifically, Xcel Energy estimated it could meet the RES of 30 percent by 2020 if it added 400 megawatts

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[28] *See* Minn. Stat. § 216B.1691, subd. 2a.

[29] *See In the Matter of Detailing Criteria and Standards for Measuring an Elec. Util.'s Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. § 216B.1691*, Docket No. E999/CI-03-869, ORDER SETTING FILING REQUIREMENTS AND CLARIFYING PROCEDURES (Nov. 12, 2008) (establishing the original filing requirements under the RES statute). Over the years, the Commission has standardized the format and information needed from the utilities' for their biennial reporting obligations.

[30] *See In the Matter of Comm'n Consideration and Determination on Compliance with Renewable Energy Standards*, Docket No. E999/M-16-83, ORDER FINDING UTILITIES IN COMPLIANCE WITH MINN. STAT. § 216B.1691 (Aug. 2, 2017).

(MW) of wind to its system by that time.[31] As part of the IRP, however, the Commission determined that it was reasonable for Xcel Energy to acquire at least another 1,000 MW of wind by 2019, in addition to other renewable resources, including 650 MW of solar by 2021.[32]

North Dakota[33] and South Dakota[34] have voluntary targets of 10 percent by 2015 and Wisconsin has a mandatory standard of 10 percent by 2015.[35] Iowa implemented the first RPS in 1983 with an original state-wide goal of 105 MW[36] that has been exceeded many times over. Today, there are 6,974 MW of wind generation installed in Iowa, totaling more than 36 percent of Iowa's total electricity generation.[37]

The Lawrence Berkley National Lab estimates that roughly half of all growth in U.S. renewable energy capacity since 2000 is associated with state portfolio requirements. However, the role of state policies has diminished as the sole development driver over time and other factors have influenced the economics of renewable energy generation.[38]

3.3.3 Federal Policies for Production and Investment Tax Credits

Favorable federal tax policies have also helped to spur investments in wind generation over the last decades. The federal Renewable Electricity PTC, provides a tax credit based on the amount of electricity generated by a qualified energy resource and sold

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[31] *In the Matter of Xcel Energy's 2016-2030 Integrated Res. Plan*, Docket No. E002/RP-15-21, PREFERRED PLAN at 59 (Jan. 2, 2015).

[32] *In the Matter of Xcel Energy's 2016-2030 Integrated Res. Plan*, Docket No. E002/RP-15-21, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS at Order Points 3 and 4.a (Jan. 11, 2017).

[33] N.D. Cent. Code § 49-02-28 (goal established in 2007).

[34] S.D. Codified Laws Ann. § 49-34A-101 (goal established in 2008).

[35] Wis. Stat. § 196.378 (standard established in 1998). The targets for each utility vary depending on their baseline renewable percentage (average of 2001, 2002, and 2003 levels), with a maximum requirement for the target being 14 percent.

[36] Iowa Code § 476.44 (goal established in 1983).

[37] AMERICAN WIND ENERGY ASSOCIATION, U.S. WIND ENERGY STATE FACTS: IOWA (accessed Dec. 14, 2017), *available at* https://www.awea.org/state-fact-sheets. Data are current to third quarter 2017 on wind projects.

[38] *See* Galen Barbose, *U.S. Renewables Portfolio Standards, 2017 Annual Status Report*, LAWRENCE BERKELEY NAT'L LAB (July 2017), *available at* https://emp.lbl.gov/sites/default/files/2017-annual-rps-summary-report.pdf.

to an unrelated person during the taxable year.[39] The amount of PTC is adjusted for inflation and counted per kilowatt-hour (kWh).[40] When a project qualifies for the PTC, the duration of the incentive is ten years from the date the facility is placed in service. Although originally set to expire in 2015, the federal PTC was extended, with incentives eventually scaling down to 0 percent, to 2020.[41]

The Business Energy Investment Tax Credit, originally enacted in 2005, provides a tax credit based on the amount of expenditures invested in eligible renewable technologies.[42] The amount of Investment Tax Credit is a percentage of the eligible expenditures. Although initially drafted as the solar energy Investment Tax Credit, qualified facilities, including wind projects, can opt for the Investment Tax Credit in lieu of the PTC. The Investment Tax Credit was also due to expire in 2015 but was extended, with incentives eventually scaling down to 0 percent, after 2019. Developers moved quickly to begin construction of projects in 2016 in order to maximize benefits and qualify for full Production and Investment Tax Credits.

3.3.4 Midwest's Favorable Wind Conditions

Southwestern and southern parts of Minnesota as well as most of Iowa, North Dakota, and South Dakota have strong wind resources. As **Figure 12** shows, these areas have higher average wind speeds as compared to the rest of the country and as a result, wind turbines in these areas yield more energy than those in areas with lower wind speeds.

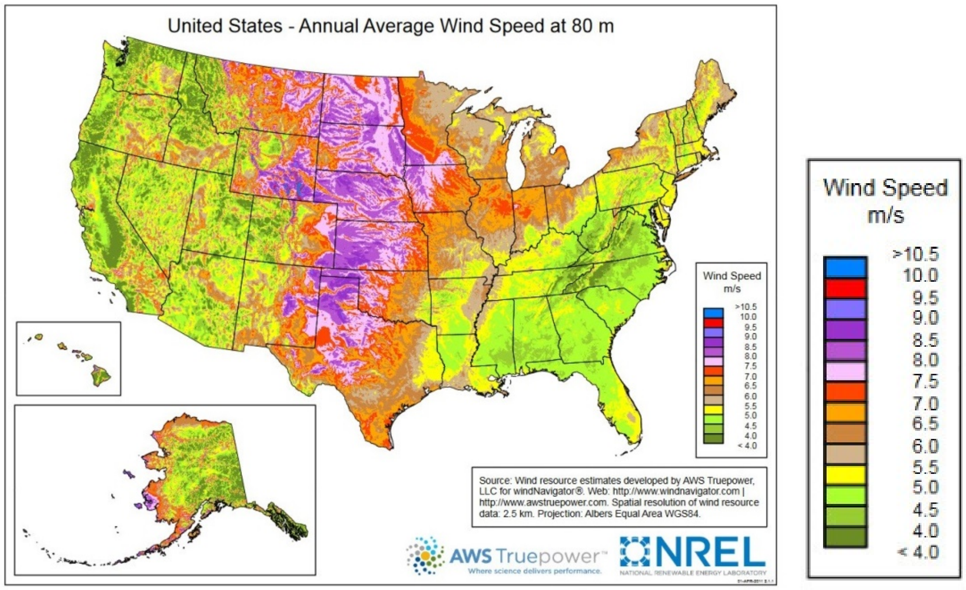
[39] The PTC has been renewed and expanded numerous times, most recently by the American Recovery and Reinvestment Act of 2009 (H.R. 1 Div. B, Section 1101 & 1102) in February 2009; the American Taxpayer Relief Act of 2012 (H.R. 8, Sec. 407) in January 2013; the Tax Increase Prevention Act of 2014 (H.R. 5771, Sec. 155) in December 2014; and the Consolidated Appropriations Act, 2016 (H.R. 2029, Sec. 301) in December 2015.

[40] The tax credit amount is $0.015 per kWh in 1993 dollars for wind and solar facilities; the Internal Revenue Service (IRS) publishes an inflation adjustment factor annually. For 2016, the factor is 1.5556 and the credit is $0.023/kWh.

[41] There are two ways to begin construction to meet safe harbor guarantee: (1) commencing "physical work of significant nature" at the project site or at a factory if the work involves equipment for the project or (2) incurring at least five percent of the total project cost (with taking delivery requirements). Under either safe-harbor method, the project must be placed in service within four years from the end of the year that construction started. For solar systems, biomass, and geothermal energy resources, the project must begin construction by the end of 2016. There is no PTC for later projects.

[42] The Business Energy Investment Tax Credit has been renewed and expanded numerous times, most recently by the Consolidated Appropriations Act, 2016 (H.R. 2029, Sec. 301) in December 2015.

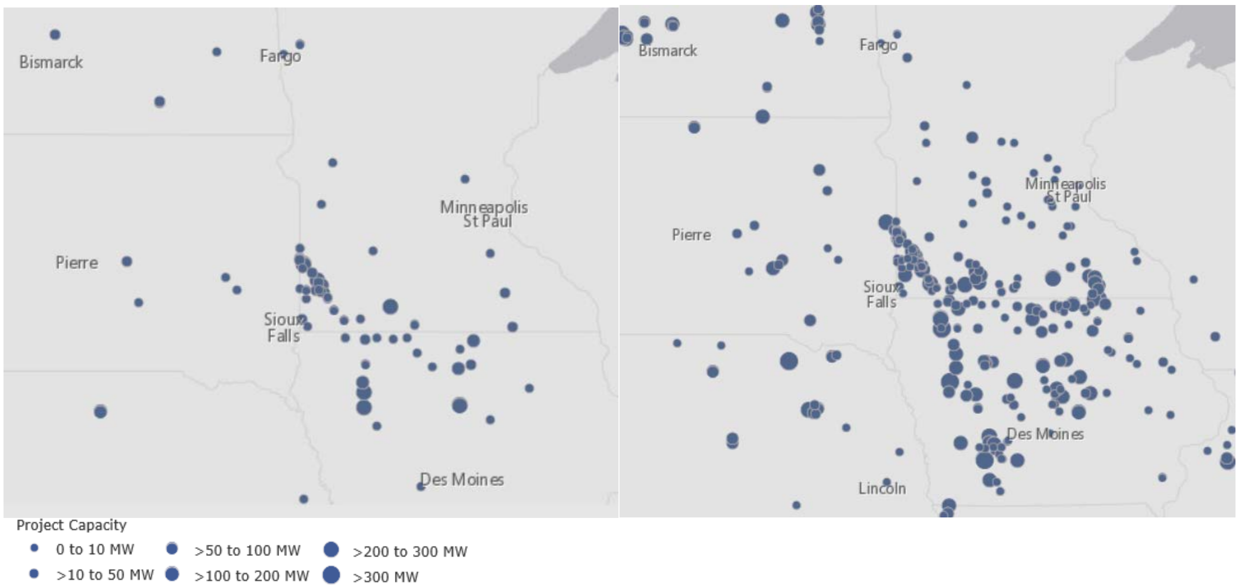
Figure 12
U.S. Annual Average Wind Speed at 80 Meters



These same regions can be characterized as sparsely populated rural areas with an abundance of agricultural and farm land. These higher-than-average wind speeds combined with vast areas of land capable of accommodating new wind turbines makes these regions ideal locations for wind generation. However, at the same time, these same characteristics mean that best wind energy resources are often located far from load centers, and, therefore, transmission capacity is needed to transport this generation to more populated areas.

It is not surprising that wind generation has followed the favorable wind conditions. **Figure 13** demonstrates how the installed wind projects in the region are concentrated in Iowa and southwestern and southern Minnesota. The map on the left shows installed wind facilities in the beginning of 2005. The map on the right shows how the concentration of wind power along the Minnesota-Iowa border has intensified in the past decade.

Figure 13
Wind Facilities in Service as of January 1, 2005 (Left Map) and June 30, 2017 (Right Map)[43]



These favorable wind conditions in southern Minnesota and northern Iowa will continue to drive additional development of wind generation facilities in this area.

3.3.5 Technological Advancement and Economics

Continued and forecasted expansion of wind generation has also been driven by advancements in wind generation technology improving the cost and performance of today's wind turbines. These advancements in wind generation technology have also led older wind facilities to investigate and propose turbine refurbishment projects that, while maintaining existing turbine towers, allow for increased generation from the facilities by replacing key components such as blades and gearboxes.

The average generating capacity of newly-installed wind turbines in the United States in 2016 was 2.15 MW, more than twice the capacity of wind turbines installed from 1998 to 2001.[44] The average capacity factor among wind projects built in the United

[43] Am. Wind Energy Ass'n, *U.S. Wind Industry Map* (last visited Jan. 10, 2018), *available at* http://www.awea.org/.

[44] U.S. DEP'T OF ENERGY – OFFICE OF ENERGY EFFICIENCY & RENEWABLE ENERGY, *2016 Wind Technologies Market Report* at 26 (Aug. 2017) [hereinafter 2016 Wind Power Technologies Market Report], *available at* https://emp.lbl.gov/sites/default/files/2016_wind_technologies_market_report_final_optimized.pdf.

States in 2014 – 2015 was 42.6 percent, compared to an average of 32.1 percent among projects built from 2004 to 2011 and 25.4 percent among projects built from 1998 to 2001.[45]

As a result of the recent technology improvements, low operational costs, state policies, and availability of federal tax credits, wind has become a very economic source of electricity. National trends show that in 2016, the average levelized United States power purchase price for wind was about $20 per megawatt-hour (MWh), which is over a 70 percent reduction from the peak price of nearly $70 per MWh in 2009. Similarly, the cost to install a wind turbine is now 67 percent of the cost in 2009.[46]

A recent example of highly favorable pricing of wind in Minnesota is Xcel Energy's 1,550 MW wind portfolio, approved by the Commission in September 2017.[47] This portfolio includes 750 MW of wind projects developed by Xcel Energy and 800 MW of wind projects based on a competitive bidding process. As a response to the competitive bidding process, Xcel Energy received more than 30 proposals that had a levelized cost of energy priced below $22 per MWh. The estimated net benefits of the total approved wind portfolio are $2.319 billion (on a Present Value of Societal Costs basis) and the estimated net customer bill savings are $1.599 billion (on a Present Value of Revenue Requirements basis). The wind portfolio is predicted to decrease customer bills beginning in 2021 and save them an average of $127 million per year through the life of the projects.[48]

It is expected that these favorable economic conditions where wind is at or among the lowest cost generation sources will also result in construction of additional wind generation in the future.

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[45] *Id.* at 39.

[46] 2016 Wind Power Technologies Market Report at 49, 59. The 2016 capacity-averaged installed project cost was roughly $1,590/kW. *See also* Robert Fares, *Wind Energy is One of the Cheapest Sources of Electricity, and It's Getting Cheaper* (Aug. 28, 2017), *available at* https://blogs.scientificamerican.com/plugged-in/wind-energy-is-one-of-the-cheapest-sources-of-electricity-and-its-getting-cheaper/.

[47] *In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Co.'s 2016-2020 Integrated Res. Plan*, Docket No. E-002/M-16-777, ORDER APPROVING PETITION, GRANTING VARIANCE, AND REQUIRING COMPLIANCE FILING (Sept. 1, 2017).

[48] *See In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Co.'s 2016-2030 Integrated Res. Plan*, Docket No. E002/M-16-777, XCEL ENERGY SUPPLEMENT at 2, 6 (Mar. 16, 2017).

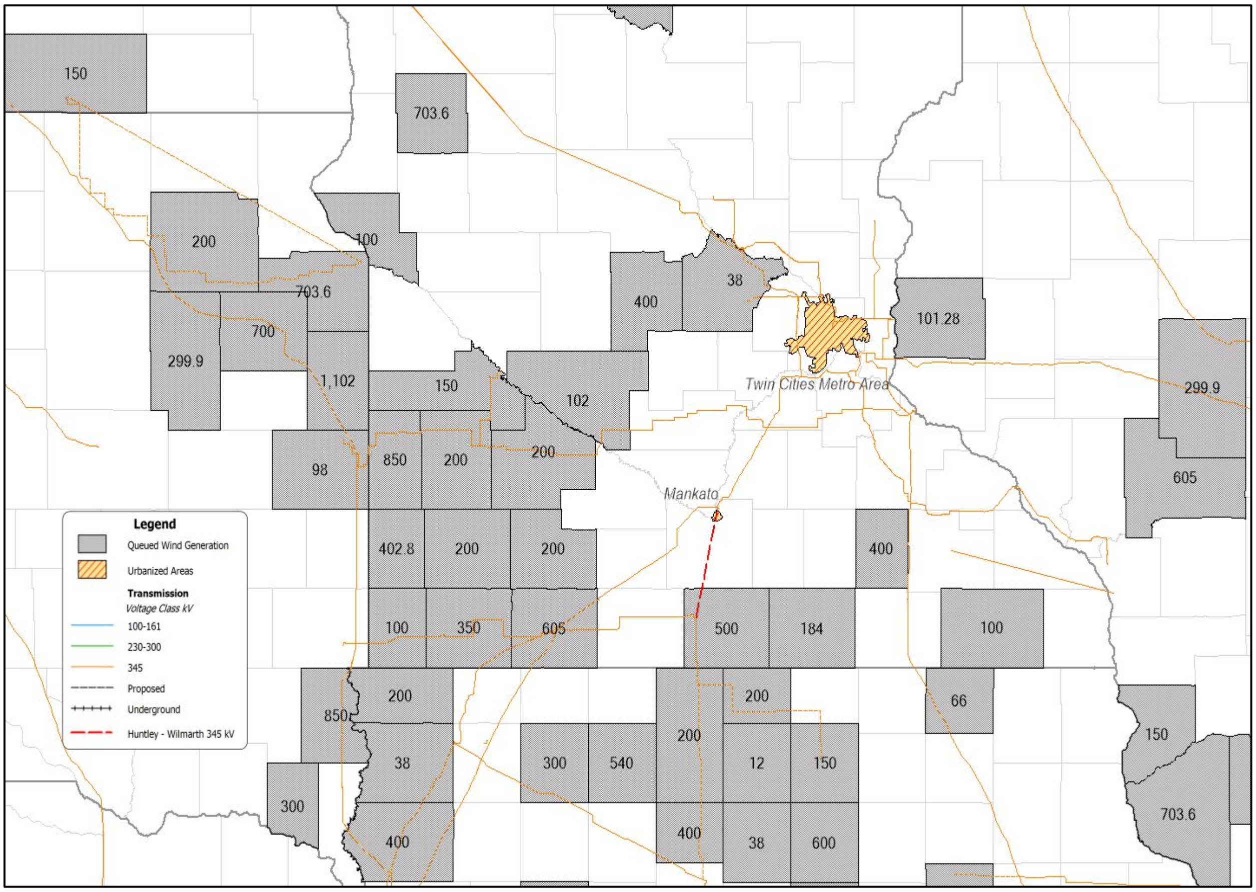
3.3.6 Acceleration of Large-Scale Wind Production

All these conditions discussed above have generated a recent, accelerated expansion in wind development nationally and in Minnesota and Iowa. The United States added 8,203 MW of new wind power in 2016, and strong growth is expected to continue through 2020. Currently, there are more than 140,000 MW of wind projects in the nation's interconnection queues.[49]

As of September 2017, the MISO interconnection queue had approximately 23,100 MW of active wind projects that were expected to be placed in service in Minnesota or Iowa prior to 2021. In 2016 and 2017 alone, more than 6,600 MW of new wind generation to be located in Minnesota or Iowa entered the MISO queue. As of November 2017, the MISO interconnection queue had approximately 19,400 MW of wind that is expected to be placed in service prior to 2021. **Figure 14** shows that a large amount of this additional wind generation is located in southern Minnesota and northern Iowa, areas that already have a high concentration of facilities.

[49] 2016 Wind Power Technologies Market Report at 10. The analysis covered 35 different interconnection queues administered by independent system operators, regional transmission organizations, and utilities.

Figure 14
Wind Projects in MISO Interconnection Queue[50]



The exceptional wind generation growth in Minnesota and the surrounding states has put unprecedented pressure on the transmission system to deliver the inexpensive wind power to customers.[51] Specifically, as more wind generation facilities have been constructed along the Minnesota and Iowa border over the past decade, transmission congestion in this area has increased. Congestion occurs when the amount of energy available to be moved on the transmission system exceeds the physical limits of the system. These physical limits are in place to ensure grid reliability. The next chapter discusses MISO's long-term study of congestion along the Minnesota-Iowa border that eventually led to the development of the Huntley – Wilmarth Project.

[50] This map is based on the MISO queue as of November 2017. Queue numbers are shown in MW.

[51] *See* NAT'L RENEWABLE ENERGY LAB., *2016 State of Wind Development in the United States by Region* (Apr. 2017), *available at* https://www.nrel.gov/docs/fy17osti/67624.pdf.

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4. NEED ANALYSIS

In Chapter 4, we explain why we are proposing the Project. This is referred to as "the need" for the Project. We explain that this Project is needed to reduce overall costs of delivering energy by addressing one of the most congested areas in the MISO electric transmission system, near the Minnesota and Iowa border. Due to this congestion in southern Minnesota and Iowa, the ability of low-cost renewable energy to reach load centers, like the Twin Cities, is limited. When this congestion occurs, customers pay more for electricity because higher cost generators from other areas (without transmission constraints) are used to meet customer demand.

In this chapter, we explain the analysis undertaken by MISO as part of MTEP16 to select the Huntley – Wilmarth Project as the best overall transmission solution to addresses the congestion in this area. MISO's analysis in MTEP16 that designated the Project as an MEP concluded that the Project will provide an anticipated $210 million (2016$) in APC benefits on a present value basis over 20 years with a weighted benefit-to-cost ratio of between 1.51 and 1.86 based on MISO's estimated costs of $88 to $108 million (2016$). This chapter will also summarize MISO's analysis of 23 other transmission alternatives to address the identified congestion and MISO's conclusion that the Project will relieve 100 percent of the congestion and will provide the highest weighted benefit-to-cost ratio compared to these other alternatives.

In addition to MISO's analysis, the Applicants conducted an analysis of the Huntley – Wilmarth Project using MISO's most recent Future scenarios developed for MTEP17. Applicants' analysis using these MTEP17 Futures confirmed that the Project will relieve 100 percent of the identified congestion and will provide an anticipated $246.3 million (2016$) in APC benefits on a present value basis over 20 years. Using the Project costs for the range of route and design alternatives proposed by the Applicants, the Project will have a weighted benefit-to-cost ratio of 1.64 to 2.14.

In addition to the economic benefits of the Project, the Applicants also studied curtailments and determined that the Project will alleviate between 9 percent and 24 percent of curtailments within Minnesota, Iowa, North Dakota, and South Dakota in 2031 as well as improving the reliability of the regional transmission system and providing socioeconomic benefits by enabling development of additional renewable generation in the region.

Key Terms:

- ***Adjusted Production Cost (APC)*** – is the total production costs of a generation fleet including fuel, variable operations and maintenance, startup cost, and emissions, adjusted for import costs and export revenue.
- ***Adjusted Production Cost (APC) savings*** – are utilized to measure the economic benefits of proposed transmission projects. APC savings are calculated as the difference in total production costs of a generation fleet adjusted for import costs and export revenues with and without the proposed transmission project.
- ***Capacity of Transmission Facility*** – is the load-carrying capacity, expressed in terms of Mega-Volt-Amperes or MVA, of a transmission line or other electrical equipment.
- ***Contingency*** – is an outage of a transmission line, generator, or other piece of equipment, which affects the flow of power on the transmission network and impacts other network elements.
- ***Cost/Benefit Analysis*** – the costs of a proposed transmission project are compared to the benefits (in this case, the APC savings).
- ***Curtailment*** – is a reduction in the output of a generator from what it could otherwise produce given available resources (e.g., wind, sunlight). Curtailment can occur because of transmission congestion, lack of transmission access, or excessive supply during low load periods.
- ***Demand Energy*** – is the rate at which electric energy is delivered to or by a system or part of a system at a given interval of time dependent on the current load demands of the system. Demand Energy is generally expressed in kWh or MWh.
- ***Definitive Planning Phase (DPP)*** – the phase of the MISO interconnection process where interconnection studies occur to identify the facilities needed to interconnect a new generator to the transmission system. There are three phases to the DPP during which MISO studies the impact of the

interconnection customer's request on the reliability of the transmission system and whether upgrades to the system are required to accommodate the request. Generation interconnections in the final phase of the DPP are likely to be constructed.

- ***Futures*** – as part of its annual transmission planning process, MISO, in coordination with stakeholders, develops a variety of future scenarios or "Futures" under which to study potential transmission projects. Each Future contains different assumptions as to future demand and energy levels, fuel prices, generation retirements and additions, and potential environmental regulations. The purpose of developing a variety of Futures is to provide reasonable bookends to account for uncertainty such that actual events will fall somewhere between the defined Futures most of the time and, in certain occasions, wholly within one Future.

- ***Load*** – all the devices that consume electricity and make up the total demand for power at any given moment or the total power drawn from the system.

- ***MISO Stakeholders*** – includes representatives from transmission-owning MISO members, independent power producers and exempt wholesale generators, power marketers and brokers, municipal utilities, cooperatives, transmission dependent utilities, public consumer advocates, state regulators, environmental organizations, competitive transmission developers, eligible end use customers, and coordinating members. This diverse group of stakeholders provides input into the MTEP report through proposed model updates, input on appropriate assumptions, and review results and the drafts of the MTEP report.

- ***MISO Transmission Expansion Planning (MTEP)*** – an annual planning process whereby MISO and stakeholders analyze transmission constraints and reliability issues and analyze transmission improvements that will address these constraints and issues.

- ***Peak Demand*** – the highest point in the amount of load online. Can be expressed hourly, daily, monthly, quarterly, or yearly. Peak Demand is expressed in kilowatts (kW) or MW.

- ***PROMOD*** – short for PROduction MODeling, PROMOD is a computer program that simulates the electric market on an hourly constrained-dispatch basis based on models containing generation unit locations and operating characteristics, transmission grid topology, and market system operations. The PROMOD software can calculate the future cost of producing electricity, market congestion, and energy losses based on these assumptions. PROMOD is used to support economic transmission planning.

- ***Production Cost*** – the cost to produce sufficient generation to meet the demand for energy while maintaining system reliability.

- ***Renewable Generation*** – generation resources that rely on fuel sources that restore themselves over short periods of time and cannot be depleted. Examples of renewable generation include solar, wind, hydro, or biomass.

- ***Voltage*** – a type of 'pressure' that drives electrical charges through a circuit. Higher voltage lines generally carry power longer distances.

- ***Weighted benefit-to-cost ratio*** – MISO assigns different weighting to each Future scenario based on the likelihood of that Future occurring. The weighted benefit-to-cost ratio is calculated by multiplying the weight of the Future by the benefit-to-cost ratio of that Future.

4.1 MISO's Analysis of the Need for the Project

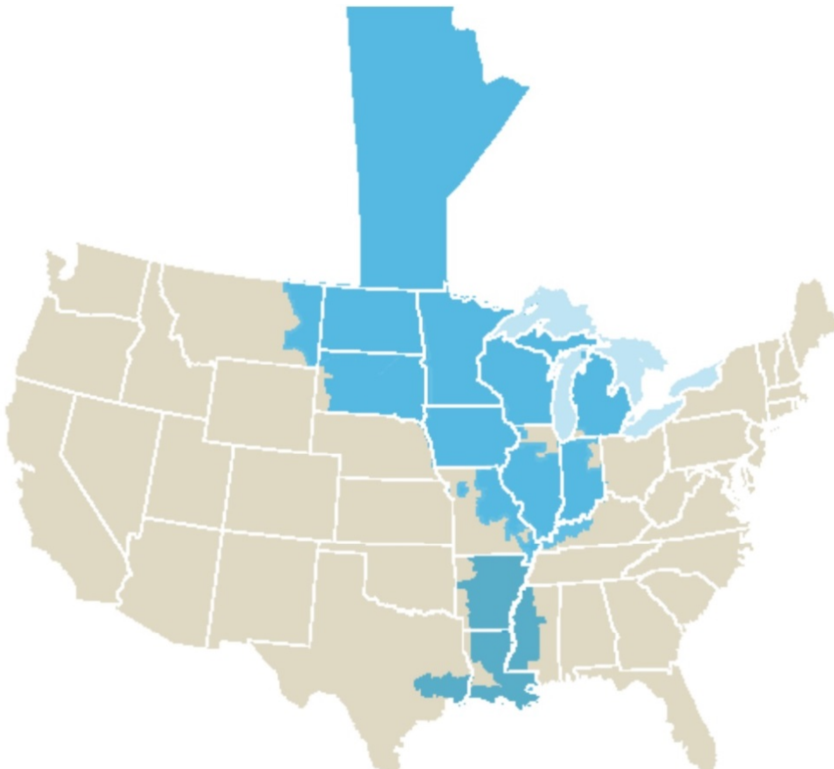
4.1.1 MISO Overview

MISO is a regional transmission organization (RTO) which operates the transmission system and an energy market in parts of 15 states and the Canadian province of Manitoba. As an RTO, MISO is responsible for planning and operating the transmission system within its footprint in a reliable manner. MISO also provides operational oversight and control, market operations, and oversees planning of the transmission systems of its member Transmission Owners (TOs). MISO has 48 TO members, including Xcel Energy and ITC Midwest, with more than 65,800 miles of transmission lines that are under MISO's functional control.[52] MISO's members also

[52] *See* MISO, *Fact Sheet* (updated Mar. 2017), *available at* https://www.misoenergy.org/AboutUs/Pages/FactSheet.aspx.

include 128 non-TOs such as independent power producers and exempt wholesale generators, municipals, cooperatives, transmission dependent electric utilities, and power marketers and brokers.[53] A map of MISO's geographic footprint is provided in **Figure 15** below.

Figure 15
MISO Footprint



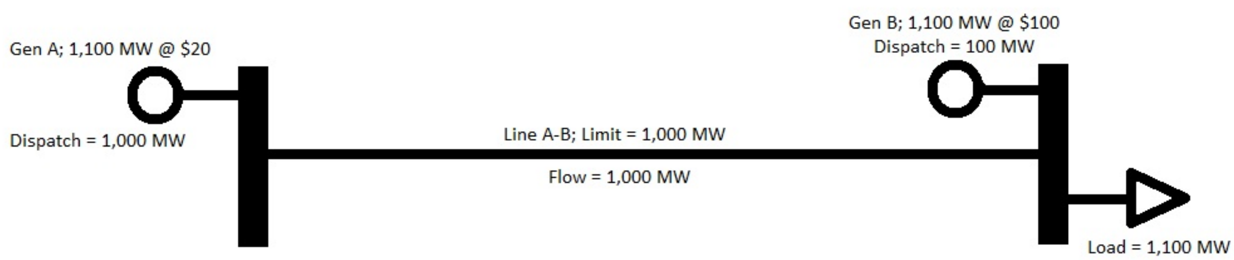
4.1.2 Congestion Overview

In fulfilling its responsibility to operate an energy market in an efficient manner, MISO operates a day ahead and real-time energy market. Limits on transmission facilities can prevent MISO from dispatching the most efficient generation resources during all hours of the year, increasing wholesale energy costs. Currently, there is low-cost energy being produced in Iowa and southern Minnesota that is unable to serve load centers, like the Twin Cities, due to transmission constraints in the area of the

[53] A complete membership list of MISO members by stakeholder group is available at: https://www.misoenergy.org/Library/Repository/Communication%20Material/Corporate/Current%20Members%20by%20Sector.pdf.

southern Minnesota/northern Iowa border that create congestion. More specifically, some energy cannot be delivered to load centers because the loading limits on certain system components preclude this additional energy from being transmitted along those facilities. As a result, not all available wind energy can be delivered and it must be replaced by more costly substitute energy from other areas (without transmission constraints). These transmission constraints create inefficiencies in the wholesale energy market and increase costs. **Figure 16** is an illustration of how congestion affects the energy used and pricing in a single moment of time. The illustration assumes an energy need of 1,100 MW that could be supplied by two potential generators, one at a charge of $20 per MW and one at $100 per MW.

Figure 16
Congestion Illustration



In this theoretical intact system, Generator A could serve the entire 1,100 MW needed, but cannot do so because of the 1,000 MW limit on Line A-B. Instead, Generator A's dispatch is limited to 1,000 MW and Generator B will be called on to deliver the 100 MW balance. If Generator A were able to deliver the entire 1,100 MW it can generate, the energy cost would be $22,000 assuming no energy is lost during transmission. Due to system constraints, the total cost to deliver the 1,100 MW rises to $30,000 because 100 MW cannot be delivered, and replacement energy is required (1,000 MW X $20 for Generator A plus 100 MW X $100 for Generator B). In short, the congestion causes the overall cost of energy to increase $8,000 or 36 percent based on this simplified example. When there is no congestion, the lowest cost generator, regardless of fuel source, is the one that serves load.

An MEP is designed to address congestion to basically level the playing field for all generators to deliver their energy based on supply and demand, which in turn ensures that the energy market operates in the most efficient and cost-effective manner.

4.1.3 MISO's Transmission Planning Process

Since its formation, MISO has studied the transmission system within its footprint to identify necessary transmission projects to address reliability issues. This study includes the development of the annual MTEP in collaboration with TOs and other stakeholders.

The MTEP is developed each year in an 18-month overlapping cycle of model building, stakeholder input, reliability analysis, economic analysis, resource assessments, and drafting of the MTEP report. MISO adheres to the planning principles outlined in FERC Order Nos. 890[54] and 1000[55] in developing the MTEP. These FERC Orders require an open and transparent regional transmission planning process and include the requirement to plan for public policy objectives and for coordinated inter-regional planning and cost allocation. Consistent with these FERC directives, the MTEP process seeks to ensure the reliable operation of the transmission system, support the achievement of state and federal energy policy requirements, and enable a competitive energy market to benefit all customers.

The Market Congestion Planning Study (MCPS) is a study conducted as part of the MTEP report that focuses exclusively on identifying congestion on the transmission system that limits access to the lowest-cost generation resources and evaluates transmission improvements that may relieve this congestion and increase market efficiency under a variety of different future scenarios. The future scenarios are developed through the stakeholder process to identify modeling assumptions for each Future, including but not limited to fuel prices, demand growth, and possible policy regulations.

[54] FERC Order No. 890, 18 C.F.R. parts 35, 36 (2007), *available at* https://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

[55] FERC Order No. 1000, 18 C.F.R. part 35 (2011), *available at* https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

The two types of projects that would result from the MCPS are the MEP and the "Other" type project, which can include lower cost or lower voltage economically justified projects. MEPs, such as the Huntley – Wilmarth Project, are defined in the MISO Open Access Transmission, Energy and Operating Markets Tariff (Tariff) as:

> Network Upgrades proposed by the Transmission Provider, Transmission Owner(s), ITC(s) [Independent Transmission Companies], Market Participant(s), or regulatory authorities as providing market efficiency benefits to one or more Market Participant(s), but not determined by the Transmission Provider to be Multi Value Projects and provide sufficient market efficiency benefits as determined by the Transmission Provider to justify inclusion into the MTEP.[56]

To qualify as an MEP, a project candidate must meet all of the following criteria:

1. Greater than 50 percent of the total cost of the candidate project must be attributed to facilities that operate at a 345 kV voltage level or higher;

2. The benefit-to-cost ratio of the candidate project must meet or exceed 1.25; and

3. The total project costs must exceed $5 million.

MISO utilizes the 1.25 threshold for the benefit-to-cost ratio because it captures the uncertainties associated with calculating future economic benefits of a transmission project while not setting the thresholds so high that projects with net benefits are not approved.

If a project candidate is found to be economically justifiable, but does not meet all of the MEP criteria, it can still be approved as an "Other" type project based on an economic justification. The full costs of "Other" projects are paid by customers in the transmission pricing zone where the facility is located. As discussed in greater detail below, MISO designated the Huntley – Wilmarth Project as an MEP because it met all three MEP criteria.

[56] MISO, FERC Electric Tariff, Module A, § 1.M (48.0.0).

4.1.4 Prior MISO Studies of Congestion Near Minnesota/Iowa Border

A summary of MISO's analysis of the Project from 2009 through MTEP15 is provided below. A more detailed description of MISO's study work is contained in **Appendix G**.

MISO studies first publicly reported congestion as a problem in the border area of Minnesota/Iowa in 2009 in the MTEP08 Regional Generation Outlet Study (RGOS).[57] At this time, these elements were considered a minor point of congestion as the amount of wind generation resources projected to be constructed in this area was far below the levels being seen today. The congestion identified in the Mankato/Blue Earth area on the Minnesota/Iowa border has been further studied in multiple subsequent MISO studies and MTEPs as described below.

In its 2011 Market Efficiency Analysis, MISO implemented a stand-alone analysis to identify and rank the top congested flowgates on the MISO system, appropriately named the "Top Congested Flowgate Study." A flowgate is defined as a facility or group of facilities that may act as a constraint to power transfer on the Bulk Electric System. MISO identified congestion on the Huntley – Blue Earth – South Bend – Wilmarth line[58] during the loss of the Lakefield Generating Station - Lakefield Junction 345 kV transmission line.[59] This means that this line cannot carry the lower-cost renewable generation to the load centers; thus, it becomes necessary for higher cost generation to be "redispatched" (i.e., increase output) or requested to commence operation. As a result of this congestion, the electrical system is operated less efficiently and less cost-effectively. **Figure 17** shows the Huntley – Blue Earth – South Bend – Wilmarth 161 kV path.

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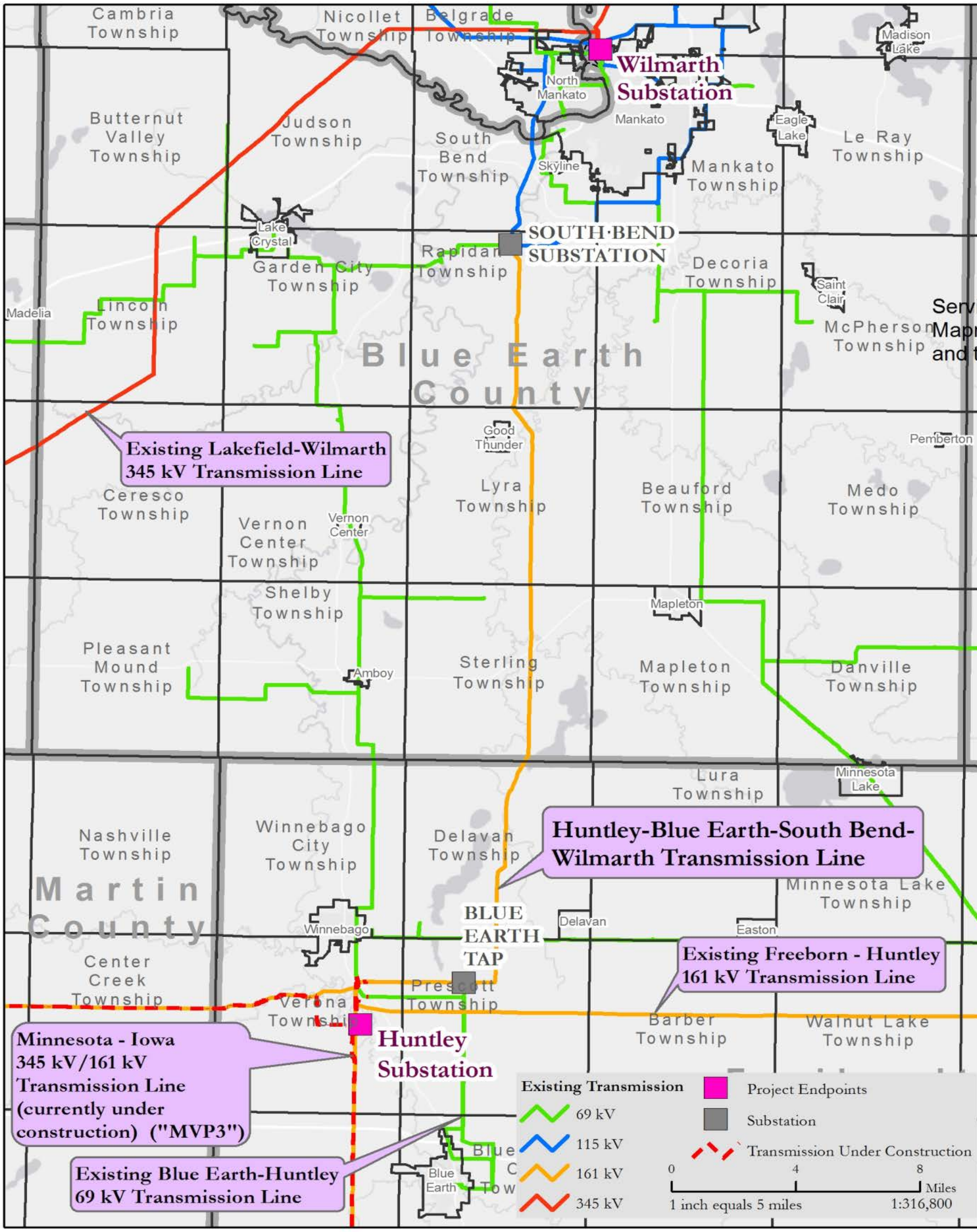
[57] The MTEP08 RGOS is available at https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP08.zip.

[58] This line is referred to as the "Blue Earth – Winnebago 161 kV."

[59] MISO, *Market Efficiency Analysis: 2011 Top Congested Flowgate Study* at 33 (May 2012), *available at* https://www.misoenergy.org/Library/Repository/Study/MTEP/2011%20Market%20Efficiency%20Analysis.pdf.

Figure 17
Mankato Area Transmission System



This congestion was classified as the ninth most severely congested flowgate under existing conditions. [60] MTEP11 also included a portfolio of 17 high voltage projects. The Multi-Value Project (MVP) portfolio aimed, in part, at supporting states' renewable energy goals. Even after construction of the MVP portfolio, the study identified this flowgate as the 14th most severely congested flowgate.[61]

The next year, MISO's MTEP12 analysis indicated that this flowgate was congested between 10-20 percent of the total hours in the year analyzed, meaning 10-20 percent of the time period between November 2011 and October 2012, lower cost energy was available that was unable to be delivered to customers due to the congested nature of this portion of the transmission system.[62] Congestion was again confirmed in MTEP13 as the Mankato area transmission system was included on the list of the top 22 congested flowgates.[63]

In MTEP14,[64] the transmission lines in the Blue Earth area were again identified as a top congested flowgate on the MISO system, primarily due to future wind generation assumptions in the models. The congestion on this flowgate was regarded as a lower priority than those flowgates showing recent real time congestion during actual system operation.

In MTEP15,[65] the number of top congested flowgates decreased, but the Blue Earth area remained a major source of congestion on the MISO system. MTEP15 was the first study to identify a new 345 kV transmission line between the Huntley and Wilmarth substations as a potential solution to address the identified congestion. However, a 345 kV line between the Huntley and Wilmarth substations was not approved by MISO as part of MTEP15 because the proposal showed a low benefit in

[60] *Id.*

[61] *Id.*

[62] MISO, *MTEP 12 Report – Chapter 5.2 Top Congested Flowgate Study* (2014), *available at* https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP12.zip.

[63] MISO*, MTEP13 Report - Chapter 5.3: Market Efficiency Planning Study* at 73 (2014), *available at* https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP13.zip.

[64] MISO, *MTEP14 Report – Book 1: Transmission Studies, 5.3 Market Congestion Planning Study* (last visited Dec. 15, 2017), *available at* http://www.misomtep.org/market-congestion-planning-study/.

[65] MISO, *MTEP15 Report – Chapter 5.3: Market Congestion Planning Study* (last visited Jan. 10, 2018), *available at* http://www.misomtep.org/market-congestion-planning-study-mtep15/.

three of the four MTEP15 Futures and the weighted benefit-to-cost ratio did not reach the 1.25 MEP threshold.

4.1.5 MTEP16

As discussed above, the need being addressed by this Project is one that has long been identified and studied by MISO and its stakeholders. In the past few years, due to rapid expansion of wind development along the Minnesota/Iowa border, the congestion in this area has continued to worsen. This congestion has reached a point where, as part of the MTEP16 PROMOD analysis, the benefit-to-cost analysis justified approval of the Project as an MEP. This section provides an overview of MISO's MTEP16 analysis of the Project. A copy of MTEP16 and selected appendices is provided in **Appendix F** to this Application.

4.1.5.1 Futures Development

As part of each MTEP cycle, MISO and its stakeholders develop a range of future electrical system scenarios that are guided by assessments of possible future state and federal energy policy decisions. The possible future scenarios and energy policies (Futures) form the basis for forecasts of resources and load that would be economical and consistent with the particular policy. These Futures are then used to assess and identify transmission needed to reliably and efficiently deliver the necessary energy from generation resources to customers. The Futures are designed to "bookend" the potential range of future economic and policy outcomes, ensuring that the actual future is within the range of the Futures. The MISO stakeholders that help develop the MTEP Futures include representatives from transmission owning members of MISO, state regulatory authorities, public consumer advocates, environmental representatives, and independent power producers.

The five MTEP16 Futures that resulted from this stakeholder process were defined as: Business As Usual (BAU), High Demand (HD), Low Demand (LD), Regional Clean Power Plan (CPP) Compliance (RCPP), and Sub-regional CPP Compliance (SRCPP). The key components of these Futures are:

- *Business as Usual*: captures all current policies and trends in place at the time of Futures development and assumes they continue, unchanged, throughout the duration of the study period. All applicable United States Environmental Protection Agency (EPA) regulations are modeled. Demand and energy growth are modeled at 0.9 percent. All current state-level RPS and Energy Efficiency Resource Standard (EERS) mandates are modeled. Assumes retirement of 12.6 gigawatts (GW) of coal generation.

- *High-Demand*: captures the effects of increased economic growth resulting in higher energy costs and medium-high gas prices. Demand and energy growth are modeled at 1.6 percent. All applicable EPA regulations are modeled. All current state-level RPS and EERS mandates are modeled. Assumes retirement of 12.6 GW of coal generation as well as age-related generation retirements.

- *Low-Demand*: captures the effects of reduced economic growth resulting in lower energy costs and medium to low gas prices. Demand and energy growth are modeled at 0.2 percent. All applicable EPA regulations are modeled. All current state-level RPS and EERS mandates are modeled. Assumes retirement of 12.6 GW of coal generation as well as age-related generation retirements.

- *Regional Clean Power Plan Compliance*: assumes a MISO footprint-wide plan to comply with the CPP that will result in significant reductions in carbon emissions. Assumes retirement of 12.6 GW of coal generation as well as age-related generation retirements. Also assumes 14 GW of additional coal unit retirements, coupled with $25/ton carbon costs, and state mandates for renewables. Includes declining costs for wind and solar generation. Demand and energy growth are modeled at 0.9 percent.

- *Sub-Regional CPP Compliance*: assumes zonal or state-level compliance with the CPP that will result in significant reductions in carbon emissions. Assumes retirement of 12.6 GW of coal generation as well as age-related generation retirements. Also assumes 20 GW of additional coal unit retirements, coupled with $40/ton carbon costs, and state mandates for renewables. Demand and energy growth are modeled at 0.9 percent.

The key characteristics of these five Futures are summarized in **Table 8**.

Table 8
MTEP16 Futures Key Characteristics

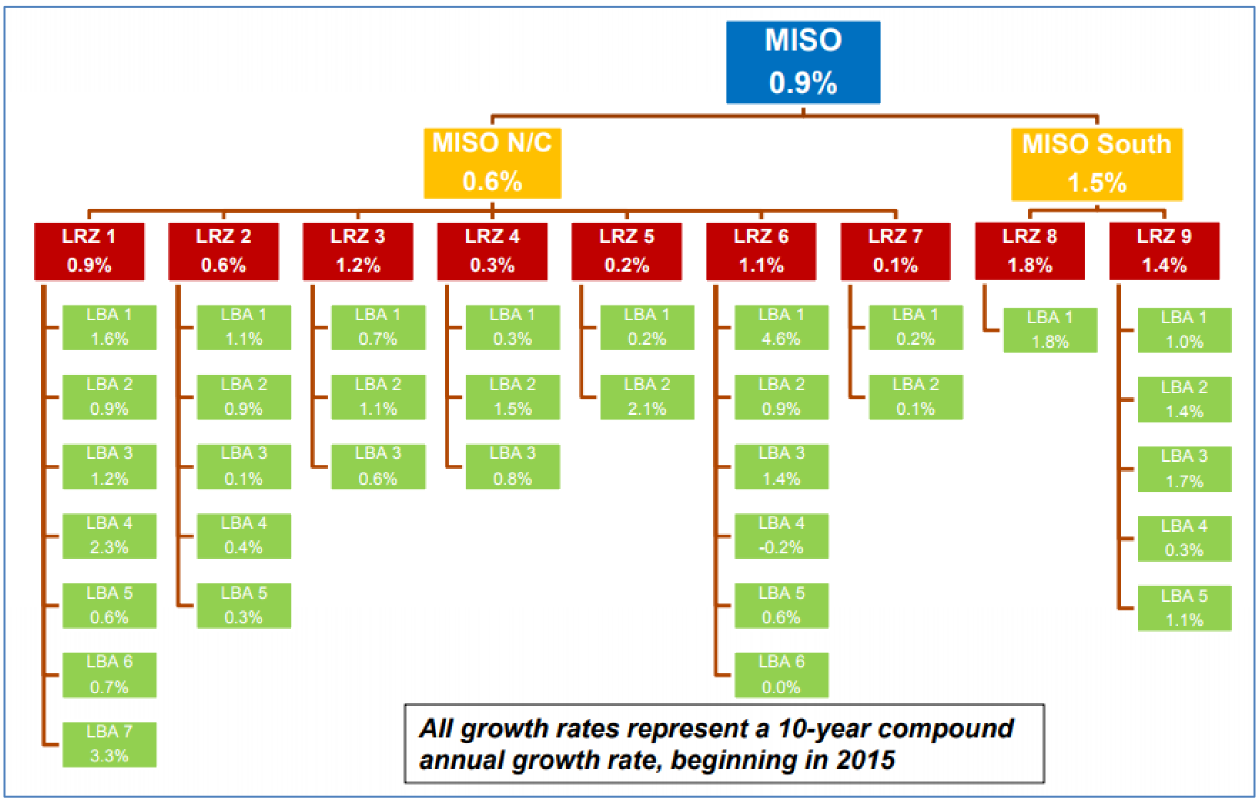
Future	Demand and Energy Growth	Retirement Level* (GW)	Peak Natural Gas Price (2015 $/MMBtu)	Incremental Renewables (GW) N/C: North/Central S: South	CO_2 Cost (2015 $/ton
Business as Usual	0.9%	No Additional	$4.30	N/C: 4.2 Wind/ 1.4 Solar S: 0 Wind/ 0 Solar	N/A
High Demand	1.6%	Age-related	$4.30	N/C: 7.2 Wind/ 1.6 Solar S: 0 Wind/ 0 Solar	N/A
Low Demand	0.2%	Age-related	$3.44	N/C: 2.4 Wind/ 1.3 Solar S: 0 Wind/ 0 Solar	N/A
Regional CPP Compliance	0.9%	14 GW coal + age-related	$5.16	N/C: 4.2 Wind/ 1.4 Solar S: 0 Wind/ 0 Solar + economically chosen wind/solar based on cost maturity curves	$25 / ton
Sub-Regional CPP Compliance	0.9%	20 GW coal + age-related	$5.16	N/C: 4.2 Wind/ 1.4 Solar S: 0 Wind/ 0 Solar + economically chosen wind/solar based on cost maturity curves	$40 / ton

To develop the demand and energy growth rates for each Future, MISO proposes an aggregated, footprint-wide demand and energy growth rate based on historical local growth in demand. These growth rates are typically referenced as 50/50, 10/90, or 90/10 forecasts. The mid-range of these forecasts is the 50/50 forecast, meaning there is an equal chance that the forecast could be higher or lower than the stated growth rate. This represents the typical normal growth rate. The other two forecasts, 10/90 and 90/10 represent what would be considered a low- and high-growth forecast, respectively. The numbers associated with the forecast description give the likelihood of these forecasts of being lower than forecast (first number) or higher than the forecast (second number). This means that a 10/90 forecast has a 10 percent likelihood of the actual demand growth to be under the stated growth projection and 90 percent likelihood of being over the stated growth assumption.

The demand and energy growth numbers stated in the Futures assumptions represent an aggregated average of the Local Balancing Areas (LBA) within MISO, meaning that the load growth input into the Futures models are based on local growth projections instead of a footprint-wide average being applied across the board. This is intended to capture the local growth and area trends to better capture subregional differences and typically include both positive and negative growth rates. These LBA values are aggregated into a Local Resource Zone level, then aggregated again to a MISO footprint level and represent a 10 year compound annual growth rate.

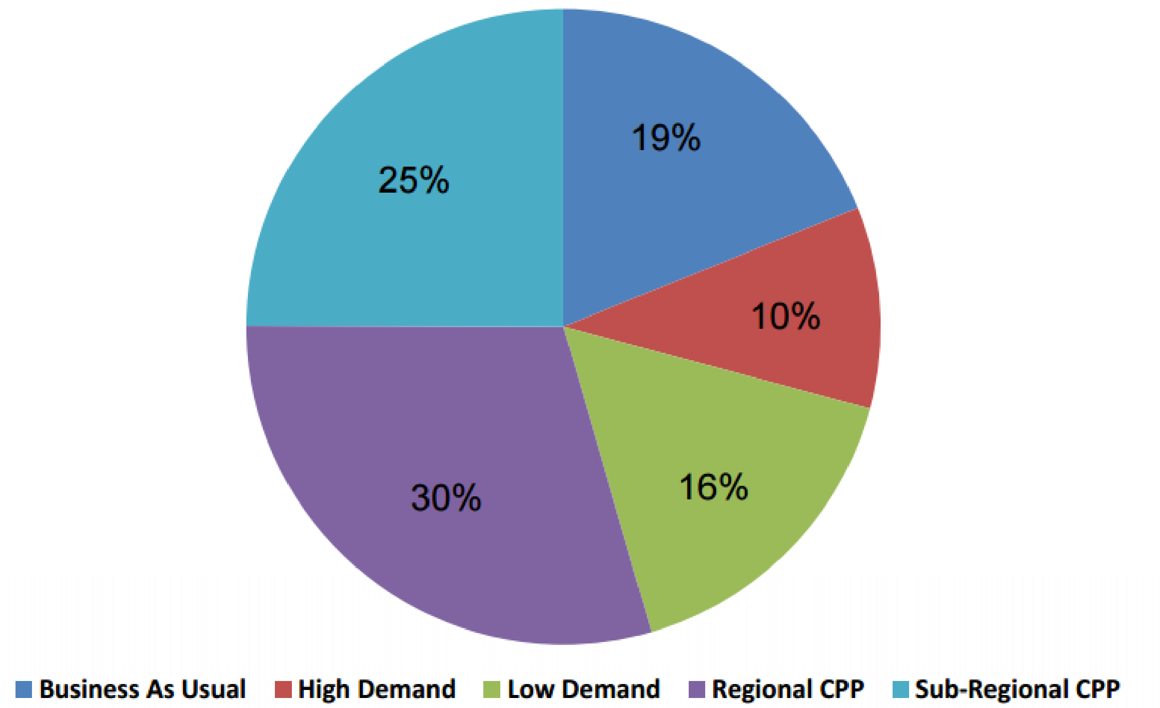
In MTEP16, these projections were applied to the base Module E load forecast data provided by the MISO Load Serving Entities through year 10, and then the forecast assumptions for demand and energy growth were utilized to project beyond year 10. **Figure 18** below shows the breakdown of the 50/50 forecast for MTEP16 that was utilized in the Business As Usual, Regional CPP Compliance, and Sub-regional CPP Compliance Futures.

Figure 18
MTEP16 – 50/50 Forecast



MISO also assigned weights to each of these Futures through a stakeholder process. The weighting is intended to represent the likelihood each one of the Futures is to occur. For these MTEP16 Futures, the weighting is shown in **Figure 19**.

Figure 19
MTEP16 Futures Weighting



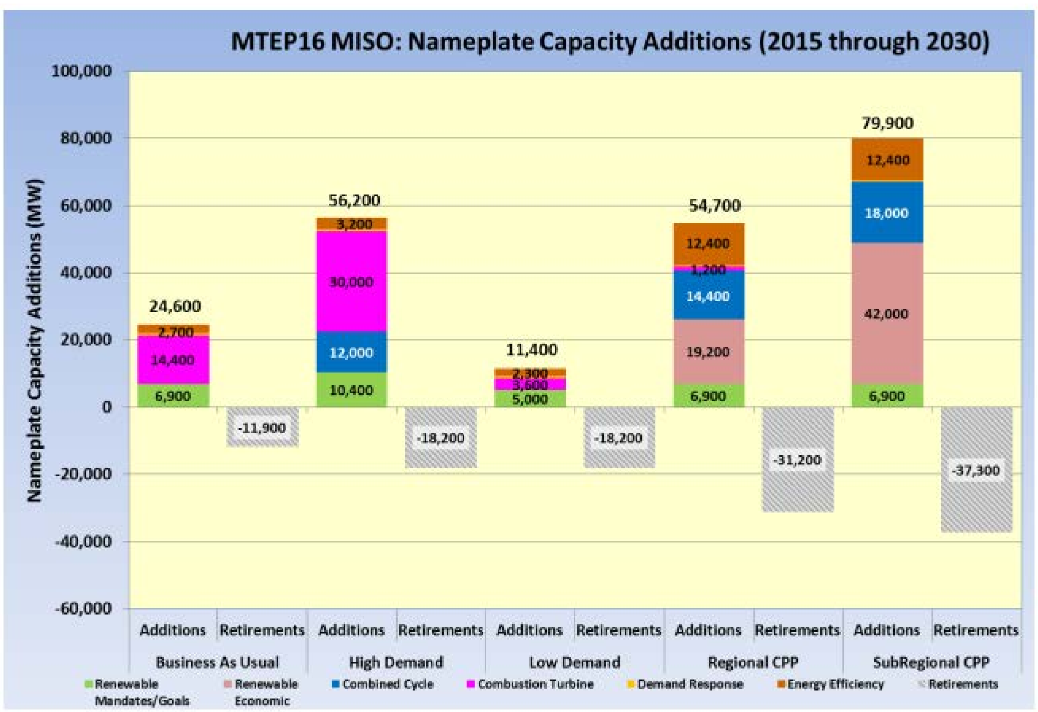
As shown in **Figure 19**, the Regional CPP was the highest weighted future at 30%, with the Sub-Regional CPP Future slightly lower at 25%. The remaining three Futures – Business As Usual, Low Demand, and High Demand – received lower weights at 19%, 16%, and 10%, respectively. This distribution of weights depicts the collective thought of the MISO stakeholders that additional development of renewable energy sources and potential impacts of public policies are a more likely future scenario than any variation of energy demand levels without such changes.

Once the Futures were finalized in September 2015, the MISO Generation Expansion and Siting process commenced. As shown in the table above, each of the individual Futures utilizes different generation capacity, generation retirement, fuel price, and policy regulations to determine a cost-effective generation expansion scenario to meet regional generation capacity needs not being met by the existing generation fleet. This generation expansion analysis is performed using the assumptions agreed upon during the first stage of the Futures development process, which are then incorporated into the MISO generation expansion model using the Electric Generation Expansion

Analysis System (EGEAS),[66] which determines a cost-effective way to meet the region's generation capacity requirements in each of the Futures.

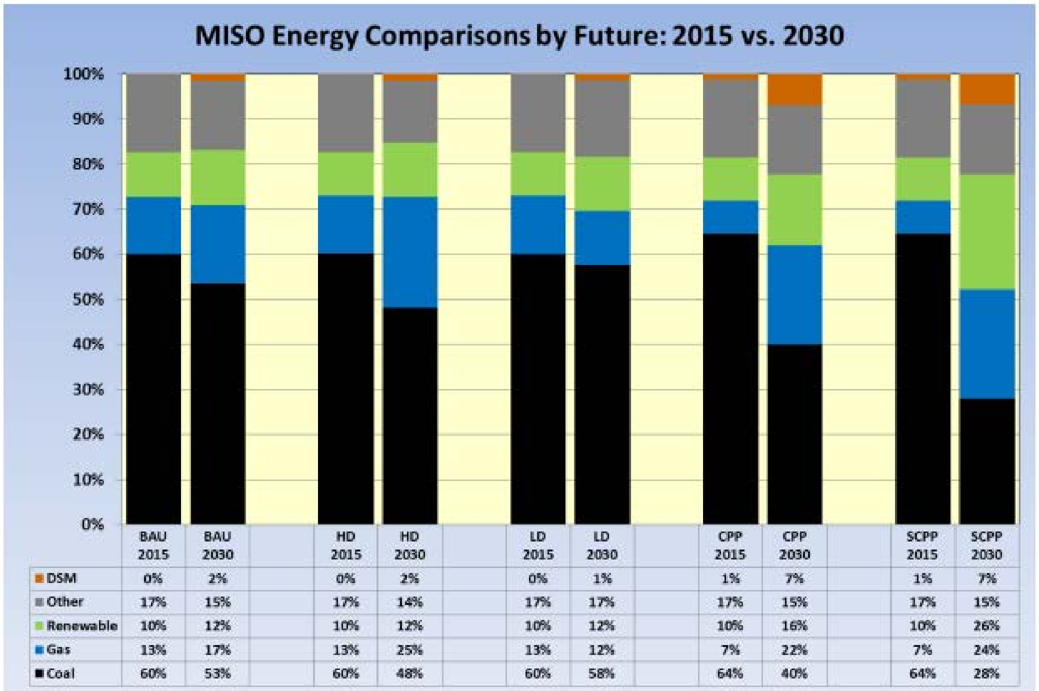
The following tables and images show the magnitude of generation expansion and retirements assumed in each of the five MTEP16 Futures. The following diagrams depict the projected generation fleet capacity changes and energy production produced as a result of the Futures assumptions being analyzed in the scope of a least cost generation expansion analysis. As shown below in **Figure 20** and **Figure 21**, when renewable energy becomes a more economical way to meet all capacity and environmental requirements, the system-wide capacity expansion and energy usage shift substantially away from larger thermal generation and start to favor renewable energy and more efficient and flexible natural gas-fueled generation.

Figure 20
MTEP16 Regional Resource Forecasting



[66] MISO, *MTEP16 EGEAS Results* (Aug. 21, 2015), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2015/20150821/20150821%20EPUG%20Item%2005b%20MTEP16%20EGEAS%20Results.pdf.

Figure 21
MTEP16 Futures Energy Utilization



	BAU 2015	BAU 2030	HD 2015	HD 2030	LD 2015	LD 2030	CPP 2015	CPP 2030	SCPP 2015	SCPP 2030
DSM	0%	2%	0%	2%	0%	1%	1%	7%	1%	7%
Other	17%	15%	17%	14%	17%	17%	17%	15%	17%	15%
Renewable	10%	12%	10%	12%	10%	12%	10%	16%	10%	26%
Gas	13%	17%	13%	25%	13%	12%	7%	22%	7%	24%
Coal	60%	53%	60%	48%	60%	58%	64%	40%	64%	28%

After a reasonable and cost-effective generation expansion plan is determined, MISO then proceeds to develop locations in which these new generation resources will be placed in the economic models in accordance with the rules established for siting of these Regional Resource Forecast (RRF) units.

This analysis resulted in specific generation assumptions for each of the Futures to be analyzed in the MCPS study. Through this process, and as in prior MTEPs, the transmission system in the Mankato/Blue Earth area was identified as having congestion, including the Huntley – Blue Earth – South Bend – Wilmarth 161 kV line. Due to the ever increasing wind development in this area, the congestion increased on this flowgate to a level that warranted further analysis and identification of potential cost-effective solutions to resolve this congestion.

4.1.5.2 Alternatives Development

MISO and its stakeholders work collaboratively to identify potential transmission solutions to address the top congested flowgates. Potential solutions can be submitted by stakeholders or developed by MISO staff. To analyze the 23 possible transmission solutions for addressing congestion in the Minnesota/Iowa border area, MISO first conducted a screening analysis based on a one-year benefit-to-cost ratio. The benefits were based on APC calculations from the 15 year out models. The APC is the production cost adjusted for import/export revenues which measures the cost to produce energy. The difference in APC between the base case and a case including the project candidate is the APC benefit provided by the project. The capital costs for each alternative were also estimated. To compare the alternatives, a weighted one-year benefit-to-cost ratio for each alternative was computed using the Futures weights. The calculation for the Weighted APC Savings is shown below. This sum is divided by the cost for each alternative to calculate the benefit-to-cost ratio.

$$\text{Weighted APC Savings} = (\text{APC Savings}_{RCPP} * 0.3) + (\text{APC Savings}_{SRCPP} * 0.25) + (\text{APC Savings}_{BAU} * 0.19) + (\text{APC Savings}_{LD} * 0.16) + (\text{APC Savings}_{HD} * 0.1)$$

In this screening process, projects that showed a one-year benefit-to-cost ratio greater than or equal to 0.9 were carried forward for further analysis as a potential MEP.[67] Of the 23 alternatives proposed, 16 met this screening test. The 16 alternatives that MISO carried forward are in **Table 9**.

[67] MISO, *Project Candidate Identification Process* (Apr. 18, 2016), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160418/20160418%20EPUG%20Item%2003%20Project%20Candidate%20Identification%20Process.pdf.

Table 9

Alternatives Meeting Screening Threshold

ID	Project Description	MISO Cost Estimate (2016 $M)	Flowgate(s) Addressed	Pass Screening
I-01	Huntley – Wilmarth 345 kV new circuit (double bundled 954 Cardinal ACSR)	$65.0	E	Y
I-02	Huntley – Wilmarth 345 kV new circuit (double bundled 1780 Chukar ACSR)	$70.0	E	Y
I-03	Huntley – Wilmarth 345 kV new circuit (2-795 ACSS)	$90.0	E	Y
I-04	Huntley – Wilmarth 345 kV new circuit (double bundled 1272 54/19 ACSR)	$67.0	E	Y
I-06	Huntley – South Bend – Wilmarth 345 kV new circuit; South Bend 161 kV substation upgraded to 345 kV and existing 161/115 kV transformer replaced by a 345/115 kV transformer, also retire Blue Earth – South Bend 161 kV	$107.0	E	Y
I-07	Huntley – Wilmarth – Cedar Mountain 345 kV new circuit	$214.0	E	Y
I-08	Huntley – South Bend – Wilmarth – Cedar Mountain 345 kV new circuit; South Bend 161 kV substation upgraded to 345 kV and existing 161/115 kV XFMR replaced by a 345/115 kV transformer, also retire Blue Earth – South Bend 161 kV	$231.0	E	Y
I-09	Lakefield Junction – Cedar Mountain 345 kV new circuit	$158.0	E	Y
I-10	Lakefield Junction – Cedar Mountain 345 kV; 3rd 345/161 kV Lakefield transformer	$167.0	E	Y
I-11	Huntley – West Owatonna – North Rochester 345 kV new circuit; West Owatonna 161 kV substation upgraded to 345 kV with a new 345/161 kV transformer	$229.0	E	Y
I-12	Huntley – N. Rochester 345 kV new circuit	$160.0	E	Y
I-13	Colby – Adams 345 kV new circuit	$99.0	E	Y
I-14	Huntley – South Bend 161 kV upgrade; South Bend – North Point – Wilmarth – Swan Lake – Ft. Ridgely – Franklin 115 kV upgrade; Franklin – Cedar Mountain 115 kV does not need to upgrade; South Bend 161/115 kV transformer replacement	$55.0	E	Y
I-15	Huntley – South Bend 161 kV reconductor, South Bend – Wilmarth 161 kV new circuit; Wilmarth substation 161 kV expansion with a 345/161 kV and a 161/115 kV transformer	$38.0	E	Y
I-16	Huntley – Loon Lake – West Owatonna 161 kV; Loon Lake substation 161 kV expansion with a 161/115 kV transformer	$59.0	E	Y
I-19	Freeborn – West Owatonna 161 kV new circuit	$27.0	E	Y

MISO then took the 16 alternatives and grouped them into four groups of solutions based on voltage level and design approach. The alternatives within each group were then ranked. The four groups and the top performer in the screening analysis for each group are listed below:

- ***Group 1***: projects (above 300 kV) that directly strengthened the Huntley/Lakefield to Wilmarth path. The best performer was the Huntley – Wilmarth Project, which was the lowest cost alternative and addressed 100 percent of the congestion.

- ***Group 2***: projects (above 300 kV) that strengthened the southeast transmission corridor into the Twin Cities. The best performer with the highest benefit/cost screening ratio was a new 345 kV circuit between Huntley and North Rochester.

- ***Group 3***: projects (less than 300 kV) that directly strengthened the Huntley/Lakefield to Wilmarth path. The best performer was a project that reconductored the existing 161 kV transmission line from Huntley to South Bend, added a new 161 kV transmission line from South Bend to Wilmarth, and expanded the existing Wilmarth Substation to accommodate the additional 161 kV transmission line. This alternative had the highest benefit/cost screening ratio in the group.

- ***Group 4***: projects (less than 300 kV) that strengthened the southeast transmission corridor into the Twin Cities. The best performer was a project consisting of a new 161 kV transmission line between the existing Freeborn and West Owatonna substations. This alternative had the highest benefit/cost screening ratio in the group.

4.1.5.3 Initial Alternatives Screening

MISO performed a full 20-year NPV calculation for the best performer in each group to determine their initial benefit/cost ratio. This analysis utilized the 5-, 10-, and 15-year horizons for each of the 5 Futures developed for the MTEP16 cycle to develop the 20-year NPV. **Table 10** summarizes the results of this NPV analysis.

Table 10
Summary of NPV Analysis

ID	Transmission Solution	Top Down Cost Estimate (2016 $M)	Benefit-to-Cost Ratios						20-yr PV Benefit ($M)
			BAU	HD	LD	RCPP	SRCPP	Weighted	
I-02	Huntley – Wilmarth 345 kV new circuit (double bundled 1780 Chukar ACSR)	$100.9	0.51	1.29	0.12	1.71	6.72	2.44	$344
I-12	Huntley – N. Rochester 345 kV new circuit	$234.7	0.25	0.64	0.05	0.53	2.67	0.95	$288
I-15	Huntley - South Bend 161 kV reconductor, South Bend – Wilmarth 161 kV new circuit; Wilmarth Substation 161 kV expansion with a 345/161 kV and a 161/115 kV transformer	$48.4	0.42	1.32	0.09	1.81	5.15	2.06	$121
I-19	Freeborn – West Owatonna 161 kV new circuit	$40.8	0.60	1.68	0.11	0.97	12.62	3.75	$189

MISO then eliminated the Huntley – North Rochester 345 kV alternative because it had a weighted benefit-to-cost ratio (0.95) of less than 1.0, meaning its costs exceed its benefits.[68]

4.1.5.4 Updated Modeling and Analysis

MISO then refreshed its analysis to more accurately depict locations of recent wind generation additions in the Futures models. In the first set of MTEP16 Futures, the future wind generation sited in wind zone WI-B, which is meant to be in southwestern Wisconsin, was incorrectly modeled at the Freeborn Substation in southern Minnesota. When the wind generation was moved to the correct location, the benefits attributed to the Freeborn – West Owatonna 161 kV proposal significantly declined. In contrast, the Huntley – Wilmarth 345 kV Project maintained

[68] MISO, *Solution Screening and Preliminary Project Candidates – MN/IA* (Apr. 18, 2016), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160418/20160418%20EPUG%20Item%2004c%20Screening%20and%20PV%20Analysis%20-%20MN%20IA.pdf.

a high level of benefit. **Table 11** below shows the results obtained from the refreshed 20-year NPV analysis.[69]

Table 11
Revised NPV Analysis

ID	Transmission Solution	Top Down Cost Estimate (2016 $M)	Benefit-to-Cost Ratios						20-yr PV Benefit ($M)
			BAU	HD	LD	RCPP	SRCPP	Weighted	
I-2	Huntley – Wilmarth 345 kV new circuit	$100.9	0.48	1.22	0.14	1.39	4.85	1.87	$242
I-15	Huntley - South Bend 161 kV reconductor, South Bend – Wilmarth 161 kV new circuit; Wilmarth Substation 161 kV expansion with a 345/161 kV and a 161/115 kV transformer	$48.4	0.35	1.01	0.12	1.38	4.00	1.60	$95
I-19	Freeborn – West Owatonna 161 kV new circuit	$40.8	0.32	0.82	0.04	0.56	3.54	1.20	$60

MISO also analyzed the amount of the identified congestion that each project mitigated. As shown in **Table 12** below, while the two lower voltage 161 kV projects did provide economic benefits, they did not address all of the identified congestion. To eliminate all of the congestion, additional facilities would be required in addition to the 161 kV facilities.

[69] MISO, *Robustness Testing – North/Central* (June 14, 2016), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160614/20160614%20EPUG%20Item%2003%20Robustness%20Testing.pdf.

Table 12
Summary of Comparison of MTEP16 Alternatives

ID	Transmission Solution	B/C Above 1.0?	Highest B/C Ratio?	Highest 20-yr PV Benefit?	% Congestion Relief (Year 2031)
I-2	Huntley – Wilmarth 345 kV new circuit (double bundled 1780 Chukar ACSR)	✓	✓	✓	100%
I-15	Huntley - South Bend 161 kV reconductor, South Bend – Wilmarth 161 kV new circuit; Wilmarth Substation 161 kV expansion with a 345/161 kV and a 161/115 kV transformer	✓	×	×	66%
I-19	Freeborn – West Owatonna 161 kV new circuit	✓	×	×	30%

4.1.5.5 Selection of Huntley – Wilmarth Project as an MEP

In comparing these three alternatives, MISO eliminated the Freeborn – West Owatonna 161 kV circuit alternative because it relieved only 30 percent of the congestion. MISO determined that the I-15 project had a lower benefit-to-cost ratio and lower 20-year Present Value benefit than the Huntley –Wilmarth Project and did not relieve 100 percent of the congestion. Ultimately, MISO selected the Huntley – Wilmarth Project as the best overall solution because it resolves 100 percent of the congestion and had the highest benefit-to-cost ratio. MISO also determined that the Project was a robust solution because it maintained a high benefit-to-cost ratio under a variety of different Futures. To further test the robustness of this solution, MISO conducted an economic sensitivity analysis and a reliability analysis.

MISO completed two sensitivity analyses based on the physical location of the future wind units and interconnection points assumed to be in the Futures and announced generation retirements. The first of these economic sensitivity analyses included a look at the impacts of the retirement and replacement of the large Sherburne County Generation Station (Sherco) units 1 and 2 located northwest of the Twin Cities metro area. The units, which are 682 MW each, are planned to retire in 2023 and 2026, respectively. Specifically, MISO examined the retirement of these two large baseload generation sources northwest of the Twin Cities area, the largest urban area in Minnesota, and replaced this capacity with a 600 MW natural gas combined cycle generator and a 600 MW natural gas combustion turbine at the current Sherco location.

The second sensitivity tested whether the Project's benefits were sensitive to the location of forecasted wind generation additions meant to meet resource requirements external to MISO. To accomplish this second sensitivity, MISO removed the RRF generators, sited using the MTEP Futures siting guidelines, intended to meet non-MISO resource requirements. The result of these sensitivities showed that the Project maintains a high benefit-to-cost ratio under the generation location variations studied, with increased projected benefits in the Sherco replacement sensitivity. **Table 13** shows the sensitivity analysis results.

Table 13
Sensitivity Analysis Results

<table>
<tr><th rowspan="2">ID</th><th rowspan="2">MISO Cost Estimate (2016 $M)</th><th rowspan="2">Sensitivities</th><th colspan="6">Benefit-to-Cost Ratios</th><th rowspan="2">20-yr PV Benefit ($M)</th></tr>
<tr><th>BAU</th><th>HD</th><th>LD</th><th>RCPP</th><th>SRCPP</th><th>Weighted</th></tr>
<tr><td rowspan="3">I-02</td><td rowspan="3">$100.9</td><td>Base Case</td><td>0.51</td><td>1.29</td><td>0.12</td><td>1.71</td><td>6.72</td><td>2.44</td><td>$344</td></tr>
<tr><td>Sherco Retirement/ Replacement</td><td>0.70</td><td>1.84</td><td>0.30</td><td>1.71</td><td>6.72</td><td>2.55</td><td>$360</td></tr>
<tr><td>External RRF Wind in IA Removal</td><td>0.51</td><td>1.29</td><td>0.12</td><td>0.91</td><td>4.50</td><td>1.64</td><td>$232</td></tr>
</table>

MISO also analyzed two alternatives that included the Huntley – Wilmarth 345 kV Project and additional 115 kV facilities. MISO evaluated where congestion would next develop on the system once the Project was in service. The incremental benefit-to-cost ratio was analyzed for each alternative. **Table 14** shows the results of MISO's analysis which showed that the Huntley – Wilmarth 345 kV line by itself provided the highest benefit-to-cost ratio.

Table 14 also summarizes a generation interconnection queue sensitivity analysis MISO performed to look at the physical location of the future wind units assumed to be in the Futures. This generation interconnection queue sensitivity tested whether the Project's benefits were dependent on the location of forecasted wind generation additions. To accomplish the goal of this sensitivity, MISO replaced the RRF wind generators, sited using the MTEP Futures siting guidelines, with wind generation which was sited at the same location as wind generation interconnection requests that were in the final stage of the MISO Generator Interconnection Process. The results of this analysis showed that, with the level of wind likely to be interconnected based on historical interconnection trends, the benefits of the Project increase in all Futures. The analysis indicated increased economic benefits when more precise generator locations were included in the modeling.

Table 14
Huntley – Wilmarth Project Variations

ID	Transmission Solution	Model	MISO Cost Estimate (2016 $Millions)	Benefit to Cost Ratios						20-yr PV Benefit ($ Millions)
				BAU	HD	LD	RCPP	SRCPP	Weighted	
I-2	Huntley – Wilmarth 345 kV new circuit	Base	$88-108	0.43-0.52	1.16-1.42	0.10-0.13	1.32-1.62	3.63-4.45	1.51-1.86	$210
		Queue Wind Sensitivity		1.39-1.71	2.40-2.95	0.69-0.85	2.45-3.01	2.03-2.49	1.86-2.28	$251
I-2b	Huntley – Wilmarth 345 kV new circuit, Wilmarth to Swan Lake – Ft Ridgely 115 kV upgrade	Base	$113.3-133.3	0.37-0.43	1.12-1.31	0.09-0.10	1.15-1.35	3.31-3.90	1.36-1.60	$234
		Queue Wind Sensitivity		1.13-1.33	2.08-2.45	0.55-0.65	2.02-2.39	1.73-2.03	1.55-1.83	$259
I-2d	Freeborn – West Owatonna 161 kV new circuit	Base	$154.8-174.8	0.27-0.31	0.92-1.04	0.08-0.10	0.98-1.11	3.03-3.43	1.21-1.36	$272
		Queue Wind Sensitivity		0.86-0.97	1.74-1.97	0.44-0.50	1.68-1.90	1.55-1.76	1.30-1.47	$285

For reliability, MISO conducted studies to assess whether there would be any reliability issues resulting from the construction of the Huntley – Wilmarth Project. This was referred to as a "No-Harm test." Through this analysis, MISO found that there were no additional reliability needs created by the inclusion of the Huntley – Wilmarth Project in the MISO transmission system. Based on this study work, the

MISO Board of Directors approved the Huntley – Wilmarth Project as an MEP and for inclusion in Appendix A of MTEP16.[70]

4.2 Applicants' Analysis of Need

The MISO Board of Directors approved the Huntley – Wilmarth Project in December 2016. Since that time, MISO and its stakeholders have continued to examine recent developments and trends in the energy policy, demand growth, and fuel prices. MISO and its stakeholders have incorporated this examination into the development of new and updated Futures for its MTEP17 report that was approved by the MISO Board of Directors on December 7, 2017.[71] To verify that the Project provides economic benefits under these most recent MISO Futures, the Applicants analyzed the Project under the three MTEP17 Futures. The results of this analysis, as described further below, demonstrate that the projected 20-year NPV benefits of the Huntley – Wilmarth Project are even greater than those projected under the MTEP16 Futures.

4.2.1 MTEP17 Analysis

4.2.1.1 MTEP17 Futures

For MTEP17, MISO, in coordination with stakeholders, narrowed the number of Futures from the five Futures used in MTEP16 to three Futures – Existing Fleet (EF), Policy Regulations (PR), and Accelerated Alternative Technologies (AAT). The key components of these Futures are:

- <u>*Existing Fleet Future*</u>: is a baseline future in which the existing generation fleet is mostly unchanged, with the exception of age-related retirements. This Future has no carbon regulations, uses the low-point gas price forecast, and has low demand (0.3 percent) and energy (0.3 percent) growth rates. Sufficient renewable resources are added to meet all current state-level RPSs. This Future

[70] MISO, *MTEP16 – MISO Transmission Expansion Plan* (2016) [hereinafter MTEP16], *available at* https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Full%20Report.pdf or as Appendix F to this Application.

[71] MISO, *MTEP17 – MISO Transmission Expansion Plan* (2017) [hereinafter MTEP17], *available at* https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEP17.aspx.

assumes that renewable tax credits continue until 2022. Nuclear units are assumed to have license renewals granted and remain online.

- *Policy Regulations Future*: has a carbon reduction target of 25 percent. This carbon reduction target is met through increased renewable resources as well as age and economic-related coal retirements. The mid-point gas price forecast was used in this Future, along with a 50/50 forecast for demand and energy growth rates (0.7 percent). This Future assumes that renewable tax credits continue until 2022. Nuclear units are assumed to have license renewals granted and remain online.

- *Accelerated Alternative Technologies*: is a high-renewable Future with a carbon reduction target of 35 percent. Coal units are economically retired to meet this carbon reduction target. High renewable development has been implemented using a maturity cost curve reflecting technological advancement and economies of scale associated with a large renewable build out. Demand and energy growth rates are the highest in this Future (1.0 percent). The high-point gas price forecast is used. This Future assumes that renewable tax credits continue until 2022. Nuclear units are assumed to have license renewals granted and remain online.

A summary of the key assumptions for these three Futures is provided in **Table 15**.

Table 15
MTEP17 Futures Comparisons: Key Assumptions[72]

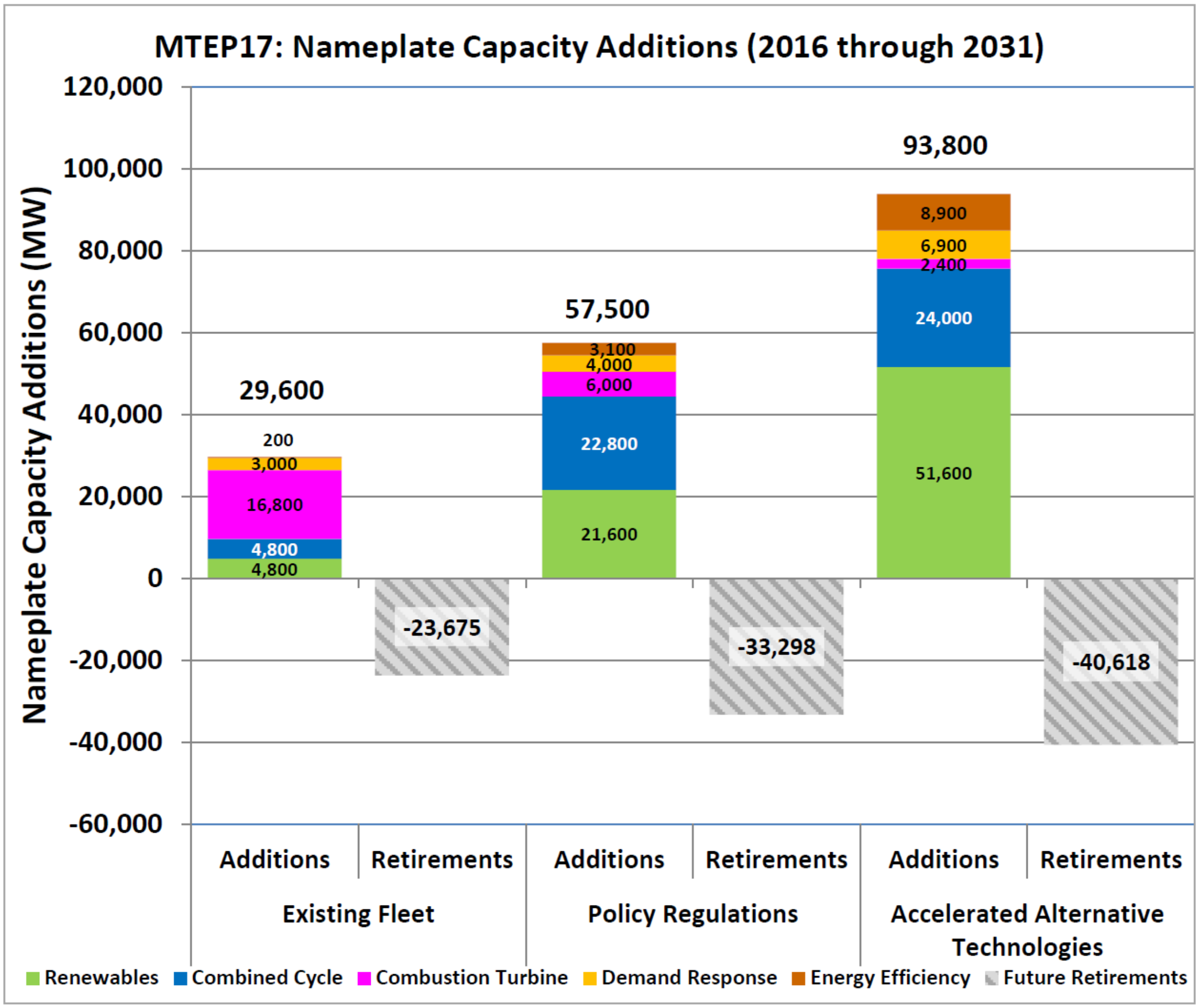
MTEP 2017 Future	Existing Fleet	Policy Regulations	Accelerated Alternative Technologies
Carbon Reductions *From 2005 Levels*	Current levels: ~14%	25%	35%
Demand and Energy	Low (10/90)	Base (50/50)	High (90/10)
Natural Gas Price *Nominal Dollars/MMBTU*	Base –30%	Base	Base +30%
Demand Side Additions *By Year 2031*	EE: 0.2 GW DSM: 3 GW	EE: 3 GW DSM: 4 GW	EE: 9 GW DSM: 7 GW
Renewable Additions *By Year 2031*	5 GW	22 GW	52 GW
Generation Retirements *By Year 2031*	Coal: 8 GW Gas/Oil: 16 GW	Coal: 16 GW Gas/Oil: 16 GW	Coal: 24 GW Gas/Oil: 16 GW

To determine the demand and energy growth rates for each Future, MISO employed the same process utilized for MTEP16 that is discussed in detail above. Load-serving entities submit demand forecasts for the upcoming 10 years. MISO utilizes these forecasts to calculate the Existing Fleet Future load growth. Based on these forecasts, MISO anticipates a system-wide average growth rate of 0.3 percent for 2018-2028.

The future resource additions and retirements for each MTEP17 Future are provided in **Figure 22**. As shown in this figure, renewables are only added to the Existing Fleet Future to meet RPS requirements (not on an economic basis), achieving 11 percent renewable energy in this low load growth Future. In contrast, the Policy Regulation Future shows an increased buildout of renewables (16 percent increase) and natural gas to meet the need for lower CO_2 emitting replacements for coal retirements as well as to meet medium load growth and RPS requirements. In the Accelerated Alternative Technologies Future, the Future with the highest (26 percent) increase in renewables, this increase is driven by stricter CO_2 regulations resulting in more coal retirements while at the same time higher load growth requires replacement of these resources with renewable sources.

[72] MTEP17 at 73.

Figure 22
MTEP17 Futures Comparisons: Nameplate Capacity Additions (2016-2031)[73]

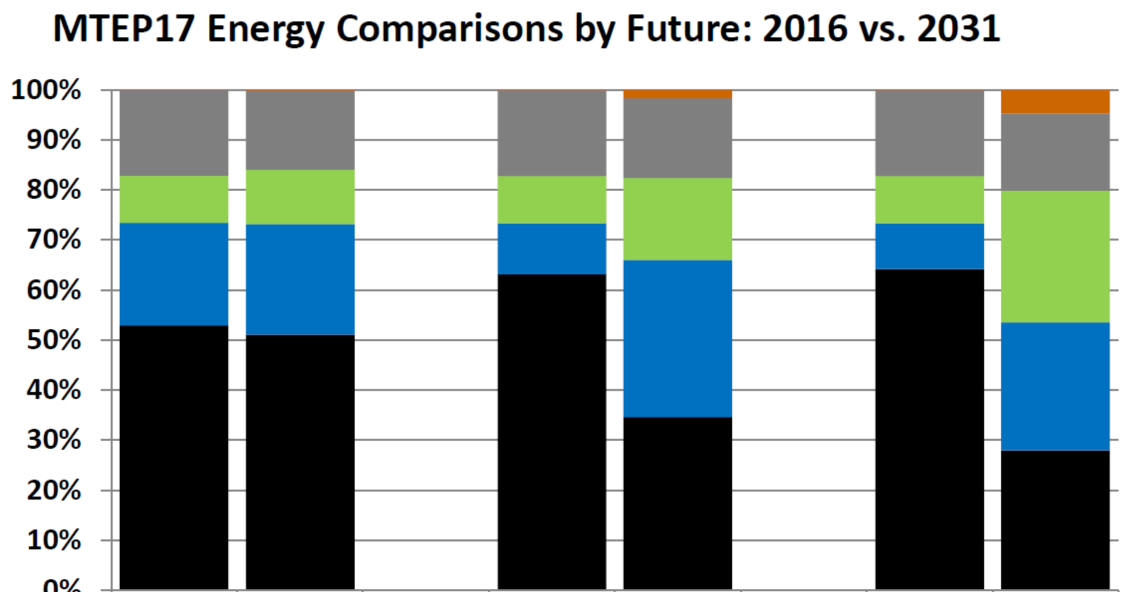


A comparison of the energy utilization of the system for each MTEP17 Future in 2016 (base year) versus 2031 (final year of PROMOD for MTEP17) is provided in **Figure 23**. As illustrated by **Figure 23**, the Existing Fleet Future shows very little change from 2016 through 2031 whereas the Policy Regulations Future and Accelerated Alternative Technology Future, over the same time period, show much more dramatic changes to generation technologies. Specifically, both of these Futures show significant decreases in coal generation and significant increases in both renewable and natural gas generation.

[73] MTEP17 at 76.

Figure 23

MTEP17 Futures Comparisons: Energy Mix 2016 v. 2031[74]



	EF 2016	EF 2031		PR 2016	PR 2031		AAT 2016	AAT 2031
DSM	0%	0%		0%	2%		0%	5%
Other	17%	16%		17%	16%		17%	15%
Renewable	9%	11%		9%	16%		9%	26%
Gas	20%	22%		10%	31%		9%	26%
Coal	53%	51%		63%	35%		64%	28%

These three MTEP17 Futures were approved by MISO stakeholders as appropriate bookends for different possible future scenarios. The goal of these three Futures is not to exactly match reality but rather to bookend future uncertainty by defining a wide range of potential outcomes such that the future reality will be captured within this range of Futures.

After the development of the Futures scenarios, MISO and the MISO stakeholders agreed upon the likelihood of each Future occurring as compared to the other Futures by assigning each Future a percentage weight. **Table 16** below provides the Future weighting for MTEP17.

[74] MTEP17 at 77.

Table 16
MTEP17 Futures Weighting

MTEP17 Future	Weighting
Existing Fleet	31%
Policy Regulations	43%
Accelerated Alternative Technologies	26%

4.2.1.2 MTEP17 Futures Analysis

The Applicants analyzed the Huntley – Wilmarth Project under the three Futures included in MTEP17. As shown in **Table 17** below, the weighted 20-year present value for the Project was even higher than that projected by MISO's MTEP16 analysis ($210 million vs. $296 million). These differences are likely due to the increased reliance on wind generation in the MTEP17 Futures, as well as the increased weight placed on the Futures with higher wind penetration levels.

Applicants further examined the benefit-to-cost ratio of the Huntley – Wilmarth Project based on the Applicants' route- and design-specific cost estimates. As detailed in Chapter 2, the Applicants' Project costs range from $105.8 million to $138.0 million (2016$) depending on the route and design selected by the Commission. As outlined in **Table 17** below, with these updated costs, the benefit-to-cost ratio for the Project is between 1.64 and 2.14 under the MTEP17 Futures.

Table 17
MTEP17 Analysis with Current Project Cost Estimates (2016$)

Project	Applicants' Project Cost Estimates (2016$ Millions)	Expected In-Service	PV Benefit (Million 2016$)				Benefit-to-Cost Ratios (Millions, 2016$)			
			AAT	EF	PR	Weighted	AAT	EF	PR	Weighted
Huntley – Wilmarth 345 kV	$105.8-$138.0	2022	821.79	2.33	136.56	273.11	4.93-6.43	0.01-0.02	0.82-1.07	1.64-2.14

As a result, the benefits of the Project outweigh the costs of the Project regardless of the route or design selected by the Commission. **Appendix K** contains detailed benefit-to-cost calculations for each specific route and design proposed by the

Applicants. In addition, the MTEP17 benefit-to-cost ratios are higher than those from MTEP16 base case (1.51-1.86 compared to 1.64 to 2.14) and slightly lower than the MTEP16 Queue wind sensitivity (1.86 to 2.28 compared to 1.64 to 2.14). This demonstrates that the Project provides net benefits under a range of future scenarios.

4.2.2 Deliverability of Wind Generation

4.2.2.1 Curtailment Benefits

One of the other benefits of the Huntley – Wilmarth Project is that it increases the deliverability of wind resources by reducing curtailments of wind generation on the system. When existing wind generation is curtailed, ratepayers lose the benefit of cost-effective renewable energy. Instead, other generation, typically higher cost fossil fuel generation, must be relied on thereby increasing costs and reducing the potential economic and environmental benefits of wind generation.

Economic curtailment occurs when congestion on the transmission system reaches a point where the Locational Marginal Price (LMP) at a wind node decreases to a point where the wind farm cannot generate economically; this is generally at or below $0/MWh. This congestion lowers LMPs on the generation side of the constraint, signaling resources to reduce production. Simultaneously, LMPs on the load side of the constraint increase which incentivize resources to increase production. This high LMP enables other higher cost generation to dispatch as the higher prices justify the operating costs. This rebalancing of the generation alleviates the transmission overload but increases wholesale energy costs as more expensive generation is dispatched.

The curtailment price set in the MTEP17 database is $0.50/MWh in 2026 and 2031. When the LMP at the bus that the wind resource is located drops below $0.50/MWh that resource will be curtailed to the level required to maintain the $0.50/MWh during that hour. If there is no feasible level of dispatch that will keep the LMP at the curtailment price, the generation schedule will go to 0 MW and the LMP will go below the curtailment price.

An example would be if the LMP at a 100 MW capacity wind resource is at or below $0.50/MWh, PROMOD will attempt to limit the power generated by the resource to maintain the LMP at $0.50/MWh. If 50 MW is the proper level of generation to maintain the price at $0.50/MWh, the resource will be limited to 50 percent output for that hour. PROMOD treats hourly resources (wind or, in general, all non-hydro renewable resources) as a dispatchable resource with the dispatch cost/bid being set to the curtailment price. Generally, the LMP is higher than the curtailment price, so the full amount of wind available at that hour is generated; only when the price reaches the curtailment price does PROMOD reduce the level of generation from the resource.

To determine the effect the Project will have on wind resource curtailments, Applicants analyzed the curtailments of wind resources in the MTEP17 model with the 345 kV Huntley – Wilmarth line "in" and "out-of-service." PROMOD reports curtailment data for all wind resources in the MISO footprint as well as surrounding areas. To ensure wind resources studied were close to the Project, wind resource data was filtered by location to Minnesota, North Dakota, South Dakota, and Iowa. The results of this analysis can be found in **Table 18** through **Table 20**. It is important to note that, while the Project will lower curtailments in the area due to the congestion relief, curtailments will still be present on the overall transmission system. The Project is solving a large flowgate but other transmission system limitations exist and will change as generation, transmission, and load changes. Elimination of all congestion is not reasonable due to the high cost of system improvements in comparison to the benefits provided by a transmission system without congestion.

Table 18
Existing Fleet Projected Curtailments

Year	Project	Base Curtailments (MWh)	Curtailments With Project Added (MWh)	Reduction In Curtailments (MWh)	Percent Reduction
2026	Huntley – Wilmarth 345 kV line	45,359	41,519	3,841	8.5%
2031	Huntley – Wilmarth 345 kV line	71,827	55,519	16,308	22.7%

Table 19
Policy Regulation Projected Curtailments

Year	Project	Base Curtailments (MWh)	Curtailments With Project Added (MWh)	Reduction In Curtailments (MWh)	Percent Reduction
2026	Huntley – Wilmarth 345 kV line	149,894	106,863	43,031	28.7%
2031	Huntley – Wilmarth 345 kV line	1,387,356	1,184,008	203,348	14.7%

Table 20
Advanced Alternative Technologies Projected Curtailments

Year	Project	Base Curtailments (MWh)	Curtailments With Project Added (MWh)	Reduction In Curtailments (MWh)	Percent Reduction
2026	Huntley – Wilmarth 345 kV line	8,246,099	7,067,818	1,178,281	14.3%
2031	Huntley – Wilmarth 345 kV line	18,134,162	16,457,680	1,676,482	9.2%

As shown in **Table 18** through **Table 20**, the Huntley – Wilmarth Project reduces wind curtailments by as much as 28 percent in the Policy Regulation Future and, at minimum, by 8.5 percent under the Existing Fleet Future.

4.2.2.2 Development of Future Wind Contingent on the Project

The unprecedented level of interconnection requests for wind generators in the area of the Project has continued since the Project's approval. Moreover, and in accordance with MISO model development practices, the Project has been included in all economic, reliability, and interconnection models that have been developed since the Project's approval as part of MTEP16. Interconnection of these generators is conditional upon the completion of the Project.

Starting with the February 2016 DPP cycle, the Huntley – Wilmarth Project will be considered in-service at the beginning of 2022. The DPP cycles before February 2016 utilized model years before the in-service date of the Project. Based on the studies conducted to date, 134 interconnection requests amounting to over 21,000 MW are conditioned on, but not necessarily dependent on, the Huntley – Wilmarth Project. These generators can be subject to quarterly operating studies that can restrict the output of the plants each quarter. Even if these quarterly studies allow the maximum output of the generators, the MISO real-time and day-ahead market could constrain the output of these units because of system limits that would be addressed by the Project. Once the Project and the other conditional facilities are constructed and put into operation, the quarterly operating studies will no longer be performed.

5. ALTERNATIVES ANALYSIS

In Chapter 5 we explain our analysis of different alternatives that we have considered to solve the need that we identified in the previous chapter. This includes examining generation, different transmission line voltages, and different transmission line configurations, as well as demand-side management and a "no build" alternative to solve the identified need. As explained in Chapter 4, MISO also evaluated 23 alternative transmission line voltages and configurations as part of its analysis in MTEP16. As discussed in more detail below, both Applicants' and MISO's analysis of these alternatives determined that the Project is the best solution to resolve the identified transmission system congestion on the Minnesota/Iowa border and would provide the highest benefit-to-cost ratio compared to other transmission alternatives.

Key Terms:

- ***Alternating Current (AC)*** – an electric current that reverses its direction many times at regular intervals. AC is the typical form in which electric power is delivered to homes and businesses.
- ***Ampere or amp*** – the unit used for measuring electric current, which is the measure of the number of electrons flowing through a conductor at a fixed rate.
- ***Ampacity*** – the current, in amps, that a conductor can carry continuously under specified conditions of use without exceeding its temperature rating.
- ***Conductor*** – an object or type of material that allows the flow of an electrical current in one or more directions. An overhead transmission line consists of one or more conductors (commonly multiples of three) suspended by structures.
- ***Current*** – the measure of the flow of electrons through a conductor.
- ***Demand-side management*** – actions that influence the quantity or patterns of use of energy consumed by end users, such as actions targeting reduction of peak demand during periods when energy supply systems are constrained.

- ***Double Circuiting*** – refers to an arrangement where two transmission line circuits (three phases for each circuit) are combined onto a single transmission structure such that the structure supports and insulates six conductors.

- ***Direct Current (DC)*** – the unidirectional flow or movement of electrons. For movement of electricity over long distances, DC transmission lines can have certain advantages as compared to the more common AC transmission lines including lower electrical losses.

- ***Generation*** – the act of converting various forms of energy input (thermal, mechanical, chemical, and/or nuclear energy) into electric power. The amount of electric energy produced is usually expressed in kWh or MWh.

- ***Renewable energy*** – an energy source that is renewed by nature, such as solar, wind, hydroelectric, geothermal, biomass, or similar sources of energy.

Applicants analyzed a range of alternatives to the Project as required by Minnesota Certificate of Need statutes and rules. These alternatives included: (i) size alternatives (different voltages or conductor arrays, AC/DC, and double circuiting); (ii) type alternatives, including alternative terminals/substations, double circuiting with existing transmission lines, generation alternatives, and underground transmission lines; and (iii) the no build alternative (including an analysis of Demand Side Management). In this chapter, Applicants describe their analysis of these alternatives and their conclusion that none is a more prudent or reasonable alternative to the Project.

5.1 Size Alternatives

5.1.1 Different Voltages

Both MISO and the Applicants evaluated the feasibility of different line voltages (both higher and lower) to relieve the identified congestion along the Minnesota/Iowa border. Given the significant amount of wind generation currently in place and planned for southern Minnesota and northern Iowa, it is important that sufficient transmission capacity be in place to transfer this renewable generation efficiently. The capacity of a transmission line is a function of its voltage as, generally speaking, higher voltage lines have higher capacity than lower voltage lines.

In Minnesota, 345 kV is the standard high voltage that is utilized to transfer large amounts of power across long distances. The 345 kV voltage is the standard because it provides sufficient capacity to accommodate large power transfers, can be easily incorporated into the existing transmission system, and minimizes line losses. Voltages higher than 345 kV are currently less utilized in Minnesota and are reserved for long distance point-to-point power transfers (i.e., moving power from Manitoba hydro generation facilities into Minnesota). Voltages lower than 345 kV are used primarily for load serving support. Following an exhaustive evaluation both as part of MTEP16 and for purposes of this Application, both MISO and the Applicants concluded that the proposed 345 kV voltage is the appropriate voltage level to relieve all of the congestion and to efficiently transfer the wind generation currently projected to be developed in southern Minnesota and northern Iowa.

5.1.1.1 Higher Voltage Alternatives

For higher voltage lines, the Applicants considered 765 kV and 500 kV lines. As there are no existing transmission lines of either of these voltages currently in southwest Minnesota or northern Iowa, constructing a new line of these higher voltages would require substantial additional substation facilities. Specifically, in order to connect these higher voltage lines to the existing electric system, mainly comprised of 345 kV, 161 kV, and 115 kV lines in this area, would require new transformers to be installed at both the Huntley and Wilmarth substations to accommodate these higher voltages. In addition to the costs of these transformers, 765 kV and 500 kV lines are, in general, more costly to construct than 345 kV lines. As the proposed 345 kV transmission line is projected to relieve all of the identified congestion in this area until at least 2031, Applicants determined that there was little benefit to incurring the higher costs associated with these higher voltage lines at this time.

5.1.1.2 Lower Voltage Alternatives

Transmission line voltages lower than 345 kV include: 230 kV, 161 kV, 138 kV, 115 kV, and 69 kV. As there are no existing 230 kV or 138 kV transmission lines in the Project area, these voltages were eliminated from further study due to the costs associated with the substation upgrades required to accommodate these new voltages.

MISO and the Applicants considered 69 kV, 115 kV, and 161 kV voltages as these voltages are present among the existing transmission lines in the Project area. In examining transmission alternatives to relieve congestion, the capacity of the transmission line is an important consideration as the amount of congestion present in a region is, in part, a function of the amount of available transmission capacity. Assuming all other things being equal, as the amount of transmission capacity increases when new transmission is added to the system, the cost of congestion declines because the number of hours congestion occurs and the energy price differentials within the system are reduced.

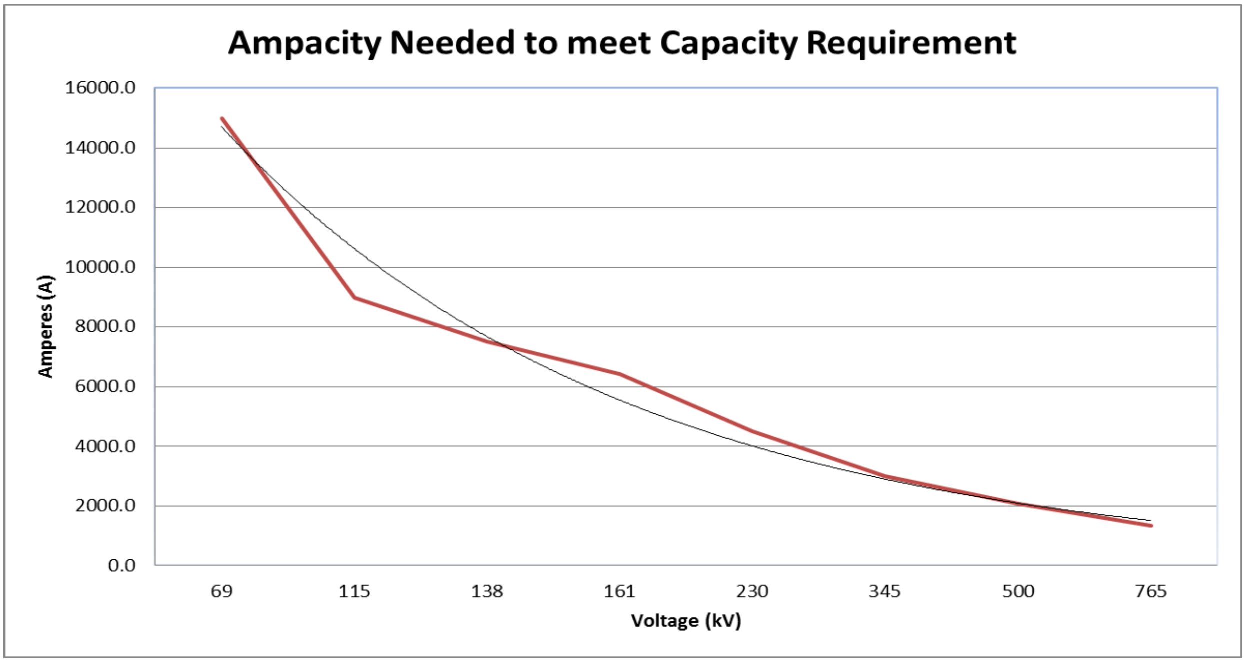
Moreover, as additional renewable generation is constructed in southern Minnesota and Iowa, the existing congestion problem will only worsen if there is not sufficient capacity available to transmit this generation to load centers such as the Twin Cities. As of November 2017, there is approximately 19,400 MW of wind in the MISO queue that has requested to be placed in-service prior to 2021, as discussed in **Chapter 4**.

Generally speaking, the higher the voltage of a transmission line, the higher capacity that the line has to carry energy, assuming the same current strength. The correlation between voltage level and the capacity of a transmission line is shown by the following equation:

$$\text{Three Phase AC Power (MVA, capacity)} = \text{Volts (V)} \times \text{Amperes (I)} \times \sqrt{3}$$

The proposed Huntley – Wilmarth 345 kV transmission line has a capacity rating of 1792 MVA. **Figure 24** below shows the current rating that would need to be assumed for the various lower voltages to achieve this same level of capacity.

Figure 24
Capacity Calculation *



**Red line is actual calculation and black line is the trend line*

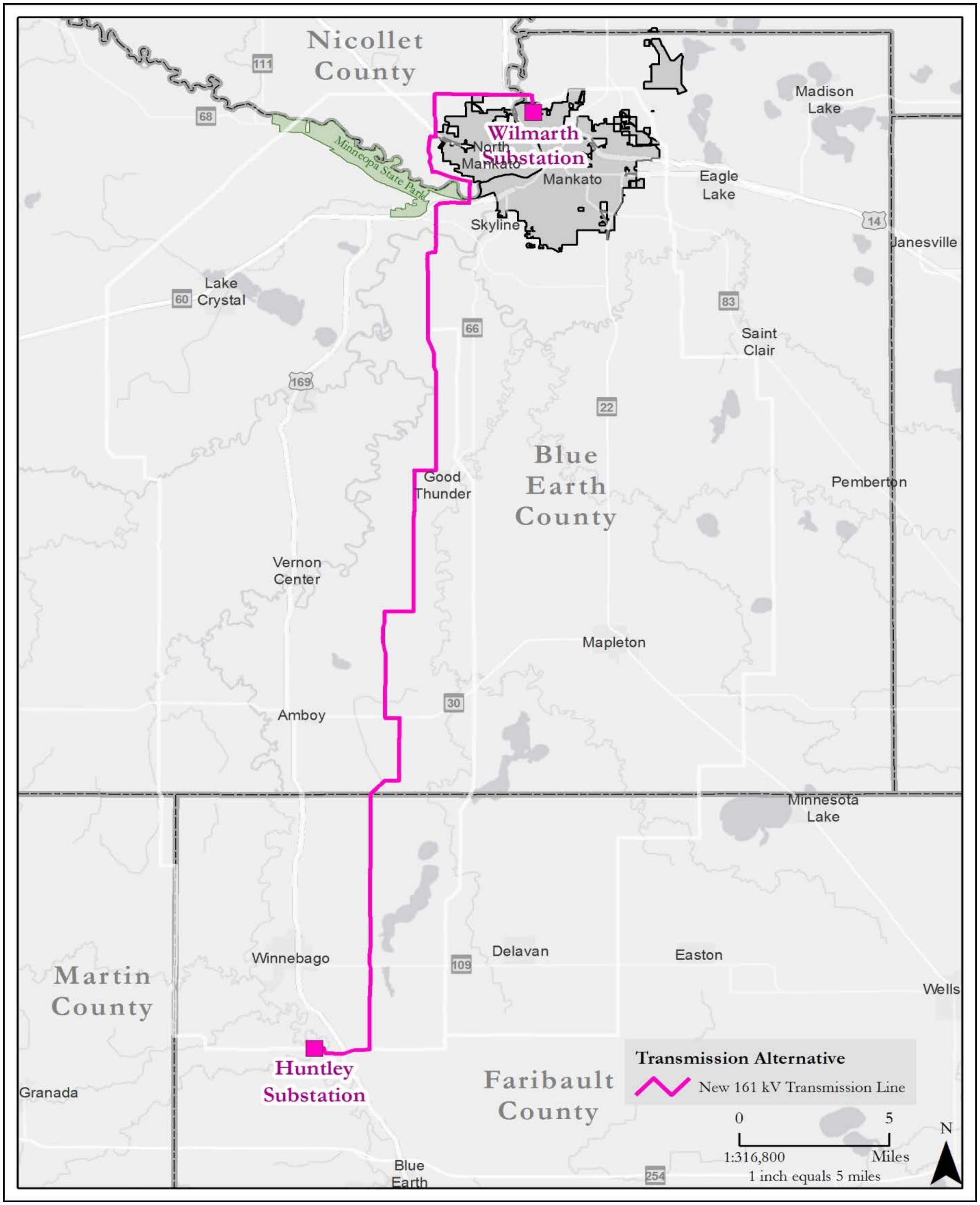
For a 69 kV line, the current rating of the line would need to be approximately 15,000 amps to achieve the same capacity as the proposed 345 kV line. Likewise, a 115 kV line would require a current rating of 9,000 amps and a 161 kV line would require a current rating of approximately 6,000 amps to achieve the same capacity as the 345 kV line at 3,000 amps. While it might be possible to select a conductor for a transmission line with a current rating higher than 3,000 amps, the substation equipment used to protect and control the transmission lines are typically limited to 3,000 amps for 345 kV and 1,200 to 3,000 amps for lower voltages. Based on these system limitations, any lower voltage transmission alternative would have a lower capacity than the proposed higher voltage 345 kV transmission line.

Given the lower capacity of 69 kV and 115 kV lines, Applicants eliminated these alternatives from further study as these lines would not have sufficient capacity to relieve all of the existing system congestion and would not be robust enough to support additional future renewable generation, thus likely requiring more facilities to be constructed in the future. The Applicants and MISO did however analyze several different 161 kV transmission alternatives as 161 kV was the only voltage that could potentially provide the necessary congestion relief.

As described in **Chapter 4**, MISO examined five different 161 kV alternatives as part of MTEP16. The two best performing 161 kV alternatives were project ID I-15 and ID I-19. Project ID I-15 consisted of reconductoring the existing 161 kV transmission lines between the Huntley and South Bend substations, then constructing a new 161 kV circuit from the South Bend Substation to the Wilmarth Substation, making the necessary substation expansion and upgrades to accommodate those upgrades. Project ID I-19 was a new 161 kV circuit between the Freeborn and the West Owatonna substations. As discussed in **Chapter 4**, MISO determined that unlike the Huntley – Wilmarth Project, none of the 161 kV alternatives provided 100 percent congestion relief throughout the 15-year study period and none of the 161 kV alternatives had as high a benefit-to-cost ratio or 20-year NPV benefit as the Project.

The Applicants also examined a 161 kV alternative that matched the endpoints of the proposed Project (i.e., Huntley and Wilmarth substations). This Huntley – Wilmarth 161 kV alternative is depicted in **Figure 25** below.

Figure 25
Huntley – Wilmarth 161 kV Alternative



Applicants evaluated the performance of the Huntley – Wilmarth 161 kV transmission alternative using MTEP17 models and Future assumptions and on multiple metrics, and for each metric, the performance of the proposed 345 kV Huntley – Wilmarth line was superior. Specifically, as detailed below, the Huntley – Wilmarth 345 kV line outperformed the 161 kV alternative with respect to:

- 20-Year NPV Benefit: The Huntley – Wilmarth 345 kV line produced a higher 20-year NPV benefit ($296 million vs. $215 million) under the PROMOD analysis performed using the MTEP17 Futures than the 161 kV alternative and thus provides greater economic benefits. A higher NPV benefit is important to ensure the Project maintains a high benefit over a longer period of time under differing circumstances.

- Congestion Relief: The Huntley – Wilmarth 345 kV line relieves 100 percent of congestion in southern Minnesota and northern Iowa for the entire 15-year study period (up to at least 2031), whereas the 161 kV alternatives does not.[75] By the year 2031, it is projected that the 161 kV alternative will relieve only 84 percent of the identified congestion and this congestion relief appears to be trending downward. With the rapid expansion of wind generation in the region, the generation assumptions in the MTEP17 Futures may actually underestimate future wind additions. The Huntley – Wilmarth 345 kV line is a more robust, long-term solution that can accommodate this possibility.

- Curtailment Reduction: The Huntley – Wilmarth 345 kV line reduces a greater percentage of curtailments as compared to the 161 kV alternative. When wind generation is curtailed, other generation sources, likely more expensive sources, must be called upon to fulfill system needs. In addition, curtailments can deter future wind development in this area as developers seek to locate new facilities in areas with sufficient capacity to transmit their generation to load centers. Thus, by reducing more curtailments than the 161 kV alternative, the 345 kV

[75] This, alone, would likely be grounds for disqualification of this alternative in the MISO study process.

Project provides greater system benefits by unlocking wind generation in this area and promotes future wind development.

- System Loss Savings: The Huntley – Wilmarth 345 kV line was more effective at reducing system losses than a 161 kV line. When system losses are reduced, less generation is needed to serve the same system load. This means that the 345 kV line has a corresponding effect of reducing the cost to serve the system load as compared to the 161 kV alternative.

- Externalities' Benefits: Considering public policy benefits further illustrates the value of the Project when compared to a lower voltage alternative. The proposed Project provides greater reductions in both CO_2 and NO_x emission costs compared to the 161 kV alternative as shown in **Appendix I**. Using the most recent Commission-approved values for Externalities, and the dispatch assumptions from MISO's MTEP17 PROMOD cases, produces indicative results showing that the Project provides $5.3 million to $21.1 million in annual public policy benefits from emissions reduction during the simulated study years. In comparison, the 161 kV alternative provides indicative benefits of $2.6 million to $15.1 million in the same years.

- Cost Allocation: As an MEP, the proposed Project is more beneficial to Minnesota energy consumers because, as an MEP, the costs of the Project would be spread across the region. In contrast, a 161 kV transmission line does not qualify as an MEP under MISO's Tariff. As a result, 100 percent of the costs of a 161 kV transmission alternative would be assigned locally to the applicable TO(s) pricing zone. In contrast, 80 percent of the costs of an MEP is allocated more broadly to Local Resource Zones based on the distribution of benefits and the remaining 20 percent is allocated to each pricing zone based on its MISO load share. Thus, even though the region may benefit from the 161 kV alternative the majority of the costs would be borne by the TO's customers. The Huntley – Wilmarth Project as proposed will be paid for by all who benefit from the savings it provides as discussed in **Chapter 2**.

5.1.1.2.1 20-Year NPV Benefits

The Applicants performed a PROMOD analysis of the Huntley – Wilmarth 345 kV line and the 161 kV line using the three MTEP17 Futures which utilize three single-year models for each Future at 5, 10, and 15 years. Applicants then compared both the APC savings and 20-year NPV benefit results for both lines.

APC savings are calculated as the difference in total production cost adjusted for import costs and export revenues with and without the proposed transmission line. A 20-year NPV benefit is calculated by linearly interpolating and extrapolating from these three single-year models. The total project benefit is determined by calculating the weighted average present value of annual benefits for the multi-future calculated through the multi-year evaluations.

To calculate the benefit-to-cost ratio, Applicants estimated the costs of a new Huntley – Wilmarth 161 kV line using the same methodology employed to estimate the costs of the 345 kV line. However, rather than estimating costs for all routes and design options under consideration for the Project, Applicants estimated the costs for the 161 kV using the shortest proposed route (Green Route) and a single-circuit steel monopole design. Applicants estimated this 161 kV to be $80.9 million (2016$). To provide a suitable comparison, Applicants inputted the similar route and design selections for the 345 kV line which has a $121.3 million cost estimate (2016$). Applicants' PROMOD results are summarized in **Table 21** below.

Table 21
MTEP17 PROMOD Comparison[76]

Transmission Alternative*	Cost Estimate (2016$)	Weighted Benefit-to-Cost Ratio	20-year Present Value Benefit ($millions)
Huntley – Wilmarth new 345 kV transmission line (Green Route, monopole design)	$121.3	1.87	$296.02
Huntley – Wilmarth new 161 kV transmission line (Green Route, monopole design)	$80.9	2.08	$214.95

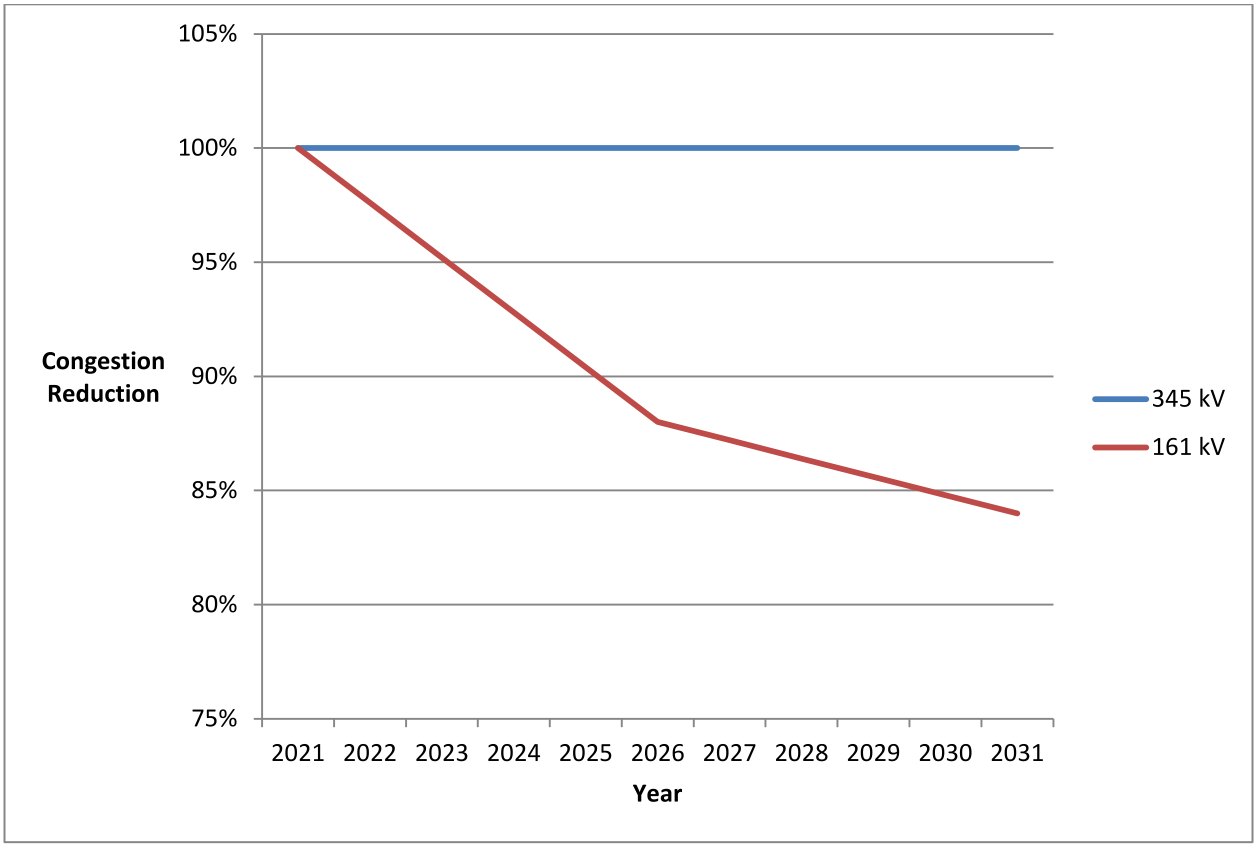
As shown above, the 345 kV line provides higher present value benefits as compared to the 161 kV line by nearly 40 percent. The lower estimated costs for the alternative resulted in a slightly higher benefit-to-cost ratio. The benefit-to-cost ratios are within approximately 11 percent of each other and as outlined below, the 345 kV line outperforms the 161 kV in all other metrics and solves completely the identified congestion concerns in this area.

5.1.1.2.2 Congestion Relief

The Huntley – Wilmarth 345 kV Project was specifically designed to relieve 100 percent of the identified congestion along the Minnesota/Iowa border over the entire 15-year study period. In contrast, while the Huntley – Wilmarth 161 kV line initially reduces 100 percent of the congestion in 2021, this lower voltage line only provides 88 percent and then 84 percent congestion relief by 2026 and 2031, respectively. A comparison of the system congestion relief over the planning horizon (2031) is depicted in **Figure 26**.

[76] The cost estimates developed for purposes of this comparison assumed the least cost capital investment necessary to achieve the explained alternative. Therefore, any changes to route or structure type used for purposes of the estimates would impact the overall cost analysis and comparisons. This approach was undertaken to ensure consistency when comparing multiple alternatives of different size or type.

Figure 26
Congestion Relief



The 161 kV alternative has less capacity than the proposed 345 kV alternative and therefore is unable to fully address the identified congestion. Relief of less than 100 percent of this portion of the system's congestion means that this same area will remain a system constraint and likely become a major point of congestion again less than five years following its in-service date, likely hindering the development of new renewable energy resources in southern Minnesota.

This portion of the electrical system has experienced increasing congestion over time due to the rapid development of new wind generation in this area. Given this rapid development, the generation assumptions in the MTEP17 Futures may actually underestimate future wind additions and thus future congestion. As a result, the Huntley – Wilmarth 345 kV line is a more robust, long-term solution than the 161 kV line.

5.1.1.2.3 Curtailment Relief

Applicants also compared the impacts of a Huntley – Wilmarth 161 kV line to the 345 kV line in terms of wind resource curtailments. As discussed in **Chapter 4**, curtailment occurs when congestion on the transmission system reaches a point where the LMP at a wind node decreases to a point where the wind farm cannot generate economically; this is generally at or below $0/MWh.

As illustrated in **Table 22** through **Table 24**, both transmission solutions reduce the level of curtailments, however, the 345 kV line is more effective at reducing curtailments in each of the three MTEP17 Future scenarios. These curtailment calculations demonstrate that the 345 kV Huntley – Wilmarth line outperforms the 161 kV Huntley – Wilmarth line with respect to enabling wind generation to be delivered across the transmission system.

Table 22
Existing Fleet Future Projected Curtailments

Year	Project	Base Curtailments (MWh)	Curtailments With Project Added (MWh)	Reduction In Curtailments (MWh)	Percent Reduction
2026	Huntley – Wilmarth 345 kV line	45,359	41,519	3,840	8.5%
2026	Huntley – Wilmarth 161 kV line	45,359	44,051	1,308	2.9%
2031	Huntley – Wilmarth 345 kV line	71,827	55,519	16,308	22.7%
2031	Huntley – Wilmarth 161 kV line	71,827	59,372	12,456	17.3%

Table 23
Policy Regulation Future Projected Curtailments

Year	Project	Base Curtailments (MWh)	Curtailments With Project Added (MWh)	Reduction In Curtailments (MWh)	Percent Reduction
2026	Huntley – Wilmarth 345 kV line	149,894	106,863	43,031	28.7%
2026	Huntley – Wilmarth 161 kV line	149,894	128,143	21,752	14.5%
2031	Huntley – Wilmarth 345 kV line	1,387,356	1,184,008	203,348	14.7%
2031	Huntley – Wilmarth 161 kV line	1,387,356	1,246,472	140,884	10.2%

Table 24
Advanced Alternative Technologies Future Projected Curtailments

Year	Project	Base Curtailments (MWh)	Curtailments With Project Added (MWh)	Reduction In Curtailments (MWh)	Percent Reduction
2026	Huntley – Wilmarth 345 kV line	8,246,099	7,067,818	1,178,281	14.3%
2026	Huntley – Wilmarth 161 kV line	8,246,099	7,368,758	877,341	10.6%
2031	Huntley – Wilmarth 345 kV line	18,134,162	16,457,680	1,676,482	9.2%
2031	Huntley – Wilmarth 161 kV line	18,134,162	16,934,890	1,199,272	6.6%

5.1.1.2.4 System Loss Savings

Energy losses on the transmission system can result in increased costs for utilities and ratepayers due to the need to generate enough energy to adequately serve loads while also accounting for the losses accrued during the transmission of this energy. Each new transmission line that is added to the electric system affects the losses of the system. If a new transmission line reduces transmission losses, utilities will not have to generate as much energy to meet customer demands. Thus, if a new transmission line reduces system losses, then the costs to ratepayers to provide that energy will also be reduced.

Lower voltage lines tend to have higher losses than higher voltage lines. This is because when the voltage of a line is lowered, the current must be increased to achieve similar levels of line capacity. This increases losses because of the correlation between the physical requirements of the transmission line conductor and the amount of current flowing on that conductor.

Applicants compared the loss savings achieved by the 345 kV Huntley – Wilmarth line to the loss savings of the 161 kV line across the entire Eastern Interconnection.[77] While this analysis uses models that assess losses across the Eastern Interconnection, it can be assumed that loss reductions would accrue primarily very close to the Project area. As shown in **Table 25** below, while the reduction of system losses of these transmission line alternatives is fairly similar during summer peak, during off-peak, high wind periods, the 345 kV line reduces system losses by more than six times that of the 161 kV line. This is because during high wind periods there is a dramatic increase in the current flowing on these lines and thus higher losses are experienced by a lower voltage line. As the summer peak occurs for such a short period of time, the 345 kV line reduces system losses at a greater rate for the majority of a given year.

Table 25
System Losses Comparison

Transmission Alternative	Summer Peak (Reduction in System Losses)	Off-Peak, High Wind (Reduction in System Losses)
Huntley – Wilmarth 345 kV line	2.3 MVA	75.89 MVA
Huntley – Wilmarth 161 kV line	3.4 MVA	12.6 MVA

[77] The Eastern Interconnection is one of the two major AC electrical grids in the continental U.S. power transmission grid. The other major interconnection is the Western Interconnection. All of the electric utilities in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency at an average of 60 Hz. The Eastern Interconnection reaches from Central Canada eastward to the Atlantic coast (excluding Quebec), south to Florida, and back west to the foot of the Rockies (excluding most of Texas).

The results of **Table 25** demonstrate that the 345 kV line is more effective at reducing system losses during a greater part of the year than a 161 kV line between the Huntley and Wilmarth substations.

5.1.1.3 Cost Allocation Considerations with Lower Voltage Alternative

A lower voltage 161 kV alternative would also not meet MISO's voltage thresholds to qualify as an MEP, as greater than 50 percent of the total cost of the candidate project must be attributed to facilities that operate at a 345 kV voltage level or higher. As a result, any lower voltage alternative would not qualify for MEP's regional cost allocation treatment. Eighty percent of the costs for transmission projects that qualify for MEP status are allocated to pricing zones based on the distribution of positive APC savings to the Local Resource Zones and the remaining 20 percent are allocated to each pricing zone based on MISO LRS.

In contrast, a lower voltage alternative would likely be classified as an "Other" project under the MISO Tariff and the costs for such Other project would be assigned 100 percent locally to the applicable TO(s) pricing zone and not all beneficiaries of the Project will pay for the limited benefits provided by its construction.

5.1.1.4 Summary of Evaluation of 161 kV Alternative

The 161 kV alternative is not a prudent and reasonable alternative because it will not serve the long-term needs of the transmission system to reliably integrate new wind generation along the Minnesota/Iowa border. This portion of the transmission system has seen and is expected to continue to see a great deal of growth in the development of wind generation. As noted in Chapter 4, as of November 2017, the MISO interconnection queue had approximately 19,400 MWs of wind that is expected to be placed in service prior to 2021. The proposed 345 kV line is best suited to transfer this additional wind generation to customers. Under all but one of the metrics examined by the Applicants, the 345 kV line between the Huntley and Wilmarth substations outperformed the 161 kV alternative. The 345 kV line provides greater economic benefits in terms of APC savings, 20-year present value benefits, 100 percent congestion relief through the study period, greater reduction in curtailments and system losses, and is eligible for MEP cost sharing under the MISO

Tariff. Thus, the Huntley – Wilmarth 161 kV line is not a reasonable and prudent alternative to the 345 kV line.

5.1.2 Double Circuit – Upsizing

Applicants examined whether constructing the Project as a double circuit 345/345 kV line as opposed to a single circuit 345 kV line provided any additional economic or electrical benefits. The Applicants concluded that any additional costs incurred to increase the capacity of this line by adding a second 345 kV circuit would not provide any measurable additional benefit as compared to the proposed single circuit 345 kV line. As determined by MISO's MTEP16 analysis, and validated by the Applicants' additional analyses described in **Chapter 4**, the proposed Project mitigates 100 percent of the identified congestion on the Minnesota/Iowa border. Due to the full amount of the identified congestion being mitigated through 2031, adding additional transmission capacity would only increase the cost of the Project without any identifiable amount of additional benefit at this time or in the future forecast horizon.

5.2 Type Alternatives

5.2.1 Transmission with Different Terminals/Substations

As explained in **Chapter 4**, the electrical system congestion identified between the Huntley and Wilmarth substations is due to the system operation and generation dispatch procedures used in the MISO market to ensure both the reliability of the transmission system and the efficiency of that system. These procedures can limit the amount of low-cost generation utilized because they are designed to anticipate an event that would cause the loss of a single circuit and lead to a situation that may not be able to be mitigated by a post event action.

When considering transmission system congestion based on the potential loss of an existing circuit or facility, the end points of that circuit or facility become increasingly more important. In this instance, MISO identified congestion on the Huntley (Winnebago) – Blue Earth – South Bend – Wilmarth line during the loss of the Lakefield Junction – Wilmarth Line. Thus, in the case of the Huntley – Wilmarth Project, the end point of both the outage element as well as the congested transmission path are electrically very similar. Due to this unique combination, and as it has been shown throughout the development of this Project, an alternative transmission line with end points other than that of the constraint and outage element would be unlikely to provide the same level of congestion relief as a transmission line directly connecting those end points.

As part of MTEP16, MISO analyzed various transmission alternatives with different substation endpoints to relieve the identified congestion on the Minnesota/Iowa border. In **Chapter 4**, the Applicants outlined the results of MISO's analysis for the numerous 345 kV alternative configurations. As discussed in **Chapter 4**, none of these other 345 kV transmission proposals provided as high of a benefit-to-cost ratio as the proposed Huntley – Wilmarth Project.

5.2.2 Upgrading Existing Transmission Lines

Another alternative that the Applicants and MISO compared to the proposed 345 kV transmission line between the Huntley and Wilmarth substations is reconductoring or rebuilding the existing transmission facilities that currently connect these two end points. As discussed in **Chapter 4**, MISO analyzed reconductoring the existing 161 kV transmission line connecting Huntley (Winnebago) to Blue Earth, and from Blue Earth to South Bend and then adding a new 161 kV circuit between South Bend to Wilmarth as project I-15 in MTEP16. MISO's analysis determined that this solution provides some market benefits, but the benefit-to-cost ratio is lower than the proposed 345 kV Project and the 161 kV alternative would not fully address the identified congestion along the Minnesota/Iowa border. The higher voltage of the proposed 345 kV Project also provides additional capacity to support future generation development in the area until at least 2031.

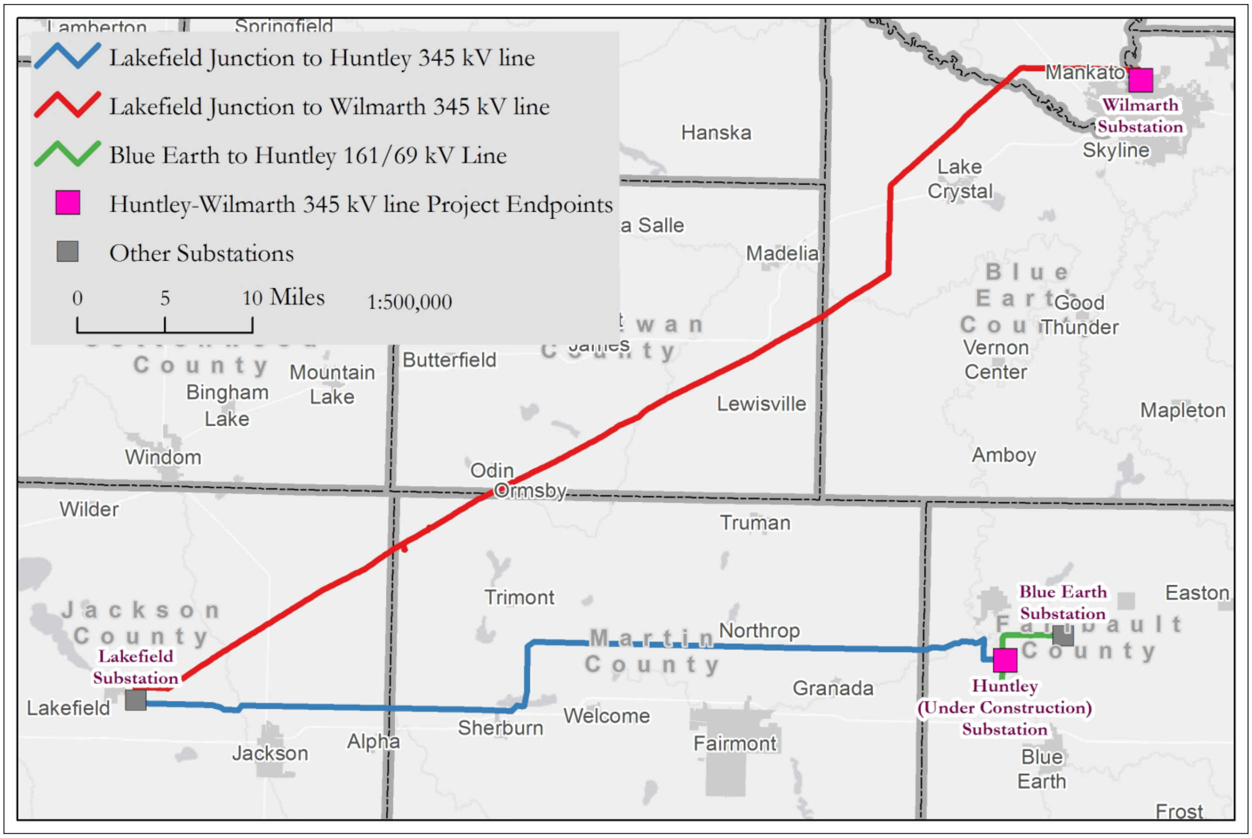
5.2.3 Double-Circuiting of Existing Transmission Lines

Double-circuiting is the construction of two separate circuits on the same structures to reduce the overall amount of right-of-way required. Double-circuiting minimizes the need for new right-of-way and expansion of the overall footprint of the transmission system. The downside to double-circuiting is that it places more transmission lines within a single corridor; increasing the potential risk of reliability or congestion concerns should a natural or man-made event affect that corridor.

Xcel Energy's planning engineers examined whether the Project could be double-circuited with existing transmission lines in the area and determined that there were no reliability or maintenance considerations that would preclude double-circuiting. Accordingly, Applicants have proposed routing options that, at varying proportions, double-circuit the proposed new 345 kV transmission line with existing 161 kV transmission lines between the Huntley and Wilmarth substations.

Applicants also analyzed double-circuiting in terms of adding a second circuit to the existing Lakefield Junction – Wilmarth Line. While this alternative was not part of MISO's MTEP16 analysis, a similar 345 kV transmission alternative was analyzed. The alternative evaluated by MISO was to build a new 345 kV transmission line from Lakefield Junction to Cedar Mountain. The Cedar Mountain Substation is located in the middle of the Brookings to Hampton CapX2020 transmission line and north from the Lakefield Junction Substation making this alternative electrically similar to a second Lakefield Junction to Wilmarth 345 kV circuit. This alternative is illustrated in **Figure 27**.

Figure 27
Lakefield Junction – Wilmarth 345 kV Alternative



In MTEP16, the Lakefield Junction to Cedar Mountain 345 kV alternative was shown to have an approximately 27 percent lower benefit-to-cost ratio on a one-year present value analysis as compared to the Huntley – Wilmarth Project. Given their electric similarity, it is assumed that adding a second 345 kV line to the existing Lakefield Junction – Wilmarth 345 kV line would also not provide economic benefits as significant as the Huntley – Wilmarth 345 kV line.

Even if it is assumed that a second 345 kV circuit to the Lakefield Junction – Wilmarth 345 kV line could provide similar economic benefits as the Project, adding a second circuit would be substantially more costly than the Project. This higher cost is due in part to the longer length of this new line. The existing Lakefield Junction – Wilmarth 345 kV line is approximately 73 miles while the longest route proposed currently for the Huntley – Wilmarth Project is approximately 57 miles. In addition, adding a second 345 kV circuit to the existing line would require the complete removal of all 73 miles of the existing 345 kV transmission line and structures and replacement of these structures with larger double-circuit capable structures which would increase the cost of this alternative substantially.

5.2.4 Direct Current Lines

Applicants considered the alternative of a High Voltage Direct Current (HVDC) line in place of the proposed AC facilities. An HVDC transmission system consists primarily of a converter station, in which the AC voltage of the conventional power grid is converted into HVDC voltage, a transmission line, and another converter station on the other end, where the voltage is converted back into AC. HVDC transmission lines normally consist of two current-carrying conductors instead of the three associated with an AC configuration.

HVDC transmission lines have been built throughout the world, with two in service in the upper Midwest and two in Manitoba. An HVDC transmission line's primary intended purpose is to deliver electricity from a distant generation location (several hundred miles away) to a load center. This is because the line losses and conductor costs associated with HVDC lines are generally less than those associated with high voltage AC lines. While DC lines offer loss and materials savings benefits, HVDC lines also require expensive conversion stations at each end point of the line to convert power from AC to HVDC and then back again. A review of recent cost estimates for converter stations for 500 to 600 kV HVDC lines indicates that such stations can range upwards of $375 million.[78] It should be noted that HVDC converter stations do not eliminate the need for AC substation facilities that would be required after the power is converted back to AC. Given the substantial additional cost imposed by the required HVDC converter stations, the costs associated with a HVDC design would exceed the economic benefits and therefore such a design is not a reasonable alternative.

5.2.5 Conductor Arrays

The Applicants use several types of conductors for their transmission lines. The standard bare aluminum overhead transmission conductors, Aluminum Conductor

[78] *See* BLACK AND VEATCH, *Gateway South and Transwest Express Conceptual Technical Report* at 4-3 (Feb. 29, 2008), *available at* http://www.transwestexpress.net/WECC/docs/Conceptual_Technical_Report.pdf.

Steel Supported (ACSS) and ACSR, offer known reliable power performance, operating at temperatures up to 200°C and 100°C, respectively. The proposed bundled, twisted pair ACSR conductor is the most prudent conductor selection as it is less susceptible to galloping while maintaining the same capacity as the conductor used in MISO's analysis and it is also lighter than the 1780 Chukar conductor which saves costs in structure design necessary to support higher weights.

During MISO's MTEP16 analysis, MISO assumed the Project would be constructed using a 1780 Chukar ACSR conductor. Prior to the October 19, 2016 Planning Advisory Committee meeting, the Applicants worked with MISO to change this conductor. In environments that experience high wind speeds and freezing conditions such as the Project Study Area, the 1780 Chukar ACSR is typically not used as this conductor is susceptible to galloping during high winds.

The proposed bundled, twisted pair ACSR conductor will have a capacity equal to or greater than 3,000 amps. This capacity is sufficient to meet the needs of the Project as this amount of capacity is sufficient to relieve 100 percent of the identified congestion through the study period (2031).

5.2.6 Generation

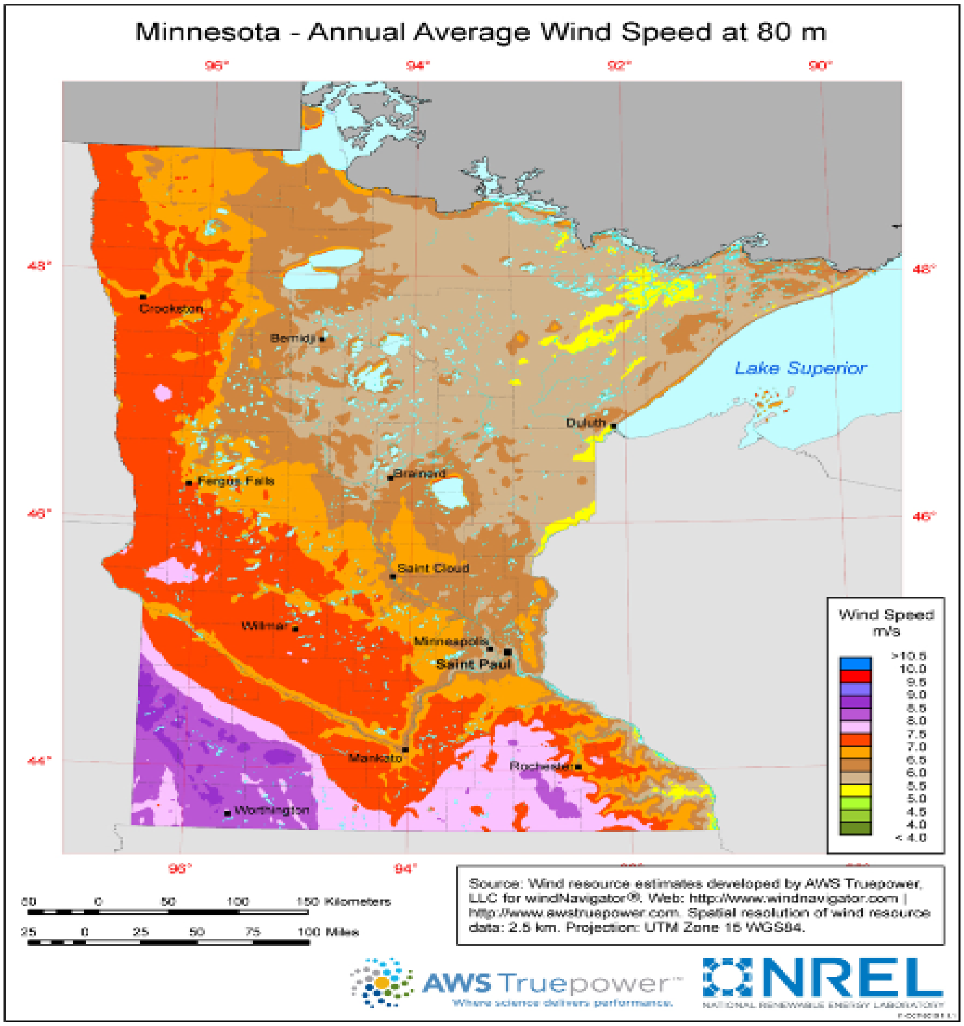
In evaluating alternatives to the proposed Project, Applicants considered the addition of new generation resources rather than the proposed transmission line facilities to resolve the congestion currently present near the Minnesota/Iowa border. Fundamentally, however, adding new generation resources to resolve congestion is not a prudent alternative given the nature of the problem. Transmission congestion occurs when there is not enough transmission capacity to support all generation requests for transmission services at a particular time. Thus, regardless of the type of the generation facility evaluated, fossil-fueled or renewable, the construction of additional generation facilities is not a feasible and prudent alternative to the Project because such generation would: (1) further exacerbate the congestion already present on the system unless this generation is sited north of the existing congestion; (2) result in underutilization of existing generation resources; and (3) likely be more costly than the proposed Project.

A generation alternative to reduce this congestion would need to be of equal or lower cost to the wind generation that is currently being constrained and would need to be built on the north side of the identified point of congestion (i.e., the Huntley – Blue Earth – South Bend – Wilmarth 161 kV line). Generation sited to the south of the congestion point would only exacerbate the existing congestion. Further, this new generation would also need to be able to generate at minimum between approximately 120 MW and 370 MW (depending on the Future scenario) during times when congestion is present to achieve the necessary congestion reduction.[79]

Given these existing conditions on the transmission system, Applicants examined construction of new wind generation facilities on the north side of the identified congestion (i.e., north of the Wilmarth Substation). Siting new large-scale wind generation north of the area of congestion would be difficult given the existing development and other considerations in the urban areas near the City of Mankato. In addition, there is a decrease in the average annual wind speed in areas farther north from the Iowa border. In particular, as shown in **Figure 28**, wind speeds north of the City of Mankato are between 6.0 and 7.0 meters per second (m/s) whereas areas closer to the Iowa border range from 7.5 to 9.0 m/s.

[79] These calculations are based on the flow reductions shown in Table 26 below.

Figure 28
Minnesota Average Wind Speeds[80]



As a result, a larger quantity of wind turbines would need to be constructed north of the area of congestion to achieve the same output as similar generation sited in areas to the south. Specifically, because of the difference in wind speeds, 15 to 30 percent more nameplate capacity would be needed as compared to wind generation installed further south or approximately 340 MW to 1,800 MW of nameplate wind generation capacity.

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80 U.S. DEP'T OF ENERGY – OFFICE OF ENERGY EFFICIENCY & RENEWABLE ENERGY, *Minnesota 80-Meter Wind Resource Map* (last visited Dec. 15, 2017), *available at* https://windexchange.energy.gov/maps-data/63.

Applicants also note that siting additional generation near the Mankato area has not been studied using a power flow model and such additional generation may have other system consequences such as reliability violations or result in new congested elements. Moreover, adding more wind generation to the north of congestion, while it may relieve certain system constraints, will also result in underutilization of existing and more efficient wind generation sited in southern Minnesota and northern Iowa.

5.2.7 Underground Transmission Line

Applicants also considered an underground design for the proposed transmission line and concluded that an underground design would not meet the purpose and need for the Project as an MEP due to cost. Specifically, Applicants developed a cost estimate to underground two miles of a 345 kV line using an open trench construction method. Applicants determined that this open trench underground installation would cost at least $13 million per mile (2017$). This compares to the $2 to $2.8 million cost per mile for Applicants' overhead designs. If underground is considered, the specific location must be studied as certain installations, for example a deep burial under a river, would bring additional costs. In addition, all underground cable installations behave differently, electrically, than overhead lines and therefore a study would be required to determine if reactive compensation is required. A reactive compensation study would cost between $150,000 to $300,000 (2017$). If reactive compensation is required, this would add several million dollars to the underground costs stated above. Based on this analysis, if underground design were used for the Project, the costs would vastly exceed the benefits and therefore an underground design is not a reasonable alternative.

5.3 No Build Alternative/Consequence of Delay

Applicants also considered the no build alternative, i.e., no new transmission facilities constructed to meet the identified need to reduce congestion on the transmission system in southern Minnesota/northern Iowa. To consider the no build alternative, Applicants evaluated two different scenarios: (1) reducing congestion through load growth and (2) reducing congestion through conservation or demand-side management programs.

5.3.1 Load Growth

The congestion on the transmission system along the Minnesota/Iowa border is in part the result of the fact that generation levels in this area exceed the amount of load in the area. As noted in **Chapter 4**, the Huntley – Blue Earth 161 kV is the transmission element that constrains wind generation from reaching load centers to the north. Congestion in this area could be reduced if customer load increased sufficiently to remove sufficient energy from this congested element. The required load increase would need to be between 120 MW to 370 MW (depending on Future scenario). Applicants examined the historical and forecasted load at 17 substations within and around the Project Study Area. The total coincident peak loads for these 17 substations was 273 MW in 2017 and is projected to experience moderate growth of about 18 percent in the next ten years, growing to 331 MW (58 MW growth) by 2027. This moderate load growth is insufficient to utilize the thousands of MWhs of energy that will be produced by existing and planned wind developments along the Minnesota/Iowa border. As a result, if no new transmission facilities are built, the existing congestion will continue to persist and hamper future wind development in this area.

5.3.2 Conservation and Demand-Side Management

Because the need for the Project is driven by increased amounts of wind generation along the Minnesota/Iowa border rather than increased demand, conservation and demand-side management programs are not effective alternatives to meet the identified need. Nonetheless, Applicants evaluated these two methods to address the congestion concerns in southern Minnesota. As part of this evaluation, Xcel Energy presents its system-wide efforts to reduce energy consumption via demand-side management in **Appendix H**.[81] Xcel Energy's proposed 2017-2019 Conservation Improvement Program (CIP) Triennial Plan[82] identifies annual savings goals of 1.5 percent of electric retail sales, a budget of over $280 million, and energy savings of 1,300 gigawatt hours over the three years of the plan.

[81] As ITC Midwest is not a load serving utility, it does not have conservation or demand-side management programs.

[82] *2017-2019 Minn. Elec. and Nat. Gas Conservation Improvement Program*, Docket No. E,G002/CIP-16-115, INITIAL FILING - 2017-2019 TRIENNIAL PLAN (June 1, 2016).

The requirements to address the identified congestion in southern Minnesota through the use of Xcel Energy's demand-side management programs were also evaluated. The congested elements were found to require a reduction of flows on the existing Huntley (Winnebago) – Blue Earth – South Bend – Wilmarth 161 kV line by the amount of MW listed in **Table 26** for each MTEP17 Future.

Table 26
Flow Reduction Requirements to Alleviate Congestion

Future	Flow reduction required in the Mankato area
Existing Fleet	120 MW
Policy Regulations	253.33 MW
Advanced Alternative Technologies	373.33 MW

Because the Project is intended to alleviate these congestion levels in the Mankato area, the existing system needs to be evaluated to determine if such levels can be achieved without the addition of new transmission facilities. To perform this analysis, Applicants utilized PROMOD. This analysis is performed by evaluating the shift factor, which illustrates how the flow in the targeted transmission facilities will respond with an injection of additional load at the substation bus equipment (or how reductions in load will impact the system). The shift factor represents the percentage change or impact that additional load at one point would have on an identified constraint. In this case, that constraint is the existing Huntley (Winnebago) – Blue Earth – South Bend – Wilmarth 161 kV line.

This analysis assumed a 0.3 shift factor, which would allow the load reduction in a limited area on the north side of the identified congestion, meaning all load reductions would be required in and around the Mankato area. Using a 0.3 shift factor indicates that the load reduction in and around Mankato would impact the constraint by 30 percent of the amount reduced. Therefore, if 10 MW of load was reduced in this area, the actual congestion impact on the constrained facilities would only be 3 MW. A 0.3 shift factor also indicates a very high correlation between the area of load reduction and the area of congestion. Reduction in load farther away from the constraint (beyond the Mankato area) would result in a much lower shift factor, and require an even greater load reduction to achieve the same result.

The reductions that would be necessary under each of the evaluated shift factor scenarios are summarized in **Table 27**.

Table 27
Shift Factor Congestion Analysis

Shift Factor	Existing Fleet (120 MW)	Policy Regulations (253.33 MW)	Advanced Alternative Technologies (373.33 MW)
0.2 (Simplified Network)	400 MW	844.43 MW	1,244.43 MW

As demonstrated by the various analyses, to achieve the necessary congestion alleviation, the total MW on the system would need to be reduced from 240 MW to over 600 MW if only the existing generation fleet remains and up to a range of more than 700 MW to more than 1,800 MW if no new facilities were constructed.

Further, if the proposed Project is not constructed or its construction is delayed, congestion in southern Minnesota around Mankato and south to the Minnesota/Iowa border will worsen as additional wind generation facilities are constructed in this area. Moreover, the economic benefits of this Project will not be achieved. In addition, the environmental benefits of the Project, specifically the avoidance of projected millions of dollars of environmental impacts identified in **Appendix I**, would not be realized.

6. TRANSMISSION LINE OPERATING CHARACTERISTICS

Chapter 6: Transmission Line Operating Characteristics: provides information regarding the operating characteristics of the proposed 345 kV transmission lines and associated substations. This includes information regarding electric and magnetic fields, noise, ozone and nitrogen oxide emissions, and potential radio and television interference.

Key Terms:

- ***Conductor*** – a wire made up of multiple strands, most often aluminum but can also include steel and sometimes copper, that together carry electricity. A bundled conductor is two or more of these "wires" connected together in parallel to increase the electrical capacity of a transmission line.

- ***Corona discharge*** – the breakdown or ionization of air within a few centimeters or less immediately surrounding conductors and can produce ozone and oxides of nitrogen in the air surrounding the conductor. While transmission lines are designed to limit this effect, imperfection on a conductor such as a scratch on the wire, or a protrusion on hardware, can cause this corona discharge to be noticeable from ground level.

- ***Electric fields*** – are created by the electric charge (i.e., voltage) on a conductor. Electric fields are solely dependent upon the voltage of a conductor. Electric field strength is measured in kV per meter (kV/m). The strength of an electric field decreases rapidly as the distance from the source increases. Electric fields are created anytime electricity is present even when current is not flowing or the electric device is not turned on.

- ***Extremely Low Frequency*** – this term is used to identify electric and magnetic fields within the range of 1 to 300 Hertz. Transmission lines in the United States operate at 60 Hertz.

- ***Magnetic Fields*** – are created by and are solely dependent upon the electric current in the conductor. Magnetic field strength is measured in milliGauss (mG). The strength of a magnetic field decreases rapidly as the distance from the source increases. Any device that uses electric current creates a magnetic field. Magnetic fields generated by electric lines are in the extremely-low-frequency (ELF) range of electromagnetic spectrum.

6.1 Transmission Line Operating Characteristics Overview

The major components of an overhead transmission line include: (1) an above ground structure typically made from wood or steel, often referred to as a pole or tower; (2) the wires attached to the structure and carrying the electricity, called conductors; (3) insulators connecting the conductors to the structures to provide structural support and electrical insulation; (4) shield wires which protect the line from direct lightning strikes; and (5) ground rods located below ground and connected at each structure.

During operation, transmission lines are, for the most part, passive elements of the environment as they are stationary in nature with few, if any, moving parts. Their primary impact is aesthetic, i.e., a man-made structure in the landscape. Due to the physics of how electricity works, some chemical reactions occur around conductors in the air: noise can occur in some circumstances; interference with electromagnetic signals can occur; and electrical and magnetic fields are created around the conductors. All of these operating characteristics are considered when designing the transmission line to prevent any significant impacts to its operation and to the overall environment.

6.2 Ozone and Nitrogen Oxide Emissions

Corona consists of the breakdown or ionization of air within a few centimeters of conductors. Usually some imperfection such as a scratch on the conductor or a water droplet is necessary to induce corona discharge because transmission lines are designed to be corona free under typical operating conditions. Corona can produce ozone and oxides of nitrogen in the air surrounding the conductor. Ozone also forms in the lower atmosphere from lightning discharges and from reactions between solar ultraviolet radiation and air pollutants, such as hydrocarbons from auto emissions. The natural production rate of ozone is directly proportional to temperature and sunlight, and inversely proportional to humidity. Thus, humidity or moisture, the same factor that increases corona discharges from transmission lines, inhibits the production of ozone. Ozone is a very reactive form of oxygen molecule and combines readily with other elements and compounds in the atmosphere. Because of its reactivity, it is relatively short-lived.

Currently, both state and federal governments have regulations regarding permissible concentrations of ozone and oxides of nitrogen (NO_x). The state and national ambient air quality standards for ozone are similarly restrictive. The national standard is 0.07 parts per million (ppm) on an eight-hour averaging period. The state standard is 0.08 ppm based on the fourth highest eight-hour daily maximum average in one year. Both averages must be compared to the national and state standards because of the different averaging periods. Calculations done for a 345 kV project showed that the maximum one-hour concentration during foul weather (worst case) would be 0.0007 ppm. This is well below both federal and state standards. Most calculations of the production and concentration of ozone assume high humidity or rain, with no reduction in the amount of ozone due to oxidation or air movement. These calculations would therefore overestimate the amount of ozone that is produced and concentrated at ground level. Studies designed to monitor the production of ozone under transmission lines have generally been unable to detect any increase due to the transmission line facility.

The national standard for nitrogen dioxide (NO_2), one of several oxides of nitrogen, is 100 parts per billion (ppb) and the annual standard is 53 ppb. The State of Minnesota is currently in compliance with the national standards for NO_2. The operation of the proposed transmission lines would not create any potential for the concentration of these pollutants to exceed the nearby (ambient) air standards.

6.3 Noise

6.3.1 Transmission Line Noise

Generally, activity-related noise levels during the operation and maintenance of substations and transmission lines is minimal.

Transmission conductors can produce noise under certain conditions. The level of noise depends on conductor conditions, voltage level, and weather conditions. Noise emission from a transmission line occurs during certain weather conditions. In foggy, damp, or rainy weather, power lines can create a crackling sound due to the small amount of electricity ionizing the moist air near the wires. During heavy rain, the background noise level of the rain is usually greater than the noise from the transmission line. As a result, people do not normally hear noise from a transmission line during heavy rain. During light rain, dense fog, snow, and other times when there is moisture in the air, transmission lines will produce audible noise equal to approximately household background levels. During dry weather, audible noise from transmission lines is barely perceptible by humans.

6.3.2 Substation Noise

Substations may also contribute noise. Transformer or shunt reactor "hum" is the dominant noise source at substations if such equipment exists. At substations without transformers or shunt reactors, only infrequent noise sources would exist such as the opening and closing of circuit breakers or the operation of an emergency generator. All of the substation modifications required for the Project will comply with the Minnesota Pollution Control Agency (MPCA) Noise Area Classification noise standards as set forth in Minnesota Rule 7030.0040.

6.4 Radio, Television, and GPS Interference

Overhead transmission lines are designed to not cause radio or television interference under typical operating conditions. Corona, as well as spark discharge, from transmission line conductors can generate electromagnetic "noise" at the same frequencies that some radio and analog television signals are transmitted. This noise can cause interference with the reception of these signals depending on the frequency and strength of the radio and television signal. Interference from a spark discharge source can be found and corrected.

If radio interference from transmission line corona does occur, satisfactory reception from AM radio stations previously providing good reception can be restored by appropriate modification of (or addition to) the receiving antenna system. AM radio frequency interference typically occurs immediately under a transmission line and dissipates rapidly within the right-of-way to either side.

FM radio receivers usually do not pick up interference from transmission lines because:

- Corona-generated radio frequency noise currents decrease in magnitude with increasing frequency and are quite small in the FM broadcast band (88-108 Megahertz); and

- The excellent interference rejection properties inherent in FM radio systems make them virtually immune to amplitude-type disturbances.

A two-way mobile radio located immediately adjacent to and behind a large metallic structure (such as a steel tower) may experience interference because of signal-blocking effects. Movement of either mobile unit so that the metallic structure is not immediately between the two units should restore communications. This would generally require a movement of less than 50 feet by the mobile unit adjacent to a metallic tower.

Television interference is rare but may occur when a large transmission structure is aligned very close to the receiver and between the receiver and a weak distant signal, creating a shadow effect. If television or radio interference is caused by or from the operation of the proposed facilities in those areas where good reception is presently obtained, Applicants will take necessary action to restore reception to the present level, including the appropriate modification of receiving antenna systems if deemed necessary.

6.5 Safety

The Project will be designed in compliance with local, state, and NESC standards regarding clearance to ground, clearance to crossing utilities, clearance to buildings, strength of materials, and right-of-way widths. Appropriate standards will be met for construction and installation, and all applicable safety procedures will be followed during and after installation.

The proposed transmission lines will be equipped with protective devices to safeguard the public from the transmission lines if an accident occurs, such as a structure or conductor falling to the ground. The protective devices include breakers and relays located where the line connects to the substation(s). The protective equipment will de-energize the line should such an event occur. Proper signage will be posted warning the public of the risk of coming into contact with the energized equipment.

GPS interference is also not anticipated. Applicants use GPS-based survey equipment directly under transmission lines and have not experienced any problems.

6.6 Electric and Magnetic Fields

"EMF" is an acronym for the terms electric and magnetic fields. For the lower frequencies associated with power lines (referred to as ELF), EMF should be considered separately – electric fields and magnetic fields, measured in kV/m and mG, respectively. Electric fields are dependent on the voltage of a transmission line and magnetic fields are dependent on the current carried by a transmission line. The strength of the electric field is proportional to the voltage of the line, and the intensity of the magnetic field is proportional to the current flow through the conductors. Transmission lines operate at a power frequency of 60 Hertz (cycles per second).

6.6.1 Electric Fields

There is no federal standard for transmission line electric fields. The Commission, however, has imposed a maximum electric field limit of 8 kV/m measured at one meter above the ground.[83] The standard was designed to prevent serious hazards from shocks when touching large objects parked under AC transmission lines of 500 kV or greater. **Figure 29** provides the electric fields at maximum conductor voltage for the proposed 345 kV transmission line. Maximum conductor voltage is defined as the nominal voltage plus five percent. The maximum electric field, measured at one meter (3.28 feet) above ground, associated with the Project is calculated to be 5.19 kV/m. As shown in **Figure 29**, the strength of electric fields diminishes rapidly as the distance from the conductor increases. The electric field values of all of the design options at the edge of the transmission line right-of-way and sample points beyond are shown in **Table 28**.

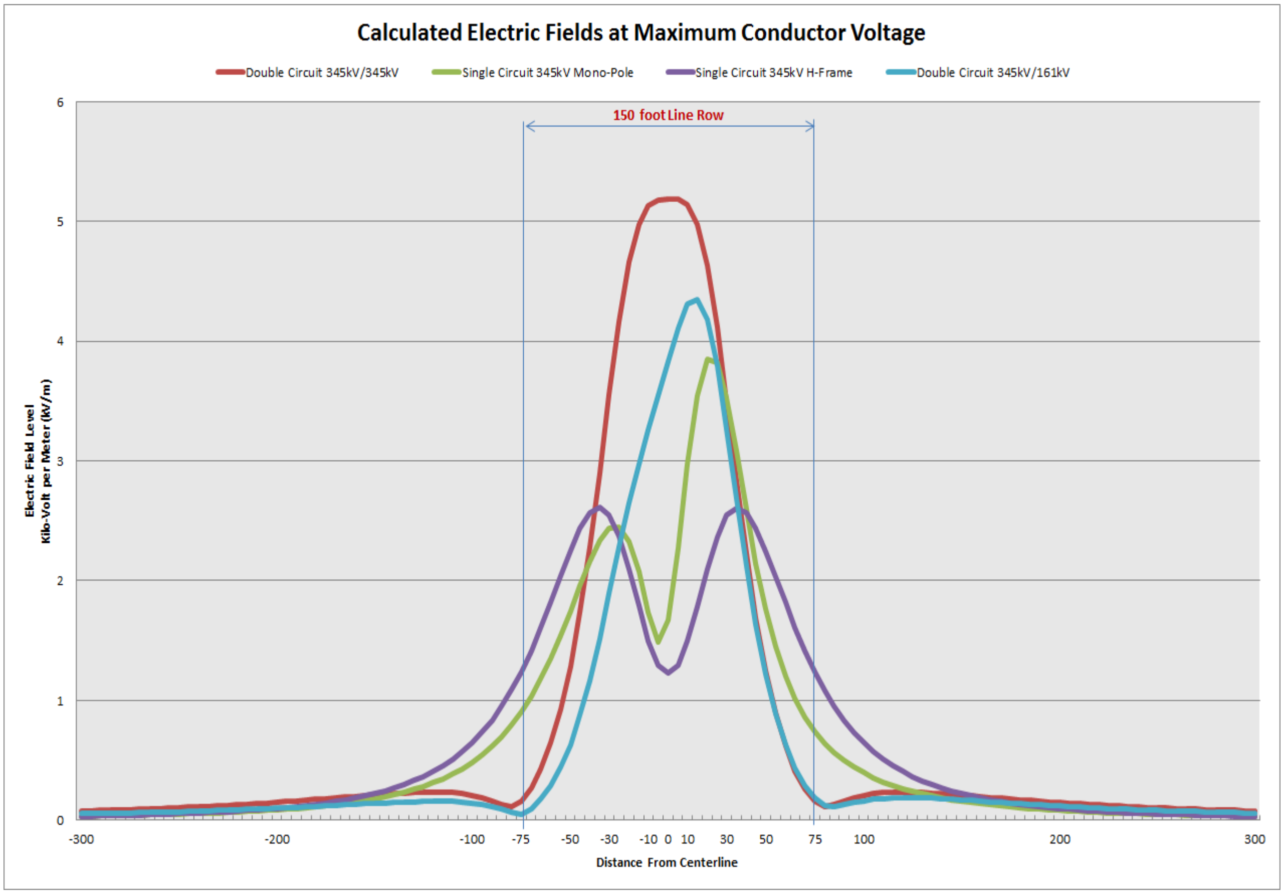
[83] *In the Matter of the Route Permit Application for a 345 kV Transmission Line from Brookings County, S.D. to Hampton, Minn.,* Docket No. ET2/TL-08-1474, ORDER GRANTING ROUTE PERMIT (Sept. 14, 2010) (adopting the Administrative Law Judge's Findings of Fact, Conclusions, and Recommendation at Finding 194).

Table 28
Electric Field Calculations

Structure Type	Nominal Voltage	Distance to Proposed Centerline (feet)												
		-300	-200	-100	-75	-50	-25	0	25	50	75	100	200	300
345 kV Single-Circuit Monopole	362 kV	0.03	0.09	0.48	0.91	1.75	2.45	1.67	3.82	1.76	0.74	0.39	0.08	0.03
345 kV/345 kV Double-Circuit Monopole	362 kV	0.08	0.15	0.21	0.16	1.29	4.16	5.19	4.11	1.25	0.15	0.21	0.15	0.08
345 kV Single-Circuit H-frame	362 kV	0.03	0.10	0.65	1.24	2.25	2.37	1.23	2.37	2.25	1.24	0.65	0.10	0.03
345 kV/161 kV Double-Circuit Monopole[84]	362 kV - 169 kV	0.05	0.10	0.14	0.05	0.63	2.28	3.83	3.79	1.22	0.18	0.16	0.12	0.06

[84] The 345/115 kV structure design will have similar (although slightly lower) electric field calculations as the 345/161 kV structure design.

Figure 29
Calculated Electric Fields (kV/m) for Proposed 345 Kilovolt Transmission Line Designs (3.28 feet above ground)*



*The colors in the figure represent different design options and do not represent route alternatives.

6.6.2 Magnetic Fields

The projected magnetic fields for different structure and conductor configurations for the Project are provided in **Figure 30**, **Figure 31,** and **Table 29**. Since magnetic fields are dependent on the current flowing on the line, magnetic fields were calculated for two different typical system conditions during the Project's first-year in service (2022). These two scenarios are: (1) System Peak Energy Demand and (2) High Wind Utilization. The assumed current for each scenario is provided in amps or MVA.

The "System Peak Energy Demand" current flow (estimated loading of 50 MVA), represents the current flow on the line during the peak hour of system-wide energy demand and is shown in **Figure 30** and **Table 29**. Typically, the peak hour of system-wide energy demand on the NSP system is characterized by a summer day with high temperatures and low levels of wind generation.

Magnetic fields were also calculated for "High Wind Utilization" current flow (estimated loading of 375 MVA), as shown in **Figure 31** and **Table 29**. This scenario represents the current flow on the line during a non-peak time (winter months) when there is high levels of wind generation and the transmission system is intact (i.e., no outages).

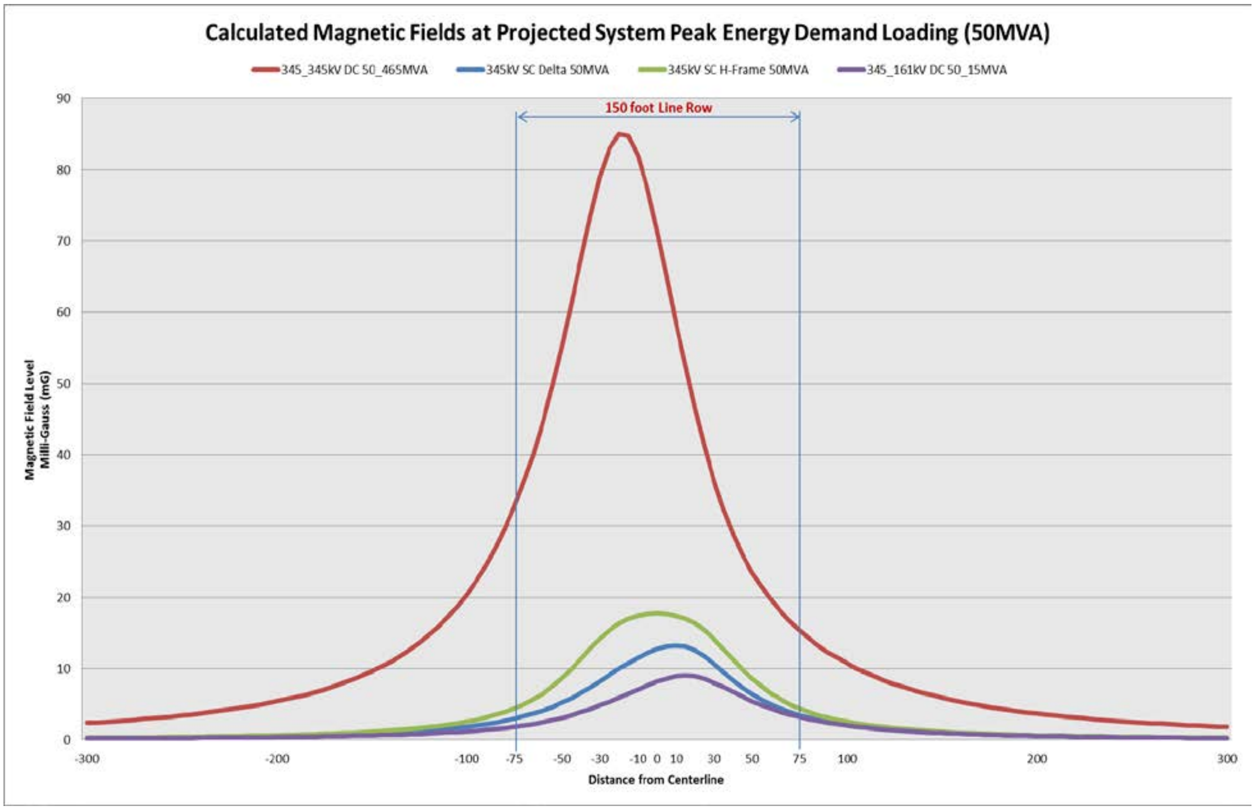
The magnetic field values for the two scenarios were calculated at a point where the conductor is closest to the ground. The magnetic field data shows that magnetic field levels decrease rapidly as the distance from the centerline increases (proportional to the inverse square of the distance from source). In addition, since the magnetic field produced by the transmission line is dependent on the current flow, the actual magnetic fields when the Project is placed in service will vary as the current flow on the line changes throughout the day.

Table 29
Magnetic Field Calculations

Structure Type	System Condition	Current (Amps)	Distance to Proposed Centerline (feet)												
			-300	-200	-100	-75	-50	-25	0	25	50	75	100	200	300
345 kV Single-Circuit Monopole	System Peak Energy Demand (50 MVA)	84	0.24	0.52	1.86	2.99	5.22	9.11	12.73	11.76	6.46	3.49	2.10	0.56	0.25
	High Wind Utilization (375 MVA)	628	1.78	3.90	13.92	22.31	38.92	67.94	94.86	87.58	48.21	26.06	15.70	4.16	1.86
345 kV/345 kV Double-Circuit Monopole	Peak System Energy Demand (50 MVA/465 MVA)	84/778	2.37	5.43	20.45	32.73	55.17	82.98	71.58	41.11	23.62	15.38	10.73	3.72	1.83
	High Wind Utilization (375 MVA/940 MVA)	682/1573	4.44	10.24	39.62	64.36	110.58	170.30	154.94	90.68	46.90	29.29	20.26	6.96	3.40
345 kV Single-Circuit H-frame	Peak System Energy Demand (50 MVA)	84	0.29	0.65	2.57	4.43	8.65	15.40	17.75	15.40	8.64	4.42	2.57	0.65	0.29
	High Wind Utilization (375 MVA)	628	2.17	4.90	19.52	34.13	69.16	129.36	148.73	129.32	69.12	34.11	19.51	4.89	2.17
345 kV/161 kV Double-Circuit Monopole[85]	Peak System Energy Demand (50 MVA/15 MVA)	84/54	0.19	0.38	1.21	1.86	3.12	5.39	8.16	8.59	5.48	3.24	2.03	0.55	0.24
	High Wind Utilization (375 MVA/45 MVA)	682/162	1.48	3.03	9.08	13.42	21.38	36.33	59.11	65.63	42.74	25.40	15.97	4.30	1.89

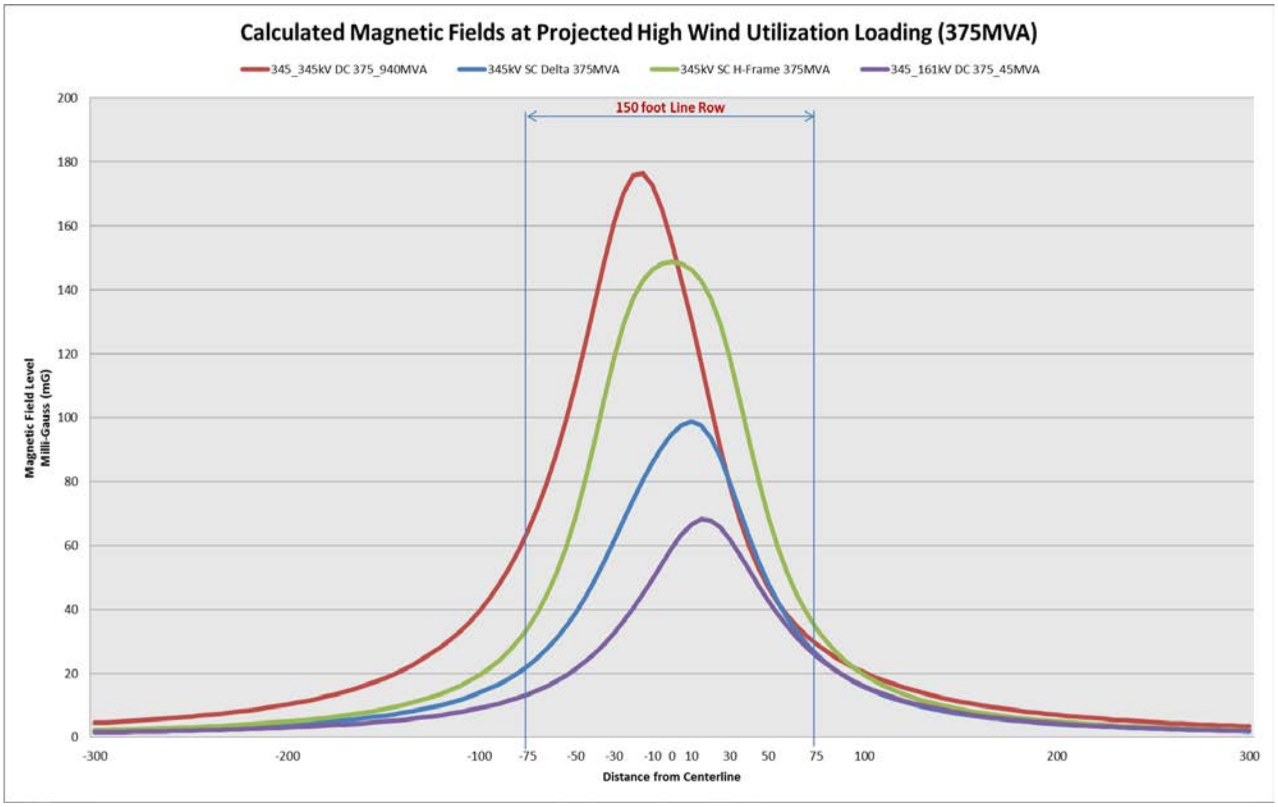
[85] The 345 kV/115 kV structure design will have similar magnetic field calculations to the 345 kV/161 kV structure design.

Figure 30*
Calculated Magnetic Flux density (mG) for Proposed 345 Kilovolt Transmission Line Designs at System Peak Energy Demand Loading (3.28 feet above ground)



* The colors in the figure represent different design options and do not represent route alternatives.

Figure 31*
Calculated Magnetic Flux density (mG) for Proposed 345 Kilovolt Transmission Line Designs at High Wind Utilization Loading (3.28 feet above ground)



* The colors in the figure represent different design options and do not represent route alternatives.

Applicants acknowledge that it is possible that the current flow on the proposed 345 kV line may, under certain system contingencies (i.e., lines are out of service), be higher than what is projected under these two scenarios. However, such system contingencies are rare and the high current flow will only persist for a limited time (i.e., no more than five minutes). The above two scenarios illustrate the typical current flow for the proposed 345 kV line.

There are presently no Minnesota regulations pertaining to magnetic field exposure. Applicants provide information to the public, interested customers, and employees so they can make informed decisions about magnetic fields. Such information includes the availability for measurements to be conducted for customers and employees upon request.

Considerable research has been conducted since the 1970s to determine whether exposure to power-frequency (60 hertz) magnetic fields causes biological responses and health effects. Public health professionals have also investigated the possible impact of exposure to EMF on human health for the past several decades. While the general consensus is that electric fields pose no risk to humans, the question of whether exposure to magnetic fields can cause biological responses or health effects continues to be debated.

Since the 1970s, a large amount of scientific research has been conducted on EMF and health. This large body of research has been reviewed by many leading public health agencies such as the U.S. National Cancer Institute, the U.S. National Institute of Environmental Health Sciences, and the World Health Organization (WHO), among others. These reviews do not show that exposure to electric power EMF causes or contributes to adverse health effects.

For example, in 2016, the U.S. National Cancer Institute summarized the research as follows:

> Numerous epidemiologic studies and comprehensive reviews of the scientific literature have evaluated possible associations between exposure to non-ionizing EMFs and risk of cancer in children (12–14). (Magnetic fields are the component of non-ionizing EMFs that are usually studied in relation to their possible health effects.) Most of the research has focused on leukemia and brain tumors, the two most common cancers in children. Studies have examined associations of these cancers with living near power lines, with magnetic fields in the home, and with exposure of parents to high levels of magnetic fields in the workplace. No consistent evidence for an association between any source of non-ionizing EMF and cancer has been found.[86]

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[86] NAT'L CANCER INSTITUTE, *Electromagnetic Fields and Cancer* (updated May 27, 2016), *available at* https://www.cancer.gov/about-cancer/causes-prevention/risk/radiation/electromagnetic-fields-fact-sheet.

Wisconsin, Minnesota, and California have all conducted literature reviews or research to examine this issue. In 2002, Minnesota formed an Interagency Working Group (Working Group) to evaluate the body of research and develop policy recommendations to protect the public health from any potential problems resulting from high voltage transmission line EMF effects. The Working Group consisted of staff from various state agencies and published its findings in a White Paper on Electric and Magnetic Field (EMF) Policy and Mitigation Options in September 2002, (Minnesota Department of Health, 2002). The report summarized the findings of the Working Group as follows:

> Research on the health effects of [MF] has been carried out since the 1970s. Epidemiological studies have mixed results – some have shown no statistically significant association between exposure to [MF] and health effects, some have shown a weak association. More recently, laboratory studies have failed to show such an association, or to establish a biological mechanism for how magnetic fields may cause cancer. A number of scientific panels convened by national and international health agencies and the United States Congress have reviewed the research carried out to date. Most researchers concluded that there is insufficient evidence to prove an association between [MF] and health effects; however, many of them also concluded that there is insufficient evidence to prove that [MF] exposure is safe. (*Id.* at p. 1.)

The Commission, based on the Working Group and WHO findings, has repeatedly found that "there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects."[87]

[87] *In the Matter of the Application of Xcel Energy for a Route Permit for the Lake Yankton to Marshall Transmission Line Project in Lyon County*, Docket No. E002/TL-07-1407, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER ISSUING A ROUTE PERMIT TO XCEL ENERGY FOR THE LAKE YANKTON TO MARSHALL TRANSMISSION PROJECT at 7-8 (Aug. 29, 2008); *see also In the Matter of the Application for a HVTL Route Permit for the Tower Transmission Line Project*, Docket No. ET2, E015/TL-06-1624, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER ISSUING A ROUTE PERMIT TO MINNESOTA POWER AND GREAT RIVER ENERGY FOR THE TOWER TRANSMISSION LINE PROJECT AND ASSOCIATED FACILITIES at

6.7 Stray Voltage and Induced Voltage

"Stray voltage" is a condition that can potentially occur on a property or on the electric service entrances to structures from distribution lines connected to these structures-not transmission lines as proposed here. The term generally describes a voltage between two objects where no voltage difference should exist. More precisely, stray voltage is a voltage that exists between the neutral wire of either the service entrance or of premise wiring and grounded objects in buildings such as barns and milking parlors. The source of stray voltage is a voltage that is developed on the grounded neutral wiring network of a building and/or the electric power distribution system.

Transmission lines do not, by themselves, create stray voltage because they do not connect directly to businesses or residences. Transmission lines, however, can induce voltage on a distribution circuit that is parallel and immediately under the transmission line. If the proposed transmission lines parallel or cross distribution lines, appropriate mitigation measures can be taken to address any induced voltages. For additional information regarding stray voltage, please see the Minnesota Stray Voltage Guide that is available online at: www.minnesotastrayvoltageguide.com or contact your electrical utility provider.

6.8 Farming Operations, Vehicle Use, and Metal Buildings near Power Lines

The power lines will be designed to meet or exceed minimum clearance requirements with respect to electric fencing as specified by the NESC. Nonetheless, insulated electric fences used in livestock operations can be instantly charged with an induced voltage from transmission lines. The induced charge may continuously drain to ground when the charger unit is connected to the fence. When the charger is disconnected either for maintenance or when the fence is being built, shocks may result. The local electrical utility can provide site specific information about how to prevent possible shocks when the charger is disconnected.

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23 (Aug. 1, 2007) ("Currently, there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects.").

Farm equipment, passenger vehicles, and trucks may be safely used under and near power lines. The power lines will be designed to meet or exceed minimum clearance requirements with respect to roads, driveways, cultivated fields, and grazing lands as specified by the NESC. Recommended clearances within the NESC are designed to accommodate a relative vehicle height of 14 feet.

Vehicles, or any conductive body, under high voltage transmission lines will be immediately charged with an electric charge. Without a continuous grounding path, this charge can provide a nuisance shock. Such nuisance shocks are a rare event because generally vehicles are effectively grounded through tires. Modern tires provide an electrical path to ground because carbon black, a good conductor of electricity, is added when they are produced. Metal parts of farming equipment are frequently in contact with the ground when plowing or engaging in various other activities. Therefore, the induced charge on vehicles will normally be continually flowing to ground unless they have unusually old tires or are parked on dry rock, plastic, or other surfaces that insulate them from the ground. Applicants can provide additional vehicle-specific methods for reducing the risk of nuisance shocks in vehicles.

Buildings are permitted near transmission lines but are generally discouraged within the right-of-way itself because a structure under a line may interfere with safe operation of the transmission facilities. For example, a fire in a building within the right-of-way could damage a transmission line. The NESC establishes minimum electrical clearance zones from power lines for the safety of the general public and utilities often acquire easement rights that require clear areas in excess of these established zones. Utilities may permit encroachment into that easement for buildings and other activities when they can be deemed safe and still meet the NESC minimum requirements. Metal buildings may have unique issues due to induction concerns. For example, conductive buildings near power lines of 200 kV or greater must be properly grounded. Any person with questions about a new or existing metal structure can contact the Applicants for further information about proper grounding requirements.

7. TRANSMISSION LINE CONSTRUCTION AND MAINTENANCE

Chapter 7 is a basic primer regarding the steps we will take to build the proposed facilities after we have obtained all regulatory and other required approvals. We describe the sequence of activities that occur during the construction of a transmission line and substation and some of the construction methods that can be taken to minimize potential impacts of construction. This chapter also identifies the activities associated with the operation and maintenance of a transmission line once it is constructed.

Key Terms:

- ***Best Management Construction Practices*** – standard construction and mitigation practices developed within the industry from past projects for avoiding and minimizing construction impacts.

- ***Easement*** – where some or all of the right-of-way for a transmission line is on private property, an easement is acquired from the landowner to build, operate, and maintain a transmission line. Landowners are paid fair market value for the easement and can continue to use the land for many purposes, although some restrictions are included in the agreement.

- ***Right-of-Way*** – a right-of-way is the land area necessary for a specific purpose, such as the operation and maintenance or access to a transmission line. Often the terms "right-of-way" and "easement" are used interchangeably.

7.1 Engineering Design and Regulatory Approvals

Detailed transmission line and substation engineering design work generally begins after a route permit or local routing approval is obtained. The design of a transmission line is refined as more site-specific information is gathered for properties along the approved route. Throughout the process, utilities work with landowners to design facilities to minimize impacts and ensure that all permit conditions are satisfied. Plan and profile documents are also prepared for each new high voltage transmission line and associated substation work. These plans provide a detailed description of the facilities, including pole placement, spans, and wire heights above ground, and are approved by the Minnesota Department of Commerce Energy Environmental Review and Analysis (EERA) staff.

7.2 Right-of-Way Acquisition

Early in the detailed design process, after the route permit is obtained, the right-of-way acquisition process begins. For transmission lines, utilities typically acquire easement rights across the parcels to accommodate the facilities. The evaluation and acquisition process includes title examination, initial owner contacts, survey work, document preparation, and purchase.

Where the Project is expected to use existing rights-of-way and the terms of the existing easement are sufficient, the agent will work with the landowner to address any construction needs, impacts, or restoration issues.

For those segments of the Project where a new or expanded right-of-way will be necessary, the agent will identify all persons and entities that may have a legal interest in the affected real estate. The agent contacts each property owner to describe the need for the transmission facilities and how the Project may affect each parcel. The agent also seeks information from the landowner about any specific construction concerns.

To aid in the evaluation of each parcel, the agent may request permission to enter the property to conduct preliminary survey work. During this process, the location of the proposed transmission line or substation facility may be staked with permission of the property owner.

The agent will discuss the construction schedule and construction requirements with the owner. Special consideration may be needed for fences, crops, or livestock. Fences and livestock may need to be moved; temporary or permanent gates may need to be installed; and crops may need to be harvested early. In each case, the right-of-way agent and construction personnel coordinate these processes with the landowner.

Land value data will be collected based on the impact of the easement to the market value of each parcel. A fair market value offer will be developed. In rare instances, a negotiated settlement cannot be reached and the landowner chooses to have an independent third party determine the value of the rights taken. Such valuation is made through the utility's exercise of the right of eminent domain pursuant to Minnesota Statutes chapter 117. The process of exercising the right of eminent domain is called condemnation.

Before commencing a condemnation proceeding, an applicant must obtain at least one appraisal and provide a copy to the property owner. The property owner may also obtain another property appraisal and the applicant must reimburse the property owner for the cost of the appraisal according to the limits set forth in Minnesota Statutes section 117.036, subdivision 2(b). To start the formal condemnation process, a utility files a petition in the district court where the property is located and serves that petition on all owners of the property.

If the court grants the petition, the court then appoints a three-person condemnation commission that will determine the compensation for the easement. The three people must be knowledgeable of applicable real estate issues. The commissioners schedule a viewing of the property and then schedule a valuation hearing where the utility and landowners can testify as to the fair market value of the easement or fee. The Commission then makes an award as to the value of the property acquired and files it with the court. Each party has 40 days from the filing of the award to appeal to the district court for a jury trial. In the event of an appeal, the jury hears land value evidence and renders a verdict. At any point in this process, the case can be dismissed if the parties reach a settlement.

There may be instances where a landowner elects to require an applicant to purchase their entire property rather than acquiring only an easement for the transmission facilities. The property owner is granted this right under Minnesota Statutes section 216E.12, subdivision 4, which is sometimes referred to as the "Buy-the-Farm Statute." The Buy-the-Farm Statute applies only to transmission facilities that are 200 kV or more; thus, the Buy-the-Farm Statute may apply to parcels crossed by the proposed 345 kV transmission line.

7.3 Construction Procedures

Construction duration for this Project will be approximately 18 to 20 months and will employ approximately 100 to 150 construction workers.

Construction will begin after necessary federal, state, and local approvals are obtained and property and rights-of-way are acquired for that segment. Construction in areas where approvals are not needed or have already been obtained may proceed while approvals for other areas are in process. The precise timing of construction will take into account various requirements of permit conditions, environmental restrictions, availability of outages for existing transmission lines (if required), available workforce, and materials.

Construction will follow Xcel Energy's standard construction and mitigation best practices as developed to minimize temporary and permanent impacts to land and the environment. Construction typically progresses as follows:

- survey marking of the right-of-way;
- right-of-way clearing and access preparation;
- grading or filling if necessary;
- installation of culvert or concrete foundations;
- installation of poles, insulators, and hardware;
- conductor stringing; and
- installation of any aerial markers required by state or federal permits.

Xcel Energy will design the transmission line structures for installations at the existing grades. Where a site slope requires (typically on slopes exceeding 10 percent), working areas may be graded or leveled with fill. If acceptable to the landowner, Xcel Energy proposes to leave the graded/leveled areas after construction to allow access for future maintenance activities. If not acceptable to the landowner, Xcel Energy will, to the best of its ability, return the grade of the site back to its original condition.

Construction will require the use of many different types of construction equipment including tree removal equipment, mowers, cranes, backhoes, digger-derrick line trucks, drill rigs, dump trucks, front-end loaders, bucket trucks, bulldozers, flatbed tractor-trailers, flatbed trucks, pickup trucks, concrete trucks, helicopters, and various trailers or other hauling equipment. Excavation equipment is often set on wheeled or track-driven vehicles. Construction crews will attempt to use equipment, when opportunities are available, that minimizes impacts to lands.

Construction staging areas are usually established for transmission projects. Staging involves delivering the equipment and materials necessary to construct the new transmission line facilities. Construction of the Project will likely include two or more staging areas. Structures are delivered to staging areas and materials are stored until they are needed for the Project.

The Applicants will evaluate construction access opportunities by identifying existing transmission line easements, roads, or trails that run near the approved route. When feasible, the Applicants will limit construction activities to the easement area. In certain circumstances, additional off-easement access may be required. Permission will be obtained from landowners prior to using off-easement access.

Improvements to existing access or construction of new access may be required to accommodate construction equipment. Field approaches and roads may be constructed or improved. Where applicable, the Applicants will obtain permits for new access from local road authorities. The Applicants will also work with appropriate road authorities to ensure proper maintenance of roadways traversed by construction equipment.

After right-of-way clearing and access preparation has been completed, pole and foundation installation will begin. Most structures for the Project will require either a drilled pier concrete foundation or an embedded culvert foundation.

Culverts are typically four feet in diameter and 15 to 20 feet deep. A hole is excavated and the culvert is placed vertically. The base of the pole is placed into the culvert and filled with an appropriate rock material.

Drilled pier foundations are typically between 5 to 10 feet in diameter and are typically 20 to 60 feet deep, depending on soil conditions. An angle or dead-end structure may require a foundation up to 12 feet in diameter. The actual diameter and depth of the hole (and foundation) depend on structure design and soil conditions that are determined during the initial survey and soil testing phases. Concrete is brought to the site by concrete trucks from a local concrete batch plant and filled around a steel rebar support cage and anchor bolts. Once the foundation is cured, the pole is bolted to the foundation.

Poles will be moved from staging areas and delivered to the foundation. Using a crane, the pole is lifted and placed. Insulators and other hardware are attached.

Conductor stringing is the last major component of transmission line construction. Stringing setup areas are typically located at two mile intervals. These sites are located within the right-of-way, when possible, or on temporary construction easements. These operations require brief access to each structure to secure the conductor wire to the insulator hardware and the shield wire to clamps once final conductor sag, compliant with Xcel Energy procedures and minimum code clearances, is established. This access can be conducted by crane or helicopter.

After conductor installation is complete, conductor marking devices will be installed if required. These marking devices may include bird flight diverters or air navigational markers. The Applicants will work with the appropriate agencies to identify locations where marking devices will be installed.

Where the transmission line crosses streets, roads, highways, or other energized conductors or obstructions, temporary guard or clearance poles may be installed before conductor stringing. The temporary guard or clearance poles ensure that conductors will not obstruct traffic or contact existing energized conductors or other cables during stringing operations and also protects the conductors from damage.

Some soil conditions and environmentally-sensitive areas will require special techniques. The most effective way to minimize impacts to these areas will be to avoid placing poles in the sensitive areas by spanning over wetlands, streams, and rivers. When it is not feasible to avoid traversing sensitive areas, one or more of the following options will be used to minimize impacts, in consultation with the appropriate agencies:

- When possible, construction will be scheduled during frozen ground conditions.
- When construction during winter is not possible, construction mats will be used where wetlands and other sensitive areas would be impacted.

- Equipment fueling and other maintenance will occur away from environmentally-sensitive and wet areas. These construction practices help prevent soil erosion and ensure that fuel and lubricants do not enter waterways or impact environmentally-sensitive areas.

- Various best management practices (BMPs) will be identified in the Project's Stormwater Pollution Prevention Plan (SWPPP), including the use of silt fences, bio logs, erosion control blankets with embedded seeds, and other sound water and soil conservation practices to protect topsoil and adjacent water resources and to minimize soil erosion.

These techniques are also used to reduce impacts to private property including driveways, yards, and drain tile.

7.4 Restoration and Clean-Up Procedures

Crews will attempt to minimize ground disturbance whenever feasible. Although these attempts will be made, areas will be disturbed during the normal course of work. Once construction is completed in an area, disturbed areas will be restored to their original condition to the maximum extent feasible. Temporary restoration before the completion of construction in some areas along the right-of-way may be required per National Pollution Discharge Elimination System (NPDES) and MPCA construction permit requirements.

After construction activities have been completed, a representative will contact the property owner to discuss any damage that has occurred as a result of the Project. This contact may not occur until after the Applicants have started restoration activities. If fences, drain tile, or other property have been damaged, the Applicants will repair damages or reimburse the landowner to repair the damages.

Farmers will be compensated for crops damaged during construction. The damaged area will be measured, yield determined in consultation with the farmer, and paid at current market rates. The Applicants will also make a payment for future year crop loss due to soil compaction. In addition, farmers will be compensated for their expense to deep rip compacted areas. If an individual does not have access to deep ripping equipment, Applicants will provide this service.

Ground-level vegetation disturbed or removed from the right-of-way during construction of the Project will naturally reestablish to pre-construction conditions. Vegetation that is consistent with substation site operation outside the fenced area will be allowed to reestablish naturally at substation sites. Areas where significant soil compaction or other disturbance from construction activities occur will require additional assistance in reestablishing the vegetation stratum and controlling soil erosion. In these areas, the Applicants will use seed that is noxious weed free to reestablish vegetation.

Another aspect of restoration relates to the roads used to access staging areas or construction sites. After construction activities are complete, the Applicants will ensure that township, city, and county roads used for purposes of access during construction will be restored to their prior condition. The Applicants will meet with township road supervisors, city road personnel, or county highway departments to address any issues that arise during construction with roadways to ensure the roads are adequately restored, if necessary, after construction is complete.

7.5 Maintenance Practices

Transmission lines and substations are designed to operate for decades and require only moderate maintenance, particularly in the first few years of operation. Xcel Energy will be responsible for the operation and maintenance of this Project. Xcel Energy performs aerial annual inspections of the 345 kV transmission line and inspects the line from the ground every six years. Typically, one to two workers are required to perform aerial inspections and two to five workers are required to perform the ground inspections. Any defects identified during these inspections will be assessed and corrected. Xcel Energy will also perform necessary vegetation management for the line. Vegetation maintenance generally occurs every four years.

The annual inspections are the principal operating and maintenance cost for transmission facilities. The aerial inspections cost approximately $150 to $200 per mile and the ground inspections cost approximately $400 to $600 per mile. Actual line-specific maintenance costs depend on the setting, the amount of vegetation management necessary, storm damage occurrences, structure types, materials used, and the age of the line.

Substations require a certain amount of maintenance to keep them functioning in accordance with accepted operating parameters and the NESC requirements. Transformers, circuit breakers, batteries, protective relays, and other equipment need to be serviced periodically in accordance with the manufacturer's recommendations. The substation site must be kept free of vegetation and adequate drainage must be maintained.

The estimated service life of the proposed transmission line for accounting purposes varies among utilities. Applicants use an approximately 60-year service life for their transmission assets. However, practically speaking, high voltage transmission lines are seldom completely retired.

7.6 Storm and Emergency Response and Restoration

Transmission infrastructure has very few mechanical elements and is built to withstand weather extremes that are normally encountered. With the exception of outages due to severe weather such as tornadoes and heavy ice storms, transmission lines rarely fail. Transmission lines are automatically taken out of service by the operation of protective relaying equipment when a fault is sensed on the system. Such interruptions are usually only momentary. Scheduled maintenance outages are also infrequent. As a result, the average annual availability of transmission infrastructure is very high, in excess of 99 percent.

However, unplanned outages of transmission facilities can happen for a variety of reasons. Unplanned outages can occur due to mechanical failures or severe weather like heavy ice, wind, and lightning. In the event an unplanned outage of the proposed Huntley – Wilmarth 345 kV transmission line occurs, Xcel Energy has the necessary infrastructure and crews in place in southern Minnesota to respond quickly and safely to return this line to service.

If there is a storm or emergency outage on the Huntley – Wilmarth line, Xcel Energy has a distribution service center in Mankato, Minnesota, that will initiate a tactical response by deploying one of its 24-hour on-call first responders or "trouble man" to the line as quickly as possible to patrol the line and immediately assess the damage. Once the damage has been assessed the first responder will immediately relay the following information back to the service center:

- Magnitude of damage;
- Isolation requirements for switching;
- Material required for restoration;
- Number of line crew needed; and
- Equipment needed.

Based on the assessment of the first responder, Xcel Energy will develop a plan to restore the damaged facilities. The goal of the repair is to place the transmission system back into service as quickly as possible to minimize the impact to the transmission system. Xcel Energy has the benefit of both internal and contract crews distributed across southern Minnesota and the Twin Cities that will enable a rapid response to outage events on the Huntley – Wilmarth transmission line. These crews can typically be mobilized and on-site in the Mankato area in two hours of an event to begin restoration activities. Xcel Energy also has an in-house experienced Engineering Department that can be called upon to quickly develop an engineering solution to any damaged transmission infrastructure.

Another key element of the emergency and unplanned outage response is having the necessary materials on-hand and nearby to replace or repair damaged facilities as quickly as possible. Xcel Energy maintains nearly 20,000 miles of transmission line and is able to promptly procure, load, and deliver materials during emergency situations. In the event of an unplanned outage of the Huntley – Wilmarth 345 kV line, Xcel Energy has a service center located in Maple Grove, Minnesota, approximately one and a half hours from Mankato, Minnesota, that has a critical stock of replacement transmission poles, wires, and hardware. In addition, the Maple Grove service center also has a fleet of tractor trailers and drivers on-call 24 hours a day that can be utilized to ship these replacement materials to the Mankato area.

Xcel Energy could also call on ITC Midwest for mutual assistance in the event of an emergency or unplanned outage. ITC Midwest has warehouses in Albert Lea and Lakefield, Minnesota, near the Project and could provide crews and equipment that would aid any efforts to bring the line back to service after an outage.

Xcel Energy has won multiple industry awards for its storm and emergency response. In June 2016, Xcel Energy received its fourth major storm response award in five years from the Edison Electric Institute. This Emergency Recovery Award recognized Xcel Energy's superior response to a three-day blizzard that damaged utility infrastructure in Xcel Energy's Texas and New Mexico service territories. Xcel Energy also won Emergency Recovery awards in 2013 and 2015 for its response to severe thunderstorms in the Twin Cities and an Assistance Award in 2012 for Xcel Energy's help with the recovery following Superstorm Sandy.

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8. ENVIRONMENTAL INFORMATION

In this chapter, we provide a general overview of the environmental features and land uses in the Project Study Area. We explain the environmental considerations associated with each of the routes that the Applicants evaluated in preparing this Application. The initial sections of this chapter are very technical in nature to provide detailed information to state agencies that will be reviewing this Application, while later sections provide more common terms describing the Project's environmental setting. Based on our review, there are no environmental issues that would preclude construction of the proposed facilities. Applicants will take the necessary mitigative measures to minimize environmental impacts of siting, constructing, and operating the Project.

Key Terms:

- ***Geomorphology*** – a science that deals with the relief features of the earth and seeks a genetic interpretation of them.
- ***Physiography*** – a branch of geography that deals with the exterior features and changes of the Earth.
- ***Mitigative Measures*** – actions taken by Applicants to lessen environmental or other impacts resulting from the construction, operation, or maintenance of the proposed Project.
- ***Cultural Resources*** – historic or archaeological sites containing unique or significant features relating to the cultural history of the region. These resources are considered non-renewable.
- ***Considered Eligible Finding (CEF)*** – Cultural Resource sites that have been identified as eligible for listing on the National Register of Historic Places (NRHP) by both state and federal agencies, but not yet nominated or listed and are afforded comparable protection to listed sites for evaluation purposes.
- ***Floodplain*** – flat or nearly flat land adjacent to a stream or river that experiences occasional or periodic flooding. The floodplain includes the floodway which consists of the stream channel and adjacent areas that carry flood flows, and the flood fringe which are areas covered by the flood but do not carry a strong current.

- ***Public Waters*** – designated as such to indicate which lakes, wetlands, and watercourses over which the Minnesota Department of Natural Resources (MnDNR) Waters has regulatory jurisdiction. The statutory definition of public waters includes public waters and public waters wetlands (Minnesota Statutes section 103G.005, subdivision 15).

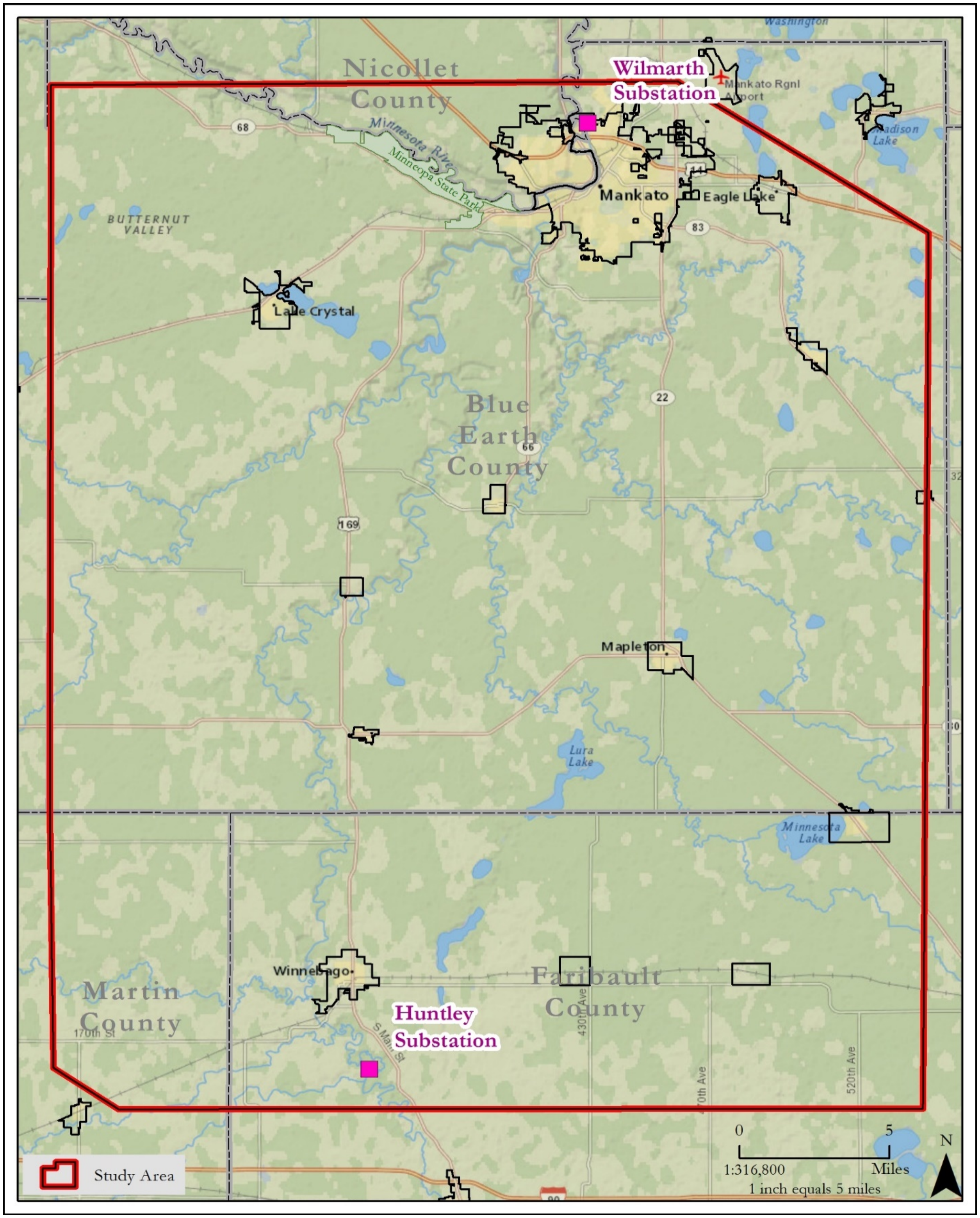
This section describes the environmental setting, land use and human settlement, land-based economies, archaeological and historical resources, hydrologic features, vegetation and wildlife, and rare and unique natural resources that are known to occur or may potentially occur in the Project Study Area. The Project Study Area is shown on **Figure 32**. This section identifies existing environmental resources, characterizes potential Project impacts to those resources, and identifies measures that can be implemented to avoid, minimize, or mitigate impacts. A summary of the major permits and approvals that may be required for the Project is provided in **Section 8.1.10**.

8.1 Project Study Area

8.1.1 Description of Environmental Setting

The Project Study Area includes portions of Nicollet, Martin, Faribault, and Blue Earth counties as shown on **Figure 32**. Topography of the Project Study Area is primarily level to rolling with major drainageways, including the Minnesota, Blue Earth, and Le Sueur rivers, as shown in **Figure 33**. Land cover is dominated by cultivated cropland. Cities within the Project Study Area include Mankato, Lake Crystal, Mapleton, and Winnebago.

Figure 32
Project Study Area



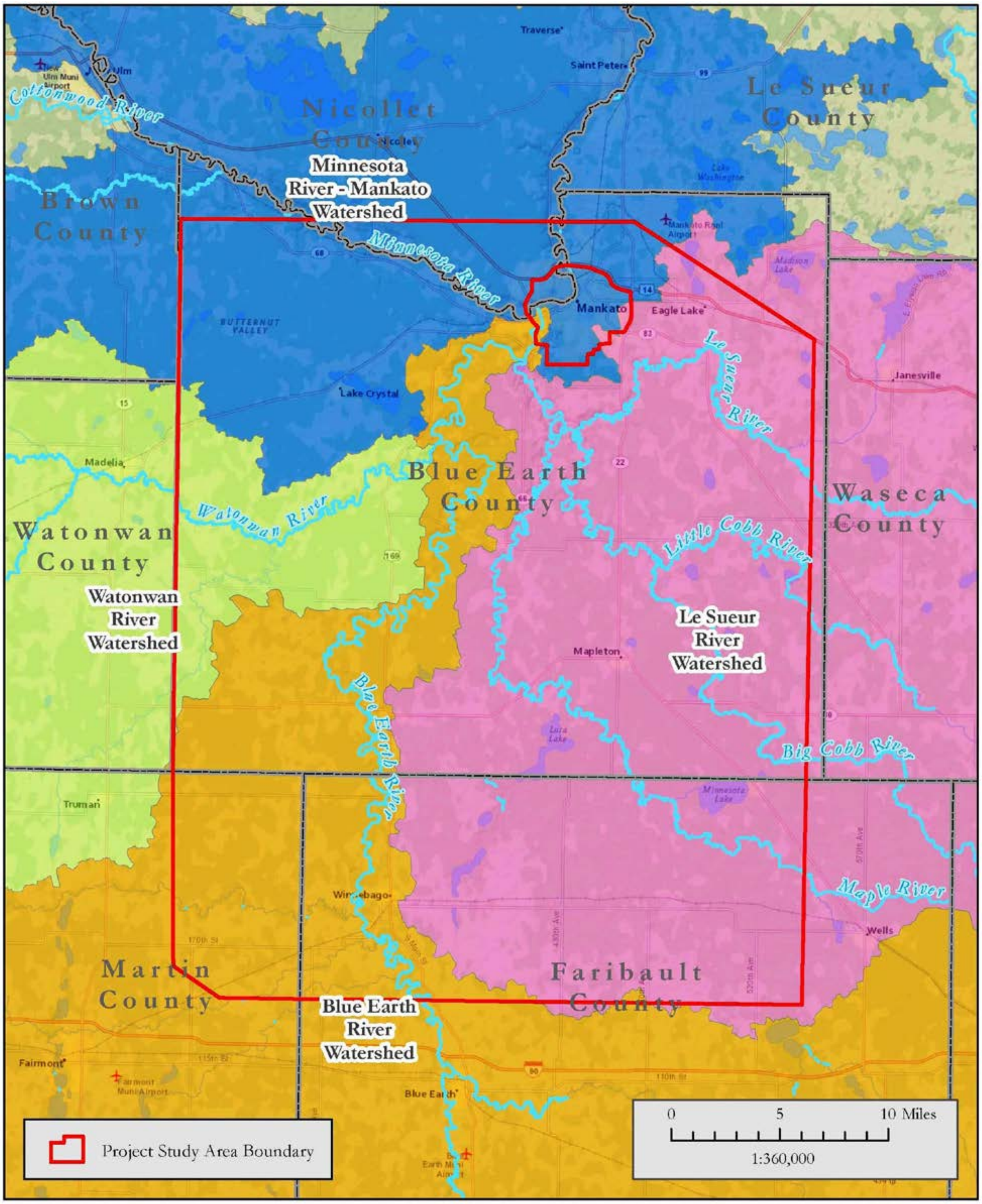
8.1.2 Geomorphology and Physiography

The MnDNR and the U.S. Forest Service have developed an Ecological Classification System (ECS) for ecological mapping and landscape classification in Minnesota. Ecological land classifications are used to identify, describe, and map progressively smaller areas of land with increasingly uniform ecological features. Under this classification system, the Project Study Area (shown in **Figure 32** above) is in the Prairie Parkland Province. Within this province, the Project Study Area primarily occurs within the North Central Glaciated Plains (251B) ecological section with a small portion of the Project Study Area near the city of Mankato lying within the Minnesota and Northeast Iowa Morainal (222M) section. The Project Study Area is characterized as a level to rolling region of calcareous till deposited by the Des Moines lobe during the late Wisconsin glaciation. Most of the Project Study Area is covered by 100 to 400 feet of glacial drift. The Project Study Area is further defined by its presence primarily within the Minnesota River Prairie subsection and a small area near the City of Mankato which is within the Big Woods subsection.

Most of the Project Study Area is between 1,000 feet and 1,050 feet above sea level. However, the main drainage channels within the Project Study Area, such as the Minnesota, Blue Earth, and Le Sueur rivers, which developed during the retreat of the last glacier, occur as abrupt gorges within the landscape. For example, the elevation of the uplands near the bluffs of the Minnesota River Valley is about 975 feet and the river at Mankato is at 756 feet.

Cretaceous shales, sandstones, and clays are the most common kinds of bedrock in the Project Study Area and are generally more than 100 feet deep except in the Minnesota River valley where near-surface or outcropping bedrock occurs. Well- to moderately well-drained loamy soils formed in gray calcareous till of Des Moines lobe origin are dominant. Soils in the project area are generally rich farmland with 80 to 90 percent classified as prime farmland. Upland prairie communities were historically the most common land cover within the Project Study Area with smaller amounts of marsh, wetland prairie, and wet meadow communities. Currently the primary landcover is agricultural, dominated by cultivated cropland.

Figure 33
Major Rivers and Watersheds in the Project Study Area



8.1.3 Land Use and Human Settlement

(a) Commercial, Industrial, Residential Land Use

Land use within the Project Study Area is primarily agricultural and agriculture-related businesses (e.g., transportation, warehousing, and distribution) with typical crops, including corn and soybeans. Within the greater Mankato area, the economy is highly diversified, with approximately 36 percent Primary Economy (i.e., manufacturing and wholesale trade), 53 percent Professional/Service Economy (e.g., healthcare, education, professional services) and 11 percent Retail/Consumer Economy (Blue Earth County, 2017). The Mankato Clinic is one of the largest private clinics in the state, with more than 100 physicians. The Mankato area also has five colleges, Bethany Lutheran College, Gustavus Adolphus College, Rasmussen College, South Central College, and Minnesota State University, Mankato.

(b) Displacement

The development and construction of the Project is not anticipated to displace any residential home or business. NESC and Xcel Energy standards require minimum clearances between transmission line facilities and buildings to ensure safe operation of transmission line facilities. To maintain these clearances, Xcel Energy plans to acquire a 150-foot-wide right-of-way for the 345 kV transmission line facilities.

The Project will be designed in compliance with State, NESC, and Xcel Energy standards for clearance to ground, crossing other utilities, buildings, strength of materials, vegetation, and other obstructions. Furthermore, the Applicants will comply with Xcel Energy's construction standards, which include requirements of NESC and OSHA.

(c) Aesthetics

Overhead transmission lines occur throughout the Project Study Area. Preliminary routes include segments that would follow existing infrastructure such as existing transmission lines or roads. The Project will be visible in the area surrounding the approved route.

(d) Socioeconomics

The Project Study Area encompasses portions of Blue Earth, Faribault, Martin, and Nicollet counties. The median household income for the counties within the Project Study Area are lower than the State of Minnesota median household income, however, the unemployment rate for these counties is lower than the State of Minnesota (refer to **Table 30**).

Table 30
Economic Characteristics for the Project Study Area

Location	Median Household Income	Unemployment Rate	Percent of Population Below Poverty
Blue Earth County	$50,061	4.9%	19.1%
Faribault County	$47,540	4.2%	13.5%
Martin County	$51,391	3.5%	11.4%
Nicollet County	$58,640	4.0%	12.4%
Minnesota	**$61,492**	**5.6%**	**11.3%**

Source: U.S. Census Bureau, 2011-2015 American Community Survey 5-Year Estimates.

The four counties in the Project Study Area combined comprise approximately 2.5 percent of the State's total population. A large majority of the population in the Project Study Area is Caucasian (refer to **Table 31**). The percentage of total minority[88] residents is lower in the Project Study Area counties as compared to the State of Minnesota.

[88] Total minority is calculated by adding the populations for all non-Caucasian races.

Table 31
Population Characteristics for the Project Study Area

Location	Total Population	Caucasian	Black or African American	Asian	Other	Hispanic	Total Minority
Blue Earth County	64,013	92.8%	2.7%	2.0%	0.6%	2.5%	7.2%
Faribault County	14,553	96.5%	0.3%	0.3%	1.5%	2.6%	3.5%
Martin County	20,840	96.7%	0.3%	0.5%	1.3%	3.6%	3.3%
Nicollet County	32,727	93.7%	2.0%	1.3%	1.2%	3.7%	6.3%
Minnesota	**5,303,925**	**85.3%**	**5.2%**	**4.0%**	**1.9%**	**4.7%**	14.7%

Source: U.S. Census Bureau, 2010 Census

(e) Cultural Values

Cultural values include those perceived by community beliefs or attitudes in an area, which provide a framework for community unity. The Project Study Area is mainly rural with an agricultural-based economy. Farming and the protection of agriculture, the land, and the ability to continue to farm and support livelihoods through agriculture are strong values within the Project Study Area. The abundance of recreational opportunities in the area, as described below, also attests to the recreational value within the Project Study Area. Examples of regional cultural events in the Project Study Area include the Martin County Fair, referred to as Minnesota's "Other Big Fair", the annual Freedom Run in the city of Minnesota, and the Anthony Ford Pond Hockey Classic in North Mankato.[89]

(f) Recreation

Recreational opportunities within the Project Study Area include wildlife viewing, camping, hiking, canoeing and kayaking, hunting, fishing, and boating. There are several MnDNR Wildlife Management Areas (WMAs) in the Project Study Area that provide outdoor recreational opportunities and wildlife protection. WPAs, public lands managed by the United States Fish and Wildlife Service (USFWS) for waterfowl

[89] *See* VISIT GREATER MANKATO, *Events* (last visited on Dec. 15, 2017), https://www.visitgreatermankato.com/mankato/visit/events/.

habitat protection, are also found in the Project Study Area. Present within the Project Study Area are Minneopa State Park and the Minnesota River, which both offer many recreational opportunities.

Construction of the Project is not anticipated to change available recreational opportunities in the Project Study Area.

(g) Public Services and Transportation

In rural areas of the Project Study Area, residents often utilize privately owned septic systems and wells, although some residents may have access to rural water distribution facilities. More urbanized areas, like the cities of Mankato, Lake Crystal, Mapleton, and Winnebago are serviced by municipal public works for water, sewer, and electrical services.

Many State and U.S. highways are within the Project Study Area, including State Highway 109, State Highway 22, State Highway 30, State Highway 60, State Highway 66, State Highway 68, and State Highway 83, as well as U.S. Highway 14 and U.S. Highway 169. There are 11 railroads that cross through the Project Study Area. The owners of the railroads are Dakota, Minnesota, and Eastern Railroad, and Union Pacific Railroad.

The Mankato Regional Airport is located within the northeast corner of the Project Study Area. Applicants analyzed structure height limitations based on two sets of imaginary surfaces and zones; those defined in 14 CFR, Part 77 (Part 77) as applied by the Federal Aviation Administration (FAA), and those defined in the Mankato Airport Zoning Ordinance (Mankato Zoning). Structure designs would not extend above these regulated surfaces. Therefore, the Project is not anticipated to have any impacts on the Mankato Regional Airport.

Construction of the Project may temporarily impact roadways if closures or diversions are necessary to accommodate construction equipment. The Project will be designed so that structures and overhead conductors will not interfere with public service and transportation activities.

8.1.4 Land-Based Economies

(a) *Agriculture*

Almost all the land area in Martin and Nicollet counties, and a large majority of the land in Blue Earth and Faribault counties, is agricultural. Average farm size in the four counties is similar, and generally slightly larger than the average size of farms in Minnesota. Crop sales account for a larger percentage of total market value of agricultural products when compared to the livestock sales in Blue Earth ($262 million/$244 million, annually), Faribault ($323 million/$91 million, annually), and Martin ($330 million/$289 million, annually) counties. In Nicollet County, however, livestock sales ($208 million, annually) account for a slightly larger percentage of total market value of agricultural products compared to crop sales ($178 million, annually). Hog barns and pork production are common in all four counties in the Project Study Area. The hog and pig inventory in Blue Earth, Faribault, Martin, and Nicollet counties accounted for 25 percent of the total hog and pig inventory in Minnesota in 2012, the year of the most recent USDA Census. Additionally, Blue Earth and Martin are in the top ten counties for hog and pig sales in the United States.[90] Agricultural statistics for the four counties within the Project Study Area are summarized in **Table 32**.

[90] U.S. DEP'T OF AGRICULTURE, *2012 Census Highlights – Hog and Pig Farming* (last visited Dec. 15, 2017), https://www.agcensus.usda.gov/Publications/2012/Online_Resources/Highlights/Hog_and_Pig_Farming/.

Table 32
Agricultural Statistics by County

Location	Number of Farms	Average Farm Size	Land in Farms	Crop Sales	Livestock Sales
Blue Earth County	1,070	352 acres	376,460 acres (76.8 percent of county)	$262 million (51.7 percent)	$244 million (48.3 percent)
Faribault County	824	473 acres	390,139 acres (84.4 percent of county)	$323 million (77.9 percent)	$91 million (22.1 percent)
Martin County	897	478 acres	428,672 acres (91.8 percent of county)	$330 million (53.3 percent)	$289 million (46.7 percent)
Nicollet County	764	359 acres	274,217 acres (91.7 percent of county)	$178 million (46.1 percent)	$208 million (53.9 percent)
Minnesota	**74,542**	**349 acres**	**26 million acres (46.7 percent of State)**	**$14 billion (65.2 percent)**	**$7 billion (34.8 percent)**

Source: USDA 2012 Census of Agriculture

Specialty crops in the Project Area include nurseries, vineyards, orchards, citrus groves, dairies, aquaculture, and tree farms. Specialty crops were evaluated through a review of public databases and agency consultation. Based on publicly available data, no specialty crops have been identified that will be impacted by the Project along the routes initially developed for, and evaluated in, this Application. Applicants searched the organic farm database and found only one organic farm in the Project Study Area. The Applicants will continue to work with individual landowners through the easement process to identify any organic farms or farms in process for becoming organic or specialty crops that may be impacted by the Project. If any organic farms or specialty crops are identified, the Applicants will work with landowners to determine measures to avoid and minimize impacts to these resources. Applicants will prepare an agriculture impact mitigation plan which will include practices to minimize impact to agriculture.

Permanent impacts to agriculture activities due to the Project are anticipated to be minimal and concentrated at pole and substation locations. Both crop and livestock activities will be able to continue around Project facilities after construction.

(b) Forestry

The Project Study Area is dominated by agricultural lands and minimal forestland. No commercial forestry operations have been identified in the Project Study Area and no impacts to commercial forestry operations are anticipated for the Project.

(c) Tourism

Tourism in the Project Study Area centers around outdoor recreational opportunities, such as fishing and water sports. Many out-of-state hunters and fishermen visit Minnesota every year to take advantage of these tourism activities. Recreation areas including state and county parks, WPAs, and WMAs are located within the study area. Impacts to tourism in the Project Study Area are not anticipated during construction or operation of the Project.

(d) Mining

Mining does not comprise a major industry in the Project Study Area. Sand, gravel, and stone quarry operations are found in Blue Earth, Martin, Faribault, and Nicollet counties. Sand and gravel are primarily mined for local use such as making concrete for highways, roads, bridges, and buildings. These operations are owned either by citizens, private companies, or MnDOT. Transmission lines are anticipated to be routed around these mining resources and no impacts to mining are anticipated.

8.1.5 Archaeological and Historical Resources

Background research on known cultural resources was received from the Minnesota State Historic Preservation Office (SHPO) in St. Paul in May 2017. An Access Database including Archaeological Sites and Standing Structure Inventory resources was provided based on the Project Study Area.

A total of 388 archaeological sites are located within the Project Study Area. Of these, 10 are NRHP-listed sites (one in Blue Earth County and nine in Faribault County). All nine of the NRHP-listed archaeological sites in Faribault County are included in the Center Creek Archaeological District. There is one site in Blue Earth County that is listed on the Minnesota State Register of Historic Places. Additionally, nine sites (eight in Blue Earth County and one in Nicollet County) have received a CEF by the SHPO for listing on the NRHP. SHPO has informed the Applicants that a new archaeological complex of sites has been located along the southern banks of the Minnesota River within Minneopa Park in Blue Earth County. Details regarding the quantity and eligibility status of these sites has not been provided to date. No archaeological sites with NRHP or CEF status were identified within Martin County.

A total of 982 standing structure inventory resources are located within the Project Study Area. Of these, there are 65 NRHP-listed structures, properties, or districts in Blue Earth County, there are five NRHP-listed structures or properties in Faribault County, and there are two NRHP listed structures or properties in Nicollet County. Additionally, 251 sites (two in Faribault County, two in Nicollet, and 247 in Blue Earth County) have received a CEF by the SHPO for listing on the NRHP. There were no inventoried standing structures identified within the Martin County portion of the Project Study Area.

Historic properties are designated as "location restricted" by SHPO for reasons of preservation, protection, or privacy and Minnesota laws protect resources in conjunction with federal laws. The Minnesota Field Archaeology Act (Minn. Stat. §§ 138.31-138.42) requires State agencies to submit development plans to the State Archaeologist, the Minnesota Historical Society, and the Minnesota Indian Affairs Council for review when there are known or suspected archaeological sites in the area. The Minnesota Historic Sites Act (Minn. Stat. §§ 138.661-138.669) established the State Historic Sites Network and the State Register of Historic Places. As necessary, the Applicants will contact the Historical Society before undertaking activities that may affect properties on the network or in the State or NRHP.

The Minnesota Historic District Act (Minn. Stat. §§ 138.71-138.75) designates certain historic districts and enables local governing bodies to create commissions to provide architectural controls in these areas. The City of Mankato is the only city within the Project Study Area that has achieved the status of Certified Local Government.

8.1.6 Hydrologic Features

The Project Study Area is within the Minnesota River Watershed. Furthermore, the Project Study Area lies within the Minnesota River - Mankato, Le Sueur, Blue Earth, and Watonwan major watersheds. Major rivers include the Minnesota, Blue Earth, Watonwan, Le Sueur, Maple, Cobb, and Little Cobb rivers (see **Figure 33**).

The Project Study Area contains several sizable lakes, many being greater than 160 acres. However, many of these are shallow perched lakes. Some of the named lakes within the Project Study Area include Rice Lake, Lake Crystal, Loon Lake, Mills Lake, Lily Lake, Lura Lake, and Minnesota Lake. Wetlands were very common before settlement; however, many have been drained for cropland.

8.1.6.1 Groundwater

The Project Study Area is within the South-Central Ground Water Province which consists of thick clay glacial drift with a limited extent of sand aquifers overlying Paleozoic sandstone, limestone, and dolostone aquifers. These sedimentary bedrock aquifers are the dominant source of water supply in the Project Study Area.

8.1.6.2 Surface water

The USFWS National Wetlands Inventory (NWI), as updated by the MnDNR, was reviewed to assess the presence of wetlands within the Project Study Area. Wetland complexes and small isolated wetlands are scattered throughout the Project Study Area. Many of these wetlands are riverine and floodplain forest wetlands associated with the Minnesota, Blue Earth, Watonwan, and Le Sueur rivers and their tributaries. Several glacial ice block lake depressions are present in the area and are characterized as lacustrine unconsolidated bottom wetlands. Wetlands are present in depressions on moraines, till plains, lake plains, flood plains, and seeps in the Project Study Area and include emergent, forested, unconsolidated bottom, and scrub-shrub wetlands.

The MnDNR Public Waters Inventory (PWI) was also reviewed to identify public wetlands, waters, and watercourses. Notable public waters in the Project Study Area include the Minnesota, Blue Earth, Watonwan, Le Sueur, Maple, Cobb, and Little Cobb rivers and Rice Lake, Lake Crystal, Loon Lake, Mills Lake, Lily Lake, Lura Lake, and Minnesota Lake.

8.1.6.3 Floodplains

Approximately 22,645 acres (3.5 percent) of the land in the Project Study Area is within FEMA designated 100-year floodplain area and are associated with the major rivers within the Project Study Area such as Minnesota, Blue Earth, Watonwan, and Le Sueur rivers.

8.1.6.4 Karst

Karst terrain and physiography result from the dissolution of soluble bedrock, such as limestone, dolomite, marble, or gypsum through the circulation of groundwater that has become slightly acidic as a result of atmospheric carbon dioxide being dissolved in the water. Karst terrain is characterized or designated by the presence of sinkholes, caverns, an irregular "pinnacled" bedrock surface, and springs. A landscape that is underlain by soluble bedrock has the potential to develop karst physiography and landforms. The main issues associated with construction and operation of transmission line facilities in karst terrain are potential impacts to cave systems, springs, and wells; construction methods triggering sinkhole development; and operational safety in karst areas.

The United States Geological Survey (USGS) has developed GIS coverage and maps that delineate areas of the U.S. that have karst or the potential to develop karst conditions[91]. The coverage is based on areas underlain by soluble bedrock such as limestone or dolomite that have potential for karst development. Except for portions of the east bank of the Minnesota River in Blue Earth County, at least 50 to 100 feet of glacial drift overlies karst formations in most of the Project Study Area. Therefore, surface expression of karst features is expected to be rare and would be significantly subdued, if present at all.

8.1.7 Vegetation and Wildlife

The pre-settlement vegetation was primarily tallgrass prairie with floodplain forest consisting of silver maple, elm, cottonwood, and willow along the Minnesota River and other streams. Oak woodland and maple-basswood forest were the most common vegetation types near Mankato. The Project Study Area is now, primarily, agricultural land with few remnants of pre-settlement vegetation remaining. Currently, most of the Project Study Area (75 percent) is cropland, with an additional

[91] *See* David J. Weary & Daniel H. Doctor, *Karst in the United States: A Digital Map Compilation and Database* (2014), *available at* https://dx.doi.org/10.3133/ofr20141156.

5 to 10 percent in pasture. Common crops in the Project Study Area include corn and soybean. The remaining 10 to 15 percent of the Project Study Area remains as either upland forest or wetland.

No National Park Service Wilderness Areas, National Wild and Scenic Rivers, or National Forests are within the Project Study Area. Federal wildlife refuge lands exist in the Project Study Area as WPAs. The Applicants initiated consultation with the USFWS regarding USFWS lands during the route identification process and continued this consultation as routes were compared and refined. There are two areas, one on the Purple Route and one on the Red Route, where proposed routes follow existing transmission lines through federally-owned WPAs. In both of these cases, no new land rights would be required on federal land and USFWS staff suggested that adjusting routes to avoid WPAs may have greater impact than following the existing lines through the Federal land. Applicants also met with the MnDNR and discussed potential impacts to rare features. The MnDNR reviewed the proposed routes and provided input on route modifications to reduce impacts to natural resources.

The MnDNR ranks Sites of Biodiversity Significance based on the relative significance of biodiversity of the site at a statewide level. This system ranks the quality of identified sites at four levels; outstanding, high, moderate, or below. Several such sites are located within the Project Study Area and are primarily associated with major drainageways such as the Minnesota, Blue Earth, Watonwan, and Le Sueur rivers. The MnDNR also maintains records of locations of plant communities that are important areas of native vegetation or habitat. Several such communities are present within the Project Study Area and primarily consist of sugar-maple basswood forest, silver maple floodplain forest, and several types of southern prairie.

8.1.8 Rare and Unique Natural Resources

8.1.8.1 Bald Eagle

Bald eagles (*Haliaeetus leucocephalus*) breed throughout Minnesota and commonly nest in trees near large bodies of water, but may also nest in other tall structures, such as rocky outcrops, cliffs, utility poles, and communication towers.[92] In Minnesota, they are primarily found along the St. Croix and Mississippi Rivers and in more heavily forested northern portions of the state, although they are becoming more frequent in the southern half of the state again as well. Primary prey for bald eagles is fish, but the species will opportunistically feed on carrion, the decaying flesh of dead animals. The species typically migrates south in the winter, but will remain in northern climates if prey is available in areas with open water year-round.[93]

In Minnesota, bald eagles begin nesting in late winter; egg-laying occurs in early February. Eggs hatch after 35 days, and eaglets leave the nest after 8-14 weeks. Young birds who have fledged will not leave the nest permanently for several more weeks, and may not disperse until July or August.

Suitable habitat for bald eagles is present within the Project Study Area along the Minnesota, Blue Earth, and Watonwan rivers, and near large lakes and wetlands. Project-specific consultations were initiated with the USFWS Twin Cities Ecological Services Field Office on August 15, 2017. As part of this consultation, Applicants described the Project and Applicants' approach to avoiding impacts on the bald eagle and other raptors. Applicants will work to avoid disturbance to nesting eagles by avoiding work near active eagle nests. Applicants will employ avian impact minimization measures such as the use of bird diverter markers in high bird use areas and will continue to work with the USFWS and MnDNR to minimize impacts to bald eagles.

8.1.8.2 Federal and State-Listed Threatened and Endangered Species

Applicants reviewed the USFWS Information for Planning and Conservation (IPaC) website for a list of federally-listed threatened and endangered species, candidate species, and designated critical habitat that may be present within the Project Study Area on September 22, 2017. Applicants also reviewed the MnDNR Minnesota

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92 U.S. FISH & WILDLIFE SERV., *National Bald Eagle Management Guidelines* (May 2007), *available at* https://www.fws.gov/southdakotafieldoffice/NationalBaldEagleManagementGuidelines.pdf.

93 MINN. DEP'T OF NAT. RES., *Rare Species Guide: Bald Eagle* (Haliaeetus leucocephalus) (last visited Dec. 15, 2017), *available at* http://www.dnr.state.mn.us/rsg/profile.html?action=elementDetail&selectedElement=ABNKC10010.

Natural Heritage Information System (NHIS) for known occurrences of federally- and state-listed species that may be present within one mile of the Project Study Area on September 13, 2017. These reviews are not intended as a comprehensive survey, but serve to identify the potential for the presence of listed or candidate species or designated critical habitat within the Project Study Area (see **Table 33**).

Table 33
Federal and State-Listed Species Within the Study Area

Common Name	Scientific Name	Status[a]	
		State	Federal
Mammals			
Eastern spotted skunk	*Spilogale putorius*	THR	-
Northern long-eared bat	*Myotis septentrionalis*	SC	THR
Mollusks			
Elktoe	*Alasmidonta marginata*	THR	-
Fluted-shell	*Lasmigona costata*	THR	-
Monkeyface	*Quadrula metanevra*	THR	-
Mucket	*Actinonaias ligamentina*	THR	-
Pistolgrip	*Tritogonia verrucosa*	END	
Rock pocketbook	*Arcidens confragosus*	END	-
Salamander mussel	*Simpsonaias ambigua*	END	-
Spike	*Elliptio dilatata*	THR	-
Wartyback	*Quadrula nodulata*	THR	-
Yellow sandshell	*Lampsilis teres*	END	-
Invertebrates			
A caddisfly	*Oecetis ditissa*	THR	-
Fish			
Paddlefish	*Polyodon spathula*	THR	-
Reptiles and Amphibians			
Blanding's turtle	*Emydoidea blandingii*	THR	-
Plants			
Hair-like beak rush	*Rhynchospora capillacea*	THR	-
Prairie bush-clover	*Lespedeza leptostachya*	THR	THR
Rock fir moss	*Huperzia porophila*	THR	-
Stream parsnip	*Berula erecta*	THR	-
Sullivant's milkweed	*Asclepias sullivantii*	THR	-
Three-leaved coneflower	*Rudbeckia triloba var. triloba*	THR	
Tuberous Indian-plantain	*Arnoglossum plantagineum*	THR	-

[a] END – Endangered, THR – Threatened, SC – Special Concern

Source: USFWS. 2017. Environmental Conservation Online System: IPaC.
MnDNR. 2017. NHIS

8.1.8.3 Northern Long-eared Bat

The northern long-eared bat (*Myotis septentrionalis*) is a federally threatened medium-sized bat found across much of the eastern and midwestern United States. In summer, the species roosts in both live trees and snags, and can be found roosting alone or in colonies under loose bark or in crevices and hollows. A habitat generalist, roost tree selection appears to be opportunistic; the species uses a variety of tree sizes and species, typically greater or equal to three inches in diameter at breast height.[94] The species is generally associated with forested habitats, including mesic hardwood, floodplain, and fire-dependent forests, particularly those near water sources.[95] However, males and non-reproductive females may also roost in cooler places such as caves and mines. The species overwinters in small crevices or cracks in hibernacula (e.g., caves and mines with constant temperatures, high humidity, and no air currents). Migration to summer habitat occurs between mid-March and mid-May.

The primary threat to the northern long-eared bat is white-nose syndrome (WNS). Other sources of mortality such as collisions with wind turbines, loss of summer habitat, and changes which alter the microhabitat of hibernacula have not been observed to produce significant population declines; however, as WNS impacts more populations, impacts from these activities may become more pronounced.[96]

Impacts on individual northern long-eared bats may occur if clearing or construction takes place when the species is breeding, foraging, or raising pups in its summer habitat. Bats may be injured or killed if occupied trees are cleared during this active window (i.e., April 1 - October 31), and the species may be disturbed during clearing or construction activities due to noise or human presence.

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[94] U.S. FISH AND WILDLIFE SERV., *Programmatic Biological Opinion on Final 4(d) Rule for the Northern Long-eared Bat and Activities Excepted from Take Prohibitions* (Jan. 5, 2016), *available at* https://www.fws.gov/midwest/endangered/mammals/nleb/pdf/BOnlebFinal4d.pdf.

[95] MINN. DEP'T OF NAT. RES., *Rare Species Guide: Northern long-Eared Bat (*Myotis septentrionalis*)* (last visited Dec. 15, 2017), *available at* http://www.dnr.state.mn.us/rsg/profile.html?action=elementDetail&selectedElement=AMACC01150.

[96] U.S. FISH AND WILDLIFE SERV., *Programmatic Biological Opinion on Final 4(d) Rule for the Northern Long-eared Bat and Activities Excepted from Take Prohibitions* (Jan. 5, 2016), *available at* https://www.fws.gov/midwest/endangered/mammals/nleb/pdf/BOnlebFinal4d.pdf.

On January 14, 2016, the USFWS published the final 4(d) rule identifying prohibitions that focus on protecting the bat's sensitive life stages (i.e., hibernation and raising young) in areas affected by WNS.[97] The Project Study Area falls wholly within the USFWS-designated WNS Zone.[98] Per USFWS guidance, incidental take from tree removal activities is not prohibited provided:

- it is not conducted within 0.25 mile of a known northern long-eared bat hibernacula; and
- it does not entail removing a known maternity roost tree (or trees within 150 feet of a known maternity roost tree) June 1-July 31.

In Minnesota, the MnDNR maintains records of known hibernacula and roost tree locations in the NHIS. Applicants reviewed the most recent NHIS to identify the presence of maternity roost trees or hibernacula in the Project Study Area. The NHIS review confirmed the absence of known hibernacula within 0.25 miles and the absence of known roost trees within 150 feet from the Project Study Area. Because of the absence of these identifying features, the lead federal agency issuing a permit for the Project (i.e., the United States Army Corps of Engineers (USACE)) may choose to rely upon the finding of the programmatic biological opinion developed by USFWS on January 5, 2016 to fulfill its Section 7 consultation obligations for this species. This reliance process requires submission of the Northern Long-Eared Bat 4(d) Rule Streamlined Consultation Form. If, after 30 days, there has been no response from the USFWS, the USACE may presume the determination of "may affect, but incidental take is not prohibited" from the biological opinion and consider its permitting responsibilities under section 7(a)(2) with respect to the northern long-eared bat fulfilled.

To reduce impacts to individual bats, the USFWS recommends that all tree clearing activities are conducted when the species is in hibernation and not present on the

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[97] U.S. FISH AND WILDLIFE SERV., *Programmatic Biological Opinion on Final 4(d) Rule for the Northern Long-eared Bat and Activities Excepted from Take Prohibitions* (Jan. 5, 2016), *available at* https://www.fws.gov/midwest/endangered/mammals/nleb/pdf/BOnlebFinal4d.pdf.

[98] U.S. FISH AND WILDLIFE SERV., *Northern Long-Eared Bat Final 4(d) Rule: Map of White-Nose Syndrome Zone Around WNS/Pd Positive Counties/Districts* (Oct. 31, 2017), *available at* https://www.fws.gov/midwest/endangered/mammals/nleb/pdf/WNSZone.pdf.

landscape (i.e., November 1 through March 31). However, it is understood that tree clearing activities cannot begin until all consultations for the species are complete.

Project-specific consultations were initiated with the USFWS Twin Cities Ecological Services Field Office on August 15, 2017. Based on a review of the proposed Project routes, USFWS staff noted that there are no known roost trees or hibernacula in the area associated with the northern long-eared bat, and as such, the Project would likely be covered under the 4(d) rule. Staff recommended conducting all tree-clearing activities between October 1 and March 31 to prevent adverse impacts to protected bat species.

8.1.8.4 Prairie Bush-clover

Prairie bush-clover (*Lespedeza leptostachya*) is a federally threatened prairie plant known to occur in Martin County. The prairie bush clover is a member of the Fabaceae (Pea) family and native to the midwest – known only to be found in the tallgrass prairie region of the upper Mississippi River Valley. Specifically, it is currently only found in small regions of Minnesota, Iowa, Illinois, and Wisconsin, and is thought to occur at fewer than 100 sites.[99] Also known as slender-leaved bush-clover, the plant grows on one or more stems and are generally between 9 to 18 inches tall, although plants can grow up to 39 inches in height.[100] The leaf is clover-like and comprised of three small leaflets; the plant often has a grayish or silver luster. Pale pink or cream-colored flowers bloom from mid-July to early September, and flowers are loosely arranged on an open spike.[101]

In southwestern Minnesota, prairie bush clover can be found on dry-mesic prairies on north or northwest-facing slopes with well-drained soils. Populations are primarily restricted to remnant prairies that have persisted despite widespread conversion to cropland; the majority of populations in the state are found on prairies that were

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[99] MINN. DEP'T OF NAT. RES., *Prairie Bush Clover: A Threatened Midwestern Prairie Plant* (2007), *available at* http://files.dnr.state.mn.us/natural_resources/ets/prairie_bush_clover.pdf.

[100] U.S. FISH AND WILDLIFE SERV., *Prairie Bush Clover Recovery Plan* (Sept. 1988), *available at* https://ecos.fws.gov/docs/recovery_plan/881006.pdf.

[101] MINN. DEP'T OF NAT. RES., *Prairie Bush Clover: A Threatened Midwestern Prairie Plant* (2007), *available at* http://files.dnr.state.mn.us/natural_resources/ets/prairie_bush_clover.pdf; U.S. FISH AND WILDLIFE SERV., *Prairie Bush Clover* (Lespedeza Leptostachya) *Fact Sheet* (last updated Oct. 15, 2015), *available at* https://www.fws.gov/midwest/endangered/plants/prairieb.html.

historically or are presently used for pasture. Threats to the species and remaining habitat include agricultural expansion, herbicides, residential development, and the lack of natural disturbances, especially fire.[102]

Project-specific consultations were initiated with the USFWS Twin Cities Ecological Services Field Office on August 15, 2017. Based on a review of the routes initially developed for the Project and discussed in this application, USFWS staff noted that prairie bush clover typically only occurs in areas of high-quality prairie; most of the Project Study Area in Martin County is associated with agricultural land cover, and suitable habitat for the species is likely not present.

8.1.9 Mitigation Measures

The Applicants reviewed USGS topographic maps, aerial photographs, agency databases, and the internet (i.e., Google Earth, Google Maps) for public lands, recreational sites, and other special use areas in the Project Study Area. The Applicants also consulted with the USFWS and MnDNR for natural resource areas, such as USFWS wetland easements and state lands, and contacted the planning department staff and reviewed the website of each county crossed by the Project for any special areas. The Applicants will avoid areas identified by this review where practicable.

The Applicants have proposed routes that allow for designing the Project to minimize or avoid impacts to surface water resources to the extent practicable. The Project will be designed to span surface water resources and floodplains where practicable and to minimize the number of structures in surface water resources where these resources cannot be spanned. The Project will have minor, mostly short-term effects on surface water resources. Waters and wetlands permits and licenses, letters of no jurisdiction, or exemptions may be required from the USACE, MnDNR, and local units of government that administer the Wetland Conservation Act. No alteration in the course, current, or cross-section below the ordinary high-water level of a public water or watercourse, which would require a Public Waters Work Permit from the MnDNR

[102] MINN. DEP'T OF NAT. RES., *Prairie Bush Clover: A Threatened Midwestern Prairie Plant* (2007), *available at* http://files.dnr.state.mn.us/natural_resources/ets/prairie_bush_clover.pdf; U.S. FISH AND WILDLIFE SERV., *Prairie Bush Clover* (Lespedeza Leptostachya) *Fact Sheet* (last updated Oct. 15, 2015), *available at* https://www.fws.gov/midwest/endangered/plants/prairieb.html.

Division of Waters is anticipated. The Applicants will apply for a License to Cross Public Lands or Waters from the MnDNR, Division of Lands and Minerals where applicable.

The MPCA, through the NPDES under the Clean Water Act, regulates construction activities that may impact stormwater runoff. An NPDES permit is required for construction activity disturbing: (1) one acre or more of soil; (2) less than one acre of soil, but part of a "larger common plan of development or sale" that is greater than one acre; or (3) less than one acre of soil, but that the MPCA determines poses a risk to water resources. As part of the NPDES requirements, a Storm Water Pollution Prevention Plan must be prepared to identify BMPs (which may include biodegradable erosion matting), inspection protocol in compliance with MPCA requirements, and stabilization measures to minimize impacts of stormwater runoff.

The Applicants do not anticipate any impacts to any archaeological or historic resources as part of the Project. If high potential areas are identified along a selected route, the Applicants will work with the State Archaeologist to develop a survey protocol to ensure no impacts result from construction of the Project. If, during construction, crews discover cultural resources, further survey work will be completed in cooperation with the SHPO. Additionally, if any unmarked burials, human remains, or grave goods are discovered during construction, they will be reported to the State Archaeologist per Minnesota Statutes § 307.08 and construction will be suspended in that area until adequate mitigation measures have been developed between the Applicants and the SHPO State Archaeologist.

Potential impacts on special status plant species, such as loss of individuals because of crushing from construction vehicles and equipment, will be avoided. Work space and Project facilities will not be located within known populations of special status plant species.

Erosion control measures will be used to prevent sediment from being transported outside of designated construction areas. Erosion and sediment control devices will be installed in accordance with the individual SWPPP developed for the Project.

Direct impacts on special status birds, mammals, fish, and reptiles from construction and operation of the Project may include limited mortality of eggs, nests, young, and less mobile species. Applicants will provide environmental training to its contractors to monitor for special status species within the construction area and to avoid mortality from construction vehicles.

Indirect impacts on special status species may include the incremental reduction of forest cover, habitat fragmentation, temporarily increased noise levels, and dust effects from construction access. However, mobile species will most likely return following construction and restoration. Indirect impacts to special status species will be avoided, minimized, and mitigated. The Applicants will design the Project to avoid and minimize habitat loss, alteration, or fragmentation due to vegetation removal, hydrologic changes, and soil compaction. The Applicants will conduct surveys immediately prior to construction as part of raptor, bald and golden eagle, and migratory bird nest inspections and will suspend ground-disturbing activities as described above and contact the agencies for further input if any occupied nests are identified.

The Applicants will maintain landowner access to agricultural fields, storage areas, structures, and other agricultural facilities during construction to the extent practicable. If irrigation systems or drain tile are present, the Applicants will work with landowners to avoid these systems. Crop production on some agricultural lands may be temporarily interrupted for one growing season while transmission line facilities are constructed. In cultivated cropland areas, the Applicants will attempt to conduct construction before crops are planted or following harvest, if possible. The Applicants will compensate landowners for impacts to crops resulting from the construction, operation, and maintenance of the Project including compaction that might result from these activities.

Lands within the Project Study Area are relatively flat areas with rural development and numerous roadways, and predominantly used for agricultural activities, with some forested and open areas. No special or unique features, designated scenic areas, or viewsheds are in or near the Project Study Area.

8.1.10 Other Permits and Approvals

The Project will require a number of regulatory reviews and approvals. **Table 34** provides a summary of the major permits, approvals, or consultations that may be required for the Project. Key agency consultations were initiated in May 2017 to introduce the Project, inform the agencies about the Certificate of Need and Route Permit process, and to request their participation. All required permits necessary for constructing in any specific area will be obtained prior to construction in that area.

Table 34
List of Other Permits, Approvals, or Consultations that May be Required

Administering Agency	Permit, Approval, or Consultation
Federal	
U.S. Army Corps of Engineers (USACE), St. Paul District	Section 404, Clean Water Act (CWA) – Dredge and Fill
USACE, St. Paul District	Section 10 Rivers and Harbors Act
U.S. Fish and Wildlife Service (USFWS),	Special Use Permit for work in waterfowl production areas
Federal Aviation Administration (FAA)	Part 7460 review
Native American Tribes	National Historic Preservation Act (NHPA), coordination upon request in support of USACE Section 106 consultation to determine impacts on Traditional Cultural Properties[103]
State	
Minnesota Pollution Control Agency (MPCA)	National Pollutant Discharge Elimination System (NPDES) Stormwater Permit
MPCA	Section 401 CWA Water Quality Certification
Minnesota Department of Natural Resources (MnDNR)	License to Cross Public Waters or State Lands Public Water Works Permit
Board of Water and Soil Resources	Conservation easements, Wetland Conservation Act
MnDNR	State Protected Species Consultations
Minnesota State Historic Preservation Office (SHPO)	Section 106 Consultation, NHPA
Minnesota Department of Transportation (MnDOT)	Utility Permit on Trunk Highway Right-of-Way (Long Form No. 2525)
MnDOT	Driveway Access
MnDOT	Oversize/overweight permits
Minnesota Department of Agriculture (MDA)	Agriculture Mitigation Plan

[103] Consultation is performed by the USACE.

Administering Agency	Permit, Approval, or Consultation
Local	
County, Township, City, BWSR	Minnesota Wetland Conservation Act (WCA) approvals
Soil and Water Conversation Districts	Coordination meetings
County, Township, City	Lands Permits
County, Township, City	Overwidth/Overweight Loads Permits
County, Township, City	Road Crossing Permits
County, Township, City	Driveway/Access Permits