STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis Reha	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Application of Northern States Power Company, d/b/a Xcel Energy, and Great River Energy for a Certificate of Need for the Hollydale 115 kV Transmission Line Project in the Cities of Plymouth and Medina

Docket No. E002, ET2/CN-12-113

FILING SUMMARY

Northern States Power Company, doing business as Xcel Energy, and Great River Energy filed an application with the Minnesota Public Utilities Commission on July 2, 2012 for a Certificate of Need to construct new 115 kilovolt transmission line facilities, to construct a new 115 kilovolt substation, and modify associated transmission facilities. All of the proposed work will occur near the cities of Plymouth and Medina, in Hennepin County, Minnesota.

The Project is needed to address electric distribution concerns, to provide increased distribution capacity, and to avoid feeder circuit overloads in the Plymouth area distribution delivery system.

Copies of the Application can be obtained from the Xcel Energy web site at www.xcelenergy.com. If you have questions concerning our filing, you may contact Paul Lehman at (612) 330-7529.

APPLICATION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR A CERTIFICATE OF NEED FOR THE HOLLYDALE 115 KV TRANSMISSION LINE PROJECT IN THE CITIES OF PLYMOUTH AND MEDINA

PUC Docket No. E-002, ET-2/CN-12-113

July 2, 2012

Submitted by
Northern States Power Company, a Minnesota corporation, and
Great River Energy, a Minnesota cooperative corporation

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EXECUTIVE SUMMARY

Two approvals must be received from the Minnesota Public Utilities Commission before a high voltage transmission line can be built within this state: a Certificate of Need and a Route Permit. A Certificate of Need proceeding examines whether a facility is needed and a Route Permit proceeding determines where the facility should be located. This document is Northern States Power Company and Great River Energy's application for one of these approvals, a Certificate of Need, to construct 115 kilovolt transmission facilities between the existing Medina Substation and Hollydale Substation and between the Hollydale Substation and the proposed Pomerleau Lake Substation. The purpose of this Executive Summary is to summarize the contents of this Certificate of Need application. We have separately applied for a Route Permit in Docket No.: E002, ET2/ TL-11 -152.

NEED:

The proposed project is designed to meet the electrical needs of the Plymouth and Medina area. The demand for power in this area has increased beyond the capability of the current electrical distribution system and additional transmission facilities are needed to provide reliable electrical service to this area. We have evaluated different ways to provide electrical service to the Plymouth and Medina areas. We believe that constructing the Pomerleau Lake Substation, expanding the Hollydale Substation's capacity, and connecting it with the 115 kilovolt transmission facilities proposed in this Application are necessary to serve the electrical needs of this area.

PROJECT:

To meet the identified need, we propose to construct approximately 8.8 miles of 115 kilovolt transmission line facilities, construct a new 115 kilovolt substation (to be called the Pomerleau Lake Substation), and modify associated transmission facilities ("Project").[1] All of the proposed work will occur near the cities of Medina and

[1] While the Hollydale Project as proposed is less than 10 miles in length, a Scoping Decision issued on December 27, 2011 in the route permit proceeding (Docket No.: E002, ET2/ TL-11 -152) includes 26 additional route alternatives to be evaluated in the environmental review document. Several of these 26 route alternatives are greater than 10 miles in length. A Certificate of Need would be required prior to issuing a route permit and construction for a route longer than

Plymouth in Hennepin County, Minnesota. **Figure 1** is a conceptual representation of the Project.[2]

Figure 1
Proposed Hollydale Project[3]

For the new 115 kilovolt structures, we propose to use primarily single steel pole braced post structures. These structures are typically placed approximately 300 to 500 feet apart and are approximately 70-to 90-feet tall. In the Route Permit proceeding already underway, we propose to locate 8 miles of the new 115 kilovolt facilities along the existing 69 kilovolt line within the existing 70-to 100-foot right-of-way. In these areas, the 69 kilovolt line would be removed. For the remaining 0.8 miles of new 115 kilovolt transmission facilities, we propose a new 75 foot wide right-of-way.

With the submission of this Certificate of Need Application in July, 2012 we estimate that the processing and approval of the application (along with the Route Permit Application) will be complete about a year from now in the spring of 2013. With

10 miles. Minn. Stat. § 216B.243, subd. 2; Minn. Stat. § 216B.2421, subd. 2(3). A map of these 26 route alternatives is included as **Figure 27**.

[3] **Figure 1** is intended as a conceptual representation of the proposed Project and is not intended to show Applicants' proposed location of the proposed transmission facilities. To review a map of all routes under consideration for the Hollydale Project in the pending route permit proceeding (Docket No.: E002, ET2/ TL-11 -152), as of July 2, 2012, see **Figure 27**.

these necessary permits in hand, we expect that construction of the Project will commence in 2013 with an in-service date of 2015.[4] The Project is estimated to cost approximately $23.1 million.

If you have questions regarding details of the Project, please contact one of the following representatives:

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Chapter Summaries

Our analysis of the need, alternatives evaluated, and potential environmental impacts are detailed in the eight chapters of this Application. Each chapter is dedicated to a specific subject area. The chapters are summarized below. These chapter summaries and key points will be repeated at the beginning of each chapter. The beginning of each chapter will also include a glossary of key terms.

Chapter 1: Project Introduction and Overview: The first chapter of this document summarizes the proposed Project. Here we provide the expected schedule for the Project and costs to construct the facilities proposed. The chapter also describes how the Project complies with the statutory and rule requirements for issuance of a Certificate of Need.

Key Points: We propose to construct new 115 kilovolt single circuit transmission line and terminating facilities. We expect that construction of the Project will

[4] This application is for a Certificate of Need. In a Certificate of Need proceeding, the Minnesota Public Utilities Commission determines if the proposed transmission lines are necessary and what the appropriate size, configuration and timing of the project should be. In the route permit proceeding that is currently pending in Docket No.: E002, ET2/ TL-11 -152, the Minnesota Public Utilities Commission will determine where the proposed 115 kilovolt transmission line facilities should be located. For additional information regarding the routes under consideration in the route permit proceeding, as of July 2, 2012, see **Figure 27**.

commence 2013 with an in-service date of 2015. The Project is estimated to cost approximately $23 million.

Chapter 2: Electrical System Overview: In Chapter 2, we will provide an overview of the electrical system. We will also provide information regarding how the distribution system which provides electricity to homes and businesses operates.

Key Points: 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 plants to the areas where the electricity is needed.

Chapter 3: Distribution Load Serving Need Analysis: In Chapter 3, we explain why we are proposing the Project. This is referred to as "the need" for the Project. We cover how the current distribution and transmission facilities provide electric service to our customers and how the current facilities are not enough to support current and future demand for electricity in this area. In this chapter, we explain our analysis of different ways that we have considered to fix the problems identified. This includes distribution system improvements and transmission system improvements.

Key Points: The Project is needed so that the distribution system can reliably meet the growing demand for electric power in the Plymouth and Medina areas. In examining ways to provide reliable electric service to the Plymouth area, we looked at common distribution improvements, including adding new feeder circuits, extending existing feeder circuits, and reconfiguring feeder circuits and determined that these improvements were not sufficient to solve the identified distribution deficiencies. We also looked at the existing 69 kilovolt facilities and alternative 115 kilovolt transmission configurations for the Project. In the end, Applicants concluded that the proposed Project best meets the electrical needs of the Plymouth and Medina area.

Chapter 4: Alternatives Analysis: In Chapter 4 we explain our analysis of different ways that we have considered to fix the problems identified in the previous chapter. As

well as options that don't require new or improved transmission facilities. These are referred to as the "non-transmission alternatives."

Key Points: We considered a "no build" alternative that made use of demand-side management solutions and using generation as an alternative to building new or improved transmission facilities. In addition, we analyzed different voltages and alternative transmission designs such as underground transmission lines and direct current lines to serve the need. In the end, we concluded that the proposed Project best serves the needs identified in Chapter 3.

Chapter 5: Project Description: In Chapter 5, we describe the specifics of the Project including the types of structures that we propose to use to support the new 115 kilovolt transmission line. We also identify the amount of right-of-way required for the Project and provide a description of the new Pomerleau Lake Substation.

Key Points: Applicants propose to construct a new 115 kilovolt line using steel poles that will be approximately 70 to 90 feet tall. Applicants also propose to construct a new substation, the Pomerleau Lake Substation, near I-494 and Schmidt Lake Road.

Chapter 6: Transmission Line Operating Characteristics: Chapter 6 provides information regarding the operating characteristics of the proposed 115 kilovolt transmission lines and associated substations. This includes information regarding electric and magnetic fields, noise, ozone and nitrogen oxide emissions, and radio and television interference.

Key Points: The proposed transmission lines and substations will be designed to meet or exceed all relevant safety codes. The noise generated by transmission lines is not expected to exceed background noise levels and will be well below the state noise standards. Electric and magnetic fields exists wherever electricity is produced or used, and surrounds any electrical appliance or wire that is conducting electricity. The potential health effects from electric and magnetic fields have been studied for more than 30 years by government and scientific institutions all over the world. No causal link between electric fields or magnetic fields and health effects has been demonstrated.

> "In addition, virtually all of the laboratory evidence and the mechanistic evidence fail to support a relationship between low-level [extremely low frequency] magnetic fields and changes in biological function or disease status."
>
> - World Health Organization

> "Most researchers concluded that there is insufficient evidence to prove an association between magnetic fields and health effects;"
>
> - Minnesota Interagency Working Group

> "The magnetic fields produced by electricity are weak and do not have enough energy to break chemical bonds or to cause mutations in DNA. . . . In addition, whole animal studies investigating long-term exposure to [extremely low frequency] magnetic fields have shown no connection between exposure and cancer of any kind."
>
> - Public Service Commission of Wisconsin

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

Key Points: The construction of a transmission line typically involves four key activities: (1) detailed engineering, design, and regulatory approvals; (2) right-of-way evaluation and acquisition; (3) construction; and (4) right-of-way restoration. Construction of the Project will follow standard construction and mitigation practices developed from experience with past projects.

Chapter 8: Environmental Information: Chapter 8 provides a general overview of the environmental features and land uses in the Project area.

Key Points: Based on our review, there are no environmental issues that would preclude construction of the proposed facilities. Applicants will take mitigative measures to minimize the environmental impacts of siting, constructing, and operating the Project.

1 PROJECT INTRODUCTION AND OVERVIEW

Chapter 1: Project Introduction and Overview: The first chapter of this document summarizes the proposed Project. Here we provide the expected schedule for the Project and costs to construct the facilities proposed. The chapter also describes how the Project complies with the statutory and rule requirements for issuance of a Certificate of Need.

Key Terms:

- **Conductor** – *A wire made up of multiple aluminum strands supported by a steel core that together carry electricity. A bundled conductor is two or more conductors connected together to increase the capacity of a transmission line.*
- **Distribution** – *An interconnected group of lines and associated equipment for the local delivery of low voltage electricity between the transmission network and end users.*
- **Kilovolt** – *A kilovolt is equal to one thousand volts.*
- **Load** – *All the devices that consume electricity and make up the total demand for power at any given moment or the total power drawn from the system.*
- **Serve load** – *The ability to reliably deliver the amounts of electricity necessary to match customer needs at any given time.*
- **Single circuit** – *One circuit made up of three sets of conductors.*
- **Substation** – *A facility that monitors and controls electrical power flows, uses high voltage circuit breakers to protect power lines and transforms voltage levels to meet the needs of end users.*
- **Transformers** – *Devices that step-up or step-down voltage between two voltage systems.*
- **Transmission** – *An interconnected group of lines and equipment for transporting electric energy in bulk between power sources (e.g. power plants) and major substations where the voltage is 'stepped down' for distribution to customers. Transmission is considered to end where the line connects to a distribution station.*

Key Points: *We propose to construct new 115 kilovolt single circuit transmission line facilities. We expect that construction of the Project will commence 2013 with an in-service date of 2015. The Project is estimated to cost approximately $23 million.*

1.1 Introduction

Applicants, Northern States Power Company, a Minnesota corporation ("Xcel Energy"), and Great River Energy, a Minnesota cooperative corporation, submit this Application for a Certificate of Need to the Minnesota Public Utilities Commission. This Application seeks a Certificate of Need to construct new 115 kilovolt transmission line facilities, to construct a new 115 kilovolt substation (to be called the Pomerleau Lake Substation), and modify associated transmission facilities ("Project"). All of the proposed work will occur near the cities of Plymouth and Medina in Hennepin County. **Figure 2** shows the proposed Project. This Application is submitted pursuant to Minnesota Statutes Section 216B.243 and Minnesota Rules 7849.0020 – 7849.0400. A checklist showing the locations of information required by the Minnesota Statutes and Rules for a Certificate of Need Application is included in **Appendix A**.

Figure 2
Proposed Hollydale Project[5]

[5] **Figure 2** is intended as a conceptual representation of the proposed Project and is not intended to show the location of the proposed facilities. To review a map of all routes currently under consideration for the Hollydale Project in the pending route permit proceeding (Docket No.: E002, ET2/ TL-11 -152), as of July 2, 2012, see **Figure 27**.

1.2 Pending Route Permit Proceeding

On June 30, 2011, Applicants filed an Application with the Commission for a Route Permit for the Hollydale Project. This proceeding is pending. (Docket No. E002/TL-11-152). Minnesota Statute § 216B.243, subd. 2 provides that "no large energy facility" shall be sited or constructed in Minnesota without the issuance of a Certificate of Need by the Commission. The definition of a "large energy facility" that is applies here is "a high-voltage transmission line with a capacity of 100 kilovolts or more with more than 10 miles of its length in Minnesota." Minn. Stat. § 216B.2421, subd. 2(3). As neither Applicants' proposed route for the Project[6] nor the four alternate route segments[7] analyzed in the Route Permit Application was greater than 10 miles in length, Applicants did not file a Certificate of Need Application concurrently with the Route Permit Application.

On December 27, 2011, the Department of Commerce issued a Scoping Decision for the Hollydale Project which included 26[8] route alternatives to be evaluated in the environmental document. Several of these route alternatives are greater than 10 miles in length. If one of these routes were selected for the Project, a Certificate of Need would be required.[9]

The Commission's rules contemplate the circumstances where, due to the route selected, a Certificate of Need may become necessary. Minnesota Rule 7849.0400, Subp. 2 (G). In such cases, a utility may apply for a Certificate of Need as soon as possible after it becomes "apparent" that the Commission may approve a route that meets the definition of a large energy facility under Minnesota Statute Section 216B.2421, subdivision 2(2), in this case, a line with a capacity greater than

[6] Applicants proposed route from the Medina Substation to their preferred Pomerleau Lake Substation Site A is approximately 8.8 miles in length.
[7] Applicants analyzed four alternative routes (Alternate Routes A-D) and two substation sites (Substation Site A and B) in the Route Permit Application. The length of the alternate routes range from 7.76 miles (Proposed Route with Alternate Route Segment D and Substation Site B) to 9.08 miles in length (Proposed Route with Alternate Route Segment C and Substation Site A).
[8] These 26 route alternatives include 13 route alternatives terminating at one of the two Pomerleau Lake Substation sites.
[9] The route alternatives that are greater than 10 miles in length include: (1) Proposed Route with Alternate Route Segment E and Substation Site B (approximately 10.8 miles); (2) Proposed Route with Alternate Route Segment F and F1 and Substation Site A (approximately 10.54 miles); (3) Proposed Route with Alternate Route Segment F and F2 and Substation Site A (approximately 10.58 miles); and (4) Proposed Route with Alternate Route Segment F and F3 and Substation Site A (approximately 10.60 miles). *See* **Figure 27** for a map of these route alternatives.

100 kilovolt that is more than 10 miles in length. Minnesota Rule 7849.0400, Subp. 2 (G).

Given the time necessary to complete the Certificate of Need process, the anticipated in-service date of 2015, and the keen public interest in the need for the Project, Applicants are submitting this Certificate of Need application for review while the Route Permit proceeding is underway. Applicants request that this Certificate of Need Application be reviewed concurrently with the pending Route Permit Application to the extent that is feasible and practical. This concurrent review will enable the efficient and timely Commission consideration of the Certificate of Need application in the event a route longer than 10 miles is approved by the Commission and will also address public interest related to the need for the Project.

1.3 Need Overview

The Project is needed to address electric distribution concerns, to provide increased distribution capacity, and to avoid feeder circuit overloads in the Plymouth area distribution delivery system.

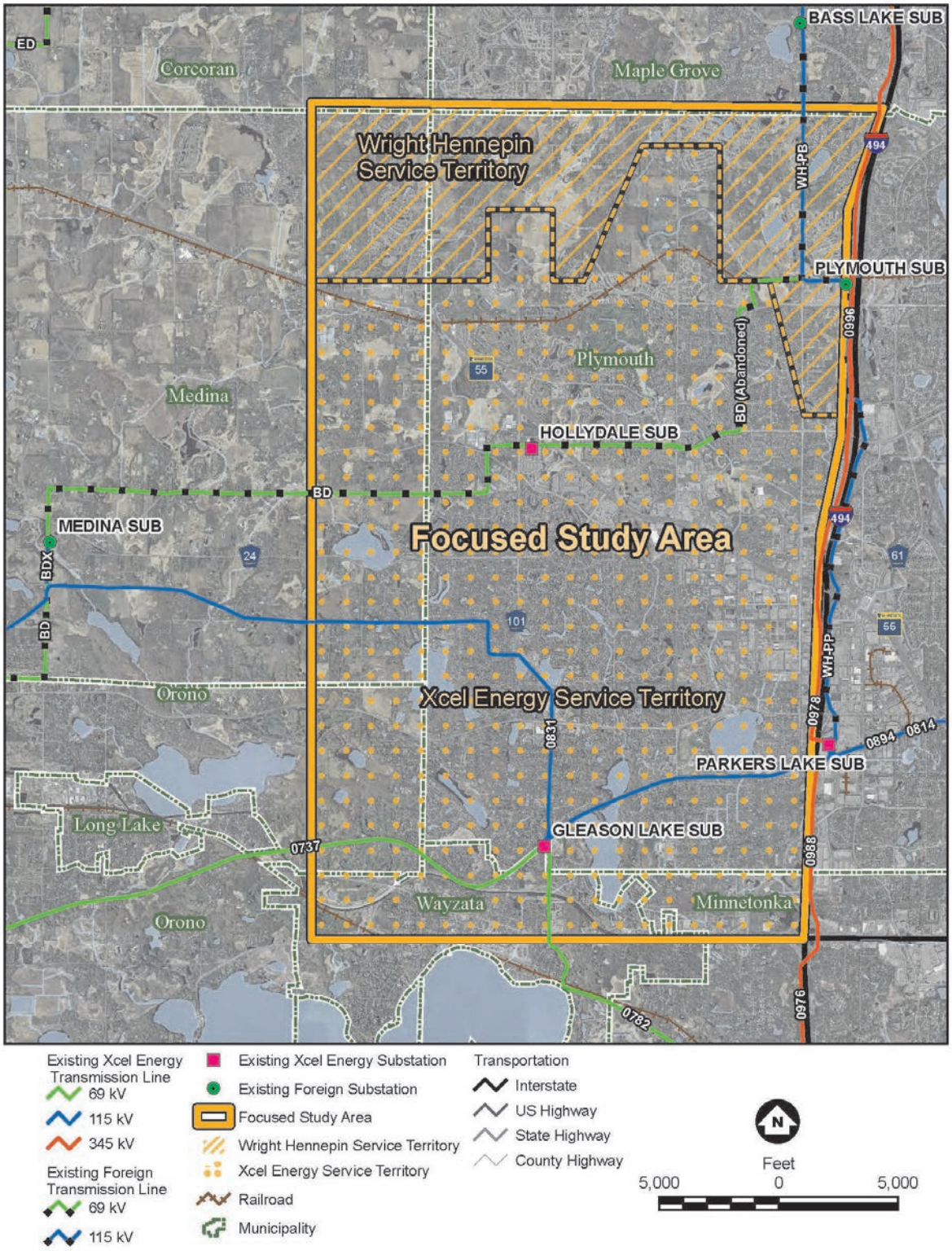
Over the past ten years, customer electricity usage has grown in the Plymouth area. There has been a great deal of development that has been concentrated along Minnesota State Highway 55 ("MN 55"), Interstate 494, and Interstate 394, specifically, the Plymouth City Center, but also including residential areas located away from these corridors. Recent development projects in the area include Lowes, Plymouth Cinema, Cub Foods, and Lifetime Fitness at MN 55 and Vicksburg Lane, a commercial development at MN 55 and Rockford Road, Providence Academy at Schmidt Lake Road and housing by Wayzata High School on Peony Lane. Additional residential developments are also planned for the area including Woodcrest, Spring Meadow, and Taylor Creek at Vicksburg and Schmidt Lake Road, Enclave on Hunters Drive, Elm Creek Highlands on Peony Lane, and Hampton Hills near 55th Avenue North and Vicksburg Lane. The population of Plymouth has also grown considerably. In 1990, the population of Plymouth was 50,899 people and by 2010 that number had grown to 73,000 people.[10] Average residential usage has also grown

[10] *See* Metropolitan Council website. http://stats.metc.state.mn.us/profile/detail.aspx?c=02396242#POPANDHH

substantially. The average residential home now uses more than twice the amount of power than it did 50 years ago.

In response to this load growth, Xcel Energy has taken numerous steps to maintain reliable service in the Plymouth area, including reinforcing existing feeder circuits, adding new feeder circuits, replacing equipment damaged by overloads, and rearranging feeder circuits to maintain service during overloads. In 2005 and 2006, the Plymouth area distribution system experienced historical peak loads. In these years it became apparent that the distribution system in the area was becoming increasingly vulnerable to more and longer overloads. As a result in 2008, Xcel Energy conducted a study of the Plymouth area distribution system, including 13 feeder circuits and associated transformers, that serve the Plymouth area that is experiencing the most overloaded conditions to assess the system deficiencies and identify potential solutions. The result of these study efforts was the *Plymouth Area Load Serving Study* ("Distribution Study"), **Appendix B.1**. The 13 feeders serve an approximately 24-square mile area in Plymouth bounded roughly by County Road 116, County Road 47, Interstate 494, and Highway 12 ("Focused Study Area"). When evaluating the existing electrical demands on the system in the Focused Study Area, Xcel Energy found that there were three areas that had the highest loads, these three areas are along MN 55, specifically, the Plymouth City Center, Interstate 494, and Interstate 394. A figure showing the Focused Study Area including these three areas of growth is shown in **Figure 3**.

Figure 3
Focused Study Area



As part of the Distribution Study, Xcel Energy examined historical peak loads on the 13 feeders (2001 to 2009) and forecast peak loads (2010 to 2030). The highest peak load occurred in 2006, when the load in the Focused Study Area reached 128 megawatts. This peak exceeded the capability of the distribution system under contingency conditions by 37 megawatts.

Demand in the Focused Study Area declined in 2007, 2008, and 2009 but in 2010 and 2011 demand on the distribution system increased. In fact, in 2011, load in the Focused Study Area reached 122 megawatts, nearly equal to the historic peak load of 128 megawatts reached in 2006. This upward demand trend in the Plymouth area is expected to continue. Planning reports issued by the City of Plymouth describe plans to facilitate continued development and redevelopment in the Plymouth area over the next few years. *See* **Appendix F**.

To address the distribution deficiencies and to identify sources of additional capacity to serve anticipated load growth, Xcel Energy developed and analyzed several transmission and distribution alternatives to increase capacity in the areas already experiencing the most severe overload conditions. *See* Distribution Study, **Appendix B.1** and the *Hollydale/Meadow Lake Load Serving Study* ("Transmission Study"), **Appendix B.2**. Xcel Energy also considered other alternatives, including other voltages, generation, and demand side management. Ultimately, Xcel Energy concluded that the option that best addressed both the immediate and long-term needs for electricity in the Plymouth area includes a new 115 kilovolt transmission line between Medina and Plymouth, expansion of the Hollydale Substation, and constructing a new substation, the Pomerleau Lake Substation.

The proposed Project is designed to alleviate the current 37 megawatt deficit identified in the Distribution Study and address future load growth in the area. This is achieved by providing approximately 50 megawatts of additional load serving capability through the new 115 kilovolt line and the new Pomerleau Lake Substation.

This additional 50 megawatts of capacity will meet the immediate distribution system needs and provide support for future demand growth in the area until at least 2030.[11]

1.4 Cost, Timing & Ownership

Depending on the route of the line and potential need for additional right-of-way, Applicants estimate the overall cost of the proposed improvements will fall within a range of $16 to $30 million. Cost estimates for Project segments are provided in **Table 1**. This range of costs accounts for considerations related to labor, materials, and varying construction conditions. Construction of the upgrades is scheduled to begin in 2013 with an anticipated in-service date of 2015.

Table 1
Estimated Project Cost

Project Item	Cost
Rebuild and New 115 kilovolt Transmission Line Facilities (Medina-Hollydale-Pomerleau Lake Substations)	$8 million
New Pomerleau Lake Substation	$8 million
Modifications to Existing Medina Substation	$2.6 million
Modifications to Existing Hollydale Substations	$4.5 million
Total Project Cost	$23.1 million[12]

Xcel Energy will construct and maintain the transmission lines proposed in this Project, as well as the new Pomerleau Lake Substation and existing Hollydale Substation. Along with Wright-Hennepin Cooperative Electric Association ("Wright-Hennepin"), Great River Energy will construct and maintain the proposed modifications to the Medina Substation. Generally, the equipment owner will also operate the equipment. Wright-Hennepin is a member-owned non-profit electric utility that provides electric power to Wright County and the western part of Hennepin County. Great River Energy is Wright-Hennepin's wholesale power supplier.

[11] The proposed Project may provide additional capacity past 2030 but the study performed by Xcel Energy forecasted load data until 2030.
[12] The Project costs provided in **Table 1** are based on Applicants' proposed route between the Medina, Hollydale, and proposed Pomerleau Lake substations.

Operating and maintenance costs after construction for Xcel Energy's portion of the Project will be nominal for several years, since the proposed transmission line will be new and there will be minimal initial vegetation management required. Typical annual operating and maintenance costs for 115 kilovolt transmission lines across Xcel Energy's Upper Midwest system area are on the order of $300 to $500 per mile of transmission right-of-way. The principal operating and maintenance costs include inspections, which may be conducted using fixed-wing aircraft and helicopter on a regular basis.

Xcel Energy performs periodic inspections of substations and equipment. The type and frequency of inspection varies depending on the type of equipment. Typical inspection intervals are semi-annual or annual. Maintenance and repair are performed on an as-needed basis, and therefore the cost varies from substation to substation.

Operating and maintenance costs after construction for Great River Energy's portion of the Project will be nominal for several years, since the proposed substation modifications will be new. Great River Energy and Wright-Hennepin perform periodic inspections of substations and equipment. The type and frequency of inspection varies depending on the type of equipment. Typical inspection intervals are semi-annual or annual. Maintenance and repair are performed on an as-needed basis, and therefore the cost varies from substation to substation.

If a Certificate of Need is being sought to meet long term needs, in excess of 80 megawatts, of a utility that is not to be an owner of the project, certain additional information is required as part of the application. (Minnesota Rule 7849.0220, Subp. 3). The Project is intended to keep the transmission system reliable and is not designed to meet the long-term needs of a particular utility that is not an owner.

1.5 Environmental Summary

The Project area contains both urban and rural land uses, as well as natural resource, cultural resource, and recreation areas. Applicants have not identified any environmental factors that would preclude construction of the Project. Impacts can be mitigated by utilizing existing right-of-ways and through best management construction practices. A detailed environmental analysis is provided in **Chapter 8**.

As part of the Certificate of Need process, the Minnesota Department of Commerce, Energy Facility Permitting Staff will also conduct an environmental review independent of the information provided in this Application. The Route Permit Application for the Project was filed on June 30, 2011 and is already proceeding. Accordingly, members of the public have had, and will continue to have, several opportunities to participate in both the Certificate of Need and Route Permit processes.

1.6 Certificate of Need Criteria

Minnesota rules and statutes specify the criteria the Commission should apply in determining whether to grant a Certificate of Need. Minnesota Statute Section 216B.243 and Minnesota Rule 7849.0120.

Minnesota Rule 7849.0120 provides that a Certificate of Need is to be granted by the Commission to an applicant on a determination that:

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

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

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

(D) The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and

regulations of other state and federal agencies and local governments.

Applicants' proposal satisfies these four criteria as discussed below.

Denial of the Project would have an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the Applicants' customers

- Denial of a Certificate of Need for this Project would result in adverse effects upon present and future adequacy, reliability, and efficiency because the Plymouth area is already experiencing feeder overload conditions. Absent additional facilities, conditions will worsen with time.

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

- The Distribution Study and Transmission Study considered costs, system losses, technical performance, and other factors. The proposed transmission upgrades, including the size, type, and timing, were identified in these studies as the best performing option among alternatives reviewed.

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

- The proposed Project will provide electric reliability and allow additional electric load and development in the Plymouth area.
- As proposed, the Project upgrades will utilize existing rights-of-way to the maximum extent possible. This will reduce the impact to the natural and socioeconomic environments.

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

- Applicants will secure all necessary permits and authorizations prior to commencing construction of the Project.
- The Project will comport with State of Minnesota policies of providing safe and reliable electric service to all customers.

1.7 Socioeconomic Considerations

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

1.7.1 Socially Beneficial Uses of Facility Output

The purpose of the Project is to ensure reliable electric service to residences and businesses in the Plymouth and Medina area.

1.7.2 Promotional Activities

Neither Xcel Energy nor Great River Energy have conducted any promotional activities or events that have triggered the need for the Project. The Project is needed due to continued and anticipated growth in the Plymouth area. The Project is required to ensure system reliability and to allow for future growth and development in the area.

1.7.3 Effect in Inducing Future Development

The Project is not necessarily intended to induce future development. It may allow future economic development that otherwise would not be possible if the transmission system upgrades are not implemented. The transmission system upgrades are being proposed based on existing conditions and forecasted demand that will continue to cause worsening electrical conditions. The transmission system upgrades will ensure system reliability for Applicants' customers and will also accommodate approximately 50 megawatts of additional load growth in the area before further upgrades are required. This additional 50 megawatts of additional load serving capability will provide load serving capability until at least 2030 assuming a 1 percent growth rate in demand.[13]

[13] The proposed upgrades may provide additional capacity past 2030 but the study performed by Xcel Energy only forecasted load data until 2030.

1.8 Other Items Required by Exemption Order

In granting Applicants' request for an exemption from certain data filing requirements under Minnesota Rules, Chapter 7849, the Commission ordered that Applicants include additional data in this Application.[14] This data can be categorized as (1) demographic information which is included in **Appendix F**; (2) demand-side management data specific to the Project area which is included in **Appendix D.3**; and (3) substation demand data which is included in **Appendix G**.

1.9 Applicants' Request

Applicants respectfully request that the Commission find that this Certificate of Need application is complete and commence the regulatory review process so that in the event that the Commission approves a route that is greater than 10 miles for the Hollydale Project, that a Certificate of Need could be granted in conjunction with the Commission's route approval.

[14] A copy of the Exemption Order is included as **Appendix E**.

2 ELECTRICAL SYSTEM OVERVIEW

In Chapter 2, we will provide an overview of the electrical system. We will also provide information regarding how the distribution system which provides electricity to homes and businesses operates.

Key Terms:

- **Contingency** – *An outage of a transmission line, generator or other piece of equipment, which affects the flow of power on the transmission network and impacts other network elements*
- **Distribution** –*A group of lines, and associated equipment, for the local delivery of low voltage electricity between the transmission network and end users.*
- **Distribution Feeder Circuit** – *These are the connections between the output terminals of a distribution substation and the input terminals of primary circuits. The distribution feeder circuits leave the distribution substation via overhead conductors, and underground cables which connect to nearby overhead primary circuits outside the substation. Several distribution feeder circuits can leave a substation extending in different directions to serve customers.*
- **Normal Operation** – *This is the condition under which all electric infrastructure equipment is fully functional .*
- **Reliability** – *The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. It is the ability to deliver uninterrupted electricity to customers on demand and to withstand sudden disturbances such as short circuits or loss of system components.*
- **Single Contingency** – *This is the condition under which a single element, feeder circuit or distribution substation, is unexpectedly out of service. This condition is also called "first contingency operation" or "N-1".*
- **Substation** – *A facility that monitors and controls electrical power flows, uses high voltage circuit breakers to protect power lines and transforms voltage levels to meet the needs of end users.*
- **Transformers** – *Devices that change voltage levels.*
- **Transmission** – *An interconnected group of lines and equipment for transporting electric energy in bulk on high voltage power lines between power sources (e.g. power plants) and major substations where the voltage is 'stepped down' for distribution to customers.*

Key Points: *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 plants to the areas where the electricity is needed.*

2.1 Electrical System Overview

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

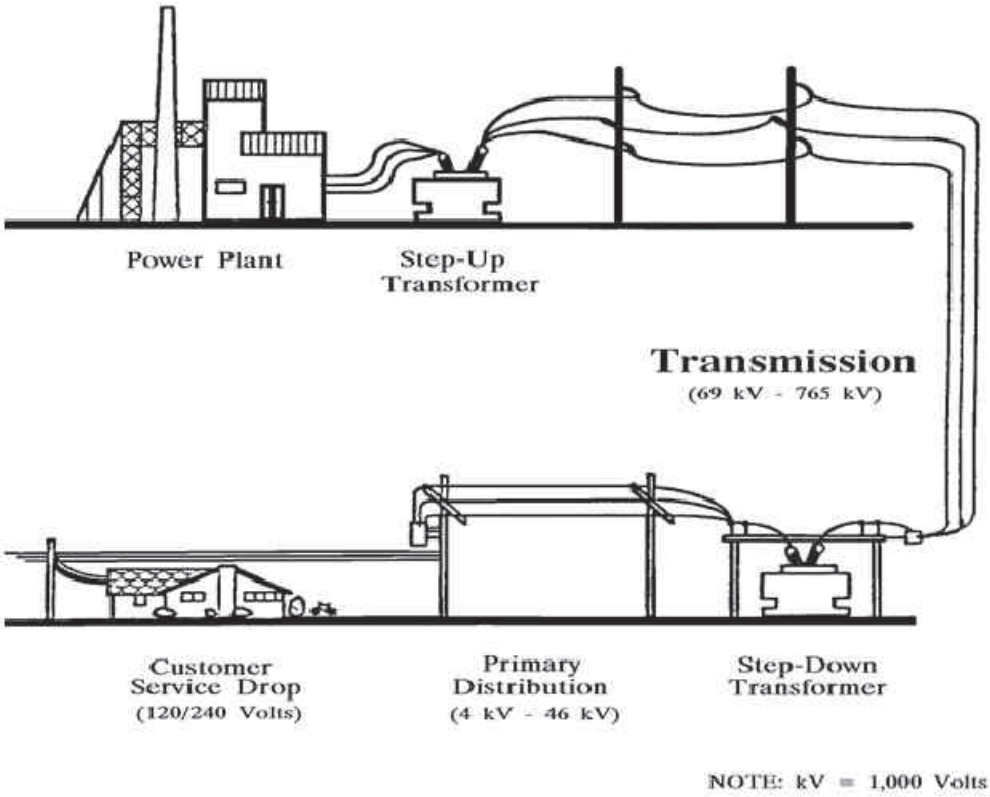
Electricity is produced at both large and small generating plants. Electricity can be generated using a variety of sources or fuels, including solar, wind, and hydro; internal and external combustion of biomass, biofuels, natural gas, and coal; and heat and steam created through nuclear fission. Regardless of the fuel used, electricity is produced by converting the fuel's energy into electric energy through the use of a generator that converts mechanical energy into electric energy. Electric energy is generated at a specific voltage and frequency. For it to be useful, electricity must be transmitted from the generation source to consumers. Unlike other products or services, electricity must be generated simultaneously with its consumption, so generators connected to the system must instantaneously adjust their electric output to respond to changes in customer demand. The transmission system must also be able to accommodate changes in both generation and consumption.

Typically, the voltage of electricity generated in a power plant is increased (stepped-up) by transformers installed close to the generating plant. The electricity is then transported over transmission lines, often at voltages in excess of one hundred thousand volts (e.g., 115 kilovolt, 230 kilovolt, 345 kilovolt, etc.). One kilovolt equals 1,000 volts. The reason for stepping up the voltage is that it is more efficient to move electricity over longer distances at higher voltages because the system experiences

fewer electrical losses. Once the electricity reaches the locality where it will be consumed, the transmission voltage (e.g., 115 kilovolt and higher) is reduced (stepped-down) to voltages appropriate for distribution to end use customers by transformers at a distribution substation facility. The electricity is then further transformed and distributed at distribution "primary" voltages (e.g., 13.8 kilovolt) within communities by the distribution system which delivers power for individual customer use.

A diagram showing the transfer of electricity from generator to consumer is shown below in **Figure 4**.[15]

Figure 4
Electrical System



Note: **Figure 4** is an artistic portrayal of an electrical system and is not a true representation of all actual electrical system components.

[15] http://psc.wi.gov/theLibrary/publications.htm#Electric.

2.2 Transmission System Overview

The transmission system is made up of high voltage transmission lines which can carry electricity long distances and deliver power to distribution systems to meet customer needs in specific locations. The transmission system is designed to be an integrated system that is able to withstand the outage of a single transmission line without major disruption to the overall power supply. The majority of the bulk transmission facilities consist of transmission lines and bulk transformers at 100 kilovolt and above.

2.2.1 High Voltage Transmission Lines

Transmission lines are made up of conductors, which are groups of wires usually made from copper or aluminum, and usually 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. Electricity is simply the movement of electrons within a conductor (the wire). The rate at which electricity moves through a wire is called current and is measured in amperes (or amps). The force that moves the electricity through the wire is called voltage. Voltage is measured in terms of volts or kilovolts ("kV"). The wire conducting the current offers resistance to its movement. This resistance is measured in a unit called ohms. Some materials are better conductors than others, i.e., they offer less resistance. The wires used by utilities to conduct electricity are usually made of copper or aluminum, which conduct electricity with relatively little resistance.

2.2.2 Substations

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

Equipment inside a substation may include, but is not limited to, power transformers, circuit breakers, instrument transformers, switches, bus, relays and electrical equipment enclosure.

Power transformers are devices that step-up or step-down voltage between two different voltage systems, such as between the 115 kilovolt transmission system and the 13.8 kilovolt distribution system.

A circuit breaker is a switching device designed to interrupt electrical energy flow between energized elements. Circuit breakers interrupt and quickly isolate electrical energy flow from transmission lines to distribution substation transformers (transformer circuit breakers) and from distribution substation transformers to distribution feeder circuits (feeder circuit breakers). Circuit breakers protect transmission lines by interrupting power from flowing when a short circuit occurs (such as one caused by a lightning strike).

Instrument transformers measure the voltage and the current for the transmission lines and the substation.

Switches are used to route or reroute the flow of electric energy and to isolate substation equipment for safe construction, maintenance, and inspection.

A bus is a substation conductor, usually aluminum, that moves the power through the substation to and from the transmission lines connecting to the substation. Buses are electrical conductors that provide both a path for electrical energy flow and connection points for electrical devices including switches, transformers, and circuit breakers.

Relays with input from the instrument transformers detect abnormal system conditions and send signals to circuit breakers so they can trip (open) or close.

The electrical equipment enclosure would contain all the relays, control equipment and systems for the substation.

Various other equipment is installed for purposes including load monitoring, remote control, electrical problem detection and isolation, voltage regulation, and security.

Ideally, substations are located as close as possible to existing transmission lines or proposed transmission line routes to minimize the length of the connecting transmission lines and associated new transmission line right-of-ways.

Substation property dimensions depend on the ultimate planned design foreseen for the substation. Depending on the timing of future load growth and electrical system needs, the configuration of a substation may change over time resulting in multiple construction stages over an extended period of years.

Substation site dimensions depend on the initial and ultimate substation plans and physical characteristics of the site, such as shape, elevation, above and below ground geographical characteristics, and proximity of the site to transmission lines.

Substation sites need to be large enough to accommodate both the planned ultimate fenced area and the required surrounding areas. The required surrounding areas, include applicable setbacks, storm water ponds, wetlands, grading, access road, and new transmission line right-of-ways.

2.2.3 Transmission Substations

Transmission substations contain equipment that allows the interconnection of two or more transmission lines, typically 69 kilovolt and above. Transmission substations may have transformers to convert between two transmission voltages and other equipment to control the power flow between transmission lines.

2.3 Distribution System Overview

The distribution system is made up of substations which house transformers and distribution feeder circuits that provide the path for delivering electrical energy from the distribution substation to the distribution customer transformer. Distribution feeder circuits for standard service to customers are designed as radial circuits, so the failure of any single critical element of the feeder circuit can cause a customer outage, which is the standard of service for a distribution system unlike for a transmission system. Generally, the distribution system is planned to facilitate single-contingency

switching to restore outages within approximately one hour. Feeders are designed to facilitate restoration of main line capacity and restoration of service to most customers with simple manual field switching with some exceptions. A description of distribution substations and feeder circuits is provided below.

2.3.1 Distribution Substations

Distribution substations typically transform transmission line voltages (typically 69 kilovolt and above) down to distribution voltage levels for delivery across a distribution system.

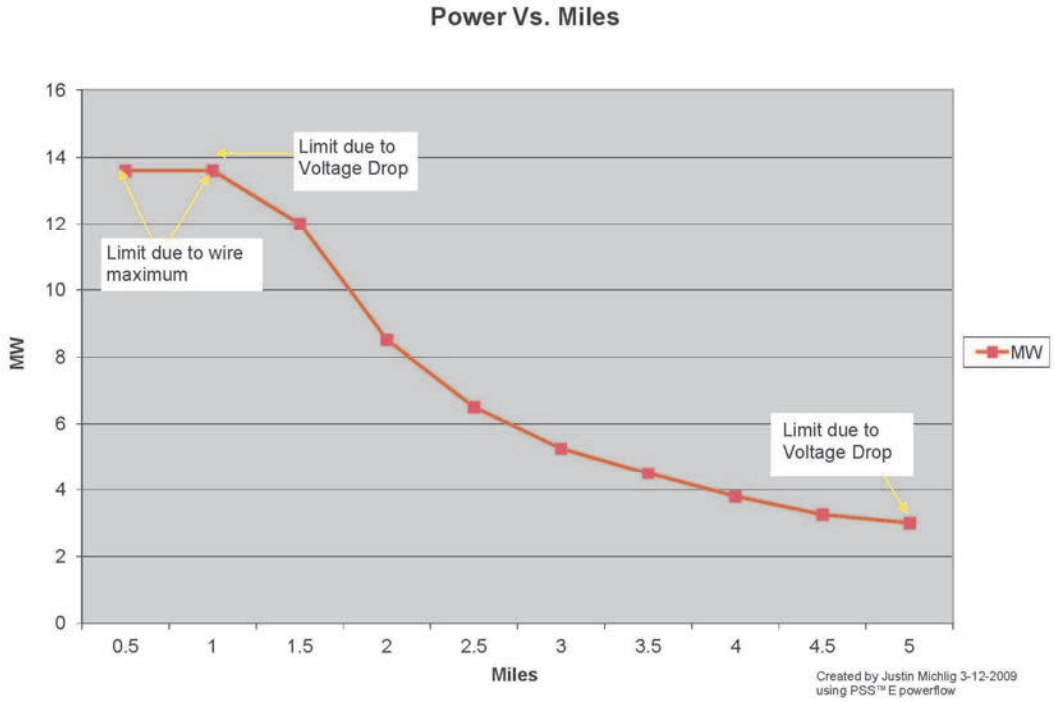
Substation distribution transformers are the key distribution substation elements used by Xcel Energy when developing plans and options to electrically serve an area of distribution customer load. Other substation equipment is selected and installed based on the number of transformers and their size that is planned for the ultimate substation design. The maximum number and size of substation transformers in the ultimate substation design are the primary limiting factors for the amount of electrical energy that a substation can deliver.

Xcel Energy plans and constructs distribution substations with a physical footprint sized for the ultimate substation design. The maximum ultimate design capacity established in Xcel Energy planning criteria is three transformers at the same distribution voltage. This maximum size balances substation and feeder circuit costs with customer service considerations including limitations of feeder circuit routes emanating from substations, circuit exposure of long feeder circuits, ease of operation, cost of operation, customer outage restoration, and the electrical losses. Transformers and feeder circuits are incrementally added within the established footprint until the substation is built to ultimate design capacity.

Generally, distribution substations are located as close to the area of heaviest load or electrical usage, as possible. This is because the farther a substation is from the load being served, the longer the feeder circuits are that emanate from the distribution substation, which impacts the amount of load a feeder circuit can efficiently carry to customers while maintaining required voltage levels. **Figure 5** illustrates how the ability of a distribution feeder line to adequately serve customer load decreases as the

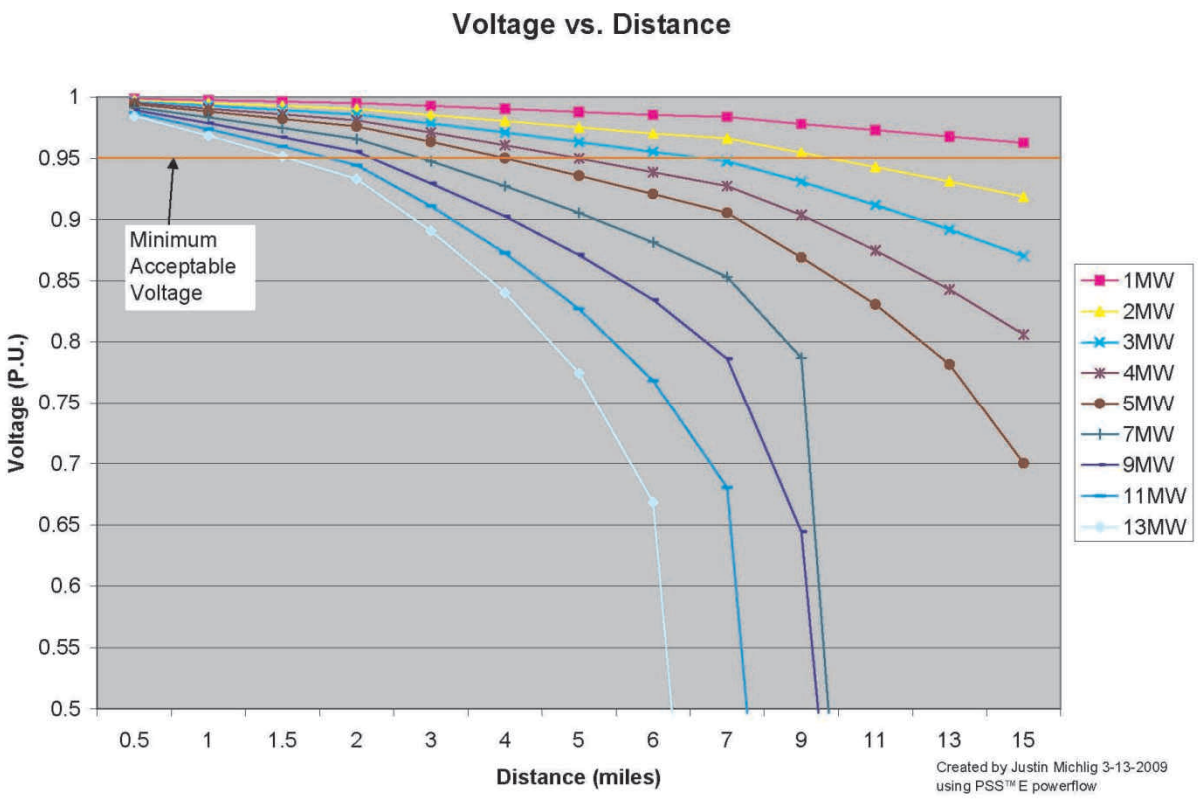
load is farther from the substation along the feeder circuit. This capacity reduction is caused by a reduction in voltage—as the line length increases, the voltage at the end of the line decreases. This is due to electrical and physical properties in the power system. Closest to the substation, a feeder circuit's limit is the maximum amount of current the circuit can carry. At points along the feeder circuit farther away from the substation, the limit becomes the maximum amount of allowable voltage drop. For example, at 2.5 miles from the transformer, the capacity of a feeder at an adequate voltage is reduced by half. By analogy, a person generally can hold greater weight closer to the person's body and as the weight moves further from the body, the amount of weight that a person can hold straight out decreases. Therefore, when planning the electric distribution delivery system, Xcel Energy tries to locate distribution substations as close to the major load areas as possible, which decreases the lengths of the feeder circuits serving that load and consequently maintains the ability of those feeder circuits to carry load efficiently.

Figure 5
Relationship Between Feeder Circuit Load and Length



When feeders circuits traverse a long distance from their sources (i.e., distribution substation transformers) and serve load the entire length of their lines, then those feeders may experience excessive voltage drop, which can result in unsatisfactory operation of and damage to customer electrical equipment. **Figure 6** shows the relationship between distance and voltage drop on a typical feeder conductor. Each line represents increasing levels of load served by the feeder.

Figure 6
Relationship Between Voltage and Distance From Substation Transformer



2.3.2 Distribution Feeder Circuits

The primary voltage distribution feeder circuit elements are the feeder breaker, the feeder circuit main line, and the feeder circuit taps.

A feeder breaker is both part of the distribution substation and the beginning of the distribution feeder. The feeder breaker is a piece of equipment located at a substation which, in combination with associated measurement equipment, is capable of

detecting, switching, and interrupting the electrical power on a particular feeder under predetermined conditions.

A distribution feeder main line typically begins at the feeder breaker and radially feeds segments of overhead wire or underground cable with switch connections to adjacent feeder circuit main lines. The main line feeder circuit is typically comprised of electrical equipment including overhead wire, underground cable, voltage regulation equipment, and overhead and underground switching devices. The typical feeder circuit main line is capable of delivering all of the electric energy from the feeder breaker to an average of 1,000 mixed use distribution customers.

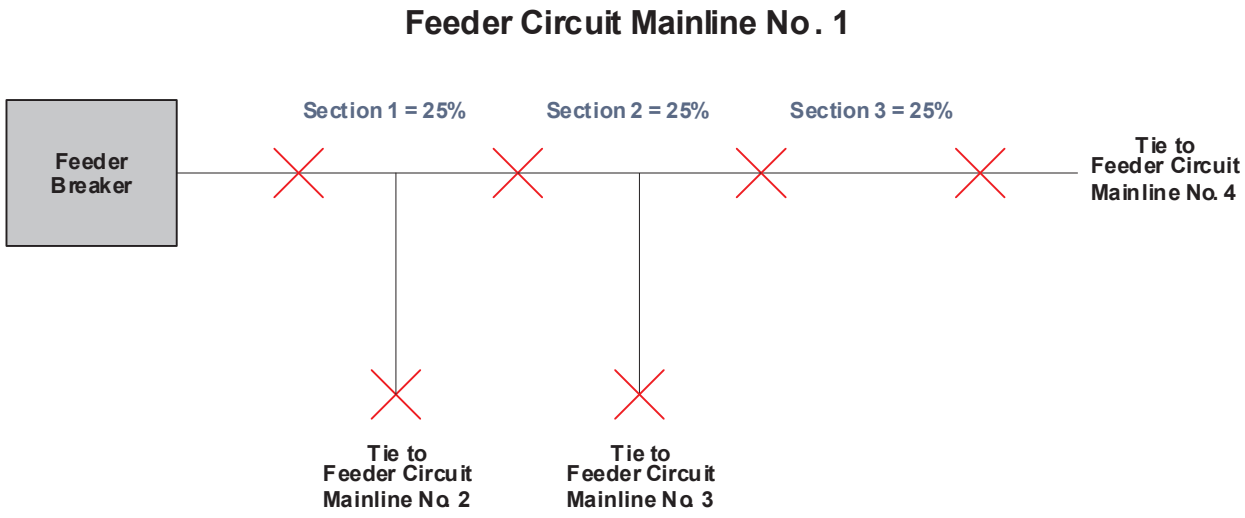
A distribution main feeder is generally composed of three equal sections that should serve no more than 25% of the total capacity of the main feeder. As a result, during system intact conditions, a feeder circuit with three sections should be loaded to no more than 75% of capacity (also known as utilization rate), which reserves 25% of the capacity to be used to meet the load of an adjacent feeder circuit in the event of a failure.

Main line feeder sections are separated by switches so that sections can be isolated from each other and from the substation breaker to facilitate maintenance of individual pieces of equipment while continuing uninterrupted electric service to distribution customers. Each section is connected to an adjacent feeder so that the entire feeder may be restored by conducting a minimum number of switching operations for rapid restoration of a worst case failure, an outage of the head end element of the feeder circuit.

Feeder circuit taps are fuse connected segments of overhead wire or underground cable fed from the feeder main line that deliver electrical energy to distribution transformers adjacent to customer locations. Tap fuses, which separate the tap from the main line, operate when an electrical problem occurs downstream of the fuse to isolate the problem from the main line and keep the largest possible number of customers in service at all times.

Figure 7 depicts a feeder circuit, including the breaker, and the three sections of the main feeder, which are separated by switches, each represented by an "X".

Figure 7
Typical Distribution Feeder Circuit Main Line With Three Sections Capable Of System Intact N-0 and First Contingency N-1 Operations



3 NEED ANALYSIS

In Chapter 3, we explain why we are proposing the Project. This is referred to as "the need" for the Project. We cover how the current distribution and transmission facilities provide electric service to our customers and how the current facilities are not enough to support current and future demand for electricity in this area. In this chapter, we explain our analysis of different ways that we have considered to fix the problems identified. This includes distribution system improvements and transmission system improvements.

Key Terms:

- **Capacity** – *The load-carrying ability, expressed in megawatts, of generation, transmission or other electrical equipment.*
- **Contingency** – *An outage of a transmission line, generator or other piece of equipment, which affects the flow of power on the transmission network and impacts other network elements.*
- **Demand** – *The rate at which electric energy is delivered to or by a system or part of a system at a given instant or averaged over any designated interval of time. Demand is generally expressed in kilowatts (kW) or megawatts (MW).*
- **Distribution Feeder Circuit** – *These are the connections between the output terminals of a distribution substation and the input terminals of primary circuits. The distribution feeder circuits leave the distribution substation via overhead conductors, and underground cables which connect to nearby overhead primary circuits outside the substation. Several distribution feeder circuits can leave a substation extending in different directions to serve customers*
- **Focused Study Area** –*This is a geographic area that was studied in the Distribution Study. This area is an approximately 24-square mile area in Plymouth that includes the 13 feeder circuits that are experiencing the most severe overload conditions.*
- **Greater Study Area** – *This is a geographic area that was studied in the Distribution Study. Compared to the Focused Study Area, the Greater Study Area is a larger area of Plymouth, approximately 50 square miles, that includes three distribution substations, which house an aggregate total of 7 distribution substation transformers and the 27 distribution feeder circuits from those three distribution substations.*
- **Load** – *All the devices that consume electricity and make up the total demand for power at any given moment or the total power drawn from the system*

- ***Outage*** *– The unavailability of electrical equipment, possibly as a result of planned for maintenance or unplanned (forced) problems caused by weather or equipment failures.*
- ***Overloads*** *– Occur when power flowing through wires or equipment is more than they can carry without incurring damage.*
- ***Reliability*** *– The degree of performance of the elements of the Bulk Electric System that results in electricity being delivered to customers within accepted standards and in the amount desired. It is the ability to deliver uninterrupted electricity to customers on demand and to withstand sudden disturbances such as short circuits or loss of system components.*
- ***Voltage*** *– A type of 'pressure' that drives electrical charges through a circuit. Higher voltage lines generally carry power longer distances.*

Key Points: *The Project is needed so that the distribution system can reliably meet the growing demand for electric power in the Plymouth and Medina areas. In examining ways to provide reliable electric service to the Plymouth area, we looked at common distribution improvements, including adding new feeder circuits, extending existing feeder circuits, and reconfiguring feeder circuits and determined that these improvements were not sufficient to solve the identified distribution deficiencies. We also looked at alternative 115 kilovolt transmission configurations for the Project. In the end, Applicants concluded that the proposed Project best meets the electrical needs of the Plymouth and Medina area.*

3.1 Need Overview

Customer electricity usage has grown over the past decade in the Plymouth area. The growth in the Plymouth area has been most significant along and around MN 55, Interstate 494, and Interstate 394. Recent land development projects in the area includes Lowes, Plymouth Cinema, Cub Foods, and Lifetime Fitness at MN 55 and Vicksburg Lane, a commercial development at MN 55 and Rockford Road, Providence Academy at Schmidt Lake Road, housing developments by Wayzata High School on Peony Lane, and other housing developments.

The need for the Project is driven by the continuing increase in the demand for power and anticipated future increase in demand. The City of Plymouth's 2009 comprehensive plan notes that the Metropolitan Council classifies Plymouth as a "developing" community based on the amount of undeveloped land in northwest

Plymouth.[16] This comprehensive plan also describes plans to facilitate continued development and redevelopment in the Plymouth area over the next few years. Current and future development is concentrated along MN 55 corridor and areas adjacent to that corridor (*e.g.*, Plymouth City Center). The City of Plymouth's plans designate planned land use along this major growth corridor to include higher density housing, commercial, office, and other land uses.

In addition to land development, the population of Plymouth has also increased in the past decades. Census data shows that the population of the City of Plymouth has grown from 18,077 people in 1970 to 50,889 people in 1990 and reached 70,576 people in 2010.[17] The Metropolitan Council[18] projects that population of Plymouth will increase to 78,500 people by 2030.[19] The population of the city of Medina has also grown from 2,396 people in 1970 to 3,096 people in 1990 and reached 4,892 people in 2010.[20] The Metropolitan Council projects that the population of Medina will reach 11,200 people by 2030.[21]

Average residential electric usage has also grown substantially in recent decades. The average residential home now uses more than twice the amount of power than it did 50 years ago. Information from the Minnesota Department of Commerce in a report titled "Energy Policy and Conservation Report 2004" shows that weather normalized electric consumption among Minnesota residential customers increased from just over 4.0 annual megawatt hours in 1965 to just under 9.0 annual megawatt hours in 2000.[22]

In response to the growing power demands, Xcel Energy conducted a study of the Plymouth area distribution system. The study considered the growing power demands, the forecast population growth, and forecast power demands.

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[16] http://www.ci.plymouth.mn.us/Modules/ShowDocument.aspx?documentid=3517; *See* also **Appendix F**.
[17] *See* Appendix F.4.
[18] The Metropolitan Council is the regional planning agency serving the Twin Cities seven-county metropolitan area and providing essential services to the region. *See* www.metrocouncil.org.
[19] *See* Appendix F.4.
[20] *See* Appendix F.4.
[21] *See* Appendix F.4.
[22] *See* http://www.state.mn.us/mn/externalDocs/Commerce/Quadrennial_Report__2004_071404102049_2004-QuadReport.pdf

Xcel Energy determined that the demand on the distribution system serving the Plymouth area exceeded capacity by 37 megawatts beginning in 2006. The typical distribution mitigation strategies that have been implemented previously in the Plymouth area, such as extending feeder circuits, reconfiguring feeder circuits, and adding new feeder circuits, are no longer effective to address capacity deficits and voltage problems. Xcel Energy also determined that existing distribution substations in the Plymouth area are at design capacity and cannot be expanded to alleviate the overload conditions. Therefore, new transmission sources are required to meet load serving requirements.

Xcel Energy developed and analyzed several alternatives to provide additional capacity to the Plymouth area experiencing the most severe overload conditions. Xcel Energy determined that the solution that best addresses the current and future needs for electricity in the Plymouth area includes constructing a new 115 kilovolt transmission line connecting the Medina Substation, the Hollydale Substation, and new Pomerleau Lake Substation near I-494.

This chapter summarizes Xcel Energy's analysis and conclusions. The Distribution Study and Transmission Study are included in **Appendix B.1, Appendix B.2**, **and Appendix B.3.**

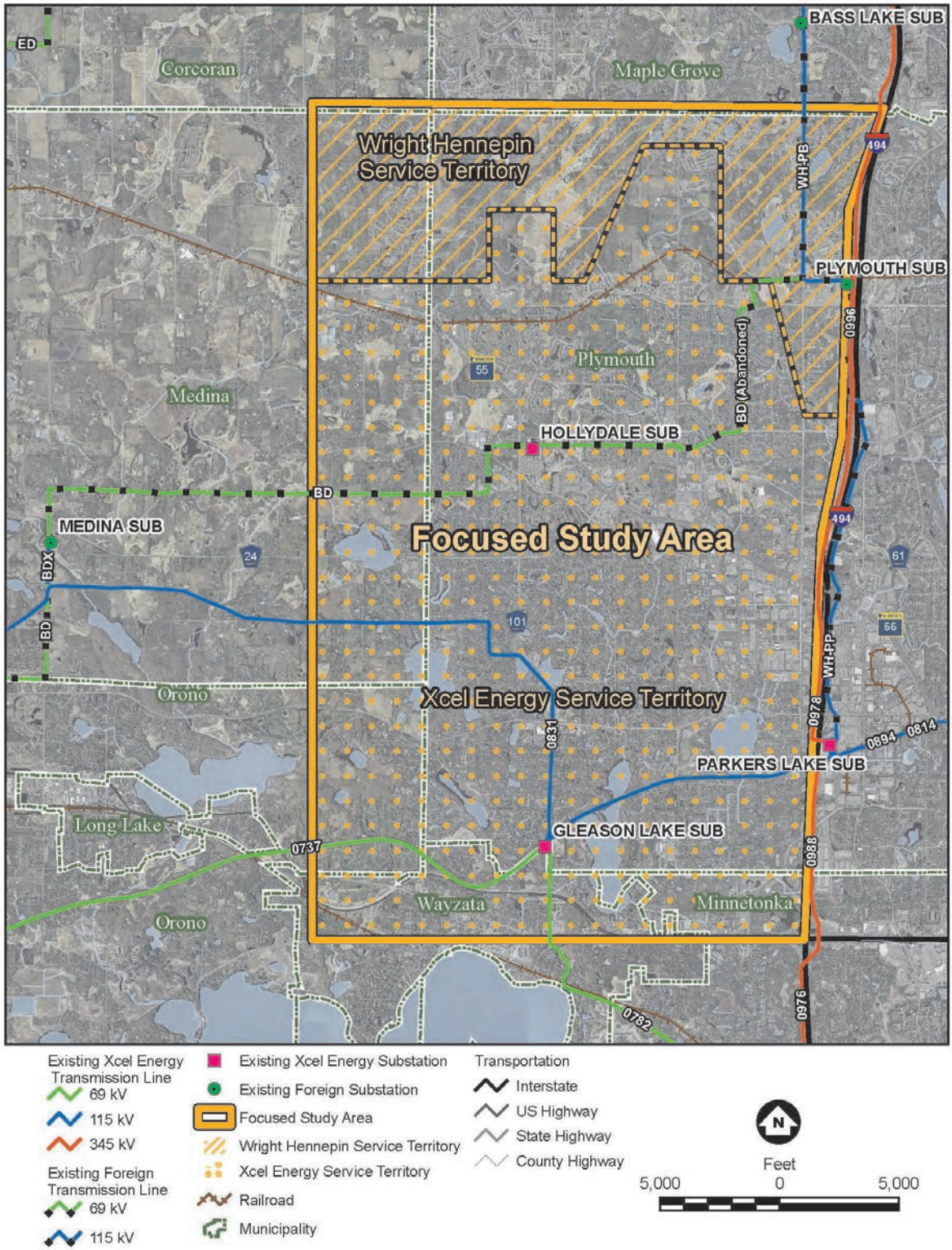
3.2 Distribution Study Areas

3.2.1 Focused Study Area

To assess the deficiencies, Xcel Energy identified a "Focused Study Area" and a "Greater Study Area" for analysis. The Focused Study Area is an approximately 24-square mile area in Plymouth that includes the 13 feeder circuits that are experiencing the most severe overload conditions. The northern portion of the Focused Study area is Wright Hennepin[23] service territory and the southern portion is Xcel Energy service territory. A diagrams of the Focused Study Area is shown in **Figure 8.**

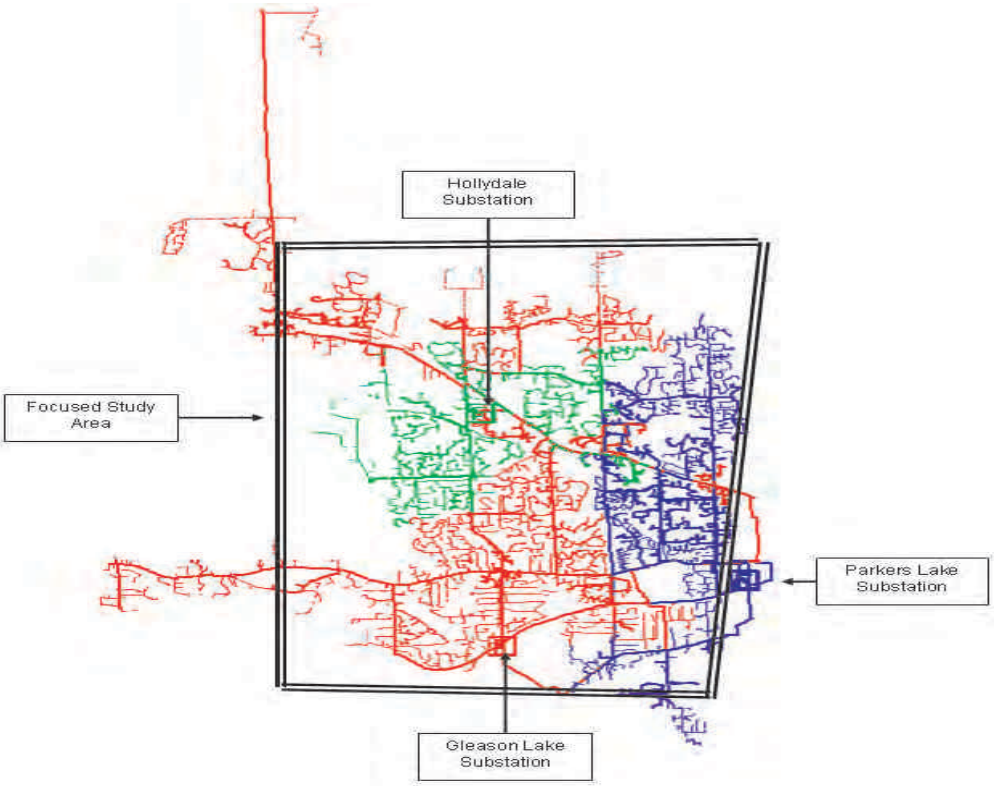
[23] Wright Hennepin is a member cooperative served by Great River Energy that provides wholesale electric service to Wright Hennepin.

Figure 8
Focused Study Area



The Focused Study Area distribution load is primarily fed from three 115 kilovolt transmission lines: Medina –Gleason Lake, Gleason Lake – Parkers Lake, and Parkers Lake – Medicine Lake, which make up part of the looped 115 kilovolt transmission system that extends from the western metro area, east towards Minneapolis. Thirteen feeder circuits emanating from three substations serve the Focused Study Area. The three substations are Gleason Lake, Hollydale, and Parkers Lake substations. The 13 feeder circuits, 11 at a distribution voltage of 13.8 kilovolts and two at a distribution voltage of 34.5 kilovolts, provide power to the Focused Study Area. **Figure 9** shows each of the distribution substations and their associated feeder circuits that serve the Focused Study Area load. Red feeder circuits are served by Gleason Lake Substation, blue feeder circuits are served by Parkers Lake Substation, and green feeder circuits are served by Hollydale Substation.

Figure 9
Primary Electric Distribution Substation and Associated Feeder Circuits in Focused Study Area



3.2.2 Background on Focused Study Area

In 1993 Hollydale Substation was constructed as a 69/13.8 kilovolt distribution substation that tapped a Great River Energy 69 kilovolt transmission line running from Medina substation to Plymouth substation. The Hollydale Substation was positioned such that it added capacity to an area of the Focused Study Area that Parkers Lake and Gleason Lake 13.8 kilovolt feeder circuits could not reasonably reach. By 1998 the 13.8 kilovolt feeder circuit and substation transformer capacity within the Focused Study Area had been used up and there was once again a need for additional substation transformers and feeder circuits. Additionally, Great River Energy transmission planners identified an overload on the 69 kilovolt transmission line serving Hollydale Substation. Both of these issues drove the decision to introduce the 34.5 kilovolt distribution voltage to the Focused Study Area. At the 34.5 kilovolt level, new feeder circuits were able to not only serve more load but also serve load further from the substation in which they were housed. Subsequently, a 70 megawatts 115/34.5 kilovolt substation transformer was added at Gleason Lake Substation. The new 34.5 kilovolt feeder circuits out of Gleason Lake Substation were able to relieve existing overloads on the 13.8 kilovolt system. Additionally, to mitigate the overload on the 69 kilovolt transmission line, the Hollydale load was moved from the 69/13.8 kilovolt transformer to a 34.5/13.8 kilovolt transformer which used one of the Gleason Lake 34.5 kilovolt feeder circuits as its "transmission" source.

The 13.8 kilovolt and 34.5 kilovolt distribution delivery systems in Plymouth have struggled to keep up with the increasing customer demand for electricity. Since the Gleason Lake Substation is the only remaining distribution substation source in the Focused Study Area, the feeders in that area are serving increasingly larger loads farther from the nearest substation source, resulting in higher electrical line losses and reduced customer reliability. In response to this load growth, Xcel Energy has taken numerous steps to maintain reliable service in the Focused Study Area, including reinforcing existing feeder circuits, adding new feeder circuits, replacing equipment damaged by overloads, and rearranging feeder circuits to maintain service during overloads.

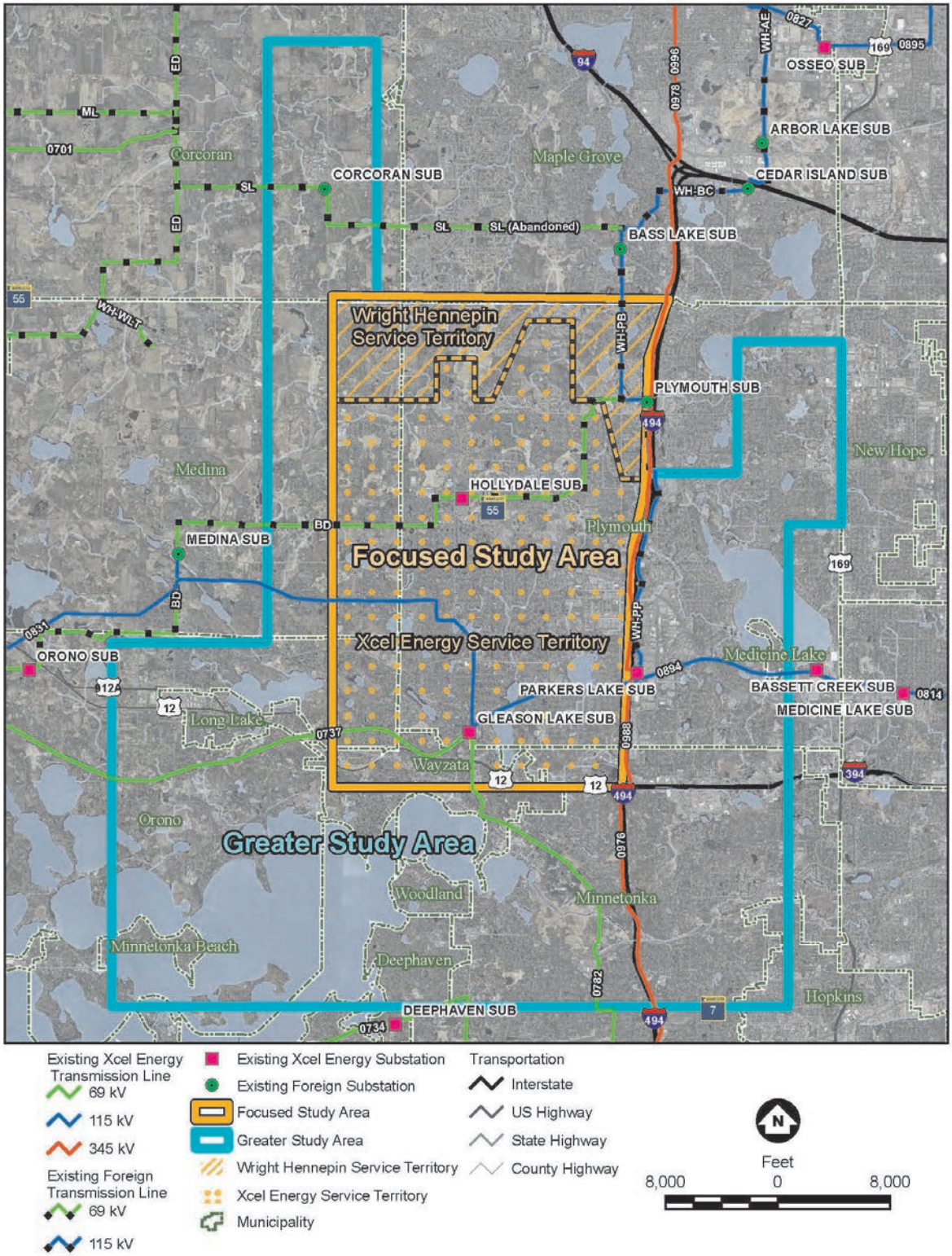
In 2005 and 2006, the Plymouth distribution delivery system experienced historical peak loads. It became apparent that the distribution delivery system in the area was

becoming increasingly vulnerable to more and longer overloads. As a result, Distribution Planning Engineers in 2008 intensified their analysis of the Plymouth distribution delivery system, concentrating in particular on the Focused Study Area to develop a more robust, longer-term solution to address the continued growth in power demand.

3.2.3 Greater Study Area

The Greater Study Area is a larger area of Plymouth, approximately 50 square miles, that includes three distribution substations, which house an aggregate total of 7 distribution substation transformers and the 27 distribution feeder circuits from those three distribution substations. A diagram of the Greater Study Area is shown in **Figure 10.** The Greater Study Area distribution load is served by 27 feeder circuits, two at a distribution voltage of 34.5 kilovolts and 25 at a distribution voltage of 13.8 kilovolts. These feeder circuits are served from seven distribution substation transformers that are housed at a total of three substations: Gleason Lake, Hollydale, and Parkers Lake. The three substations, in turn, are served from 115 kilovolt transmission lines that loop the Greater Study Area, with the exception of Hollydale Substation.

Figure 10
Greater Study Area



3.3 Distribution Planning Criteria

Xcel Energy is committed to and obligated by Minnesota law to provide safe, adequate, efficient, and reliable electrical service at just and reasonable rates. To meet these objectives, Xcel Energy's distribution system load is planned, measured, and forecasted on an annual basis with the goal to reliably serve all customer electric load under system intact and first contingency operating conditions.

Normal operation (also called "system intact" or "N-0" operation) is the condition under which all electric infrastructure equipment is fully functional. First contingency operation (also called single contingency operation or "N-1") is the condition under which a single element (e.g., feeder circuit or distribution substation transformer) is out of service. A distribution delivery system that has adequate first contingency capacity is one in which all customer load can be restored through distribution system reconfiguration, e.g., electrical switching. Xcel Energy uses distribution planning criteria to achieve uniform development of Xcel Energy's distribution systems. These planning criteria are described below.

3.3.1 Feeder Circuits

Under system intact operating conditions, typical feeder circuits should be loaded to less than 75% of capacity. Xcel Energy developed this indicator to help ensure that service to customers can be maintained under single contingency operating conditions. If feeder circuits were loaded to their maximum capacity and an outage occurred, the remaining system components would not be able to make up for the loss because adding load to the remaining feeder circuits would cause them to overload. By targeting a 75% loading level, there is generally sufficient remaining capacity on the system (25% per feeder) to cover an outage of an adjacent feeder with minimal service interruptions. A typical feeder circuit capable of delivering 12 megavolt-ampere ("MVA"), for example, is normally loaded to less than 9 MVA. During contingency conditions, it can be loaded up to 12 MVA.

3.3.2 Substation Transformers

Under system intact operating conditions, substation transformers should be loaded at 75% of normal rating or lower. Substation transformer utilization rates below 75%

are indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. The higher the transformer utilization rate (i.e., greater than 75% of capacity is being used under normal system conditions), the higher the risk that customer electrical service will be interrupted in the event of a transformer or feeder outage.

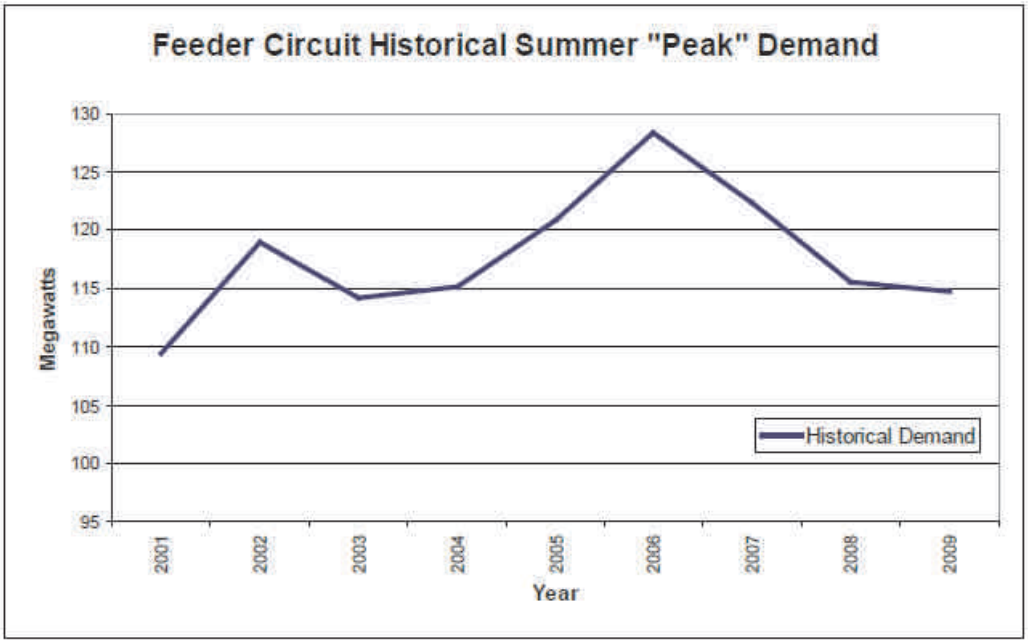
3.4 Feeder Circuits Historical and Future Loads

3.4.1 Feeder Circuit Historical Loads

Feeder circuit peak loading in the Plymouth area occurs during the summer months. Measured peak loads fluctuate from year to year due to the duration and intensity of hot weather. In the 2010 study, Xcel Energy evaluated historical peak loads from 2001 to 2009. In the Focused Study Area, the measured peak load increased an average of 0.7 % per year in the eight years between 2001 and 2009. Feeder circuit load peaks were experienced in 2002 (119 megawatts) and 2006 (128 megawatts). Loads declined in 2007, 2008, and 2009 as these years experienced cooler weather conditions compared to 2006.

Even though the measured peak load decreased since 2006, the historic peak of 2006 represents a load level that will recur in years that have higher temperatures similar to those experienced in 2006. The historical loads for the feeder circuits serving the Focused Study Area from 2001 to 2009 are shown below in **Figure 11**.

Figure 11
Historical Summer "Peak" Demand in Focused Study Area



In addition, while the Distribution Study examined only loads from 2001 to 2009, loads in the Focused Study Area increased in 2010 and in 2011 reached 122 megawatts, nearly reaching 2006's historic peak of 128 megawatts.

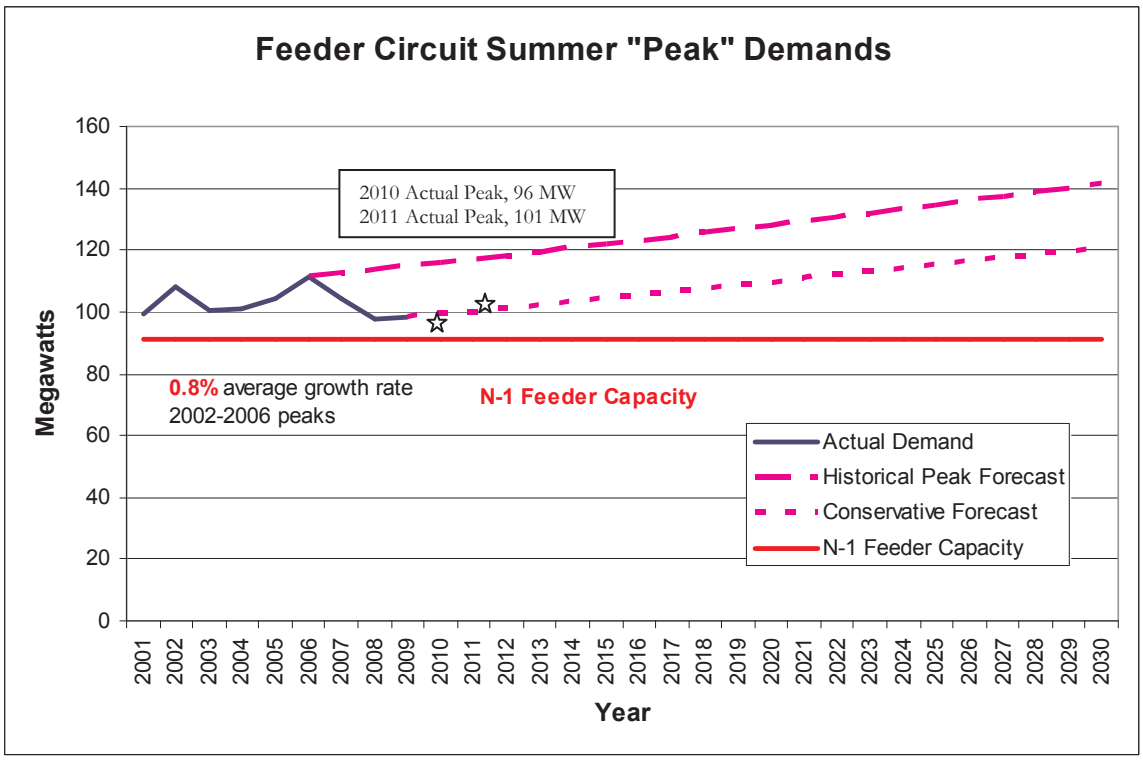
3.4.2 Feeder Circuit Load Forecasts

The historical load data in the above section combined the 13.8 kilovolt areas and the 34.5 kilovolt areas to gain an accurate representation of historical load growth within the Focused Study Area from 2001 to 2009. To analyze the distribution system for the future and identify the capacity needs, the 13.8 kilovolt and 34.5 kilovolt areas need to be analyzed separately. Approximately 9 MVA of 34.5 kilovolt load was assumed transferred to the 13.8 kilovolt system for this analysis. The 34.5 kilovolt feeder analysis includes the imbedded Hollydale 13.8 kilovolt feeder load to reflect the impact of the 34.5 kilovolt source at Hollydale.

As part of the Distribution Study, Xcel Energy applied a 1.0% growth rate based on historic loading, anticipated customer conservation, and soft economic growth. Xcel Energy analyzed 11 13.8 kilovolt feeders and two 34.5 kilovolt feeders for the next 20 years. Xcel Energy first applied the 1.0% from the 2006 peak load level of 128

megawatts and resulted in a growth in demand of approximately 16 megawatts on the 13.8 kilovolt feeders and approximately 5 megawatts on the 34.5 kilovolt feeders between 2006 and 2020 ("Historic Peak Forecast"). Xcel Energy also applied the same 1.0% growth rate from the cooler 2009 peak load level which resulted in growth in demand of approximately 11 megawatts on the 13.8 kilovolt feeders and approximately 4 megawatts on the 34.5 kilovolt feeders between 2009 and 2020 ("Conservative Forecast"). Actual peak loads will likely fall between the Historic Peak Forecast and the Conservative Forecast. **Figure 12** and **Figure 13** depict these two forecast scenarios.

Figure 12
Historical and Forecasted Load Growth on Eleven 13.8 kilovolt Feeder Circuits in Focused Study Area[24]



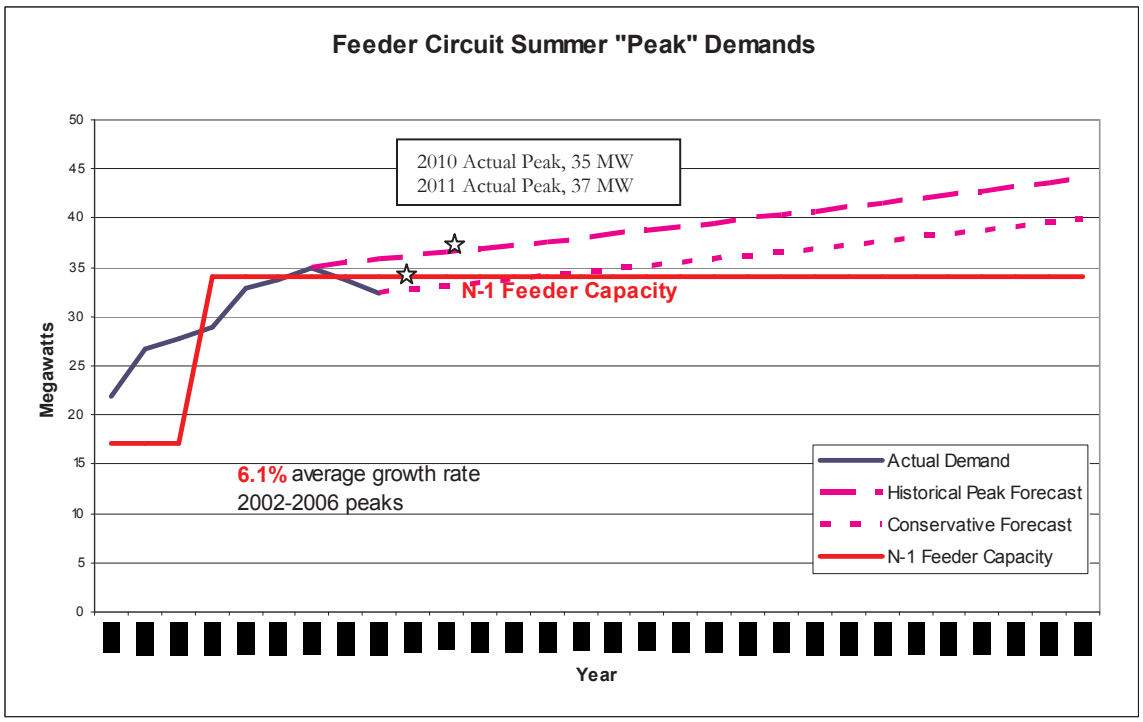
Over time, demand on the distribution system generally trends upward, with some dips due to weather or economic downturns. The historic downturns have been followed by increases in demand that reach levels equal or greater than the prior peak.

[24] The data used to create this chart is located in Appendix G.3-5.

For example, on the 13.8 kilovolt feeders, from the year 2002 to the year 2004, demand declined by approximately 7 megawatts. Then, from the year 2004 to 2006, demand increased again by approximately 10 megawatts, reaching a new peak of 111 megawatts. From 2006 to 2009, there has been a similar decline in demand from the historical 2006 peak by approximately 13 megawatts.

In 2010, the 13.8 kilovolt feeders experienced peak demand of 96 megawatts and in 2011 that demand grew to 101 megawatts. The 2010 peak demand was slightly below the Conservative Forecast and the 2011 peak demand was slightly higher than the Conservative Forecast. The load growth on the 13.8 kilovolt system was closer to the Conservative Forecast because the majority of the new load was placed on 34.5 kilovolt system as opposed to the 13.8 kilovolt system which is at capacity.

Figure 13
Historical and Forecasted Load Growth on Two 34.5 kilovolt Feeder Circuits in the Focused Study Area[25]



[25] The data used to create this chart is located in Appendix G.3-4.

Just as the 13.8 kilovolt feeders in **Figure 12**, **Figure 13** shows that demand on the 34.5 kilovolt system generally trends upward. Unlike the 13.8 kilovolt feeders, there are no significant dips due to weather or economic downturns, indicating that the 34.5 kilovolt system has experienced significant growth over the last decade. The only drop in demand on the 34.5 kilovolt feeders is from 2007 to 2009 and that drop can be attributed to cooler weather. It can be expected that the decision to no longer expand the 34.5 kilovolt system in this area will slow the growth. However, steady growth on the existing load should be expected and future years should look much more like the linear depiction of the historical 13.8 kilovolt loads. It should also be noted that the spike in N-1 capacity from 2003 to 2004 is due to the addition of the second 34.5 kilovolt feeder circuit out of Gleason Lake Substation.

In 2010 peak demand on the 34.5 kilovolt system grew to 35 megawatts and then reached 37 megawatts in 2011. This 37 megawatts of peak demand in 2011 was above the Historic Peak Forecast of 36 megawatts contained in the Distribution Study. This significant growth on the 34.5 kilovolt system can be attributed to the fact that the 13.8 kilovolt system is currently at capacity so the majority of the new load was placed on the 34.5 kilovolt system.

3.5 Feeder Circuit Overloads

Xcel Energy aims to maintain utilization rates at or below 75% on distribution feeder circuits to help ensure a robust distribution system capable of providing electrical service under first contingency N-1 conditions. This desired loading level of 75% only applies to the 13.8 kilovolt feeder circuits, the 34.5 kilovolt feeder circuits have a unique configuration and therefore have a different desired loading level. There are only two 34.5 kilovolt feeder circuits in this geographical area and therefore the feeder circuits only have one tie for backup during a contingency situation, while the 13.8 kilovolt feeders generally have three ties. Since the 34.5 kilovolt feeder circuits only have one tie as opposed to three, their desired loading level is 50%. At 50% utilization, each feeder circuit can fully back the other one up during N-1 conditions.

To assess the robustness of the system in the Focused Study Area over time, Xcel Energy analyzed the historical utilization rates and projected utilization rates of the 13.8 kilovolt and 34.5 kilovolt feeder circuits based on forecast demand. This analysis

revealed the utilization rates of the 13.8 kilovolt feeder circuits have exceeded the desired 75% utilization level since 2001. Even using the more conservative forecast based on the cooler summer peaks of 2009, average utilization rates on the 13.8 kilovolt feeder circuits will exceed 90% by approximately 2020 unless system improvements are made.

This analysis also demonstrates a capacity need on the 34.5 kilovolt distribution system within the Focused Study Area. The change in utilization from 2003 to 2004, is due to the addition of the second 34.5 kilovolt feeder circuit in the Focused Study Area. Even with this capacity addition, peak load levels still continued to exceed the desired 50% loading level. Just as on the 13.8 kilovolt distribution system within the Focused Study Area, these utilization levels are only projected to increase unless system improvements are made.

Table 2 and **Table 3** provide additional detail on the historical and anticipated utilization percentages and overloads for the 11 13.8 kilovolt feeder circuits and two 34.5 kilovolt feeder circuits in the Focused Study Area for various years between 2001 and 2030.

Table 2
Summary of Feeder Circuit Utilization and Overloads for the Eleven 13.8 kilovolt Feeder Circuits in the Focused Study Area

Historical Feeder Circuit Utilization and Overloads And Forecast Using Conservative Trending									
	2001	**2004**	**2006**	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
# of Circuits	11	11	11	11	11	11	11	11	11
MW Capacity	121	121	121	121	121	121	121	121	121
Feeder Actual	2001-2009 Average								
% Growth	0.8								
% Utilization	82%	83%	92%	81%					
Forecast					2010-2020 Average			2020-2030 Average	
% Growth					1.0%			1.0%	
% Utilization					82%	86%	90%	95%	100%
N-0 Overloads									
# Severe >115%	1	2	2	1	1	1	2	2	2
# of Circuits > 100%	2	2	4	3	3	3	3	4	6
MW > 100%	3.7	5.5	10.7	4.3	4.7	6.5	8.3	10.7	14.0
N-1 Conditions									
# of Circuits > 75%	8	7	8	7	7	7	7	8	8
MW > 75%	16.9	14.9	24.1	15.3	16.0	19.6	23.5	27.5	32.2

Table 3
Summary of Feeder Circuit Utilization and Overloads for the Two 34.5 kilovolt Feeder Circuits in the Focused Study Area

Historical Feeder Circuit Utilization and Overloads And Forecast Using Conservative Trending									
	2001	**2004**	**2006**	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
# of Circuits	1	2	2	2	2	2	2	2	2
MW Capacity	34	68	68	68	68	68	68	68	68
Feeder Actual	2001-2009 Average								
% Growth	6.1%								
% Utilization	64%	42%	49%	47%					
Forecast					2010-2020 Average			2020-2030 Average	
% Growth					1.0%			1.0%	
% Utilization					48%	50%	53%	56%	58%
N-0 Overloads									
# Severe >115%	0	0	0	0	0	0	0	0	0
# of Circuits >100%	0	0	0	0	0	0	0	0	1
MW > 100%	0	0	0	0	0	0	0	0	0.8
N-1 Conditions									
# of Circuits > 50%	1	1	1	1	1	1	1	1	1
MW > 50%	4.9	10.5	12.6	11.3	11.5	13.0	14.5	16.1	17.8

The information in **Table 2** and **Table 3** shows that the Focused Study Area distribution system experienced steady peak growth in the decade leading up to 2009 loads that increasingly exceeded circuit capacities with increasing numbers of circuits

overloaded in both system intact N-0 and first contingency N-1 conditions. Even when the number of circuits overloaded does not increase, the quantity of overloads increases. **Table 4** summarizes the additional feeder circuit capacity in megawatts needed to mitigate the overloads detailed in **Table 2.**

Table 4
Summary of Feeder Circuit Capacity Required to Mitigate Feeder Circuit Overloads

Minimum Number of Feeders Required to Correct N-0 and N-1 Overloads									
	2001	2004	2006	2009	2010	2015	2020	2025	2030
N-0 Deficiency (MW)	3.7	5.5	10.7	4.3	4.7	6.4	8.3	10.7	14.8
Minimum # of New Feeders Needed	1	1	2	1	1	1	1	2	2
N-1 Deficiency (MW)	21.8	25.4	36.7	26.6	27.5	32.6	38.0	43.6	50.0
Minimum # of New Feeders Needed	3	3	4	3	3	4	4	5	6

Note: Minimum number of feeders assumes 13.5MW feeder circuits loaded to 75% or less.

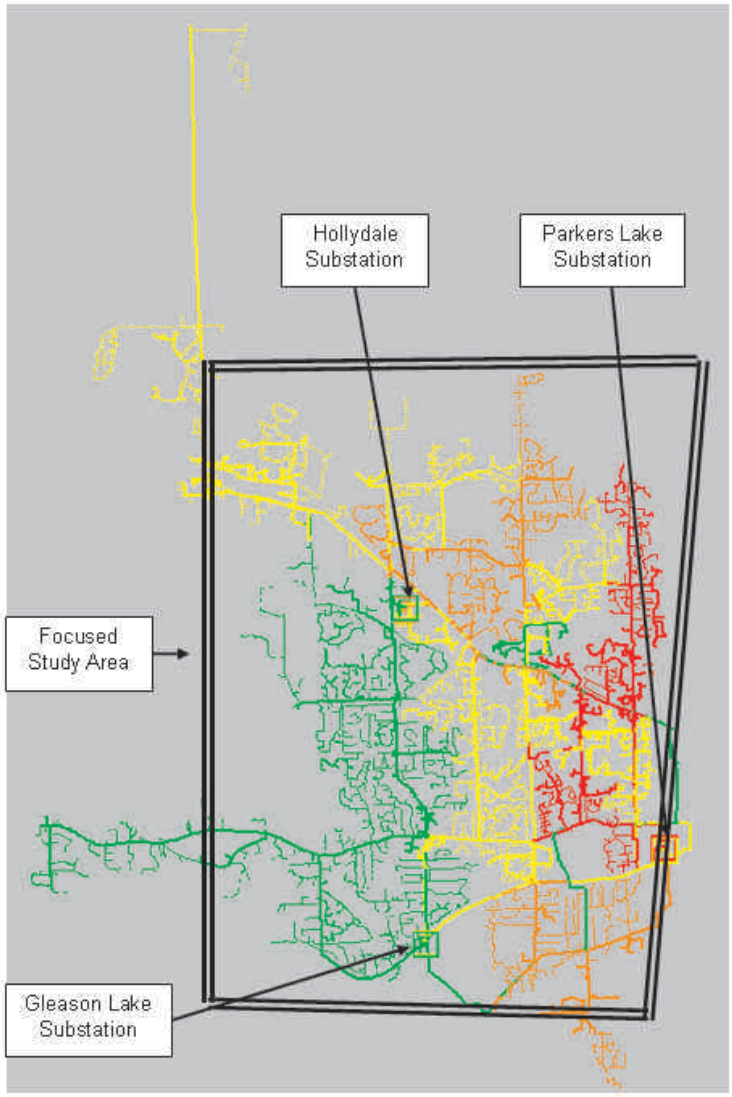
This analysis shows that there is currently a deficit of approximately 37 megawatts in the Focused Study Area based on the 2006 peak loading and the system capacity under N-1 conditions. 2006 loading levels represent established overloads for connected load that exists on the electrical system and peak loading that has been previously reached under the most recent hottest weather conditions. Using conservative forecasting methods, which use the cooler summer peaks of 2009 as a starting point; by 2020, the deficit will be 38 megawatts, essentially returning to the 2006 level.

To better illustrate the number, concentration and location of the historical and forecasted overloads, Planning Engineers developed distribution system maps depicting the overloaded feeder circuits in N-0 system intact and N-1 first contingency operating conditions for 2006 and future forecast year 2020. These

distribution system maps are contained in the Distribution Study, **Appendix B.1**. Two of those maps for 2006 are depicted in **Figure 14** and **Figure 15**. The color codes in the distribution system maps represent rows in **Table 2** and **Table 3** for the labeled years as follows:

> # Severe > 115%, N-0 Overloads: The quantity of feeder circuits that are severely overloaded under system intact conditions are identified as shown in red.
>
> # of Circuits >100%, N-0 Overloads: The quantity of feeder circuits that are overloaded under system intact conditions are identified as shown in orange and red depending on the severity of the overload with red feeder circuits having the most severe overloads.
>
> MW > 100%, N-0 Overloads: The sum of the system intact overloads, in megawatts for the number of circuits that are identified as overloaded and shown in orange and red.
>
> # Circuits > 75%, N-1 Conditions: The quantity of feeder circuits that are loaded above 75% capacity indicating first contingency overload conditions are identified as shown in yellow, orange, and red. Yellow circuits are feeder circuits with first contingency overloads.
>
> MW > 75%, N-1 Conditions: The sum of the first contingency overloads, in megawatts for the number of circuits that are identified as overloaded and shown in yellow, orange, and red.

Figure 14
Focused Study Area 2006 N-0 Feeder Circuit Risks – System Intact
(Using historical feeder peak year)

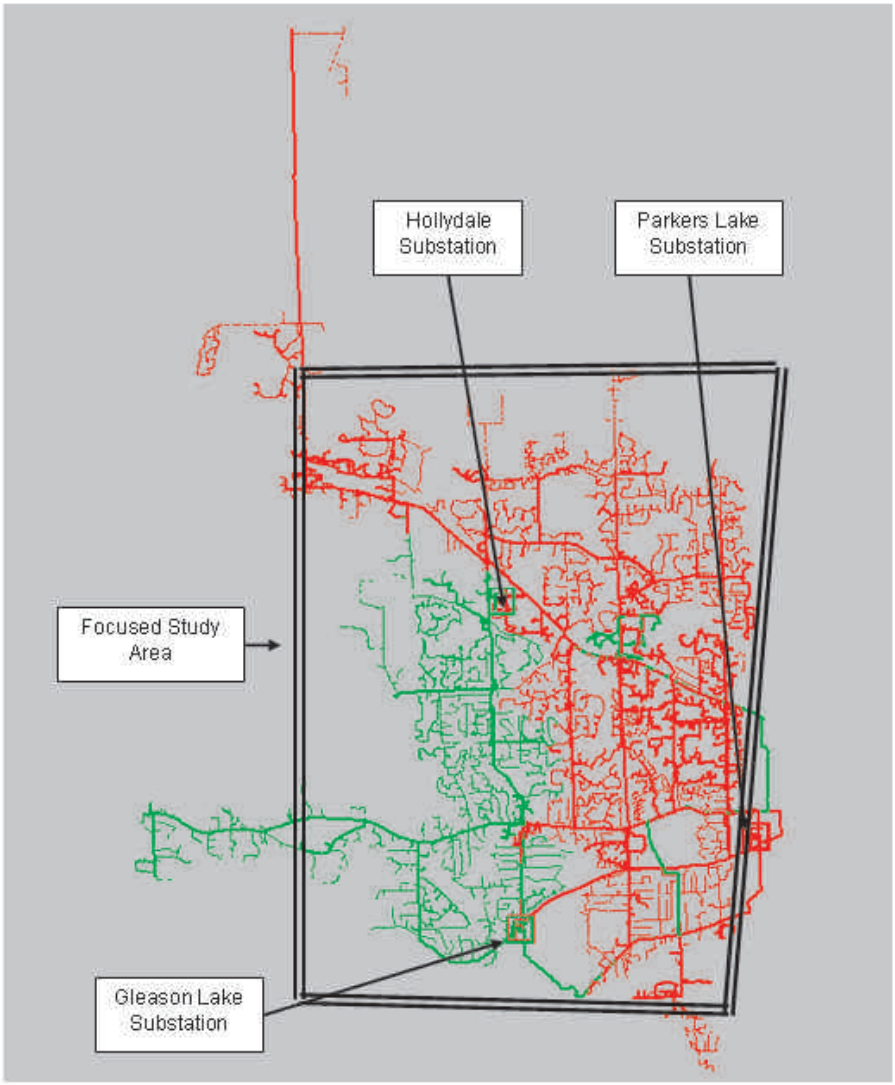


Feeder Circuits Colored by N-0 Circuit Loading:		
4 Circuits	<75%	
5 Circuits	75%-100%	
2 Circuits	100%-115%	
2 Circuits	>115%	

Figure 14 shows that of the thirteen feeder circuits in the Focused Study Area, in the historical feeder peak year of 2006, under system intact N-0 conditions, four feeders were utilized at less than 75%, 5 feeders were utilized between 75%-100%, two feeders were utilized between 100%-115%, and two circuits were utilized at greater

than 115%. Note that many of the most severe overloads occur along previously identified areas of more concentrated load and faster load growth. Overloads are even more widespread across feeder circuits in the Focused Study Area under N-1 loading conditions. **Figure 15** shows that of the 13 feeder circuits in the Focused Study Area, in 2006 under single contingency N-1 conditions, nine feeders would be at risk for experiencing overload conditions.

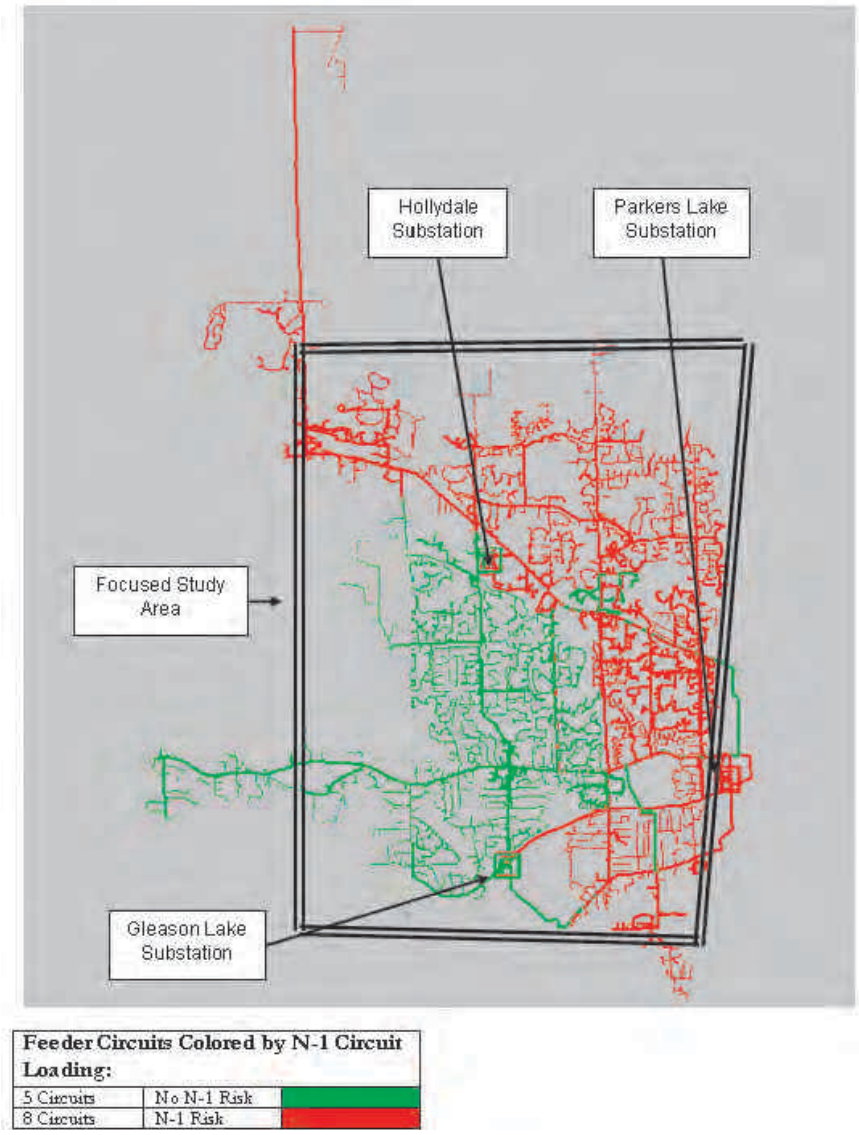
Figure 15
Focused Study Area 2006 N-1 Feeder Circuit Risks – Single Contingency



Feeder Circuits Colored by N-1 Circuit Loading:		
4 Circuits	No N-1 Risk	
9 Circuits	N-1 Risk	

Figure 16 shows that of the thirteen feeder circuits in the Focused Study Area, under 2020 forecasted load under single contingency N-1 conditions, eight feeders would be at risk for experiencing overload conditions. **Figure 16** is based on the conservative forecast and the number of feeders experiencing overloads could be greater if load levels reach 2006 historic peak levels.

Figure 16
Focused Study Area 2020 N-1 Feeder Circuit Risks-Single Contingency



The data demonstrate that the Focused Study Area has been experiencing higher than optimal utilization rates on its feeders for the past decade. Without additional capacity additions in the area, these high utilization rates will increase the number and duration of overloads on feeders. Based on this analysis, Distribution Planning concluded that to ensure continued reliable service in the area, additional improvements are required.

3.6 Transformer Overloading

After examining the feeder circuit peak demands, Xcel Energy looked at the loading levels for the two 13.8 kilovolt transformers and the one 34.5 kilovolt transformer housed at the Gleason Lake Substation. The Gleason Lake Substation is the only substation served by transmission that is in the Focused Study Area. The Hollydale Substation also lies in the Focused Study Area but its ability to provide additional capacity is dependent on the available 34.5 kilovolt capacity at Gleason Lake Substation.

Xcel Energy reviewed the historical loading from 2001 to 2009 on the two 13.8 kilovolt and one 34.5 kilovolt transformers at Gleason Lake Substation and forecasted future demand to 2030.

Figure 17 shows the Conservative Forecast and the Historical Peak Forecast applied to the two 13.8 kilovolt substation transformers at Gleason Lake Substation. The 13.8 kilovolt load levels at the Gleason Lake Substation have approached the N-1 substation limit, but have not exceeded that limit. Using the historical peak forecast demand load projections, there is roughly only 1 megawatt of additional load serving capacity on the 13.8 kilovolt Gleason Lake distribution system. Using the conservative forecast demand load projections, there is roughly 12 megawatts of additional load serving capacity on the 13.8 kilovolt Gleason Lake distribution system. Even with this 12 megawatts of additional load serving capacity, the capacity deficiencies on the 13.8 kilovolt distribution system within the Focused Study Area cannot be fully resolved because as shown in **Figure 17**, by 2030 14 megawatts of additional capacity will be needed. **Figure 17** also shows that the actual peak loading in 2010 and 2011 were within the range of the two forecasts.

Figure 17
Historical and Forecasted Load Growth on Two 13.8 kilovolt Substation Transformers at Gleason Lake Substation in the Focused Study Area (Non-Coincident)

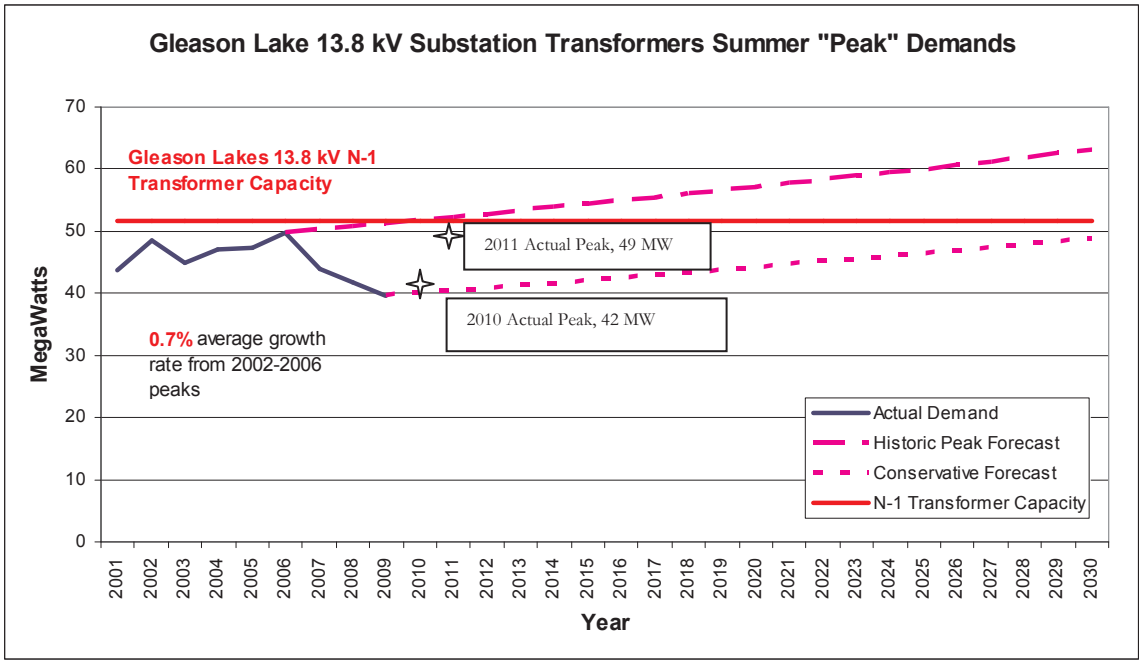
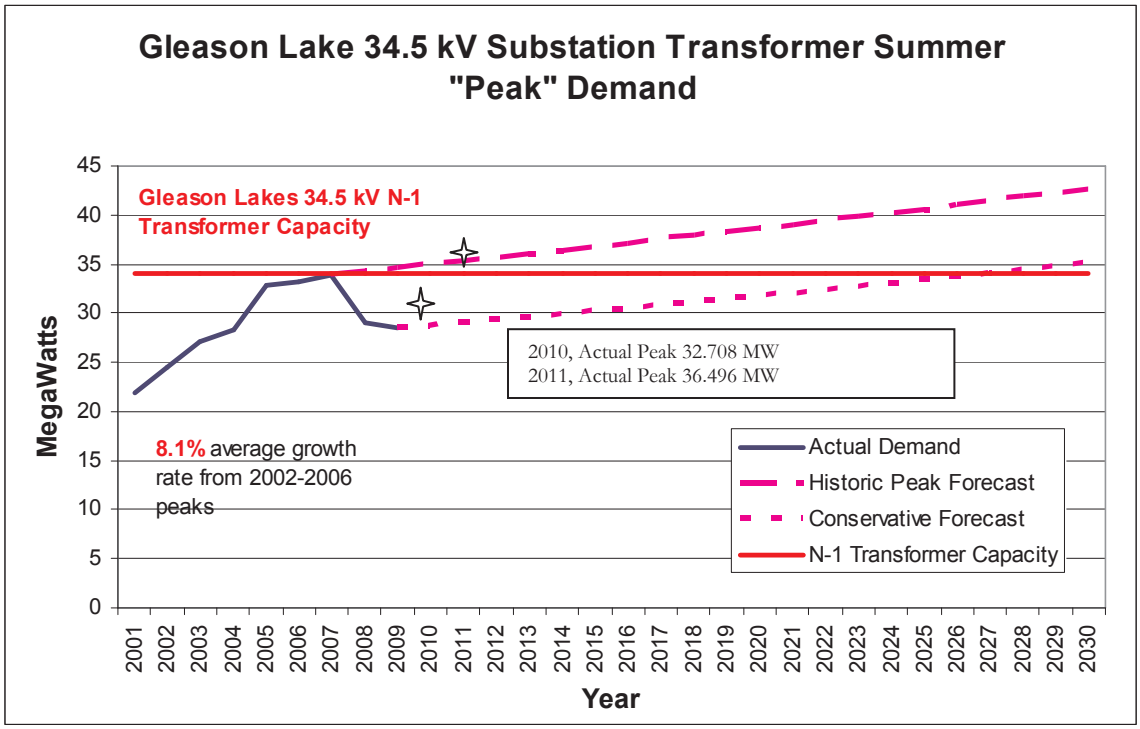


Figure 18 shows the same analysis done on the one 34.5 kilovolt transformer at Gleason Lake Substation. The 34.5 kilovolt substation transformer at Gleason Lake has experienced loading similar to the 13.8 kilovolt substation transformers. The load on the 34.5 kilovolt substation transformer has slightly exceeded the N-1 limit. Using the historic peak forecast demand projections, there are 0 megawatts of additional load serving capacity on the 34.5 kilovolt Gleason Lake distribution system. Using the conservative forecast demand projections, there is roughly 6 megawatts of additional load serving capacity on the 34.5 kilovolt Gleason Lake distribution system. As previously stated, this alone is not enough capacity to solve the deficiencies on the distribution system in the Focused Study Area. Combining the 6 megawatts of load serving capacity available on the 34.5 kilovolt substation transformer with the 12 megawatts on the 13.8 kilovolt substation transformers, the deficiencies can still not be fully solved. **Figure 18** also shows that the actual peak loading in 2010 was within the range of the two forecasts and 2011 actual peak loading was slightly higher than the historical peak forecast.

Figure 18
Historical and Forecasted Load Growth on One 34.5 kilovolt Substation Transformers at Gleason Lake Substation in the Focused Study Area



The Gleason Lake Substation is presently at its maximum design capacity based on transformer capacity ratings and available space. Based on these restrictions, and the analysis above, Xcel Energy concluded that the Gleason Lake Substation transformers do not have the required capacity to solve the capacity issues within the Focused Study Area.

3.7 New Facilities Alternatives, Distribution Study

Once it was determined that expansion of the existing feeder circuits and substations were not viable options to correct the overloading conditions in the area, Xcel Energy developed three electrical system alternatives that would provide additional loading capacity in the Project area to meet current and help address future needs.

The three alternatives are:

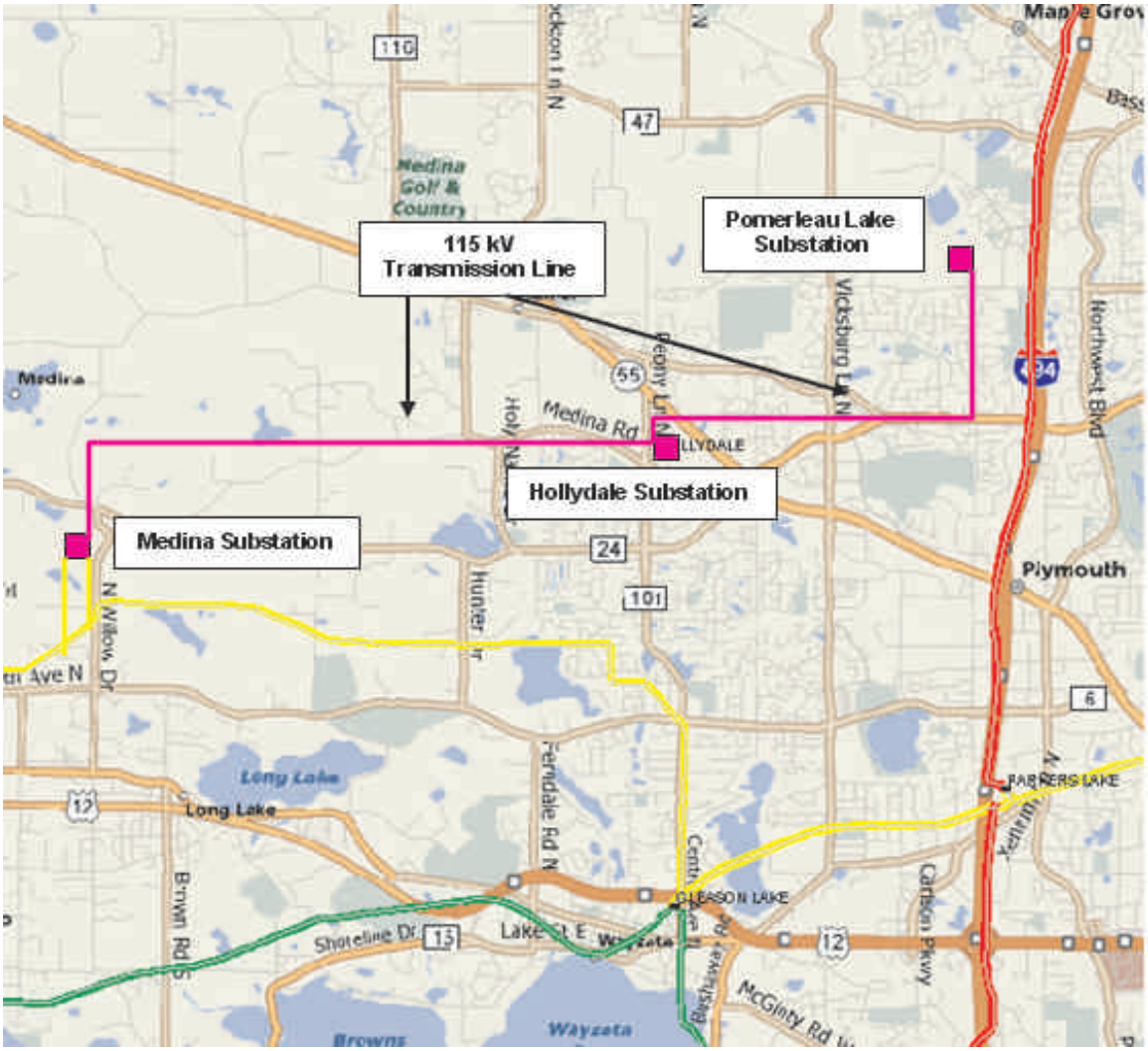
- Alternative – 1 ("A1" or "Hollydale Project"): Hollydale 115/13.8 kilovolt distribution substation and two 115 kilovolt transmission lines
- Alternative – 2 ("A2"): Perimeter 115/13.8 kilovolt distribution substation
- Alternative – 3 ("A3"): Upgrade of the Gleason Lake and Parkers Lake 115/13.8 kilovolt distribution substations

Alternative A1 is considered standard installation. Alternatives A2 and A3 are considered non-standard installation because they involve using distribution voltage express feeder circuits at 13.8 kilovolt to move power from a distant substation transformer location instead of using a 115 kilovolt transmission line to transmit power.

To evaluate the effectiveness of the three alternatives, Xcel Energy compared the alternatives with respect to system performance, operability, future growth, costs, and losses. Xcel Energy further evaluated the alternatives based on the cost of adding distribution equipment to address N-0 and N-1 overloads in the Focused Study Area as load grows to the ultimate design in 2030 that would be required. The assumed facilities and estimated costs are included in the Distribution Study, **Appendix B.1**, **Section 6.2**.

The Hollydale Project was found to best satisfy Xcel Energy's criteria. This option includes a Hollydale Substation that is designed for two 50 MVA 115/13.8 kilovolt transformers and one 13.8/34.5 kilovolt transformer with the possible addition of one 70 MVA 115/34.5 kilovolt or one 50 MVA 115/13.8 kilovolt transformer depending on load growth and available transmission capacity. The initial configuration is shown in **Figure 19**.

Figure 19
A1 - Hollydale 115/13.8 kilovolt distribution substation and two 115 kilovolt transmission lines



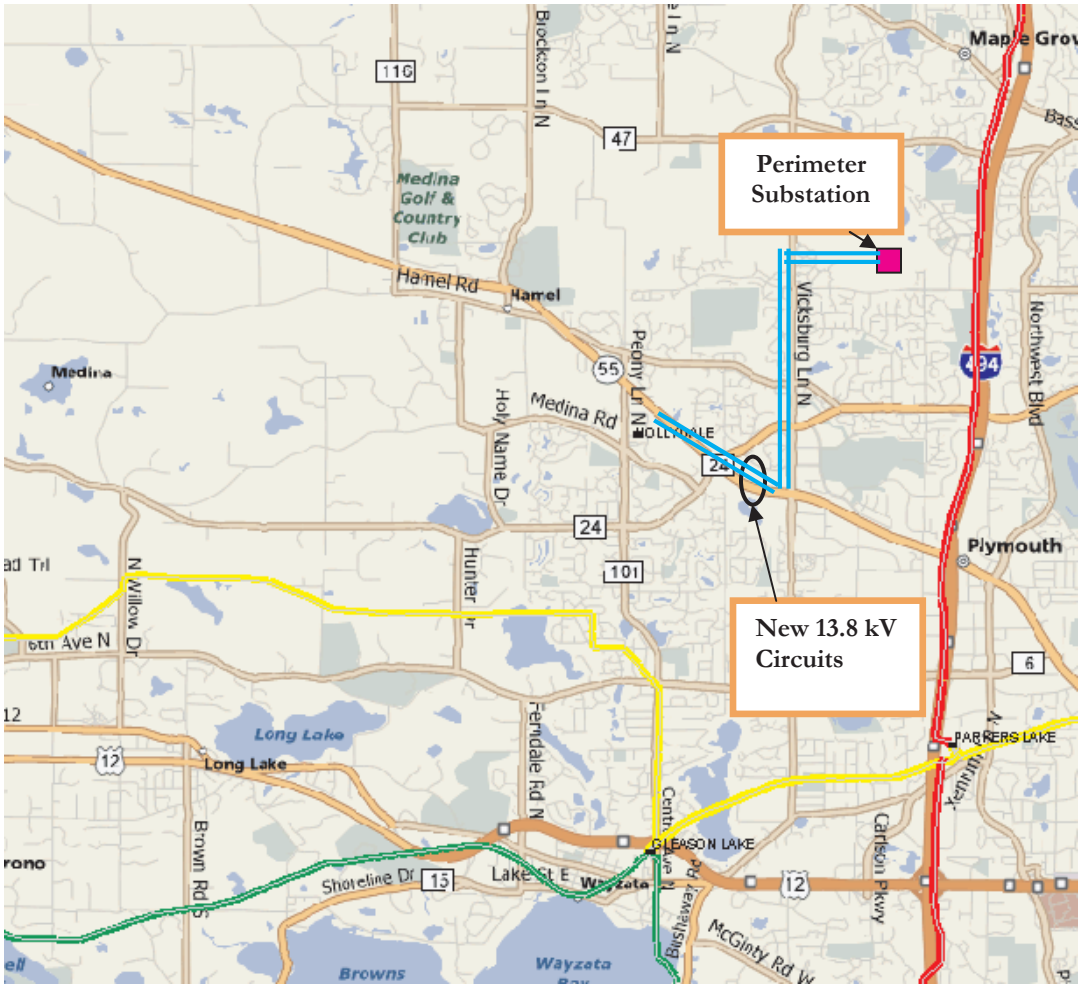
With respect to system performance, the Hollydale Project installs additional substation transformer capacity at one new substation nearest to the identified load center in the Focused Study Area. As a result, the Hollydale Project delivers power to load with shorter feeder circuits. Shorter feeder circuits consist of less equipment, have fewer elements that can fail, and have less exposure to external factors that increase the chance of feeder outages. The Hollydale Project is capable of maintaining adequate voltage on feeder circuits. The Hollydale Project also has the best operability over the other alternatives. The Hollydale Project is an extension of the existing simple distribution system and provides for a large number of standard

options that could be quickly implemented under contingency conditions. With respect to future growth, the Hollydale Project provides the most possibilities of all the alternatives for future capacity additions. As described in more detail below, Xcel Energy found that Alternatives A2 and A3 are inferior to the Hollydale Project.

Alternative A2

This option initially includes an installation with an ultimate design capacity of two (2) 115/13.8 kilovolt distribution substation transformers with a total of six (6) 13.8 kilovolt feeder circuits at a new substation somewhere on the perimeter 115 kilovolt lines, surrounding the study area. One location for the new Pomerleau Lake Substation could be just south of Pomerleau Lake in Plymouth. This new substation would be fed from Great River Energy's existing 115 kilovolt Parkers Lake - Plymouth transmission line. **Figure 20** illustrates Alternative A2.

Figure 20
A2 - Perimeter 115/13.8 kilovolt distribution substation



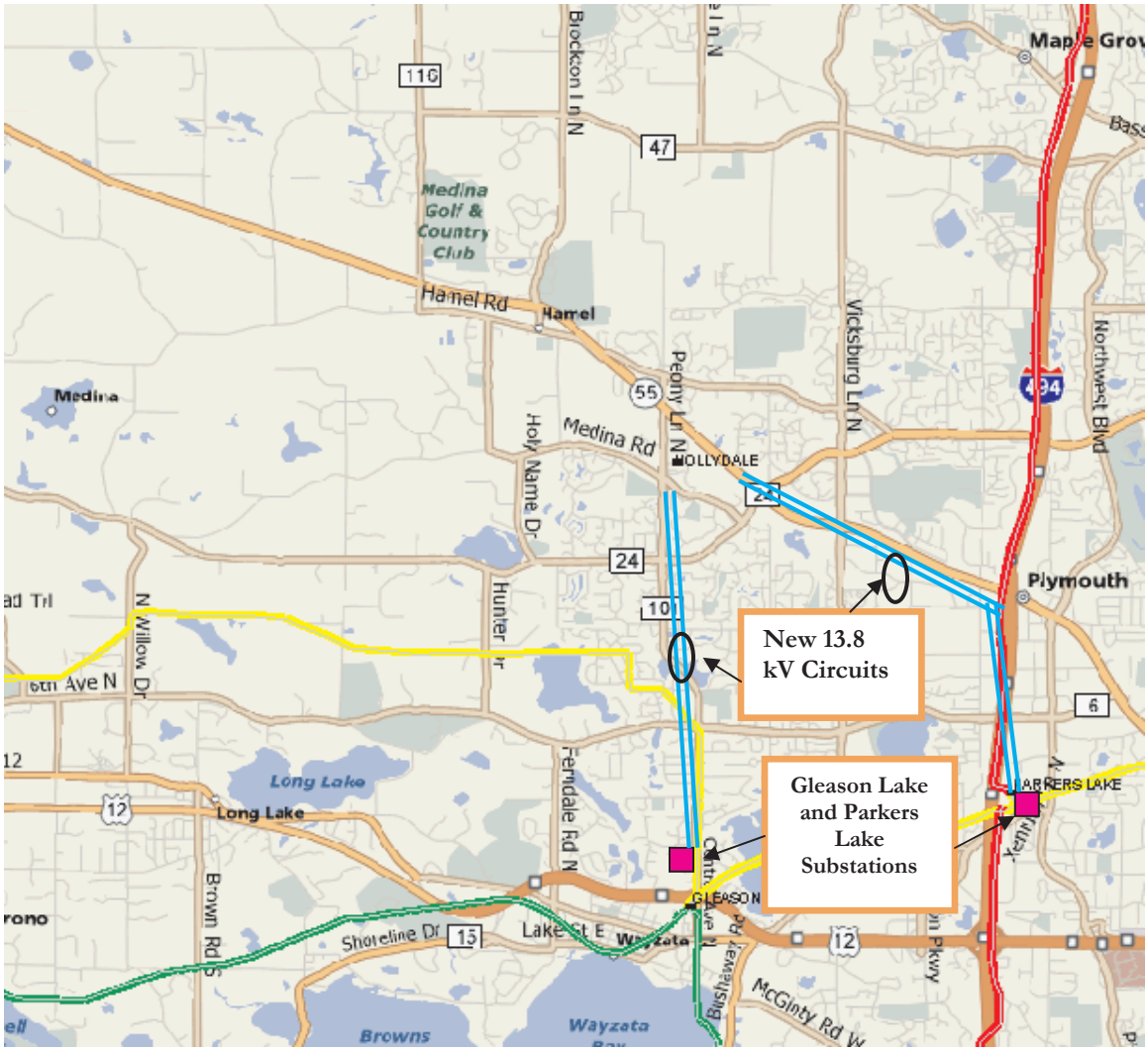
With respect to system performance, Alternative A2 installs additional substation transformer capacity at one new location which is a greater distance than the substation under the Hollydale Project from the identified load center in the Focused Study Area. As a result, Alternative A2 requires longer feeder circuits than the Hollydale Project to serve load, and therefore, is subject to greater exposure to conditions that could lead to line failures. With respect to operability, similar to the Hollydale Project, Alternative A2 is an extension of the existing distribution system and provides for a large number of standard options that could be quickly implemented under contingency conditions. With respect to future growth, Alternative A2 does not provide as many possibilities as the Hollydale Project.

Alternative A2 is estimated to cost approximately $26.3 million and is the highest cost alternative.

Alternative A3

Alternative A3 includes upgrading one substation transformer at Gleason Lake Substation to a 70 MVA unit, and installing two new feeder circuits. The three existing transformers at Parkers Lake Substation could be replaced with 70 MVA units, and three feeders could be installed in approximately 2016 followed by another feeder in 2025. **Figure 21** illustrates the Alternative A3 configuration.

Figure 21
A3 – Upgrade of the Parkers Lake 115/13.8 kilovolt distribution substation



Alternative A3 has the longest feeder circuits of the three alternatives. Longer feeder circuits consist of more equipment, have more elements that can fail, and have more exposure to external factors that increase the chance of feeder outages. Alternative A3 is the worst alternative with respect to system performance. With respect to operability, Alternative A3 uses standard distribution delivery components in a non-standard way by extending feeders from outside the Focused Study Area into the area. This results in longer feeder lines which makes Alternative A3 more vulnerable during overload and outage conditions. Alternative A3 also uses long express feeder circuits that require many more components to keep in running order and fully operational during all possible conditions and could result in low voltage conditions.

With respect to future growth, Alternative A3 provides very little possibility for future capacity additions. This option exhausts all capacity addition options at Parkers Lake substation.

In summary, Xcel Energy determined that Alternative A1 was the best performing option with respect to system performance, operability, future growth, cost, and electrical losses.

3.8 New Transmission Facilities Alternatives, Transmission Study

In addition to the alternatives studied as distribution solutions, Xcel Energy also evaluated the Hollydale Project from a transmission performance perspective and evaluated three alternative transmission options that would provide capacity to the Hollydale Substation.[26] The options evaluated in the Transmission Study are as follows:

- **Option H1 (Hollydale Project):** This connection option brings a new 115 kilovolt line from Great River Energy's Medina Substation to a new 115 kilovolt switching substation, near Great River Energy's Plymouth

[26] When Xcel Energy's Distribution Planning determines that a distribution system requires additional capacity from a new distribution source, it makes a formal request to Transmission Planning to interconnect to the transmission system. Transmission Planning takes the request and these two departments coordinate to develop several options that will address the distruibution system deficiencies. Transmission Planning also performs analyses to determine the impact of the selected options on the transmission system.

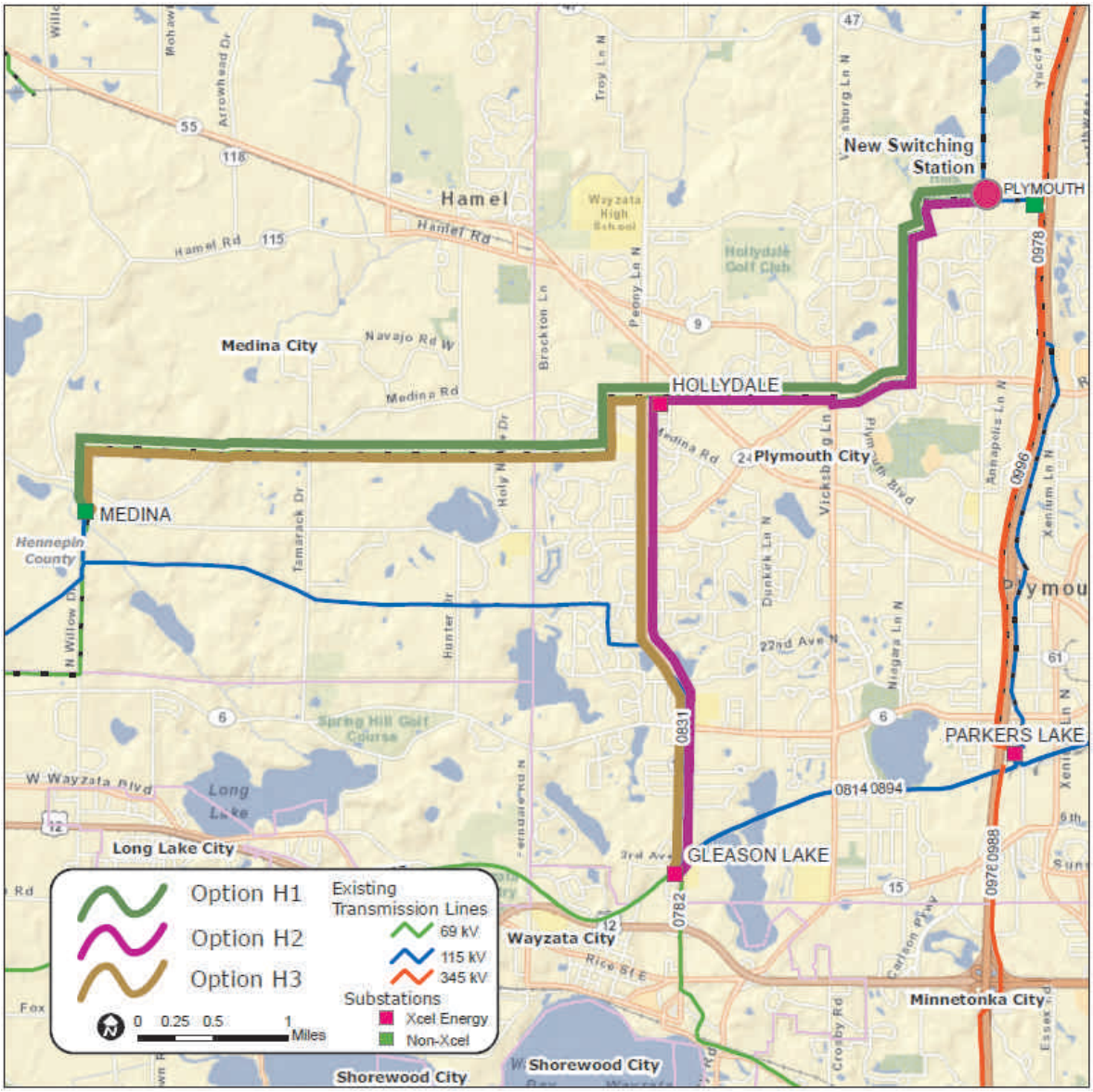
Substation. The 115 kilovolt line would replace the existing 69 kilovolt line in the corridor. The switching substation would be located on the Great River Energy 115 kilovolt line (WH-PB) between Great River Energy's Plymouth and Bass Lake substations. A proposed name for this substation is Pomerleau Lake. Approximate Miles of 115 kilovolt: 8 Miles.

- **Option H2:** Like Option H1, this path terminates into a new switching substation near Great River Energy's Plymouth Substation. The western termination would be Gleason Lake. The line could follow the 69 kilovolt corridor between Hollydale Substation and the new switching substation and the 34.5 kilovolt distribution corridor south to Gleason Lake Substation from Hollydale Substation. Approximate Miles of 115 kilovolt: 8.5 Miles.

- **Option H3:** The third possible connection is Medina-Hollydale-Gleason Lake. Similar to option H1, this connection could use the 69 kilovolt corridor between Medina and Hollydale substations. The line could then head south on the 34.5 kilovolt corridor to Gleason Lake Substation. Approximate Miles of 115 kilovolt: 8.5 Miles.

Figure 22 below illustrates these three options.

Figure 22
Transmission Study Alternatives



The transmission study costs for these three options are provided in **Table 5.** The customer rate impact for each of the three transmission line alternatives is presented in **Appendix C**.

Table 5
Transmission Study Costs (millions)

	Option H1	Option H2	Option H3
Transmission Line	$7.38	$7.481	$7.481
Substation	$13.040	$13.040	$7.340
Total	**$20.420**	**$20.881**	**$15.181**

Xcel Energy determined that the Hollydale Project is the best performing transmission alternative of the three options studied. One outage that the transmission system needs to handle is a double circuit failure between the Parkers Lake and Gleason Lake substations. During this outage the current transmission system is supported out of Crow River. It can be seen in future transmission planning models that voltages become depressed in the Plymouth area during this fault. In addition to providing a feed to the Hollydale Substation, the Hollydale Project creates a parallel path to this double circuit outage, thereby improving reliability in the area.

In comparing the Hollydale Project (Option H1) to Option H2, Xcel Energy determined that these options provide nearly identical reliability results because they connect the Parkers Lake – Crow River transmission line to another point in the western metro area 115 kilovolt system. During the loss of the double circuit from Gleason Lake to Parkers Lake, voltage is maintained at Gleason Lake and on the 69 kilovolt system to the south. There is better voltage for the connection to Gleason Lake, but both are within the designated criteria. Gleason Lake has one position left at 115 kilovolts which has been designed for a conversion of the 69 kilovolt corridor south to Westgate Substation. At this time it would be preferred to terminate the line at the Medina Substation to reserve the position at Gleason Lake when the need arises.

Xcel Energy also compared system losses for the two options. Losses are power that dissipates in electric conductors due to resistance. As seen in **Table 6** there is little difference in the system losses for the different transmission system alternatives.

Table 6
System Loss Analysis

Connection	Option H1 (Hollydale Project)	Option H2
2015	0.6	0.6
2020	0.7	0.7

In summary, Xcel Energy determined that the Hollydale Project offered the best overall results based on the following criteria:

- Power system performance (system intact and contingent loadings and voltages);
- Operability (logistics of construction and operation);
- Price (cumulative present worth cost);
- Distribution system losses; and
- Ability to serve existing and anticipated distribution load in the Plymouth area.

3.9 Forecast Coordination

Xcel Energy and Great River Energy report their energy and peak demand forecasts to the Midwest ISO ("MISO"). MISO then combines the forecasts of all its member utilities. Xcel Energy and Great River Energy also submit an integrated resource plan to the Minnesota Public Utilities Commission, which includes energy and demand forecasts. Xcel Energy submitted its most recent resource plan for the years 2011 to 2025 on August 2, 2010. This resource plan is currently under review by the Commission.[27] Great River Energy submitted its most recent resource plan for the years 2009 to 2024 on July 1, 2008. This resource plan was approved by the Commission on December 3, 2010.[28]

[27] *See* Docket No. E002/RP-10-825.
[28] *See* Docket No. ET-2/RP-08-784.

Xcel Energy also reports its forecast to the Public Service Commission of Wisconsin as part of its Strategic Energy Assessment ("SEA") process. In the SEA process, the Wisconsin portion of the total Xcel Energy system load is combined with other Wisconsin electric utilities to form a statewide Wisconsin forecast.

4 ALTERNATIVES ANALYSIS

In Chapter 4 we explain our analysis of different ways that we have considered to fix the problems identified in the previous chapter. As well as options that don't require new or improved transmission facilities. These are referred to as the "non-transmission alternatives".

Key Terms:

- **Demand-side management** – *Actions that influence the quantity or patterns of use of energy consumed by end users, such as actions targeting reduction of peak demand during periods when energy supply systems are constrained.*
- **Distributed generation** – *Small-scale generation located close to homes, farms and businesses where the power is needed, using traditional as well as renewable sources, like wind and biomass.*
- **Generation** – *The act of converting various forms of energy input (thermal, mechanical, chemical and/or nuclear energy) into electric power. The amount of electric energy produced is usually expressed in kilowatt hours or megawatt hours.*
- **Renewable resource** – *A power source that is renewed by nature, such as solar, wind, hydroelectric, geothermal, biomass, or similar sources of energy.*

Key Points: *We considered a "no build" alternative that made use of demand-side management solutions and using generation as an alternative to building new or improved transmission facilities. In addition, we analyzed different voltages and alternative transmission designs such as underground transmission lines and direct current lines to serve the need. In the end, we concluded that the proposed Project best serves the needs identified in Chapter 3.*

As part of the study process that resulted in the proposal to construct the Hollydale Project, Xcel Energy considered a number of alternatives including: (i) size alternatives (different voltages or conductor arrays, alternating current ("AC")/direct current ("DC"), and double circuit); (ii) generation alternatives; and (iii) no build (including Demand Side Management). In this chapter, Xcel Energy describes the analysis of these alternatives and its conclusion that none is more reasonable alternative to the Hollydale Project.

4.1 Size and Type Alternatives

4.1.1 Different Voltages

Xcel Energy evaluated the feasibility of different line voltages and alternative types of conductors as part of our analysis of the appropriate electrical facilities to meet the identified distribution source need in the Plymouth and Medina areas. Xcel Energy concluded that using 115 kilovolt design is the only appropriate voltage based on several factors 1) the type of need, i.e., distribution capacity; 2) the location of the proposed facilities and 3) cost.

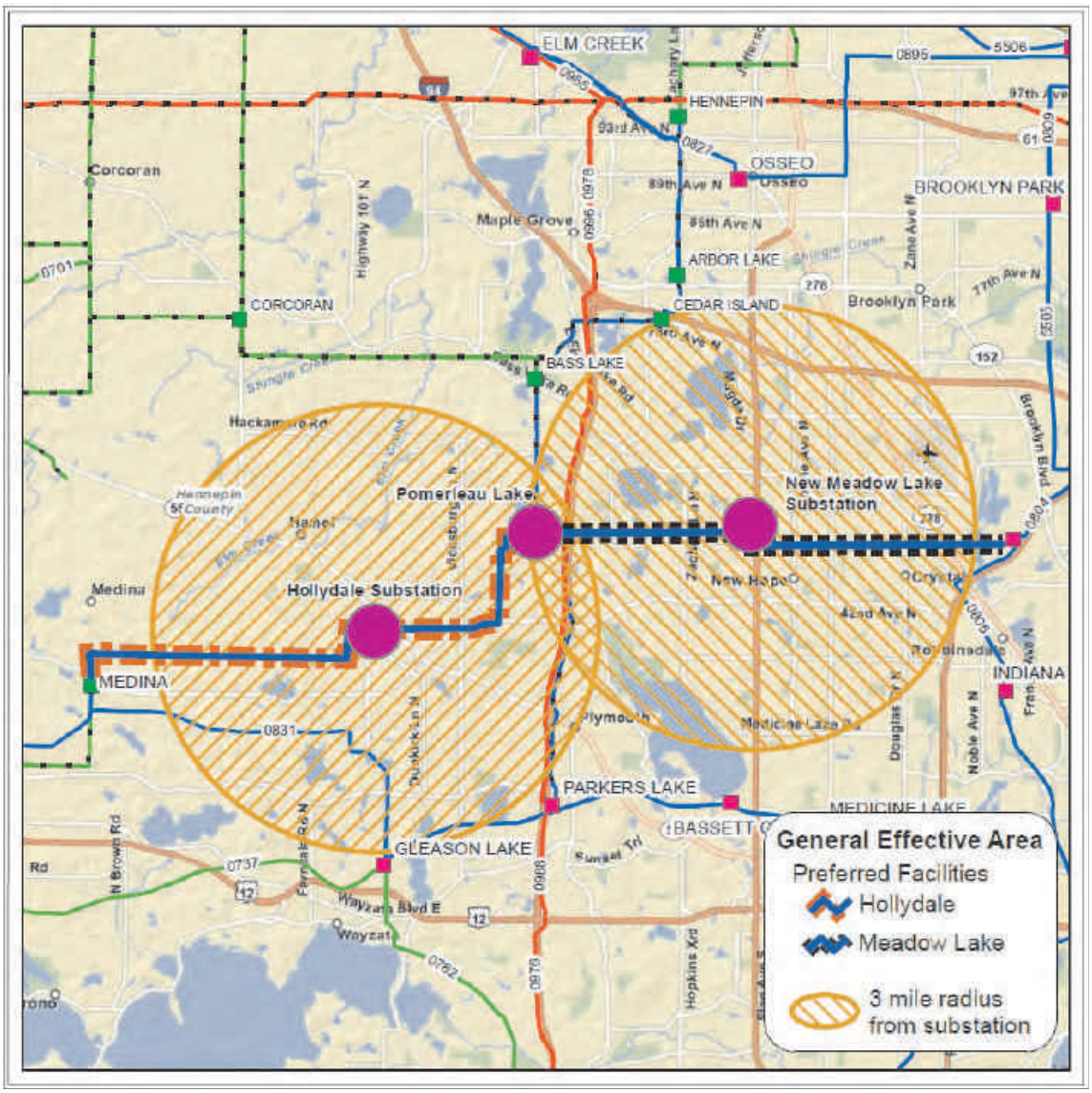
4.1.1.1 Summary of Electrical System Serving the Twin Cities

As detailed in Chapter 2, delivering power to an end consumer requires a complex system of generators, transmission lines, transmission and distribution substations, distribution lines and service lines, each having a distinct primary function. If you think of an electrical system as a road system, Extra High Voltage (EHV) transmission lines (above 300 kilovolt), typically 345 kilovolt in Minnesota, would be considered the interstate freeway. Other transmission voltages, typically 230 kilovolt, 161 kilovolt, and 115 kilovolt in Minnesota, would be your state highways or county roads. Lower subtransmission voltages, typically 69 kilovolt, could be compared to major city thoroughfares. Distribution lines, typically 34.5 kilovolt, 13.8 kilovolt, and 4.16 kilovolt would be similar to residential streets and alleys and would be the feeder circuits which are bringing the power to each individual building through a local pad or pole mounted transformer. The different types of electric lines are connected at substations which can have a transmission function, a distribution function, or both.

The geographic effectiveness of each of these system components is also important to consider when developing alternatives. EHV transmission lines can and do traverse multiple states providing the regional backbone electrical system. The EHV transmission system is capable of moving large amounts of power from generation sources to load centers in an efficient manner. Intermediate voltages are designed to serve a more limited geographic scope. Distribution voltages on feeder circuits have an even more limited geographic reach. For example, the optimum effective range of feeder circuits is generally no longer than a few miles and have reduced effectiveness

at greater distances from the substation and with greater loading. This means that a distribution substation has a limited geographic reach of several miles depending on the load connected to it. **Figure 6** of the Application shows how an individual feeder circuit becomes less effective with increases in distance from the substation. **Figure 23** from the Transmission Reliability and Assessment Study, shows the general maximum service area of the Hollydale Substation and the proposed Meadow Lake Substation (the proposed Pomerleau Substation is not intended to include distribution service).

Figure 23
Study Area Distribution Coverage



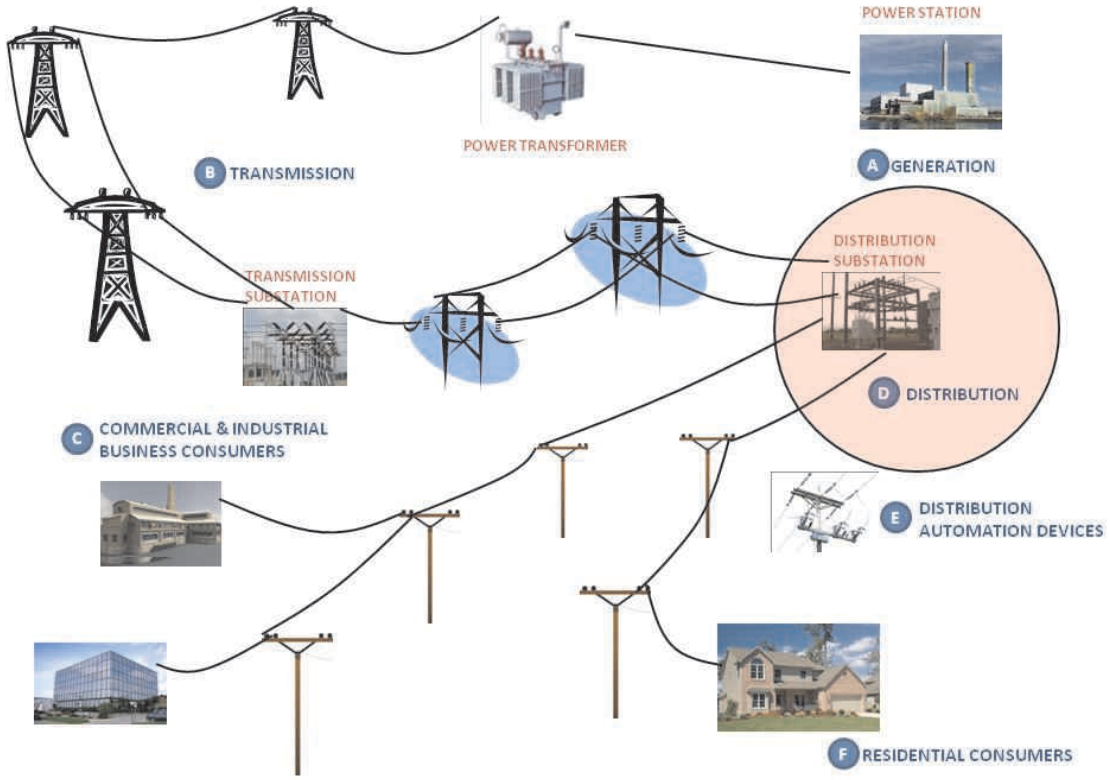
In the Twin Cities metro area, the distribution system is generally served by a 115 kilovolt transmission system initially developed in the early 1900s. Xcel Energy designed a network of 115 kilovolt lines around the Twin Cities to reliably deliver electrical power to growing metropolitan populations using power generated from smaller local power plants such as Black Dog (then 267 megawatts). New 115 kilovolt facilities were added to the system over the next 50 years. By the 1950s and 1960s, the 115 kilovolt system had become strained in their ability to carry the power required for the growing Twin Cities area over the distances from increasingly remote generation sources. To solve this, a 345 kilovolt bulk transmission ring was constructed around the Twin Cities to deliver larger amounts of power from more remote generators such as the Allen S. King Plant (529 megawatts of generation capability).

Today, the metro distribution system continues to be served off of a 115 kilovolt system, supported by the 345 kilovolt loop that roughly follows Interstate 494 and 694. This 115 kilovolt system is interconnected to substations that are specifically designed to accommodate the 115 kilovolt voltages and deliver power to the distribution substations serving local areas.

Standard distribution substation equipment includes 115 kilovolt/13.8 kilovolt transformers to step down the 115 kilovolt voltage to distribution voltage, 13.8 kilovolt. For example, downtown Minneapolis is primarily served by four substations fed by 115 kilovolt lines that bring power from the 345 kilovolt ring into the core high load density area.

As part of the on-going studies of the transmission and distribution system, Xcel Energy determined that there is a distribution system deficiency in the Plymouth and Medina areas. The 345 kilovolt system has sufficient capacity to feed the lower voltage system (69 kilovolt and 34.5 kilovolt in this case), but the existing 34.5 or 69 kilovolt system cannot deliver enough power to meet customer demands. Engineers determined that a new transmission source must be tied directly to the Hollydale Substation to provide needed power. In general terms, the specific deficit area in the electric system is shown in the pink circle on **Figure 24**.

Figure 24
Electrical System Overview



Applicants propose new 115 kilovolt line facilities to deliver additional power to the Hollydale Substation to address an existing 37 megawatts deficit and to provide additional power for future growth.[29] This future growth is expected to arise not only from new development, but from increased power demands by each customer. Average residential electric usage has also grown substantially in recent decades. The average residential home now uses more than twice the amount of power than it did 50 years ago.

Given the existing system and standard facilities in the metro area, Xcel Energy considered the 69 kilovolt voltage when analyzing a lower voltage alternative to the Project and a 345 kilovolt voltage for the higher voltage analysis.[30]

4.1.1.2 Analysis of Lower Voltage Alternative

Distribution Need-Capacity

Xcel Energy determined that existing lower voltage lines would not meet the distribution capacity need. The existing 69 kilovolt system with 397 kcmil conductor has a thermal capacity of approximately 50 MVA. As seen in the Transmission Planning report, under contingency conditions, there are unacceptable low voltages. Additional future distribution capacity at Hollydale requires transmission line construction at either 115 kilovolt or 69 kilovolt.

Through the Northern States Power Company service territory, 115 kilovolts is a very common voltage to serve larger load and loads that are more distant from generation. In the Twin Cities substations supplied by the 115 kilovolt system range in size up to approximately 180 megawattts.

The use of 69 kilovolt transmission lines in Minnesota is seen mostly in rural areas. It is used extensively to serve load in small to mid-size cities with the largest loads being approximately 20 megawatts. Above 20 megawatts of load, standard 69 kilovolt design performs less effectively. Here, the existing load exceeds the level typically served by a standard 69 kilovolt design and has the potential to grow to approximately 100 megawatts over time.

To explore 69 kilovolt facilities as a possibility, Xcel Energy looked into the use of non-standard 69 kilovolt design. To meet the ultimate distribution need of 100+ MVA, a bundled 69 kilovolt configuration or double circuit configuration would be required. The 69 kilovolt design options are shown at the end of the chapter in **Figure 26**.

[30] Adding a new voltage into the area, such as a 230 kilovolt line would require additional transformation equipment at substations. In addition, the cost of a 230 kilovolt line is very similar to that of a 345 kilovolt line and therefore if a higher voltage were needed, it would be prudent to construct at 345 kilovolt.

Location of the Facilities and Impacts

The non-standard single circuit 69 kilovolt construction design would require 50 feet of right-of-way and utilize two conductors per phase which would create more of a visual impact. The width and bulk of a non-standard 69 kilovolt line built to support the ultimate distribution need would be greater than a comparable 115 kilovolt line. This is due to the necessity of bundling conductors to gain similar capability.

A double circuit 69 kilovolt design would require 75 feet of right-of-way and require arms on both sides of the poles.

Cost

A bundled conductor 69 kilovolt line is only slightly less costly than the proposed 115 kilovolt design, but there are other costs associated with using 69 kilovolt transmission facilities that make the lower voltage alternative not a reasonable alternative. The proposed 115 kilovolt is estimated to cost approximately $600,000 per mile. A non-standard 69 kilovolt design would cost approximately $435,000 to 475,000 per mile. A double circuit 69 kilovolt line would cost approximately $350,000 to $450,000 per mile.

Overall project costs would be substantially higher, however, because of the need for supporting facilities. For a 69 kilovolt design, a large 115/69 kilovolt transformer installation at approximately $2.5 million each would be required. At a minimum, to reliably serve the increased load, the Medina Substation 115/69 kilovolt transformer would need to be replaced with a larger unit and two units would be needed at Pomerleau Lake Substation for redundancy. Similar 115 kilovolt infrastructure would need to be installed at the new Pomerleau Lake Substation as part of the proposed Project. Pomerleau Lake would also require a new 69 kilovolt yard which has not been anticipated in the substation design. The Hollydale Substation design would remain similar to the proposed Project. The Medina Substation would need further analysis into the feasibility of increasing its transformer size. It is a two level, tiered substation due to the slope of the land.

The 69 kilovolt alternative would cost an additional $6.2 million when compared to the Project. System losses should also be considered. The greater the losses on the

system, the more power that must be generated to meet the same load levels. Lower voltages have higher system losses. While not specifically quantified for this Project, the losses would be higher for a 69 kilovolt alternative than for the proposed 115 kilovolt alternative.

4.1.1.3 Higher Voltage Alternative Analysis

A higher voltage was also considered. As a line is built to a higher voltage design, capacity generally increases. Due to the availability of 345 kilovolt in the vicinity of the Project area, it would be the most reasonable choice to consider for a higher voltage transmission alternative. To provide similar reliability, this alternative would also need to bring two sources into the Hollydale Substation and therefore connect at the Medina, Hollydale and Pomerleau substations.

Distribution Need-Capacity

A typical 345 kilovolt design has a thermal capacity of 1100+ MVA. Larger, higher voltage, lines are generally constructed to deliver power across a larger area and support lines that are designed to distribute power to distribution loads. The capacity of a 345 kilovolt transmission line far exceeds the need to provide power to a distribution substation in a given location. Indeed, even the substations in downtown Minneapolis, where the load is very dense in the Twin Cities metro, are served by 115 kilovolt lines rather than 345 kilovolt lines.

Using 345 kilovolt facilities to meet the Hollydale distribution need is not prudent. The capacity of a 345 kilovolt line will not be needed to address a purely distribution-driven need. The use of a 345 kilovolt line is akin to an interstate in the highway system. Not every municipality needs a six lane highway to it. State and county highways distribute the load, like a 115 kilovolt line, to local communities and city streets connect to individual houses like a distribution line. The need to deliver power into the Hollydale Substation at 115 kilovolt is driven by, location, size of load, existing area voltages, constructability, and costs.

Location of Facilities—Impacts

A 345 kilovolt line would have considerably more impacts to the environment and human settlement than the 115 kilovolt Project that is proposed because it would require 150 feet of right-of-way compared to 75 feet and taller structures, approximately 160 feet compared to 85 feet. As detailed in the Route Permit Application, the closest residence to the existing 69 kilovolt line approximately 20 feet from the proposed centerline and the closest non-residential building is approximately 8 feet from the proposed centerline.[31] If a 345 kilovolt line were constructed, these homes would likely need to be removed. In addition, additional transformation equipment would be required at the substations to convert the voltage from 345 kilovolt to distribution. As a result, the sizes of the Hollydale and Pomerleau Lake substations would increase in size by approximately 4 to 5 acres and a new Medina area substation would need to be installed on about 6 acres.

Costs

A 345 kilovolt alternative would cost approximately $1.8 to $2.1 million per mile, nearly three times the cost of the 115 kilovolt proposal ($600,000 per mile). The substation costs would also increase in magnitude by approximately $10 million per substation requiring a 345 kilovolt connection—in this case three substations at a cost of $30 million. However, a 345 kilovolt alternative would be more efficient option because overall system losses would be reduced.

4.1.1.4 Summary of Lower/Higher Voltage Analysis

A lower voltage solution is not recommended because it would require non-standard design, is more costly and less efficient and does not reasonably address future needs to accommodate growth. A higher voltage solution is not reasonable because it would provide capacity far exceeding what is needed and would do so at significant additional cost and with greater impacts to the environment and human settlement. The 115 kilovolt alternative is the standard voltage used in the Twin Cities to move power from the 345 kilovolt system to local communities and the most reasonable

[31] *See* Route Permit Application at 79, Docket No. E002, ET-2/TL-11-152.

alternative for the Hollydale Project because it meets the identified need at the least cost and minimizes environmental impacts.

4.1.1.5 Use of Higher Voltage to Address West Twin Cities Metro Needs

Xcel Energy has proposed several 115 kilovolt transmission projects in the west metro to solve distribution and transmission deficits. The question has been raised by the Department of Commerce, Division of Energy Resources staff whether a higher voltage solution might exist to revolve the multiple needs prompting the 115 kilovolt proposals.[32] This section describes the other 115 kilovolt projects and explains why a higher voltage solution is not a reasonable alternative to the proposed 115 kilovolt projects.

West Metro 115 Kilovolt Projects

Scott County-Westgate Project: This project is needed to address thermal overloads and low voltages between the Scott County and Eden Prairie Substations. It includes rebuilding an existing 69 kilovolt line from the just north of the Bluff Creek Substation to the Westgate Substation to 115 kilovolt design. This Project also includes converting the existing 115/69 kilovolt double circuit line from between the Scott County Substation to just north of the Bluff Creek Substation to 115/115 kilovolt operation. The Excelsior and Deephaven substations will also be upgraded to 115 kilovolt design as part of this Project.

Chaska Project: The project is needed to address thermal overloads and low voltages near Chaska due to load growth. This project includes construction of about 2.9 miles of new 115 kilovolt transmission line and conversion of about 8.5 miles of existing 69 kilovolt transmission line to 115 kilovolt design. The proposed project is located in Scott and Carver counties.

[32] *See* Comments of the Minnesota Department of Commerce-Division of Energy Resources, eDocket No. 20125-74427-01, Docket No. E002/CN-11-332 (efiled May 3, 2012).

Higher Voltage Alternative for West Metro

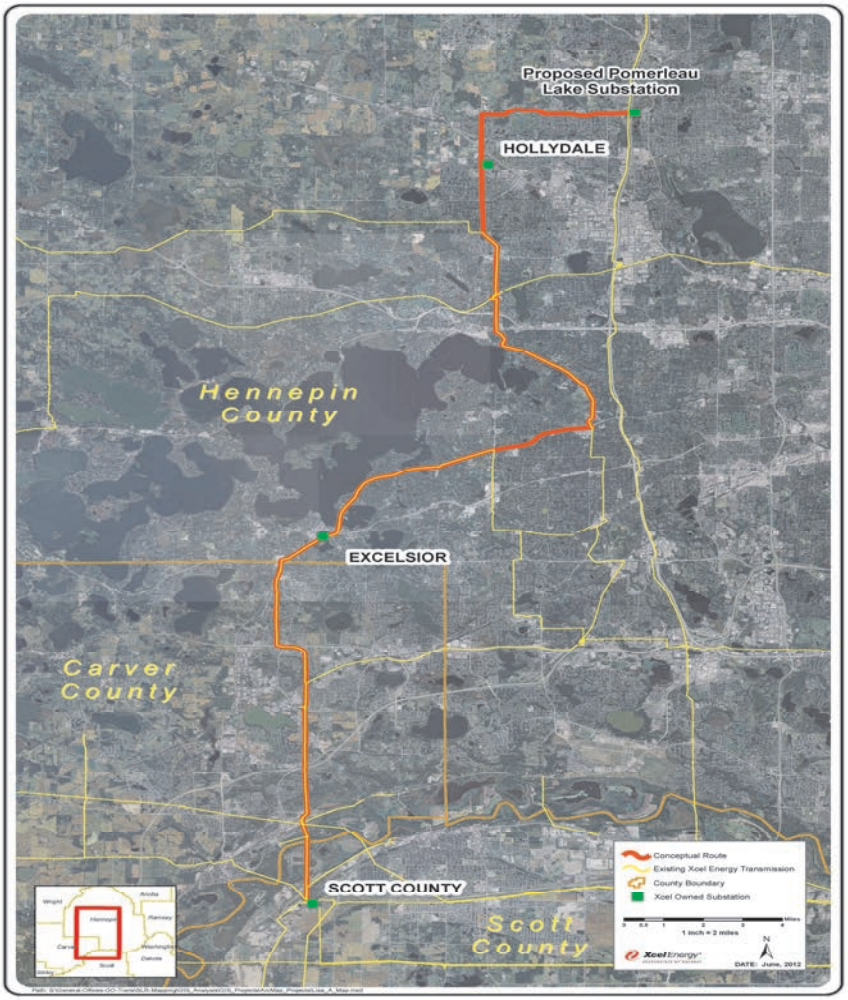
As detailed above, the hub and spoke electrical system around the Twin Cities is a 345 kilovolt system with a web of 115 kilovolt lines that carry the power from the bulk system to the distribution substations. If a higher voltage were to be considered, a 345 kilovolt voltage would be the appropriate voltage to consider.

Indeed, the potential need for additional 345 kilovolt facilities, an "outer loop" to further bolster the 345 kilovolt loop was referenced in the Southwest Minnesota-Twin Cities EHV Development Electric Transmission Study (Nov. 9, 2005) which supported the Brookings County – Hampton 345 kV Project. The study noted that the line traversed the extreme southern portion of the metro and established the southern portion of the proposed "outer loop." *Id.* at p. 3. Similarly, the CapX2020 Technical Update: Identifying Minnesota's Electric Transmission Infrastructure Needs (Oct. 2005) ("Vision Plan") identified an outer loop facility on the west side of the metro.

However, no near term deficiency has been identified between the existing 345 kilovolt loop and the ability to deliver power through the 115 kilovolt system to the areas at issue. It is expected that the 345 kilovolt loop with 115 kilovolt upgrades can continue to serve the immediate metro area, including Plymouth and Medina, for years to come.

The identified need in all of the west metro projects is to deliver more power to distribution substations that in turn deliver energy to end customers. Therefore, any electrical solution must connect in to the distribution system in the geographic areas with the identified deficits. Consequently, a 345 kilovolt higher voltage solution would have to connect at the Scott County Substation, the Excelsior Substation, the Hollydale Substation and the proposed Pomerleau Substation. A high level diagram showing this conceptual configuration is provided in **Figure 25.**

Figure 25
Conceptual 345 kilovolt Configuration



The conceptual route for the 345 kilovolt line is approximately 28 miles long and the right-of-way for the 345 kilovolt line would be 150 feet. The connecting substations would all be required to have 345 kilovolt/115 kilovolt/ 13.8 or 34.5 kilovolt transformation equipment and therefore have a space requirement of 6 acres minimum.

The cost of the transmission line alone, based on per mile estimates from the CapX2020 345 kilovolt projects, would be approximately $60 million. Converting existing substations to 345 kilovolt and adding 345 kilovolt at a new Pomerleau Substation would cost an estimated $50 million. These costs do not include the costs

of right-of-way acquisition and that there is no existing undeveloped corridor where such a line could be built. Applicants also note that this is a conceptual analysis and that no engineering study has been undertaken. A 345 kilovolt alternative could create unintended consequences that have not been studied and could cost substantially more.

Summary of Analysis of Higher Voltage Alternative for West Metro

The needs existing in the west metro are best served by 115 kilovolt solutions. A 345 kilovolt alternative would provide excess capacity and significantly greater impacts at a substantially greater cost and environmental impacts.

4.1.2 Double Circuiting Existing Transmission Lines

Double circuiting is the construction of two separate circuits on the same structures to reduce the overall amount of right-of-way required. Double circuiting minimizes the need for new right-of-way and expansion of the overall footprint of the transmission system.

Planning engineers examined whether double circuiting was an appropriate solution, in part, to the pending electrical deficiencies in the Study area. Double circuiting is not appropriate in this case because upgrading the existing line as a single circuit 115 kilovolt is adequate to serve the long-term needs of the Study area.

4.1.3 Rebuilding Existing Transmission Lines

The Project involves rebuilding 8 miles of existing 69 kilovolt transmission lines to 115 kilovolt. Only 0.8 miles of the Hollydale Project involve construction of new 115 kilovolt transmission facilities.

4.1.4 Reconductoring

Applicants examined whether transmission improvements that do not require Certificates of Need, including reconductoring existing transmission lines, could meet the identified needs in the area. The existing Great River Energy 69 kilovolt structures are not capable of being reconductored, since the weight of an upgraded conductor will exceed the mechanical strength capability of existing structures in use.

4.1.5 Direct Current Lines

Applicants further considered the alternative of a Direct Current ("DC") line in place of the proposed facilities. DC transmission lines have been built throughout the world, with two in service in the upper Midwest and two in Manitoba. DC transmission lines normally consist of two current-carrying conductors instead of the three associated with an Alternating Current ("AC") configuration.

A DC transmission line's primary intended purpose is to deliver electricity from a distant generation location (several hundred miles away) to a load center. Such lines do not have the capability to provide community load serving support to an AC system because there are no intermediate substation connections. Rather, there are converter stations at each end of the line. This characteristic of a DC line makes it unsuitable for the needs sought to be addressed by the lines proposed in this Application.

4.1.6 Conductor Choice

Xcel Energy and Great River Energy use several types of conductors for their transmission lines. The standard bare aluminum overhead transmission conductors, Aluminum Conductor Steel Supported ("ACSS") and Aluminum Conductor Steel Reinforced ("ACSR"), offer known reliable power performance, operating at temperatures up to 200ºC and 100ºC, respectively. For each of the 115 kilovolt lines proposed here, ACSR would provide 230 MVA of capacity and ACSS would provide 361 MVA of capacity. ACSS typically costs approximately 10% more than ACSR conductor. A smaller conductor than 795 ACSS will be sufficient for the Project, but the incremental cost of going from a 477 ACSR conductor to 795 ACSS conductor is minimal and at the same time the 795 ACSS conductor provides 217% capacity compared to the smaller 477 ACSR conductor. Therefore 795 ACSS is the choice of conductor for most 115 kilovolt transmission lines.

Two composite conductor alternatives can offer substantial increases in capacity and the ability to span greater distances between poles by use of innovative modern composites, but at a significantly increased cost and lower efficiency. The modern materials and manufacturing process required for these composite conductors result

in a material cost that is 300-500% higher compared to standard ACSR and ACSS. Composite conductors also experience higher losses because they are operated at higher temperatures. As a result, this type of conductor is used only in special circumstances, where long spans are required. In the case of this Project, circumstances do not warrant the use of this type of conductor.

4.1.7 Underground Transmission Line

The alternative of placing the proposed transmission line underground was also considered, but ultimately rejected because of cost, construction, and maintenance considerations. Generally, for transmission voltages of 115 kilovolt or greater, overhead construction is the preferred configuration due to costs. Underground transmission lines also have substantially longer construction times and longer repair times than equivalent overhead lines. For example, an overhead 115 kilovolt transmission line constructed with single pole structures spaced 300 to 400 feet apart cost approximately $350,000 - $500,000 per mile. The same facility placed underground could cost up to seven to 10 times as much.

This cost differential is based on the different design requirements for overhead and underground installations. Overhead transmission lines rely on the dielectric properties of air to provide insulation, thereby preventing the occurrence of short circuits. The properties of the air also efficiently dissipate heat away from the conductor surface.

When a transmission line is placed underground, the conductors must be adequately insulated from the ground and each other, and adequately cooled to prevent equipment failure. Thus, the conductors are wrapped with insulating materials and placed inside oil filled pipes. The oil is circulated through cooling stations every few thousand feet along the line. Some electric cables have been designed with a specially-formulated plastic covering that does not require circulating oil to dissipate heat. However, the amount of current that can be applied to such conductors is limited.

Technologies for construction of underground lines include surface-cut open trenching, horizontal boring, and horizontal directional drilling. Trenching is usually the preferred method of underground construction because it is easily controlled and

the most cost effective method for construction. Construction of a trench for the underground transmission line would result in greater temporary construction impacts than the proposed overhead line. Underground transmission construction as compared to overhead lines increases noise, dust, traffic disruption, and requires more clearing and grading, and increases construction time.

Underground transmission lines present challenging service issues. While they are subject to fewer outages, the outages are typically longer in duration because underground cables do not have temporary faults such as branches falling to ice breakage and are not subjected to reclosing operations. As a result, the downtime associated with an underground transmission line fault will be longer in duration than the equivalent overhead line failure. Typical overhead line outages are repaired and back in service 10-24 hours after the outage event. In contrast, typical underground line outages are repaired and the line placed back in service two or three weeks after the outage event.

Because of the significantly-greater expense associated with underground transmission, the use of underground technology is limited to locations where the impacts of overhead construction are unacceptable or where physical circumstances allow for no other option. Typical examples include congested downtown centers where there is no space available between city streets and adjacent buildings for adequate clearance, or airport approaches where an overhead transmission line cannot be constructed for safety reasons. No circumstance warrants underground construction based on Applicants' examination of the environmental and land use setting associated with the proposed Project.

4.2 Additional Alternatives

Applicants also considered several additional alternatives to constructing the proposed facilities. These alternatives included: (1) generation; (2) demand side management programs; and (3) a "no build" alternative. These options are discussed below. In the end, Applicants concluded that the proposed Project best meets the identified needs.

4.2.1 Generation

4.2.1.1 Peaking Generation

In evaluating generation alternatives to the proposed 115 kilovolt transmission project, the Applicants studied the availability of traditional peaking generation sources (e.g., diesel generation) to meet the load serving need and determined that generation would not satisfy the existing or expected future demand for electricity in the Study Area. The identified need is one of distribution load-serving capacity only; no additional generation capacity is needed to serve the Study Area. Adding additional generation would not correct the geographically diverse distribution feeder circuit overloads because the more than 27 feeder circuits including 13 in the Focused Study Area operate as radial circuits. This means that generation would need to be sized specifically to each feeder and need to be flexible enough to allow reconfiguration of feeders due to load growth or operational issues. In addition, new generation would not eliminate the need for new facilities. If only generation were installed, the generators would have to connect to each substation because each substation is a standalone facility. This would require expansion of the substation, installation of a step up transformer and lines to connect to the substation.

Also, any generation alternative would need to replace the reliability provided by adding transmission. Transmission lines have the ability to operate more than 99% of the time. This reliability level is one of the benefits of constructing transmission lines. For comparison purposes, peaking generation cannot be assumed to be available to operate more than 95% of the necessary hours. Consequently, to replicate the 99% reliability found in transmission, redundant generation would need to be installed.

In addition to the extra capital investment that would be required to install redundant generation to serve the same need as transmission, additional costs would have to be taken into account for the higher operations and maintenance of generators when compared to such expenses for transmission. Once constructed, transmission lines require relatively modest ongoing operations and maintenance costs. Peaking generators, by contrast, require much more costs for ongoing operations and maintenance. Generators also generally have a shorter expected service life than

transmission facilities (30 years for generators versus 40-plus years for transmission facilities).

4.2.1.2 Distributed Generation

Applicants also considered distributed generation as an alternative. Distributed generation is generally considered to be small generation sources, usually less than 10 megawatts, that are located close to the ultimate users. However, in some cases generators larger than 10 megawatts are considered to be distributed generation as well.

The most likely fuel for dispatchable distributed generation would be diesel. A large number of diesel generators, which are typically in the 1.5 to 2 megawatt range, would be required to generate the amount of capacity necessary to address the shortfalls currently projected. Diesel fired generators like those under consideration here are generally used on a standby basis, and fired up when conditions, such as a contingency situation, when a line or transformer is taken out of service, require operation of the generator. Diesel generators are not generally operated continually. That provides two concerns in this situation. First, if a contingency arises, such as a storm event, there could be a period of time when power was not available while the plant was placed into operation. Second, as demand for power continues to grow in the critical areas, the time these generators were in operation would continue to expand, making for expensive generation. Third, there are generally limits on the operation of diesel generators due to emissions limits.

In addition, due to the residential nature of the Project area, it would be difficult to site generation near the load in this area with the gas or oil infrastructure and interconnection facilities required to run the generating plant.

Distributed generation is not considered a viable alternative to the proposed Project.

4.2.1.3 Renewable Generation

Applicants considered the public policy preference for renewable energy generation. The state policy is embodied in two sections of state law. The first renewable energy

preference is contained in Minnesota Statutes Section 216B.243, subdivision 3a. This statute provides:

> **Use of renewable resource.** The commission may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, or that transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source. For purposes of this subdivision, "renewable energy source" includes hydro, wind, solar, and geothermal energy and the use of trees or other vegetation as fuel.

The second renewable energy preference is found at Minnesota Statutes Section 216B.2422, subdivision 4, which states:

> The Commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the Commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest.

The Minnesota Public Utilities Commission has recognized that the renewable energy preference statutes create unique issues when applied to transmission projects. The Minnesota Public Utilities Commission has found that the preference is not a bar to granting Certificates of Need for transmission facilities where the proposed transmission facility does not immediately interconnect to a new generation source and will not interconnect with a specific generation source. As the proposed transmission lines are not proposed for and will not interconnect any particular generation resource, the renewable energy preference statutes do not establish additional standards that the Applicants must satisfy as part of this Certificate of Need

proceeding. *In the Matter of the Application of Otter Tail Power Company for a Certificate of Need for Appleton-Canby 115 kilovolt High Voltage Transmission Line*, Order Granting Certificate of Need, Docket No. E-017/CN-06-677, p. 9 (April 18, 2007).

4.2.1.4 Wind Generation

Because of the theoretical possibility that generation could potentially address community reliability needs, Applicants analyzed whether the addition of small and dispersed wind generation projects could eliminate the need for the Project. The analysis concluded that sufficient wind generation cannot be installed to offset the community service reliability deficiencies in the affected area. This is due to the variability of wind and cost.

Wind generation is a "variable" resource that is dependent on the availability of wind to operate. While a wind turbine may have a stated nameplate capacity, its average net operating output may range from 10% to 40% of its nameplate capacity throughout the year. A wind turbine is a "nondispatchable" resource and cannot be relied on to produce power in the same way as a conventional power plant. A traditional power plant (e.g., natural gas, nuclear, hydro, coal) is "dispatchable", meaning it can be relied upon to produce power when power is needed. Power needs to be created and used in equal amounts for each instant of time. Power typically cannot be created one day and used the next without introducing an energy storage system such as batteries to store power until it is needed.

As a result, wind generation is generally relied upon as a source of energy but does not provide the type of capacity that is required to ensure reliable customer service for those times when the wind is not blowing. Wind generation is typically integrated into the transmission system along with dispatchable resources such as natural gas peaking plants and hydro, which are capable of generating power during those hours when customer demand is high but the wind is not blowing.

This operating characteristic creates two separate issues, each of which can be alleviated by transmission. First, the system must be capable of importing power to the affected community during those hours when sufficient wind power is not being generated to satisfy the entire need (i.e., high demand/low wind scenario). Second,

the system must be capable of exporting power from the affected community during those hours when more wind energy is being generated than can be used by the local community (i.e., low demand/high wind scenario).

Because the electric system must be designed to meet all customer requirements during all hours of the year, the addition of local wind energy generators will not eliminate the need for additional transmission. To the extent that wind generation projects might be able to meet local community service reliability needs, that ability is limited and therefore the electricity delivery system must still be designed to cover the deficiencies identified. Moreover, additional infrastructure needs to be constructed to export that wind-generated power to the transmission system at times when wind-generated power exceeds community load levels. Therefore, dispersed wind projects are not a reasonable alternative to the proposed transmission alternative for local community service reliability needs.

The alternative is not practical. Given the development of the local area along the Project, small turbines would likely need to be used. The largest turbine that can be installed at a home without major wiring changes is 20 kilowatts. If the assumption is made that wind could provide the needed capacity, 2,500 turbines would need to be installed to create the same 50 megawatt of capacity that would result from the proposed Project.

$$\frac{50\ \textit{Megawatts}}{20\ \textit{Kilowatts/turbine}} = 2{,}500\ \textit{turbines}$$

The costs associated with new turbines are also a relevant consideration. Using turbine costs provided by ReDriven (www.redriven.net)), a manufacturer of wind turbines and towers, the cost for a 20 kW unit is $61,628 ($47,737 for turbine and $13,891 for tower). Without considering shipping and installation, charges that are not included, the cost would be $154 million (2,500 * $61,628).

4.2.1.5 Solar Generation

In addition to wind generation as an alternative, Applicants considered distributed solar generation (photovoltaics) as an alternative.

Solar installations generally require significant space and are limited in capacity. For example, Xcel Energy partnered with the City of Minneapolis and Westwood Professional Services to install the largest solar voltaic array in the upper Midwest Region. The 600 kilowatts project, completed in December 2010, includes more than 2,600 panels installed on the roof of the Minneapolis Convention Center. All of the electricity produced annually by the panels is used on-site. The $3 million project received a $2 million grant from the Xcel Energy Renewable Development Fund.

Given the area where the Project is proposed, smaller arrays would likely to be used. For purposes of the analysis for this Application, it was assumed that solar panels will be able to output nameplate rating when demand is needed, that each panel would require 400 sq. ft of space.

Using the above assumptions, the largest array solar that can be placed on a home is approximately 4.6 kilowatts.

$$\frac{50\ \textit{Megawatts}}{4.6\ \textit{Kilowatts/array}} = 10{,}870\ \textit{arrays}$$

The cost of the equipment, excluding shipping and installation, would be approximately $26,000 per array. (http://www.wholesalesolar.com/gridtie.html). Even if a large area were identified and a project similar to the one discussed above at the Minneapolis Convention Center, the cost to provide 50 megawatts would be approximately $283 million.

Solar system output reaches its maximum output during the noonday period and falls off as the afternoon progresses. Residential load, however, typically reaches its peak later in the day and usually occurs between 4 and 6 p.m. as people return home from work and school for the day. This means that the energy output of the system has peaked prior to the load on the system peaking. This poses significant challenges to efforts to use photovoltaic systems to displace or defer investments in distribution system equipment designed primarily to serve residential customers. In order to do that, either extremely large systems requiring hundreds of acres or unrealistic photovoltaic saturation would be needed to defer investments.

4.2.1.6 C-BED Generation

In evaluating generation as an alternative, Applicants also considered the use of Community-Based Energy Development ("C-BED") generation. C-BED generation, like distributed generation, generally refers to small generation projects. The distinguishing characteristics of a C-BED project are that it is renewable and that it meets certain ownership requirements.[33] As discussed in the Distributed Generation section above, use of generation to meet the load supply needs of the Study area is not a reasonable alternative. This conclusion holds true even if the generation used is C-BED generation.

4.2.2 Conservation and Demand Side Management

Applicants present their efforts to reduce energy consumption via demand side management in **Appendix D**. Xcel Energy's proposed 2013-2015 Triennial Plan[34] represents a budget of over $304 million, energy savings of 1,307 gigawatt hours and demand savings of 315 megawatts over the three years. Great River Energy is not required to file a Triennial Plan. However, Great River Energy's demand side management programs have a budget of over $16 million, an annual energy savings of 32,781 kilowatts. Although significant reductions in energy consumption have been realized, such efforts are not a feasible alternative to the proposed transmission upgrades because there are existing overload demand in the Study area is projected to increase well beyond projected energy reductions realized from the Applicants' Demand Side Management programs. Thus, while energy conservation is an effective alternative for meeting future needs, it will not be able to address issues related to meeting existing demand at the levels indicated in the Study.

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[33] The distinguishing feature of a C-BED project is the ownership structure. "C-BED project" means a new renewable energy project that is either a stand-alone project or part of a partnership under subdivision 8:
(1) has no single qualifying owner owning more than 15% of a C-BED wind energy project unless: (i) the C-BED wind energy project consists of only one or two turbines; or (ii) the qualifying owner is a public entity listed under paragraph (b), clause (5), that is not a municipal utility;
(2) demonstrates that at least 51% of the gross revenues from a power purchase agreement over the life of the project will flow to qualifying owners and other local entities; and
(3) has a resolution of support adopted by the county board of each county in which the project is to be located, or in the case of a project located within the boundaries of a reservation, the tribal council for that reservation.
Minn. Stat. § 216B.1612, subd. 2(g) (amended 2007).
[34] Docket No. E,G002/CIP-12-447.

Additional information regarding demand side management programs in the Focused Study Area are included in **Appendix D.3**.

4.3 Consequences of Delay and No Facility Alternative

In lieu of the requirements of Minnesota Rules 7849.0300 and 7849.0340 requiring detailed information regarding the consequences of delay and no facility alternative on three levels of demand and energy consumption, the Exemption Order (**Appendix E**) requires Applicants to identify the threshold level of demand that places service at risk and the incremental change in growth. As there is a current distribution deficit of 37 megawatts, there is no benefit to analyzing different demand levels. The likely consequence of a no facility scenario would be service interruptions. The likelihood of such service interruptions during peak times will increase as load continues to grow.

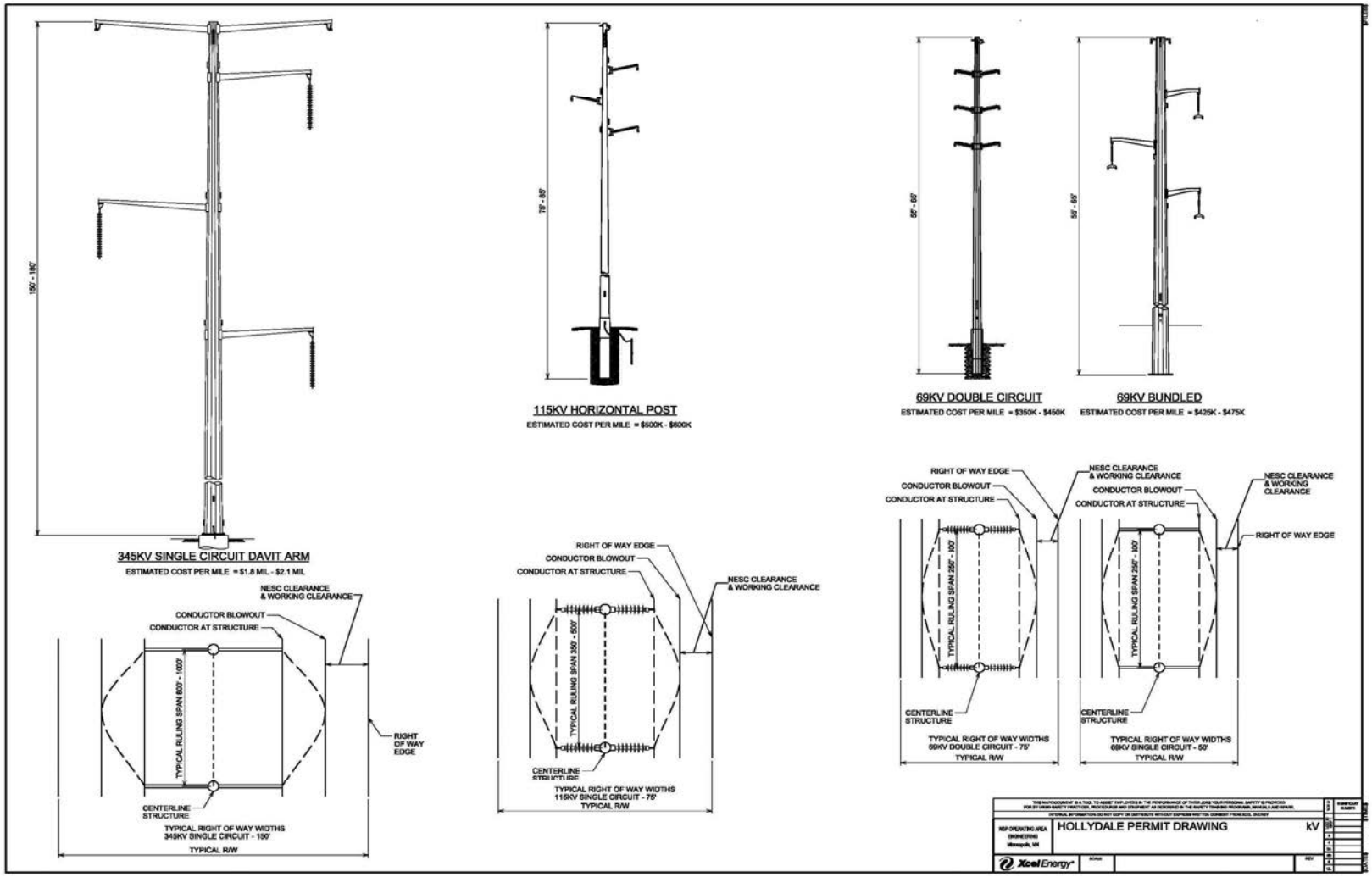
Minnesota Rule 7849.0340 further requires Applicants to discuss the impact on existing facilities under a no-facility analysis, specifically their impact on: (1) the amount of land required; (2) induced traffic; (3) fuel requirements; (4) airborne emissions; (5) water appropriation and conservation; (6) discharges to water; (7) reject heat; (8) radioactive releases; (9) solid waste production; (10) audible noise; and (11) labor requirements (the "Section B Requirements"). There would be little if any impact on existing generation and transmission facilities under a no-facility alternative. The likely consequence of a no-facility scenario would be to shed load. Similarly, the Section B Requirements are not impacted in any significant manner under a no-build scenario. Additionally, since the Section B Requirements will not be significantly impacted, no equipment or measures need be used to mitigate such impacts pursuant to Section C of the Rule.

4.4 Combination of Generation and Conservation

Based on the generation and no build alternative analysis detailed above, the Applicants concluded that a combination of generation and DSM could not address the identified needs. Even if a conservation rate of two percent of energy sales were achieved, a rate that is above the statutory objective of 1.5 percent, and even if that energy savings translated into the same percentage of demand savings (each percent of energy saved equals a percent of peak demand savings), this would result in

meeting only 2.4 megawatts of the need (0.02 * 122 megawatts of peak load from 2011). Therefore, load management programs would not provide significant additional relief in meeting current 37 megawatt deficit. Generation is not a reasonable alternative to meet this deficit for the reasons set forth above.

Figure 26
Structure Design Alternatives



5 PROJECT DESCRIPTION

In Chapter 5, we will describe the specifics of the Project including the types of structures that we propose to use to support the new 115 kilovolt transmission line. We will also identify the amount of right-of-way required for the Project and provide a description of the new Pomerleau Lake Substation.

Key Terms:

- ***Easement***– *An easement is a permanent right authorizing a person or party to use the land or property of another for a particular purpose. In the case of this Project, this means acquiring certain rights to build and maintain a transmission line. Landowners are paid a fair price for the easement and can continue to use the land for most purposes, although some restrictions are included in the agreement.*
- ***Right-of-Way (ROW)*** – *A right-of-way is the land area legally acquired for a specific purpose, such as the operation of transmission facilities and for maintenance.*
- ***Structures*** – *Towers or poles that support transmission lines.*

Key Points: *Applicants propose to construct a new 115 kilovolt line using steel poles that will be approximately 70 to 90 feet tall. Applicants also propose to construct a new substation, the Pomerleau Lake Substation, near I-494 and Schmidt Lake Road.*

5.1 General Route Description

This Certificate of Need Application is focused on documenting the need for new 115 kilovolt transmission facilities in the Plymouth area. In the pending Route Permit proceeding, the exact location of the proposed new 115 kilovolt facilities will be determined. (Docket No. E002/TL- 11-152). In that proceeding, Applicants proposed the following:

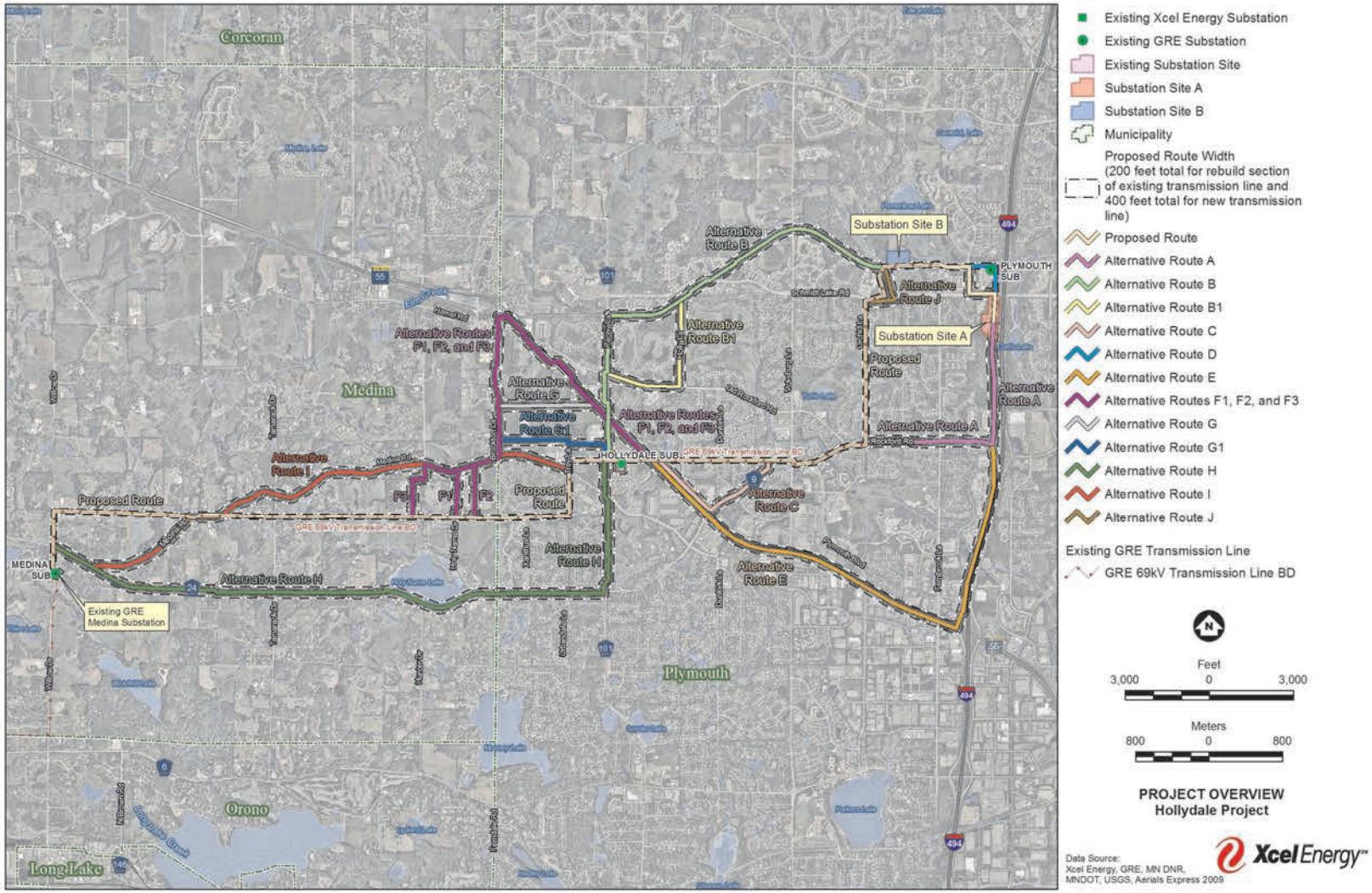
- rebuild approximately 8 miles of existing Great River Energy 69 kilovolt transmission line BD to a 115 kilovolt transmission line. The proposed transmission line runs from the existing Great River Energy Medina Substation to the existing Xcel Energy Hollydale Substation, to the intersection with existing Great River Energy 115 kilovolt transmission line WH-PB located north of Fernbrook Lane turnaround and north of the Canadian Pacific Railway;

- construct a new 115 kilovolt transmission line on new right-of-way from the above described existing Great River Energy line intersection location, which completes the connection of the rebuild line to the proposed new Pomerleau Lake Substation;
- construct the proposed new Pomerleau Lake Substation;
- construct new transmission line terminations within the proposed new Pomerleau Lake Substation for an in-out for existing Great River Energy 115 kilovolt transmission line WH-PP to connect this line with the Pomerleau Lake Substation; and
- modify the existing Medina and Hollydale substations to accommodate the proposed 115 kilovolt transmission line rebuild.

All of the route alternatives, including Applicants' proposed route, that are under consideration in the Route Permit proceeding, as of July 2, 2012, are depicted in **Figure 27**.[35]

[35] **Figure 27** includes all route alternatives that were included in the December 2011 Scoping Decision issued by the Department of Commerce in the route permit proceeding (Docket No. TL-11-152).

Figure 27
Project Overview



5.2 Transmission Lines – Type, Heights, and Spans

The proposed structures for this Project are galvanized steel or weathering steel poles. The structures will be approximately 70 to 90 feet tall. The average span will be about 300 to 500 feet, with a maximum span of approximately 1,200 feet to keep the conductor within existing right-of-way or to span wetland areas, where applicable. Applicants propose to use mainly braced post 115 kilovolt structures but other structure designs may be utilized depending on the final design of the transmission line. **Table 7** summarizes the structure designs and foundation for the line.

The 115 kilovolt lines would be constructed with 795 Aluminum Conductor Steel Supported or similar equivalent. The average service life of high voltage transmission lines is 50 to 60 years. **Figure 28** depicts typical 115 kilovolt braced post single circuit structures. **Figure 29** illustrates typical dimensions and right-of-way requirements for a single circuit braced post structure.

The proposed transmission line will be designed to meet or surpass relevant local and state codes including the National Electric Safety Code ("NESC") and Xcel Energy standards. Appropriate standards will be met for construction and installation, and applicable safety procedures will be followed during and after installation.

Figure 28
Photo of Typical Single Circuit 115 kilovolt Braced Post Structure

Figure 29
Typical Dimensions and Right-of-Way Requirements for Single Circuit Braced Post Structure

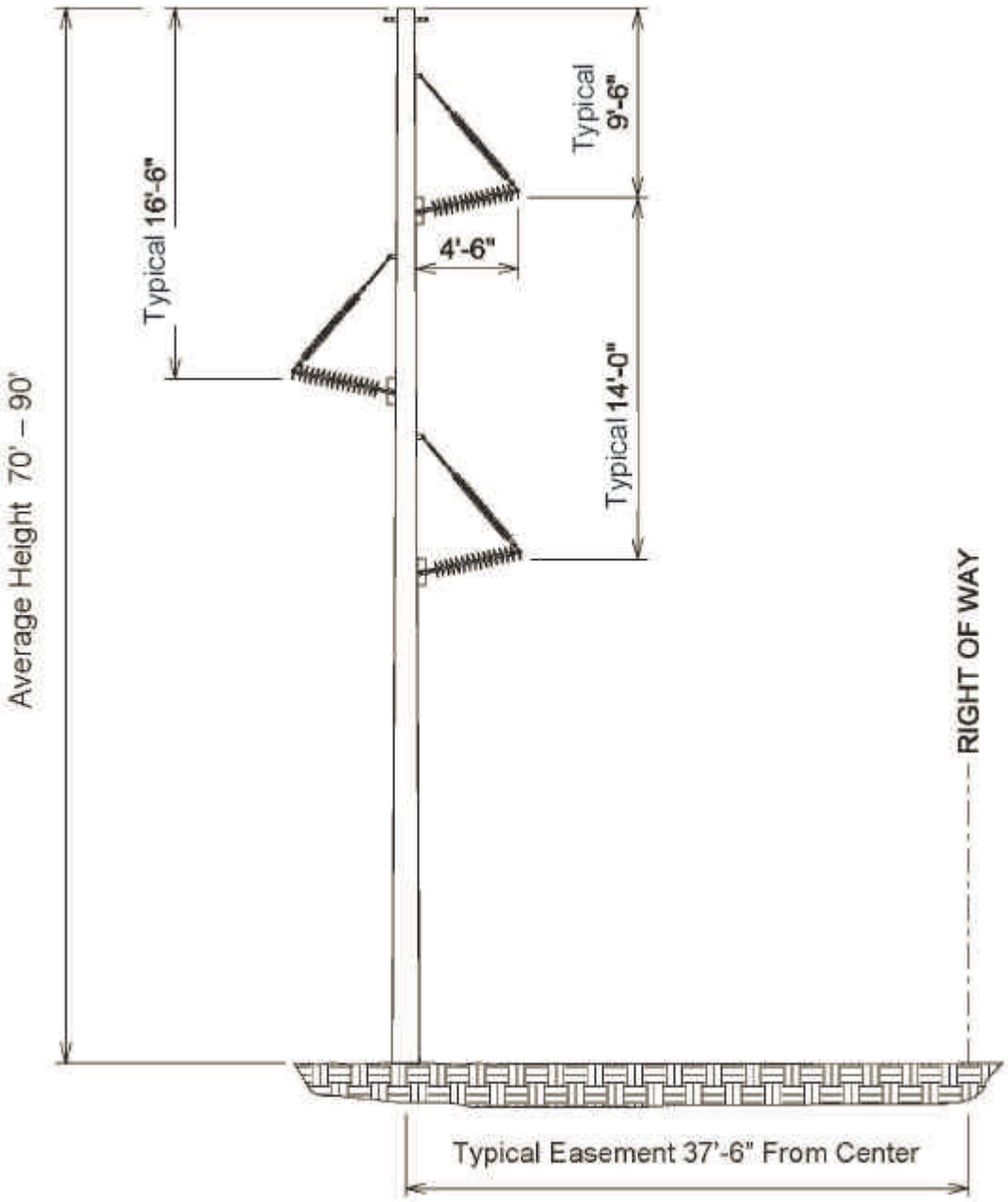


Table 7 summarizes the structure design for the Project.

Table 7
Structure Design Summary

Line Type	Structure Type	Structure Material	Typical Right-of-way Width (feet)	Structure Height (feet)	Structure Base Diameter (inches)	Foundation Diameter (feet)	Span Between Structures (feet)
Single Circuit 115 kilovolt	Single Pole Braced Post (for longer spans)	Galvanized Steel or Weathering Steel	75	70 to 90	24 to 42: tangent structures 36 to 72: angle structures	Direct embedded in 4 foot culvert	300 to 500
Single Circuit 115 kilovolt	Single Pole Horizontal Post (all one side)	Galvanized Steel or Weathering Steel	75	70 to 90	24 to 42: tangent structures 36 to 72: angle structures	5 to 6	300 to 500
Single Circuit 115 kilovolt	Single Pole Horizontal Post	Galvanized Steel or Weathering Steel	75	70 to 90	24 to 42: tangent structures 36 to 72: angle structures	Direct embedded in 4 foot culvert	300 to 500
Single Circuit 115 kilovolt	Single Pole, Cross Arm, Y-Frame	Galvanized Steel or Weathering Steel	75	70-90	36 to 72	5 to 8	500 to 1,200
Double Circuit 115/115 kilovolt	Single Pole, Davit Arm	Galvanized Steel or Weathering Steel	75	75-105	Direct embedded or 4 foot diameter culvert or 6 to 8 foot concrete	Direct embedded for tangents and self-supporting for angle/ dead-end and switch structures 6-8	300 to 500

5.3 Need for New Right-of-Way

An electric transmission line right-of-way is a strip of land used to construct, operate, maintain and repair transmission line facilities. A transmission line usually is centered in the right-of-way. The right-of-way required will be dependent on the ultimate route selected in the route permit proceeding. In that proceeding, Applicants will propose to remove the existing 69 kilovolt transmission line and replace it with a new 115 kilovolt transmission line within existing right-of-way whenever practical. For new 115 kilovolt transmission line construction, a right-of-way width of up to 75 feet

is typically used. Approximately 0.8 miles of new right-of-way, 75 feet in width will be required for the new construction portion of the Project.

5.4 Substations

5.4.1 Proposed New Pomerleau Lake Substation

Xcel Energy's proposed Pomerleau Lake Substation will be built in multiple stages, the timetable of which would be need-driven.

For the proposed Substation Site A, the planned initial stage would include a fenced area estimated at 400 by 475 feet (4.5 acres). The planned ultimate configuration would expand the initial fenced area to a total estimated 400 by 1000 feet (9 acres). The larger 1000 feet dimension would be the north-south direction along Highway I-494.

The initial Pomerleau Lake Substation site plan would be a low profile design. The initial construction would include four 115 kilovolt transmission line terminations (Hollydale, Parkers Lake, Cedar Island, and Meadow Lake), a 115 kilovolt, 4-position ring bus configuration and an electrical equipment enclosure with future expansion capability to an ultimate 115 kilovolt breaker-and-a-half configuration.

The ultimate Pomerleau Lake Substation site plan would provide for the future installation of up to four-345 kilovolt transmission line terminations, two 345-115 kilovolt transformers with tertiary shunt reactors, one additional 115 kilovolt transmission line termination, two 115 kilovolt capacitor banks, two 118-14.3 kilovolt distribution transformers, twelve 13.8 kilovolt outdoor, box structure type, distribution feeders, a second electrical equipment enclosure, and all of the associated structures and equipment.

5.4.2 Modifications to Existing Medina Substation

The existing Great River Energy Medina Substation will be converted from 69 kilovolt to 115 kilovolt as part of the Project. The 69 kilovolt transmission line facilities will be removed along with the 115/69 kilovolt transformer and a 3-way pole mounted switch. Equipment additions at this substation will include installation of a

115 kilovolt straight bus with two breaker positions. One of the breaker positions will serve the rebuilt 115 kilovolt transmission line and the other breaker will be reserved for future use. The distribution equipment and existing feeders will be re-oriented and the northwest fence corner will be expanded to accommodate the modifications. Modifications to the Medina Substation will occur within the existing property limits. No more than an additional 0.25-acres will be added to the substation layout and fenced area of the existing substation will be increased. However, if it is determined that over an acre will be disturbed, Great River Energy will apply for a National Pollutant Discharge Elimination System ("NPDES") construction stormwater permit.

5.4.3 Modifications to Existing Hollydale Substation

The Xcel Energy Hollydale Substation is an existing 69-13.8 kilovolt and 34.5-13.8 kilovolt distribution substation located near the intersection of Highway 101 and Highway 55 in Plymouth. The Project provides for an approximate 100 foot expansion to the west and an approximate 50 foot expansion to the north of the existing 150 by 250 feet graded and fenced area. The resulting 250 by 300 feet fenced area would be within the existing property lines and represents the ultimate dimensions of the Hollydale Substation.

The transmission portion of this substation, which is presently operated at 69 kilovolt consists of a 115 kilovolt rated dead-end structure and some 115 kilovolt rated equipment. The Project provides for converting the 115 kilovolt portion of the substation from a tapped configuration to an in-and-out high profile, box structure, 115 kilovolt configuration with overhead connections to the existing Medina Substation (to be upgraded concurrently to 115 kilovolt) and to the new 115 kilovolt Pomerleau Lake Substation.

This Project provides for the removal of the 69 kilovolt transformer and the installation of a 118-14.3 kilovolt, 50 megavolt-amperes ("MVA") transformer. The existing 15 kilovolt switchgear enclosure would remain in its existing location and a second new 15 kilovolt switchgear enclosure would be installed. The existing 34.5-13.8 kilovolt transformer would remain in its present location.

A new electrical equipment enclosure would be installed within the newly fenced area and would contain all of the control equipment and systems for the substation.

Presently, the ultimate Hollydale Substation site plan would provide for the future installation a second 118-14.3 kilovolt transformer, one 115 kilovolt capacitor bank, a third 15 kilovolt switchgear enclosure, and all the associated structures and equipment.

6 TRANSMISSION LINE OPERATING CHARACTERISTICS

Chapter 6: Transmission Line Operating Characteristics: Chapter 6 provides information regarding the operating characteristics of the proposed 115 kilovolt transmission lines and associated substations. This includes information regarding electric and magnetic fields, noise, ozone and nitrogen oxide emissions, and radio and television interference.

Key Terms:

- **Conductor** – *A wire made up of multiple aluminum strands supported by a steel core that together carry electricity. A bundled conductor is two or more conductors connected together to increase the capacity of a transmission line.*
- **Corona** – *Corona is caused when there is some imperfection on a conductor such as a sharp edge, a protrusion on hardware, a scratch on the conductor, or if moisture collects on the line. This causes breakdown or ionization of air within a few centimeters or less immediately surrounding conductors and can produce ozone and oxides of nitrogen in the air and surrounding conductor.*
- **Electric and magnetic fields** – *Invisible lines of force that surround any electrical appliance or wire that is conducting electricity. The weight of scientific evidence indicates that exposure to electric and magnetic fields does not negatively impact health.*
- **Extremely Low Frequency** – *This term is used to identify electric and magnetic fields within the range of 3 to 300 hertz. Transmission lines operate at 60 hertz.*
- **Ozone** – *Ozone is a very reactive form of oxygen molecules and combines readily with other elements and compounds in the atmosphere. Because of its reactivity, ozone is relatively short-lived.*

Key Points: *The proposed transmission lines and substations will be designed to meet or exceed all relevant safety codes. The noise generated by transmission lines is not expected to exceed background noise levels and will be well below the state noise standards. Electric and magnetic fields exists wherever electricity is produced or used, and surrounds any electrical appliance or wire that is conducting electricity. The potential health effects from electric and magnetic fields have been studied for more than 30 years by government and scientific institutions all over the world. No causal link between electric fields or magnetic fields and health has been demonstrated.*

"In addition, virtually all of the laboratory evidence and the mechanistic evidence fail to support a relationship between low-level [extremely low frequency] magnetic fields and changes in biological function or disease status"

- World Health Organization

"Most researchers concluded that there is insufficient evidence to prove an association between magnetic fields and health effects;"

- Minnesota Interagency Working Group

"The magnetic fields produced by electricity are weak and do not have enough energy to break chemical bonds or to cause mutations in DNA. . . . In addition, whole animal studies investigating long-term exposure to [extremely low frequency] magnetic fields have shown no connection between exposure and cancer of any kind."

- Public Service Commission of Wisconsin

6.1 Transmission Line Operating Characteristics Overview

Overhead transmission line components typically include: (1) an above ground structure, often referred to as a pole or tower; (2) the wires carrying the electricity, called conductors; (3) insulators that connect the conductors to the structures and provide structural support and electrical insulation; (4) ground rods located below ground and connected to each structure; and (5) grounded shield wires to protect the line from direct lightening strikes. Transmission poles are generally made or either steel or wood. Overhead conductors are typically comprised of aluminum and steel strands.

During operation, transmission lines are for the most part passive elements of the environment. Their primary impact is aesthetic, *i.e.*, a man made structure in the landscape. Because of the line's electrical characteristics, 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 as part of the design of a transmission line to prevent any significant impacts to its operation and, generally, to the overall environment.

6.2 Ozone and Nitrogen Oxide Emissions

Corona consists of the breakdown or ionization of air within a few centimeters of conductors. Usually some imperfection such as a scratch on the conductor or a water droplet is necessary to cause corona. 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, inhibit the production of ozone. Ozone is a very reactive form of oxygen molecules 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 ("NOx"). The state and national ambient air quality standards for ozone are similarly restrictive. The national standard is 0.075 parts per million "ppm" on an eight hour averaging period. The state standard is 0.08 ppm based upon the fourth highest eight hour daily maximum average in one year. Both averages must be compared to the national and state standards because of the different averaging periods. Calculations done for a 345 kilovolt project showed that the maximum one hour concentration during foul weather (worst case) would be 0.0007 ppm. This is well below both federal and state standards. Lower voltage lines would have correspondingly lower concentrations. Most calculations of the production and concentration of ozone assume high humidity or rain, with no reduction in the amount of ozone due to oxidation or air movement. These calculations would therefore overestimate the amount of ozone that is produced and concentrated at ground level. Studies designed to monitor the production of ozone under transmission lines have generally been unable to detect any increase due to the transmission line facility.

There is not a state or national standard for general NOx. The national standard for nitrogen dioxide ("NO_2"), one of several oxides of nitrogen, is 0.053 ppm on an annual basis and the Minnesota State Air Quality Standard for NO_2 is 0.08 ppm. The operation of the proposed transmission lines would not create any potential for the concentration of these pollutants to exceed the nearby (ambient) air standards.

6.3 Noise

Transmission Line Noise

Transmission conductors produce noise under certain conditions. The level of noise depends on conductor conditions, voltage level, and weather conditions. Generally, activity-related noise levels during the operation and maintenance of substations and transmission lines is minimal.

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. At substations, noise is created primarily by transformers.

Since human hearing is not equally sensitive to all frequencies of sound, the most noticeable frequencies of sound are given more "weight" in most measurement schemes. The A-weighted scale corresponds to the sensitivity range for human hearing. Noise levels capable of being heard by humans are measured in "dBA," which is the A-weighted sound level recorded in units of decibels. A noise level change of 3 dBA is barely perceptible to human hearing. A 5 dBA change in noise level, however, is clearly noticeable. A 10 dBA change in noise level is perceived as a doubling of noise loudness, while a 20 dBA change is considered a dramatic change in loudness. **Table 8** below shows noise levels associated with common, everyday sources.

Table 8
Common Noise Sources and Levels

Sound Pressure Level (dBA)	Noise Source
140	Jet Engine (at 25 meters)
130	Jet Aircraft (at 100 meters)
120	Rock and Roll Concert
110	Pneumatic Chipper
100	Jointer/Planer
90	Chainsaw
80	Heavy Truck Traffic
70	Business Office
60	Conversational Speech
50	Library
40	Bedroom
30	Secluded Woods
20	Whisper

Source: Minnesota Pollution Control Agency (2008).

In Minnesota, statistical sound levels (L Level Descriptors) are used to evaluate noise levels and identify noise impacts. The standards are expressed as a range of permissible dBA within a one hour period; L_{50} is the dBA that may be exceeded 50 percent of the time within an hour (*i.e.,* 30 minutes), while L_{10} is the dBA that may be exceeded 10 percent of the time within the hour (*i.e.,* 6 minutes).

Land areas, such as picnic areas, churches, or commercial spaces, are assigned to an activity category based on the type of activities or use occurring in the area. Activity categories are then categorized based on their sensitivity to traffic noise. The Noise Area Classification ("NAC") is listed in the Minnesota Pollution Control Agency ("MPCA") noise regulations to distinguish the categories. **Table 9** identifies the MPCA established daytime and nighttime noise standards by NAC

Table 9
Noise Standards by Noise Area Classification (dBA)

Noise Area Classification	Daytime		Nighttime	
	L_{50}	L_{10}	L_{50}	L_{10}
1	60	65	50	55
2	65	70	65	70
3	75	80	75	80

Table 10 provides noise data for the proposed Project's 115 kilovolt structures. Noise levels may vary somewhat depending upon actual conditions, which cannot be determined until the final routes have been determined.

Table 10
Calculated Audible Noise (db) for Proposed 115 kilovolt Transmission Line Designs (3.28 Feet Above Ground)

Structure Type	Noise L_5 (Edge of Right-of-way) (Decibels a weighted)	Noise L_{50} (Edge of Right-of-way) (Decibels a weighted)
Single Pole, Braced Post, 115 kilovolt Single Circuit	21.4	17.9
Single Pole, Horizontal Post (All Phases one side), 115 kilovolt Single Circuit	20.2	16.7
Single Pole, Horizontal Post, 115 kilovolt Single Circuit	15.2	11.7
Single Pole, Cross Arm, 115 kilovolt Single Circuit, Y-Frame	16.3	12.8
Single Pole, Davit Arm, 115 kilovolt/115 kilovolt Double Circuit	23.0	19.5

Transformer Substation Noise

Transformer "hum" is the dominant noise source at substations. All of the substation modifications required for the Project will comply with the MPCA NAC noise standards.

6.4 Radio and Television Interference

Corona from transmission line conductors can generate electromagnetic "noise" at the same frequencies that radio and television signals are transmitted. This noise can cause interference with the reception of these signals depending on the frequency and strength of the radio and television signal. Tightening loose hardware on the transmission line usually resolves the problem.

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 between the receiver and a weak distant signal, creating a shadow effect. Loose and/or damaged hardware may also cause television interference. If television or radio interference is caused by or from the operation of the proposed facilities in those areas where good reception is presently obtained, Applicants will inspect and repair any loose or damaged hardware in the transmission line, or take other necessary action to restore reception to the present level, including the appropriate modification of receiving antenna systems if deemed necessary.

6.5 Safety

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

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

6.6 Electric and Magnetic Fields

The term electromagnetic fields ("EMF") refer to electric and magnetic fields that are coupled together such as in high frequency radiating fields. For the lower frequencies associated with power lines (referred to as "extremely low frequencies" ("ELF")), EMF should be separated into electric fields ("EFs") and magnetic fields ("MFs"), measured in kilovolts per meter ("kV/m") and milliGauss ("mG"), respectively. These fields are dependent on the voltage of a transmission line (EFs) and current carried by a transmission line (MFs). The intensity of the electric field is proportional to the voltage of the line, and the intensity of the magnetic field is proportional to the current flow through the conductors. Transmission lines operate at a power frequency of 60 hertz (cycles per second).

6.6.1 Electric Fields

There is no federal standard for transmission line electric fields. The Commission, however, has imposed a maximum electric field limit of 8 kV/meter measured at one meter above the ground. *In the Matter of the Route Permit Application for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota,* Docket No. ET-2/TL-08-1474, ORDER GRANTING ROUTE PERMIT (*adopting* ALJ FINDINGS OF FACT, Conclusions and Recommendation at Finding 194 (Apr. 22, 2010 and amended Apr. 30, 2010)) (Sept. 14, 2010). The standard was designed to prevent serious hazards from shocks when touching large objects parked under AC transmission lines of 500 kilovolt or greater. **Table 11** provides the EFs at maximum conductor voltage for the proposed 115 kilovolt transmission line. Maximum conductor voltage is defined as the nominal voltage plus five percent. The maximum EF, measured at one meter (3.28 feet) above ground, associated with the Project is calculated to be 1.34 kV/m.

Table 11
Calculated Electric Fields (kV/m) for Proposed Transmission Line Designs (3.28 feet above ground)[36]

Structure Type	Maximum Operating Voltage (kV)	Distance to Proposed Centerline (feet)														
		-300	-200	-100	-75	-50	-37.5	-25	0	25	37.5	50	75	100	200	300
Single Pole, Braced Post, 115 kV Single Circuit	121	0.01	0.03	0.10	0.16	0.26	0.33	0.49	0.95	0.79	0.56	0.38	0.18	0.10	0.03	0.01
Single Pole, Horizontal Post (All Ph one side), 115 kV Single Circuit	121	0.01	0.02	0.05	0.06	0.05	0.02	0.13	1.12	1.09	0.42	0.09	0.08	0.08	0.03	0.01
Single Pole, Horizontal Post, 115 kV Single Circuit	121	0.01	0.03	0.131	0.24	0.50	0.70	0.86	1.09	1.38	0.73	0.40	0.20	0.12	0.03	0.01
Single Pole, Davit Arm, 115 kV/115 kV Double Circuit	121	0.00	0.01	0.02	0.02	0.15	0.44	1.00	0.56	0.10	0.43	0.15	0.02	0.03	0.01	0.00
Single Pole, Davit Arm, 115 kV Single Circuit Y-Frame	121	0.00	0.01	0.09	0.20	0.54	0.96	1.52	0.75	1.52	0.96	0.54	0.20	0.09	0.01	0.00

6.6.2 Magnetic Fields

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

The magnetic field profiles around the proposed transmission lines for each structure and conductor configuration proposed for the Project are shown in **Table 12**. Magnetic fields were calculated under normal system conditions (systems intact) for

[36] The electric field calculations that were included in the Route Permit Application for (1) Single Pole, Horizontal Post (All Ph one side), 115 kV Single Circuit; (2)Single Pole, Horizontal Post, 115 kV Single Circuit; and (3) Single Pole, Davit Arm, 115 kV Single Circuit Y-Frame were calculated at 60 feet as opposed to 3.28 feet above the ground. The electric field calculations for these structures have been corrected in this table.

the expected peak and average current flows as projected under the Midwest Independent Transmission System Operator ("MISO") model for the year 2012. The peak magnetic field values are calculated at a point directly under the transmission line and where the conductor is closest to the ground. The same method is used to calculate the magnetic field at the edge of the right-of-way. The magnetic field profile data show that magnetic field levels decrease rapidly as the distance from the centerline increases (proportional to the inverse square of the distance from source).

The magnetic field produced by the transmission line is dependent on the current flowing on its conductors. Therefore, the actual magnetic field when the Project is placed in service is typically less than shown in the charts. This is because the charts represent the magnetic field with current flow at expected normal peak based on projected regional load growth through 2012, the maximum load projection timeline available. Actual current flow on the line will vary, so magnetic fields will be less than peak levels during most hours of the year.

Table 12
Calculated Magnetic Flux density (mG) for Proposed 115 kilovolt Transmission Line Designs (3.28 feet above ground)[37]

Segment	System Condition	Current (Amps)	Distance to Proposed Centerline (feet)														
			-300	-200	-100	-75	-50	-37.5	-25	0	25	37.5	50	75	100	200	300
Single Pole, Braced Post, 115 kV Single Circuit	Peak	250	0.32	0.69	2.53	4.25	8.30	12.47	19.43	32.10	16.27	10.50	7.04	3.63	2.16	0.55	0.24
	Average	150	0.19	0.41	1.52	2.55	4.98	7.48	11.66	19.26	9.76	6.30	4.22	2.18	1.29	0.33	0.14
Single Pole, Horizontal Post (All Ph one side), 115 kV Single Circuit	Peak	250	0.36	0.76	2.55	3.99	6.93	9.60	13.83	29.87	29.97	20.64	13.91	6.96	4.01	0.98	0.42
	Average	150	0.21	0.46	1.53	2.39	4.16	5.76	8.30	17.92	17.98	12.38	8.34	4.18	2.41	0.59	0.25
Single Pole, Horizontal Post, 115 kV Single Circuit	Peak	250	0.64	1.37	4.85	7.86	14.33	20.16	28.38	47.01	37.45	25.24	17.08	8.79	5.18	1.31	0.57
	Average	150	0.38	0.82	2.91	4.72	8.60	12.09	17.03	28.21	22.47	15.14	10.25	5.27	3.11	0.79	0.34
Single Pole, Davit Arm, 115 kV/115kV Double Circuit	Peak	250/250	0.21	0.37	1.76	3.59	8.91	15.12	25.75	41.99	24.30	13.91	7.97	3.02	1.39	0.28	0.18
	Average	150/150	0.12	0.22	1.06	2.15	5.35	9.07	15.45	25.19	14.58	8.34	4.78	1.81	0.83	0.17	0.11
Single Pole, Davit Arm, 115 kV Single Circuit Y-Frame	Peak	250	0.44	1.02	4.09	7.16	15.15	24.31	40.31	65.80	40.63	24.61	15.42	7.36	4.25	1.10	0.50
	Average	150	0.27	0.61	2.45	4.29	9.09	14.58	24.19	39.48	24.38	14.77	9.25	4.42	2.55	0.66	0.30

[37] The magnetic field calculations that were included in the Route Permit Application for (1) Single Pole, Horizontal Post (All Ph one side), 115 kV Single Circuit; (2) Single Pole, Horizontal Post, 115 kV Single Circuit; and (3) Single Pole, Davit Arm, 115 kV Single Circuit Y-Frame were calculated at 60 feet as opposed to 3.28 feet above the ground. The magnetic field calculations for these structures have been corrected in this table.

Considerable research has been conducted throughout the past three decades to determine whether exposure to power-frequency (60 hertz) MFs causes biological responses and health effects. Epidemiological and toxicological studies have shown no statistically significant association or weak associations between MF exposure and health risks. Public health professionals have also investigated the possible impact of exposure to EMF upon human health for the past several decades. While the general consensus is that EFs pose no risk to humans, the question of whether exposure to MFs can cause biological responses or health effects continues to be debated.

In 1999, the National Institute of Environmental Health Sciences ("NIEHS") issued its final report on "Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields" in response to the Energy Policy Act of 1992. The NIEHS concluded that the scientific evidence linking MF exposure with health risks is weak and that this finding does not warrant aggressive regulatory concern. However, because of the weak scientific evidence that supports some association between MFs and health effects, passive regulatory action, such as providing public education on reducing exposures, is warranted.

In 2007, the World Health Organization ("WHO") concluded a review of the health implications of electromagnetic fields. In this report, WHO stated:

> Uncertainties in the hazard assessment [of epidemiological studies] include the role that control selection bias and exposure misclassification might have on the observed relationship between magnetic fields and childhood leukemia. In addition, virtually all of the laboratory evidence and the mechanistic evidence fail to support a relationship between low-level [extremely low frequency] magnetic fields and changes in biological function or disease status. Thus, on balance, the evidence is not strong enough to be considered causal, but sufficiently strong to remain a concern. (*Environmental Health Criteria Volume N°238 on Extremely Low Frequency Fields* at p. 12, WHO (2007)).

Also, regarding disease outcomes, aside from childhood leukemia, WHO stated:

> A number of other diseases have been investigated for possible association with ELF magnetic field exposure. These include cancers in children and adults, depression, suicide, reproductive dysfunction, developmental disorders, immunological modifications and neurological disease. The scientific evidence supporting a linkage between ELF magnetic fields and any of these diseases is much weaker than for childhood leukemia and in some cases (for example, for cardiovascular disease or breast cancer) the evidence is sufficient to give confidence that magnetic fields do not cause the disease. (*Id.* at p. 12.)

Furthermore, in its "Summary and Recommendations for Further Study" WHO emphasized that:

> The limit values in [ELF-MF] exposure guidelines [should not] be reduced to some arbitrary level in the name of precaution. Such practice undermines the scientific foundation on which the limits are based and is likely to be an expensive and not necessarily effective way of providing protection. (*Id.* at p. 12).

Although WHO recognized epidemiological studies indicate an association on the range of three to four mG, WHO did not recommend these levels as an exposure limit but instead provided: "The best source of guidance for both exposure levels and the principles of scientific review are international guidelines." *Id.* at pp. 12-13. The international guidelines referred to by WHO are the International Commission on Non-Ionizing Radiation Protection ("ICNIRP") and the Institute of Electrical and Electronic Engineers ("IEEE") exposure limit guidelines to protect against acute effects. *Id.* at p. 12. The ICNIRP-1998 continuous general public exposure guideline is 833 mG and the IEEE continuous general public exposure guideline in 9,040 mG. In addition, WHO determined that "the evidence for a casual relationship [between ELF-MF and childhood leukemia] is limited, therefore exposure limits based on epidemiological evidence is not recommended, but some precautionary measures are warranted." *Id.* at 355-56.

WHO concluded that:

> given the weakness of the evidence for a link between exposure to ELF magnetic fields and childhood leukemia, and the limited impact on public health, the benefits of exposure reduction on health are unclear and thus, the costs of precautionary measures should be very low… Provided that the health, social and economic benefits of electric power are not compromised, implementing very low-cost precautionary procedures to reduce exposure is reasonable and warranted. (*Id.* at p. 372).

In 2010, ICNIRP revised its continuous general public exposure guideline increasing it from 833 mG to 2,000 mG. The WHO has not provided any analysis of the ICNIRP-2010 continuous general public exposure guideline to date.

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 HVTL (High Voltage Transmission Lines) EMF effects. The Working Group consisted of staff from various state agencies and published its findings in a White Paper on Electric and Magnetic Field (EMF) Policy and Mitigation Options in September 2002, (Minnesota Department of Health, 2002). The report summarized the findings of the Working Group as follows:

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

> there is insufficient evidence to prove an association between [MF] and health effects; however, many of them also concluded that there is insufficient evidence to prove that [MF] exposure is safe. (*Id.* at p. 1.)

The Public Service Commission of Wisconsin ("PSCW") has periodically reviewed the science on MFs since 1989 and held hearings to consider the topic of MF and human health effects. The most recent hearings on MF were held in July 1998. In January 2008, the PSCW published a fact sheet regarding MFs. In this fact sheet the PSCW noted that:

> Many scientists believe the potential for health risks for exposure to [MFs] is very small. This is supported, in part, by weak epidemiological evidence and the lack of a plausible biological mechanism that explains how exposure to [MFs] could cause disease. The [MFs] produced by electricity are weak and do not have enough energy to break chemical bonds or to cause mutations in DNA. Without a mechanism, scientists have no idea what kind of exposure, if any, might be harmful. In addition, whole animal studies investigating long-term exposure to power frequency [MF] have shown no connection between exposure and cancer of any kind. (*EMF-Electric & Magnetic Fields*, PSC).

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." *In the Matter of the Application of Xcel Energy for a Route Permit for the Lake Yankton to Marshall Transmission Line Project in Lyon County*, Docket No. E-002/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 p. 7-8 (Aug. 29, 2008); *See also*, *In the Matter of the Application for a HVTL Route Permit for the Tower Transmission Line Project*, Docket No. ET-2, 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 p. 23 (Aug. 1, 2007) ("Currently, there is

insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects.”).

The Commission again confirmed its conclusion regarding health effects and MFs in the Brookings County – Hampton 345 kV Route Permit proceeding (“Brookings Project”). In the Brookings Project Route Permit proceeding, Applicants Great River Energy and Xcel Energy and one of the intervening parties provided expert evidence on the potential impacts of electric and magnetic fields on human health. The ALJ in that proceeding evaluated written submissions and a day-and-half of testimony from these two expert witnesses. The ALJ concluded: “there is no demonstrated impact on human health and safety that is not adequately addressed by the existing State standards for [EF or MF] exposure.” *In the Matter of the Route Permit Application by Great River Energy and Xcel Energy for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota*, Docket No. ET-2/TL-08-1474, ALJ FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION at Finding 216 (Apr. 22, 2010 and amended Apr. 30, 2010). The Commission adopted this finding on July 15, 2010. *In the Matter of the Route Permit Application by Great River Energy and Xcel Energy for a 345 kV Transmission Line from Brookings County, South Dakota to Hampton, Minnesota*, Docket No. ET-2/TL-08-1474, ORDER GRANTING ROUTE PERMIT (Sept. 14, 2010).

6.7 Stray Voltage

“Stray voltage” is a condition that can occur on the electric service entrances to structures from distribution lines. More precisely, stray voltage is a voltage that exists between the neutral wire of the service entrance and grounded objects in buildings such as barns and milking parlors. Because transmission lines convey power for subsequent distribution and are not connected to non-utility structures, stray voltage is not encountered in such lines.

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

Insulated electric fences used in livestock operations can pick up an induced charge from transmission lines. Usually, the induced charge will drain off 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. Potential shocks can be prevented by using a couple of methods, including:

i. one or more of the fence insulators can be shorted out to ground with a wire when the charger is disconnected; or
ii. an electric filter can be installed that grounds out charges induced from a power line while still allowing the charger to be effective.

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 specified by the NESC. Recommended clearances within the NESC are designed to accommodate a relative vehicle height of 14 feet.

There is a potential for vehicles under high voltage transmission lines to build up an electric charge. If this occurs, the vehicle can be grounded by attaching a grounding strap to the vehicle long enough to touch the earth. Such buildup is 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, vehicles will not normally build up a charge unless they have unusually old tires or are parked on dry rock, plastic, or other surfaces that insulate them from the ground.

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 on the right-of-way could damage a transmission line. As a result, NESC guidelines establish clear zones for transmission facilities. Metal buildings may have unique issues. For example, metal buildings near power lines of 200 kilovolt or greater must be properly grounded. Any person with questions about a new or existing metal structure can contact Xcel Energy for further information about proper grounding requirements.

7 TRANSMISSION LINE CONSTRUCTION AND MAINTENANCE

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

Key Terms:

- ***Best Management Construction Practices*** *– standard construction and mitigation practices developed from experience with past projects.*
- ***Easement*** *– Where some or all of the right-of-way for a transmission line is on private property, an easement is acquired from the landowner to build, operate and maintain a transmission line. Landowners are paid a fair price for the easement and can continue to use the land for many purposes, although some restrictions are included in the agreement.*
- ***Right-of-Way*** *– A right-of-way is the land area necessary for a specific purpose, such as the operation and maintenance .*

Key Points: *The construction of a transmission line typically involves four key activities: (1) detailed engineering, design, and regulatory approvals; (2) right-of-way evaluation and acquisition; (3) construction; and (4) right-of-way restoration. Construction of the Project will follow standard construction and mitigation practices developed from experience with past projects.*

The construction of a transmission line typically involves four key activities: (1) detailed engineering, design, and regulatory approvals; (2) right-of-way evaluation and acquisition; (3) construction; and (4) right-of-way restoration.

7.1 Engineering Design and Regulatory Approvals

Detailed transmission line and substation engineering design work generally begins after a route permit or local routing approval is obtained. The design of a transmission line is refined as more site-specific information is gathered for properties along the approved route. Throughout the process, utilities work with landowners to design facilities to minimize impacts and ensure that all permit conditions are satisfied.

Plan and profile documents are also prepared for each new high voltage transmission line and associated substation work. These plans provide a detailed descriptions of the facilities, including pole placement, and are approved by the Department of Commerce staff or local authorities, as appropriate.

7.2 Right-of-Way Evaluation and Acquisition

Early in the detailed design process, the right-of-way acquisition process begins. For transmission lines, utilities typically acquire easement rights across the parcels to accommodate the facilities. For substations, utilities typically purchase land outright and buy enough land to accommodate the facilities and to provide a buffer area around the facilities. In both circumstances, the evaluation and acquisition process includes title examination, initial owner contacts, survey work, document preparation and purchase. Each of these activities, particularly as it applies to easements for transmission line facilities, is described below.

Where the Project is expected to use existing rights-of-way , the right-of-way agent will evaluate all existing easements. If the terms of the existing easement are sufficient and no new right-of-way is needed, the right-of-way agent will continue to work with the landowner to address any construction needs, impacts, or restoration issues. To the extent the existing easement needs to be expanded, the right-of-way agent will work with landowners to expand existing easements.

For those segments of the Project where new right-of-way will be necessary, the acquisition process begins early in the detailed design phase. The first step in the right-of-way process is to identify all persons and entities that may have a legal interest in the real estate upon which the facilities will be built. To compile this list, a right-of-way agent or other persons engaged by the utility will complete a public records search of all land involved in the project. A title report is then developed for each parcel to determine the legal description of the property and the owner(s) of record of the property, and to gather information regarding easements, liens, restriction, encumbrances and other conditions of record.

After owners are identified, a right-of-way representative contacts each property owner or the property owner's representative. The right-of-way agent describes the

need for the transmission facilities and how the Project may affect each parcel. The right-of-way agent also seeks information from the landowner about any specific construction concerns.

The next step in the acquisition process is evaluation of the specific parcel. For this work, the right-of-way agent may request permission from the owner for survey crews to enter the property to conduct preliminary survey work. Permission may also be requested to take soil borings to assess the soil conditions and determine appropriate foundation design. Surveys are conducted to locate the right-of-way corridors, natural features, man-made features and associated elevations for use during the detailed engineering of the line. The soil analysis is performed by an experienced geotechnical testing laboratory.

During the evaluation process, the location of the proposed transmission line or substation facility may be staked with permission of the property owner. This means that the survey crew locates each structure or pole on the ground and places a surveyor's stake to mark the structures or substation facility's anticipated location. By doing this, the right-of-way agent can show the landowner where the structure(s) will be located on the property. The right-of-way agent may also delineate the boundaries of the easement area required for safe operation of the line.

Prior to the acquisition of easements or fee purchase of property, land value data will be collected. Based on the impact of the easement or purchase to the market value of each parcel, a fair market value offer will be developed. The right-of-way agent then contacts the property owner(s) to present the offer for the easement and discuss the amount of just compensation for the rights to build, operate and maintain the transmission facilities within the easement area and reasonable access to the easement area. The agent will also provide maps of the line route or site, and maps showing the landowner's parcel. The landowner is allowed a reasonable amount of time to consider the offer and to present any material that the owner believes is relevant to determining the property's value. This step is often performed prior to full evaluation in the form of an "option to purchase" contract and can be very helpful in obtaining permission for completion of all necessary evaluations.

In nearly all cases, utility companies are able to work with the landowners to address their concerns and an agreement is reached for the utility's purchase of land rights. The right-of-way agent prepares all of the documents required to complete each transaction. Some of the documents that may be required include: easement; purchase agreement; contract; and deed.

In rare instances, a negotiated settlement cannot be reached and the landowner chooses to have an independent third party determine the value of the rights taken. Such valuation is made through the utility's exercise of the right of eminent domain pursuant to Minnesota Statutes Chapter 117. The process of exercising the right of eminent domain is called condemnation.

Before commencing a condemnation proceeding, the right-of-way agent must obtain at least one appraisal for the property proposed to be acquired and a copy of that appraisal must be provided to the property owner. Minn. Stat. § 117.036, subd. 2(a). The property owner may also obtain another property appraisal and the company must reimburse the property owner for the cost of the appraisal according to the limits set forth in Minnesota Statute Section 117.036, subdivision 2(b). The property owner may be reimbursed for reasonable appraisal costs up to $1,500 for single-family and two-family residential properties, $1,500 for property with a value of $10,000 or less, and $5,000 for other types of properties.

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. Once appointed, the commissioners schedule a viewing of the property over and across which the transmission line easement is to be located. Next, the commission schedules 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.

As part of the right-of-way acquisition process, the right-of-way agent will discuss the construction schedule and construction requirements with the owner of each parcel. To ensure safe construction of the line, special consideration may be needed for fences, crops or livestock. For instance, fences may need to be moved, temporary or permanent gates may need to be installed; crops may need to be harvested early; and livestock may need to be moved. In each case the right-of-way agent and construction personnel coordinate these processes with the landowner.

7.3 Transmission Line Construction

Construction will begin after all federal, state, and local approvals are obtained, property and rights-of-way are acquired, soil conditions are determined and the design is completed. The precise timing of construction will take into account various requirements that may be in place due to permit conditions, system loading issues, available workforce and materials. Applicants anticipate that construction will take approximately 3 weeks per mile of transmission line and that the construction crew will be about 15 people (3-4 person construction teams).

The actual construction will follow standard construction and mitigation practices that have been developed from experience with past projects. These best practices address right-of-way clearance, staging, erecting transmission line structures and stringing transmission lines. Construction and mitigation practices to minimize impacts will be developed based on the proposed schedule for activities, permit requirements, prohibitions, maintenance guidelines, inspection procedures, terrain and other practices. In certain cases some activities, such as schedules, are modified to minimize impacts to sensitive environments.

Typical construction equipment used on transmission projects includes: tree removal equipment, mowers, cranes, backhoes, digger-derrick line trucks, track-mounted drill rigs, dump trucks, front end loaders, bucket trucks, bulldozers, flatbed tractor-trailers, flatbed trucks, pickup trucks, concrete trucks and various trailers. Many types of excavation equipment are set on wheel or track-driven vehicles. Poles are transported on tractor-trailers.

Steel poles are proposed to be used for the structures for the Project. Steel pole tangent structures are proposed to be directly embedded into the ground if soil conditions warrant. Rock-filled culvert foundations may be required in areas with poor soils. This method typically involves digging a hole for each pole, filling it partially with crushed rock and then setting the pole on top of the rock base. The area around the pole is then backfilled with crushed rock and/or soil. Culvert foundations involve auguring a hole for each pole, installing a galvanized steel culvert, filling the annular space outside the culvert with hole spoils, filling the culvert partially with crushed rock and then setting the pole on top of the rock base. The annular space between the pole and culvert is filled with crushed rock.

Long span, angle and dead end structures along the route will require concrete foundations. In those cases, holes will need to be drilled in preparation for the concrete foundations. Drilled pier foundations may vary from five to eight feet in diameter and 20 to 30 feet deep, depending on soil conditions. Steel reinforcing bars and anchor bolts are installed in the drilled holes prior to concrete placement. Concrete trucks are required to bring the concrete in from a local concrete batch plant. Steel pole structures are hauled unassembled on pole trailers to the staked location and placed within the right-of-way until the pole sections are assembled and the arms attached. Insulators and other hardware are attached while the steel pole is on the ground. The pole is then lifted, placed, and secured on the foundation using a crane.

Construction staging areas are usually established for transmission projects. Staging involves delivering the equipment and materials necessary to construct the new transmission line facilities. Construction of the Project will likely include one or two staging areas. Structures are delivered to staging areas and materials are stored until they are needed for the Project. The materials are then sorted and loaded onto structure trailers for delivery to the staked location.

In some cases, additional space (temporary lay down areas) may be required. These areas will be selected for their location, access, security and ability to efficiently and safely warehouse supplies. The areas are chosen to minimize excavation and grading. The temporary lay down areas outside of the transmission line right-of-way will be secured from affected landowners through rental agreements.

Typically, access to the transmission line right-of-way corridor is made directly from existing roads or trails that run parallel or perpendicular to the transmission line right-of-way. In some situations, private field roads or trails are used. Where easements exist, Xcel Energy notifies the property owner that it will access the easement area. Where necessary to accommodate the heavy equipment used in construction, including cranes, concrete trucks and foundation drilling equipment, existing access roads may be upgraded or new roads may be constructed. New access roads may also be constructed where no current access is available or the existing access is inadequate to cross roadway ditches.

Environmentally sensitive areas and wetland areas may also require special construction techniques in some circumstances. During construction, the most effective way to minimize impacts to wet areas will be to span wetlands, streams, and rivers. In addition, Xcel Energy will not allow construction equipment to be driven across waterways except under special circumstances and only after discussion with the appropriate resource agency. Where waterways must be crossed to pull in the new conductors and shield wires, workers may walk across, use boats, or drive equipment across ice in the winter. These construction practices help prevent soil erosion and ensure that equipment fueling and lubricating will occur at a distance from waterways.

Impacts to wetlands will be minimized through construction practices. Construction crews will maintain sound water and soil conservation practices during construction and operation of the facilities to protect topsoil and adjacent water resources and to minimize soil erosion. Practices may include: containing excavated material, protecting exposed soil and stabilizing restored soil. Crews will avoid major disturbance of individual wetlands and drainage systems during construction. This will be accomplished by strategically locating new access roads and spanning wetlands and drainage systems where possible.

When it is not feasible to span the wetland, construction crews will consider the following options during construction to minimize impacts:

- When possible, construction will be scheduled during frozen ground conditions;

- Crews will attempt to access the wetland with the least amount of physical impact to the wetland (i.e., shortest route);
- The structures will be assembled on upland areas before they are brought to the site for installation; or
- When construction during winter is not possible, construction mats will be used where wetlands would be impacted.

7.4 Right-of-Way Restoration and Clean Up

During construction, crews will attempt to limit ground disturbance wherever possible. However, areas are typically disturbed during the normal course of work, which can take several weeks in any one location. As construction on each parcel is completed, disturbed areas will be restored to their original condition to the maximum extent practicable. The right-of-way agent contacts each property owner after construction is completed to determine whether any damage has occurred as a result of the Project.

If damage has occurred to crops, fences or the property, Xcel Energy will fairly reimburse the landowner for the damages sustained. In some cases, Xcel Energy may engage an outside contractor to restore the damaged property to as near as possible to its original condition. Portions of vegetation that are disturbed or removed during construction of transmission lines will naturally reestablish to pre-disturbance conditions. Resilient species of common grasses and shrubs typically reestablish with few problems after disturbance. Areas with significant soil compaction and disturbance from construction activities along the proposed transmission line corridor will require assistance in reestablishing vegetation and controlling soil erosion.

Commonly used methods to control soil erosion and assist in reestablishing vegetation include, but are not limited to:

- Erosion control blankets with embedded seeds;
- Silt fences;
- Hay bales;
- Hydro seeding; and

- Planting individual seeds or seedlings of native species.

These erosion control and vegetation establishment practices are regularly used in construction projects and are referenced in the construction storm water permit plans. Long-term impacts are also minimized by utilizing these construction techniques.

7.5 Maintenance Practices

Transmission lines and substations are designed to operate for decades and require only moderate maintenance, particularly in the first few years of operation.

The estimated service life of the proposed transmission line for accounting purposes is approximately 50 years. However, practically speaking, high voltage transmission lines are seldom completely retired. Transmission infrastructure has very few mechanical elements and is built to withstand weather extremes that are normally encountered. With the exception of severe weather such as tornadoes and heavy ice storms, transmission lines rarely fail.

Transmission lines are automatically taken out of service by the operation of protective relaying equipment when a fault is sensed on the system. Such interruptions are usually only momentary. Scheduled maintenance outages are also infrequent. As a result, the average annual availability of transmission infrastructure is very high, in excess of 99 percent.

The principal operating and maintenance cost for transmission facilities is the cost of inspections, which is usually done monthly by air. Annual operating and maintenance costs for transmission lines in Minnesota and surrounding states vary. However, past experience shows that costs are approximately $300 to $500 per mile for voltages from 69 kilovolt through 345 kilovolt. 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.

8 ENVIRONMENTAL INFORMATION

Chapter 8: Environmental Information: Chapter 8 provides a general overview of the environmental features and land uses in the Project area.

Key Terms:

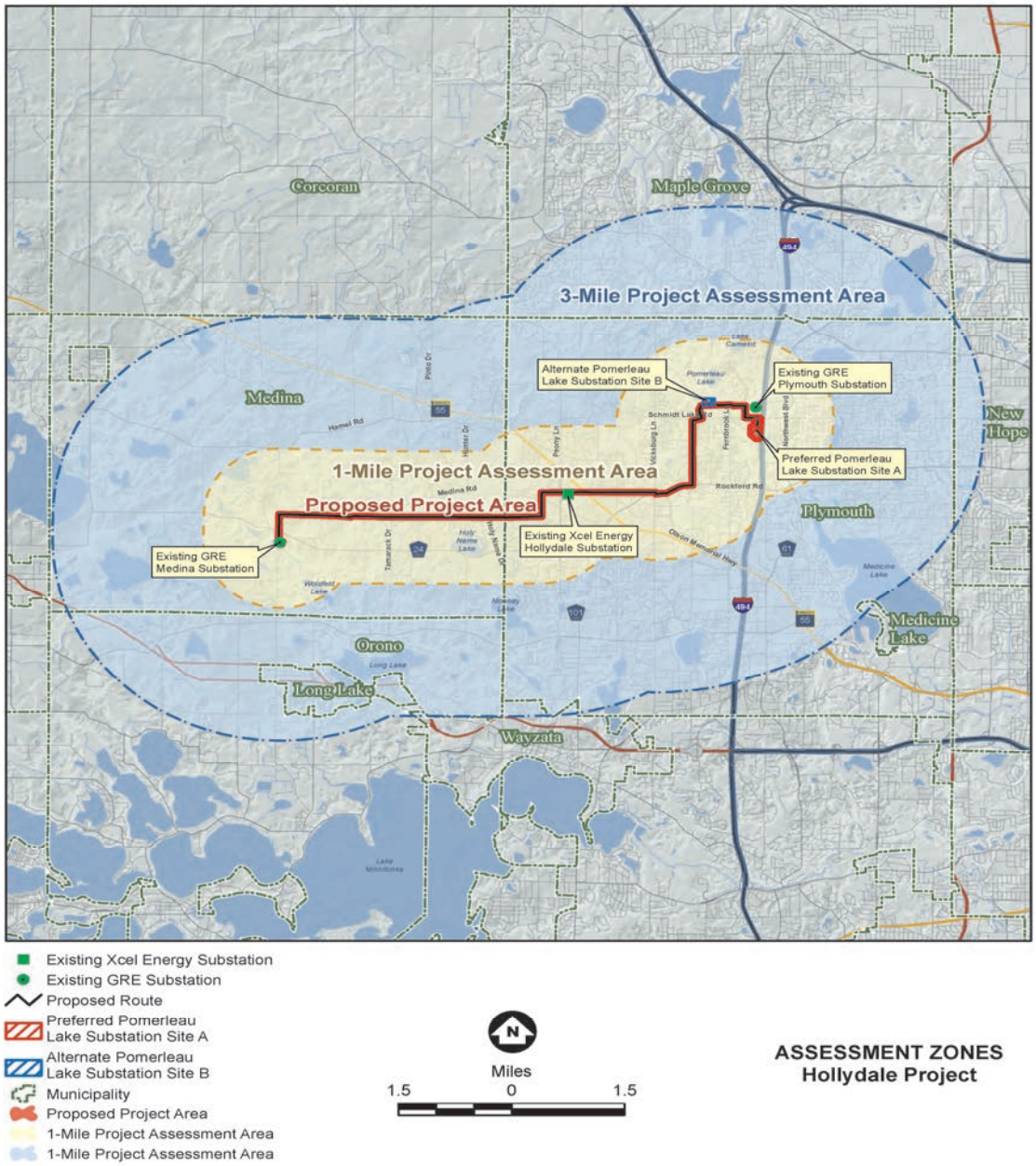
- ***Proposed Project Area*** *– This term refers to the Proposed Route, 200 feet on each side of the centerline of the Proposed Route, the existing Medina Substation, the existing Hollydale Substation, and the proposed new Pomerleau Lake Substation at Site A.*
- ***1-Mile Project Assessment Area*** *– This term refers to an area that extends one mile on either side of the centerline of the Proposed Route and substations.*
- ***3-Mile Project Assessment Area*** *– This term refers to an area that extends three miles on either side of the centerline of the Proposed Route and substations.*
- ***Geomorphology*** *– Geomorphology is a science that deals with the relief features of the earth and seeks a genetic interpretation of them.*
- ***Physiography*** *– Physiography is a branch of geography that deals with the exterior features and changes of the earth.*
- ***Mitigative Measures:*** *These terms refer to actions taken by Applicants to lessen environmental or other impacts resulting from the construction, operation, or maintenance of the proposed Project.*
- ***Cultural Resources*** *– Cultural Resources are historic or archaeological sites containing unique or significant features relating to the cultural history the region. These resources are considered non-renewable.*
- ***Considered Eligible Finding ("CEF")*** *– Cultural Resource sites that have been identified as eligible for listing on the National Register by both state and federal agencies, but not yet nominated or listed are identified as Considered Eligible Findings and are afforded comparable protection to listed sites for evaluation purposes.*
- ***Floodplain*** *– A floodplain is flat or nearly flat land adjacent to a stream or river that experiences occasional or periodic flooding. The floodplain includes the floodway which consists of the stream channel and adjacent areas that carry flood flows, and the flood fringe which are areas covered by the flood but do not carry a strong current.*
- ***Public Waters*** *– Public waters are designated as such to indicate which lakes, wetlands, and watercourses over which the Minnesota Department of Natural Resources ("MnDNR")*

Waters has regulatory jurisdiction. The statutory definition of public waters includes public waters and public waters wetlands (Minnesota Statute 103G.005, Subd. 15).

Key Points: *Based on our review, there are no environmental issues that would preclude construction of the proposed facilities. Applicants will take mitigative measures to minimize the environmental impacts of siting, constructing, and operating the Project.*

This section provides a description of the environmental setting, potential impacts, and mitigative measures the Applicants have proposed, where appropriate, to minimize the impacts of siting, constructing, and operating the proposed Project. If the proposed transmission lines were removed in the future, the land could be restored to its prior condition and/or put to a different use. The majority of the measures proposed are part of the Applicants' standard construction processes. Unless otherwise identified in the following text, the costs of the mitigative measures proposed are considered nominal. For purposes of this section, there are three assessment zones: the Proposed Project Area, which consists of the Proposed Route, 200 feet on each side of the centerline of the Proposed Route, the existing Medina Substation, the existing Hollydale Substation, and the proposed new Pomerleau Lake Substation at Substation Site A; the 1-Mile Project Assessment Area, which refers to an area that extends one mile on either side of the centerline of the Proposed Route and proposed substations; and the 3-Mile Project Assessment Area, which refers to an area that extends three miles on either side of the centerline of the Proposed Route and substations. The 3-Mile Project Assessment Area encompasses all alternative routes included in the December 2011 scoping decision issued by the Department of Commerce, Energy Facilities Permitting. A map of these three assessment zones is **Figure 30**.

Figure 30
Map of Assessment Zones



8.1 Description of Environmental Setting

The proposed transmission line conversion and rebuild is located in Hennepin County, Minnesota. Municipalities present within the Proposed Project Area include the cities of Medina and Plymouth. Additional municipalities present within the 3-

Mile Project Assessment Area include the cities of Corcoran, Long Lake, Orono, Wayzata, Medicine Lake, New Hope, and Maple Grove. The Proposed Route begins at the existing Great River Energy Medina Substation located in south-central Medina and extends east along an existing 69 kilovolt transmission line corridor to the existing Xcel Energy Hollydale Substation in west central Plymouth; the route then continues east and north to the proposed new Pomerleau Lake Substation, which would be located in northwest Plymouth. Land use in the 3-Mile Project Assessment Area consists primarily of residential and commercial development, with areas of cropland, forest, and wetland also present.

8.2 Geomorphology and Physiography

The 3-Mile Project Assessment Area is located within the Big Woods subsection of the Minnesota and Northeast Iowa Morainal Section, a section within the biogeographic province known as the Eastern Broadleaf Forest Province under the Ecological Classification System ("ECS") developed by the Minnesota Department of National Resources ("MnDNR") and the United States Forest Service ("USFS") (MnDNR, 2010).

The Big Woods subsection is characterized by gently to moderately rolling topography with the primary landform consisting of a loamy mantled end moraine associated with the Des Moines lobe of the Late Wisconsin glaciations. Soils are primarily loams, ranging in texture from loam to clay loam. Pre-settlement vegetation consisted primarily of oak woodland and maple basswood forest (MnDNR, 2010). The majority of the 3-Mile Project Assessment Area consists of residential and commercial development, with areas of cropland, forest, and wetland also present.

8.3 Land Use and Human Settlement

8.3.1 Residential and Non-Residential Land Use

Land use in the Proposed Project Area has been developed for residential and commercial uses; areas of cropland, forest, and wetlands are also present. The 3-Mile Project Assessment Area includes portions of nine individual municipalities located in Hennepin County. The City of Plymouth is the largest municipality located along the Proposed Route with a population of over 70,000 (2010 Census). The Proposed

Project Area includes two school properties, Glenwood Elementary and Providence Academy, and there are 36 schools located within the 3-Mile Project Assessment Area.

8.3.2 Displacement

No displacement of residential homes or businesses would occur along the Proposed Route. The NESC and the Applicants' standards require certain clearances between transmission line facilities and buildings for safe operation of the proposed transmission line. The Applicants will acquire a right-of-way for the transmission line that is sufficient to maintain these clearances.

8.3.3 Aesthetics

Because the Proposed Route will mainly follow an existing 69 kilovolt transmission line, it is anticipated that the proposed Project will have incremental effects on the visual and aesthetic character of the area. The structures on the existing Great River Energy 69 kilovolt transmission line are single-pole and H-frame structures which are approximately 60 to 90 feet tall with spans ranging from approximately 200 to 500 feet. The proposed structures for the 115 kilovolt transmission line are single-pole, galvanized steel or weathering steel structures, which are similar to the structures for other 115 kilovolt transmission lines used on the Applicants' systems. In comparison to the existing 69 kilovolt structures, the proposed structures will be slightly taller with similar span distances between structures. The proposed single circuit structures will be about 70 to 90 feet tall (or 75 to 105 feet tall for double circuit structures) with an average span of 300 to 500 feet between the structures. Where Y-frame structures are used to span wetlands, the structures will range from 70 to 90 feet tall and the spans between them from 500 and 1,200 feet. The typical right-of-way required for these types of structures is a minimum of 75 feet wide. However, the new 115 kilovolt transmission line will be designed to be maintained within the existing easements of the Proposed Route (typically 70 feet wide, with some areas up to 100 feet) where reasonably possible.

Like the existing single circuit 69 kilovolt transmission line, the new single circuit 115 kilovolt transmission line will be visible to area residents. The visual effect will

depend largely on the perceptions of the observers. The transmission lines and substations that already exist in the Proposed Project Area will limit the extent to which the new line and substations are viewed as a disruption it the area's scenic integrity. The new Pomerleau Lake Substation will create new visual impacts to surrounding land uses. However, at Substation Site A (the proposed site for the Pomerleau Lake Substation), the site is bounded by Interstate Highway I-494 to the east, Schmidt Lake Road and commercial/industrial facilities to the north, industrial and some residential uses to the west and southwest, and park/open/vacant land to the south.

Mitigative Measures

Although the proposed line will alter views of surrounding land uses, the Applicants have identified the route that predominantly uses existing transmission corridors and avoids residences and businesses to the greatest extent practicable. The Applicants will work with landowners to identify concerns related to the transmission line and new substation aesthetics.

8.4 Socioeconomic

The population and economic characteristics for the State of Minnesota, Hennepin County, and municipalities within the 3-Mile Project Assessment Area are presented in **Table 13**.

Table 13
Population and Economic Characteristics

Location	Population	Minority Population (Percent)	White, Non-Hispanic Population (Percent)	Annual Per Capita Income	Percentage of Individuals Below Poverty Level
State of Minnesota	5,303,925	16.9	83.1	$29,582	10.6
Hennepin County	1,152,425	28.3	71.7	$35,902	12.1
Medina	4,892	6.7	93.3	$83,106	3.3
Plymouth	70,576	17.5	82.5	$46,405	4.5

Location	Population	Minority Population (Percent)	White, Non-Hispanic Population (Percent)	Annual Per Capita Income	Percentage of Individuals Below Poverty Level
Corcoran	5,379	8	92.0	$35,712	4.1
Long Lake	1,768	8.9	91.1	$38,310	5.5
Orono	7,437	4.6	95.4	$73,518	0.5
Wayzata	3,688	9.2	90.8	$56,663	10.8
Medicine Lake	371	10.8	89.2	$69,842	1.7
New Hope	20,339	28.6	71.4	$26,104	9.9
Maple Grove	61,567	15.3	84.8	$40,891	3.0

Source: 2010 U.S. Census: General Demographic Characteristics

According to 2010 Census data, Hennepin County has a population of approximately 1.2 million. The population is 71.7 percent Caucasian, with a slightly higher minority population than the state of Minnesota. At $35,902, annual per capita income is slightly higher than the statewide value; however, poverty levels are slightly higher than the statewide value.

The Proposed Project Area includes portions of Medina and Plymouth. The population of Plymouth is more than 14 times larger than the population of Medina. Plymouth also has a higher minority population percentage, a lower per capita income, and a higher percentage of persons living below the poverty level relative to Medina. Both Medina and Plymouth have lower minority populations and populations below the poverty level than Hennepin County.

The 3-Mile Project Assessment Area encompasses portions several municipalities in addition to Plymouth and Medina, including: Corcoran, Long Lake, Orono, Wayzata, Medicine Lake, New Hope, and Maple Grove. Population in this group of municipalities ranges from 371 in Medicine Lake to 61,567 in Maple Grove. With the exception of New Hope, all of these communities have lower minority populations than both Hennepin County and the State of Minnesota. With the exception of New Hope and Corcoran, all of these communities have higher per capita incomes than both Hennepin County and the State of Minnesota. As indicated in **Table 1**, only

Wayzata has higher poverty levels than Hennepin County and the State of Minnesota. Of these communities, Orono, Wayzata, and Medicine Lake all have higher per capita incomes than Plymouth and Medina. With the exception of Orono, all of the additional communities in the 3-Mile Project Assessment Area have higher minority populations than Medina. All of these communities except New Hope have a lower minority population than Plymouth. At 10.8 percent, Wayzata has the highest percentage of the population living below poverty level and at 0.5 percent Orono has the lowest.

Utility personnel or contractors will be used for all construction activities and it is not expected that additional permanent jobs will be created by any of these actions. Construction of the proposed Project will require approximately 10 to 15 workers for transmission line construction and 8 to 12 workers, on average, for substation construction. The transmission line work will take approximately 6 months to construct and the new and modified substation work will take approximately 6 to 12 months to construct.

Socioeconomic impacts resulting from the proposed Project will be primarily positive with a short-term influx of expenditures at local businesses during construction of the proposed Project, and long-term increased tax revenue once the proposed Project is operational. The communities near the Proposed Project Area should experience short-term positive economic impacts through the use of the hotels, restaurants, and other services used by the various workers during the construction of the proposed Project. Materials such as concrete may be purchased from local vendors where feasible.

Mitigative Measures

No socioeconomic impacts are anticipated and therefore no mitigative measures are proposed.

8.4.1 Cultural Values

Cultural values include those perceived community beliefs or attitudes in a given area, which provide a framework for community unity. The cities within the Proposed Project Area, Medina and Plymouth, have strong cultural ties to recreation, with a

diversity of trails, parks, and lakes present within the area. In addition, residents of Medina and Plymouth value the highly regarded school systems, proximity to nearby shopping and entertainment districts, and easy access to Minneapolis and St. Paul. Medina also has cultural values tied to farming.

The communities present within the 3-Mile Project Assessment Area represent a somewhat similar set of cultural values. The cities of Corcoran, Long Lake, Orono, Wayzata, and Medicine Lake are all small suburban communities that value a small town atmosphere with easy access to the amenities of the Twin Cities. With a population of less than 6,000 residents and an area covering 36 square miles, the City of Corcoran has strong cultural ties to its un-crowded open space. The city of Orono is located on the north shore of Lake Minnetonka and high cultural value is placed protecting their natural resources, open space, and recreational assets and preserving the unique mix of urban and rural/recreational character that defines the community. Long Lake values their thriving downtown and easy access to the Twin Cities as well as protecting recreational opportunities on nearby Long Lake and associated parks. The City of Medicine Lake is a small suburb community that values their small town atmosphere and takes pride in the beauty and recreational aspects of Medicine Lake, the second largest lake in the Twin Cities area. Wayzata is also located on the shore of Lake Minnetonka and the city takes pride being a historic lakeside village with a thriving downtown business community, boutique shopping locations, high quality developments and beautiful residential neighborhoods. New Hope and Maple Grove are slightly larger suburban communities but both communities place cultural value on access to recreation as well as preservation of nearby open space, proximity to nearby shopping and entertainment, and access to the Twin Cities.

Mitigative Measures

Construction of the proposed Project is not expected to conflict with the cultural values along the Proposed Route. No impacts to cultural values are anticipated and therefore no mitigative measures are proposed.

8.4.2 Recreation

The Proposed Project Area runs through Medina and Plymouth. Recreational opportunities within the vicinity of the Proposed Project Area include parks, trails,

and bikeways. Two parks are located within the Proposed Project Area; these include Turtle Lake Park and Nature Valley Park, both of which are located in Plymouth. The proposed Project is not expected to directly impact either of these recreational resources.

All parks, recreational areas, and preserves that are located within the 3-Mile Project Assessment Area were also identified. A total of 85 parks, recreation areas, and preserves (identified by municipality) are located within the 3-Mile Project Assessment Area and are summarized in **Table 14**.

Table 14
Parks, Recreational Areas, and Preserves in 3-Mile Project Assessment Area

Municipality	Area Name
Medina	Hamel Legion Park, Holy Name Park, Hunter Lions Park, Lakeshore Park, Maple Park, Medina Lake Preserve, Medina Morningside Park, Rainwater Nature Area, Morris T. Baker, Wolsfeld Woods Scientific and Natural Area, Wood-Rill Scientific and Natural Area*
Plymouth	Bass Lake Playfields, Circle Park, Egan Off-Leash Dog Park, Elm Creek Playfield, Fazendin, Gateway, Green Oaks, Heather Ponds, Heritage Park, Imperial Hills, Jaycee's Hemlock, Lake Camelot, Legacy Greenway, Lions Park, Maple Creek, Mission Hills, Nature Valley, Oakwood Playfield, Parkers Lake Playfields, Plymouth Creek, Plymouth Playfield, Queensland Park, Reserve, Rolling Hills, Schmidt Lake, Shenandoah, Shiloh, Skate Park, Southwood Green, Sunrise Park, Swan Lake, Three Ponds, Timber Shores, Turtle Lake, West Medicine Lake, Woodland Trails, Zachary Playfields, Clifton E. French*, Eagle Lake*
Corcoran	None
Long Lake	Dexter Park, Hardin Park, Holbrook Park, Nelson Lakeside Park
Orono	Chevy Chase Park, Cygnet Park, Hackberry Park, Lee Carlson Baseball Fields, Luce Line Trail, Lurton Park, Seven Nations Park, Summit Park Swimming Beach, Morris T. Baker*, Wood-Rill Scientific and Natural Area*
Wayzata	None
Medicine Lake	City Park (name unknown)

Municipality	Area Name
New Hope	Northwood Park, Holiday Park, Lighted Field, Victory Park
Maple Grove	Basswood Park, Cedar Island Shores, Donahue North, Donahue South, Eagle Lake Woods, Forest Preservation Area B, Grove West, Hemlock Ponds, Hillpointe Hills, Maple Meadows, Maple Tree, Polaris, South Elm Road Park, Thoresen, Timbercrest Forest, Ulster Green, Worden, Eagle Lake*, Fish Lake*

"*"Indicates parks that are located in more than one municipality.

According to the Hennepin County 2011 road and bike map, there are eight locations where bike paths intersect the Proposed Project Area in Medina and Plymouth. In addition, there are networks of trails within the vicinity of the Proposed Project Area. For example, Turtle Lake Park has a network of trails associated with it, some of which are located beneath the existing 69 kilovolt transmission line within the existing corridor. There are regional trails associated with the Clifton E. French Park, which is located on the east side of Interstate 494.

Mitigative Measures

The proposed Project will be visible from the parks in the vicinity of the Proposed Project Area; however direct impacts to these resources are not anticipated. If impacts to these resources are encountered during construction of the proposed Project, the Applicants will work with the appropriate representatives to minimize any impacts.

8.4.3 Public Services and Transportation

Public services and facilities in the 3-Mile Project Assessment Area generally include emergency services provided by government entities, including hospitals, fire departments, and police departments; water supply or wastewater disposal systems; gas and electricity services; and existing and future transportation corridors and projects.

<u>Emergency Services</u>

Any required temporary roadway or lane closures during construction will be coordinated with the local jurisdictions, and will provide for safe access of police, fire, and other rescue vehicles.

Utilities

For the portion of the Proposed Project Area located within City of Plymouth, public sewer and water service is managed by the Plymouth Public Works Department. Along the portion of the route located in Medina, landowners and residences are served by privately owned septic systems and wells. Gas, telephone, internet, and electric services are supplied to residents in the Proposed Project Area by variety of providers.

The 3-Mile Project Assessment Area includes areas served by public sewer and water services as well as areas with private septic systems and wells. Gas, telephone, internet, and electric services are supplied to residents by a variety of providers throughout this assessment area.

Construction and operation of the proposed Project is not anticipated to permanently affect any public service utilities. Where impacts to utilities have the potential to occur, the Applicants will work with landowners, local agencies, and utility providers to determine the most appropriate placement for structures. It may be necessary for the Applicants to work with other public service utilities to relocate their facilities if they conflict with the location of transmission facilities. Disruptions to public services during construction may occur; however, these will be temporary and coordinated with applicable providers.

Transportation

Transportation infrastructure includes roads, railroads, and airports. The Proposed Project Area runs parallel to and crosses roads, including township roads, county roads, and state highways. It is likely that any specific location chosen within the 3-Mile Project Assessment Area or the 1-Mile Project Assessment Area will also run parallel to and cross roads, including township roads, county roads, and state highways.

Operation of the transmission line is not expected to impact traffic along roadways. Structure placement and construction procedures will be developed in consultation with state, county, and local roadway authorities to meet requirements for clear zones and roadside obstructions. Roadways can potentially be impacted temporarily during construction activities and during maintenance of the transmission line. Access during construction and maintenance is expected to be primarily from existing roads and will only cause minor and temporary disruption to traffic. Structure placement along roadways can also impact future road expansions, as structures placed within the right-of-way must be moved to allow a safe distance between structures and the edge of the roadway.

The nearest airport to the Proposed Project Area is the Crystal Airport, which is located approximately 5 miles to the east in the City of Crystal. The Crystal Airport is a publicly owned airport with four runways. Tall high-voltage transmission lines can conflict with the safe operation of public and private airports and air strips. The Federal Aviation Administration ("FAA") and the Minnesota Department of Transportation ("MnDOT"') have each established development guidelines on the proximity of tall structures to public use airports. The FAA has also developed guidelines for the proximity of structures to Very-High-Frequency Omni-Directional Range ("VOR") navigation systems. The Crystal Airport is located more than 5 miles from the proposed Project, therefore construction and operation of the line and substation are not anticipated to impact safe operation and use of the airport.

Mitigative Measures

No impacts on public services and transportation are anticipated and therefore no mitigative measures are proposed.

8.5 Land-Based Economies

8.5.1 Agriculture

Hennepin County has limited economic dependence on agricultural production. According to the 2007 U.S. Department of Agriculture ("USDA") Census of Agriculture, Hennepin County has 582 individual farms, marking a 7 percent decrease in total number of farms over the previous five years. Agricultural lands cover 66,558 acres, representing over 18 percent of all land in Hennepin County with an average farm size of 114 acres. Hennepin County ranks among the top twenty Minnesota counties in the production of nursery, greenhouse, floriculture, and sod products (ranking 3rd statewide); and horses, ponies, mules, burros, and donkeys (ranking 3rd statewide). Over $51 million was generated from both crop and livestock sales in 2007.

A few areas of cropland, dominated by alfalfa and soybeans, are present along the rebuild portion of the Proposed Route in Medina. While permanent impacts to these croplands are not anticipated, temporary impacts may occur during construction of the proposed Project. Construction of the new transmission line structures and removal of existing facilities will require repeated access to structure locations to install foundations, structures, and conductors. Equipment used in this process includes drill rigs, concrete trucks, backhoes, cranes, boom trucks, and assorted small vehicles. Operation of these vehicles on fields can cause rutting and compaction, particularly during springtime and otherwise wet conditions.

Mitigative Measures

Where new easements are required, landowners will be compensated for the use of their land through easement payments. Additionally, to minimize loss of farmland and rural properties and to ensure reasonable access to the land near the structures, the Applicants intend to place the structures approximately 5 feet from, and overhang, the road right-of-way where applicable. When possible, the Applicants will attempt to remove existing facilities and construct the new transmission lines before crops are planted or following harvest.

When possible, spring-time construction will be avoided. However, if construction during spring-time is necessary, disturbance to farm soil from access to each structure location will be minimized by using the shortest access route. This may require construction of temporary driveways between the roadway and the structure, but will limit traffic on fields between structures. Construction mats may also be used to minimize impacts on the access paths and in construction areas. The Applicants' construction teams will work with the property owner, right-of-way agent, and transmission line engineers to minimize the impact on property through use of the owner's knowledge of the property. In addition to payments for new easements that would need to be acquired, the Applicants will compensate landowners for any crop damage and soil compaction that occurs as a result of the proposed Project.

8.5.2 Forestry

There are no federal or state forests located within the 3-Mile Project Assessment Area. There is an approximate 7-acre tree farm located in Medina, southeast of the intersection of Medina Road and Tamarack Drive. This tree farm abuts the existing Great River Energy 69 kilovolt transmission line along the Proposed Route.

Although not considered economically important forest resources, there are several densely forested areas present within the Proposed Project Area and 3-Mile Project Assessment Area. These forested areas are typically associated with wetlands, waterways, and homesteads. Construction of the 115 kilovolt transmission line rebuild and new 115 kilovolt transmission line corridor may require removing trees and vegetation located within existing and new right-of-ways.

Mitigative Measures

To minimize impacts to trees in the Proposed Project Area, the Applicants will limit tree clearing and removal to the transmission line right-of-way, areas that limit construction access to the Proposed Project Area, and areas that impact the safe operation of the facilities. The Applicants will work with landowners to identify concerns related to tree clearing.

8.5.3 Tourism

With the exception of several recreational parks and trails, the Proposed Project Area is not located near any tourist attractions.

Mitigative Measures

No impacts to tourism resources are anticipated and therefore no mitigative measures are proposed.

8.5.4 Mining

There are no gravel pits, rock quarries, commercial aggregate sources, or any other mining resources located within the 3-Mile Project Assessment Area.

Mitigative Measures

No impacts to mining operations are anticipated and therefore no mitigative measures are proposed.

8.5.5 Archaeological and Historical Resources

In May of 2012, a query of the Minnesota State Historic Preservation Office ("SHPO") database was conducted. The SHPO database identified 38 archaeological sites and 233 historical properties within the 3-Mile Project Assessment Area.

All of the archaeological sites are located between one and three miles from the Proposed Route (i.e., none of these sites are located within the Proposed Project Area). The 38 archaeological sites include: 15 lithic scatters, 10 artifact scatters, 4 earthworks, 1 earthwork with a documented human burial, 4 single artifacts, 3 structural ruin/artifact scatter, and 1 cemetery. None of these sites are registered on the National Register of Historic Places ("NRHP"). The eligibility of these inventoried archaeological resources for listing on the NRHP is not known.

Out of the 233 historical properties identified within the 3-Mile Project Assessment Area, 160 historical properties were identified between 1 and 3 miles of the Proposed Route, 72 historical properties were identified between 200 feet and 1 mile of the Proposed Route, and only 1 historical property was identified within the Proposed

Project Area (within 200 feet of the Proposed Route). None of the historical properties are registered on the NRHP; however, two historic properties, both of which are between 1 and 3 miles from the Proposed Route, are identified as Considered Eligible Finding ("CEF") by the SHPO. The eligibility of the remaining historical resources for listing on the NRHP is not known. Due to the developed nature of the 3-Mile Project Assessment Area, it is likely that some of these historical properties have been razed.

Mitigative Measures

The proposed Project will avoid impacts to identified archaeological and historic/ architectural resources to the extent possible, primarily through use of the Proposed Route and existing transmission corridor. Should a specific resource impact be identified, the Applicants will consult with SHPO on whether the resource is eligible for listing in the NRHP. While avoidance will be the preferred action, mitigation for Project-related impacts on NRHP-eligible archaeological and historic resources may include resource investigations and/or additional documentation through data recovery.

8.6 Hydrological Features

8.6.1 Water Quality

Floodplains

Floodplains are associated with waterbodies, watercourses, and wetlands. Within the Proposed Project Area, there are approximately 53 acres of 100-year floodplain and 1.5 acres of 500-year floodplain. Within the 3-Mile Project Assessment Area, there are approximately 7,833 acres of 100-year floodplain and 275 acres of 500-year floodplain.

Wetlands, Waters, and Watercourses

Large wetland complexes and small isolated wetlands are sporadically located throughout the Proposed Project Area and the 3-Mile Project Assessment Area. Wetlands were field reviewed within the Proposed Project Area. Based on the field review, the Proposed Project Area contains approximately 104 acres of wetland,

which represents approximately 23 percent of the area. The majority (94 percent) of these wetlands are freshwater emergent wetlands, dominated by cattails (*Typha* sp.) and reed canary grass (*Phalaris arundinacea*). Hardwood swamps and shrub swamps represent the remaining 6 percent of wetlands in the Proposed Project Area.

Based on the U.S. Fish and Wildlife Service ("USFWS") National Wetland Inventory ("NWI") maps, approximately 11,355 acres of wetland are mapped within the 3-Mile Project Assessment Area; this represents approximately 33 percent of the area. Note that the NWI has not been field verified and sometimes contains inaccuracies; however, it is a good tool for initial wetland identification and assessment. Approximately 55 percent of the wetlands within the 3-Mile Project Assessment Area are classified as freshwater emergent wetlands, with lacustrine (associated with lakes; 23 percent), forested/shrub swamps (18 percent), freshwater ponds (4 percent), and riverine (associated with rivers; <1 percent) wetlands also present.

The MnDNR Public Waters Inventory ("PWI") identifies wetlands, basins, and watercourses over which MnDNR has regulatory jurisdiction. Portions of six PWI wetlands, one PWI Lake (Turtle Lake), and two PWI watercourses (Bassett Creek and an unnamed creek) are present within the Proposed Project Area. Portions of 165 PWI wetlands, 44 PWI basins, and 12 PWI watercourses are present within the 3-Mile Project Assessment Area.

The proposed Project will have minor, mostly short-term effects on surface water resources. Most potential effects on surface waters will be related to reconstruction of the transmission line across wetlands adjacent to the existing transmission corridor. The proposed Project could require wetland and water resource approvals from the U.S. Army Corps of Engineers ("USACE"), MnDNR, and several Local Government Units ("LGU's"). These agencies administer regulatory programs of the federal Clean Water Act ("CWA") and Rivers and Harbors Act, the Minnesota Public Water Resources Act and Utility Crossing Licenses, and the Minnesota Wetland Conservation Act ("WCA").

Mitigative Measures

The Applicants will minimize impacts to watercourses, basins, and wetlands to the greatest extent possible. The Applicants will apply erosion control measures

identified in the MPCA Stormwater Best Management Practices Manual, such as using silt fence, to minimize impacts to adjacent water resources. During construction, the Applicants will control operations to minimize and prevent material discharge to surface waters. If materials do enter streams, they will be promptly removed and properly disposed of to the extent feasible.

Disturbed surface soils will be stabilized at the completion of the construction process to minimize the potential for subsequent effects on surface water quality. Permanent impacts to public waters and wetlands will be avoided wherever feasible by maximizing the typical span length over these areas and minimizing the number of structures within wetlands.

The proposed Project may require waters and wetlands permits, letters of no jurisdiction, or exemptions from the USACE, MnDNR Division of Waters, and LGU's that administer WCA. After coordination and application submission, authorization from the USACE will likely fall under the utility line discharge provision of a Regional General Permit (RGP-3-MN) or a Letter of Permission (LOP-05-MN). The MnDNR Division of Waters requires a Public Waters Work Permit for any alteration of the course, current, or cross-section below the ordinary high water level of a watercourse or PWI watercourse, basin, or wetland. No such alterations are anticipated.

Minnesota Statutes Section 84.415 requires the Applicants to obtain a license from the MnDNR Division of Lands and Minerals for the passage of any utility over, under, or across any state land or public waters. Therefore, the Applicants will either confirm the applicability of existing licenses for these crossings or obtain new utility crossing licenses prior to construction.

The MPCA regulates construction activities that may impact storm water under the CWA. In the event that an NPDES construction storm water permit and Stormwater Pollution Prevention Plan ("SWPPP") are required for the proposed Project, the Applicants will obtain the permit and prepare a SWPPP. An NPDES permit is required for owners or operators for any construction activity disturbing: 1) one acre or more of soil; 2) less than one acre of soil if that activity is part of a "larger common

plan of development or sale" that is greater than one acre; or 3) less than one acre of soil, but the MPCA determines that the activity poses a risk to water resources.

8.7 Vegetation and Wildlife

8.7.1 Vegetation

Table 15 below summarizes land cover within the Proposed Project Area and 3-Mile Project Assessment Area. Land cover in both the Proposed Project Area and the 3-Mile Project Assessment Area consists primarily of developed land, wetlands, forest, and cropland. The dominant vegetation found in wetlands includes reed canary grass, cattail, box elder (*Acer negundo*), and willows (*Salix* sp.). Common species in forested areas include maples (*Acer* sp.), ashes (*Fraxinus* sp.), and oaks (*Quercus* sp.).

Table 15
Land Cover in the Proposed Project Area and 3-Mile Project Assessment Area

Cover Type	Percent Cover within Proposed Project Area	Percent Cover within 3-Mile Project Assessment Area
Forest	11%	18%
Grassland Herbaceous	3%	3%
Shrubland	2%	2%
Herbaceous and woody wetlands	15%	13%
Pasture/Hay/Cropland	9%	9%
Open water	<1%	6%
Developed/Low Intensity	22%	20%
Developed/Medium Intensity	13%	9%
Developed/High Intensity	2%	4%
Developed/Open Space	22%	15%
Barren land	0%	<1%

Source USDA, NASS Cropland Data Layer (2011)

Mitigative Measures

To minimize impacts to vegetation in the Proposed Project Area, the Applicants will limit vegetation clearing and removal to the transmission line and new substation site right-of-ways, areas that limit construction access to the Proposed Project Area, and areas that impact the safe operation of the facilities.

8.7.2 Wildlife

The croplands, wetlands, and forests in the area provide habitat for a variety of wildlife that are commonly found in rural and urban areas. Wildlife that may inhabit the Proposed Project Area and 3-Mile Project Assessment Area include small mammals such as mice, voles, and ground squirrels; large mammals such as white-tailed deer; waterfowl and other birds such as pelicans and egrets, songbirds, raptors, and upland gamebirds; and reptiles/amphibians such as frogs, salamanders, snakes, and turtles.

Wildlife that resides within the construction zone will be temporarily displaced to adjacent habitats during the construction process. It is anticipated that fish and mollusks that inhabit the local watercourses will not be affected by the proposed Project.

The proposed Project may affect raptors, waterfowl, and other bird species. Birds have the potential to collide with all elevated structures, including transmission lines. Avian collisions with transmission lines can occur in proximity to agricultural fields that serve as feeding areas, wetlands, and water features, and along riparian corridors that may be used during migration.

The electrocution of large birds, such as raptors, is more commonly associated with small distribution lines than large transmission lines. Electrocution occurs when birds with large wingspans come in contact with two conductors or a conductor and a grounding device. The Applicant's transmission and distribution line design standards provide adequate spacing to eliminate the risk of raptor electrocution and will minimize potential avian impacts of the proposed Project.

Mitigative Measures

It is anticipated that most wildlife displacement and habitat impacts will be temporary. Consequently, no wildlife population mitigation measures are proposed. Xcel Energy has been working with various state and federal agencies for over 20 years to address avian issues as quickly and efficiently as possible. In 2002, Xcel Energy Operating Companies, including Xcel Energy, entered into a voluntary Memorandum of Understanding ("MOU") with the USFWS to work together to address avian issues throughout its service territories. The MOU sets forth standard reporting methods and the development of Avian Protection Plans ("APP") for each state that Xcel Energy serves. APPs include designs and other measures aimed at preventing avian electrocutions, as described in guidance provided by the Avian Power Line Interaction Committee ("APLIC" 2006) and the guidelines for developing APPs (APLIC and USFWS, 2005). The APP for the Minnesota Territory is complete and retrofit actions for areas with potential avian impacts are underway across the territory. Xcel Energy also addresses avian issues related to transmission projects by working with resource agencies such as the MnDNR and the USFWS to identify areas that may be appropriate for marking transmission line shield wires with bird diverters attempting to avoid areas known as primary migration corridors or migratory resting areas. Great River Energy has also worked with various state and federal agencies in avian issues that have occurred on their projects; this has included bird diverters, APPs and other mitigation measures according to APLIC guidelines.

The proposed Project will be assessed for areas with potential avian issues prior to construction and areas where bird diverters might be warranted will be identified. In general, shield wires are generally the most difficult part of overhead transmission lines for birds to see. The Applicants have successfully reduced collisions on certain transmission lines by marking the shield wires with Swan Flight Diverters ("SFDs"), which are pre-formed spiral shaped devices made of polyvinyl chloride that are wrapped around the shield wire.

8.8 Rare and Unique Natural Resources

The MnDNR Natural Heritage Information System ("NHIS") database (updated May 2011) was queried to obtain the locations of rare and unique natural resources within

the 3-Mile Project Assessment Area. The MnDNR was previously contacted in September 2010 and December 2010 with a request for a NHIS database search and comments regarding rare species and natural communities reported within the 1-Mile Project Assessment Area. The MnDNR provided comments on rare species within the 1-Mile Project Assessment Area on October 21, 2010 and January 13, 2011, stating that they generally agree that significant impacts to state-listed species are unlikely within the 1-Mile Project Assessment Area. On September 29, 2010 the USFWS provided comments on the proposed Project, expressing concerns of impacts to bald eagles (*Haliaeetus leucocephalus*) and golden eagles (*Aquila chrysaetos*).

Table 16 identifies the known occurrences of rare species and sensitive natural communities documented within three miles of the Propose Route. There are no known occurrences of rare species or sensitive natural communities reported within the Proposed Project Area. In addition, no reports of federally-listed species have been documented within the 3-Mile Project Assessment Area.

There are 10 known occurrences of state-listed rare species and sensitive natural communities within the 1-Mile Project Assessment Area, as indicated in **Table 16** below. These records include: seven occurrences of the following four vertebrate species: blanding's turtle (*Emydoidea blandingii*; state-threatened), cerulean warbler (*Dendroica cerulean*; state-special concern), red-shouldered hawk (*Buteo lineatus*; state-special concern), and trumpeter swan (*Cygnus buccinators*; state-threatened); one tamarack swamp; and two terrestrial plant communities (undetermined class).

Within one to three miles of the Proposed Route, there are 32 known occurrences of state-listed rare species and sensitive natural communities, as indicated in **Table 16** below. These records include: 3 occurrences of the vascular plant, American ginseng (*Panax quinquefolius*; state-special concern); 17 occurrences of the following 7 vertebrate species: Acadian flycatcher (*Empidonax virescens*; state-special concern), bald eagle (state-special concern), blanding's turtle, least darter (*Etheostoma microperca*; state-special concern), pugnose shiner (*Notropis anogenus*; state-special concern), red-shouldered hawk, and trumpeter swan; 1 colonial waterbird nesting area; the following native plant communities: a tamarack swamp, two sugar maple forests, seven terrestrial plant communities (undetermined class); and ice deposition (quaternary).

Table 16
Rare and Unique Resources

Common Name	Scientific Name	Number of Occ.	Type	MN Status[1]	State Rank[2]	Last Obs.	Proximity (Miles)
Blanding's Turtle	*Emydoidea blandingii*	1	Vertebrate Animal	THR	S2	2006	0-1.0
Cerulean Warbler	*Dendroica cerulea*	1	Vertebrate Animal	SPC	S3B	1982	0-1.0
Red-shouldered Hawk	*Buteo lineatus*	3	Vertebrate Animal	SPC	S3B,SNRN	2007	0-1.0
Trumpeter Swan	*Cygnus buccinator*	2	Vertebrate Animal	THR	S2B	2010	0-1.0
Tamarack Swamp (Southern)	Tamarack Swamp (Southern)	1	Wetland Community	NA	S3	1996	0-1.0
Native Plant Community	Native Plant Community (Undetermined Class)	2	Terrestrial Community	NA	SNR	1995	0-1.0
American Ginseng	*Panax quinquefolius*	3	Vascular Plant	SPC	S3	1995	1.0-3.0
Acadian Flycatcher	*Empidonax virescens*	1	Vertebrate Animal	SPC	S3B	1997	1.0-3.0
Bald Eagle	*Haliaeetus leucocephalus*	3	Vertebrate Animal	SPC	S3B,S3N	2005	1.0-3.0
Blanding's Turtle	*Emydoidea blandingii*	3	Vertebrate Animal	THR	S2	1986	1.0-3.0
Least Darter	*Etheostoma microperca*	1	Vertebrate Animal	SPC	S3	2006	1.0-3.0
Pugnose Shiner	*Notropis anogenus*	2	Vertebrate Animal	SPC	S3	1948	1.0-3.0
Red-shouldered Hawk	*Buteo lineatus*	3	Vertebrate Animal	SPC	S3B,SNRN	2007	1.0-3.0
Trumpeter Swan	*Cygnus buccinator*	4	Vertebrate Animal	THR	S2B	2010	1.0-3.0
Colonial Waterbird Nesting Site	Colonial Waterbird Nesting Area	1	Animal Assemblage	NA	SNR	1998	1.0-3.0
Tamarack Swamp (Southern)	Tamarack Swamp (Southern)	1	Wetland Community	NA	S3	1996	1.0-3.0
Sugar Maple Forest (Big Woods)	Sugar Maple Forest (Big Woods)	2	Terrestrial Community	NA	SNR	1980	1.0-3.0
Native Plant Community	Native Plant Community (Undetermined Class)	7	Terrestrial Community	NA	SNR	1996	1.0-3.0
Ice Deposition (Quaternary)	Ice Deposition (Quaternary)	1	Ecological	NA	SNR	1980	1.0-3.0

Source: MnDNR NHIS database, 2012. [1]SPC = Special Concern, THR = Threatened, END=Endangered, NA = Not Applicable. [2]Minnesota state rank; ranks range from S1 (in greatest need of conservation action in the state) to S5 (secure under present conditions); S#B and S#N are used for migratory animals, where B = breeding population and N = non-breeding population; SNR = rank not yet assessed.

Mitigative Measures

The proposed Project and construction process will be designed to avoid encroachment and effects on rare species and unique natural resources to the extent practicable. If rare species or unique natural resources will be affected, the Applicants will coordinate with the MnDNR and consider modifying either the construction footprint or the construction practices to minimize impacts. Efforts will be made to minimize potential impacts to occupied eagle nests from construction activities which may include alteration of structure locations or scheduling construction to avoid nesting season.

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