

**APPLICATION TO THE  
MINNESOTA PUBLIC UTILITIES COMMISSION  
FOR A CERTIFICATE OF NEED  
FOR THE MINNESOTA ENERGY CONNECTION  
PROJECT**

**MPUC Docket No. E002/CN-22-131**

**March 2023**

**Submitted by**

**Northern States Power Company**



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**DEFINED TERMS**

AC	Alternating Current
ACSR	Aluminum Conductor Steel Reinforced
AFUDC	Allowance of Funds Used During Construction
Alternate Plan	Xcel Energy's proposed Integrated Resource Plan
AMA	Aquatic Management Area
Amps	Amperes
Applicant or the Company	Xcel Energy
Application	Xcel Energy's Certificate of Need Application
BESS	Battery energy storage systems
BGEPA	Bald and Golden Eagle Protection Act
BMPs	best management practices
BPM	MISO Business Practice Manual
BWSR	Board of Water and Soil Resources
CFR	Code of Federal Regulations
CN	Certificate of Need
Commission or MPUC	Minnesota Public Utilities Commission
CREP	Conservation Reserve Enhancement Program
CT	Combustion turbine
DC	Direct Current
DER	Distributed Energy Resources
DOC-DER	The Department of Commerce, Division of Energy Resource
DOC-EERA	Minnesota Department of Commerce Energy Environmental Review and Analysis
DOE	Department of Energy
DSM	Demand Side Management
ECS	Ecological Classification System
EE	Energy Efficiency
EIA	U.S. Energy Information Administration

ELCC	Effective Load Carrying Capacity
ELF	extremely-low-frequency
EMF	Electric and Magnetic Field
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
EV	Electric Vehicle
Exemption Order	June 28, 2022 Order Approving Exemption from Certain Certificate of Need Application Content Requirements (Appendix D)
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
FSA	Farm Service Agency
GAP	Gap Analysis Project
GNTL Order	June 30, 2015 Order Granting Certificate of Need with Conditions, <i>In the Matter of the Request of Minnesota Power for a Certificate of Need for the Great Northern Transmission Line</i> , Docket No. E-015/CN-12-1163
Guidehouse Report	December 29, 2022 Final Report prepared by Guidehouse Inc. (Appendix C).
HUC	Hydrologic Unit Code
HVDC	Direct Current High Voltage
ICAP	Installed Capacity
Intermediate Substation	A new substation located in or near Lyon County, Minnesota, approximately 140-160 miles from the Sherco Substation.
IPaC	Information for Planning and Conservation
IRP	Integrated Resource Plan
IRP Order	April 15, 2022 Order Approving Plan with Modifications and Establishing Requirements for Future Filings, <i>In the matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy</i> , Docket No. E-002/RP-19-368 (Appendix B)

ITC	Investment tax credit
kV	Kilovolt
LCC	Line Commutated Converter
LOLE Study	MISO’s 2020-2021 Loss of Load Expectation Study
LRTP	Long Range Transmission Planning
LSEs	Load Serving Entities
MDNR	Minnesota Department of Natural Resources
mG	milliGauss
MISO	Midcontinent Independent System Operator, Inc.
MMUA	Minnesota Municipal Utilities Association
MnDOT	Minnesota Department of Transportation
Monticello	Xcel Energy’s Monticello Nuclear Generating Plant
MPCA	Minnesota Pollution Control Agency
MVAR	Megavolt Ampere Reactive Power
MW	Megawatts
MWFRA	Migratory Waterfowl Feeding and Resting Areas
NAC	Noise Area Classifications
NESC	National Electric Safety Code
NLCD	National Land Cover Database
NLEB	northern long-eared bat
NO <sub>2</sub>	Nitrogen Dioxide
NO <sub>x</sub>	Nitrogen Oxides
NPC	Native plant community(ies)
NPDES	National Pollution Discharge Elimination System
NPV	Net present value
NRCS	Natural Resources Conservation Service
NREL	U.S. Department of Energy’s National Renewable Energy Laboratory
NRHP	National Register of Historic Places
NSP	Northern States Power Company, a Minnesota corporation,

	doing business as Xcel Energy
NSP Companies	Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy, together with its sister company, Northern States Power Company, a Wisconsin corporation
NWR	National Wildlife Refuge
OSHA	Occupational Safety and Health Administration
PCE	primary constituent elements
PEM	palustrine emergent
PFO	palustrine forested
PHMSA	Pipeline and Hazardous Materials Safety Administration
POI	Point of Interconnection
PPB	Parts Per Billion
PPM	Parts Per Million
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirements
Project	Minnesota Energy Connection Project
Project Study Area	Includes all or portions of Sherburne, Stearns, Wright, Swift, Kandiyohi, Meeker, McLeod, Carver, Lac qui Parle, Chippewa, Renville, Sibley, Yellow Medicine, Redwood, Brown, Nicollet, Lincoln, Lyon, Murray, and Cottonwood counties as shown on Image 1.2.
PSS	palustrine scrub shrub
PTC	Production Tax Credit
PWI	Public Waters Inventory
RA	Resource adequacy
RFI	Request for Information
RFP	Request for Proposals
RIM	Reinvest in Minnesota
SF6	Sulfur hexafluoride
Sherco	Sherburne County Generation Station
Sherco Substation	Sherburne County Generation Station Substation

SNA	Scientific and Natural Area
SOBS	Sites of Biodiversity Significance
SSCI	Sub-Synchronous Controller Interaction
SSR	Sub-Synchronous Resonance
STATCOM	Static Synchronous Compensator
SWPPP	Stormwater Pollution Prevention Plan
TCB	Tricolored bat
Terminal Substation	The new substation in Lyon County, Minnesota
UCAP	Unforced Capacity
USACE	U.S. Army Corps of Engineers
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
V	Volts
Voltage Support Substation	A new substation located halfway along the transmission line out of the Sherco Substation.
VSC	Voltage Source Converter
WHO	World Health Organization
WMA	Wildlife Management Area
WNS	white-nose syndrome
Working Group	Interagency Working Group
WPA	Waterfowl Production Area
WRP	Wetland Reserve Program



## I. EXECUTIVE SUMMARY

### A. Introduction

Northern States Power Company (NSP), a Minnesota corporation, doing business as Xcel Energy (Xcel Energy, the Company, or the Applicant), requests a Certificate of Need (CN) from the Minnesota Public Utilities Commission (Commission) to construct the Minnesota Energy Connection project. The project is proposed as an approximately 160- to 180-mile double circuit 345 kilovolt (kV) transmission line connecting the existing Sherburne County Generation Station Substation (Sherco Substation) in Becker, Minnesota, and a new substation in Lyon County, Minnesota, and other associated facilities, including intermediate and voltage support substations (Project).

The Project will support Xcel Energy's and the State's transition to clean energy by enabling the predictable and cost-effective interconnection and delivery of at least 1,996 megawatts (MW) of generation to the Sherco Substation point of interconnection (POI), providing necessary energy resources and optimizing the reuse of the Company's interconnection rights that will become available as the coal units at Sherco retire by the end of 2030. The Project will also enable the interconnection of more than 4,000 MW of generation overall that will support the recently enacted "100 percent by 2040" law that, generally, sets a standard for public utilities to generate or acquire 100% of the energy for retail sales from carbon-free resources. To minimize impacts to the human and natural environments, Xcel Energy proposes that both circuits be co-located on a double-circuited line.

Xcel Energy submits 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 identifies where in this Application information required by Minnesota statutes and rules can be found.

Xcel Energy will also apply for a Route Permit for the Project (Docket No. E002/TL-22-132), as required by Minn. Stat. § 216E.03. Xcel Energy anticipates submitting the Route Permit Application later in 2023. In the Route Permit proceeding, the Commission will evaluate the transmission line route and substation locations.

### B. Xcel Energy's 2020-2034 Upper Midwest Integrated Resource Plan (IRP)

Xcel Energy is committed to delivering clean, reliable, and safe electricity service to customers. The Project was first proposed as part of Xcel Energy's recently approved IRP.<sup>1</sup>

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<sup>1</sup> *In the matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, MPUC Docket No. E-002/RP-19-368, Order Approving Plan with Modifications and Establishing Requirements for Future Filings, at Ordering ¶ 2.A.6 (Apr. 15, 2022) (hereafter, the "IRP Order") (Appendix B).

In an IRP proceeding, the Commission evaluates a utility's need for resources to serve its customers. At the conclusion of an IRP proceeding, the Commission approves the size, type, and timing of needed resources on a generic basis.<sup>2</sup> A Certificate of Need proceeding “[s]tarts with a resource plan-determined size, type, and timing of a need, confirms a specific need exists, and evaluates the economic, environmental, and social consequences of the alternatives to fulfill the need.”<sup>3</sup>

In its most recently concluded IRP, Xcel Energy proposed a plan (Alternate Plan) to reduce carbon emissions more than 85% from 2005 levels by 2030 and help Xcel Energy's deliver 100% carbon-free electricity by 2050. After careful consideration of Xcel Energy's proposal along with comments and analysis from numerous stakeholders, the Commission's Order provided this summary:

In this Order, the Commission approves a modified version of Xcel's Alternate Plan that will guide investments through 2034. With the benefit of significant stakeholder engagement spanning more than two years, the Commission is able to approve a plan largely reflecting the positions taken jointly by Xcel, many environmental groups (the CEOs), and many labor groups (the Carpenters, IUOE, and LIUNA). The plan is designed to manage costs for households and businesses; reduce emissions that contribute to climate change; and ensure reliable electric service for Xcel customers. Most significantly, it provides for –

- retiring all of Xcel's coal-powered generators,
- adding substantial amounts of solar- and wind-powered generation,
- reinforcing system reliability,
- exploring options for adding new technology such as energy storage and hydrogen powered generation, and
- pursuing the process of extending the life of Xcel's Monticello Nuclear Generating Plant (Monticello) in Monticello, Minnesota.

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<sup>2</sup>In the Matter of the Application for a Certificate of Need for the Hollydale 115 kV Transmission Line Project in the Cities of Plymouth and Medina, MPUC Docket No. E002, ET2/CN-12-113, Attachment SSR 2 to the Direct Testimony of Dr. Steve Rakow.

<sup>3</sup> *Id.*

Under this plan, Xcel will reduce its greenhouse gas emissions by 86% relative to 2005 levels; by 2032, 81% of Xcel's electricity will be generated from carbon-free resources.<sup>4</sup>

Xcel Energy also proposed retirement dates for its remaining Sherburne County Generation Station (Sherco) coal units in the IRP proceeding. The Commission generally agreed, directing Xcel Energy to retire Sherco Unit 3 by 2030.<sup>5</sup> Previously, in connection with Xcel Energy's 2016-2030 IRP, the Commission approved Xcel Energy's plan to retire Sherco Units 1 and 2 in 2026 and 2023, respectively.<sup>6</sup>

The Commission also found that Xcel Energy proved it needs to procure 600 MW of solar and 2,150 MW of wind, or an equivalent amount of energy and capacity from a combination of wind, solar, and/or storage between 2027 and 2032 to meet energy and capacity needs.<sup>7</sup>

During the IRP proceeding, Xcel Energy proposed to construct two 345 kV gen-ties between Lyon County and the existing Sherco Substation to acquire the needed resources and also reuse Xcel Energy's existing and valuable interconnection rights at the Sherco Substation. Xcel Energy proposed two 345 kV gen-tie lines would deliver 1,996 MW to Sherco. As part of that proposal, Xcel Energy included combustion turbine (CT) capacity of approximately 400 MW with a clutch that can provide the same attributes as a synchronous condenser, slated to be installed at Lyon County. The proposed CT capacity would have provided required system support for the gen-ties, in addition to meeting customers' capacity needs. The Commission determined that it is more likely than not that 800 MW of firm capacity will be needed between 2027 and 2029, but deferred the selection of the resources to meet this firm capacity need to a separate resource acquisition docket.<sup>8</sup>

The Commission ordered Xcel Energy to begin proceedings to obtain a Certificate of Need and Route Permit for the gen-ties.<sup>9</sup> The Project is one part of an overall resource acquisition

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<sup>4</sup> IRP Order at 3.

<sup>5</sup> The Commission also directed Xcel Energy to retire the Allen S. King Generating Station (King) in 2028 and to begin permitting proceedings for a transmission line designed to permit new energy resources to connect to the grid at that location. *See* IRP Order at Ordering ¶¶ 2.A.4; 2.A.6. That transmission line will be the subject of separate permitting processes.

<sup>6</sup> *In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan*, MPUC Docket No. E-002/RP-15-21, Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings at Ordering ¶ 7 (Jan. 11, 2017).

<sup>7</sup> IRP Order at Ordering ¶ 2.A.8. Further, Xcel Energy will acquire, by 2026, of 720 MW of Xcel Energy-owned solar resources to reuse Sherco Unit 2's interconnection rights—which will not require the Project to be interconnected—and 600 MW of solar resources unconstrained by interconnection location or ownership. IRP Order at Ordering ¶ 2.A.5.

<sup>8</sup> IRP Order at Ordering ¶ 3.

<sup>9</sup> IRP Order at Ordering ¶ 2.A.6.

plan. The generators that will connect to the Project will be identified through a future request for proposals (RFP) process and will be subject to separate regulatory approvals. Connecting the new renewable energy Xcel Energy will pursue as a result of the IRP process to the Sherco Substation enables Xcel Energy to reuse its valuable and existing transmission interconnection rights (approximately 2,000 MW total). These rights will be retained pursuant to the Federal Energy Regulatory Commission (FERC) Electric Tariff, Midcontinent Independent System Operator, Inc. (MISO) Attachment X. The FERC has granted current generation owners the right to re-use the associated transmission interconnection for new generation at those sites as the old generation retires as part of the energy transition from carbon-based fuels to renewable energy.

With the Project, Xcel Energy will be able to interconnect new renewable energy generation without needing to go through the generation interconnection process at MISO, which currently typically takes years to complete and identifies substantial and costly needed upgrades for interconnections that often result in projects' withdrawal from the process. For Xcel Energy's modeling, the Company assumed interconnection costs in 2021 dollars on a Net Present Value (NPV) of \$500/kW for wind and \$200/kW for solar based on its understanding of the current MISO queue constraints and review of the latest Definitive Planning Phase process, where interconnection costs are assigned. These estimates remain appropriate for MISO interconnection costs.<sup>10</sup>

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<sup>10</sup> The equivalent NPV in 2023 dollars is \$564/kW for wind and \$225/kW for solar.

To meet FERC requirements, Xcel Energy must own the replacement generation and meet certain MISO-established milestones associated with the replacement of resources following the retirement of the Sherco units. Table 1.1 lists the capacity of each Sherco unit, its anticipated retirement date, and the date the replacement generation must be online.

**Table 1.1: Sherco Units—Retirements and Replacements**

	Unit 1	Unit 2	Unit 3
Capacity	720 MW	710 MW	566.4 MW <sup>11</sup>
Replacement Generation Request Submitted to MISO <sup>12</sup>	2025	2022 <sup>13</sup>	2029
Sherco Unit Retirement Date	2026	2023	2030
Last Possible Commercial Operation Date of Replacement Generation Facility <sup>14</sup>	2029	2026	2033

The Project proposed in this Application is needed to enable the full reutilization of Xcel Energy’s interconnection rights at the existing Sherco Substation and will make it possible to build thousands of megawatts of new renewable energy in southern and southwestern Minnesota and create new jobs in construction and operations in the communities in which the new renewable energy and the Project will be located. New wind and solar farms will also bring new property tax revenue to communities and lease payments to landowners.

Since the issuance of the IRP Order, a multi-disciplinary team at Xcel Energy has diligently worked to further refine the Project given MISO requirements, Xcel Energy capacity and energy needs, construction constraints, and route development. Xcel Energy has also conducted a request for information (RFI) process to identify potential renewable generators to interconnect via the Project.

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<sup>11</sup> This amount represents Xcel Energy’s 59 percent ownership of Sherco Unit 3 (876 MW). The remaining capacity is owned by Southern Minnesota Municipal Power Agency.

<sup>12</sup> The request for a replacement facility must be submitted to MISO at least one year prior to the date that the Existing Generating Facility will cease operation. MISO Tariff Attach. X § 3.7.1(ii).

<sup>13</sup> This request was submitted to MISO in December 2022.

<sup>14</sup> Note that the dates in this table reflect MISO requirements and not the timing of resource needs identified in the IRP, which is earlier in some instances.

Initially, Xcel Energy identified an area endpoint and broad notice area for the Project as part of its Notice Plan filing. After obtaining approval for and implementing the Notice Plan, Xcel Energy commenced a routing analysis and is in the process of identifying potential routing corridors, as discussed further in Section 1.3.2 herein. Xcel Energy also identified and refined the scope of the Project and its associated facilities, including a detailed consideration of potential alternative configurations to ensure reliable delivery of energy to the Sherco Substation given the specifications associated with solar and wind generators. *See* Sections 1.3, 1.7, and 5. Xcel Energy also analyzed options to minimize Project costs, including alternative pole designs that were ultimately rejected due to landowner impacts. Xcel Energy updated its cost estimates from the IRP, taking into account the need to replace the attributes of CTs at Lyon County (since those specific resources will be determined in a separate proceeding), and to account for current economic conditions and inflation rates as well as resource constraints lingering from COVID supply chain delays (see Sections 1.6 and 2.2). Likewise, the Project proposed in this Application reflects responses to the Company's RFI analysis which was completed in late 2022 and which indicates that there are thousands of MWs of renewable resources under development which could ultimately connect to this Project.<sup>15</sup> After vetting the Project through this additional analysis, Xcel Energy continues to conclude that the Project is the best option to meet the identified need.

This Application is an early step in implementing the IRP and Xcel Energy's clean energy goals, and additional regulatory and permitting proceedings will be necessary to further define this Project and related resources. For example, the Project's routing proceeding will inform the ultimate route for the Project, and there will be additional regulatory proceedings related to the wind and solar resources which will interconnect to the Project. There will also be Commission determinations regarding the 800 MW of firm dispatchable resources, some of which could offset the need for synchronous condensers at the substation at the west end of the line, named solely for the purposes of this Application as the "Terminal Substation".<sup>16</sup> Although it does not propose a specific route, this Application provides the appropriate level of detail to be considered in a Certificate of Need proceeding and also describes the more specific design details that are likely to be informed by further regulatory proceedings.

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<sup>15</sup> The 2022 RFI Independent Expert Report prepared by Guidehouse, Inc. is included as [Appendix C](#).

<sup>16</sup> The formal name of all substations, including the Terminal Substation, will be determined as part of the Route Permit proceeding.

## C. Project Description

### 1. Project Facilities

The proposed Project consists of a double circuit 345 kV transmission line and associated facilities connecting the Sherco Substation to a new endpoint substation in the Lyon County area at the end of the transmission line, the Terminal Substation. The Terminal Substation will require two synchronous condensers to provide system stability once the level of wind and/or solar energy interconnected reaches 1,000- 1,600 MW.<sup>17</sup> Needed system stability support could also be provided by a CT in the vicinity of the Terminal Substation. Because the Company has not yet specifically proposed, and the Commission has not yet determined whether a CT at that location may be constructed as part of Xcel Energy's overall 800 MW firm capacity need, the Project includes the synchronous condensers necessary to provide the required system support at the Terminal Substation. If a CT were ultimately proposed, selected as needed and placed into service before interconnected generation reaches 1,000 – 1,600 MW, the CT would provide the requisite system support and replace the synchronous condensers.

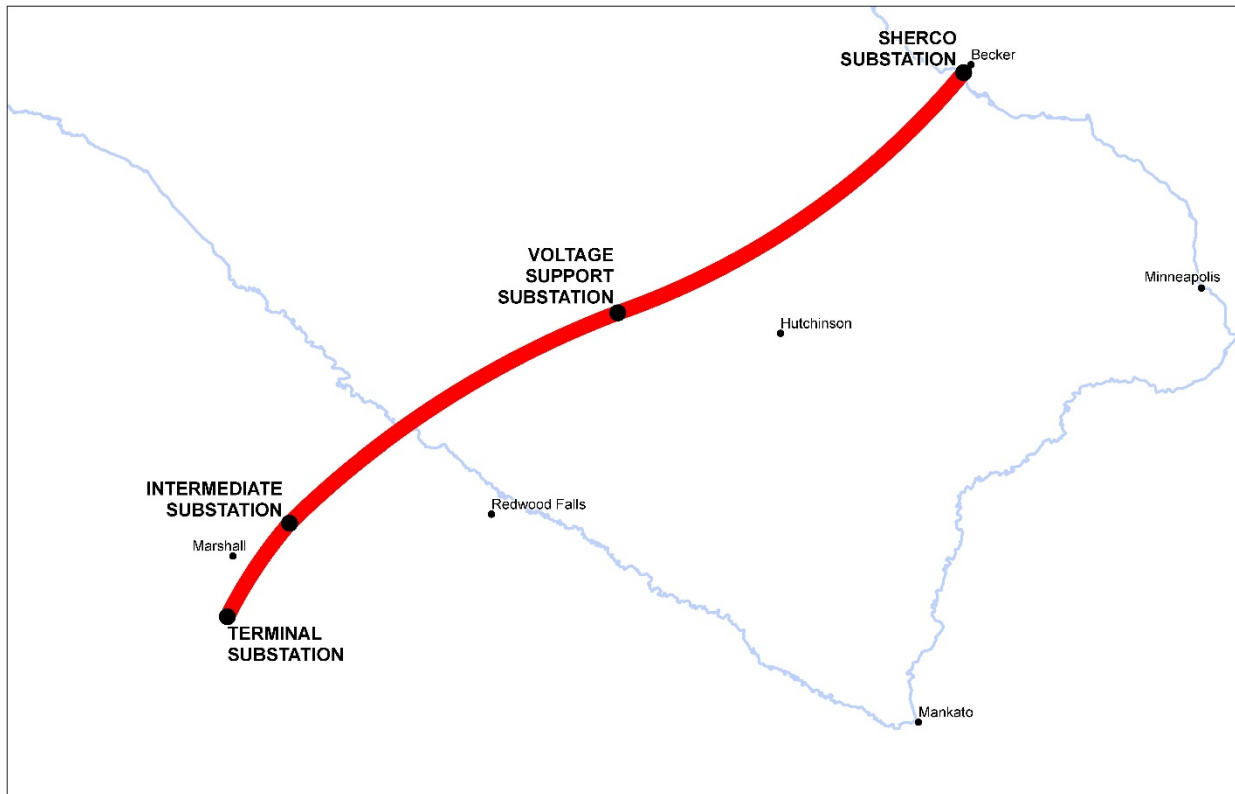
The Project will also include an intermediate substation (Intermediate Substation) and a substation to house voltage support equipment (Voltage Support Substation). The Voltage Support Substation is proposed based on today's technology and would include series capacitors (20%) and two 150 MW static synchronous compensators (STATCOMs). This is a conservative approach to ensure that the potential wind turbine resonant frequency interactions associated with long highly compensated radial lines are accounted for in Project components and costs. It is possible that these interactions will not occur and the costs associated with any support equipment will be reduced. The attributes of the STATCOMS also could potentially be provided by solar facilities located in the vicinity of the Voltage Support Substation. Every 250 MW of interconnected solar at that location would replace 150 MW of STATCOM. The need for voltage support equipment will also be impacted by the resources that interconnect to the Project and the technology available at that time. The final determinations regarding the need for and composition of voltage support equipment will be made after resource determinations. The Company will update the Commission on any proposed changes in a separate filing.

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<sup>17</sup> The higher level of 1,600 MW would trigger the need for synchronous condensers if additional voltage stability equipment is first added to the Voltage Support Substation.

Image 1.1 depicts the conceptual design of Project Facilities as currently proposed, presuming that the Project must provide the system support at Lyon County and all voltage support at the Voltage Support Substation.

**Image 1.1: Conceptual Design: Project Facilities**



Further detail regarding the Project description and associated facilities is provided in Section 2.1.

## 2. Notice Area and Routing Corridors

Depending on the final route selected by the Commission, the Project will be approximately 160 to 180 miles long. (The IRP assumed a route length of 140- to 175-miles long; those estimates were refined as more details of the Project were developed in connection with this Application.)<sup>18</sup> Xcel Energy plans to place the Project in-service by September 30, 2027.

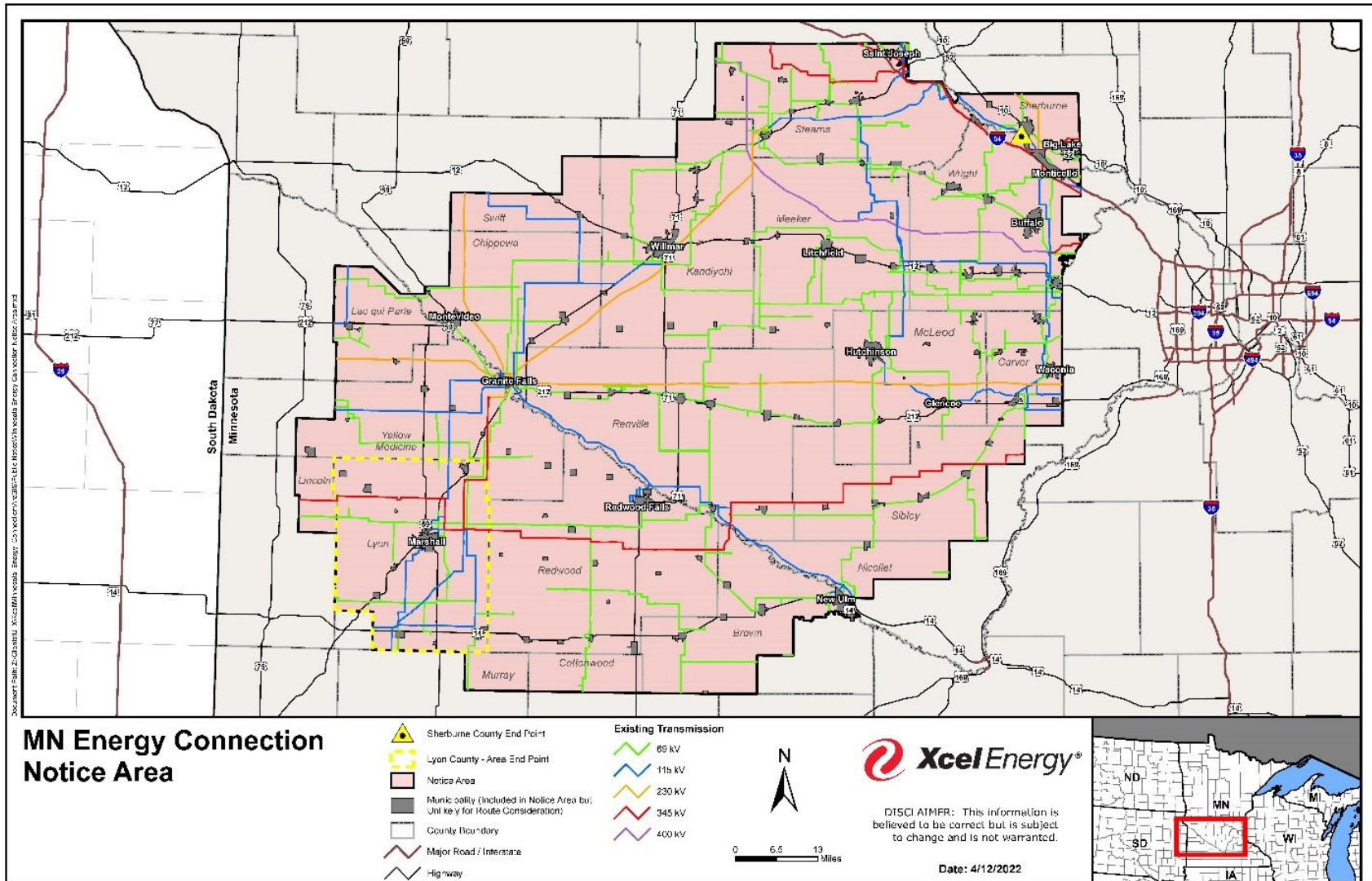
<sup>18</sup> *In the Matter of the 2020-2034 Upper Midwest Integrated Resource plan of Northern States Power Company d/b/a Xcel Energy*, Reply Comments at 151 (June 25, 2021).



Additional substation equipment may need to be added at the Terminal, Intermediate, and Voltage Support substations as additional renewable resources come online. All Project components are expected to be in service by September 30, 2031. The type and amount of additional substation equipment will be dependent on current technology when the renewable resource is selected. As noted above, the need for additional equipment could be reduced at the Terminal Substation if firm capacity were constructed near the Terminal Substation.

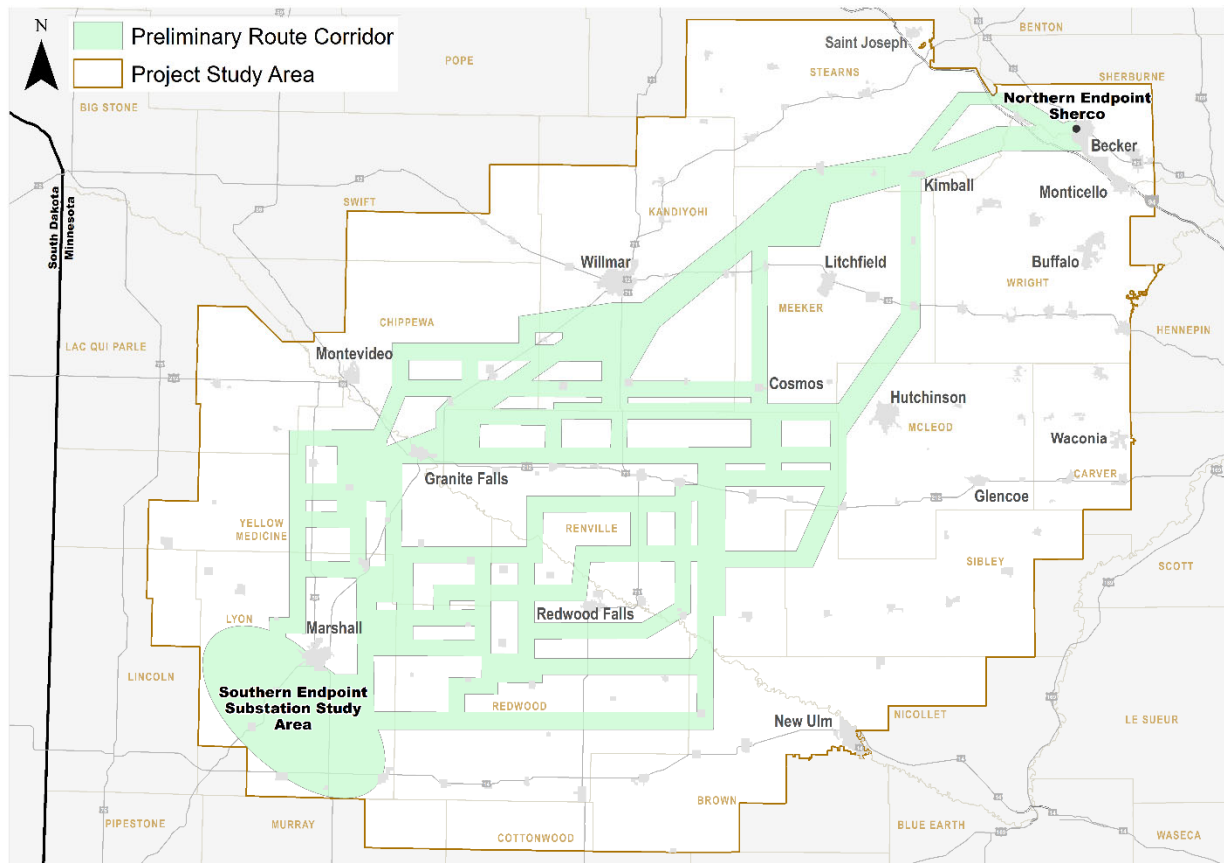
Image 1.2 is the map showing the Notice Area for the Project and which area was used to notify landowners and other stakeholders about the Project in the summer of 2022. This Notice Area also represents the Project study area (Project Study Area).

Image 1.2: Project Study Area



Since implementing the Notice Plan, Xcel Energy developed route corridors and alternatives for the Project. Although Xcel Energy has identified a Project Study Area and potential route corridors, the route development process has just begun and the final route will not be identified until the Route Permit process concludes. [Image 1.3](#) shows the preliminary route corridors Xcel Energy has identified for the Project through an analysis of opportunities and constraints. Opportunities include existing transmission and highway rights-of-way and constraints include environmental constraints like rivers and sensitive environmental resources.

**Image 1.3: Preliminary Route Corridors (January 2023)**



### 3. Lyon County Endpoint & Interconnection Generation

Xcel Energy proposes an endpoint in Lyon County based on MISO queue requests for wind generation in that area, along with the renewable resources generally available in that region. To verify this decision, Xcel Energy also conducted an RFI in June 2022 regarding wind and solar generation in MISO Zone 1, with preference to projects in the vicinity of Sherco, Lyon County, and areas between. The RFI specified that projects will ultimately need to be designed with MISO generator interconnection application requirements in mind and that

only projects that can be built to a quality standard of MISO interconnection requirements will be considered.

The result of that RFI confirmed the significant interest in renewable development and appropriateness of a Lyon County endpoint. Overall, responders identified a maximum potential build of 2,300 MW of solar, 7,600 MWh of energy storage and 4,214 MW of wind capacity, well in excess of the 2,200 MW contemplated to connect with this Project. Xcel Energy calculated the geographic center of the RFI responses in the area, which was located in Lyon County. Within 10 miles of that center, there were approximately 2,200 MW identified, with an additional 1,500 MW within 25 miles. Conversely, there were only 600 MW of resources identified in the northern portion of the Notice Area.

Xcel Energy retained an independent expert, Guidehouse Inc., to evaluate the RFI. Guidehouse completed its Final Report (Guidehouse Report) on December 29, 2022, which is included as Appendix C to this Application. The Guidehouse Report offered several conclusions, including a confirmation that the Project is needed to make renewable resources in Lyon County viable. Guidehouse recognized that: “It is clear that projects in Lyon County/Sherco Gen-Tie Region have greater difficulty reaching commercial operations through the MISO interconnection study.”<sup>19</sup> Guidehouse further concluded:

Given the dense clustering of both wind, solar and storage projects in the Sherco/Lyon County Gen-Tie region and historically high regional interconnection costs, it is reasonable to assume that this development zone, with its potentially rich wind and solar resources, will remain untapped until new transmission network upgrades are implemented.<sup>20</sup>

Xcel Energy will undertake formal competitive solicitation processes later in 2023 or in early 2024 to procure specific projects for interconnection via the Project. These projects will be brought forward to the Commission for approval in a separate docket.

Project components supporting the transmission line may adapt and change as resources are finally determined. As noted, the Alternate Plan in the IRP included CT capacity at Lyon County that would have served the same function as the synchronous condensers, as well as serving as a dispatchable resource (which the synchronous condensers cannot do). The Company anticipates that it will seek Commission review of the need for the 800 MW resources in a separate competitive resource selection proceeding. Should the Commission approve firm capacity in the vicinity of the Project Terminal Substation, Xcel Energy

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<sup>19</sup> Appendix C at 37.

<sup>20</sup> *Id.* at 4.

anticipates that such resource could provide the required stability support with minimal equipment additions and obviate the need for standalone synchronous condensers in Lyon County to support the double circuit 345 kV line.

#### **D. Project Ownership**

The Project will be owned entirely by Xcel Energy. 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 1.5 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 have over 46,000 conductor miles of transmission lines and approximately 550 transmission and distribution substations.

#### **E. Need for the Project**

The need for the Project arises from Xcel Energy's recent IRP proceeding, which the Commission described as "long, rigorous, and iterative."<sup>21</sup> As part of that proceeding, Xcel Energy presented multiple rounds of analyses which culminated in Xcel Energy proposing to construct the Project to re-use Xcel Energy's existing and valuable interconnection rights at the Sherco Substation to connect new renewable generation, including wind and solar, to the grid as coal operations at Sherco cease in 2030. In that proceeding, the Commission received comments from private individuals and more than 40 organizations, including the Department of Commerce, Office of the Attorney General, local governments, labor groups, and others.<sup>22</sup> In the IRP Order, the Commission explained that it had the "benefit of significant stakeholder engagement spanning more than two years" and that the approved plan is "designed to manage costs for households and businesses; reduce emissions that contribute to climate change; and ensure reliable electric service for Xcel Energy customers."<sup>23</sup>

As discussed in Section 1.2, in the IRP, the Commission concluded that Xcel Energy had demonstrated that it will need additional renewable generation and directed Xcel Energy to

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<sup>21</sup> IRP Order at 12.

<sup>22</sup> *Id.* at 1-3.

<sup>23</sup> *Id.* at 3.

begin regulatory proceedings for this Project to permit those new energy resources to connect to the MISO transmission grid.<sup>24</sup>

As Xcel Energy discussed in the IRP docket and supported by the Guidehouse Report, it is not feasible or cost-effective to interconnect the needed renewable generation to the regional transmission grid using the MISO queue process. The Department of Commerce, Division of Energy Resource (DOC-DER) agreed that acquiring renewable generation outside of the MISO Generator Interconnection Queue will be necessary: “one of the few realistic paths in the near term for adding substantial, cost-effective capacity of any type is through [Xcel Energy] ownership of Sherco and King gen-tie lines and re-use of the existing interconnection rights.”<sup>25</sup> DOC-DER also recommended that the Commission approve Xcel Energy’s plan to re-use its existing generation interconnection at the Sherco Substation site.<sup>26</sup>

Thus, the Project will deliver generation which Xcel Energy demonstrated will be needed in the IRP proceeding. Further, consistent with the Commission’s June 28, 2022 order concerning Xcel Energy’s exemption requests, Chapter 4 of this Application provides “updates to the quantity of new generation needed based upon the updated demand and energy forecasting provided under Minnesota Rules 7849.0270.”<sup>27</sup> As described further in Chapter 4, Xcel Energy’s updated forecast confirms the need for additional accredited resources beginning in 2026 to replace retiring generation resources and to meet customer needs.<sup>28</sup>

## F. Project Schedule and Costs

Construction of the Project is anticipated to commence in third quarter 2025 and the gen-ties are expected to be in-service at the end of the third quarter 2027. Substation additions at

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<sup>24</sup> The facts stated in the Commission’s IRP Order are considered established or proven unless or until evidence is submitted disproving those facts. *See* Minn. R. 7843.0600, subp. 2.

<sup>25</sup> In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy, MPUC Docket No. E-002/RP-19-368, DOC-DER Supplemental Comments, at 47 (Oct. 15, 2021).

<sup>26</sup> *Id.* at 42.

<sup>27</sup> Order Approving Exemption from Certain Certificate of Need Application Content Requirements, at 1 (June 28, 2022) (hereafter, the “Exemption Order”) ([Appendix D](#)).

<sup>28</sup> This approach is consistent with prior, similar certificate of need proceedings which arose from other resource plan dockets. *See In the Matter of the Request of Minnesota Power for a Certificate of Need for the Great Northern Transmission Line*, Docket No. E-015/CN-12-1163, Order Granting Certificate of Need with Conditions (June 30, 2015) (hereafter, the “GNTL Order”). In that proceeding, the applicant relied on Commission decisions in related resource plan proceedings and presented testimony affirming that the generation continued to be needed. DOC-DER provided testimony stating that the Commission’s decision on the applicant’s IRP determined the need for the 250 MW of energy and capacity resources. *See id.*; Direct Testimony of Sachin Shah, at 13 (Sept. 19, 2014). The Commission found that the IRP and the record evidence in the Certificate of Need docket supported the need for the transmission line. GNTL Order at finding 169.

the Terminal Substation and the Voltage Support Substation are expected to be complete by the September 30, 2031.

During the IRP, Xcel Energy estimated the net present value (NPV) of the gen-ties to deliver 1,996 MW to Sherco to be \$528 to \$713 million (2021\$), assuming 140- to 175-mile lines.<sup>29</sup> (When updated for inflation and the passage of time, the NPV of this estimate in 2023 dollars is \$596 million to \$805 million.) In the IRP, Xcel Energy explained that the cost estimate: would be subject to further detailed design; assumed that CT capacity would provide reactive support in Lyon County; and would be modified based upon additional factors, including commodity costs and routing.<sup>30</sup> Updating the NPV of the high end estimate in the IRP for a 180-mile line results in an NPV (2023\$) of \$830 million.

For purposes of this Application, Xcel Energy prepared a Project cost estimate based on the Project components required to deliver at least 1,996 MW (2,200 MW/hour of energy) from the Lyon County area to the Sherco Substation. Based on these components and a double circuit transmission line approximately 180-miles long, the Project is estimated to cost \$ 1.14 billion (2023\$); with an NPV of \$816 million (2023\$ NPV). In other words, when updating for the passage of time, the current project estimate is in line with the cost assumptions from the IRP. Moreover, should other synergistic resource additions, also be approved, the cost of the line will likely decrease materially.

The Project will enable the predictable interconnection of energy for Xcel Energy customers. It is predictable because it does not require a multi-step and years-long MISO interconnection process. It is also cost-effective. Assuming the connection of 2,750 MWs a 2023 NPV of \$816 million (NPV 2023\$) the interconnected renewable generation cost is \$297/kW. Interconnecting the same amount of renewable generation on a MISO system basis would cost substantially more, approximately \$1.35 billion (NPV 2023\$) through the MISO interconnection queue or \$490/kW based on the assumptions of \$564/kW wind and \$225/kW of solar.

These estimates reflect recent impacts of inflation, supply chain issues, and a tight labor market, each of which contributes to increased costs of construction across the industry. Additional details regarding the Project costs are provided in **Chapter 2**.

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<sup>29</sup> See *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, MPUC Docket No. E-002/RP-19-368, Xcel Energy Reply Comments, at 151 (June 25, 2021).

<sup>30</sup> See *id.* at 104-06.

## G. System Alternatives

For the IRP, Xcel Energy evaluated one option that would include two separate 345 kV lines, one south to Lyon County and one west to the Morris area. Xcel Energy did not carry this alternative forward because it would require two transmission corridors and associated increased costs. Instead, Xcel Energy proposed two 345 kV lines to deliver 1,996 MW from Lyon County, known for its abundance of good wind resources.

After the IRP, Xcel Energy refined its analysis. As more fully detailed in Chapter 5 herein, the Company evaluated a dozen transmission line alternatives with and without voltage support ranging from a single circuit 345 kV line to a single 500 kV line. Of these alternatives, seven were eliminated because they could not deliver the requisite 1,996 MW to Sherco from Lyon County, and therefore would not maximize the energy benefits of renewable resources interconnecting via the line. There are four 345 kV/345 kV line configurations that would deliver greater than 1,996 MW.

The 500 kV line was screened from further consideration because there are no other 500 kV facilities in the Project area and this option had greater costs. Of the four 345 kV/345 kV options, the Project (Option 9A) is proposed as the best configuration because it enables the interconnection of thousands of MWs of energy in Lyon County and includes STATCOMs to address potential turbine interaction issues that may occur due to the amount of anticipated wind generation and series compensation and the radial nature of the Project. Based on current wind turbine technology, STATCOMs are a recognized means of providing the necessary support to mitigate potential wind turbine resonant frequency interactions associated with long highly compensated radial lines. Two of the other 345 kV/345 kV options did not include STATCOMs and the one other 345 kV/345 kV option that did include STATCOMs would deliver less energy to Sherco at higher cost.

Xcel Energy also evaluated non-transmission alternatives. These alternatives included: (i) size alternatives (different voltages or conductor arrays, alternating current (AC)/direct current (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. The preferred option was Option 9a, the Project. It would enable the delivery of at least 1,996 MW of energy to the Sherco POI.

Xcel Energy concluded that the Project could be co-located on the same structures and meet transmission system planning criteria.



## H. MISO Long Range Transmission Planning

The Project will complement the Long Range Transmission Planning (LRTP) projects portfolio MISO approved in July 2022. The \$10.3 billion LRTP Tranche 1 portfolio of 18 projects will provide multiple benefits, including more reliable and resilient energy delivery; congestion and fuel savings, and reduced carbon emissions. The LRTP projects will also support the interconnection of approximately 53 GW of new generation resources throughout the upper Midwest. Three of the projects are located in Minnesota: Big Stone South – Alexandria – Big Oaks across the midsection of the State; Iron Range – Benton – Big Oaks, connecting the Iron Range and the western Metro area; and Wilmarth – North Rochester – Tremval, connecting Wilmarth, Minnesota with an expanded substation in eastern Wisconsin.<sup>31</sup> No LRTP Tranche 1 projects are located in southwestern Minnesota.

Although the LRTP projects are designed to provide substantial interconnection capacity, alleviate existing congestion, and enable additional renewable resource interconnections, they do not obviate the need for the Project. The LRTP projects are not located in the prime wind resource areas in southwestern Minnesota. The LRTP projects will also be networked lines, and any generator will be able to seek to interconnect using MISO's generator interconnection queue. The only way that Xcel Energy can retain its interconnection rights at Sherco is to directly connect Xcel Energy-owned generation to the Sherco Substation via a single-user generation tie line, like those proposed with this Project. The Project also helps ensure that Xcel Energy is able to acquire needed capacity and energy resources in a timely fashion without having to go through the interconnection queue and potentially face delays and relatively higher interconnection costs.

## I. 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 Image 1.2 above. As discussed in further detail in Chapter 8, environmental and land use features vary moving from northeast to southwest portion in the Project Study Area. The primary land use within the Project Study Area is agriculture, with municipalities and rural homesteads scattered throughout the Project Study Area. The Mississippi River and the Minnesota River both cross the Project Study Area, and, to the extent there are sensitive or rare environmental features, they tend to be concentrated in the vicinity of these rivers. Many Project impacts can be avoided and minimized through prudent routing, consistent with the Commission's routing criteria. The Applicant will coordinate with applicable

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<sup>31</sup> The expected in-service dates of these projects are, respectively: June 1, 2030; June 1, 2030; and June 1, 2028.

agencies and other stakeholders to avoid, minimize, and mitigate potential human and environmental impacts throughout the more detailed routing process for the Project.

## J. Public Input and Involvement

The Company has a long history of working with landowners and in partnership with local communities. As contemplated by the IRP Order, Xcel Energy has continued its cooperation and partnership with the City of Becker, as well as other local communities, in advance of the Sherco retirements. These efforts are described more fully in Xcel Energy's compliance reports<sup>32</sup> and will continue through and beyond development of this Project. Since implementation of the Notice Plan, Xcel Energy has also conducted further public outreach regarding this Project, more specifically, holding virtual open houses in November 2022 and six in-person open houses along the potential routing corridors in February and March 2023.

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/>. Click on the eDockets link near the top right-hand side, and then enter the docket number "22-131" in the "Docket Lookup" section. A copy of the Application is also available on the Project website: [www.xcelenergy.com/MNEnergyConnection](http://www.xcelenergy.com/MNEnergyConnection).

To subscribe to the Project's Certificate of Need docket and to receive email notifications when information is filed in that docket visit: <https://www.edockets.state.mn.us/EFiling> and select "Subscribe to Dockets", enter your email address, and select "Docket Number" from the Type of Subscriptions dropdown box, then select "22" from the first Docket number drop down box and enter "131" 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 submit your subscription request. You should receive an email from [Efiling.Admin@state.mn.us](mailto:Efiling.Admin@state.mn.us) to the e-mail address you provided, you must click the link in this email to confirm your subscription to the Project's Certificate of Need docket.

If you would like to have your name added to the Certificate of Need mailing list, send an email to [docketing.puc@state.mn.us](mailto: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-22-131), your name, and your complete mailing address or email address.

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<sup>32</sup> See In the Matter of Xcel Energy's Site Remediation Plans for Decommissioning the Sherburne County Generating Station and In the Matter of Xcel Energy's 2020-2034 Upper Midwest Integrated Resource Plan, MPUC Docket Nos. M-22-263 and RP-19-368, Compliance Report (Dec. 23, 2022).

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

Minnesota Public Utilities Commission  
Scott Ek  
Energy Facility Planner  
121 7<sup>th</sup> Place East, Suite 350  
St. Paul, Minnesota 55101  
651-201-2255  
[scott.ek@state.mn.us](mailto:scott.ek@state.mn.us)  
<https://mn.gov/puc/>

Minnesota Department of Commerce  
Andrew Levi  
85 7<sup>th</sup> Place East, Suite 280  
St. Paul, Minnesota 55101  
651-539-1840  
[andrew.levi@state.mn.us](mailto:andrew.levi@state.mn.us)  
[www.mn.gov/commerce/energyfacilities](http://www.mn.gov/commerce/energyfacilities)

### **K. 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. Subdivision 3 of Minn. Stat. § 216B.243 identifies the criteria the Commission must evaluate when assessing need. Minnesota Rule 7849.0120 further 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.

Applicant’s 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 Applicant’s 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 required to enable the full reutilization of Xcel Energy’s interconnection rights at Sherco, enable Xcel Energy to acquire necessary capacity and energy resources, and interconnect thousands of megawatts of new renewable energy in southern and southwestern Minnesota. If the Project were delayed or denied, it could impact the availability of sufficient energy capacity to meet customer needs or the timing of the retirements of Sherco Unit 1 and Unit 3, or preclude Xcel Energy from retaining its interconnection rights.

(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 to the Project has not been demonstrated. For example, as analyzed in the IRP proceeding, it is not as cost effective or as predictable and indeed may not be feasible, to instead interconnect the needed renewable generation to the regional transmission grid using the MISO queue process. This Application also demonstrates that lower and higher voltage lines are not feasible or reasonable alternatives 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 enable the interconnection of thousands of megawatts of new renewable energy, helping Xcel Energy to meet Minnesota’s “100 percent by 2040” law which – in addition to requiring utilities to provide 100 percent clean energy by 2040 – expands the previous Renewable Energy Standard (RES) to require Xcel Energy to generate or procure 55 percent of its energy used to serve Minnesota customers from renewables by 2035.<sup>33</sup> The Project will be integral to meeting the new standards cost-effectively by enabling the reuse of our interconnection rights. Further, the Project is directly aligned with the law’s requirement that utilities take “reasonable measures [...] to develop and construct new transmission lines or upgrade existing transmission lines to transmit” renewable energy.<sup>34</sup> The addition of renewable resources will result in decreased emissions. The Company’s approved Resource Plan including the Project achieves substantially more carbon reduction

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<sup>33</sup> See Minn. Stat. § 216B.1691 as amended by Minnesota Session Laws 2023, Chapter 7.

<sup>34</sup> Minn. Stat. § 216B.1691 subd. 2b as amended by Minnesota Session Laws 2023, Chapter 7 (emphasis added).

than cases in which the Project is not included. The Project will also provide tax revenue for local units of government and 100 to 200 construction jobs. Pursuant to the Commission's routing criteria, the Project will be routed in a manner compatible with protecting the natural and socioeconomic environments.

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

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

## **L. Socioeconomic Considerations**

Subpart 2 of Minnesota Rule 7849.0240 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. Socially Beneficial Uses of Facility Output**

The Project will enable Xcel Energy to meet the demand for energy and, particularly, renewable energy economically because it will re-use Xcel Energy's existing interconnection rights, and will provide economic benefits in the form of property tax revenue and jobs—both from this Project and the new renewable generation which will ultimately interconnect via the Project.

### **2. Promotional Activities**

Xcel Energy has not conducted any promotional activities or events that have triggered the need for the Project. In fact, Xcel Energy engages in significant demand-side management and conservation programs, as discussed further in [Appendix E](#). Therefore, the Project is not needed due to growth in demand due to Xcel Energy's promotional activities. Rather, the Project is needed to meet energy needs and retain the interconnection rights connected to Sherco Units 1 and 3, and the benefits associated with reusing those existing and valuable interconnection rights.

### **3. Effect in Inducing Future Development**

The Project will have a positive impact on the local communities and enables future development of wind and solar energy generation in the region. Notably, in the IRP Order, the Commission directed Xcel Energy to work with local governments and other stakeholders concerning the Project, including “to assess and account for local land use and

planning impacts.”<sup>35</sup> Consistent with the Commission’s direction, Xcel Energy will continue to engage with stakeholders throughout this process.

### **M. Route Permit Application**

Xcel Energy will apply for a Route Permit for the Project and currently anticipates submitting a Route Permit application later in 2023. The first step in the routing process is underway and involves routing studies and public outreach. This outreach commenced with virtual open houses in November 2022 and will continue with additional opens houses, mailed and published meeting invitations, and a Project website.

### **N. 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 – Forecast
- Chapter 5 – Need Analysis
- Chapter 6 – Transmission Line Operating Characteristics
- Chapter 7 – Transmission Line Construction and Maintenance
- Chapter 8 – Environmental Information

### **O. Applicant’s Request and Contact Information**

For the reasons discussed above and in the remainder of this Application and Appendices, Xcel Energy respectfully requests 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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<sup>35</sup> IRP Order at Ordering ¶ 20.C.7.

Bria E. Shea  
Regional Vice President, Regulatory Policy  
Xcel Energy  
414 Nicollet Mall, 401-7  
Minneapolis, MN 55401  
612-330-6064  
[bria.e.shea@xcelenergy.com](mailto:bria.e.shea@xcelenergy.com)

Matt Harris  
Managing Attorney, State Regulatory  
Xcel Energy  
414 Nicollet Mall, 401-8  
Minneapolis, MN 55401  
612-215-4605  
[matt.b.harris@xcelenergy.com](mailto:matt.b.harris@xcelenergy.com)

Christine Schwartz  
Regulatory Administrator  
Xcel Energy  
414 Nicollet Mall, 401 – 7<sup>th</sup> Floor  
Minneapolis, MN 55401  
[regulatory.records@xcelenergy.com](mailto:regulatory.records@xcelenergy.com)

Docketing  
Fredrikson & Byron, P.A.  
200 South Sixth Street  
Suite 4000  
Minneapolis, MN 55402  
[docketing@fredlaw.com](mailto:docketing@fredlaw.com)

## II. Project Description

### A. Project Components

Xcel Energy proposes to construct an approximately 160- to 180-mile double circuit 345 kV transmission line connecting the Sherco Substation in Becker, Minnesota, and a new substation in Lyon County, Minnesota. The Project will also include an Intermediate Substation approximately 20 miles from the new substation endpoint -- Terminal Substation, a Voltage Support Substation at the Project's approximate mid-point, and modifications at the Sherco Substation to accommodate interconnection of the new 345 kV line.

#### 1. Transmission Line and Structures

The new 345 kV transmission line would be constructed primarily of single (monopole) steel pole structures. For angles and dead-end structures, a two-pole design will be used. All transmission structures will be a double-circuit 345 kV/ 345 kV design and proposed to be weatherizing steel. Other specialty structures may be used depending on site-specific conditions. The new 345 kV/345 kV line would have a right-of-way of 150 feet.

The proposed structures will typically range in height from approximately 90- to 160-feet tall. The typical spans between structures will be about 1,000 feet. The structures will typically be installed on a drilled pier concrete foundation.



Image 2.1 provides photos of the single-pole double-circuit tangent structure and the two-pole structure for angles and dead-ends that Xcel Energy proposes to use for this Project. Technical diagrams of these structure types are included in Appendix F.

**Image 2.1: Exemplar Structures**



Double-circuit tangent structure



Two-pole structures for angles and dead-ends

Table 2.1 summarizes the characteristics of the proposed double circuit 345 kV transmission line structures.

**Table 2.1: Transmission Line Characteristics**

Line Type	Structure Type	Structure Material	Typical Right-of-way Width (feet)	Typical Structure Height (feet)	Foundation Diameter (feet)	Average Span Between Structures (feet)
345 kV Double-Circuit & 345 kV Double-Circuit Angle and Dead-end*	Monopole w/ Davit Arms & Two-pole w/Davit Arms	Weathering Steel	150	90-160	7-12	1,000
*Structure sizes may change based on site conditions and further analysis of proposed routes.						

A single circuit transmission line carries three phases (conductors) and shield wire(s). A double circuit transmission line carries six phases (conductors) and two shield wires. The 345 kV line will utilize bundled (twisted pair) 2x636 kcmil Aluminum Conductor Steel Reinforced (ACSR) or similar performance conductor. The 345 kV twisted pair conductors will have a capacity equal to or greater than 3,000 amps.

This type of conductor is the preferred conductor in areas of wind generation due to its anti-galloping characteristics. - If the galloping action is significant, it can cause phase-to-phase and phase-to-ground faults. The design of two twisted pair conductors in a bundled configuration reduces aeolian vibration and galloping due to its changing cross-section.

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. Associated Facilities

The Project will include modifications to the Sherco Substation and three new substations: the Terminal Substation in Lyon County; the Intermediate Substation approximately 20 miles to the northeast of the new Lyon County substation, and a Voltage Support Substation at the approximate Project mid-point. Each substation will be constructed on a 40- to 80-acre parcel.

### a. Sherco Substation Modifications

The existing Sherco Substation, owned by Xcel Energy, is the northeastern endpoint of the proposed double circuit 345 kV transmission line. This substation is located on Xcel Energy property near the Sherburne County Generating Plant in Becker, Minnesota. New substation equipment necessary to accommodate the proposed 345 kV transmission line is proposed to be installed at the Sherco Substation.<sup>36</sup>

### b. Terminal Substation in Lyon County

Xcel Energy proposes to construct a new 345 kV substation. The substation will include the installation of two 116/-58 MVAR synchronous condensers.<sup>37</sup> The Terminal Substation will facilitate the interconnection of renewable resources in the vicinity of that substation.

A control building and road access will also be constructed at the site.

### c. Voltage Support (Series Compensation) Substation

Xcel Energy proposes to construct a new 345 kV voltage support substation. This substation is currently proposed to include a Series Capacitor and one 150 MVAR STATCOM system per line. Selection of voltage support equipment will be dependent on the technologies available at the time of construction and the resources selected to interconnect to the line. A control building and road access will also be constructed at the site.

### d. Intermediate Substation

Xcel Energy proposes to construct an intermediate substation near the Terminal Substation. The Intermediate Substation will facilitate the interconnection of renewable resources in the vicinity of that substation.

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<sup>36</sup> The Project may interconnect with a Sherco Solar Project substation. The final determination will be made in the routing process for the Project.

<sup>37</sup> The attributes provided by these synchronous condensers could also be fulfilled by a CT, as discussed elsewhere in this Application.

A control building and road access will also be constructed at the site.

## **B. Project Costs**

The Project will cross a large section of southwest and central Minnesota and is expected to be approximately 160- to 180-miles long. Although Xcel Energy has identified a Project Study Area and potential route corridors, the route development process has just begun and the final route will not be identified until the Route Permit process concludes. As a result, Xcel Energy developed a Project cost based on an estimated route length, plus substation costs.

There are several main components of these cost estimates, (1) transmission line structures and materials; (2) transmission line construction and restoration; (3) transmission line permitting and design; (4) transmission line and substation right-of-way acquisition; and (5) substation materials, permitting, design, and construction. Each of these components also includes a risk contingency and financing expenses, Allowance of Funds Used During Construction (AFUDC).

To prepare a cost estimate for the transmission line portions of the Project, Xcel Energy relied in part upon the actual costs incurred for constructing the Huntley-Wilmarth 345 kV Project, construction of which was completed in October 2021. Xcel Energy updated this data based on current market conditions and included a contingency factor. The estimate values are based on long straight alignments. The introduction of many corner structures and/or an alignment that jumps across features will have a cost increase. Right-of-way cost estimates for the transmission line and substations were based on a 150-foot right-of-way for the transmission line and 40 to 80 acres for each substation. Xcel Energy considered actual costs from prior project acquisitions and approximated the number of easements required to estimate the overall land acquisition costs.

To estimate substation construction costs, Xcel Energy identified the necessary components for each substation. Xcel Energy then estimated material, construction, design, and permitting costs based on cost estimates for these items from prior substation improvement projects.

To calculate an appropriate risk contingency, Xcel Energy identified potential risks that could result in additional costs. These risks include unexpected weather conditions, poor soil conditions in areas where no soil data was obtained, transmission line outage constraints, potential shallow rock, river crossings, labor shortages, and market fluctuations in material pricing and labor costs. Xcel Energy then developed an appropriate cost contingency for each of these risks and applied them to each of the cost categories above.

Xcel Energy estimates that construction of the Project, including substation construction and all substation equipment, including STATCOMs and series compensation, will cost \$1.14 billion, representing the sum of the expenditures over the life of the Project using 2023\$ dollars. These costs include all transmission line costs (including materials, associated construction, permitting and design costs, and risk assessment contingencies), two new substations and a series compensation substation, Sherco Substation modification costs (including materials, construction, permitting and design costs, and risk contingencies), AFUDC, and right-of-way/land acquisition costs.

Table 2.2 provides a breakdown of the Project costs.

**Table 2.2: Project Capital Cost Estimates (2023\$)**

Project Components	2023\$
Transmission line (Gen-tie (\$3.8 million /mile))	\$689 million
Sherburne County Substation (Sherco) Modifications	\$9 million
Terminal Substation (Lyon County) Costs	\$164 million
Intermediate Substation	\$24 million
Voltage Support Substation	\$253 million
<b>Project Total</b>	<b>\$1.139 billion</b>

The transmission line only is approximately \$3.8 million per mile. These estimated costs are generally consistent with the \$3.5 million per-mile transmission line cost estimates Xcel Energy provided during the IRP proceeding. The estimates have been updated to account for cost pressures occurring more generally, as well as changed assumptions regarding Project components. More specifically, for example, the Project as proposed in this Application would include synchronous condensers at the Terminal Substation; those facilities were not included in the IRP cost estimate because, at that time, the attributes provided by the synchronous condensers were planned to be fulfilled via CT capacity with a clutch feature. Separately, too, the cost estimate in this Application incorporates changes since 2021 as a result of inflation, supply chain issues, rising material costs, and a tight labor market.

To enable a comparison between the IRP estimate and the current Project estimate, the IRP estimate was converted to an NPV in 2023\$ dollars. The observed inflation rate in 2022 was 9.41% and the inflation in 2023 is estimated at 3.18%. These are weighted inflation costs

based on both labor and non-labor inflation rates. The equivalent NPV 2023 dollars from the 2019 MN IRP is \$596M-\$805M. [Table 2.3](#) below summarizes the calculations:

**Table 2.3: NVP Calculations**

Inflation		9.41%	3.18%
Year	2021	2022	2023
Capital Cost – Low (140 miles) \$M	\$528	\$ 578	\$ 596
Capital Cost – High (175 miles) \$M	\$713	\$ 780	\$ 805

The total Project capital expenditure of \$1.14 billion is converted to a 2023\$ NPV by determining the capital cost by year in 2023 dollars (inclusive of escalation & AFUDC). The capital cash flow, now in nominal year dollars is discounted back to 2023 dollars using the same discount rate from the 2019 MN IRP, which is 6.47%. This results in a 2023\$ NPV of \$816 million.

These Project cost estimates will be updated in the Route Permit application based on route-specific length and environmental conditions and land use. When the routing process is complete, Xcel Energy will be able to update the costs based on the final route length and Project components with greater precision. Given the uncertainty of the route location at the Certificate of Need stage, Xcel Energy believes that for purposes of potential cost recovery under Minn. Stat. § 216B.16, Subd. 7b, it would be appropriate for the Commission to adjust and approve final Project costs after the route permit process concludes.

### C. Rate Impact

The total cost of the Project will be recovered from Xcel Energy retail customers. The tables below summarize the estimated rate and bill impacts by customer class. For the typical residential customer using 650 kWh per month, the bill impact in 2028, the first full year after the gen-tie in-service date, would be approximately \$1.86 per month. Xcel Energy may seek recovery of these investments through a Transmission Cost Recovery rider or in a rate case proceeding. Because the Project will enable the addition of more cost-effective renewable generation, the impact to customer bills would be mitigated by the cost-beneficial renewables over the long term, relative to a scenario without the Project. [Table 2.4](#) provides

the estimated monthly bill impact by customer class. Table 2.5 provides the estimated monthly bill impact \$/kWh.

**Table 2.4: Estimated Monthly Bill Impact – Typical Usage\* by Customer Class**

Year	Residential	Small Commercial Non-Demand	Demand
2023	\$0.00	\$0.00	\$0.06
2024	\$0.01	\$0.01	\$0.38
2025	\$0.08	\$0.12	\$3.62
2026	\$0.14	\$0.22	\$6.46
2027	\$0.73	\$1.12	\$33.66
2028	\$1.86	\$2.88	\$86.24
2029	\$1.84	\$2.85	\$85.09
2030	\$1.82	\$2.84	\$84.57
2031	\$2.16	\$3.43	\$101.98
2032	\$2.44	\$3.96	\$117.61
2033	\$2.36	\$3.91	\$115.90
2034	\$2.25	\$3.86	\$113.95
2035	\$2.08	\$3.77	\$110.67
2036	\$1.89	\$3.58	\$104.61
2037	\$1.75	\$3.39	\$98.54
2038	\$1.62	\$3.24	\$94.03
2039	\$1.50	\$3.09	\$89.22
2040	\$1.39	\$2.96	\$85.26
2041	\$1.29	\$2.83	\$81.40

\*Typical Monthly Usage: Residential - 650 kWh, Small Commercial Non-Demand - 1,000 kWh, and Demand - 37,500 kWh

**Table 2.5: Estimated Monthly Rate Impact (\$/kWh)**

<b>Year</b>	<b>Residential</b>	<b>Small Commercial Non-Demand</b>	<b>Demand</b>
2023	\$0.000002	\$0.000002	\$0.000002
2024	\$0.000013	\$0.000013	\$0.000010
2025	\$0.000121	\$0.000120	\$0.000097
2026	\$0.000216	\$0.000215	\$0.000172
2027	\$0.001125	\$0.001122	\$0.000898
2028	\$0.002865	\$0.002882	\$0.002300
2029	\$0.002827	\$0.002850	\$0.002269
2030	\$0.002794	\$0.002837	\$0.002255
2031	\$0.003328	\$0.003427	\$0.002719
2032	\$0.003758	\$0.003958	\$0.003136
2033	\$0.003625	\$0.003911	\$0.003091
2034	\$0.003465	\$0.003862	\$0.003039
2035	\$0.003197	\$0.003771	\$0.002951
2036	\$0.002901	\$0.003582	\$0.002790
2037	\$0.002692	\$0.003386	\$0.002628
2038	\$0.002493	\$0.003240	\$0.002508
2039	\$0.002309	\$0.003086	\$0.002379
2040	\$0.002139	\$0.002960	\$0.002274
2041	\$0.001989	\$0.002834	\$0.002171



#### D. Project Schedule and Work Force

Table 2.6 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. Xcel Energy estimates it will engage 100 to 200 laborers for Project construction.

**Table 2.6: Anticipated Project Schedule**

Activity	Estimated Dates
Minnesota Certificate of Need Proceeding	Through 2023
Route Permit Proceeding Commenced	September 30, 2023
Land Acquisition Begins	June 30, 2025
Required Federal, State, and Local Permits Obtained	Throughout 2025
Start Project Construction	September 30, 2025
Gen Ties In-Service	September 30, 2027
Project Complete with all substations built out	September 30, 2031

**III. ELECTRICAL SYSTEM AND CHANGING GENERATION PORTFOLIO OVERVIEW****A. Electrical System Overview**

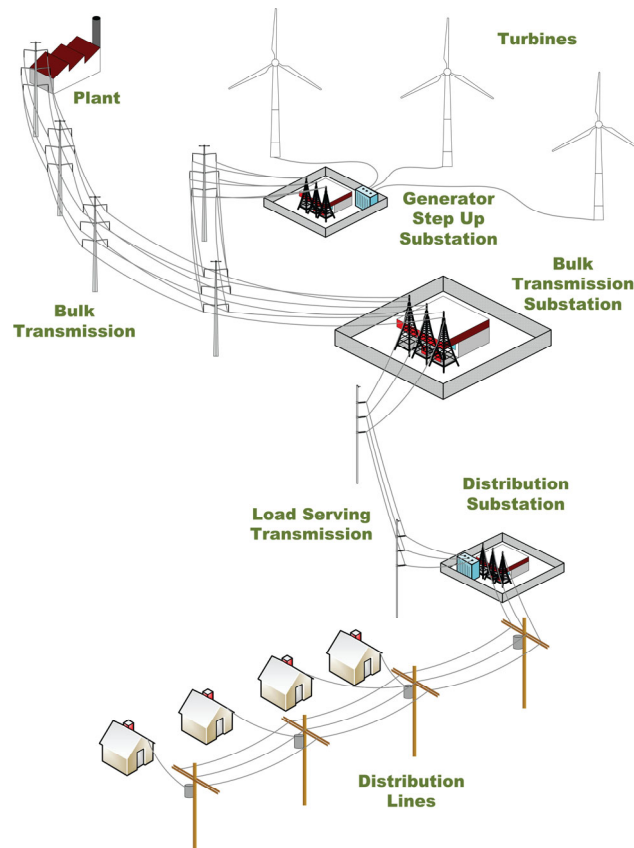
When a customer turns on a light switch, a circuit is completed that connects the light with the wires that serve the customer's building. The building wires are connected to a transformer and a distribution line outside of the building. The distribution lines, in turn, are connected to substations and 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. However, energy storage technologies, including battery energy storage systems (BESS), are advancing.

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 100,000 volts (e.g., 115 kV, 230 kV, 345 kV). One kV equals 1,000 volts. Voltage is stepped-up because moving electricity over longer distances at higher voltages reduces electrical losses on the system; this means that more of the energy that is generated reaches the ultimate customer. 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 [Image 3.1](#).

**Image 3.1: Electrical System**

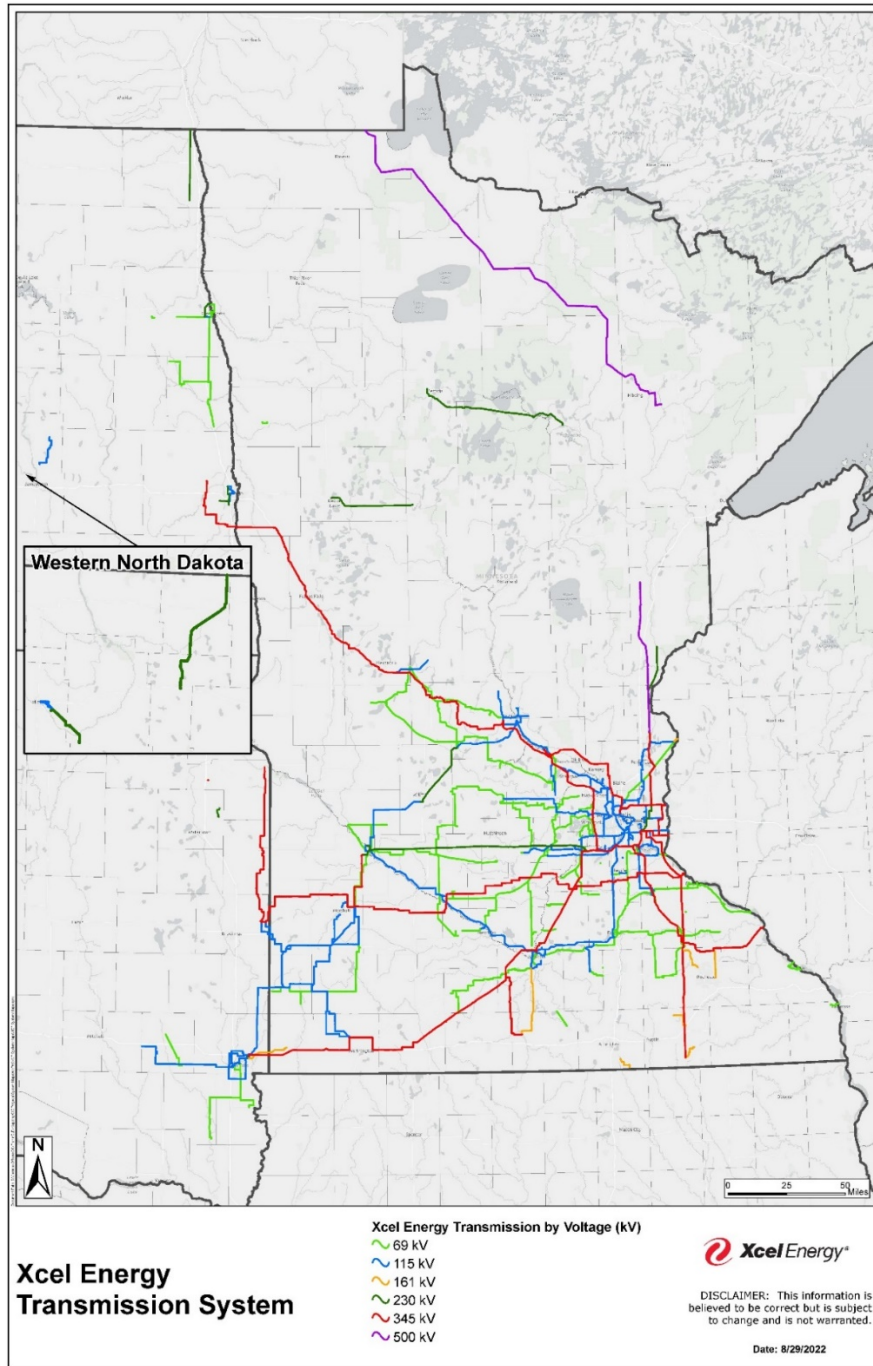


Note that Image 3.1 is an artistic portrayal of an electrical system and is not an actual representation of all electrical system components.

## **B. 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 customer needs in specific locations, and bulk transformers at 100 kV and above. The transmission system is designed to withstand the outage of a single transmission line without major disruption to the overall power supply. Xcel Energy's transmission system in Minnesota and portions of North Dakota and South Dakota is depicted below in [Image 3.2](#).

Image 3.2: Xcel Energy’s Transmission System in Minnesota, North Dakota, and South Dakota<sup>38</sup>



<sup>38</sup> Portions of the lines depicted above are transmission facilities that Xcel Energy owns with other utilities.

### 1. High Voltage Transmission Lines Substations

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 lightning 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 through the wire is called voltage. Voltage is measured in volts (V) or kilovolts (kV). The wire conducting the current offers resistance to its movement. This resistance is measured in a unit called Ohms. Copper or aluminum wires conduct electricity with relatively little resistance.

### 2. Substations

Substations are a part of the electric generation, transmission, and distribution system and contain high-voltage electric equipment to monitor, regulate, and distribute electricity. 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 project and anticipated future needs based on the 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 fenced area and the required surrounding areas, including storm water ponds, wetlands, grading, access roads, and the transmission line rights-of-way that will enter/exit the substation. The configuration of a substation may change over time to accommodate future load growth or electric system needs.

## **C. The Changing Energy Landscape**

### 1. Federal Renewable Energy and Transmission Policies

Current federal energy policy promotes the expansion of renewable energy and the transmission that will be necessary to interconnect that energy to the grid. For example, the Inflation Reduction Act puts the United States on a path to approximately 40% emissions reduction by 2040 by supporting, among other things, continued development of domestic renewable energy. More specifically, the Inflation Reduction Act of 2022 extends the production tax credit (PTC) and investment tax credit (ITC) for renewable energy facilities through 2024, after which time the technology-neutral Clean Energy PTC and ITC begin in 2025.

Similarly, federal policy recognizes that additional transmission infrastructure will be critical to expanding renewable energy and maintaining a resilient and reliable grid. The Infrastructure Investment and Jobs Act of 2021 reflects a significant investment in transmission to facilitate the expansion of renewable energy, including the Department of Energy’s (DOE) “Building a Better Grid” Initiative. DOE explained: “[A]s the number of generation and storage projects proposed for interconnection to the bulk-power system is growing, interconnection queue wait times are increasing and the percentage of projects reaching completion appears to be declining, particularly for wind and solar resources. Needed investments in transmission infrastructure include increasing the capacity of existing lines, using advanced technologies to minimize transmission losses and maximize the value of existing lines, and building new long-distance, high-voltage transmission lines.”<sup>39</sup>

## 2. State of Minnesota Renewable Energy Policies

In 2005, about 65% of electricity generated in Minnesota came from coal and natural gas.<sup>40</sup> In 2020, renewable energy provided the largest share of electricity generation statewide.<sup>41</sup>

State energy policies have also grown and evolved over the years. Minnesota’s original Renewable Energy Objective, adopted in 2001, 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 to seven percent by 2010. Minnesota statute also required Xcel Energy to generate 30% of its retail sales from renewable energy by 2020.<sup>42</sup> Xcel Energy met that target.<sup>43</sup>

More broadly, Minnesota had previously set a goal to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 30% below 2005 levels by 2025 and to a level at least 80% below 2005 levels by 2050.<sup>44</sup> Similarly, Minnesota has recognized a “vital interest in providing for . . . the development and use of renewable

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<sup>39</sup> See Department of Energy, Notice of Intent, Building a Better Grid Initiative to Upgrade and Expand the Nation’s Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization, at 4 (Jan. 11, 2022), available at [https://www.energy.gov/sites/default/files/2022-01/Transmission%20NOI%20final%20for%20web\\_1.pdf](https://www.energy.gov/sites/default/files/2022-01/Transmission%20NOI%20final%20for%20web_1.pdf) (last accessed Feb. 23, 2023).

<sup>40</sup> U.S. Energy Information Administration (EIA), *Electricity Data Browser*, available at <https://www.eia.gov/electricity/data/browser/> (last accessed Feb. 23, 2023).

<sup>41</sup> EIA, *Minnesota State Profile and Energy Estimates*, available at <https://www.eia.gov/state/?sid=MN> (last accessed Feb. 23, 2023).

<sup>42</sup> Minn. Stat. § 216B.1691, subds. 2 and 2a.

<sup>43</sup> See *In the Matter of Commission Consideration and Determination of Compliance with Renewable Energy Standards for Year 2020*, MPUC Docket No. E999/PR-21-12, Renewable Energy Certificate Retirement and Solar Energy Standards Reporting for Compliance Year 2020 (June 2, 2021).

<sup>44</sup> Minn. Stat. § 216H.02, subd. 1.

energy resources wherever possible.”<sup>45</sup> Xcel Energy has been working to meet these goals and, more recently, in February 2023, the Governor Tim Walz signed the “100 Percent by 2040” legislation into law, which, at a high level, directs electric utilities to transition to meeting the needs of Minnesota retail customers with 100% carbon-free electricity by the end of 2040. Xcel Energy supported the legislation and is committed to achieving a zero-carbon future as quickly as possible while also ensuring affordability and reliability. Additional sources of emission-free electric energy—like wind and solar—will be necessary to meet these goals.

### 3. Xcel Energy Goals and Approved Resource Plan

Xcel Energy is committed to delivering carbon-free electricity and is on track to meet Minnesota’s 100% by 2040 law targets. In December 2018, Xcel Energy was the first major U.S. energy provider to commit to delivering 100% carbon-free electricity by 2050, with one of the most aggressive interim targets to reduce carbon emissions more than 80% by 2030, from 2005 levels. Xcel Energy has already reduced carbon emissions by 51%, and the most recent IRP surpasses Xcel Energy’s interim target, reducing estimated carbon emissions over 85% by 2030, with even deeper carbon reductions beyond 2030 that position Xcel Energy well to reach 100 percent carbon-free energy faster, meeting the ambitious new goals of the State of Minnesota.

More specifically, the Commission approved Xcel Energy’s plan that is expected to reduce carbon dioxide emissions more than 85% from 2005 levels and deliver at least 80% of customers’ electricity from carbon-free energy sources by 2030. Under the plan, Xcel Energy will:

- Add 2,150 MW of wind and 2,500 MW of solar by 2032, with another 1,100 MW of wind and solar capacity beyond 2032;
- Retire all remaining Upper Midwest coal plants by the end of 2030;
- Ensure reliable, affordable energy by extending the generation of carbon-free nuclear energy at Xcel Energy’s Monticello Plant an additional 10 years to 2040;
- Build on Xcel Energy’s successful energy efficiency programs to help customers save energy and money and work with customers on new demand response options to manage energy load; and
- Develop new transmission infrastructure to connect more clean energy to the

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<sup>45</sup> Minn. Stat. § 216C.05, subd. 1.

power grid, reusing important connections near retiring coal plants, which will help maintain reliability.

This Project is a critical part of the new transmission infrastructure identified in the IRP. Xcel Energy is a national leader in wind energy and has steadily expanded its wind portfolio since 2005. Xcel Energy also continues to increase solar and wind capacity. At the end of 2022 Xcel Energy had approximately 1,200 MW of large and distributed-scale solar and over 4,500 MW of wind. Wind and solar will be integral to Xcel Energy’s plan to reduce carbon emissions 85% by 2030 from 2005 levels, produce more than 50 percent of Xcel Energy’s customers’ electricity by 2030, and meet Minnesota’s new “100 % by 2040” standard. As discussed in the following section, by re-using Xcel Energy’s existing interconnection rights, the Project will enable the interconnection of additional renewable energy generation in a timely and cost-effective manner.

#### 4. Re-using Interconnection Rights to Interconnect Renewable Generation

Large power plants, such as the coal units at Sherco, interconnect to the regional transmission grid, and the incumbent generation owner owns the associated transmission interconnection rights. Those rights cannot be bought or sold as standalone assets.<sup>46</sup> The closure of the Sherco coal units will open up approximately 2,000 MW of transmission interconnection rights to Xcel Energy (the incumbent transmission owner). MISO rules require replacement generation to achieve commercial operation within three years of the closure date of the existing facility.<sup>47</sup>

Interconnection rights are a valuable asset in part because the regional transmission grid is congested: there is not currently enough transmission capacity on the regional system to accommodate all the renewable energy projects that wish to interconnect. Although additional infrastructure is planned, interconnection delays and high estimated upgrade costs are expected to persist. Therefore, reusing available, existing interconnection rights can speed the addition of renewable energy resources, in this case, replace retiring thermal generation.

In Minnesota, the most productive wind resources are in the southwest portion of the state, as shown in Image 3.3 below. The majority of the state’s installed wind capacity is also located in southwest Minnesota.<sup>48</sup> In addition, the state’s highest solar irradiance is located in southwest Minnesota where limited tree cover and expansive non-forested lands result in

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<sup>46</sup> See MISO Tariff, Attachment X, § 16.

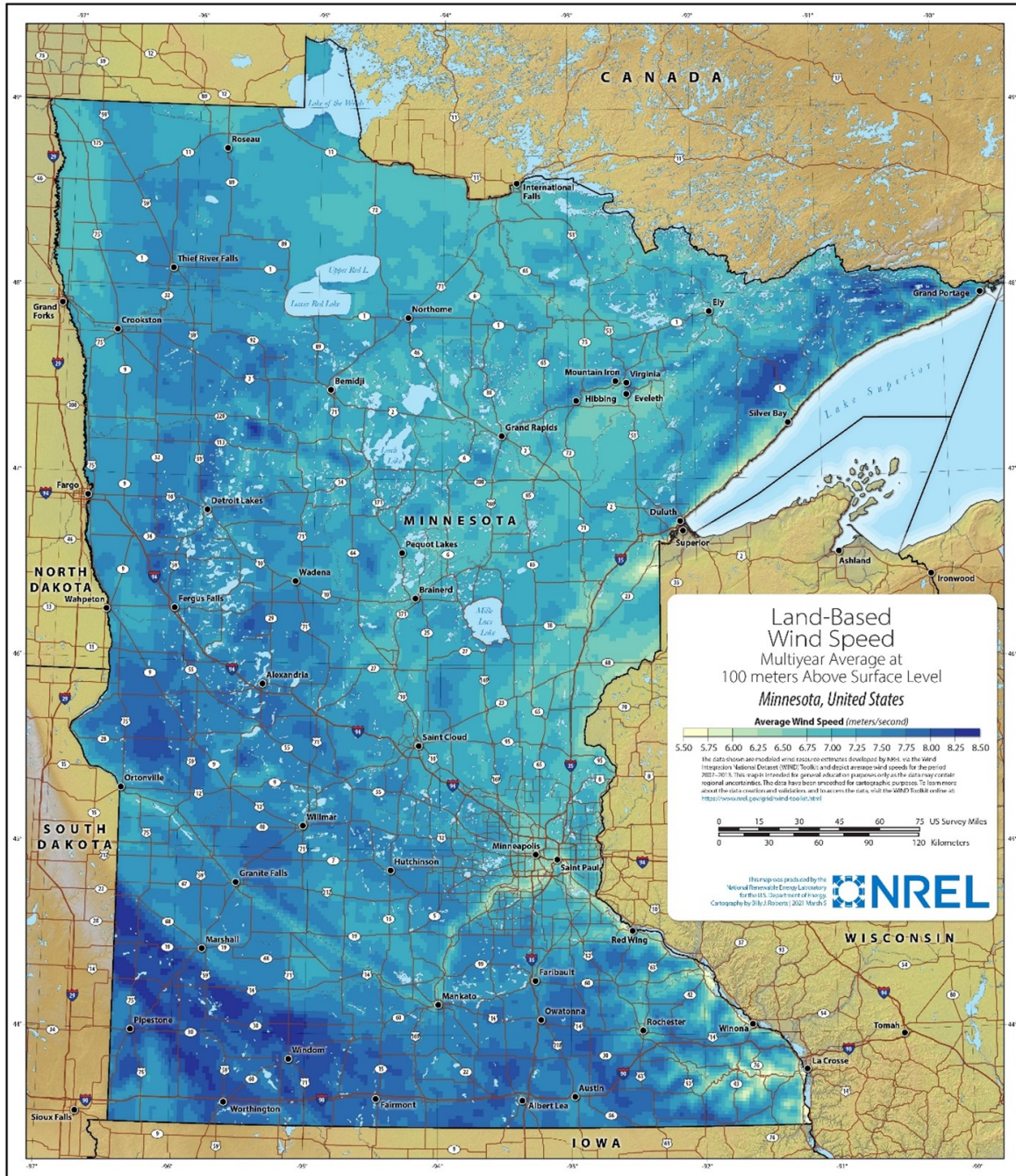
<sup>47</sup> See MISO Tariff, Attachment X, § 3.3.1.

<sup>48</sup> See USGS, *The U.S. Wind Turbine Database*, available at <https://eerscmap.usgs.gov/uswtdb/> (last accessed Feb. 23, 2023).



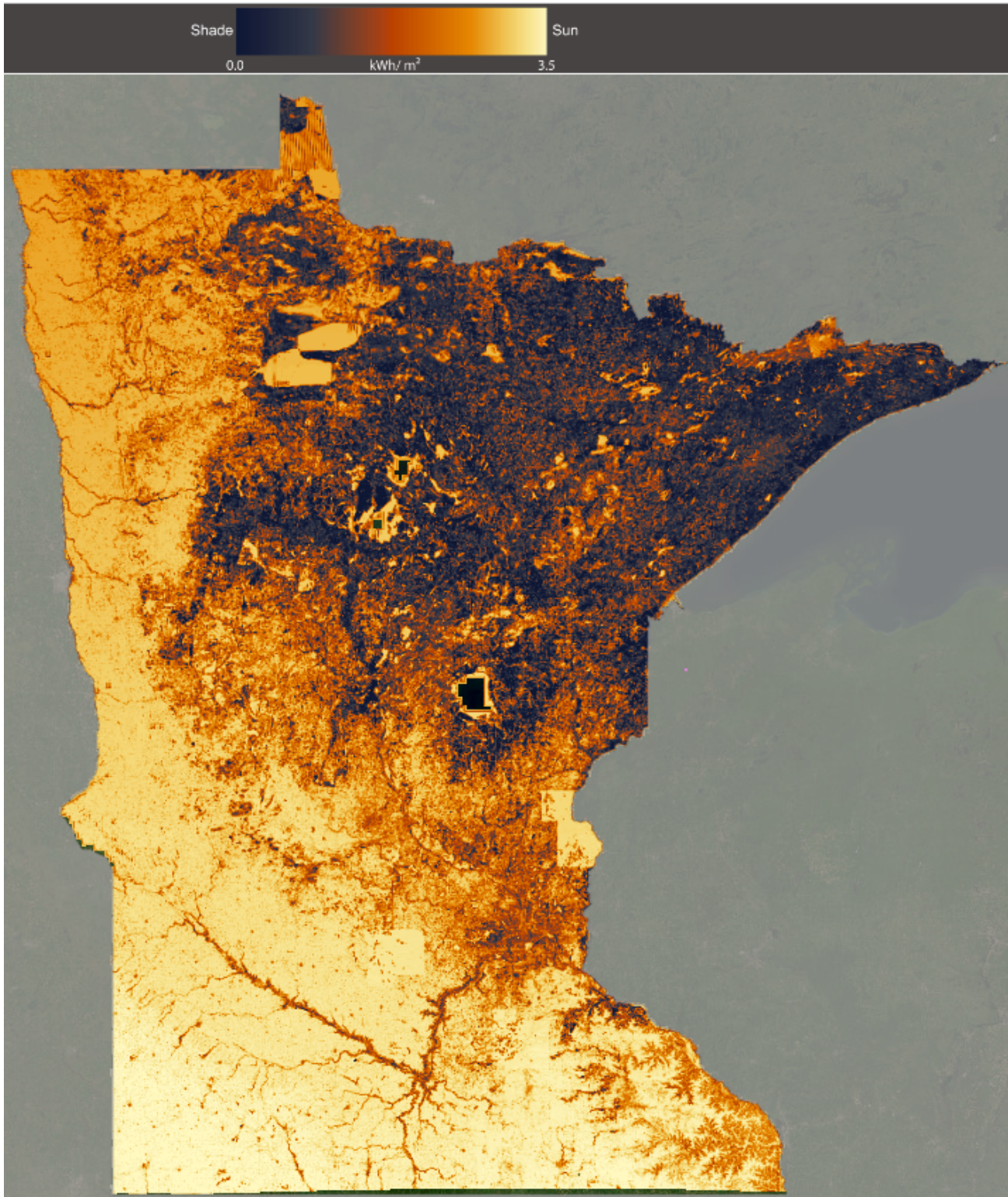
ample sun exposure at ground level.<sup>49</sup> A solar suitability Minnesota map is shown in Image 3.4.

Image 3.3: Minnesota Average Annual Wind Speeds at 80 meters



<sup>49</sup> See e.g., University of Minnesota, *Minnesota Solar Suitability Analysis*, available at <https://solar.maps.umn.edu/index.php> (last accessed Feb. 28, 2023).

Image 3.4: Minnesota Solar Suitability Map



The Project is needed to connect resources like these in wind- and solar-rich western Minnesota to an available point of interconnection at the Sherco Substation. The results of Xcel Energy’s 2022 RFI on renewable projects between the Sherco Substation and Lyon County confirm that renewable development is planned in this area in the latter half of this decade. Specifically, Xcel Energy issued an RFI on June 3, 2022 (with responses provided by July 1, 2022), to collect information about potential generation assets in development that may be candidates for interconnection to the Project. The RFI indicated that the information collected would be used in future planning processes to inform the need, and specific routing, for the Project. In 2022, Xcel Energy issued its first RFP to meet capacity needs approved in the IRP, and plans to issue another RFP later in 2023 to begin sourcing renewable capacity that can interconnect to the Project. The 2022 RFP yielded a shortlist of 464 MW of solar projects – out of a targeted 900 – including capacity that would reutilize the first tranche of open interconnection at the Sherco site. The results of the RFP and other external benchmarks show that it is currently challenging to bring on new renewable resources cost effectively; and while some of these market conditions are transitory, the current significant constraints in the broader grid are a key contributor to this challenging environment. As such the Project is an important component of the Company’s ability to achieve its clean energy goals and the newly enacted state clean energy requirements. As discussed in Chapter 4, these resources continue to be needed to meet both customer needs, as well as carbon reduction goals.

## IV. FORECAST

### A. Forecasting Overview

The Project was proposed as a method of ensuring that sufficient energy resources could be interconnected to the Company's system in the timeframe needed to meet Xcel Energy's resource and capacity requirements, as well as achieve clean energy goals cost effectively and to make efficient re-use of the Company's interconnection rights at the Sherco site after the coal units retire.

In the IRP, the Commission determined that between 2027 and 2032, Xcel Energy would need approximately 600 MW more solar-powered generation and 2,150 MW more wind-powered generation, or an equivalent amount of energy and capacity from a combination of wind, solar and/or storage.<sup>50</sup> The Commission also determined that between 2027 and 2029 the Company will likely require up to 800 MW of generic firm dispatchable resources.<sup>51</sup>

Xcel Energy's updated Spring 2022 forecast confirms the need for additional accredited resources beginning in 2026 and continuing thereafter to replace retiring generation resources and meet customer needs. In the IRP Xcel Energy estimated a need of 210 MW of accredited capacity in 2026, increasing to nearly 3,000 MW by 2032 without new additions – this is the deficit the Company's resource plans are designed to address. However, the Company's load forecast has changed since the time of the RFP, increasing the amount of capacity the Company expects to need to meet customer demand and the Company's planning requirements. Under MISO's legacy annual resource adequacy (RA) requirements and with this updated load forecast, the Company would expect this need to increase to just over 500 MW by 2026 and grow to around 3,500 by 2032. Although the resource adequacy construct is changing for the upcoming and future planning years, as discussed below, this reinforces the benefit of the Project to bring new capacity onto the system through the Company's existing interconnection rights in a transmission constrained part of MISO.

The need for resources that can be interconnected through the Project is expected to persist, and indeed the overall need for new resources may increase, in yet unquantifiable ways based on significant changes to the market since the IRP. MISO has recently received approval for significant RA construct changes with additional reforms expected in the near future that will impact Xcel Energy's resource obligations relative to the current construct. Further, the federal government has passed the Inflation Reduction Act, which includes many new and

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<sup>50</sup> IRP Order at Ordering ¶ 2a(8).

<sup>51</sup> *Id.* at Ordering ¶ 3.

extended incentives to accelerate and advance the clean energy transition which will likely lead to increased renewables development on the Company's system. The 100 by 2040 law will also increase the need for additional renewable resource for all utilities in the state, including Xcel Energy. Given the current oversubscribed state of the MISO queue, both these factors only increase the importance of, and the value provided by, the Project to the Xcel Energy system.

This chapter discusses the resource and capacity needs identified in Xcel Energy's IRP, as well as major changes to the MISO RA construct and load forecasts prepared in Spring 2022.

### 1. Determining Customer Needs

The Company's internally developed customer needs forecast is derived from customer demand and energy forecasts and adjustments for the effects of energy efficiency (EE) resources, distributed energy resources (DER), and electric vehicle (EV) adoption. To this, Xcel Energy adds a reserve margin that is prescribed by MISO. Then Xcel Energy subtracts the capacity accreditation of the energy resources the Company has, or expects to have, on the system, to determine the net surplus or need.

Forecasting the Company's customers' energy needs starts with a peak-hour demand forecast (in MW) and a forecast of customers' total energy needs (in MWh) for each year of the planning period.

#### a. Forecast for Peak Demand Requirements

Xcel Energy uses econometric analysis and historical actual coincident net peak demand data to determine forecasted system demand, which forms the basis of the Company's capacity requirements for each planning year. From these corporate forecasts, Xcel Energy makes adjustments that add back in the effect of anticipated future EE achievements and distributed solar generation, so that Xcel Energy can model EE and distributed solar as competing with supply-side resources in the modeling process. This was a change the Company first implemented with the Company's July 2019 initial Resource Plan filing and is further discussed below.

The methodology used to develop the Spring 2022 Forecast has not changed from the initial Resource Plan filing, though the inputs used to develop the forecast have been updated.

The Spring 2022 peak corporate demand forecast for this update shows an average annual growth rate of 0.02% from 2022 through 2034. [Image 4.1](#) below shows the updated

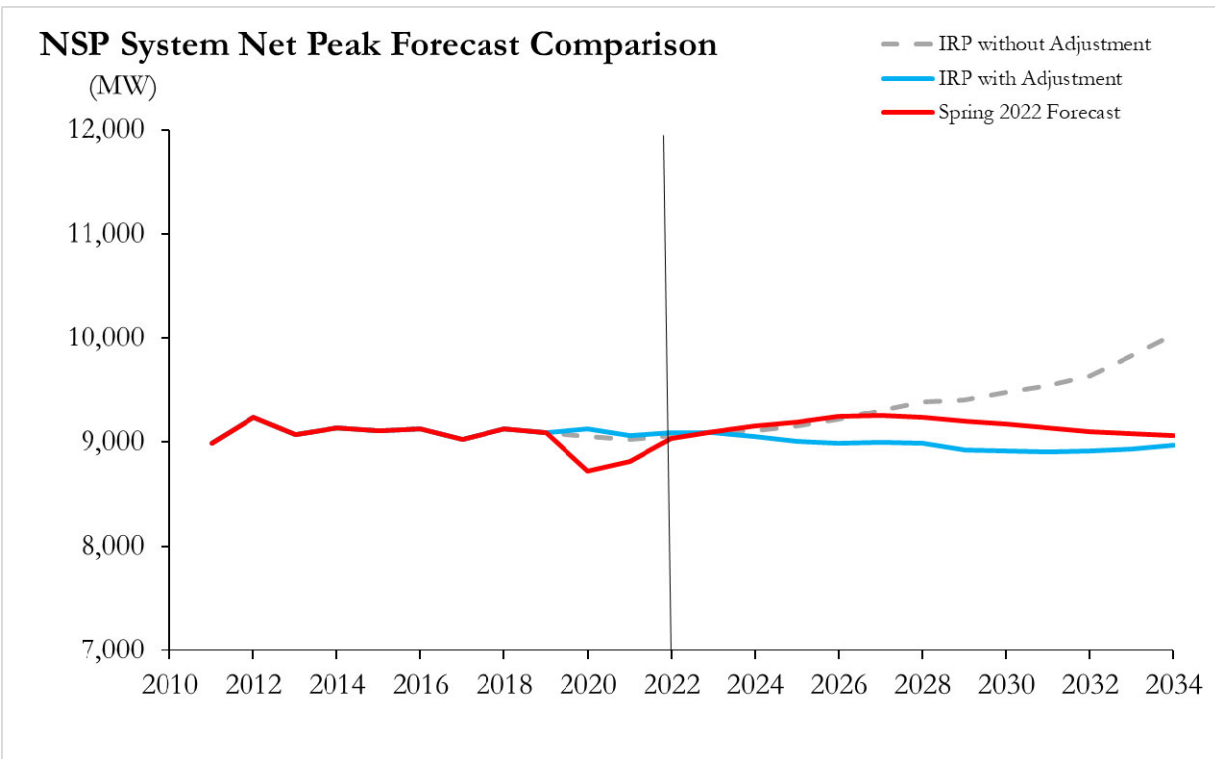
corporate net load forecast – called “Spring 2022 Forecast” in the Image 4.1 in relation to the forecast from the IRP Fall 2019 Forecast referred to as “IRP without Adjustments”. In addition, Image 4.1 includes an “IRP with Adjustments” series where the Future Demand Side Management (DSM) adjustment used in the IRP forecast is updated with the Future DSM adjustment from the Spring 2022 forecast. The “IRP with Adjustments” series provides an “apples-to-apples” comparison for the Spring 2022 forecast with the IRP forecast that eliminates the differences in DSM forecasts. After accounting for the differences in the IRP and Spring 2022 forecasts in the “IRP with Adjustments” forecast, the Spring 2022 peak demand forecast exceeds the “IRP with Adjustments” peak demand forecast through the 2034 horizon. Xcel Energy undertook additional steps in the course of resource plan modeling, for incremental new EE to be modeled as a supply-side resource. This required that the Company adjust the base energy forecast (discussed in Part 1 above) to remove the embedded EE adjustment that projects the effects of new 2022-2034 program year EE achievements.<sup>52</sup>

In other words, after accounting for increased levels of DSM that were approved in the IRP, the updated 2022 load forecast result in a larger incremental resource need than the Company had anticipated in the IRP. This higher peak forecast is driven by a higher energy forecast which includes stronger than expected actual energy demand in 2021 and a higher level of EV adoptions over the forecast horizon. While a higher EV adoption rate results in more energy needed to support charging, a change in the EV charging profile results in lower peak impact per vehicle during the system peak hour.

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<sup>52</sup> Xcel Energy also disaggregated DG Solar resources, as discussed previously. This included incremental potential EE savings amounts from the 2022-2034 program years in Strategist and Encompass modeling processes as “Bundles,” which compete on an economic basis with supply-side resources. In effect, this allows Xcel Energy to treat projected additions of DG solar and portfolios of new EE measures, at a given average cost, like generic supply-side resources.

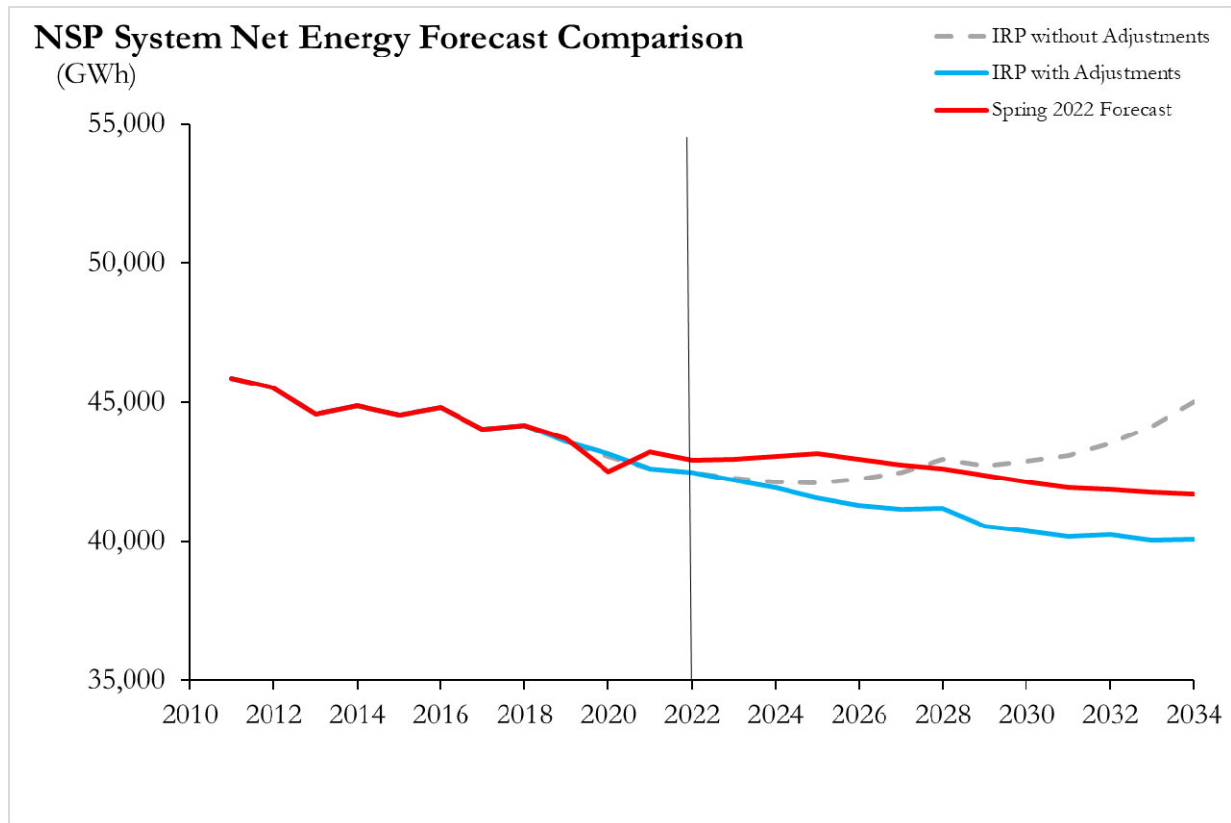
Image 4.1: Corporate Forecast of Peak Load by Vintage



#### b. Forecast for Energy Requirements

In addition to forecasting peak demand, Xcel Energy also forecasts customers' energy requirements. Xcel Energy expects net energy requirements to remain above the forecasts used to determine the need for new supply side resources in the IRP filing. The Spring 2022 forecast is calling for approximately -0.2% growth over the full 2022-2034 planning period. [Image 4.2](#) below portrays the net energy from the Spring 2022 forecast, as compared to the IRP Fall 2019 forecast referred to as "IRP without Adjustments". [Image 4.2](#) also includes an "IRP with Adjustments" series where the Future DSM adjustment used in the IRP forecast is updated with the Future DSM adjustment from the Spring 2022 forecast. The "IRP with Adjustments" series provides an "apples-to-apples" comparison for the Spring 2022 forecast with the IRP forecast that eliminates any differences in DSM forecasts. Changes from the Company's Fall 2019 forecast vintage to the Spring 2022 forecast are attributable to higher than previously expected historical energy consumption, the long-term impact of the COVID-19 pandemic on customer sales, and additional sales from higher EV adoption.

Image 4.2: Corporate Forecasted Net Energy Requirements by Vintage



#### c. Forecast Adjustments for Anticipated Customer Trends

After determining the base peak capacity and energy demand forecasts, Xcel Energy makes adjustments to account for the impact of events or trends reasonably expect to occur in the planning period. The forecast has been exogenously adjusted for trends in DER and adoption of EVs. DER in the form of behind-the-meter rooftop solar results in a reduction to the forecast while EV charging results in an increase to the forecast. The forecast also made certain adjustments to overall demand for large customer changes expected in future years.

#### d. Adjustments to Model Certain Load-Modifying Resources as Competing with Supply-Side Resource Options

There are no changes to the methodology used in the IRP filing to account for load-modifying resources – such as energy efficiency, demand response, and distributed generation – as competing with supply-side resources in the Company’s modeling process.



## 2. Resource Adequacy Requirements

MISO prescribes RA requirements that are intended to help ensure adequate reliability of the bulk electric supply system. MISO's RA process requires load serving entities (LSEs) like the Company to maintain resources that exceed their level of demand by a specific margin – the planning reserve margin or PRM – to cover potential uncertainty in the availability of resources or level of demand.<sup>53</sup> These RA requirements are fundamental to the resource planning process, informing the level of capacity Xcel Energy needs in the Company's portfolio to adequately serve customers' peak demand.

The MISO RA construct is currently undergoing significant reform, as the system continues to transition away from legacy baseload generation assets to future state with more renewables and flexible generation. Recently, MISO proposed and FERC approved a new method to incorporate RA requirements on a seasonal basis, rather than the historical annual approach. This means that – whereas previously Xcel Energy needed to plan the system in a way that met summer peaks plus a reserve margin – Xcel Energy now will need to evaluate customer needs across summer, fall, winter, and spring, and resource availability in each season will impact capacity accreditation. Further, MISO continues to work on a new methodology for accrediting non-thermal resources, such as renewables and demand response, which continues to be considered by stakeholders and MISO now intends to file a proposed methodology to the FERC in late 2023 or early 2024. MISO may also propose further changes to the auction mechanism through which generation owners and LSEs offer and procure capacity credits to ensure full coverage of their PRM in the coming months. Overall, the Company supports development of these reforms and participates in MISO stakeholder processes to better understand and guide reform proposals.

That said, these are significant changes to the Company's planning processes and obligations, and it will likely take some time to understand implications, in the upcoming 2023-2024 Planning Year and beyond. With respect to the Project and the Company's resource plans more broadly, it is likely that the exact mix of resources Xcel Energy needs to serve customers in the future will change, in response to these new requirements (as well as other significant market changes such as new tax policy and commodity volatility). However, it is clear that the Company will need significant quantities of new generation, and the aforementioned reforms are expected to make the Project even more critical to achieving Xcel Energy's and the State of Minnesota's carbon goals and ensuring sufficient capacity on the system in the coming years.

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<sup>53</sup> The factors affecting availability and demand include: planned maintenance, unplanned or forced outages of generating facilities, deratings in resource capabilities, variations in weather, and load forecasting uncertainty.

- a. Annual MISO Reserve Margin Requirements Applied to the NSP System in the IRP

Historically, MISO based its PRM requirements on an annual analysis of the amount of reserve capacity required to avoid loss of load events, evaluated based on the system's summer peak. Based on the needs indicated in MISO's 2020-2021 Loss of Load Expectation Study (LOLE Study) – which Xcel Energy used to develop the Company's approved IRP – the Company calculated its effective reserve margin to be 3.46%. Below is a discussion on how Xcel Energy's reserve margin obligation (2022) was derived in the IRP.

For the 2020-21 planning year, MISO had indicated an unforced capacity (UCAP) PRM of 8.9%, and this requirement was expected to remain relatively constant at 8.8-8.9% over the full MISO planning period, to 2029. The Company determined the NSP-specific reserve margin based on this information, and the coincident peak demand factor of the Company's own peak load in relation to the MISO peak. The Company assumed this coincident factor to be 95%; meaning that NSP expects to experience load levels that are approximately 95% of the peak load during times when the total MISO system load is peaking. Considering the overall MISO PRM and the Company's own coincident peak factor together, the Company's NSP-system effective reserve margin declined from the 8.9% MISO-wide PRM to 3.46%.

**Image 4.3: MISO Planning Reserve Margin Calculation – NSP System**

**Planning Year June 1, 2021 to May 31, 2022**

$$\begin{aligned} & (95 \text{ percent coincidence factor}) \times (1 + 8.9 \text{ percent}) - 1 \\ & = 3.46 \text{ percent effective reserve margin for NSP} \end{aligned}$$

Applying the Company's effective reserve margin to the Company's annual load forecast over the planning period determined the capacity obligation the Company needed to meet in the Company's IRP. This calculation for 2022 is illustrated below.

**Table 4.1: Capacity Obligation Calculation under IRP Assumptions – 2022 Example**

Total Capacity Obligation Component	Value
Forecasted NSP Peak Load	9,101 MW
NSP Effective Reserve Margin	x (1+ 3.46%)
<b>NSP Obligation</b>	<b>= 9,416 MW</b>

b. NSP Resources Capacity Accreditation in the IRP

After the Company determined this MISO obligation level, the Company considered the types of resources suitable to meet the requirement. MISO's tariff and business practices, at the time, set forth procedures to enable various types of resources to be used to achieve the Company's RA requirements: (1) capacity resources,<sup>54</sup> (2) load modifying resources,<sup>55</sup> and (3) energy efficiency resources.<sup>56</sup>

Resource accreditation represents a measure of a resource's reliable contribution to System RA needs. A generator's operation, maintenance, and utilization directly impact the portion of nameplate capacity rating currently recognized as an accredited resource. Therefore, for a resource's expected contribution to RA, MISO has historically used UCAP rather than installed capacity (ICAP). This is a measure that estimates the amount of capacity that can be counted on to contribute to customer needs in peak hours. UCAP is calculated differently

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<sup>54</sup> Physical Generation Resources (i.e., physical assets and purchase agreements), External Resources if located outside of MISO's footprint, and DR Resources participating in MISO's energy and operating reserves market, available during emergencies.

<sup>55</sup> Behind-the-Meter Generation and DR available during emergencies, which reduces the demand for energy supplies coming from the LSE.

<sup>56</sup> Energy Efficiency Resources: Installed measures on retail customer facilities designed and tested to achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.

for dispatchable resources (e.g., nuclear, natural gas, coal), EE, and DR as compared to non-dispatchable, variable resources (e.g., wind and solar).<sup>57</sup>

The RA values for most types of resources have not historically changed significantly year over year -- in particular thermal resources that were available to run during summer peak needs. For variable resources, however, especially wind – MISO modifies its assigned RA values from time to time. In the 2020 report the Company used for the approved IRP, MISO assigned wind an Effective Load Carrying Capability (ELCC) of 16.7% for wind in Zone 1.<sup>58</sup> This means that for every 100 MW of installed wind capacity, the Company counted 16.7 MW toward the Company’s UCAP-denominated RA requirements. MISO does not, as a matter of practice, issue guidance regarding forward-looking wind ELCC values, so the Company used 16.7% across the planning period. As noted, MISO re-evaluates this value each year, but for wind the changes are generally small; for example, for the 2022-23 planning year, the value changed to 16.9%.

For solar resources, it is widely accepted within the industry and confirmed by MISO studies that, as solar capacity on the MISO grid increases, it is expected to contribute a diminishing marginal amount of RA capacity value.<sup>59</sup> In response, MISO’s Transmission Expansion Plan analysis that was most current at the time of the Company’s IRP uses solar capacity accreditation values that start at the current 50% level in 2020-2023 and decline to 30% by 2033. The Company elected to mirror this assumption in the Company’s IRP modeling.

After assessing the Company’s anticipated load and MISO requirements, the Company compares Xcel Energy system-wide obligations to the resources the Company already has – existing or approved – on the Company’s system. While this does not yet reflect the seasonal RA construct that will be in place going forward – discussed further below – the Company’s revised load and resources table shows that the result is an increased net accredited capacity deficit relative to the Company’s approved IRP.

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<sup>57</sup> See *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, MPUC Docket No. E-002/RP-19-368, 2020-2034 Upper Midwest Integrated Resource Plan, at 53.

<sup>58</sup> See MISO, *Planning Year 2020-2021 Wind & Solar Capacity Credit*, at 4 (December 2019), available at: <https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf> (last accessed Feb. 23, 2023).

<sup>59</sup> For example, DTE Energy, Indianapolis Power & Light and Dominion Virginia and the California Public Utilities Commission— among others – have all used declining solar ELCC in their resource planning modeling.

**Table 4.2: 2020-2034 System Net Accredited Capacity Surplus/Deficit Prior to Expansion Planning (MW, resource values measured in terms of UCAP)**

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Obligation with Reserves, less Existing EE	9,655	9,695	9,748	9,770	9,761	9,767	9,758	9,685	9,669	9,624	9,604
Existing Fossil Thermal	6,154	6,154	5,320	5,011	4,603	3,448	3,448	2,965	2,454	2,340	2,064
Existing Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642
Existing Large Hydro	831	831	831	0	0	0	0	0	0	0	0
Existing Renewables	1,625	1,581	1,641	1,522	1,497	1,474	1,417	1,373	1,349	1,300	1,267
Existing Demand Response	1,041	1,055	1,066	1,072	1,077	1,078	1,077	1,071	1,059	1,048	1,037
Net Surplus/(Deficit) before New Resources Added	1,637	1,567	753	(523)	(944)	(2,126)	(2,175)	(2,635)	(3,166)	(3,295)	(3,595)

- c. Changes to planning reserve margins and resource accreditation in the recently approved MISO RA construct

MISO is in the process of significantly reforming the capacity accreditation and obligation construct, with the goal of ensuring reliability as the utilities within MISO transition away from traditional baseload generation and toward a more flexible system that relies more heavily on variable renewables. In 2022, MISO submitted a proposal to change its resource adequacy construct from an annual assessment – that focuses primarily on summer peak – to a seasonal process where each load serving entity (like Xcel Energy) would have distinct reserve requirements and resource accreditation values for each season. FERC recently approved seasonal accreditation methods for thermal resources and identifying seasonal needs, and further work is being done to identify a new method of accreditation for non-thermal resources. MISO is still in the process of finalizing the accreditation values the Company will use for the upcoming planning year, as of the date of this filing. As a result, the Company has not yet fully updated the Company’s resource plan modeling to account for these changes, but they are discussed qualitatively below.

### **Accreditation approach**

First, MISO has initiated changes to the method by which thermal resources are accredited. To date, thermal resources have been accredited based on their deliverable capacity, discounted by their forced outage rate. MISO has used a rolling three-year average of the forced outage rate which tends to stay fairly stable over time for thermal resources, as a general statement.

MISO’s stated purpose in pursuing its seasonal accreditation construct was to “assure that Resources are available when needed the most by aligning Resource accreditation with availability during the highest risk hours in each Season.”<sup>60</sup> In the new construct, each resource will get a separate accreditation value for summer, fall, winter, and spring. These accreditation values will be calculated to account for the resources availability in high risk hours for each region during each season, rather than only applying a forced outage rate to the deliverable output. MISO intends this change to better account for non-summer system risks, whereas the previous annual construct planned for summer and essentially assumed

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<sup>60</sup> MISO Correspondence, at 4 (Nov. 30, 2021), available at <https://elibrary.ferc.gov/eLibrary/filedownload?fileid=5C874A8F-4C12-C0D4-AF05-7D7262000000> (last accessed Feb. 23, 2023).

that sufficient capacity would then be available for all other seasons at the system level, given MISO is summer peaking as a whole.

At this time the seasonal accreditation approach is only finalized and approved for thermal resources. Non-thermal resource – such as wind, solar, battery energy storage and load modifying resource – accreditation is still under development and is slated to be filed to FERC later in 2023 or early 2024. For the upcoming planning year, non-thermal resources will receive an accreditation value for each season, but the approach by which those values are determined will be subject to change in the future.

As of the date of this filing, MISO is still finalizing the Company's Planning Year 2023/2024 accreditation values, and thus the Company has not updated the Company's resource plan modeling in response to these changes yet. In general, the Company expects thermal resources to retain a fairly high accreditation across seasons, except for those resources that took relatively long outages or have extended start-up times in the past three years. In the future, the Company and other generation owners will likely adjust their outage schedule plans to better optimize around their individual seasonal needs.

#### **Planning reserve margin approach**

In conjunction with seasonal accreditation, MISO will also be calculating planning reserve margin requirements (PRMR) by season. As MISO has described in its FERC filing, the PRMR will still be designed to meet the typical 1-in-10 Loss of Load Expectation standard on an annual basis. However, a LOLE target of 0.01 will be used to calculate the PRM requirement for any season that does not exceed a 0.01 LOLE risk from the annual study.

The result of the first year of this calculation has produced the following seasonal PRMR values, which are applied to the Company's load forecast to determine the Company's overall obligation as described earlier in this section. Notably, the summer PRMR is actually lower than in past years. However, the PRMR in the winter and spring is substantial; this means that if the Company's need were perfectly coincident with the MISO system broadly, the Company would need to carry sufficient accredited capacity to meet its expected winter load, plus an additional 25.5% to meet its MISO requirements.

**Table 4.3: PRMR Values for Planning Year 2023-2024**

<b>Season</b>	<b>PRMR, expressed as a percent of UCAP</b>
Summer	7.4
Fall	14.9
Winter	25.5
Spring	24.5

Given these substantial changes – both those that have been adopted at FERC and ones that are yet to be proposed and accepted – the Company will need to reassess its plans in the future to determine the best mix of resources to meet its requirements. However, it is clear that incremental resources will be needed in substantial quantities as Xcel Energy continues to retire the Company’s baseload thermal generators. Xcel Energy plans to address this need with new renewable and firm dispatchable resources to serve customers’ needs, of which the resources on the Project will be an integral piece.



## V. NEED ANALYSIS

Xcel Energy conducted an engineering analysis to evaluate potential alternatives for meeting the need to deliver at least 1,996 MW of energy to Sherco, which will maximize the cost-effective delivery of energy from resources on the line to the rest of the grid. The report of that analysis is presented in this chapter rather than as an appendix. The headings and acronyms have been updated to conform to the Application format.

### A. Executive Summary

Xcel Energy plans to retire its coal-powered generators at Sherco. There are three Xcel Energy units currently in operation with a combined capacity of 1,996 MW<sup>61</sup> as shown in [Table 5.1](#):

**Table 5.1: Xcel Energy Sherco Generating Capacity**

	Unit 1	Unit 2	Unit 3
<b>Capacity</b>	720 MW	710 MW	566.4 MW
<b>Retirement Date</b>	2026	2023	2030

The Commission approved Xcel Energy's plans to retire all three units and to add significant amounts of renewable generation resources. In Xcel Energy's most recent IRP proceeding,<sup>62</sup> the Commission concluded that Xcel Energy had demonstrated that between 2027 and 2032, it will need approximately 2,150 MW more wind-powered generation and 600 MW more solar-powered generation, or an equivalent amount of energy and capacity from a combination of wind, solar and/or storage.<sup>63</sup> The Commission authorized Xcel Energy to own approximately 1,300 MW of this energy which would re-use the 1,286 MW of interconnection rights associated with Unit 1 and Unit 3. The Commission directed Xcel Energy to begin CN and route permit proceedings for 345 kV transmission facilities extending from Sherco to enable new energy resources to connect to the MISO transmission grid.

The maximum generation that could be delivered to the Sherco POI (which currently connects Sherco Units 1, 2, and 3) at any one time is 1,996 MW due to MISO requirements

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<sup>61</sup> This amount represents Xcel Energy's 59 percent ownership of Sherco Unit 3 (876 MW). Southern Minnesota Municipal Power Agency owns 393.6 MW, or 41% of Sherco Unit 3, and thus holds those interconnection rights.

<sup>62</sup> See generally, IRP Order.

<sup>63</sup> *Id.* at Ordering ¶ 2.A.8.

and limitations. The amount of generation interconnected, however, could be substantially greater (in the Company's Plan, approximately 4,000 MW) if the generation is a combination of resources, wind, solar, combustion turbine, and/or batteries because these types of resources are often complementary, not often generating at their full output at the same time. In the event the total amount of generated resources exceeded 1,996 MW, operational controls would be used to limit the amount of energy delivered to the POI to 1,996 MW.

Given the Commission's determinations regarding Sherco retirements, this study evaluates the transmission facilities needed to deliver at least 1,996 MW of energy to the Sherco POI from energy resources located in and around Lyon County, Minnesota.

This stability assessment studied the power system's ability to experience a fault or sudden change in the system without prolonged loss of synchronism. For modeling, the generation was assumed to be all wind turbine generation and 10 transmission line options and two sub-options were evaluated, as discussed in more detail in Section 5.3 of this Chapter. Wind generation was assumed in the study because it is the most likely resource in Southeastern Minnesota and because both solar and wind are inverter-based generation. Consequently, the study results could be generalized to any mix of wind and solar resources, with some variation in substation equipment depending on the final composition of resources.

The best-performing option consists of two 345 kV circuits between Lyon County and the Sherco POI. Option 9 would enable the delivery of at least 1,996 MW and up to 2,396 MW of energy to the Sherco POI (referred to as Option 9 below). The 345 kV line facilities in Option 9 could be co-located on the same structures as a double circuit 345 kV line and meet transmission system planning criteria. Option 9 was also stress-tested for a longer transmission route length of 180 miles and continued to enable the delivery of 1,996 MW at the Sherco POI. Option 9 includes a substation in Lyon County, an Intermediate Substation approximately 20 miles from the endpoint and a Voltage Support Substation at the midpoint along the line.

This study also details Xcel Energy's evaluation of alternatives to Option 9, 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.

## B. Background and Study Assumptions

The Commission approved Xcel Energy's IRP on April 15, 2022. In its IRP Order, the Commission approved Xcel Energy's acquisition of approximately 600 MW of solar and 2,150 MW of wind, or an equivalent amount of energy and capacity from a combination of wind, solar and/or storage between 2027 and 2032, which will maximize the use of the generation rights associated with Sherco using a radial gen-tie line. The scope of this study is to determine the transmission facilities needed to deliver at least 1,996 MW of new generation at the Sherco Substation POI.

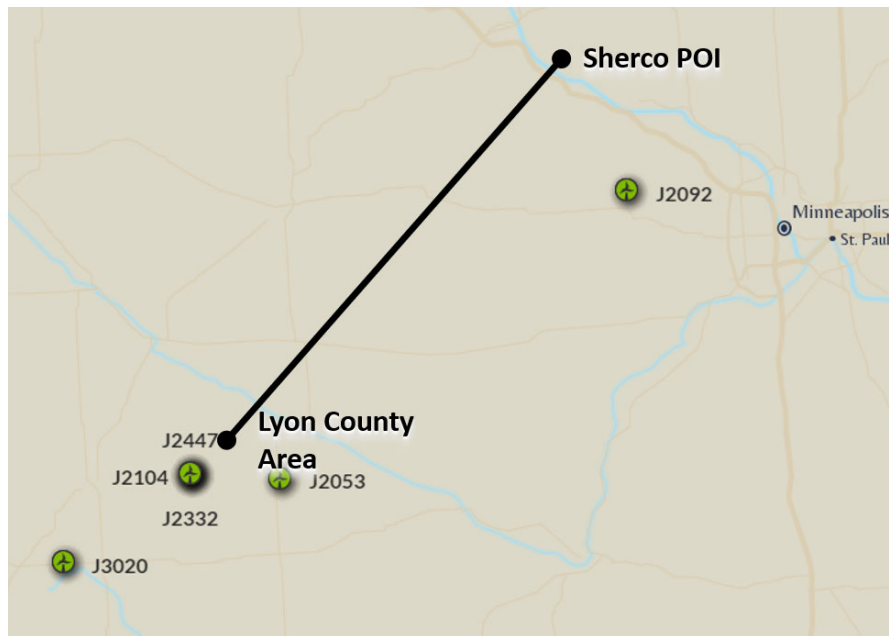
The primary assumptions underlying this analysis are summarized in the subsections that follow. Detailed modeling assumptions are described in Appendix G. Appendix G also describes the technical analyses Xcel Energy performed on the ten transmission options.

### 1. Generation Type

Wind generation was assumed to be Type 3 wind turbine models. Type 3 wind turbine models are doubly fed induction generators with the active control by a power converter connected to the rotor terminals. As a result, the amount of energy that could be transmitted by the Project would not differ based on the type of resource, *i.e.* wind or solar, because wind and solar facilities are both inverter-based. However, if the generation differed from Type 3 wind turbine models, additional equipment installations at the substations may be required. Regardless of generation type, any interconnections would require further analysis to determine any necessary substation equipment based on size, type, and location of installed generation.

### 2. Location

In the IRP, Xcel Energy proposed Lyon County as the location for the Project's endpoint. This location is proposed based on the quality of the wind resource in Southwestern Minnesota. The Lyon County west-end termination is also supported by the MISO generation interconnection queue. [Image 5.1](#) shows the location of approximately 1,300 MW of wind generation in the MISO Queue seeking interconnection to the transmission system as of October 2022.

**Image 5.1: MISO Interconnection Requests**

Further support for the endpoint derives from the RFI Xcel Energy conducted in June 2022 regarding wind and solar generation within and near Lyon County. The responses to the RFI confirmed the significant interest in renewable development and appropriateness of a Lyon County endpoint -- more than 5,000 MW of potential capacity was identified in the area. A Request for Proposal process will be used to further identify and procure more specific energy resources.

### 3. MISO Replacement Generation Process Requirements

The MISO Business Practice Manual (BPM) establishes requirements for interconnecting replacement generation through the MISO Generation Queue. All transmission and generation connections must comply with BPM-015. Within MISO BPM-015, replacement generation is covered under Section 6.7.2, Generating Facility Replacement Process. The key requirements are:

- The reliability of the transmission system with the replacement generation must be comparable with the reliability of the transmission system with existing generation. This is analyzed through a Replacement Impact Study and is completed by MISO.

- The transmission system must be reliable during the time between the date that the existing generation facility ceases commercial operations and the commercial operation date of the replacement generation facility. This is analyzed through a Reliability Assessment Study and is completed by MISO.
- Steady-state performance (voltage and thermal) must be comparable to the existing system.
- Reactive power performance at POI must be comparable to the existing system.
- System stability (stability analysis) must be comparable to the existing system.

Based on the requirements laid out in MISO BPM-015, system stability is a critical factor to maintain when replacing a firm dispatchable resource like coal-powered generation with an intermittent, non-dispatchable generation resource such as wind and solar. This stability assessment studied the power system's ability to experience a fault or sudden change in the system without prolonged loss of synchronism.

#### 4. Sherco Retirement, Unit 1 and Unit 2 and Conversion to Synchronous Condensers

Sherco Unit 1 and Unit 2 are expected to be converted to synchronous condensers when retired. Previous steady state studies have shown the need for 300 megavolt ampere reactive power (MVAR) in the Sherco area to maintain steady state voltages at Monticello Nuclear Power Plant within permissible voltage requirements. Synchronous condensers at Sherco fulfill the steady state voltage needs in the area and provide robust system stability in a critical area of the transmission system. The transmission system has been built around having robust system stability support at Sherco and converting the existing units will help ensure compliance with the requirements laid out above in MISO BPM-015, will provide similar required reactive performance to the existing generation units, and are important to system stability.

Conversions of Sherco Unit 1 and Unit 2 to synchronous condensers are included in every evaluated option. If Sherco Unit 3 were also converted to a synchronous condenser, it would strengthen the system stability further and provide redundancy to the results in this study for loss of one Sherco synchronous condenser for maintenance or outage.

## 5. Modeling Assumptions and Technical Analyses

Detailed modeling assumptions are described in Appendix G. Appendix G also describes the technical analyses Xcel Energy performed on the ten transmission options.

### C. Transmission Options

#### 1. Description

The transmission solutions analyzed in this study were designed to keep the system stable while transferring the maximum amount of energy on the radial line. All options assume line length of 140 to 180 miles and include an intermediate substation near Lyon County with 200 MW interconnected and a Terminal Substation in Lyon County approximately 20 miles away with the rest of the interconnected generation, with total interconnected generation levels (delivered) ranging from 663 MW to 2,396 MW.

Nine 345 kV options and one 500 kV option were evaluated for this study. The options include line compensation and line bifurcation. Synchronous condensers were analyzed to optimize performance. Series compensation to decrease overall line impedance was explored and was similar in performance to bifurcation<sup>64</sup> of two circuits at lower cost. The options with series compensation, Options 2, 3, 7, 8, 9, 9a, 9b, and 10, include a substation at the transmission halfway point to house the compensation equipment. The addition of inverter-based generation such as wind and solar does not have the inertia and fast responding reactive power capabilities historically provided by synchronous generators, such as a combustion turbine. In the event of a fault, fast responding dynamic reactive power support (synchronous condensers or static compensators) quickly provide reactive power to stabilize the voltage. The inertia (physical or synthetic) provided by these devices helps to dampen power oscillations that can cause load and generation to trip, leading to potential cascading.

The ten options and two sub-options are described below:

- Option 1: One 345 kV line without series compensation.
- Option 2: One 345 kV line compensated to 51% of its impedance.
- Option 3: One 345 kV line, the longest section of line compensated to 51% of its impedance, and two synchronous condensers at the Terminal Substation.

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<sup>64</sup> Bifurcation is when two circuits on common structures are connected at both ends of the line to act as a single circuit.

- Option 4: Two 345 kV lines, bifurcated at the substation to act electrically like a single line at the substations, without line compensation.
- Option 5: Two 345 kV lines, bifurcated at the substation to act electrically like a single line at the substations, without line compensation, and two synchronous condensers at the Terminal Substation.
- Option 6: Two 345 kV lines, without compensation.
- Option 7: Two 345 kV lines, with the longest line sections compensated to 51% of impedance.
- Option 8: Two 345 kV lines, with the longest portion of both lines compensated to 51% of impedance, and two synchronous condensers at the Terminal Substation connected to one line.
- Option 9: Two 345 kV lines, with the longest portion of both lines compensated to 51% of impedance, and one synchronous condenser at the Terminal Substation connected to each line.
- Option 9a: Two 345 kV lines, with the longest portion of both lines compensated to 20% of impedance, one 150 MVAR STATCOM located in the middle of the longest line section of each line, and one synchronous condenser at the Terminal Substation connected to each line.
- Option 9b: Two 345 kV lines, two 175 MVAR STATCOMs located in the middle of the longest line section of each line, and one synchronous condenser at the Terminal Substation connected to each line.
- Option 10: One 500 kV line, the longest section of line compensated to 51% of its impedance, and two synchronous condensers at the Terminal Substation.

Voltage support was included in Options 3, 5, 8, 9, 9a, 9b, and 10. Voltage support can be provided by standalone synchronous condensers, combustion turbines or battery storage units.<sup>65</sup> For these options, standalone synchronous condensers at the Terminal Substation in

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<sup>65</sup> As initially proposed in the Alternate Plan in the IRP, two transmission lines and a 400 MW combustion turbines in Lyon County would be constructed. Xcel Energy's need for capacity resources of 800 MW was deferred and will be the subject of separate Certificate of Need proceedings. The combustion turbine would have been able to provide

Lyon County were included as part of each option. The inclusion of synchronous condensers at the Terminal Substation end of the proposed project provides the dynamic reactive power support to allow for an additional 300 to 400 MW of inverter-based generation for each line, for a total of 600 to 800 MW.

In the IRP, the Commission found that it was more likely than not there will be a need for approximately 800 MW of generic firm dispatchable resources between 2027 and 2029. The Commission will be evaluating the need for the 800 MW resources in a separate proceeding. Should the Company propose, and the Commission approve, a combustion turbine or battery storage units in the vicinity of the Project Terminal Substation to meet a portion of this need, it is possible such resource could provide the required stability support and obviate the need for synchronous condensers in Lyon County to support the new double circuit 345 kV line.<sup>66</sup> Xcel Energy will conduct the appropriate assessment when the firm dispatchable resources are better known.

## 2. Summary of Results

All options were able to interconnect at least 700 MW of wind energy. In the case of all alternatives, system losses equal the losses on the transmission lines because the lines will be radial lines between Lyon County and the Sherco POI. The options delivered from 663 MW to 2,396 MW to the Sherco POI. Options 1-5, which were single circuit options, did not provide enough capacity to meet the identified need; of these options, the best performing option, Option 5, would interconnect only 1,500 MW. Similarly, Options 6, 7, and 10 also did not meet the identified need because they would not deliver at least 1,996 MW of energy to the POI.

Options 8, 9, 9a, and 9b meet the identified need of delivering at least 1,996 MW of energy to the POI. The major differences between these options are the type and size of voltage support located at the middle of the line and how the synchronous condensers are attached to each line, however the backbone transmission line is the same. Options 9 and 9a have the potential to deliver more energy than Option 8 and differ only in the way the synchronous condensers are connected, either to one of the lines (Option 8) or one synchronous condenser on each line (Option 9).

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energy resources and dynamic reactive power needed for voltage support, minimizing the need for large scale voltage support devices. In the absence of the combustion turbine, other facilities were identified in this study to provide the voltage support necessary for two transmission lines to function at the studied megawatt levels.

<sup>66</sup> The estimated costs for synchronous condensers at the Terminal Substation is \$140 million (2023\$).



Option 9 would enable the interconnection of at least 2,200 MW and up to 2,600 MW of nameplate capacity resources, providing at least 1,996 MW and up to 2,396 MW of generation at the Sherco POI, after accounting for losses. The analysis confirmed that the two lines could be built on a single tower and meet NERC TPL-001 criteria. Two voltage support alternatives were analyzed as part of Option 9, Option 9a and 9b, which both achieved 1,996 MW at the POI. These alternatives could be utilized if turbine type, size, and location cause the need for series compensation to be decreased to achieve necessary system performance. These two options include a combination of low levels of series compensation and STATCOMs to achieve a minimum of 1,996 MW at the Sherco POI.

Table 5.2 below, summarizes the performance of all 10 options and two sub-options.

**Table 5.2: Summary of Results**

Option	Voltage	Lines	Bifurcated	Line 1					Line 2					Total Wind Nameplate Gen (MW)	Line Losses (MW)	Total POI Gen (MW)
				Line Comp	STATCOM Size (MVAR)	Intermediate Sub (MW)	Terminal Sub (MW)	Terminal Sub Synchron Cond.	Line Comp	STATCOM Size (MVAR)	Intermediate Sub (MW)	Terminal Sub (MW)	Terminal Sub Synchron Cond.			
1	345	1	---	---	---	200	500	---	---	---	---	---	---	700	37	663
2	345	1	---	49%	---	200	900	---	---	---	---	---	---	1100	74	1026
3	345	1	---	49%	---	200	1200	2	---	---	---	---	---	1400	118	1282
4	345	2	Y	---	---	200	1000	---	---	---	---	---	---	1200	59	1141
5	345	2	Y	---	---	200	1400	2	---	---	---	---	---	1600	100	1500
6	345	2	---	---	---	200	400	---	---	---	200	400	---	1200	58	1142
7	345	2	---	49%	---	200	700	---	49%	---	200	700	---	1800	107	1693
8	345	2	---	49%	---	200	1200	2	49%	---	200	700	---	2300	172	2128
9	345	2	---	49%	---	200	1100	1	49%	---	200	1100	1	2600	204	2396
9a	345	2	---	20%	1x150	200	1000	1	20%	1x150	200	1000	1	2400	218	2182
9b	345	2	---	---	2x175	200	900	1	---	2x175	200	900	1	2200	173	2027
10	500	1	---	49%	---	200	1700	2	---	---	---	---	---	1900	137	1763

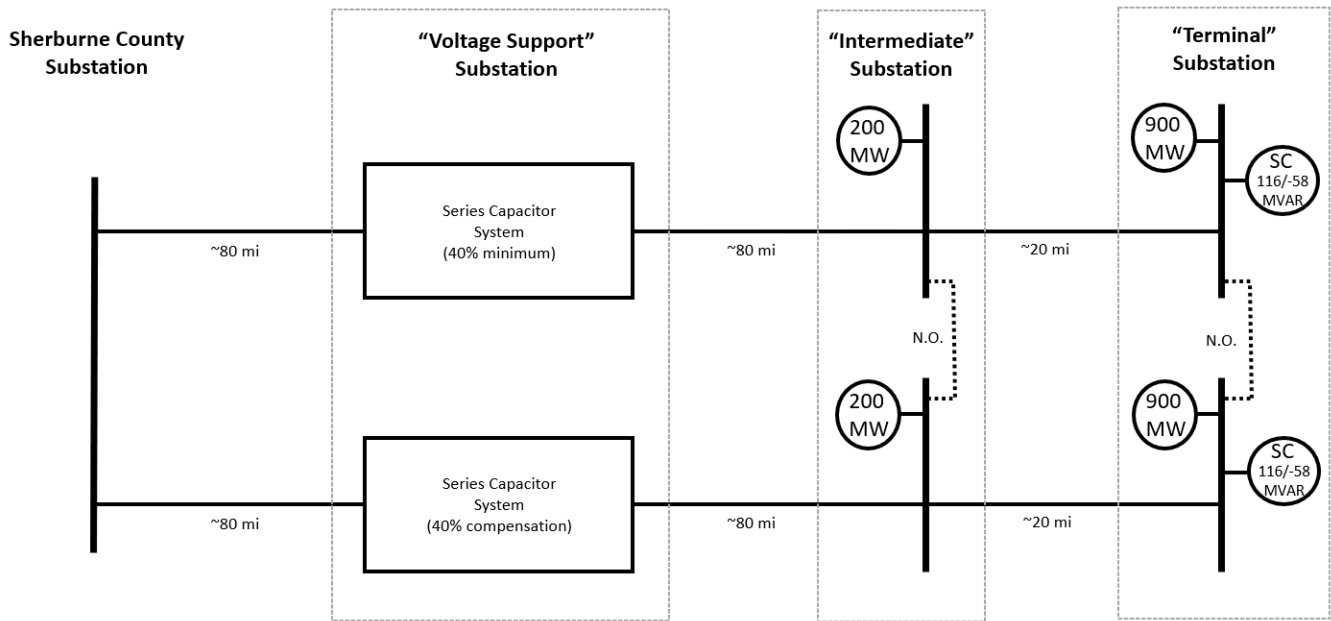
### 3. Voltage Support Alternatives

The need for voltage support in Options 3, 5, 8, 9, 9a, 9b, and 10 is due to the long length of the lines and the amount of generation that will be connected. The ultimate design of the voltage support system will be dependent on the electrical characteristics of the generators that interconnect to the transmission lines as well as technologies available to provide that voltage support. It is difficult to precisely predict what facilities may be required to ensure efficient and effective connections to the grid given these uncertainties. Wind generation in particular has experienced rapid technological and size changes. For example, in Minnesota, the commercial turbine sizes have increased from 3 MW to over 6 MW over the past several years.

Specifically for Option 9, it and two sub-options were identified using different voltage support technologies assuming a line length of 180 miles and a minimum of 1,996 MW of generation at the Sherco POI. The sub-options were developed as examples of technologies that could address potential issues with using high levels of series compensation. The options involve combinations of lower series compensation and STATCOMs, which will require additional future analysis based on actual generation size, type, and location. The level of compensation and size of STATCOMs identified are indicative of the required voltage support based on the generation assumptions in the study. The three voltage support combinations evaluated are [1] series compensation, [2] series compensation with two STATCOMs, and [3] four STATCOMs.

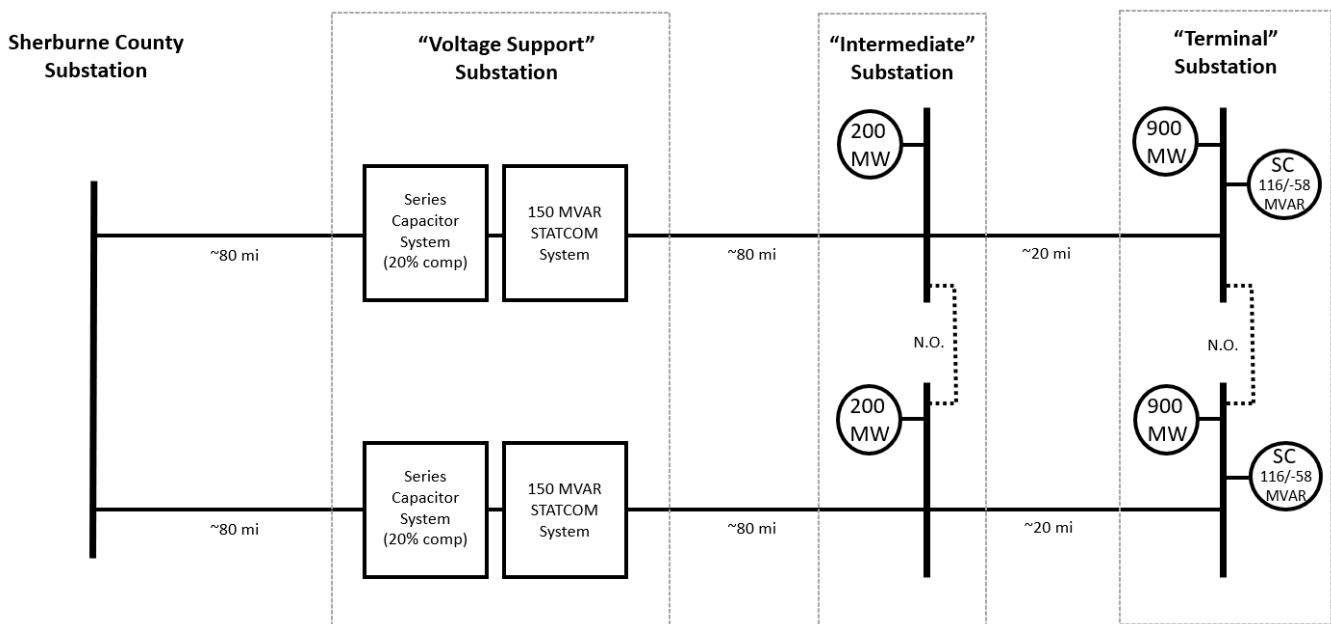
High levels of series compensation on long radial lines have known potential Sub-Synchronous Resonance (SSR) and Sub-Synchronous Controller Interaction (SSCI) issues with current wind turbine technologies. However, future wind turbines are expected to use technology which may eliminate potential SSCI and SSR issues. Option 9 was studied with 49% series compensation in the main study, which enables 2,400 MW at the POI, and requires a minimum of 40% compensation to achieve 1,996 MW at the POI. Image 5.2 below shows a simple diagram of Option 9 as listed above.

Image 5.2: Option 9



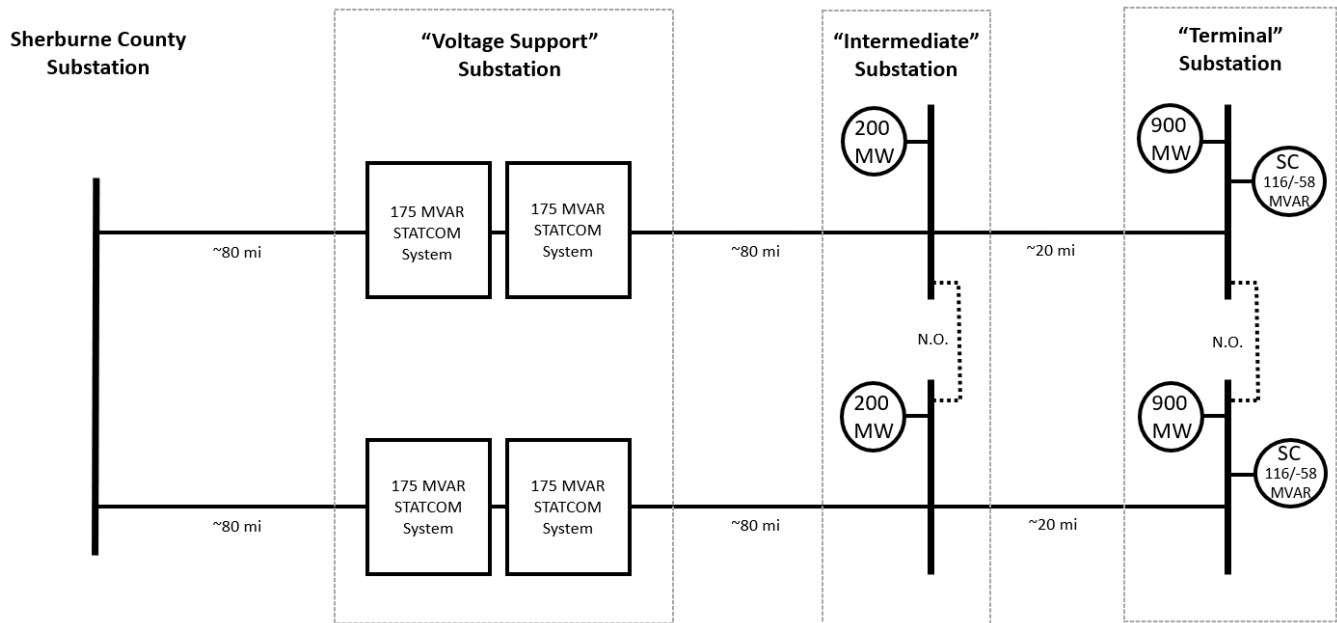
Combining lower levels of series compensation with STATCOMs was shown to mitigate SSR and SSCI issues in initial studies. Series compensation is a lower cost technology than STATCOMs and therefore was studied at multiple levels to minimize overall cost. Each line compensated to 20% required one 150 MVAR STATCOM per line to achieve 1,996 MW at the Sherco POI. Further tuning the STATCOM could allow it to be decreased to 125 MVAR but would require additional studies based on actual generation type, size, and location. Image 5.3 below shows a simple diagram of Option 9a as listed above for 20% series compensation.

Image 5.3: Option 9a



Using only STATCOMs was the most costly option studied but mitigates any potential concerns with SSR and SSCI issues. Utilizing two 175 MVAR STATCOMs per line allowed 1,996 MW at the Sherco POI. Image 5.4 below shows a simple diagram Option 9b as studied.

**Image 5.4: Option 9b**



4. Costs

The four 345 kV/345 kV options that would enable at least 1,996 MWs are 8, 9, 9a and 9b. For purposes of comparing costs of these options, engineers calculated indicative capital costs in (2023\$) (exclusive of AFUDC and contingencies). Options 8 and 9 were estimated at \$840 million. Option 9a was \$930 million and 9B was \$970 million.

## 5. Phased Construction

The construction of Option 9a could occur in multiple ways due to system conditions based on actual generation size, type, and location. One example buildout is shown below in [Table 5.3](#). In this example, Option 9a with two lines with 20% series compensation provides 1,000 MW of installed capacity. The synchronous condensers at the Terminal Substation and the STATCOMs at the Voltage Support substation would each add 600 MW of interconnection capacity for 2,200 MW. For example:

**Table 5.3: Option 9a Buildout**

Facility	Capacity Achieved	Total Capacity
Two 345 kV lines with 20% series compensation	1,000 MW	1,000 MW
+ Synchronous condensers	600 MW	1,600 MW
+ STATCOM	600 MW	2,200 MW

The attributes provided by STATCOMs can also be provided by solar generators. Using solar generators as STATCOMs is achieved by powering the inverters from the grid and utilizing the unused inverter capacity to provide the grid with reactive support, very similar to a traditional STATCOM. The general rule for sizing solar farms as STATCOMs and the potential output characteristics is 60% of the installed inverter capacity would be available for STATCOM operation. For example, a 150 MVAR STATCOM could be replaced with a 250 MW solar farm with STATCOM capabilities.

Other solutions may become available as technology changes and additional study work is completed based on actual generation size, type, and locations. Any technology with similar performance to the three options above is expected to achieve similar generation levels at the Sherco POI. The current resource acquisition process anticipates that the contracts will be in place in the mid-2020s.

### D. Stability Analysis

All faults studied were stable for all 10 options and 2 sub-options at the generation levels listed in this study. Higher generation levels resulted in system instability. Details of this analysis are included in Appendix G.

## E. Steady State Analysis

All NERC TPL-001-4 analysis steady state results were within Xcel Energy Planning Criteria. The transient stability analysis was the limited factor.

## F. Other Transmission and Non-Transmission Alternatives

Minnesota CN statutes and rules require analyses of transmission and non-transmission alternatives. This section summarizes Xcel Energy's analysis of: (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 DSM). None of these alternatives is a more feasible and prudent alternative to Option 9 for the reasons set forth below.

### 1. New Generation of Various Technologies, Sizes, and Fuel Types

The identified need is to interconnect new generation to the Sherco POI. Consequently, on its own, new generation, regardless of the technology, size, or fuel type, would not meet the need.

### 2. Upgrading Existing Transmission Lines or Existing Generating Facilities

As noted, the need is to transmit new energy resources and, therefore, upgrading existing generating facilities will not meet the identified need.

Existing transmission lines are insufficient to transmit the new energy resources on the timeline on which they are needed. Xcel Energy has discussed MISO queue congestion issues at length in other recent filings and, as previously noted, existing transmission capacity continues to be constrained in this region and beyond, requiring high, often prohibitive, estimated upgrade costs to bring new projects online.<sup>67</sup> The DOC-DER has reached similar conclusions regarding the lack of available, existing transmission capacity to interconnect new renewable generation.<sup>68</sup>

Further, to be able to utilize existing transmission interconnection rights at the Sherco POI, the proposed connection must be a radial connection per the MISO FERC Electric Tariff,

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<sup>67</sup> See, e.g., Xcel Energy Reply Comments, MPUC Docket No. E-002/RP-19-368, at 147 (June 25, 2021).

<sup>68</sup> See DOC-DER Comments, MPUC Docket No. E002/RP-19-368, at 41-44 (Feb. 11, 2021).

Attachment X. Existing transmission lines are not radial. Therefore, upgrading existing transmission lines cannot meet the identified need.

### 3. Different Voltages

To deliver 1,996 MW of energy to the Sherco POI, the transmission facilities must be capable of transferring the entirety of the needed energy on one or two lines utilizing a minimum of 3,000 amp substation equipment. The necessary capacity at 3,000 amps can only be provided by voltages of 230 kV and higher. Therefore, Xcel Energy determined that lower voltage 69 kV and 115 kV facilities would not meet the need.

Xcel Energy also evaluated and screened a 230 kV option because it would have to operate at thermal operating limits to meet the required capacity at 3,000 amps with two lines. Losses on a 230 kV option would be more than double a comparable 345 kV option and would result in an unstable system with the required generation at a distance like Sherco to Lyon County due to the line impedance. The impedance of a 230 kV line is greater than a 345 kV line — a 230 kV single circuit line has 225% higher impedance than a single circuit 345 kV line when using the same conductor. Additionally, 230 kV lines would require four 230 kV/345 kV transformers to convert the voltage to 345 kV for the interconnection to the Sherco POI.

For higher voltages, Xcel Energy analyzed a single circuit 500 kV line option, Option 10. The analysis showed that while a single circuit 500 kV line could transfer a large amount of power, it did not perform as well as the 345 kV/345 kV Option 9 option. The single circuit 500 kV would transfer up to approximately 1,900 MW before the system would become unstable. The 500 kV option would also be more costly. For comparison, a single circuit 500 kV line would generally cost approximately \$4.1 million per mile and require four 500 kV/345 kV transformers at Sherco (costing an additional \$75 million). A double circuit 500 kV line would be able to carry equal to or more energy than Option 9, but would cost approximately \$4.5 million to \$5 million per mile. In contrast, the indicative cost for a 345 kV/345 kV line is approximately \$3.5 million per mile. The 500 kV option was also determined not to be the preferred option for the following reasons:

- Using 3,000-amp substation equipment, the thermal rating of a double circuit 345 kV line (3,581 megavolt amperes (MVA)) is higher than a single circuit 500 kV line (2,595 MVA).
- Using the same conductor, the impedance of a double circuit 345 kV line, i.e., the losses, is only 5% higher than a single circuit 500 kV line.



- Although there are two 500 kV facilities present in Minnesota, neither is located in southwest Minnesota.

A higher voltage, 765 kV, was screened from consideration because they do not exist in Minnesota and because a single circuit 765 kV line costs far more than a double circuit 345 kV line.

#### 4. Conductor

All transmission options studied utilized 345 kV lines and utilized single circuit bundled (x2) twisted pair Grosbeak 636 ACSR conductor. This conductor is a large capacity, low impedance conductor and represents a good baseline conductor for analysis. So long as the final conductor selected has similar impedance characteristics, it will achieve similar system performance.

#### 5. Transmission Lines with Different Terminals or Substations

The Project must connect at the Sherco Substation for it to be considered Replacement Generation under the MISO Tariff. Recognizing that this termination point is fixed, the Commission granted an exemption to this Application content requirement.<sup>69</sup>

On the west end, both lines perform best when each is connected to a synchronous condenser at the terminal substation in Lyon County. Locating the synchronous condensers at a common location could provide potential redundancy if one line experiences an outage and the other is still in service. The intermediate substation is also proposed to be located in or near Lyon County, approximately 20 miles from the terminal substation. The final location of the substations and route will be informed by the RFI and RFPs issued by Xcel Energy to developers for generation resources.<sup>70</sup>

#### 6. Double Circuiting of Existing Transmission Lines/Double Circuiting Project

Double circuiting with an existing line is not a feasible alternative because two 345 kV circuits are required to meet the identified need; thus, circuiting the Project with an existing line would result in triple-circuiting. Triple circuiting for short sections would not reduce the performance of Option 9 from a planning perspective and may be technically feasible, but there are operational concerns. Triple circuit structures are taller than double circuit

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<sup>69</sup> See Order (June 28, 2022).

<sup>70</sup> See Xcel Energy, 2022 Request for Information, available at <https://mn.my.xcelenergy.com/s/renewable/developers/2022-rfi> (last accessed Feb. 23, 2023).

structures and require atypical maintenance techniques which present increased safety concerns. Generally, all three lines must be taken out of service to work on any single line.

Xcel Energy assessed whether Option 9 and its suboptions, could be constructed with both circuits co-located on the same structures. Planning analyses confirmed that the double circuit configuration performed adequately. The transmission system ultimately returned to a stable condition after loss of both circuits connecting 2,200 MW of generation near Lyon County and netting approximately 1,996 MW of generation at the Sherco POI.

### 7. DC Line

A high voltage direct current (HVDC) transmission line is generally employed to deliver generation over a considerable distance, more than 300 miles, to a load center. HVDC systems typically do not allow for cost-effective interconnections along the line. The two dominant types of HVDC generally considered for transferring large amounts of power are Line Commutated Converter (LCC) and Voltage Source Converter (VSC). The technologies have different performance benefits and would require a converter station on each end of the line to convert the voltage from AC to DC and DC to AC. There are also extended lead times (6 plus years) for HVDC systems.

Assuming the shorter route length of 165 miles, Xcel Energy estimates the cost (2023\$) of a 2,000-2,400 MW HVDC line to be in the range of \$1.4B-\$1.7B (2023\$ including AFUDC and engineering design).

### 8. Underground

Underground transmission, both AC and HVDC, was evaluated and determined not to be a feasible or reasonable alternative. High voltage AC underground cable systems at 345 kV are generally limited in length to approximately 50 miles because of the rate at which cables consume reactive power. While longer installations can be constructed with the addition of shunt reactors along the line, this is an atypical design and practical applications of underground AC lines for more than 50 miles are technically infeasible.

HVDC cable systems are used for underground lines of 100 miles or more. HVDC systems do not have the same reactive power limitations and line losses in HVDC cables are approximately half that of HVAC cables when using comparable conductor. HVDC cable systems require converter stations on each end of the line to convert the voltage from DC to AC and AC to DC. Because of the need for conversion from overhead to underground and conversion of voltage through converter stations, HVDC lines do not accommodate interconnections at midpoints along the lines.

Both underground AC and DC designs are infeasible due to costs. Xcel Energy indicative estimates for underground HVDC over 100 miles are \$25 million or more per mile, depending on the ultimate design. As with any HVDC option, the costs of two converter stations would be approximately \$540 million to \$700 million. Construction costs for AC underground transmission are anticipated to be similar.

#### 9. Conservation and Demand-Side Management

The Project is needed to interconnect generation resources that will replace the capacity and energy of Sherco Units 1 and 3 and are required to both utilize existing interconnection rights and maximize the Sherco interconnection. Consequently, conservation and demand-side management cannot meet the need. The Commission recognized that conservation and demand-side management cannot meet the need and granted Xcel Energy an exemption from this content requirement. The Commission in its June 28, 2022 Exemption Order agreed that Xcel Energy could present a summary of the conservation information in the IRP and Conservation Improvement Program filings rather than replicate the data in the instant docket. Xcel Energy has provided alternative data in Appendix E.

#### 10. Consequence of Delay/No Build

To retain interconnection rights for Sherco Unit 1 and Unit 3, based on the current retirement dates of Sherco Unit 1 (2026) and Unit 3 (2030), the transmission lines must be in-service by the end of 2029. Based on this schedule, if the Project were delayed beyond the in-service date at the end of 2029, or if new 345 kV lines are not constructed to deliver at least 1,300 MW of energy to the Sherco POI, Xcel Energy may lose its valuable interconnection rights under the MISO Tariff. In addition, if the lines are not constructed as proposed, Xcel Energy will not be able to acquire and deliver the 2,150 MW of wind or 600 MW of solar as the Commission directed Xcel Energy to do in its IRP Order.

#### 11. Any Reasonable Combination of Alternatives

Because the only feasible alternatives to meet the identified need are transmission lines, there is no reasonable combination of the alternatives that could result in an alternative approach to the development, construction, and operation of the proposed Option 9a, the Preferred option.

### **G. Conclusion and Recommendations**

The analysis of ten transmission options and two sub-options demonstrates that all options are technically feasible. All options include a terminal substation in Lyon County and 200

MW of generation assumed at an intermediate substation 20 miles away. Options with voltage support along the line included a substation at approximately the midpoint of the lines. The analysis showed the system is stable at the generation levels listed in Table 5.2 under all critical regional faults and could reliably operate under the assumptions in this report.

The analysis further showed that a single circuit 345 kV configuration, by itself, could provide up to 1,282 MW of delivered energy to the Sherco POI, depending on ultimate line length. This is 18 MW less than the amount of generation Xcel Energy must own and connect to preserve its interconnection rights for Sherco Unit 1 and Sherco Unit 3.

To interconnect at least 1,996, two 345 kV transmission lines are required using Options 8, 9, 9a or 9b with two synchronous condensers and a voltage support substation located in the mid-point of the line. Option 9a and 9b are preferred over Option 8 and Option 9 because they include STATCOMs to address potential turbine interaction issues that may occur due to the amount of anticipated wind generation, the high levels of series compensation and radial nature of the Project. Based on current wind turbine technology, STATCOMs are a recognized means of providing the necessary support to mitigate potential wind turbine resonant frequency interactions associated with long radial lines. The selection of Option 9a is a conservative approach to ensure that the Project includes components to address this potential issue.

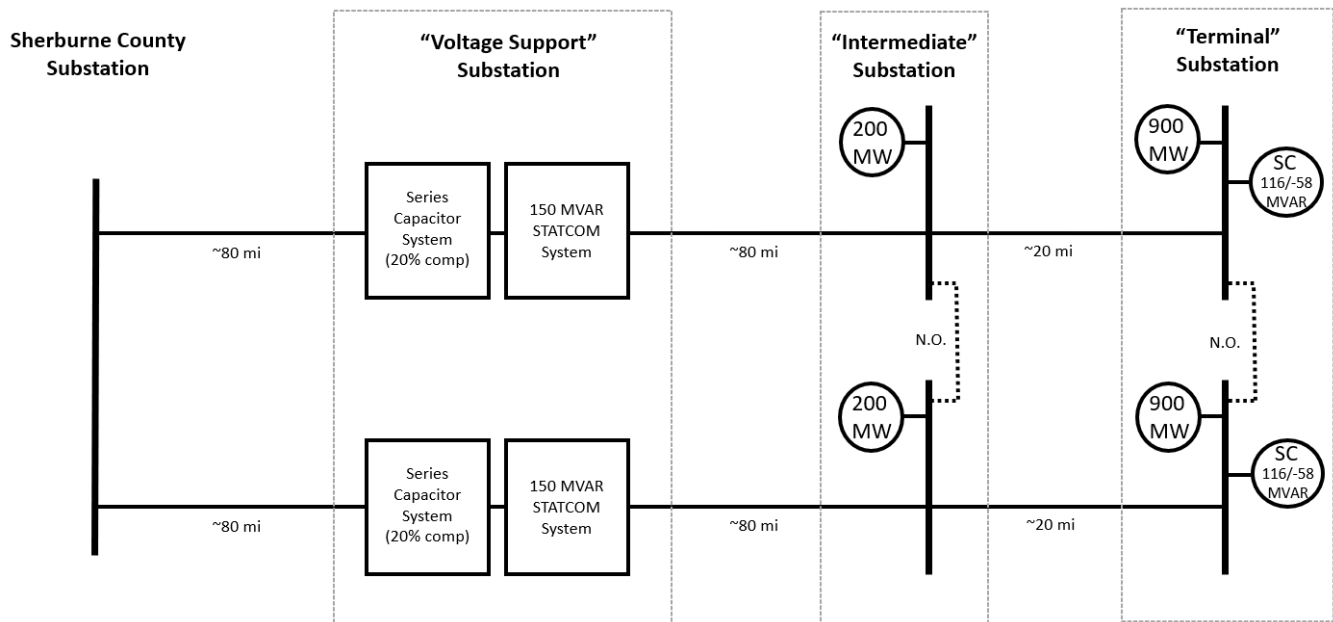
As between Option 9a and Option 9b, Option 9a provides more interconnection capacity (2,182 MW v. 2,027 MW) for lower cost. Because Option 9a provides more MWs of capacity, it is the preferred option. Option 9a would consist of the following facilities:

- A Voltage Support Substation located halfway between the Intermediate Substation and Sherco (approximately 70-80 miles from the Sherco POI). This substation includes series compensation and one STATCOM for each line.
- An Intermediate Substation located in or near Lyon County and located approximately 140 to 160 miles from Sherco. This substation would be configured as a breaker and a half substation with bus breakers to keep electrical separation of the two circuits. The substation would be capable of expansion as wind interconnections occur in the future. This substation was studied with 200 MW of generation on each line, 400 MW total connected to the substation.
- A Terminal Substation located in Lyon County and located approximately 160-180 miles from Sherco. This substation would be configured as a breaker and a

half substation with bus breakers to keep electrical separation of the two circuits. The substation would be capable of expansion as wind interconnections occur in the future. In Option 9, this substation included two synchronous condensers (one for each line) and up to 2,000 MW of generation (1,000 MW on each line).

Image 5.5 shows an illustrative map of the facilities required for Option 9a.

**Image 5.5: Recommended Option, Option 9a**



Additional substation facilities may be required depending on the final generation locations, size, and specific available inverter types are known to determine the final design of the Project. When these variables are known, additional study work will be conducted, including SSR and SSCI studies, to assess the need for an such additional substation facilities.

## VI. TRANSMISSION LINE OPERATING CHARACTERISTICS

### A. 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.

### B. Ozone and Nitrogen Oxide Emissions, Sulfur Hexafluoride

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<sub>x</sub>). 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. The ozone created by the Project will be below these standards.

The national standard for nitrogen dioxide (NO<sub>2</sub>), 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<sub>2</sub>. 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.

Sulfur hexafluoride (SF<sub>6</sub>) will be used at the substation(s). Small releases will occur as part of regular breaker operation and maintenance. Xcel Energy will minimize sulfur hexafluoride emissions through operational best management practices (BMPs) and will monitor equipment for leaks. Xcel Energy will comply with Environmental Protection Agency reporting requirements in the event a leak is detected.

## C. Noise

### 1. Transmission Line Noise

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

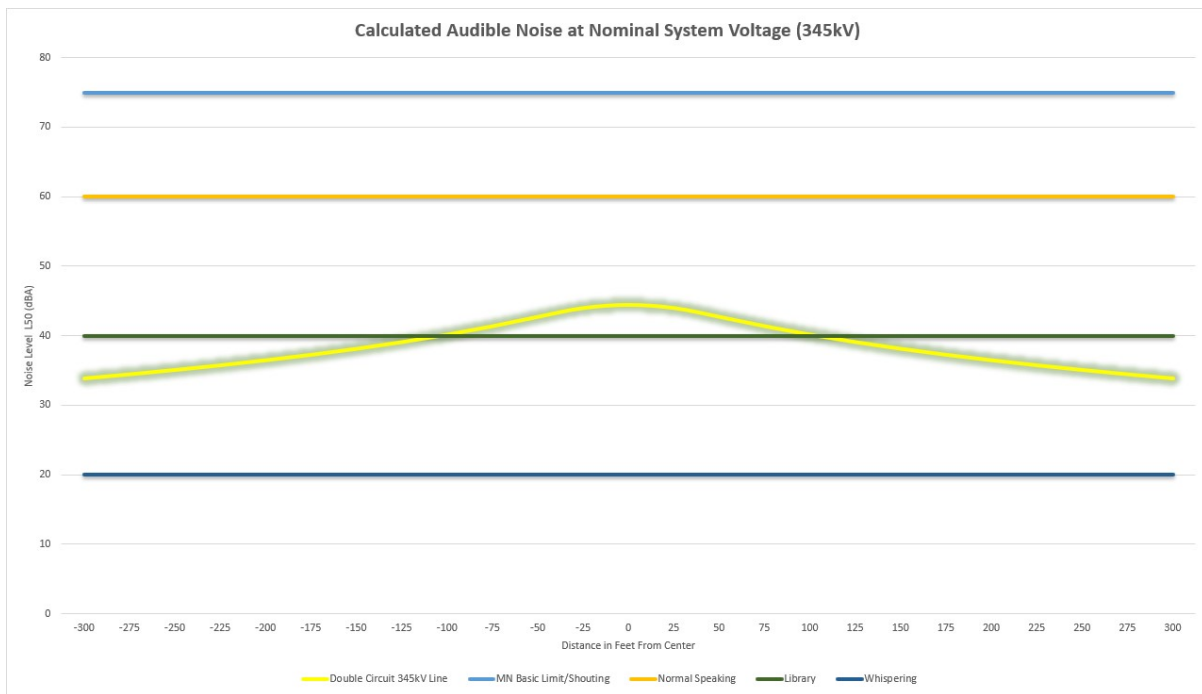
Transmission conductors can produce noise under certain conditions. The level of noise depends on conductor conditions, voltage level, and weather conditions. Noise emission from a transmission line occurs during certain weather conditions. In foggy, damp, or rainy weather, power lines can create a crackling 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.

The Project will comply with Minn. R. Ch. 7030, which are rules established by the Minnesota Pollution Control Agency (MPCA) which set forth standards for three noise area classifications (NAC).

- NAC 1 includes residential housing, religious activities, camping and picnicking areas, health services, hotels, educational services.
- NAC 2 includes retail, business and government services, recreational activities, transit passenger terminals.
- NAC 3 includes manufacturing, fairgrounds and amusement parks, agricultural and forestry activities.

Xcel Energy anticipates that NAC 3 is likely to apply to the large majority of the Project. NAC 3 has a daytime L50 limit of 75 dBA and a nighttime L50 limit of 75 dBA. As shown in [Image 6.1](#), the proposed 345 kV lines will be below Minnesota limits:

**Image 6.1: Noise Chart**



## 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. Typical substation design is such that noise produced by these sources does not reach beyond the substation property, in the rare cases that space is limited such that it cannot be accomplished, noise reduction designs are applied such as sound walls placed around transformers to reduce the distance the sound can travel. Like the transmission lines themselves, Project substations will comply with the MPCA noise standards as set forth in Minn. R. 7030.0040.

### D. 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.<sup>71</sup> 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, Applicant will take necessary action to restore reception to the present level, including the appropriate modification of receiving antenna systems if deemed necessary.

## **E. 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

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<sup>71</sup> Full power television stations were required by the DTV Delay Act, Public Law No: 111-4, to cease broadcasting signals by June 12, 2009.

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.

GPS interference is also not anticipated. Applicant uses GPS-based survey equipment directly under transmission lines and has not experienced any problems.

## F. Electric and Magnetic Fields

“EMF” is an acronym for the phrases 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 milliGauss (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).

### 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.<sup>72</sup> The standard was designed to prevent serious hazards from shocks when touching large objects parked under AC transmission lines of 500 kV or greater. Image 6.2 provides the electric fields at maximum conductor voltage for the proposed 345 kV transmission lines. 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 Image 6.2, the strength of electric fields diminishes rapidly as the distance from the conductor increases. The electric field values of

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<sup>72</sup> *In the Matter of the Route Permit Application for a 345 kV Transmission Line from Brookings County, S.D. to Hampton, Minn.*, MPUC 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).

all of the design options at the edge of the transmission line right-of-way and sample points beyond are shown in Table 6.1.<sup>73</sup>

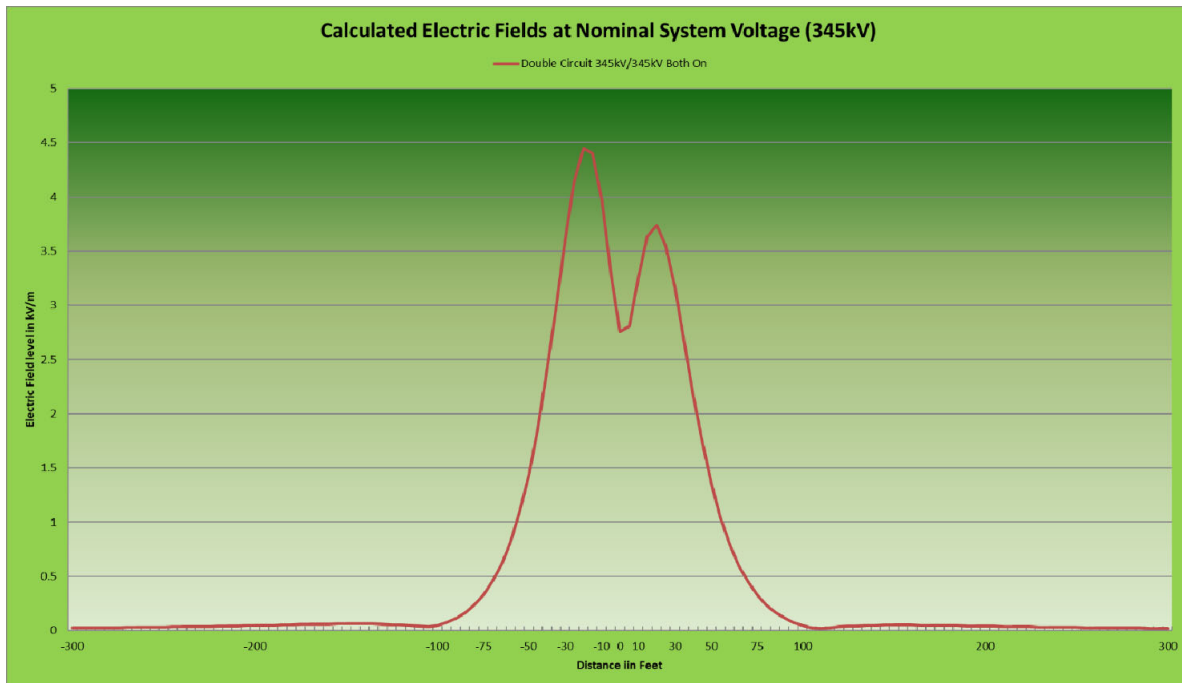
**Table 6.1: Electric Field Calculations Summary**

Structure Type	Nominal Voltage	Distance to Proposed Centerline (feet)												
		-300	-200	-100	-75	-50	-25	0	25	50	75	100	200	300
345 kV/345 kV Double-Circuit Monopole	362 kV	0.2	0.05	0.04	0.33	1.44	4.14	2.76	3.5	1.36	0.33	0.05	0.04	0.02

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<sup>73</sup> Electric field calculations are not provided for Project substations because Project substations will not be accessible to the public, and electric fields associated with the substations are anticipated to be similar to the 345-kV lines —and thus, well below the Commission’s electric field limit.

**Image 6.2: Calculated Electric Fields (kV/m) for Proposed 345 Kilovolt Transmission Line Designs (3.28 feet above ground)**



## 2. Magnetic Fields

The projected magnetic fields for different structure and conductor configurations for the Project are provided in [Image 6.3](#), and [Table 6.2](#). 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) System Average Energy Demand. The "System Peak Energy Demand" current flow (estimated loading of 1100 MVA), represents the current flow on the line during the peak hour of system-wide energy demand. The "System Average Energy Demand" current flow (estimated loading of 660 MVA), 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 lines 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.<sup>74</sup>

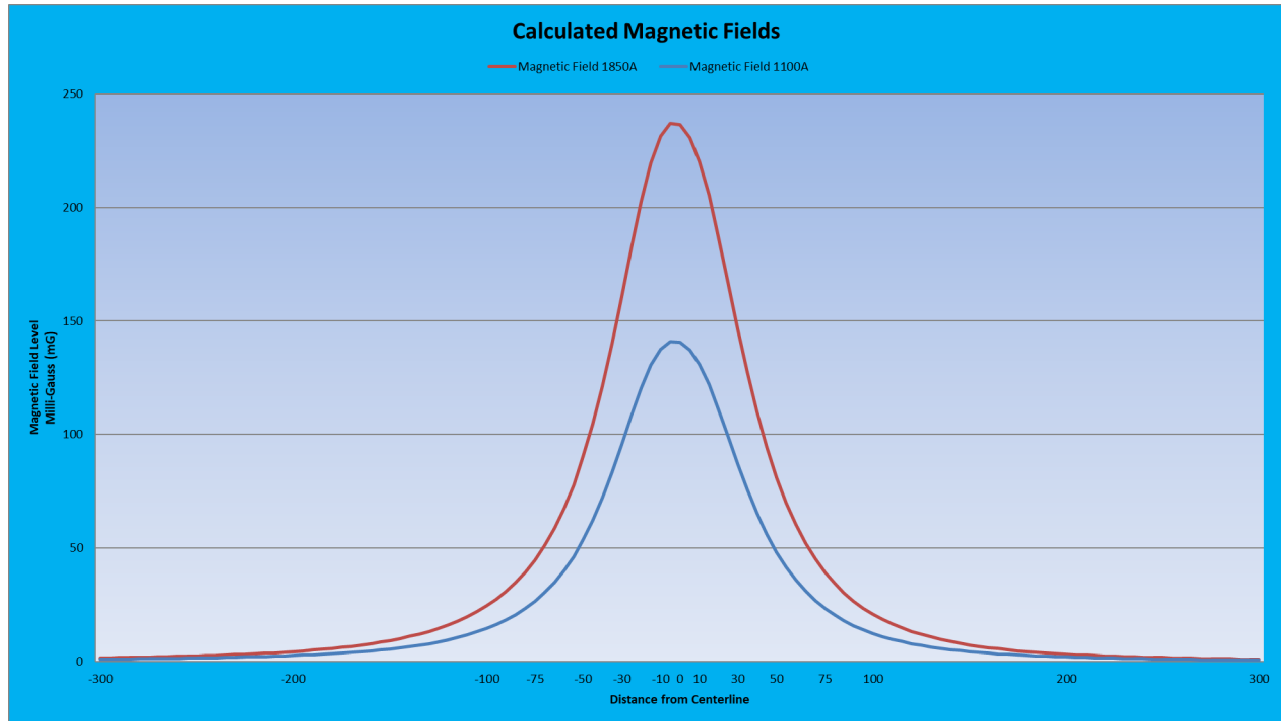
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<sup>74</sup> Magnetic field calculations for the Project substations are not provided here because the specific physical design of a substation is required for a software package to calculate representative magnetic fields, and that level of design is not yet available for the Project substations. Magnetic fields associated with the Project's substations are anticipated to be similar to other existing 345-kV substations in Minnesota.

Table 6.2: Magnetic Field Calculation Summary

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/345 kV Double-Circuit Monopole	Peak System Energy Demand (1100MVA/1100MVA)	1850/1850	1.5	4.5	25	45	90	161	237	167	95	45	24	3.5	1
	Average System Energy Demand (660 MVA/660 MVA)	1100/1100	1	2.6	15	27	54	96	141	99	56	27	14	2	0.6

**Image 6.3: Calculated Magnetic Flux density (mG) for Proposed 345/345 Kilovolt Transmission Line Design (3.28 feet above ground)**



There are presently no Minnesota regulations pertaining to magnetic field exposure. Applicant provides 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 (13–15). (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.<sup>75</sup>

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;

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<sup>75</sup> National Cancer Institute, *Electromagnetic Fields and Cancer* (reviewed May 30, 2022), available at <https://www.cancer.gov/about-cancer/causes-prevention/risk/radiation/electromagnetic-fields-fact-sheet> (last accessed Feb. 23, 2023).



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.”<sup>76</sup>

### **G. 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.

### **H. 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

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<sup>76</sup> *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*, MPUC 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*, MPUC 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 23 (Aug. 1, 2007) (“Currently, there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects.”).

specific information about how to prevent possible shocks when the charger is disconnected.

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. Xcel Energy 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 Applicant for further information about proper grounding requirements.

## VII. TRANSMISSION LINE CONSTRUCTION AND MAINTENANCE

### A. Engineering Design and Regulatory Approvals

Detailed transmission line and substation engineering design work generally begins after the Commission designates a route and issues a route permit. 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 reviewed by the Minnesota Department of Commerce Energy Environmental Review and Analysis (DOC-EERA) staff.

### B. Right-of-Way Acquisition

Early in the detailed design process, typically 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.

If there are portions of the Project that will 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 new right-of-way, 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 and geotechnical 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 Minn. Stat. ch. 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 Minn. Stat. § 117.036, subd. 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 Minn. Stat. § 216E.12, subd. 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 lines.

### **C. Construction Procedures**

Construction duration for this Project will be approximately 18 to 24 months and will employ approximately 100 to 200 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 ten 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/laydown yards 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 Applicant will evaluate construction access opportunities by identifying existing transmission line easements, roads, or trails that run near the approved route. When feasible, the Applicant 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 Applicant will obtain permits for new access from local road authorities. The Applicant 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 a drilled pier concrete foundation. Drilled pier foundations are typically between eight to ten 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. Poles are assembled near 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 Applicant 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 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.

#### **D. Restoration and Clean-Up Procedures**

Crews will attempt to minimize ground disturbance whenever feasible, but 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 Applicant has started restoration activities. If fences, drain tile, or other property have been damaged, the Applicant 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 Applicant 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, the Applicant 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 Applicant 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 Applicant will ensure that township, city, and county roads used for purposes of access during construction will be restored to their prior condition. The Applicant 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.

### **E. 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 will perform aerial annual inspections of the 345 kV transmission lines and will inspect the lines from the ground every four years. Typically, one to two workers are required to perform aerial inspections and three 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 \$35 to \$55 per mile and the ground inspections cost approximately \$200 to \$400 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 lines for accounting purposes varies among utilities. Xcel Energy uses an approximately 60-year service life for its transmission assets. However, practically speaking, high voltage transmission lines are seldom completely retired.

#### **F. 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%.

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 Project occurs, Xcel Energy has the necessary infrastructure and crews in place in central and southern Minnesota to respond quickly and safely to return this line to service.

If there is a storm or emergency outage on the lines, Xcel Energy has distribution service centers in the region that will initiate a tactical response by deploying one of its 24-hour on-call first responders or "trouble man" to the lines 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 central and southern Minnesota and the Twin Cities that will enable a rapid response to outage events on the transmission line. These crews can typically be mobilized and on-site within 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 line, Xcel Energy's primary transmission material emergency stock is stored at its service center located in Maple Grove, Minnesota that has a critical stock of replacement 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 Project area.

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.

## VIII. ENVIRONMENTAL INFORMATION

### A. Project Study Area

The Project Study Area includes all or portions of Sherburne, Stearns, Wright, Swift, Kandiyohi, Meeker, McLeod, Carver, Lac qui Parle, Chippewa, Renville, Sibley, Yellow Medicine, Redwood, Brown, Nicollet, Lincoln, Lyon, Murray, and Cottonwood counties as shown on Figure 1<sup>77</sup>. As described further in Section 8.2 Physiographic Regions, the landscape within the Project Study Area changes from the northeast to southwest as a result of past glacial activity and other ecological factors that affected the developing landscape over time. These changes are apparent in the hydrology, vegetation, topography, land use, and human settlement patterns within the Project Study Area.

The northeastern portion of the Project Study Area is characterized by a gently rolling to undulating topography with moraines and outwash plains that were formed by the Des Moines lobe of the late Wisconsin glaciation. The Mississippi River valley cuts through the northeastern tip of the Project Study Area. South of the river valley, lakes and wetlands are abundant. Continuing southwest across the Project Study Area, the landscape transitions to generally level to slightly undulating landforms that were once tallgrass prairie. Agricultural fields now dominate this portion of the Project Study Area. The Minnesota River valley bisects the Project Study Area running northwest to southeast between the communities of Montevideo, Granite Falls, Redwood Falls, and New Ulm. South of the Minnesota River valley, level topography and agricultural fields continue to dominate the southwestern portion of the Project Study Area.

Throughout this chapter, information about existing resources is presented from the northeast to the southwest Project Study Area and by physiographic regions, as appropriate.

### B. Physiographic Regions

The Minnesota Department of Natural Resources (MDNR) and the U.S. Forest Service developed an Ecological Classification System (ECS) for ecological mapping and landscape classification in Minnesota that is used to identify, describe, and map progressively smaller areas of land with increasingly uniform ecological features (MDNR, 2022a). Through the ECS, the State of Minnesota is split into ecological provinces, sections, and subsections. The most northeastern portion of the Project Study Area is in the Minnesota and NE Iowa Morainal Section of the Eastern Broadleaf Forest Province while the remainder of the Project Study Area to the southwest is in the North Central Glaciated Plains Section of the Prairie Parkland Province.

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<sup>77</sup> All Figures referenced in this Chapter are located in [Appendix H – Figures](#).

The Minnesota and NE Iowa Morainal Section is further broken down into ecological subsections, of which the Project Study Area overlaps the Hardwood Hills, Anoka Sand Plain, and Big Woods subsections. Within the North Central Glaciated Plains Section, the Project Study Area is in the Minnesota River Prairie and Coteau Moraines subsections.

Table 8.1 provides the acreage and percentage of the Project Study Area within each ECS subsection. Figure 2 depicts the ECS subsections in relation to the Project Study Area.

**Table 8.1: ECS Subsections in Project Study Area**

<b>Table 8-1 ECS Subsections in Project Study Area</b>			
<b>ECS Subsection<sup>a</sup></b>	<b>Counties</b>	<b>Acres in Project Study Area</b>	<b>Percentage of Project Study Area</b>
Anoka Sand Plain Subsection	Sherburne, Stearns, Wright	141,749	3%
Hardwood Hills Subsection	Stearns, Wright, Kandiyohi, Meeker	378,082	7%
Big Woods Subsection	Stearns, Wright, Meeker, McLeod, Carver, Sibley	828,153	14%
Minnesota River Prairie Subsection	Stearns, Swift, Kandiyohi, Meeker, McLeod, Lac qui Parle, Chippewa, Renville, Sibley, Yellow Medicine, Redwood, Brown, Nicollet, Lincoln, Lyon, Cottonwood	4,020,877	70%
Coteau Moraines Subsection	Yellow Medicine, Redwood, Lincoln, Lyon, Murray, Cottonwood	371,161	6%
<b>Total</b>		<b>5,740,023</b>	<b>100.0%</b>
<sup>a</sup> ECS boundaries do not conform to county boundaries. As such, portions of each county listed are within the ECS and some counties are within multiple ECSs. Source: MDNR, 2022			

### 1. Anoka Sand Plain Subsection

The Anoka Sand Plain ECS is characterized by flat, sandy lake plains and terraces along the Mississippi River, which forms the western boundary of the subsection separating it from the Hardwood Hills and Big Woods subsections. Approximately three percent of the Project Study Area is within the Anoka Sand Plain ECS including portions of Sherburne, Stearns, and Wright Counties. Landforms in the Anoka Sand Plain consist of small dunes, kettle

lakes, and tunnel valleys that create a level to gently rolling topography. Sandy terraces are found along the Mississippi and its tributaries throughout the subsection. Bedrock outcrops can be found near St. Cloud and, in general, surface glacial deposits are less than 200 feet thick. Soils in the subsection are generally sandy, droughty upland soils with some organic soils in ice block depressions and tunnel valleys and poorly drained prairie soils along the Mississippi River. Most rivers and streams in this subsection flow into the Mississippi River, though some flow east to the St. Croix River. Rivers, streams, and lakes are located in old glacial tunnel valleys, and peatlands occupy linear depressions of many of the tunnel valleys. Pre-settlement vegetation consisted of droughty uplands and oak barrens, open areas, and brushland, with narrow swaths of sand prairie and floodplain forest along the Mississippi River. Current land use in this subsection is a mix of urban development and agricultural production, such as sod and vegetable crop production in peat and muck areas.

## 2. Hardwood Hills Subsection

About seven percent of the Project Study Area is within the Hardwood Hills ECS, including portions of Stearns, Wright, Kandiyohi, and Meeker Counties. The Hardwood Hills ECS is characterized by steep slopes, high hills, and lakes formed in glacial end moraines and outwash plains (MDNR, 2022). The western and southern boundaries are formed by the Alexandria Moraine Complex and the eastern boundary is defined by the landform changes between land that was previously dominated by northern hardwoods and land dominated by conifer or aspen-birch forest. During the Wisconsin age glaciation, ice stagnation moraines, end moraines, ground moraines, and outwash plains were formed in this subsection. Kettle lakes are abundant within the moraines and outwash deposits and there are over 400 lakes greater than 160 acres in size. Most of this subsection is covered in 100 to 500 feet of glacial drift over diverse bedrock. Glacial drift is thickest in the northwestern half with Middle Precambrian bedrock locally exposed in the southeast along the Crow River. Loamy soils are dominant in this subsection with loamy sands and sandy loams on outwash plains, to loams and clay loams on moraines. The high ridge of the Alexandria Moraine is the headwaters region for many rivers and streams that flow east and west; the Chippewa, Long Prairie, Sauk, and Crow Wing are the major rivers in this subsection and the Mississippi River forms part of the eastern boundary. The Hardwood Hills subsection is split by the Continental Divide and waters north of the divide eventually flow toward Hudson Bay and waters south of the divide flow into the Mississippi River system. While pre-settlement vegetation was dominated by woodland or forest, much of the land has been cleared and is currently used for agricultural production, though some forested areas remain along the margins of the lakes and steep areas. Tourism in areas around lakes is a significant contributor to the local economy.

### 3. Big Woods Subsection

Fourteen percent of the Project Study Area falls within the Big Woods ECS, including portions of Stearns, Wright, Meeker, McLeod, Carver, and Sibley Counties. The Big Woods ECS is characterized by a large block of deciduous forest, present at the time of Euro-American settlement, that separates the Anoka Sand Plain from the tallgrass prairie to the southwest (MDNR, 2022). The Mississippi River and extensive outwash and lake plain define the northern boundary of this subsection and distinguish it from the Hardwood Hills subsection. Topography is gently to moderately rolling, and the primary landform is a loamy mantled moraine formed by the Des Moines lobe of the late Wisconsin glaciation. Circular, level-topped hills with smooth side slopes dominate the landscape, with broad level areas between the hills that contain closed depressions with lakes and peat bogs. More than 100 lakes greater than 160 acres in size are present within this subsection. Drainage within this subsection is undeveloped and is generally controlled by groundwater with no inlets or outlets. Soils are predominantly loamy and range from loam to clay loam formed by the calcareous glacial till of the Des Moines lobe, with depth to bedrock ranging between 100 and 400 feet. Major rivers within this subsection are the Minnesota River, which bisects the Big Woods subsection, and the Crow River and its tributaries. Most of the land in this subsection is currently used for agricultural production, including row crop agriculture and pastureland (collectively about 80-85%). Areas not used for agricultural production generally consist of upland forest and wetlands.

### 4. Minnesota River Prairie Subsection

The majority of the Project Study Area (70%) is within the Minnesota River Prairie ECS, including all or portions of Stearns, Swift, Kandiyohi, Meeker, McLeod, Lac qui Parle, Chippewa, Renville, Sibley, Yellow Medicine, Redwood, Brown, Nicollet, Lincoln, Lyon, and Cottonwood Counties. The Minnesota River Prairie ECS is characterized by large till plains that are bisected by the broad valley of the Minnesota River (MDNR, 2022). The Minnesota River was formed by Glacial River Warren which drained Glacial Lake Agassiz. Topography is steepest along the Minnesota River and the Big Stone Moraine, which has steep kames and broad slopes, while topography outside of the river valley consists of level to gently rolling ground moraine. Glacial drift generally ranges between 100 and 400 feet throughout this subsection. Soils are predominantly well-to-moderately well-drained loams formed in gray calcareous till of the Des Moines lobe with some localized inclusions of clayey, sandy, and gravelly soils. Streams and small rivers drain into the Minnesota River or the Upper Iowa River, though drainage networks are poorly developed due to landscape characteristics. There are 150 lakes greater than 160 acres in size throughout this subsection, though many are shallow. Wetlands were common within this subsection prior to Euro-American settlement, and most have been drained to establish usable cropland. Prior to Euro-American settlement, vegetation in this subsection was predominantly tallgrass prairie

interspersed by many islands of wet prairie and areas of deciduous forest along the margins of the Minnesota River, floodplains, and other small streams. Current land use in the subsection is dominated by agricultural activity and remnants of tallgrass prairie are rarely found.

### 5. Coteau Moraines Subsection

About six percent of the Project Study Area is within the Coteau Moraines ECS, including portions of Yellow Medicine, Redwood, Lincoln, Lyon, Murray, and Cottonwood Counties. The Coteau Moraines ECS is characterized as a transition from shallow deposits of windblown silt (loess) over glacial till to deeper deposits of loess (MDNR, 2022). A high glacial landform in Southwestern Minnesota distinguishes this subsection and stretches through Southwestern Minnesota, Southeastern South Dakota, and Northwestern Iowa. The Coteau Moraines subsection is split into two distinct landforms: the middle Coteau and the outer Coteau. Landforms in the middle Coteau are rolling moraine ridges of late-Wisconsin drift mantled with loess 1 to 3 feet thick while landforms in the outer Coteau are a series of terminal and end moraines separated by ground moraines that range from gently undulating to steeply rolling and hilly. A high elevation point in this subsection is Buffalo Ridge (1,995 feet above sea level) which is in central Pipestone County. The ridge was formed by thick deposits of pre-Wisconsin glacial till (up to 800 feet thick) and, in general, glacial deposits range between 600 to 800 feet throughout the subsection. A steep escarpment that is cut by several streams within narrow, straight ravines marks the northeast edge of the subsection. Soils are loamy and well-drained with thick dark surface horizons. The Coteau Moraines subsection primarily drains into the Minnesota River system or southeast into Iowa. The middle Coteau has few lakes and a moderately developed dendritic drainage network. In contrast, the outer Coteau has a poorly developed drainage network comprised primarily of glacial till where a greater number of wetlands and lakes have formed. Prior to Euro-American settlement, vegetation in this subsection was almost entirely tallgrass prairie. Wet prairies were less common than in the Minnesota River Prairie subsection and are generally restricted to narrow stream margins, and forests were similarly restricted to ravines along a few streams, such as the Redwood River. Land in this subsection is currently used for agricultural production and remnants of pre-settlement vegetation (i.e., tallgrass prairie) are rare (MDNR, 2022a).

### C. Hydrologic Features

Three major basins occur in the Project Study Area (MPCA, 2022a); the Upper Mississippi River Basin, the Minnesota River Basin, and the Des Moines River Basin. Within the Project Study Area, there are 16 major watersheds in these basins. [Table 8.2](#) summarizes the major watersheds within each basin and [Figure 3](#) depicts the major watersheds in relation to the ECS subsections and the Project Study Area.

Table 8.2: Basins and Major Watersheds by ECS within the Project Study Area

Table 8-2 Basins and Major Watersheds by ECS within the Project Study Area					
<b>UPPER MISSISSIPPI RIVER BASIN</b>					
Mississippi River - Sartell	1,798			40,446	
Mississippi River - St. Cloud	126,448	89,082		116,121	
Mississippi River - Twin Cities		147			
North Fork Crow River	8,529	345,894		65,703	311,705
Sauk River	4,977			155,812	69,608
South Fork Crow River		268,650			518,603
<b>MINNESOTA RIVER BASIN</b>					
Chippewa River					324,874
Cottonwood River			211,914		492,841
Lac Qui Parle River					138,946
Lower Minnesota River		124,399			340,555
Minnesota River - Headwaters					1,295
Minnesota River - Mankato					449,783
Minnesota River - Yellow Medicine River			66,134		1,125,793
Redwood River			75,897		240,299
Watonwan River					6,578
<b>DES MOINES RIVER BASIN</b>					
Des Moines River - Headwaters			17,215		
<sup>a</sup> ECS boundaries do not conform to watershed boundaries. As such, portions of each watershed listed may be within multiple ECSs. Note: HUC = Hydrologic Unit Code					

The majority of the Project Study Area lies within the Minnesota River Basin which drains almost 20% of the state's waters and has rich soils where agriculture is the major land use for over 90% of its area (Minnesota River Basin Data Center, 2009).



Within the 16 watersheds located in the Project Study Area, 11 are watershed management districts managed by the Minnesota Board of Water and Soil Resources (BWSR; BWSR, 2019a).

### 1. Groundwater

Groundwater in the state of Minnesota is divided into six aquifer provinces based on glacial geology and bedrock (MDNR, 2021). The majority of the Project Study Area falls within the Western Groundwater Province which is defined by limited buried sand aquifers. This province is mainly in the Coteau Moraines and Minnesota River Prairie ECSs. The Central Groundwater Province covers the second largest area of the Project Study Area and is dominated by surficial and buried sand and gravel aquifers found within the Minnesota River Prairie ECS. Small portions of the remaining Project Study Area include the Arrowhead/Shallow Bedrock, East-Central, and South-Central Provinces. These groundwater provinces are the main source of drinking water within the Project Study Area.

### 2. Surface Water

Surface waters are interspersed throughout the Project Study Area. Waterbodies (e.g., streams, rivers, ditches) are prevalent throughout; however, wetlands are concentrated within the northern portion of the Project Study Area (see Figures 4 and 5).

Many designated Minnesota public waters occur within the Project Study Area. These are surface water features that are under the MDNR jurisdiction. As shown in [Table 8.3](#), most of the surface water features occur within the Minnesota River Prairie ECS.

**Table 8.3: Public Waters within the Project Study Area**

<b>Table 8-3 Public Waters within the Project Study Area</b>					
Anoka Sand Plain	36	12	52	91	191
Big Woods	124	42	309	350	825
Coteau Moraines	82	11	44	12	149
Hardwood Hills	75	13	111	224	423
Minnesota River Prairie	378	381	441	362	1,562
<b>Total</b>	<b>695</b>	<b>459</b>	<b>957</b>	<b>1,039</b>	<b>3,150</b>
Note: PWI = Public Waters Inventory					

There are two major rivers that span the width of the Project Study Area, the Mississippi River and the Minnesota River; both of which are Section 10 navigable waters. Section 10

waters are defined by the Rivers and Harbors Act as navigable waters subject to the ebb and flow of tides and waters used to conduct interstate and foreign commerce. The U.S. Army Corps of Engineers (USACE) has jurisdiction over all Section 10 waters and Project crossings of these waterbodies will require a permit.

a. Mississippi River Crossing

The Mississippi River travels across the Project Study Area from the northeast edge of the Stearns County line and along the border of Wright and Sherburne Counties through the Anoka Sand Plains ECS region with small portions in the Big Woods region on the northeast side of the Project Study Area. This river is classified as a lower riverine feature with an unconsolidated bottom with crossing widths ranging from 500 to over 1,000 feet. Wetlands and riparian areas are prevalent along both banks. These wetlands are mostly palustrine emergent (PEM) with persistent vegetative cover and palustrine forested (PFO) wetlands dominated by broad-leaved deciduous trees. Several smaller waterways connect with the Mississippi in the Project Study Area including Watab River, Sauk River, Elk River, Crow River, Clearwater River, Plum Creek, Johnson Creek, and several other named and unnamed tributaries.

b. Minnesota River Crossing

The Minnesota River travels a similar trajectory across the southwest portion of the Project Study Area, flowing northwest to southeast, and turns north in Mankato traveling along the edge of the Project Study Area before flowing into the Mississippi River. The Minnesota River enters the Project Study Area at the northwestern corner where it travels through several sizable lakes. The entire length of the river within the Project Study Area travels through the Minnesota River Prairie ECS region. This river is classified as a lower riverine feature with an unconsolidated bottom that is permanently flooded. As part of this characterization, the river has extensive floodplains dominated by wetland and riparian habitats. Many of the floodplain areas are utilized for farming. The majority of adjacent wetland areas are PEM with persistent vegetative cover, palustrine scrub shrub (PSS) wetlands, and PFO wetlands dominated by broad-leaved deciduous trees. A few smaller waterways connect with the Minnesota River on its path through the Project Study Area including the Lac qui Parle River, Yellow Bank River, Pomme de Terre River, Chippewa River, Yellow Medicine River, Redwood River, Cottonwood River, Hawk Creek, Beaver Creek, Wabash Creek, Spring Creek, Little Rock Creek, Eight Mile Creek, Morgan Creek, Fort Ridgely Creek, and many smaller named and unnamed tributaries.

c. Wetlands

The Minnesota River Prairie ECS has approximately half of all the wetlands in the Project Study Area which is a slightly lower concentration of wetlands by size of all the ECSs. Many

of the wetlands are focused near the Minnesota River and adjacent prairies dominated by PEM wetlands. The Big Woods ECS contains approximately 30% of the total wetlands for the Project Study Area with the highest concentration of wetlands of any ECS, many of which are near or adjacent to the Mississippi River. This ECS contains converted forest land with primarily PEM wetlands interspersed. The Hardwood Hills has approximately 12% of the wetlands in the Project Study Area and is dominated by lakes. The Coteau Moraines and Anoka Sand Plain ECSs contain the remaining eight percent of the wetlands distributed in the Project Study Area. Many of the areas of wetlands occur along the Mississippi River for the Anoka Sand Plain region. Table 8.4 provides the acres of wetlands within each ECS subsection in the Project Study Area.

**Table 8.4: Wetland Acreage by ECS within the Project Study Area**

Table 8-4 Wetland Acreage by ECS within the Project Study Area		
ECS	Wetland (acres)	Percent (%) within Project Study Area
Anoka Sand Plain	23,064	4%
Big Woods	169,212	29%
Coteau Moraines	25,216	4%
Hardwood Hills	72,843	12%
Minnesota River Prairie	292,977	50%
<b>TOTAL</b>	<b>583,312</b>	<b>100%</b>

There are a number of calcareous fens within the Project Study Area, which is typical for western Minnesota and the Minnesota River Valley area. Calcareous fens are rare habitats created by upwelling groundwater that occurs on slopes with high concentrations of calcium carbonate and low nutrient availability. The calcareous fens are primarily located within the Minnesota River Prairie ECS near the Minnesota River valley in the southwest and in the Hardwood Hills ECS in the northeast portion of the Project Study Area where there are higher occurrences of surface water features. Fens in these areas typically range from a tenth of an acre to several dozen acres but are commonly smaller than four acres in size throughout their range in Minnesota (MDNR, 2018a). Fens support rich biodiversity including rare plants and are highly susceptible to surface disturbing activities. Future Project design and routing will avoid these listed sensitive habitats<sup>78</sup>.

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<sup>78</sup> Minn. R. 8420.0935, subp. 2.

#### d. Floodplains

The major floodplains in the Project Study Area occur adjacent to the Minnesota and Mississippi Rivers where the Federal Emergency Management Agency regulates floodways. Outside the 100-year floodplain, some areas along the Minnesota and Mississippi have 200-year floodplains that reach beyond the adjacent riverine areas into agricultural areas and the edges of communities. Additional floodplains are found adjacent to larger perennial streams and areas with shallow banks and low terraces.

#### e. Karst

Southeastern Minnesota is a region comprised of porous limestone rich in karsts that were characterized by caves, sinkholes, and hollows with rolling hills and bluffs. These karsts are directly connected to groundwater aquifers through infiltration. Karsts as mapped by the MDNR are known to occur in the Minnesota River Prairie, Big Woods, and Anoka Sand Plain ECS regions (Alexander et al., 2006). Future Project activities will use BMPs for all construction activities in these areas to prevent surface runoff and sedimentation in these areas. In addition, the Applicant will conduct geotechnical analyses where appropriate to evaluate whether karst is present at structure locations and structure foundation design will account for the presence of karst, as needed.

### **D. Natural Vegetation and Associated Wildlife**

The pre-settlement and current natural vegetation, and associated wildlife species, vary significantly across the Project Study Area due to the characteristics of each ECS. A general description of each subsection can be found in Section 1.2, and Figure 2 depicts the subsections within the Project Study Area.

Pre-settlement vegetation in the Anoka Sand Plain ECS was composed primarily of oak barrens and openings harboring small, malformed bur and northern pin oaks. Jack pines could be found along the northern edge of this subsection, with upland prairie and floodplain forests located in a narrow band along the Mississippi River, while a large portion of the sandplain was primarily brushland. Current land use in the Anoka Sand Plain subsection utilizes drained peat for sod and vegetable crops. Sub- and ex-urban development are growing pressures as a result of the expanding Minneapolis metropolitan area (MDNR, 2022a).

In the Hardwood Hills ECS, pre-settlement vegetation was a mosaic of aspen-oak forested areas, oak openings, savanna, and tallgrass prairie. Mixed hardwood forests were found in the eastern portion of the subsection, while tallgrass prairie was found on flatter terrain. Agriculture is the current predominant land use, with some upland forest areas persisting in steeper areas and along lakes and wetlands (MDNR, 2022a).

The Big Woods ECS previously consisted of oak woodlands and maple-basswood forests. Aspen forests were found to be common along the western edge of the subsection, along with bur oak forests. Most of the land in this subsection is currently used for agricultural production including row crops and pastureland. Those areas not in agricultural production persist as upland forest and wetlands (MDNR, 2022a).

The majority of the Project Study Area falls within the Minnesota River Prairie ECS. Pre-settlement vegetation here consisted primarily of tallgrass prairie and wet prairie islands. Riparian areas along the Minnesota River and other waterbodies contained deciduous floodplain forest species such as elm, cottonwood, willow, and silver maple. Other prairie types including dry, dry-mesic, and dry gravel prairies could be found along the western edge of the subsection. Current land use in the subsection is dominated by agricultural activity and remnants of tallgrass prairie are rarely found (MDNR, 2022a).

The Coteau Moraines ECS was historically dominated by tallgrass prairie. Wet prairies were found along narrow stream margins, while forested areas were restricted to stream valleys. Very little pre-settlement vegetation exists in this subsection; land in this subsection is primarily in agricultural production currently (MDNR, 2022a).

As routing for the Project is refined, the Applicant will work with the relevant agencies to develop the appropriate BMPs and mitigation measures to ensure Project activities will not have significant impacts on resources.

#### 1. Sensitive or Managed Wildlife Habitat

No National Park Service Wilderness Areas, National Wild and Scenic Rivers, or National Forests are located within the Project Study Area.

A variety of state-managed lands are present in the Project Study Area, including Wildlife Management Areas (WMAs), Aquatic Management Areas (AMAs), state parks, state recreation areas, state trails, state forests, Scientific and Natural Areas (SNAs), and Migratory Waterfowl Feeding and Resting Areas (MWFRA). In addition, there are several U.S. Fish and Wildlife Service (USFWS) Waterfowl Production Areas, USDA-Natural Resources Conservation Service (NRCS) and USFWS conservation easements, and lands owned by the Nature Conservancy and several state- and privately-owned wildlife refuges in the Project Study Area. Restrictions to development on these lands vary depending on the agency and land management type. Specific restrictions may be applied that would limit or restrict development of a transmission line. Some state and federal land agencies may require special use permits for access and construction activities. These permits and other authorizations may include conditions designed to reduce impacts on sensitive resources. Time of year restrictions and minimization of workspaces, access routes, and staging areas, among other conditions, may be necessary.

The primary method of mitigation for sensitive or managed wildlife habitat is avoidance. If avoidance of federal and state-managed areas is not possible, the Applicant will work with the appropriate federal or state agencies to develop mitigation measures to ensure Project activities will not have significant impacts on sensitive resources.

## 2. Federally Listed Species

The USFWS' Information for Planning and Consultation (IPaC) website was accessed in February 2023 to obtain information regarding federally listed threatened or endangered species, candidate species, and designated critical habitat that may be present within the Project Study Area (Table 8.5; USFWS, 2023).

**Table 8.5: Federally Listed Species Potentially Present in the Project Study Area**

Table 8-5 Federally Listed Species Potentially Present in the Project Study Area			
Species Name	Common Name	Federal Status	County of Occurrence
<i>Myotis septentrionalis</i>	Northern long-eared bat	Threatened	All
<i>Perimyotis subflavus</i>	Tricolored bat	Proposed Endangered	All
<i>Danaus plexippus</i>	Monarch butterfly	Candidate	All
<i>Bombus affinis</i>	Rusty patched bumble bee	Endangered	Sherburne, Stearns
<i>Hesperia dacotae</i>	Dakota skipper	Threatened	Swift, Lac Qui Parle, Chippewa, Lincoln
<i>Hesperia dacotae</i>	Dakota skipper	Designated Critical Habitat	Lincoln
<i>Oarisma poweshiek</i>	Poweshiek skipperling	Designated Critical Habitat	Lyon
<i>Lespedeza leptostachya</i>	Prairie bush clover	Threatened	Renville, Yellow Medicine, Redwood, Brown, Lyon, Cottonwood
<i>Platanthera praeclara</i>	Western prairie fringed orchid	Threatened	Lincoln, Murray
<i>Notropis topeka</i> (= <i>tristis</i> )	Topeka shiner	Endangered	Lincoln
<i>Notropis topeka</i> (= <i>tristis</i> )	Topeka shiner	Designated Critical Habitat	Yellow Medicine, Redwood, Lincoln, Lyon, Murray, Cottonwood

As routing for the Project is refined, the Applicant will work with the appropriate agencies to develop avoidance and minimization measures to ensure Project activities will not have adverse impacts on federally listed species.

## a. Northern Long-eared Bat

The northern long-eared bat (NLEB; *Myotis septentrionalis*) is a federally threatened medium-sized bat of the Vespertilionidae family. Approximately 3.0 to 3.7 inches in length with a wingspan of 9 to 10 inches, the species derives its name from oversized ears relative to other members of the genus *Myotis* (USFWS, 2022a). 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 than or equal to 3 inches diameter at breast height (USFWS, 2016a). The species is generally associated with forested habitats, including mesic hardwood, floodplain, and fire-dependent forests, particularly those near water sources. The species overwinters in small crevices or cracks in hibernacula (e.g., caves and mines with constant temperatures, high humidity, and no air currents).

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 (USFWS, 2015a).

On November 29, 2022, USFWS published a final rule to reclassify the northern long-eared bat from threatened to endangered. (USFWS, 2022b). On January 25, 2023, USFWS announced that it was extending the effective date of the new rule from January 30, 2023, until March 31, 2023, to allow the agency to finalize conservation tools and guidance.

Potential impacts on individual NLEBs may occur if clearing or construction take 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, and the species may be disturbed during clearing or construction activities due to noise or human presence. Tree clearing activities conducted when the species is in hibernation and not present on the landscape will not result in direct impacts to individual bats but could result in indirect impacts due to removal of suitable foraging and roosting habitat.

In Minnesota, the species is most likely to be found in forested wetlands and riparian areas. However, individual trees, fence rows, or small wooded lots (less than 10 acres) that are greater than 1,000 feet from forested/wooded areas are considered unsuitable for the species, as are pure stands of less than 3-inch diameter-at-breast-height trees that are not mixed with larger trees and trees found in highly developed urban areas. Potentially suitable roosting and foraging habitat is present in the Project Study Area, most frequently found along the Mississippi River and the Minnesota River, and near the large lakes associated with the Minnesota River Prairie subsection. The Applicant will consult with the USFWS to



develop necessary avoidance and minimization measures for this species and will comply with any applicable USFWS requirements.

b. Tricolored Bat

The tricolored bat (TCB; *Perimyotis subflavus*) is a small bat also of the Vespertilionidae family. The species is so named because the coat appears dark at the base, lighter in the middle, and dark at the tip. The species is found roosting in spring, summer, and fall in both live trees and snags in deciduous hardwood forested areas. Roosting takes place among leaf clusters of live or recently dead deciduous hardwood trees. The species will also roost in Spanish moss and “bony beard” lichen (*Usnea trichodea*) in the southern and northern portions of the range, respectively. The USFWS also notes that TCB have been observed in summer roosting among pine needles and in eastern red cedar (USFWS, 2022c).

In winter, TCB utilize caves and mines for hibernation; however, in the southern portions of its range where caves are not as abundant, the species will often hibernate in road-associated culverts. TCB are one of the first bat species to enter hibernation in the fall, and one of the last to leave in the spring (USFWS, 2022c).

On September 14, 2022, the USFWS published a proposed rule to the Federal Register proposing to list the tricolored bat as an endangered species under the Endangered Species Act (ESA). The USFWS is proposing the species for listing due to substantial declines in tricolored bat abundance across its range. The main threats to the species are the impacts of WNS, wind-energy-related mortality, the effects of climate change, and habitat loss and disturbance (USFWS, 2022c).

Like the NLEB, tree clearing and construction may impact individual TCBs if the work 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 the species’ active season.

Proposed species are not protected under the ESA; however, a decision on the final rule listing the species as endangered would be prior to construction of the Project. Avoidance and minimization measures implemented for the NLEB will also be protective of TCBs; the Applicant will consult with the USFWS to determine if additional measures are needed to prevent adverse impacts on TCBs.

c. Monarch Butterfly

The monarch butterfly is a large butterfly with an approximate 3-4-inch wingspan and characterized by bright orange coloring on the wings, with distinctive black borders and veining. The species can be found in a wide variety of habitats including prairies, grasslands, urban gardens, road ditches, and agricultural fields, provided a supply of nectaring plants are

available for adult foraging and milkweed plants are present for laying eggs and as a food source for caterpillars (USFWS, 2022d).

On December 17, 2020, the USFWS published the result of its 12-month review of the monarch butterfly and determined that listing the species under the ESA was “warranted but precluded,” meaning the species meets the criteria for listing as an endangered or threatened species, but the USFWS cannot currently implement the listing because there are other listing actions with a higher priority. The species is now a candidate for listing; however, candidate species are not protected under the ESA (USFWS, 2020). The USFWS has added the monarch to the updated national listing workplan and, based on its listing priorities and workload, intends to propose listing the monarch in Fiscal Year 2024, if listing is still warranted at that time, with a possible effective date within 12 months of the proposed rule (USFWS, 2022d). The USFWS will also conduct an annual status review to determine if changes in prioritization are necessary. Xcel Energy will comply with applicable requirements in place at the time the Project is constructed.

Suitable habitat for monarchs is present across all ECS subsections within the Project Study Area. If the USFWS determines the species should be listed and protections for the species will coincide with Project planning, permitting, and/or construction, the Applicant will review Project activities for potential impacts on the species, develop appropriate avoidance and minimization measures, and consult with the USFWS as appropriate.

#### d. Dakota Skipper

The Dakota skipper is a small-to-medium sized butterfly characterized by a short, sturdy body and a quick, skipping flight. Adult males are tawny-orange to brown on dorsal surfaces with lighter, dusty yellow-orange ventral surfaces; forewings display conspicuous dark markings. Dakota skipper adults have a lifespan of only one to two weeks and can be seen during the breeding and egg-laying season between mid-June and mid-July. Adult skipper flight periods may be tied to the purple cornflower blooming period in prairie habitats where this species is present. The species is present in suitable habitat year-round as the larvae overwinter at the base of plants on which they forage in the spring.

The species is an obligate of untilled, high-quality native prairie containing a variety of wildflowers and grasses. Dakota skippers do not thrive in heavily grazed or cultivated areas, but can be found in both wetlands and uplands. The preferred wetland habitat is associated with plant species consisting of little bluestem (*Schizachyrium scoparium* var. *scoparium*), wood lily (*Lilium philadelphicum*), and harebell (*Campanula rotundifolia*) (USFWS, 2014). In Minnesota, the Dakota skipper may be found primarily in native dry-mesic to dry prairie where mid-height grasses such as little bluestem, prairie dropseed (*Sporobolus heterolepis*), and side-oats grama (*Bouteloua curtipendula* var. *curtipendula*) dominate (MDNR, 2018b).

The current status of the Dakota skipper in Minnesota is tenuous: intensive survey efforts since 2012 have found only one remaining Dakota skipper population in Minnesota (MDNR, 2018b). Potentially suitable prairie habitat for Dakota skippers may be present within the Minnesota River Prairie and Coteau Moraines subsections in the Project Study Area.

e. Dakota Skipper Designated Critical Habitat

Critical habitat has been designated for the Dakota skipper, and is present in Lincoln County (USFWS, 2015b). Designated critical habitat is defined as those areas that are considered crucial for the conservation of a species and that may require special management or protection. This designation is based on the presence of certain primary constituent elements (PCEs: i.e., those physical and biological features of habitat that are considered essential for the conservation of the species).

The PCEs of Dakota skipper critical habitat include wet-mesic tallgrass or mixed-grass remnant untilled prairie containing a predominance of native grasses and native flowering forbs, glacial soils that provide the soil surface or near surface (between soil surface and 2 cm depth) micro-climate conditions conducive to Dakota skipper larval survival and native prairie vegetation, trees or large shrub cover of less than five percent of area in dry prairies and less than 25% in wet-mesic prairies, and non-native invasive plant species occurring in less than five percent of area. In addition, native grasses and native flowering forbs must be available for larval and adult food and shelter, specifically Prairie dropseed (*Sporobolus heterolepis*) or little bluestem (*Schizachyrium scoparium*), and one or more specific flowering forbs in bloom during the Dakota skipper flight period. Lastly, dispersal grassland habitat must fall within 1 km (0.6 mi) of native high-quality remnant prairie that connects high-quality wet-mesic to dry tallgrass prairies or moist meadow habitats. Dispersal grassland habitat consists of undeveloped open areas dominated by perennial grassland with limited or no barriers to dispersal including tree or shrub cover less than 25% of the area and no row crops such as corn, beans, potatoes, or sunflowers (USFWS, 2013).

The Applicant will avoid intersecting the designated critical habitat unit in Lincoln County; therefore, Project activities would not have adverse impacts on Dakota skipper designated critical habitat.

f. Poweshiek Skipperling

The Poweshiek skipperling is a small and slender-bodied butterfly, with a wingspan ranging from 0.9 to 1.2 inches (USFWS, n.d.). The Poweshiek skipperling has a single annual generation. Adults have been recorded from the last week of June into the first week of August in Minnesota, but in a typical year most adults fly between the end of June and the

middle of July. Eggs hatch in about ten days, and the partly grown larvae overwinter and complete development the following spring (MN DNR, 2018).

Habitat preferences of the Poweshiek skipperling include untilled prairie fens, grassy lake and stream margins, moist meadows, and wet-mesic to dry tallgrass prairie. The species relies on a variety of nectar plants for feeding. Smooth ox-eye (*Heliopsis helianthoides*), purple coneflower, stiff tickseed (*Coreopsis palmata*), black-eyed susan (*Rudbeckia hirta*), and palespike lobelia (*Lobelia spicata*) are common food sources, but preferred plants vary across the species' range (USFWS, 2014). In Minnesota, the butterfly utilizes both high, dry tallgrass and low, wet prairie remnants. In drier habitats, skipperlings are likely to use purple coneflower almost exclusively, and adult emergence is closely tied to the coneflower lifecycle (USFWS, 2014).

Poweshiek skipperlings are thought to be extirpated from Minnesota (USFWS, n.d.). The last confirmed sightings of this butterfly in Minnesota were in 2007, despite extensive annual surveys beginning in 2013 covering a large fraction of the many sites in Minnesota where the species used to occur. The only known remaining population in the western part of its range, where more than 95 percent of the species' global population occurred, is in Manitoba, Canada, a few kilometers north of the Minnesota border (MN DNR, 2018).

As shown in Table 8.5, the IPaC results did not identify the Poweshiek skipperling as a species that may be present within the Project Study Area; only designated critical habitat for the species was identified.

#### g. Poweshiek Skipperling Critical Habitat

Critical habitat has been designated for the Poweshiek skipperling and is present in Lyon County. The PCEs of Poweshiek skipperling critical habitat include wet-mesic to dry tallgrass remnant untilled prairies or remnant moist meadows and/or prairie fen habitats with undisturbed (untilled) glacial soil types that contain native grasses and native flowering forbs for larval and adult food and shelter. In addition, dispersal grassland habitat that is within 1 km (0.6 mi) of native high-quality remnant prairie that connects high quality wet-mesic to dry tallgrass prairies, moist meadows, or prairie fen habitats. Dispersal grassland habitat consists of undeveloped open areas dominated by perennial grassland with limited or no barriers to dispersal including tree or shrub cover less than 25% of the area and no row crops such as corn, beans, potatoes, or sunflowers (USFWS, 2013).

The Applicant will avoid intersecting the designated critical habitat unit in Lyon County, Project activities would not have adverse impacts on Poweshiek skipperling designated critical habitat.

#### h. Prairie Bush Clover

Prairie bush clover is found only in the tallgrass prairie region of four Midwestern states. It is a member of the bean family and a midwestern "endemic" – known only from the tallgrass prairie region of the upper Mississippi River Valley. The majority of known populations are found in north central Iowa and southern Minnesota (USFWS, 1988). Main threats to the species include loss of suitable prairie habitat from land conversion to agricultural uses and urban development. Competition from invasive species, climate change, and increased herbicide use are also threats which may contribute to population declines (USFWS, 1988; USFWS, 2021a).

The species is typically found in undisturbed prairie remnants but is also tolerant of disturbed sites. Tallgrass prairie habitats with a history of mowing, burning, cultivation, or grazing may provide suitable conditions as well (USFWS, 1988).

The extent of extant populations of prairie bush clover are well-known in Minnesota; these are present in the Project Study Area within the Minnesota River Prairie ECS subsection. In coordination with the USFWS and MDNR and in advance of construction, the Applicant will conduct field surveys to determine the extent of potentially suitable prairie bush clover habitat that may be affected by the Project. If suitable habitat cannot be avoided the Applicant will consult with the USFWS and MDNR to determine next steps and develop appropriate avoidance and minimization measures.

#### i. Western Prairie Fringed Orchid

A member of the orchid family, the western prairie fringed orchid is found in moist tallgrass prairies in Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and Manitoba, Canada (USFWS, 2021b). The species occurs most often in mesic to wet unplowed tallgrass prairies and meadows (native prairie areas and prairie remnants) in full sun on sandy or calcareous till soils. In Minnesota, habitat characteristics vary with location: In northern Minnesota, the species is typically found in northern wet prairie, northern mesic prairie, and occasionally prairie wet meadow/carr, while in southern Minnesota most populations occur in either southern mesic or southern wet prairie (MDNR, 2020).

Potentially suitable habitat for the species is present in the Minnesota River Prairie ECS subsection of the Project Study Area. In coordination with the USFWS and MDNR and in advance of construction, the Applicant will conduct field surveys to determine the extent of potentially suitable western prairie fringed orchid habitat that may be affected by the Project. If suitable habitat cannot be avoided the Applicant will consult with the USFWS and MDNR to determine next steps and develop appropriate avoidance and minimization measures.

## j. Topeka Shiner

The Topeka shiner is a small minnow, typically less than three inches in length, primarily found in small to mid-size prairie streams in the central United States (i.e., South Dakota, Minnesota, Kansas, Iowa, Missouri, and Nebraska) where it is usually found in pool and run areas containing clear, clean water (MDNR, 2022b). Typical Topeka shiner streams are perennial, but the species may be found in those which lose flow seasonally. Suitable streams tend to have good water quality and cool to moderate temperatures (USFWS 2019).

Potentially suitable prairie streams may be present in the extreme southern portion of the Project Study Area in the Coteau Moraines subsection.

Impacts on Topeka shiner are possible if construction activities impact suitable stream habitat by increasing sediment load, altering the temperature, flow, or streambed composition of suitable streams. The species is particularly vulnerable to impacts which take place during the spawning season (generally, mid-May to early July, but are temperature-dependent; MDNR, 2022b). The Applicant will implement the mitigation measures outlined in the USFWS' *Recommendations for Construction Projects Affecting Waters Inhabited by Topeka Shiners in Minnesota (Revised November 18, 2016)* (USFWS, 2016b) to prevent sedimentation from entering Topeka shiner habitat including the following:

- Follow all applicable requirements and BMPs for stormwater and erosion control.
- In non-cropland areas, mulching areas of disturbed soils and reseeded promptly with native species.
- Implement appropriate erosion and sediment prevention measures to the maximum extent practicable. Inspect devices frequently to ensure that they are effective and in good repair, especially after precipitation.

## k. Topeka Shiner Designated Critical Habitat

The PCEs of Topeka shiner critical habitat include streams most often with permanent flow, but that can become intermittent during dry periods; side-channel pools and oxbows either seasonally connected to a stream or maintained by groundwater inputs; streams and side-channel pools with water quality necessary for unimpaired behavior, growth, and viability of all life stages; sand, gravel, cobble, and silt substrates with amounts of fine sediment and substrate to allow for nest building and maintenance of nests and eggs; adequate terrestrial, semiaquatic, and aquatic invertebrate food base; a hydrologic regime capable of forming, maintaining, or restoring the flow periodicity, channel morphology, fish community composition, off-channel habitats, and habitat components described in the other primary

constituent elements; and few or no non-native predatory or non-native competitive species present (USFWS, 2004).

In Minnesota, designated critical habitat includes the stream channels within the identified stream reaches and off-channel pools and oxbows. Designated critical habitat streams and reaches are potentially present within the Minnesota River Prairie and Coteau Moraines subsections in the Project Study Area. Impacts on Topeka shiner designated critical habitat are possible if construction activities impact or alter the PCEs as defined above. Implementation of the USFWS mitigation measures discussed for the Topeka shiner in the section above will minimize potential impacts on designated critical habitat.

### 1. Bald Eagles

Bald eagles (*Haliaeetus leucocephalus*) are protected by both the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act (BGEPA). The BGEPA prohibits the take of a bald or golden eagle adults, juveniles, or chicks including their parts, nests, or eggs without a permit. Take is defined by the BGEPA as to pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest, or disturb. The BGEPA also addresses impacts resulting from human-induced alterations occurring around previously used nesting sites. Work conducted within 660 feet of an active eagle nest during the nesting season may disturb nesting eagles to such a degree that adults abandon the nest, resulting in take of eggs and/or chicks; an active nest is one where eggs or chicks are present. In Minnesota, the bald eagle nesting season is generally January 15 – July 31 (USFWS, 2022e).

Bald eagles may be present in Minnesota year-round; the species overwinters near the Mississippi River in Wabasha and Red Wing, and breeds and nests in northeastern and north central Minnesota (MDNR, 2022c; 2022d). The species is primarily found near rivers, lakes, marshes, and other waterbodies where opportunities to fish are plentiful. Bald eagles nest in tall trees with clear lines of sight and large sturdy branches for perching and nest building.

Potentially suitable nesting habitat for bald eagles is present in all ECS subsections. Known nests are present throughout the Project Study Area, most frequently found along the Mississippi River and the Minnesota River crossings, with additional nests concentrated around the large lakes associated with the Minnesota River Prairie subsection (M. Rheude, USFWS, pers. comm. 2019).

If construction activities will take place in suitable eagle nesting habitat during the species nesting season, surveys to identify active nests within 660 feet of work areas will be conducted in early spring (i.e., late March/early April) of the year of construction. If active nests are identified within the disturbance buffer, the Applicant will consult with the USFWS to determine next steps and develop appropriate avoidance and minimization measures.

## 3. State Listed Species

The Minnesota Natural Heritage Inventory System database was also reviewed for state-listed threatened and endangered species that may have the potential to occur within the Project Study Area (Table 8.6). The review does not represent a comprehensive survey but acknowledges the potential for the presence of listed or candidate species or designated critical habitat within the Project Study Area. The Applicant will conduct a Natural Heritage Review utilizing the Minnesota Conservation Explorer online tool and will consult with the MDNR to ensure that Project activities will not have adverse impacts on state-listed species.

**Table 8.6: State Listed Species Potentially Present in the Project Study Area**

<b>Table 8-6</b>			
<b>State Listed Species Potentially Present in the Project Study Area</b>			
<b>Birds</b>			
Burrowing Owl	<i>Athene cunicularia</i>	END	-
Common Tern	<i>Sterna hirundo</i>	THR	-
Henslow's Sparrow	<i>Ammodramus henslowii</i>	END	-
Horned Grebe	<i>Podiceps auratus</i>	END	-
King Rail	<i>Rallus elegans</i>	END	-
Loggerhead Shrike	<i>Lanius ludovicianus</i>	END	-
Wilson's Phalarope	<i>Phalaropus tricolor</i>	THR	-
<b>Mollusks</b>			
Ebonsyshell	<i>Reginaia eburnus</i>	END	-
Elktoe	<i>Alasmidonta marginata</i>	THR	-
Ellipse	<i>Venustaconcha ellipsiformis</i>	THR	-
Fawnsfoot	<i>Truncilla donaciformis</i>	THR	-
Fluted-shell	<i>Lasmigona costata</i>	THR	-
Monkeyface	<i>Quadrula metanevra</i>	THR	-
Mucket	<i>Actinonaias ligamentina</i>	THR	-
Pistolgrip	<i>Tritogonia verrucose</i>	END	-
Rock Pocketbook	<i>Arcidens confragosus</i>	END	-
Salamander Mussel	<i>Simpsonaias ambigua</i>	END	-
Spike	<i>Elliptio dilatate</i>	THR	-
Wartyback	<i>Quadrula nodulata</i>	THR	-
Winged Mapleleaf	<i>Quadrula fragosa</i>	END	-
Yellow Sandshell	<i>Lampsilis teres</i>	END	-
<b>Fish</b>			
Black Buffalo	<i>Ictiobus niger</i>	THR	-



<b>Table 8-6</b>			
<b>State Listed Species Potentially Present in the Project Study Area</b>			
Paddlefish	<i>Polyodon spathula</i>	THR	-
Pugnose Shiner	<i>Notropis anogenus</i>	THR	-
<b>Reptiles and Amphibians</b>			
Blanding's turtle	<i>Emydoidea blandingii</i>	THR	-
<b>Insects</b>			
Ottoe Skipper	<i>Hesperia ottoe</i>	END	-
Poweshiek Skipperling	<i>Oarisma poweshiek</i>	END	END
<b>Plants</b>			
Beach Heather	<i>Hudsonia tomentosa</i>	THR	-
Blunt-lobed Grapefern	<i>Botrychium oneidense</i>	THR	-
Butternut	<i>Juglans cinerea</i>	END	-
Clustered Broomrape	<i>Orobanche fasciculata</i>	THR	-
Eared False Foxglove	<i>Agalinis auriculata</i>	END	-
Hair-like Beak Rush	<i>Rhynchospora capillacea</i>	THR	-
Hairy Fimbry	<i>Fimbristylis puberula var. interior</i>	END	-
Hooded Arrowhead	<i>Sagittaria calycina var. calycina</i>	THR	-
Kitten Tails	<i>Besseyia bullii</i>	THR	-
Prairie Bush-clover	<i>Lespedeza leptostachya</i>	THR	THR
Ram's Head Orchid	<i>Cypripedium arietinum</i>	THR	-
Rock Sandwort	<i>Minuartia dawsonensis</i>	THR	-
Seaside Three-awn	<i>Aristida tuberculosa</i>	THR	-
Short-pointed Umbrella-sedge	<i>Cyperus acuminatus</i>	THR	-
Sterile Sedge	<i>Carex sterilis</i>	THR	-
Stream Parsnip	<i>Berula erecta</i>	THR	-
Sullivant's Milkweed	<i>Asclepias sullivantii</i>	THR	-
Tuberclad Rein Orchid	<i>Platanthera flava var. herbiola</i>	THR	-
Water Hyssop	<i>Bacopa rotundifolia</i>	THR	-
Western Prairie Fringed Orchid	<i>Platanthera praeclara</i>	END	THR
Whorled Nutrush	<i>Scleria verticillate</i>	THR	-
Wolf's Spikerush	<i>Eleocharis wolfii</i>	END	-
<sup>a</sup> END = Endangered, THR = Threatened, SC = Special Concern			

a. Native Plant Communities and Sites of Biodiversity Significance

The MDNR classifies native vegetation in Minnesota by considering a variety of features, including hydrology, vegetation, soils, topography, and natural disturbance regimes (e.g., fire, floods, drought). This classification system is meant to “provide a framework and common language for improving the Company’s ability to manage vegetation, survey natural areas for biodiversity conservation, identify research needs, and promote study and appreciation of native vegetation in Minnesota” (MDNR, 2022e). Native Plant Communities (NPCs) are divided into classes, types, and subtypes. A variety of NPCs are found within the Project Study Area, primarily prairie and wetland communities located in the Minnesota River Prairie, Hardwood Hills, and Coteau Moraines subsections.

Calcareous fens are protected by Minnesota state statutes. In addition, several state-protected plant species are found in calcareous fen habitats (e.g., hairy frimby, sterile sedge, hair-like beak rush, whorled nutrush) (MDNR, 2018a). A review of MDNR data identified a number of fens within the Project Survey Area.

The MDNR ranks Sites of Biodiversity Significance (SOBS) based on the relative significance of biodiversity of the site at a statewide level. This system ranks sites at four levels: outstanding, high, moderate, or below based on the presence of rare species populations, the size and condition of native plant communities within the site, and the landscape context of the site (MDNR, 2022f). Within the Project Study Area, there are 114 sites ranked as high and 26 ranked as outstanding. Most of the highly ranked sites are present in the Minnesota River Prairie, Hardwood Hills, and Big Woods subsections, and the sites ranked as outstanding are found primarily in the Big Woods and Coteau Moraines subsections in the Project Study Area.

As routing for the Project is refined, the Applicant will avoid NPCs and SOBS where practicable and will work with the appropriate agencies to develop the appropriate BMPs and mitigation measures to ensure Project activities will not have significant impacts on sensitive resources.

b. Native Prairie

The MDNR has developed the Minnesota Prairie Conservation Plan to preserve existing prairie habitats, identify areas in need of conservation, and build cooperation between federal and state agencies and conservation organizations. A primary strategy for protecting existing prairie resources is to maintain habitat through conservation easements on public and private lands (MDNR, 2022g). A review of the MDNR’s 2018 Native Prairie Bank Easement Boundaries identified 38 easements within the Project Study Area, primarily in the Minnesota River Prairie and Coteau Moraines ECSs. As shown in Table 8.7, roughly 80% of land in the Minnesota River Prairie and Coteau Moraines ECSs is categorized as cultivated

cropland. Native prairie is present within these ECSs, but is generally found in small, scattered pockets along the margins of waterbodies where native vegetation has not been disturbed by agricultural production.

As routing for the Project is refined, the Applicant will avoid native prairie easements where practicable and will work with agencies to develop the appropriate BMPs and mitigation measures to ensure Project activities will not have significant impacts on sensitive resources.

### **E. Topography and Land-use Types**

Topography within the Anoka Sand Plain, Hardwood Hills, and Big Woods ECSs is generally rolling to undulating (860 to 1,460 feet above sea level). The Mississippi River is the main drainage channel in these subsections and creates a natural boundary between the Anoka Sand Plain and the Hardwood Hills and Big Woods subsections. Topography in the Minnesota River Prairie and Couteau Moraines subsections is generally more level to slightly rolling (790 to 1,710 feet above sea level). The Minnesota River is the main drainage channel for both subsections and occurs as an abrupt gorge within the Minnesota River Prairie subsection.

Most of the Project Study Area is rural and agricultural with scattered small municipalities and farmsteads throughout. Based on review of the U.S. Geological Survey (USGS) National Land Cover Database, the predominant land use category throughout the Project Study Area is cultivated crops followed by developed land (Dewitz and USGS, 2021). Table 8.7 presents the acres of each land-use category within the Project Study Area organized by ECS.

**Table 8.7: Land Use within the ECSs in the Project Study Area**

Table 8-7 Land Use within the ECSs in the Project Study Area						
Cultivated Crops	38.1	53.0	58.3	83.1	79.1	76.2%
Developed	16.5	6.9	7.9	5.3	4.4	6.0%
Hay/Pasture	12.3	10.6	9.3	2.5	8.7	4.6%
Emergent Herbaceous Wetlands	7.2	6.9	6.8	4.1	2.6	4.6%
Deciduous/Evergreen/Mixed Forest	15.7	13.3	8.1	2.0	1.4	3.9%
Open Water	5.0	5.3	7.2	1.9	1.3	3.0%
Woody Wetlands	3.8	2.7	1.7	0.6	0.2	1.0%
Herbaceous Land	1.0	1.1	0.4	0.2	2.1	0.5%
Shrub/Scrub Land	0.2	0.1	0.2	<0.1	<0.1	0.1%
Barren Land	0.2	0.1	0.1	0.1	4.4	0.1%
<b>Total</b>	<b>100.0</b>	<b>100.0</b>	<b>100.0</b>	<b>100.0</b>	<b>100.0</b>	<b>100.0%</b>
Source: Dewitz and USGS, 2021						

The data in Table 8.7 illustrates how land uses differ between the ECSs in the Project Study Area. While cultivated cropland is the predominant land-use type throughout the Project Study Area, there is a greater amount of cultivated cropland in the Minnesota River Prairie and Coteau Moraines subsections (83.1 and 79.1%, respectively) as compared to the Hardwood Hills, Anoka Sand Plan, and Big Woods subsections (53.0, 38.1, and 58.3%, respectively). The Hardwood Hills, Anoka Sand Plan, and Big Woods subsections have a higher percentage of surface waters and forested areas, as well as developed land, than the Minnesota River Prairie and Coteau Moraines subsections.

The primary method used to minimize impacts on existing land uses such as cultivated cropland, forested land, or wetlands, is to locate transmission lines along road rights-of-way, section lines, or property lines and space transmission line structures in a manner that avoids sensitive areas while still maintaining safety and design standards.

## 1. Conservation Easements

Various conservation easements owned or managed by federal, state, county, and private non-profit agencies are present throughout the Project Study Area. A conservation easement is land that has been sold or leased by the landowner to a federal, state, county, or non-profit agency, who will in turn apply specific development or activity restrictions designed to protect and conserve natural resources. The Applicant reviewed publicly available information to identify existing conservation easements within the Project Study Area.

Table 8.8 presents the acres of conservation easements present in each of the ECSs in the Project Study Area. Federal, state, and locally owned or managed lands designated for protection and conservation of sensitive wildlife habitat are discussed in Section 8.4.1 and lands that provide public recreation opportunities are discussed in Section 8.5.2.

**Table 8.8: Conservation Easements within the ECSs in the Project Study Area**

<b>Table 8-8 Conservation Easements within the ECSs in the Project Study Area</b>					
Federal	--	3,815	7,879	31,859	1,171
State	155	930	2,646	64,149	4,913
Private/Non-Governmental Organization	--	--	169	--	--
<b>Total</b>	<b>155</b>	<b>4,745</b>	<b>10,694</b>	<b>96,008</b>	<b>6,084</b>
Source: USGS-GAP, 2022					
Note: Dashes indicate zero acres of conservation easements are present in the ECS.					

Most of the conservation easements in the Project Study Area are located within the Minnesota River Prairie subsection. Most of these are conservation easements along the Minnesota River associated with the Conservation Reserve Enhancement Program (CREP), Reinvest in Minnesota (RIM), and Wetland Reserve Program (WRP).

The CREP is an offshoot of the Conservation Reserve Program which is a land conservation program established by the U.S. Department of Agriculture (USDA) and administered by the Farm Service Agency (FSA) that pays farmers a yearly rental fee for agreeing to take environmentally sensitive land out of agricultural production to improve environmental health and quality (USDA-FSA, 2022). Minnesota implemented the CREP to target state-identified, high-priority conservation resources by offering payments to farmers and agricultural landowners to retire environmentally sensitive land using the RIM Reserve Program (BWSR, 2019b). Both conservation programs are administered by BWSR. Enrollment in the CREP and RIM programs is voluntary.

The WRP is managed by the USDA-NRCS and provides financial and technical support to landowners who voluntarily enroll in the program (USDA-NRCS, n.d.). The goals of the program are to work with landowners to restore wetland function and values and reestablish wildlife habitat on wetlands that previously were farmed or are adjacent to sensitive or degraded surface waters.

Depending on the governing conservation program, specific restrictions may be applied that would limit or restrict development of a transmission line. The primary method of mitigation for impacts on conservation easements is avoidance. As routing of the Project proceeds, the Applicant will work with federal, state, and county agencies and landowners to identify conservation easements that may be affected by the Project. If a conservation easement cannot be avoided through modifications in Project design, the Applicant will work with the owner and managing agency to develop appropriate mitigation measures to minimize effects.

## 2. Human Settlement

Human settlement within the Project Study Area includes reservations for two indigenous nations, municipalities, farmsteads, utility infrastructure, roadways, and commercial and industrial areas. The Applicant reviewed publicly available information to characterize human settlement patterns throughout the Project Study Area.

Reservations for two indigenous nations are present within the Project Study Area: the Pezihutazizi Oyate (Upper Sioux Community) and the Lower Sioux Indian Community in the State of Minnesota. The Pezihutazizi Oyate reservation is located along the Minnesota River valley in Yellow Medicine County. In addition, an area of off-reservation Pezihutazizi Oyate trust land is directly adjacent to the western boundary of the reservation. The Lower Sioux Indian Community in the State of Minnesota reservation is located within the Minnesota River valley in Redwood County.

Municipalities in the Project Study Area are concentrated along roadways such as Interstate 94 or U.S. Highways 212 and 14 and along the Mississippi and Minnesota River valleys (see Figure 1). Larger municipalities in the Project Study Area include Big Lake, Monticello, Saint Joseph, Buffalo, Wilmar, Litchfield, Hutchinson, Glencoe, Waconia, Montevideo, Granite Falls, Redwood Falls, New Ulm, and Marshall. Outside of the larger municipalities, communities are generally small and rural in nature with farmsteads and residences located along roadways, away from population centers. Commercial and industrial areas in the Project Study Area are generally located within or adjacent to larger municipalities.

Residential areas in the Project Study Area are located within large and small municipalities, as well as scattered farmsteads located in more rural areas. National Electric Safety Code (NESC) and Xcel Energy standards require minimum clearances between transmission line facilities and buildings to ensure safe operation of transmission line facilities.

The primary method of mitigation for minimizing effects on human settlements and related infrastructure is to route transmission lines away from municipalities, and residential areas. Routing a transmission line adjacent to existing utility corridors and roadways can help to minimize the effects of transmission lines, as well.

The Project will be designed in compliance with State, NESC, and Xcel Energy standards for clearance to ground, crossing other utilities, clearance from buildings, strength of materials, vegetation, and other obstructions. Furthermore, the Applicant will comply with Xcel Energy's construction standards, which include requirements of NESC and Occupational Safety and Health Administration (OSHA). Adherence to NESC, Xcel Energy, and OSHA standards will limit the effects of the Project on areas of human settlement and related infrastructure.

The Applicant will work with tribal, state, county, and local stakeholders to identify areas of concern and work collaboratively to minimize effects on areas of human settlement and related infrastructure.

a. Demographics and Socioeconomics

Demographic information for the Project Study Area is based on the U.S. Census Bureau 2020: American Community Survey 5-year Estimates Data Profiles, available on Explore Census Data and QuickFacts websites. U.S. Census information is available at the state and county levels; for a listing of counties within each ECS, refer to Section 8.2 and Table 8.1.

The Project Study Area encompasses all or portions of 20 counties with populations that vary in size from 158,292 persons in Stearns County to 5,640 persons in Lincoln County (U.S. Census Bureau, 2021). Counties in the north and east portions of the Project Study Area (e.g., Sherburne, Stearns, Wright, Carver) are closer to the Twin Cities metro area and, as such generally have larger populations and are more densely populated than counties in the southwestern portion of the Project Study Area, which are more rural in nature (e.g., Yellow Medicine, Lyon, Redwood, Cottonwood, Brown). For example, population densities in counties in the northeastern portion of the Project Study Area are often above 200 persons per square mile, while population densities in the southwestern portion of the Project Study Area are generally less than 50 persons per square mile (see [Table 8.9](#)).

Table 8.9 presents demographic and socioeconomic information from the U.S. Census Bureau for the State of Minnesota and each county within the Project Study Area and [Table 8.10](#) presents information about the racial and ethnic groups in these areas.

Table 8.9: Demographic Information in the Project Study Area

Table 8-9 Demographic Information in the Project Study Area							
Minnesota	5,706,494	7.1	71.7	\$38,881	2.6	8.3	E, M, R/P
Sherburne	97,183	9.8	224.5	\$36,022	1.7	4.4	E, M, R
Stearns	158,292	5.1	117.9	\$31,574	3.5	10.6	E, M, R
Wright	141,337	13.3	213.8	\$37,416	2.0	4.6	E, M, C
Kandiyohi	43,732	3.5	54.8	\$31,778	2.6	8.2	E, R, M
Meeker	23,400	0.4	38.5	\$32,412	1.5	6.2	E, M, C
McLeod	36,771	0.3	74.8	\$33,628	1.8	5.8	M, E, R
Carver	106,922	17.4	302.0	\$48,492	1.8	3.5	E, M, P
Sibley	14,836	-2.6	25.2	\$32,471	2.0	7.9	M, E, Ag/C
Swift	9,838	0.6	13.3	\$33,416	2.1	9.5	E, M, Ag
Lac qui Parle	6,719	-7.4	8.8	\$34,091	1.7	8.6	E, Ag, M
Chippewa	12,598	1.3	21.7	\$30,957	3.5	9.3	E, M, R
Renville	14,723	-6.4	151.0	\$31,243	1.8	8.6	E, M, Ag
Yellow Medicine	9,528	-8.7	12.6	\$31,033	1.2	8.6	E, R, M
Redwood	15,425	-3.9	17.6	\$29,086	1.0	8.6	E, M, Ag
Brown	25,912	0.1	42.4	\$30,900	1.6	6.8	E, M, R
Nicollet	34,454	5.3	76.8	\$38,120	1.7	7.2	E, M, R
Lincoln	5,640	-4.3	10.5	\$30,178	1.8	8.7	E, Ag, R/M
Lyon	25,269	-2.3	35.4	\$30,706	2.1	8.8	E, R, M
Cottonwood	11,517	-1.5	18.0	\$27,709	3.0	11.2	E, M, Ag
Murray	8,179	-6.3	11.6	\$32,791	1.8	7.6	E, Ag, M
<sup>a</sup>	U.S. Census Bureau, 2021						
<sup>b</sup>	Percent population change is based on Population Census April 1, 2020, as compared to Population Census April 1, 2010.						
<sup>c</sup>	U.S. Census Bureau, 2020. Industries are defined under the 2012 North American Industry Classification System and abbreviated as follows: Ag = Agriculture, Forestry, Fishing, and Hunting, and Mining; C = Construction; E = Educational, Health and Social Services; M = Manufacturing; P = Professional, Scientific, and Management, and Administrative and Waste Management Services; and R = Retail Trade.						



Table 8.10: Race and Ethnicity of the Population in the Project Study Area

Table 8-10 Race and Ethnicity of the Population in the Project Study Area							
<b>Minnesota</b>	<b>78.1</b>	<b>7.4</b>	<b>1.4</b>	<b>5.4</b>	<b>0.1</b>	<b>5.8</b>	<b>21.9</b>
Sherburne	88.9	4.0	0.6	1.6	<0.1	3.1	11.1
Stearns	82.8	9.0	0.5	2.3	0.1	3.9	17.2
Wright	90.6	2.3	0.5	1.6	<0.1	3.4	9.4
Kandiyohi	77.6	6.5	0.6	1.4	0.2	13.4	22.4
Meeker	93.5	0.7	0.4	0.5	0.1	4.3	6.5
McLeod	89.7	1.1	0.6	0.8	0.1	7.2	10.3
Carver	87.7	2.4	0.4	3.6	0.1	4.5	12.3
Sibley	87.8	1.1	0.5	0.8	<0.1	9.1	12.2
Swift	89.0	1.0	0.7	0.8	1.0	6.1	11.0
Lac qui Parle	94.0	0.8	0.4	0.8	0.3	2.8	6.0
Chippewa	85.5	1.0	1.4	1.3	1.6	8.2	14.5
Renville	86.2	0.8	1.6	0.8	<0.1	10.0	13.8
Yellow Medicine	88.8	0.8	3.8	0.6	0.1	5.1	11.2
Redwood	85.8	1.1	5.3	2.8	0.1	4.1	14.2
Brown	92.6	0.6	0.3	0.8	<0.1	4.9	7.4
Nicollet	86.8	4.5	0.6	1.6	<0.1	5.1	13.2
Lincoln	94.7	0.4	0.5	0.8	0.1	2.6	5.3
Lyon	82.2	3.4	0.9	5.3	0.1	7.7	17.8
Cottonwood	82.4	1.6	0.9	4.4	0.7	9.9	17.6
Murray	91.0	0.6	0.5	2.0	0.3	5.0	9.0
<sup>a</sup> Total minority percentage equals the total population minus the percentage of white alone, not Hispanic or Latino. Source: U.S. Census Bureau, 2021							

Transmission line projects have the potential to benefit the socioeconomic conditions of an area in the short term through an influx of non-local personnel, creation of construction jobs, purchases of construction material and other goods from local businesses, and expenditures on temporary housing for non-local personnel. In the long term, transmission line projects may beneficially impact the local tax base in the form of revenues generated from utility property taxes. Additionally, permanent job creation or relocation of personnel to the area for operation of a transmission line project could affect area demographics.

Potential mitigation measures that may enhance the socioeconomic benefits experienced by local communities include use of local personnel and construction material retailers during construction of the Project. The Applicant will work with local communities to identify opportunities for further enhancing the socioeconomic benefits of the Project.

### 3. Environmental Justice

The U.S. Environmental Protection Agency (EPA) defines environmental justice as the “fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income in the development, implementation, and enforcement of environmental laws, regulations, and policies.” (EPA, 2022a). Fair treatment means that no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental, and commercial operations or policies. Meaningful involvement means:

- people have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health;
- the public’s contributions can influence the regulatory agency’s decision;
- community concerns will be considered in the decision-making process; and
- decision makers will seek out and facilitate the involvement of those potentially affected.

EPA developed a mapping and screening tool, EJScreen, that can be used as an initial step to gather information regarding minority and/or low-income populations; potential environmental quality issues; environmental and demographic indicators; and other important factors (EPA, 2022b). EPA recommends that screening tools like EJScreen be used for a "screening-level" look and a useful first step in understanding or highlighting locations that may require further review.

The MPCA website Understanding Environmental Justice provides tools to help identify environmental justice communities throughout the state and provide guidance for integrating environmental justice principles such as fair treatment and meaningful involvement of environmental justice communities (MPCA, n.d.[b]). The MPCA uses data on income, poverty levels, and race from the U.S. Census Bureau to identify areas of environmental justice concern at the census tract level. Areas of environmental justice concern are defined by MPCA when one or both of the following criteria are met:

- The number of persons of color is greater than 50%; or

- More than 40% of the households have a household income of less than 185% of the federal poverty level.

Federally recognized Indian Tribes and reservation areas are also defined by MPCA as areas of environmental justice concern. MPCA has created an interactive map that shows identified areas of environmental justice concern throughout the state (MPCA, n.d.[c]).

As routes are developed for the Project, the Applicant will review EJScreen and the MPCA's integrative mapper to assess where areas of environmental justice concern may exist in relation to the Project. In addition, the Applicant would conduct an analysis of U.S. Census block data to identify where environmental justice communities exist in the relation to the proposed Project and whether such communities would be disproportionately affected by the Project.

a. Public Services and Transportation

The Project Study Area encompasses a mostly rural area in central and southwestern Minnesota. In rural areas, residents often rely on privately owned septic systems and wells, although some residents may have access to rural water distribution facilities. Larger population centers, like the cities of Buffalo, Wilmar, Litchfield, Hutchinson, Glencoe, Granite Falls, Redwood Falls, New Ulm, and Marshall are serviced by municipal public works for water, sewer, and electrical services (MMUA, 2022).

Existing road infrastructure within the Project Study Area is a mix of federal, state, and county highways, and township roads. Interstate 94 travels southeast-northwest through the northeastern tip of the Project Study Area. Major north-south roadways include U.S. Highways 71 and 59, and State Highways 4 and 15. Major east-west roadways include U.S. Highways 12, 212, and 14, and State Highways 55 and 60. There are nine railroads in the Project Study Area. Railroads in the Project Study Area connect larger population centers throughout Minnesota; the majority of these railroads travel between the Twin Cities metropolitan area and larger municipalities such as Wilmar, Granite Falls, and Marshall. The owners and operators of the railroads are Canadian Pacific, Burlington Northern Santa Fe Railroad, SOO Railroad, Northern Lines Railroad, Twins Cities and Western Railroad, Minnesota Prairie Line Railroad, and Dakota, Minnesota, and Eastern Railroad, and Union Pacific Railroad.

Numerous electric transmission lines exist throughout the Project Study Area, as depicted on Figure 1. Transmission line crossings of the Minnesota River are concentrated near Granite Falls, Redwood Falls, Franklin, and New Ulm. Electrical substations that support the network of transmission lines are scattered throughout the Project Study Area; these features

are generally sited on the outer edges of municipalities or away from population centers in rural areas.

Oil and gas transmission and distribution pipelines are present throughout the Project Study Area (PHMSA, 2022). Transmission pipelines are generally sited away from population centers, while distribution lines typically supply population centers. The location of pipelines will be identified with more specificity as routes are developed for the Project. If the proposed transmission line is routed near or crosses a pipeline, appropriate engineering standards will be incorporated into Project design, and any required crossing permissions or agreements will be obtained.

Thirty-four public airports and 20 private airports are present within the Project Study Area (see [Table 8.11](#)). In general, airports are more prevalent in the northern and eastern portions of the Project Study Area; this portion of the Project Study Area is closer to the twin cities metropolitan area (see Figure 1). Public airports are located in larger municipalities in the Project Study Area such as Clear Lake, Buffalo, Hutchinson, and Granite Falls. Private airports are a mixture of hospital or medical center airstrips or landing pads and privately owned landing strips.

**Table 8.11: Public and Private Airports in the Project Study Area**

<b>Table 8-11 Public and Private Airports in the Project Study Area</b>		
Anoka Sand Plain Subsection (222Mc): Sherburne, Stearns, Wright	1	5
Hardwood Hills Subsection (222Ma): Stearns, Wright, Kandiyohi, Meeker	--	2
Big Woods Subsection (222Mb): Stearns, Wright, Meeker, McLeod, Carver, Sibley	4	10
Minnesota River Prairie Subsection (251Ba): Stearns, Swift, Kandiyohi, Meeker, McLeod, Lac qui Parle, Chippewa, Renville, Sibley, Yellow Medicine, Redwood, Brown, Nicollet, Lincoln, Lyon, Cottonwood	14	17
Coteau Moraines Subsection (251Bb): Yellow Medicine, Redwood, Lincoln, Lyon, Murray, Cottonwood	1	--
<b>Total</b>	<b>20</b>	<b>34</b>
Source: MnDOT Aeronautics ASE, 2022.		

In general, impacts on public services and transportation can be avoided through routing design including paralleling existing utility corridors and other linear infrastructure. However, during Project construction roadway closures or diversions may be necessary to accommodate construction equipment. If road closures cannot be avoided, the Applicant will work with the federal, state, and county agencies to develop appropriate mitigation

measures to minimize impacts on public services and transportation. Mitigation measures could include avoiding construction during hours of peak use, detours, signage, and ensuring access to public service infrastructure is not restricted.

Airport impacts can be addressed through the route selection process (generally through avoidance) and structure design (where an airport cannot be avoided). A flight hazard determination from the Federal Aviation Administration (FAA) may be required. The FAA requires notification of any transmission line constructed near an airport if the structure height exceeds a slope of 100:1 within 20,000 feet (3.8 miles) or a slope of 50:1 within 10,000 feet (1.9 miles) of the airport. In general, a transmission line will need to be approximately one mile from municipal airports to avoid conflicts with local requirements (14 Code of Federal Regulations [CFR] Part 77). The Project will comply with other rules that establish safety zones for airports, where appropriate.

#### 4. Recreation

Recreational opportunities within the Project Study Area include wildlife viewing, camping, hiking, canoeing, kayaking, hunting, fishing, and boating. There are several types of formally managed and regulated lands across the Project Study Area, including federal easements and managed lands, National Wildlife Refuges (NWRs), Waterfowl Production Areas (WPAs), trust lands, state trails, public waters, WMAs, state parks, SNAs, and municipal and county parks and trails. These lands are typically used for recreational purposes, habitat management, and conservation. Figure 6 shows the distribution of managed lands and recreation areas within the Project Study Area.

NWRs within the Project Study Area are primarily found near bodies of water in the Anoka Sand Plain subsection and the northeastern portion of the Minnesota River Prairie subsection. The USFWS manages NWRs to conserve wildlife habitat (USFWS, n.d.[a]). Not all NWRs are open to the public for recreation. When public use is allowed, recreational opportunities typically include wildlife viewing and hiking.

WPAs are part of the USFWS Refuge System, but unlike NWRs, they tend to be dispersed across counties and townships versus a distinct, contiguous area (USFWS, n.d.[b]). WPAs are scattered throughout all the ECSs in the Project Study Area, but most WPAs are in the Minnesota River Prairie and Big Woods subsections.

WMAs are located throughout all ECSs within the Project Study Area and are predominantly concentrated near surface waters and wetlands, including the Minnesota River. WMAs are managed by the MDNR to protect and conserve wildlife habitat. WMAs are typically open to the public for wildlife viewing, hiking, hunting, and fishing (MDNR, 2022h).

SNAs are present in the Anoka Sand Plain and Hardwood Hills subsections in the northeastern Project Study Area. In the Minnesota River Prairie subsection, SNAs are predominantly concentrated along the Minnesota River. A few additional SNAs are present in the Couteau Moraines subsection portion of the Project Study Area. SNAs are managed by the MDNR to conserve and protect native plant communities, rare species, and geological features (MDNR, 2022i). Recreational opportunities at SNAs include wildlife viewing, hiking, nature photography, snowshoeing and cross-county skiing.

AMAs in the Project Study Area are concentrated in the northern portion of the Minnesota River Prairie subsection (e.g., Kandiyohi and Meeker Counties) and along the Minnesota River, though a couple of AMAs are in the southern portion of this ECS, as well. AMAs are managed by MDNR to protect and conserve aquatic species and critical shore land habitat (MDNR, 2022j). Public use of AMAs is allowed for wildlife viewing, non-motorized travel, fishing, hunting, and trapping.

State forests within the Project Study Area are limited to the Sand Dunes State Forest in the Anoka Sand Plain and Big Woods subsections. The 2,700-acre Sand Dunes State Forest is owned and managed by MDNR. The forest is open to the public for camping, hiking, canoeing, kayaking, fishing, hunting, picnicking, swimming, and snowshoeing.

Designated State Water Trails are present throughout the Project Study Area, including the Mississippi River, Sauk River, North and South Forks of the Crow River, in the Anoka Sand Plain and Big Woods subsections. In the Minnesota River Prairie subsection, State Water Trails include the Minnesota, Chippewa, Redwood, and Cottonwood Rivers. State Water Trails are managed by MDNR to provide opportunities for public recreation including canoeing, kayaking, paddleboarding, and camping (MDNR, 2022k).

State hiking trails are present throughout the Project Study Area but are generally concentrated in the Hardwood Hills, Big Woods, and Minnesota River Prairie subsections. Examples of state hiking trails in Project Study Area include the Glacial Lakes State Trail in the Hardwood Hills subsection and the Dakota Rail State Trail MS84.029 and the Luce Line State Trail in the Big Woods subsection. Each of these trails extend into the Minnesota River Prairie subsection, as well.

Additional hiking trails are located within state, local and county parks throughout the Project Study Area. Most state parks are in the Minnesota River Prairie subsection and are generally located near surface waters including, but not limited to, the Minnesota River, Redwood River, Monson Lake, Norway Lake, and other small lakes and streams throughout the Project Study Area; Figure 6 shows the distribution of state parks in the Project Study Area. County and municipal parks are distributed throughout each of the ECSs in the Project Study Area.

Snowmobile trails are found throughout the Project Study Area and generally follow existing county and township roads, though many state parks and hiking trails also allow snowmobiling during the winter months. As most of the Project Study Area is in the Minnesota River Prairie subsection, most snowmobile trails in Project Study Area are in this subsection. Additionally, Powder Ridge Winter Recreation Area is located in Kimball within the Hardwood Hills subsection.

In general, public recreation areas and managed lands can be avoided through routing design, as needed. If these areas cannot be avoided, the Applicant will work with the federal, state, county, and local agencies to develop appropriate mitigation measures to minimize impacts on public recreational use of these areas. Mitigation measures could include avoiding construction during seasons of peak use, signage, and ensuring public access to recreation areas is not restricted.

a. Aesthetics

The visual character and setting of the majority of the Project Study Area includes largely level agricultural fields broken up by shelterbelts, roads, and large water features (i.e., wetlands, lakes, and rivers). The Mississippi and Minnesota Rivers are the primary drainages within the Project Study Area and represent the most significant change in topography.

Public roadways and utility corridors, including overhead transmission lines, exist throughout the Project Study Area (see Section 8.5.1 and Figure 1). Overhead transmission lines, existing wind and solar facilities are visible from a variety of potential viewpoints within the Project Study Area, including private residences, highways, county and township roads and recreation areas. Structures, conductors, insulators, aeronautical safety markings, avian diverters, vegetation clearing, and access roads may be seen from any of these vantage points. Potential mitigation measures that could minimize interruptions in the visual landscape include:

- Locating facilities in relationship to landforms so they will screen transmission line features.
- Locating rights-of-way and structures with input from landowners or land management agencies.
- Using care in routing, structure design and pole placement to preserve the natural landscape.
- Implementing restoration measures that reflect the existing vegetation as much as possible without impacting the safe and reliable operation of the lines.
- Where practicable, proposing river crossings near existing transmission lines, highways, or other infrastructure.

## 5. Agricultural Production

The agricultural production industry is a significant part of local economies throughout the State of Minnesota. Information from the USDA's 2017 Census of Agriculture for each of the counties in the Project Study Area is provided in [Table 8.12](#). For a listing of counties within each ECS, refer to Section 8.2 and Table 8.1.

In the Project Study Area, the role that agricultural production plays in local economies varies by ECS. For example, in the counties within the Anoka Sand Plain, Hardwood Hills, and Big Woods subsections generally less than 80% of land is used for agricultural production (USDA, 2017). In Sherburne County, the northeastern most county in the Project Study Area, only 37% of land is used for agricultural production. An exception is McLeod County, located partially within both the Big Woods and Minnesota River Prairie subsections, where 85% of land in the county is used for agricultural production. In the Minnesota River Prairie and Couteau Moraine subsections, most counties use upwards of 85% of land for agricultural production. At the high end, about 99% of land in Renville County is used for agricultural production; Renville County is in the center of the Project Study Area and the Minnesota River Prairie subsection. At the low end, Kandiyohi County, which overlaps both the Hardwood Hills and Minnesota River Prairie subsections, only 79% of land is used for agricultural production.

Variations in crops by acreage and livestock by farms do not vary significantly between ECSs in the Project Study Area. Corn is the primary row crop by acreage in most of the counties in the Project Study Area, along with soybeans, forage, and sugar beets. Cattle are the primary livestock by farms in most of the Project Study Area along with hogs and pigs, sheep and lambs, and poultry.

**Table 8.12: Agricultural Statistics for the Project Study Area**

Table 8-12 Agricultural Statistics for the Project Study Area			
Sherburne	102,544 (37% of county)	Corn, soybeans, potatoes	Cattle, poultry, sheep and lambs
Stearns	650,821 (76% of county)	Corn, soybeans, forage	Cattle, poultry, hogs and pigs
Wright	240,651 (57% of county)	Soybeans, corn, forage	Cattle, poultry, sheep and lambs
Kandiyohi	455,854 (89% of county)	Corn, soybeans, sugar beets	Cattle, poultry, sheep and lambs
Meeker	301,439 (77% of county)	Soybeans, corn, forage	Cattle, poultry, hogs and pigs
McLeod	268,636 (85% of county)	Corn, soybeans, forage	Cattle, poultry, hogs and pigs/sheep and lambs



Table 8-12 Agricultural Statistics for the Project Study Area

Table 8-12 Agricultural Statistics for the Project Study Area			
Carver	158,644 (70% of county)	Corn, soybeans, forage	Cattle, poultry, hogs and pigs/sheep and lambs
Sibley	350,036 (93% of county)	Corn, soybeans, forage	Cattle, poultry, hogs and pigs
Swift	344,976 (73% of county)	Corn, soybeans, forage	Cattle, poultry, hogs and pigs
Lac qui Parle	419,884 (86% of county)	Soybeans, corn, forage	Cattle, hogs and pigs, poultry
Chippewa	341,030 (92% of county)	Corn, soybeans, sugar beets	Cattle, poultry, hogs and pigs
Renville	624,114 (99% of county)	Corn, soybeans, sugar beets	Cattle, hogs and pigs, sheep and lambs/poultry
Yellow Medicine	383,646 (79% of county)	Corn, soybeans, forage	Cattle, hogs and pigs, sheep and lambs/poultry
Redwood	523,912 (93% of county)	Corn, soybeans, forage	Cattle, hogs and pigs, poultry
Brown	355,766 (91% of county)	Corn, soybeans, forage	Cattle, hogs and pigs, poultry
Nicollet	264,832 (92% of county)	Corn, soybeans, forage	Cattle, hogs and pigs, poultry
Lincoln	297,836 (87% of county)	Corn, soybeans, forage	Cattle, hogs and pigs, poultry
Lyon	395,132 (87% of county)	Corn, soybeans, forage	Cattle, hogs and pigs, sheep and lambs
Murray	395,079 (88% of county)	Corn, soybeans, forage	Cattle, hogs and pigs, sheep and lambs
Cottonwood	370,389 (90% of county)	Corn, soybeans, forage	Cattle, hogs and pigs, poultry
Source: USDA, 2017			

Designated "prime farmland" exists throughout the Project Study Area. In particular, prime farmland is abundant in the Minnesota River Prairie and Couteau Moraines ECSs. Federal regulations define prime farmland as "land that has the best combination of physical and chemical characteristics for producing food, feed, forage, fiber and oilseed crops and is available for these uses." 7 CFR, 657.5 (a) (1).

Impacts on agricultural fields and production can be minimized through avoidance and routing transmission lines along field edges and other existing linear infrastructure (e.g., roads, transmission lines). The Applicant 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 Applicant will work with landowners to avoid these systems. Crop production on some portion of agricultural lands may be temporarily interrupted for one growing season while transmission line facilities are constructed. In cultivated cropland areas, the Applicant will attempt to conduct construction before crops are planted or following harvest, if possible. The Applicant will compensate landowners for impacts on crops resulting from the construction, operation, and maintenance of the Project including compaction that might result from these activities.

#### 6. Forestry Production

Commercial forestry operations are not common in the Project Study Area. Forested areas in the Project Study Area typically consist of narrow swaths of trees along the margins of waterbodies and shelterbelts surrounding farmsteads, along the boundaries of agricultural fields, or in state parks or forest and other federal, state, or locally designated and managed lands (see Figure 7). No commercial forestry operations have been identified within the Project Study Area and the Project is not expected to impact forestry production.

#### 7. Mineral Extraction

The Applicant reviewed publicly available information from the Minnesota Department of Transportation (MnDOT) Aggregate Source Information System and the USGS Mineral Resources Data System to identify mineral mining operations in the Project Study Area (MnDOT, 2022; USGS, n.d.). There are various active and inactive sand, gravel, and stone quarry operations throughout all the ECSs in the Project Study Area, but mining operations are most common in the Hardwood Hills, Big Woods, Minnesota River Prairie, and Couteau Moraines subsections (see Figure 7). In the Minnesota River Prairie subsection, mining operations are common along the Minnesota River valley. Sand and gravel are primarily mined for local uses such as making concrete for highways, roads, bridges, and buildings. These operations are owned either by citizens, private companies, or MnDOT.

Mining operations can generally be avoided through route design. The Applicant will work with private owners and MnDOT to identify mining operations and design the Project to avoid these areas.

### **F. Archaeological and Historical Resources**

Previously identified archaeological sites (e.g., pre-contact artifact assemblages, burial mounds, and earthworks) are present in the Project Study Area, primarily along the margins of rivers (e.g., Mississippi and Minnesota Rivers) and other surface waters. The Project Study Area also contains historic architectural resources, the majority of which are located within municipalities (e.g., churches, grain elevators, banks, railroads) though some rural farmsteads

and bridges are also considered historic architectural resources. Some of the archaeological sites and historic architectural resources are listed or considered eligible for listing in the National Register of Historic Places (NRHP), while other sites have yet to be evaluated.

After routes are identified for the Project, the Applicant will complete a Phase Ia literature review to characterize the prehistoric and historic context along identified route options and to identify previously recorded archaeological sites and historic architectural resources that need to be avoided due to their listing in or eligibility for listing in the NRHP. A summary of the findings in the Phase Ia literature review will be presented in the Route Permit Application.

Effects to historic properties can be avoided by proper routing of the transmission line. If impacts to any recorded site cannot be avoided by the Project, that recorded site will require formal significance evaluation to determine if it meets the eligibility requirements of the NRHP. If found significant, mitigation strategies will be undertaken to reduce impacts. This could include identifying the site in detail prior to construction, limiting construction access and activities as much as possible, and having an archaeologist present during construction to monitor work and to gather any artifacts found. If properties are listed in the NRHP, or if they are considered eligible for listing, they may be afforded protection under federal and state regulations. The Applicant provided notice to all Minnesota tribal governments per the Notice Plan, and were invited to the virtual open houses we held in November 2022. Xcel Energy will work with the appropriate state, federal and tribal agencies during the routing process to avoid known historic resources as much as possible.

### **G. Other Permits and Approvals**

In addition to a Certificate of Need, a Route Permit from the Commission will be required, and the Applicant may also need to obtain other local, state, and federal approvals. [Table 8.13](#) lists potential permits and approvals that may be required for the Project. Typical municipal permit categories are listed, but specific permits may vary from city to city and are limited. Once the Commission issues a route permit, local zoning, building, and land use regulations and rules are preempted per Minn. Stat. § 216E.10, subd. 1.

Table 8.13: Potential Permits/Compliance Requirements

<b>Table 8-13 Potential Permits/Compliance Requirements</b>	
<b>Local Approvals</b>	
Road Crossing/Right-of-Way Permits	County, Township, City
Lands Permits	County, Township, City
Utility Permits	County, Township, City
Oversize / Overweight Permits	County, Township, City
Driveway/Access Permits	County, Township, City
<b>State Approvals</b>	
Certificate of Need	MNPUC
Route Permit	MNPUC
Threatened & Endangered Species Consultation	MDNR
License to Cross Public Waters	MDNR – Lands and Minerals
Construction Dewatering Permit	MDNR
Utility Permit	MnDOT
Driveway/Access Permits	MnDOT
Oversize/Overweight Permits	MnDOT
Wetland Conservation Act Exemption Concurrence	BWSR
Section 401 Water Quality Certification	MPCA
National Pollutant Discharge Elimination System Permit	MPCA
Cultural Resources Consultation	Minnesota State Historic Preservation Office
<b>Federal Approvals</b>	
Section 7 Consultation	USFWS
Section 10 Permit	USACE
Section 404 Permit	USACE
Notice of Proposed Construction (7460-1)	FAA
Notice of Actual Construction or Alteration	FAA
Farmland Protection Policy Act/Farmland Conversion Impact Rating	USDA/NRCS

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