Hiawatha Transmission Line Project

Environmental Report

PUC Docket Number: E002/CN-10-694

Energy Facility Permitting
85 7th Place East, Suite 500
St. Paul, Minnesota 55101-2198
ph 651.296.4026 | fx 651.297.7891
www.energyfacilities.puc.state.mn.us

August 26, 2011

Responsible Government Unit

Department of Commerce
Energy Facility Permitting
85 7th Place East, Suite 500
Saint Paul, Minnesota
55101-2198

Department Representative
Bill Storm
Project Manager
(651) 296-9535

Project Owner

Northern States Power
dba Xcel Energy
414 Nicollet Mall
Minneapolis, Minnesota 55401

Project Representative
Paul J. Lehman
Manager Regulatory Administration
(612) 330-7529

Abstract

Northern States Power Company d/b/a Xcel Energy (Applicant) submitted an application to the Minnesota Public Utilities Commission for a Certificate of Need (CN) to construct approximately 1.4 to 3.8 miles (depending on the final route) of new 115 kV transmission line. The stated purpose of the Hiawatha Project is to meet the distribution needs of Applicant's customers in south Minneapolis, Hennepin County, Minnesota. The Applicant has stated that demand for power has increased beyond the capability of the system due to population growth, higher load density, and recent successful urban revitalization efforts, particularly in the areas along Lake Street, Hiawatha Avenue, and the Chicago and Park Avenue corridors. Additional electrical infrastructure is required to address overload conditions on the distribution system and to improve the reliability of the power supply to residences and businesses. Without new infrastructure, electrical conditions will worsen with time.

Two separate approvals from the Minnesota Public Utilities Commission are required for the construction/operation of the Hiawatha 115 kV transmission line project – a certificate of need (CN) and a route permit. The Applicant submitted a CN application to the Commission on November 9, 2010. The application was accepted as complete by the Commission on February 15, 2011. Xcel Energy submitted a route permit application to the Commission on April 24, 2009. The route permit application was accepted as complete by the Commission on May 26, 2009.

The Energy Facility Permitting staff of the Department of Commerce is responsible for administering the environmental review process. The Commission is responsible for determining if the transmission lines proposed are needed.

Potential routes that the transmission lines would follow, if approved, have been put forth and are being evaluated in the high voltage transmission line (HVTL) Route Permit proceeding.

The environmental review process under the certificate of need procedures includes public information/scoping meetings and the preparation of an environmental review document, the Environmental Report (ER). The environmental report is a written document that describes the

human and environmental impacts of the proposed project, alternatives to the project and methods to mitigate anticipated adverse impacts. The ER must be prepared before the public hearing and before the Commission can make a decision on the certificate of need application.

The content of the environmental report will addresses the issues required in Minnesota Rules 7849.1500, subpart 1, and as determined in the Scoping Decision of April 21, 2011.

Persons interested in these matters can register their names on the Project Docket webpage at http://energyfacilities.puc.state.mn.us/Docket.html?Id=30489 or by contacting Bill Storm, Energy Facilities Permitting, 85 7th Place East, Suite 500, St. Paul, Minnesota 55101, phone (651) 296-9535, e-mail: bill.storm@state.mn.us. Documents of interest can be found at the above website or by going to https://www.edockets.state.mn.us/EFiling/search.jsp and entering "10" and "694" for the CN docket as the year and project identification search criteria.

Following the release of this Environmental Report, a Public Hearing will be held in the project area.

Acronyms, Abbreviations and Definitions

ACSR	Aluminum Conductor Steel Reinforced
ALJ	Administrative Law Judge
Commission	Minnesota Public Utilities Commission
CN	Certificate of Need
CSP	Concentrated Solar Power Systems
CST	Concentrated Solar Thermal
CT	Combustion Turbine
DC	Direct Current
DG	Distributed Generation
DSM	Demand Side Management
EIS	Environmental Impact Statement
ER	Environmental Report
EFP	Department of Commerce Energy Facilities Permitting
EMF	Electromagnetic field
GW	Gigawatt
HCRRA	Hennepin County Rail Road Authority
HVTL	High voltage transmission line
kV	Kilovolt
kW	Kilowatt
mg/L	milligrams per liter – equivalent to parts per million (ppm)
MN DNR	Minnesota Department of Natural Resources
MN DOT	Minnesota Department of Transportation
MPCA	Minnesota Pollution Control Agency
NERC	North American Electric Reliability Council
NESC	National Electrical Safety Code
ppm	parts per million
ROW	Right-of-Way
RPM	Revolution per Minute
RUS	Rural Utilities Service
TES	Thermal Energy Storage

CONTENTS

Abstract i
1.0 Introduction 1
1.1 Project Description 1
1.2 Project Purpose 2
1.3 Sources of Information 2
2.0 Regulatory Framework 3
2.1 Certificate of Need 3
2.2 Route Permit 4
2.3 Scoping Process CN 5
2.4 Public Hearing 6
2.5 Other Permits 6
2.6 Applicable Codes 10
2.7 Issues Outside the Scope of the ER 11
3.0 Proposed Project 12
3.1 Route Width 12
3.2 Rights-of-Way Requirements 13
3.3 Engineering and Design 16
3.4 Construction and Maintenance 19
3.5 Project Implementation/Schedule 22
3.6 Project Costs 23
4.0 Alternatives to the Proposed Project 24
4.1 No Build Alternative 24
4.2 Demand Side Management/Conservation alternative 24
4.3 Purchased Power 26
4.4 Facilities of a Different Size or Type 26
4.5 Upgrading Existing Transmission Lines 27
4.6 Generation Alternatives 27
4.6.1 Fossil Fuel Technologies 28
4.6.2 Renewable Resource Technologies 36
4.6.3 Emerging Technologies 43
4.6.4 Feasibility of Technologies and Alternatives 49
5.0 Potential Impacts of the Proposed Project 52

TABLES

Table 1. Potential Permits/Approval Required 6
Table 2. Overhead Transmission Line Design 17
Table 3. Combustion Turbine Overview 28
Table 4. Combustion Turbine Emissions 29
Table 5. Microturbine Overview 31
Table 6. Microturbine Efficiency 32
Table 7. Microturbine Cost 32
Table 8. Reciprocating Engine Overview 33

Table 9. Reciprocating Engine Emissions 34
Table 10. Photovoltaic Overview 36
Table 11. Storage Technologies Overview 44
Table 12. Fuel Cell Overview 47

FIGURES

Figure 1. General Area Map

APPENDICES

Appendix A. ER Scoping Decision

1.0 Introduction

Xcel Energy (Applicant) has made a application to the Minnesota Public Utilities Commission (Commission) for a Certificate of Need (CN) for the construction of two new distribution substations connected by two new 115 kilovolt (kV) transmission lines in Minneapolis, Hennepin County, Minnesota. The project would be located in a heavily developed urban area known as the Midtown District, located south of downtown Minneapolis.

The Department of Commerce (DOC) Energy Facility Permitting (EFP) staff is tasked with conducting environmental review of applications for certificate of need and route permits. The intent of the environmental review process is to inform the public, the applicant, and decision-makers about potential impacts and possible mitigations for the proposed project and its alternatives.

This document meets the environmental review requirements of the certificate of need procedures (Minn. Rule 7849.1500, subp. 1 and subp. 3) by a) providing information in Section 2 on the regulatory framework, certificate of need and route permit processes; b) describing in Section 3 the proposed project, including design, construction and maintenance; c) discussing in Section 4 the alternatives means of meeting the stated need, and alternatives to the proposed project; and d) summarizing in Section 5 the potential effects on people and the environment of the proposed project.

1.1 Project Description

The total length of the HVTLs would be approximately 1.4 to 3.8 miles long depending on the final route.

Xcel Energy proposes to construct the following facilities:

- A new 115 kV distribution substation near Hiawatha Avenue and 28th Street (Hiawatha Substation),
- A new 115 kV distribution substation near Oakland Avenue South and 29th Street, including the site of the former Oakland Substation (Midtown Substation), and
- Two 115 kV transmission lines between the two new substations. The routes for the transmission lines total approximately 1.4 to 3.8 miles depending on the final route selected.

Potential routes that the transmission lines would follow, if approved, were put forth in the HVTL Route Permit proceeding which is currently on hold (See Section 2 Regulatory Framework). The transmission line routes will be determined through the HVTL Route Permit process expected to recommence following the certificate of need process.

1.2 Project Purpose

The Applicant's stated purpose of the project is to serve the increasing electrical demands of the Applicant's customers in the project area (**Figure 1**) and help tie the distribution system in south Minneapolis to the overall electrical system. The project would increase the capacity of the electrical distribution delivery system and improve the reliability of the power supply to residences and businesses in south Minneapolis (Xcel Energy, 2009).

Prior to the design of the proposed project, the Applicant conducted a study on increasingly significant overload conditions on the distribution system within an approximately 22-square mile area of south Minneapolis. The 22-square mile area was referred to as the Focused Study Area. The boundaries of the Focused Study Area are as follows:

- North Boundary: Highways I-394 and I-94 extending west to east from Cedar Lake to the Mississippi River;
- East Boundary: Mississippi River;
- South Boundary: State Highway 62 extending east to west from the Mississippi River to I-35W; and
- West Boundary: A line from the intersection of I-35W and Highway 62 to the south end of Lake Harriet at West 47th Street to the north end of Cedar Lake near the junction of I-394 and Theodore Wirth Parkway.

The proposed project would expand capacity to the entire Focused Study Area. Typically, distribution substations are located as close as possible to the areas of heaviest load or electrical usage. Through a review of current and projected load in the Focused Study Area, the Applicant determined that the areas within the Focused Study Area experiencing the most frequent overloading and greatest need are in and around Lake Street and Hiawatha Avenue. The highest load density was found to be concentrated around Lake Street, Hiawatha Avenue, and the Chicago and Park Avenue corridors. (Xcel Energy, 2009)

1.3 Sources of Information

Much of the information used in this Environmental Report is derived from documents prepared by Xcel Energy. These include the Certificate of Need Application, November 9, 2010, and the HVTL Route Permit Application, April 24, 2009. Discussion of Electromagnetic Field (EMF) issues came primarily from the white paper developed by the Interagency Task Force led by the Minnesota Health Department, The National Institute for Environmental Health and the World Health Organization. The Final Environmental Impact Statement prepared for the Hiawatha HVTL Route Permit docket (E002/TL-09-38) was relied upon extensively in this ER. Additional information comes from earlier Energy Facility Permitting environmental review documents in similar dockets, other state agencies, such as the Department of Natural Resources, and additional research. First hand information was gathered by site visits along the proposed line.

2.0 Regulatory Framework

In Minnesota, transmission line projects above certain size and length thresholds must go through a two stage regulatory process. First, application is made to the Minnesota Public Utilities Commission for a Certificate of Need (CN). If a CN is granted, the utility must then obtain a Route Permit from the Commission that designates a specific route for the line.

At the time (April 24, 2009) that Xcel Energy submitted its route permit application to the Commission, the project did not meet the size and length thresholds definition of a *large energy facility* as described in Minnesota Statutes Section 216B.2421, subd. 2(2) and (3), and did not require the issuance of a CN by the Commission.

However, this project does falls under the recently enacted statutory provision that requires a CN for transmission projects of this size and length if located in an area with high population density and the proposed transmission lines parallel a below-grade bike and walking path (2010 Minn. Laws, ch. 361, art. 5, sec. 19; Effective Date: May 18, 2010).

Therefore, the Commission must determine whether the HVTLs are necessary and in the best interest of the state through the CN process.

2.1 Certificate of Need

Before any large HVTL can be constructed in Minnesota, the Commission must determine that they are necessary and in the best interest of the state. The certificate of need process includes environmental review and public hearings, and typically takes 12 months. This process is the only proceeding in which a no-build alternative and the size, type, timing, system configuration and voltage of the proposed project will be considered.

The Applicant applied for a Certificate of Need on November 29, 2010; on February 15, 2011 the Commission determined that the application was complete.

A copy of the certificate of need application, along with other relevant documents, can be viewed at the Energy Facility Permitting web page at:

http://energyfacilities.puc.state.mn.us/Docket.html?Id=30489

The Energy Facility Permitting staff is responsible for administering the environmental review process. The Commission is responsible for determining if the transmission lines proposed are needed.

Potential routes that the transmission lines would follow, if approved, are put forth and evaluated in the HVTL route permit proceeding (See Below).

Environmental Review

The environmental review process under the certificate of need procedures includes public information/scoping meetings and the preparation of an environmental review document, the Environmental Report (ER). The environmental report is a written document that describes the human and environmental impacts of the proposed project, alternatives to the project and methods to mitigate anticipated adverse impacts. The ER must be prepared before the Commission can make a decision on the certificate of need application.

2.2 Route Permit

Minnesota Statutes Section 216E.03, subd. 2, provides that no person may construct a HVTL without a route permit from the Commission. An HVTL is defined as a transmission line of 100 kV or more and greater than 1,500 feet in length in Minnesota Statutes Section 216E.01, subd. 4. The proposed transmission lines are HVTLs and therefore a route permit is required prior to construction.

On April 24, 2009, Xcel Energy submitted a HVTL Route Permit application to the Commission for the proposed Hiawatha Transmission project. The application was submitted pursuant to the provisions of the Full Permitting Process outlined in Minnesota Rules 7849.5200 to 7849.5340.

The Commission accepted the HVTL Route Permit Application as complete on May 26, 2009, which marked the beginning of the full permitting review process.

Xcel Energy's application for a HVTL Route Permit is being reviewed by the Commission under Docket TL-09-38. However, due to the recently enacted legislation requiring a Certificate of Need, the HVTL Route Permit proceedings are on hold pending the outcome of this Certificate of Need filing.

The public information/scoping meetings for the route permit application were held on June 18, 2009; a Scoping Decision was released on September 3, 2009. Public hearings were held on April 5 and April 6, 2010; evidentiary hearing were held on April 12 through 21, and April 26 through 30, 2010.

The *Final Environmental Impact Statement* was released on June 4, 2010; the administrative law judge's report was issued on October 8, 2010.

A copy of the HVTL route permit application, along with other relevant documents, can be viewed at the Energy Facility Permitting web page at:

http://energyfacilities.puc.state.mn.us/Docket.html?Id=19981

The EFP is responsible for evaluating the HVTL route permit application and administering the environmental review process. The Commission is responsible for selecting the transmission lines routes and issuing the HVTL route permit.

2.3 Scoping Process CN

On February 11, 2011, EFP sent notice of the place, date and times of the Public Information and Scoping meeting to those persons on the General List maintained by the Commission, the agency technical representatives list and the project contact list. Additionally, on February 11, 2011, Xcel Energy mailed the notice to those persons on their property owners list and local unit of government list.

Notice of the public meeting was also published in local newspapers.

On Wednesday, March 16, 2011, EFP held two public information/scoping meetings at the Plaza Verde Building in Minneapolis. The meetings included two sessions, one starting at 2:00 pm and another starting at 6:00 pm. The purpose of the meetings was to provide information to the public about the proposed project, to answer questions, and to allow the public an opportunity to suggest alternatives and impacts that should be considered during preparation of the environmental review document. Written comments were due no later than Wednesday, April 6, 2011.

Approximately 50 people attended the public information and scoping meetings; 20 individuals took the opportunity to speak on the record. A court reporter was present to document oral statements. Nineteen written comments were received.

A variety of questions were asked and answered during the oral discussion. Topics included: specifics on demand side management (DSM) and conservation efforts (past, present and future), renewable local distributed generation (DG) alternatives, and combining of the various alternatives to meet the stated need; specifics on status of the routing process and weight of the ALJ's report; sources of power generation for this project; and timeline and milestones of the CN application review process.

Written comments included requests that the ER evaluate specific alternatives to the proposed HVTLs, such as, distribution/existing infrastructure solutions, wind power, individual solar installations, combined heat and power, conservation, and energy storage devices.

Many of the written comments also requested that the record (i.e., public comments, environmental report and hearing transcripts) from the routing docket be incorporated into the certificate of need docket.

After consideration of the public comments, the DOC Commissioner issued his Scoping Decision on April 21, 2011. A copy of this order is attached in the **Appendix A**. These items, along with the typical HVTL need issues, were incorporated into the Scoping Decision.

2.4 Public Hearing

The Commission is required by Minn. Rule 7849.5710 subp 1, to hold a public hearing once the ER has been completed. It is anticipated that this hearing will be held in late September, 2011, in the project area, and will be conducted by an Administrative Law Judge (ALJ). The hearing will be noticed separately; docket details can be found online at: http://energyfacilities.puc.state.mn.us/Docket.html?Id=30489.

Interested persons may comment on the ER at the public hearing. Persons may testify at the hearing without being first sworn under oath. The ALJ will ensure that the record created at the hearing is preserved and will provide the Commission with a summary of testimony from the hearing.

Comments received on the Environmental Report become part of the record in the proceeding, but EFP staff is not required to revise or supplement the ER document. A final decision on a route permit will be made by the Commission at an open meeting within a couple of months after the public hearing, depending on scheduling opportunities. The process anticipates a decision within 12 months of application acceptance.

If issued a certificate of need and route permit by the Commission, Xcel Energy may exercise the power of eminent domain to acquire the land necessary for the project pursuant to Minnesota Statute 216E.12 and Minnesota Statute 117.

2.5 Other Permits

Besides the certificate of need, construction of the project will require a High Voltage Transmission Line (HVTL) permit from the Commission (Minnesota Statutes, section 216E.03, subdivision 2). Additional potentially required permits and approvals are listed in **Table 1** below. The table also includes applicable executive orders and regulations that may guide regulating agencies in the permit or approval processes, and standards that require compliance or verification on the part of the Applicant in the design, construction, and operation of the project.

Table 1. Potential Permits/Approval Required

Regulation/Policy	Citation	Description – As Relevant to Project
Federal Regulations and Permits		
Archaeological Resources Protection Act of 1979	16 U.S.C. § 470aa-mm	The Act requires a permit for the excavation or removal of archaeological resources from publicly held or Native American lands. Permitted excavations must further archaeological knowledge and the resources removed are to remain the property of the United States. Tribal consent must be issued if the resource is found on land owned by a Native American tribe.
Clean Air Act	42 U.S.C. § 7401 et seq.	The Act establishes NAAQS for certain pervasive pollutants. The Act establishes limitations on SO_2 and NO_x emissions and sets permitting requirements. Authority for implementation of the permitting program

		is delegated to the MPCA.
Clean Water Act, as amended in 1972	33 U.S.C. 1251 et seq.	The Act contains standards to address the causes of pollution and poor water quality, including municipal and industrial wastewater discharges, polluted runoff from urban and rural areas, and habitat destruction. Section 402 authorizes the issuance of National Pollutant Discharge Elimination System (NPDES) permits. Requires sources to obtain permits to discharge effluents and stormwaters to surface waters. The NPDES permit would be issued by the state of Minnesota.
Determination of No Hazard to Air Navigation	14 CFR 77.19	The FAA must confirm that construction of the Project does not constitute a hazard to air navigation.
Emergency Planning and Community Right-to-Know Act of 1986	42 U.S.C. 11001 et seq.	The Act requires that the Applicant maintain an inventory of specific chemicals used or stored on-site and annually report quantities present or used over applicable threshold.
Endangered Species Act of 1973	16 U.S.C. 1531 et seq.	The Act requires any federal agency authorizing, funding, or carrying out any action to ensure that the action is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of critical habitat of such species.
Highly Erodible Land & Wetland Conservation	7 CFR 12	The regulation sets forth the terms and conditions under which a person who produces an agricultural commodity on highly erodible land or designates such land for conservation use, plants an agricultural commodity on a converted wetland, or converts a wetland shall be determined to be ineligible for certain benefits provided by the USDA and agencies and instrumentalities of USDA.
Migratory Bird Treaty Act	16 U.S.C. 703 et seq.	The Act protects birds that have common migration patterns between the United States and Canada.
National Environmental Policy Act of 1969	42 U.S.C. 4321-4347	The Act requires agencies of the federal government to study the possible environmental impacts of major federal actions significantly affecting the quality of the human environment.
National Historic Preservation Act of 1966	16 U.S.C. 470 et seq.	Under Section 106 of the Act, prior to the approval of the expenditure of any federal funds on the Project or prior to the issuance of any license, the federal agency must take into account the effect of the Project on any district, site, building, structure, or object that is included in or eligible for inclusion in the National Register. The federal agency shall afford the Advisory Council on Historic Preservation established under Title II of the Act a reasonable opportunity to comment with regard to such undertaking.
Noise Control Act of 1972	42 U.S.C. 4901-4918	The Act directs federal agencies to carry out noise control programs in their jurisdictions "to the fullest

		extent within their authority" and in a manner that furthers a national policy of promoting an environment free from noise that jeopardizes health and welfare.
Occupational Safety and Health Act of 1970	29 U.S.C. 651 et seq.	The Act established regulations for the protection of worker health and safety. The Applicant would be subject to OSHA general industry standards and OSHA construction standards.
Pollution Prevention Act of 1990	42 U.S.C. 13101 et seq.	The Act establishes a national policy for waste management and pollution control.
Resource Conservation & Recovery Act	42 U.S.C. 6901 et seq.	The Act regulates the treatment, storage, and disposal of hazardous wastes. The Applicant would be required to manage hazardous wastes generated during construction or operation of the Project in accordance with RCRA.
Safe Drinking Water Act	42 U.S.C. 300	The Act authorizes the USEPA to regulate public drinking water supplies by establishing drinking water standards, delegating authority for enforcement of drinking water standards to the states, and protecting aquifers from hazards such as injection of wastes and other materials into wells. The Act is enforced in the state by the Minnesota Department of Health, who manages applicable permits and registrations.
Executive Orders		
E.O. 12898, Environmental Justice	E.O. 12898	The executive order directs federal agencies to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations.
E.O. 13112, Invasive Species	E.O. 13112	The executive order directs federal agencies to prevent the introduction or to monitor and control invasive non-native species and provide for restoration of native species.
E.O. 13186, Responsibilities of Federal Agencies to Protect Migratory Birds	E.O. 13186	The executive order directs federal agencies to avoid or minimize the negative impacts of their actions on migratory birds, and to take active steps to protect birds and their habitats.
State Regulations and Permits		
Aboveground Storage Tank Registration	Minn. R. 7151	The rule requires that aboveground storage tanks larger than 110 gallons of oil or petroleum products must be registered with the state.
Access Permit	Minn. R. 8810	The rule requires the Applicant to obtain an access permit from MnDOT when access is needed from established MnDOT ROWs.
Cultural Resources Review	36 CFR 800	The federal regulation requires state review under the National Historic Preservation Act.
Drainage Permit	Minn. R. 8810.3200-8810.3600	The rule requires a permit for the repair of utility or rebuilding of structures already in place (e.g., manholes, catch basins).
Easement Across State-Owned Land Managed by the Minnesota Department of Natural Resources	Minn. Stat. 84.63 and 84.631	The statute requires that MnDNR issue an easement to cross state-owned lands for the purposes of construction.

Electrical Inspection	Minn. R. 3800	The rule requires the Project to conform to all applicable electrical codes, enforced by the state.
Environmental Laboratory Certification	Minn. R. 4740.2010	The rule states that if sampling is required under state or federal permits (e.g., NPDES), environmental laboratory certification will be required.
Hazardous Waste Generator License	Minn. R. 7045.0225	The rule requires that if the Project generates greater than 10 gallons of hazardous waste in a calendar year, the Applicant must obtain a license.
License to Cross Public Lands and Waters	Minn. R. 6135	The rule requires a license if utility services are to cross public waters or lands administered by the MnDNR.
Minnesota Endangered Species Law	Minn. R. 6134 and Minn. Stat. 84.0895	The statute requires MnDNR to adopt rules designating species meeting the statutory definitions of endangered, threatened, or species of special concern. The resulting list of Endangered, Threatened, and Special Concern Species is codified as Minn. R. ch. 6134.
Minnesota Field Archaeology Act of 1963	Minn. Stat. 138.31-138.42	The statute establishes the office of the State Archaeologist; requires licenses to engage in archaeology on nonfederal public land; establishes ownership, custody and use of objects and data recovered during survey; and requires state agencies to submit development plans to the State Archaeologist, the Minnesota Historical Society and the Minnesota Indian Affairs Council for review when there are known or suspected archaeological sites in the area.
Minnesota Historic Sites Act	Minn. Stat. 138.661-138.669	The statute establishes the State Historic Sites Network and the State Register of Historic Places, and requires that state agencies consult with the Minnesota Historical Society before undertaking or licensing projects that may affect properties on the Network or on the State or National Registers of Historic Places.
NPDES General Construction Stormwater Permit	40 CFR 122; Minn. R. 7001	The federal regulation authorizes the state environmental agency to regulate NPDES general stormwater permits. Coverage under the state general permit is required for construction projects disturbing greater than one acre of land.
NPDES/SDS Permit	Minn. R. 7001.0020	The rule requires a permit if wastewater generated from the Project is to be discharged to water of the U.S.
Utility Permit on Truck Highway ROW	Minn. R. 8810.3100-8810.3600	The rule requires a permit to install or move existing utilities on existing highway ROWs.
Water Appropriation Permit	Minn. R. 6115.0600-6115.0810; 6115.0010	The rule requires a general notification to the MnDNR if groundwater is withdrawn for construction dewatering, landscaping, or hydrostatic testing. A Water Appropriations Permit will be required if groundwater is withdrawn at a rate greater than 10,000 gallons per day or one million gallons per year.
Local Regulations and Permits		
After Hours Work Permit	City of Minneapolis	The permit is required if construction is to be

	Ordinance 59.30	performed after 6 PM or before 7 AM on weekdays and anytime on weekends or holidays. Permits are issued by the City of Minneapolis Environmental Services Department of Regulatory Services.
Erosion Control Permit	City of Minneapolis Ordinance Chapter 52: Erosion Sediment and Control Ordinance MCWD Rule B: Erosion Control	An erosion control permit is required by the City of Minneapolis and MCWD for any activity that disturbs greater than 5,000 square-feet of land. Under permit requirements, the Applicant will be required to develop and maintain an Erosion Control Plan.
Oversize/Overweight Load Permit	Minnesota Department of Transportation	A permit for oversize, overweight, and over-width vehicles, as may needed during construction, is required from MnDOT.
Permit to Discharge to Storm Drain	City of Minneapolis Ordinance 50.60	A permit is required for all industrial wastewater discharges to the storm drains, as may occur during construction of the Project.

Sources: Xcel Energy, 2009; US Department of Energy, 2007
Notes: EO = Executive Order

Once the Commission issues a Route Permit, local zoning, building and land use regulations and rules are preempted per Minn. Statute 216E.10, subd 1. However, the Applicants are still required to obtain relevant permissions, such as road crossing permits.

2.6 Applicable Codes

The transmission line, regardless of route location, must meet all requirements of the National Electrical Safety Code (NESC) and the Rural Utilities Service (RUS) Design Manual for High Voltage Transmission Lines. These standards are designed to protect human health and the environment. They also ensure that the transmission line and all associated structures are built from high quality materials that will withstand the operational stresses placed upon them over the expected lifespan of the equipment provided normal routine operational and maintenance is performed.

Utilities must comply with the most recent edition of the National Electric Safety Code, as published by the Institute of Electrical and Electronics Engineers, Inc., and approved by the American National Standards Institute, when constructing new facilities or reinvesting capital in existing facilities. See Minn. Statute 326B.35 and Minn. Rule 7826.0300 subp 1.

The NESC is a voluntary utility developed set of standards intended to ensure that the public is protected. The NESC covers electric supply stations and overhead and underground electric supply and communication lines, and is applicable only to systems and equipment operated by utilities or similar systems on industrial premises. For more information, go to standards.ieee.org/faqs/NESCFAQ.html#q1. The RUS provides leadership and capital to "upgrade, expand, maintain, and replace America's vast rural electric infrastructure." For more information, go to http://www.usda.gov/rus/electric/index.htm.

2.7 Issues Outside the Scope of the ER

The following issues will not be considered or evaluated in the ER:

- Route or substation alternatives.
- Generation alternatives that cannot be sited locally (i.e., wind farms, etc.).
- Any alternatives that do not meet the underlying need for or purpose of the project.
- The impacts of specific energy sources, such as carbon outputs, from non-local generating facilities.
- The manner in which land owners are paid for transmission rights-of-way easements.
- Contested issues or disputes of fact with respect to the representations made in the CN application.

3.0 Proposed Project

The total length of the HVTLs would be approximately 1.4 to 3.8 miles long depending on the final route. The stated purpose of the Hiawatha Project is to meet the electrical distribution needs of the Applicant's customers in south Minneapolis, Hennepin County, Minnesota. The Applicant has stated that demand for power has increased beyond the capability of the system due to population growth, higher load density, and recent successful urban revitalization efforts, particularly in the areas along Lake Street, Hiawatha Avenue, and the Chicago and Park Avenue corridors. Additional electrical infrastructure is required to address overload conditions on the local distribution system and to improve the reliability of the power supply to residences and businesses. Without new infrastructure, electrical conditions will worsen with time.

Xcel Energy proposes to construct the following facilities:

- A new 115 kV distribution substation near Hiawatha Avenue and 28th Street (Hiawatha Substation),
- A new 115 kV distribution substation near Oakland Avenue South and 29th Street, including the site of the former Oakland Substation (Midtown Substation), and
- Two 115 kV transmission lines between the two new substations.

Potential routes that the transmission lines would follow, if approved, were put forth in the HVTL Route Permit proceeding which is currently on hold (see above).

In the HVTL Route Permit Application, the Applicant identified four separate alternative transmission line routes (Routes A, B, C, and D) and five design options for consideration by the Commission. Of the transmission line design options, three are overhead (Alignment A1 of Route A, Route B, and Route C) and two are underground (Alignments A2 and A3 of Route A and Route D). Furthermore, the advisory task force (ATF) established in the HVTL Route proceeding identified one additional alternative transmission line route (Route E2), which consists of an overhead design.

Detailed descriptions of each of the five route alternatives and corresponding design options are provided in the *Hiawatha Transmission Line Project Final Environmental Impact Statement* (EIS) dated June 4, 2010.

The transmission line routes will be determined through the HVTL Route Permit process expected to recommence following the certificate of need process, if a CN is granted.

3.1 Route Width

The Power Plant Siting Act, Minnesota Statutes Chapter 216E, directs the Commission to locate transmission lines in a manner that "minimize(s) adverse human and environmental impact while ensuring continuing electric power system reliability and integrity and ensuring that electric energy needs are met and fulfilled in an orderly and timely fashion" (Minn. Stat. § 216E.02,

subd. 1). The Act further authorizes the Commission to meet its routing responsibility by designating a "route" for a new transmission line when it issues a Route Permit. A route may have "a variable width of up to 1.25 miles," within which the right-of-way (ROW) for the facilities can be located (Minnesota Statute, section 216E.01, subdivision 8) (Xcel Energy, 2009).

For this project, the Applicant has requested varying route widths for each of the proposed routes. The final ROW could be sited anywhere within the permitted route. The requested route width for Route A is 200 feet to accommodate placement of the double circuit structures overhead or in underground duct banks along potential Alignments A1, A2, or A3. A double circuited overhead Route E2 would require a route width of 970 feet, primarily to accommodate placement of the transmission line on either side of existing interstate highway ROW. If Route B or C is selected, an 80-foot route width is requested for the single circuit structures. For Route D, an 80-foot route width is requested to accommodate double circuit underground duct banks on either side of the street. Route D is only viable when an underground design is used (Xcel Energy, 2009).

3.2 Rights-of-Way Requirements

ROW requirements vary for overhead and underground design construction. The requirements are based upon National Electrical Safety Code (NESC) clearances from the electrical conductor (i.e., the transmission line) for trees, buildings, or other objects, and take into consideration the lateral movement of overhead transmission lines due to wind. The clearance also allows for occupation safety requirements regarding tree maintenance. ROW requirements for underground transmission line designs allow for construction and maintenance of the concrete duct and splice vaults that the underground transmission lines are installed within. In addition, the clearance limits the planting of vegetation that can potentially interfere with installation. Activities and other installations that do not interfere with the transmission line structure, such as sidewalks or roads, are permissible within the ROW (Xcel Energy, Information Request, 2009).

If the proposed facilities are constructed on an overhead double or single circuit 115 kV transmission line structure, a 50-foot wide ROW would be required. All underground design alternatives would require a 30-foot wide ROW (Xcel Energy, 2009).

All route alternatives, for both overhead and underground construction designs, are located primarily within public street ROW or the HCRRA corridor. Whenever a transmission line is adjacent to a street, the line would share the existing road ROW; therefore, an easement of lesser width would be required from affected landowners, depending on road configuration and structure requirements. It is anticipated that easement acquisition from private landowners would be limited, ensuring adequate clearances for safe operation of the facilities (Xcel Energy, 2009). Underground line ROW evaluation and acquisition would proceed in a manner similar to that of overhead lines, as discussed below.

If a HVTL Route Permit is granted to the Applicant for the preferred or an alternative route, the actual alignment of the conductor may be placed anywhere that would be technically feasible within the requested route width, unless a special condition of the permit specifies otherwise. The Applicant has proposed a potential alignment for each route alternative with corresponding ROWs ranging from 30 to 50 feet to allow the flexibility to accommodate route specific features that may need to be avoided.

The EIS evaluated the impacts of the entire width of the preferred and alternative routes; while emphasis was placed on the potential alignments developed by the Applicant and corresponding ROW for each route alternative.

Right-of-Way Acquisition

The width of ROW required for construction of the project is dependent on the design and location selected. Construction of an overhead transmission line along Alignment A1 or Routes B, C, or E2 would require a 50-foot-wide ROW. Construction of an underground transmission line along Alignments A2, A3, or Route D would require a 30-foot-wide ROW.

For overhead Alignment A1 and Route E2, the transmission line structures would be placed along the centerline of the ROW, with equal widths extending out from either side of the centerline. For double circuit structures with arms on each side of pole, as proposed for Alignment A1 and Route E2, the arms would extend approximately 8 to 9.5 feet from each side of the pole, followed by 3 to 8 feet for the conductors and associated blow out zone. Under NESC code, the ROW must extend an additional 6 feet from the end of the conductors. Thus, a minimum of between 19 and 24 feet of ROW are required on each side of the transmission line pole.

For overhead Routes B and C, the arm and conductor lengths would be similar to those described above for a double circuit pole structure, although the conductor would be located on one side of the pole. To maintain a clearance of 6 feet from the conductor to the edge of the ROW under NESC code, a minimum of between 18 to 23 feet of ROW would be required on the side of the transmission line pole with the conductor. There are no requirements for the width of the ROW extending from the opposite side of the transmission line pole as the conductor. The Applicant has requested a total ROW of 50 feet for the overhead single circuit design to allow sufficient width for maintenance and construction activities.

Exceptions to ROW widths may be required to avoid impacts to existing resources.

In cases where the transmission line structures can be placed adjacent to an existing roadway, the project would share the existing road ROW. Depending on the route selected, and therefore the width of existing roadway ROW, road configurations and structure requirements, easements may be needed from adjacent residential and commercial landowners (Xcel Energy, 2009).

The acquisition of utility easement on private land consists of a multi-step process that involves contacting the land owner, conducting a land survey, preparation of legal documentation, and negotiating and purchase of the easement.

Owners of private land located within the desired ROW easement would be contacted by a ROW agent acting on behalf of the Applicant to discuss the land use needs specific to their parcel and any site-specific concerns of the land owner. Contact with private land owners would occur following the issuance of the Route Permit. The ROW agent would request permission to access the property to conduct a land survey and soil borings. The purpose of the survey is to identify natural features, man-made features, and elevations needed for detailed engineering design of the transmission line (Xcel Energy, 2009).

The ROW agent conducts negotiations with the land owner to acquire easement rights to build, operate, and maintain the transmission line and associated structures. The ROW agent would offer compensation for the easement. The specific location of structures associated with the transmission line would be staked during easement negotiations.

The monetary offer made for the easement would compensate the land owner for any diminution in value of the fair market value of the property due to the encumbrance of the easement (Xcel Energy, 2009). The land owner would be allowed a set amount of time to consider the offer and present the ROW agent with additional information needed to determine the easement's value. If the land owner does not agree with the easement value offered by the ROW agent, the land owner and/or the Applicant may have an appraisal made. Reimbursement for the cost of the appraisal, up to $3,000, could be awarded by the court-appointed Commissioner in the condemnation process, as stipulated in Minnesota Statutes, section 117.189.

The Applicant anticipates that land owner concerns would be addressed and an agreement reached regarding the purchase of land rights. Legal documentation for the acquisition of easement rights would be prepared by the ROW agent. If an agreement cannot be reached regarding the acquisition of easement rights, the Applicant can exercise the right of eminent domain, also referred to as the condemnation process, under Minnesota Statutes, chapter 117.

Under the condemnation process, the Applicant files a Petition in the district court where the property is located. The Petition would be served to all owners of the property. If granted by the courts, a three-person condemnation commission would be established to evaluate compensation for the easement. The three-person committee would be comprised of third-party individuals familiar with real estate issues, who would view the property in question. The commission would conduct a valuation hearing, at which the property owners would be allowed to testify regarding the fair market value or the easement. Following the hearing, the commission would make an award as to the value of the property, which would be filed with the court. Each party is given a 40-day window to appeal to the district court for a jury trial.

After ROW is acquired, the ROW agent would contact all land owners to discuss the construction schedule. If personal property must be moved (temporarily) for the construction of

the project (e.g., property fences), the ROW agent will make the appropriate arrangements with the land owner.

For the acquisition of utility easement on public land, the Applicant would work with applicable local and state agencies to obtain the required approvals and permits.

3.3 Engineering and Design

The project would be designed and constructed to meet the requirements of the National Electric Safety Code (NESC), North American Electric Reliability Corporation (NERC), and all applicable local and state design codes. The specific engineering design of the transmission line and substations would depend on the specific substation locations and route selected and location of the structures within the rights of way (ROW). This section provides an overview of the proposed engineering design of the transmission line and substations. Overhead and underground transmission line designs and aboveground and underground substation designs are discussed independently, due to the differences required in engineering design.

Overhead Transmission Line

Alignment A1 and Routes B, C, and E2 would be constructed as overhead transmission line routes. Alignment A1 and Route E2 would consist of a double-circuit structure with two transmission lines. Routes B and C would require two independent single-circuit transmission lines, due to the available width for a ROW. This section discusses engineering design and maintenance considerations for the overhead transmission lines.

The double-circuit structures associated with Alignment A1 and Route E2 would be constructed as single galvanized steel poles with davit arms. The structures would be bolted to concrete pier foundations. The proposed conductor would be 795,000 circular mils (795 kcmil) 26/7 Aluminum Conductor Steel Reinforced (ACSR) per phase (Xcel Energy, 2009)[1]. The height of the structures would vary based on the exact location of the structures within the ROW and whether additional height is required to avoid impacts to resources. The average height of a tangent double-circuit structure would be 75 feet, and the maximum height 110 feet. The average span distance between structures would be 500 feet (Xcel Energy, 2009).

Structures located at roadways, pedestrian paths, and future rail corridor crossings have not yet been designed due to the uncertainty of the selected route. The average height of a double-circuit dead-end structure would be 80 feet, and the maximum height 115 feet. The average span distance between structures at crossings would be 500 feet, although the span distance would vary based on crossing distances (Xcel Energy, 2009).

The single-circuit structures associated with the two independent lines that would be run along Routes B and C would be single galvanized steel poles with one side of davit arms and

[1] A circular mil is a unit of area used by the NESC. One mil is equal to one thousandth of an inch. One circular mil is the area of a circle with a diameter of one mil.

distribution underbuilt fixtures. The proposed conductor would be 795,000 circular mils (795 kcmil) 26/7 Aluminum Conductor Steel Reinforced (ACSR) per phase (Xcel Energy, 2009). The height of the structures would vary based on the exact location of the structures within the ROW and whether additional height is required to avoid impacts to resources. The average height of a tangent single-circuit structure would be 75 feet. The average span distance between structures would be 500 feet.

It is expected that the majority of pole structures would be placed adjacent to existing paved surfaces where possible. Structure foundations would be finished below-grade to allow for the sidewalk and street curb to be finished up to the surface of the structure base, allowing for more useable surface area on sidewalks.

The average height of a single-circuit dead-end structure would be between 100 and 110 feet. The average span distance between structures would be 500 feet at the crossing, although the span distance would vary based on crossing distances (Xcel Energy, 2009).

Table 2 summarizes the engineering design specifications for project conductors and overhead transmission line structures.

Table 2. Overhead Transmission Line Design

Component	Route	Line Voltage	Structure Type	Pole Type	Conductor	Foundation	Average Span Length	Average Height
Double-circuit tangent	A1& E2	115 kV	Typical	Galvanized steel	795 kcmil 26/7 ACSR	Drilled pier	500 feet	75 feet
Double-circuit dead-end	A1 & E2	115 kV	Crossing	Galvanized steel	795 kcmil 26/7 ACSR	Driller pier/ driven pile	500 feet	80 feet
Single-circuit tangent	B & C	115 kV	Typical	Galvanized steel	795 kcmil 26/7 ACSR	Driller pier/ direct imbed	500 feet	75 feet
Single-circuit dead-end	B & C	115 kV	Crossing	Galvanized steel	795 kcmil 26/7 ACSR	Drilled pier	500 feet	100-110 feet

Underground Transmission Line

Route D would be constructed as an underground transmission line. There is also an alternative that involves placing the line underground along Route A along Alignments A2 and A3. All underground routes would consist of a double-circuited 115 kV transmission line. This section discusses engineering design and maintenance considerations for the underground transmission lines.

Underground transmission lines would be placed in a concrete duct system. The underground line would require two identical concrete duct banks containing four 6-inch PVC conduits for transmission circuits and two 2-inch PVC conduits for ground continuity and communication needs. The duct banks could either be installed adjacent to each other in the same trench or in two separate trenches. The trench design is dependant on physical limitations of the route

selected, including existing subsurface features and available ROW. Manholes placed along the route would be used to pull conductors through the duct system.

The diameter of underground cables is determined by the size of the conductor that carries the load current, the cable's electrostatic shield system, and the insulation thickness (Xcel Energy, 2009). Typically, underground transmission line conductors are twice the size of conductors on overhead transmission lines, due to the limited heat dissipation from cable insulation and below grade encasement (Xcel Energy, 2009). The conductor would be high voltage extruded dielectric cable, 3000 kcmil Copper cross-linked polyethylene type or similar.

Underground cable vaults with manhole access would be required approximately every 1,500 feet and at any changes in the direction of the route. Vaults will allow for installation of the cable and access for inspection and repair. A typical vault with manhole access would be approximately 24 to 25 feet in length by 14 feet wide by 7 to 10 feet in height (Xcel Energy, 2009).

Substations

Engineering design of the Hiawatha Substation would be dependent upon the location selected; however, every Hiawatha substation alternative would require the following equipment:

- Four 115 kV transmission line dead-end structures and related substation equipment and structures (an additional three dead-end structures would be required to connect two of the lines into the correct electrical position in the substation, and one for transformer termination);
- One 50 mega voltampere (MVA), 118-14.4 kV, Load Tap Changer (LTC) distribution transformer;
- One switchgear enclosure containing six 13.8 kV distribution feeders with associated equipment; and
- One electrical equipment enclosure containing all electrical controls, protective relaying and auxiliary equipment for the operation of the substation (Xcel Energy, 2009).

Engineering design of the Midtown Substation would be dependent upon the location selected; however, every Midtown substation alternative would require the following equipment:

- Two 115 kV transmission lines and related substation equipment and structures;
- One 70 MVA, 118-14.4 kV, LTC distribution transformer; and
- One electrical equipment enclosure initially containing nine, 13.8 kV distribution feeders with associated equipment, all electrical controls, protective relaying, and auxiliary equipment for the operation of the substation (Xcel Energy, 2009).

3.4 Construction and Maintenance

Prior to construction of the project, the Applicant would conduct pre-construction soil and land-based surveys, develop location-specific engineering designs, and acquire right-of-way (ROW) easement rights.

Regardless of the route or design selected, similar construction equipment would be required. Equipment that would be used for construction 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 (Xcel Energy, 2009).

Construction of the project would require lay down and staging areas, which may be located outside the project ROW. These areas would be used for the temporary storage of construction materials and equipment. The exact location of lay down and staging areas would be determined once the route is selected. These areas would be temporarily leased from local landowners through rental agreements and would not require permanent ROW or easement acquisition.

Overhead Transmission Line

Overhead transmission line structures would be designed for installation at existing grade, such that construction areas would not be graded or leveled unless the slope of the topography is greater than 10 percent (Xcel Energy, 2009). For areas with a slope greater than 10 percent, fill material would be used to grade the area and create working pads. With the land owner's permission, fill material and working pads would remain at the site for use during future maintenance. If requested by private land owners, imported fill material can be removed following construction and the area graded back to its original condition to the extent possible (Xcel Energy, 2009).

Due to space considerations, the Applicant anticipates that overhead transmission line poles may be erected aerially, meaning that cranes will be used to vertically raise and lower the entire pole structure into place (Xcel Energy, 2009). Steel poles used for overhead transmission line construction would be transported to the ROW on tractor-trailers.

In areas where the transmission line route runs adjacent to an existing roadway, access to the transmission line structures and ROW would be provided from the roadway. Temporary road closures may be required in these situations. In most cases, road closures for construction of the transmission line adjacent to the roadway can be limited to one lane to minimize the disruption to traffic. Road closures may also be required for construction of the transmission line above the roadway at road crossings. During construction of the transmission line over road crossings, the entire road may be temporarily closed and traffic rerouted. Similarly, crossings over the Midtown Greenway may temporarily restrict full use of the Greenway.

Prior to installation of overhead transmission line poles, the structures would be moved from the staging area to the desired installation location. The structures would be stored within the ROW

immediately prior to construction so that insulators and other hardware can be attached while the pole is on the ground. The pole would then be lifted, placed, and secured on the foundation (Xcel Energy, 2009).

Tangent and angle structures associated with single circuit overhead lines (Routes B and C) would be installed through the process of direct embedding. The process consists of digging a hole for each structure, placement of a corrugated metal culvert for soil support into the hole, partially filling the hole with crushed rock, setting the pole on top of the crushed rock base, and backfilling the area around the pole with crushed rock or soil.

Tangent and angle structures associated with double circuit overhead lines (Alignment A1 and Route E2) would be installed on concrete drilled pier foundations. Any dead-end structures or structures that are considered medium or heavy angle would be supported by drilled pier foundations. Drilled pier foundations would be constructed by drilling and excavating of the ground surface in preparation for concrete foundations. Drilled pier foundations would range from 5 to 7 feet in diameter and 20 or more feet deep.

Although the estimated service life of the project for accounting purposes is 40 years, in practicality the Project would not have a specified service end point. The overhead transmission lines would be designed to operate indefinitely with minimal routine maintenance requirements. The transmission line structures would be constructed to withstand severe weather. Repair of the lines may be required in the event of damage from natural disasters in the project area (e.g., tornados). If a fault is sensed on the transmission system, the transmission line would automatically be taken out of service with use of protective relaying equipment. Scheduled maintenance on the transmission line would be infrequent and the average annual availability of the transmission infrastructure is estimated by the Applicant to be over 99 percent (Xcel Energy, 2009).

Semi-annual inspections of the overhead transmission line would be conducted from the ground by representatives of the Applicant. Annual operating and maintenance costs for the transmission line are estimated to be $300 to $500 per mile (Xcel Energy, 2009).

Underground Transmission Line

Two routes involve underground rather than aboveground transmission lines: Route D and Route A along Alignments A2 and A3. In general, construction of underground transmission lines takes longer than construction of overhead transmission lines. Significant background research and engineering and design considerations are required before construction of underground transmission lines. Prior to construction of underground transmission lines, the Applicant would conduct soil sampling and testing to determine the thermal conductivity of the earth and ability to trench and bore in the ROW (Xcel Energy, 2009).

There are several technologies available for the construction of underground transmission lines, including surface-cut open trenching, horizontal boring, and horizontal directional drilling (HDD). The Applicant has stated that trenching is the preferred method because it is the most

easily controlled and cost effective (Xcel Energy, 2009). Open cut trenching is the most commonly used construction technique to install underground duct systems and has been used by the industry since the early 1900s. Depending on the natural features of the Project Area, it may be necessary to shore up the trench for worker safety, dewater the trench due to the presence of shallow groundwater, and backfill the trench with selective fill material to improve heat transfer.

Horizontal boring and directional drilling are often used when the natural landscape makes open trenching difficult. Horizontal boring and directional drilling are used when construction is required to cross ravines, railroad lines, major roadways, and rivers. Although horizontal boring and directional drilling are not expected to be the primary construction techniques, they may be used during construction of the Project depending on the route selected and natural features present. The Applicant has identified the Hiawatha Avenue roadway crossing and Metro Transit Hiawatha Light Rail Line crossing as potential locations where HDD would be required.

HDD was developed in the 1970s as a method to avoid open cut trenching. In the past 30 years, HDD has been used for the installation of transmission lines, cables, and oil, natural gas, and water pipelines. By directionally drilling beneath existing features, HDD would reduce the potential for interference with transportation services during construction.

Construction of underground transmission lines would require installation of a duct system. The majority of underground facilities would consist of two identical concrete duct banks containing four 6-inch polyvinyl chloride (PVC) conduits for transmission circuits and two 2-inch PVC conduits for ground continuity and communication needs. The duct banks could either be installed adjacent to each other within the same trench or in two separate trenches. An extra duct bank would be constructed with extra cable to act as a backup in the event that a fault occurs along the transmission line. The duct system minimizes the length of trench open at any one time, as cables are pulled into the ducts after trench backfilling is completed. To assist in pulling cable through the duct system, manholes would be installed along the duct system.

The Applicant estimates that construction of the initial duct banks would occur at a rate of approximately 200 feet per day (Xcel Energy, 2009). During construction, a safety barrier would enclosure the work area to prevent unauthorized access to the area.

No routine maintenance or operation costs are anticipated for underground transmission lines (Xcel Energy, 2009). Visual inspections of underground transmission lines are not possible and will not be conducted. Unlike overhead transmission lines that are susceptible to a number of sources of outages (e.g., weather, birds, vehicle impacts), underground transmission lines are susceptible to only two outage causes: cable fault due to overloading of the system and failure of the cable or splices. If a fault is sensed on the transmission system, the underground transmission line will need to be accessed.

The time and cost to repair an underground transmission line would be greater than those anticipated for an overhead transmission line. While overhead transmission lines fail, on average, once every 17.8 years, underground transmission lines fail once every 50.5 years (Xcel

Energy, IR Request, 2009). In addition, the average time to resolve a failure on an overhead transmission line is nine hours. The average time to resolve a failure on an underground transmission line is three weeks (Xcel Energy, IR Request, 2009).

Substations

Once the substation sites are graded, a perimeter fence will be erected to secure the sites. Concrete foundations will be poured to support the substation equipment and the control house. After grading, fencing, and foundation work have been completed, the substation and control house erection will commence. The Applicant will also construct permanent access roads to provide for ingress and egress for its substation operating personnel and equipment maintenance. Erosion control methods will be implemented to minimize runoff during construction. The Applicant will comply with all local, state, NESC, and internal standards regarding clearance to ground, clearance to other utilities in the area, clearance to buildings, and other applicable standards.

The project substations would require routine maintenance to ensure they are operating efficiently and within the NESC and NERC requirements. Routine service would be performed on the substation transformers, circuit breakers, batteries, protective relays, and other equipment on an annual or semi-annual basis. Areas surrounding substation equipment must be kept clear of vegetation and proper drainage for the area must be maintained, both of which would require regular upkeep by the Applicant.

The Applicant would monitor the substations remotely through a control center, which is manned 24 hours a day, 365 days a year. Maintenance personnel would be available 24 hours a day to respond to an emergency.

As required under the Applicant's internal substation design standards, a minimum width of 15 feet would be maintained between the perimeter fence and any electrical parts to prevent an individual outside the fence from interfering with electrical equipment. Under NESC Rule 110A2, a 13 foot minimum clearance is required for 115 kV equipment. The 15-foot pathway would also be used for maintenance access.

3.5 Project Implementation/Schedule

The project has a target in-service date of second/third quarter 2013, with pre-construction activities (survey, ROW acquisition, equipment/materials mobilization) to begin first/second quarter 2012, and construction occurring second quarter 2012 and 2013.

This schedule is based on the best information available as of the date of this filing and upon planning assumptions that balance the timing of implementation with the availability of crews, materials, and other practical considerations. This schedule may be subject to adjustment and revision as further information is developed.

3.6 Project Costs

The cost of the project includes materials, construction, right-of-way acquisition and project management. The estimated cost of the project varies depending on the route selected and ultimate design (overhead or underground). The substation cost estimates are based on construction at the Hiawatha West and Midtown North sites.
For the Hiawatha West site, the estimate ($2010) is $15.8 million and is based on a low-profile design and includes $900,000 in private land acquisition costs and $625,000 in estimated relocation costs (fiber optic and rail spur). This estimate does not include acquisition costs for Minnesota Department of Transportation (MnDOT)-owned property.

For the Midtown North site, the 29 substation cost estimate is $11.8 million based on a high profile design and includes $700,000 estimates for land acquisition.

The total cost of the project ranges from $30 to $43 million (using Midtown North and Hiawatha West sites).

The costs of placing transmission lines underground are significantly higher than the standard construction practice of placing the facilities overhead. This is due to the engineering requirements, construction of trenches, and potential dewatering or other pre-installation measures. The incremental cost of undergrounding can be five times the cost of overhead construction, or more, depending upon the specific conditions encountered (Xcel Energy, 2009).

The incremental increased cost of the underground transmission line alternatives when compared to the Applicant's overhead transmission line route alternative, Route A, range from $10.9 million to $13.6 million.

In August of 2009, the Commission requested the Applicant provide an estimate of the monthly surcharges associated with allocating the incremental costs of undergrounding the transmission line to a variety of customer bases including the city of Minneapolis, Hennepin County, the Applicant's entire Minnesota service territory, and an additional subset of customers considered appropriate by the Applicant. The Applicant analyzed payment options for the incremental costs associated with undergrounding by using the City Requested Special Facility Surcharge (CRFS) rates, also known as the facilities surcharge rider, as a model. Timeframes of payment included three and five years. The Applicant chose to model surcharges for the seven-county metropolitan area as the fourth customer base considered appropriate by the Applicant. These calculations are provided in the *Final Environmental Impact Statement* prepared in the HVTL Route Permit proceedings.

4.0 Alternatives to the Proposed Project

In addition to need, the CN process reviews possible alternatives to the proposed project that may be able to fill that need. A general description of these alternatives is required per Minn. R. 7849.1500, Subp. 1 (B). The requirements of this rule include an investigation into the feasibility of the following alternatives:

- The no-build alternative,
- Demand side management,
- Purchased power,
- Facilities of a different size or using a different energy source than the source proposed by the applicant,
- Generation rather than transmission,
- Renewable energy sources

The following section discusses the feasibility and availability of potential alternatives to the transmission line which could eliminate the need for the proposed project.

4.1 No Build Alternative

Under the no build alternative no transmission line would be constructed, nor would the proposed substations be built.

This is not a feasible alternative. This alternative does not address the voltage support issues that are being experienced in the area. Under this alternative it is likely that there would be an unacceptable negative effect on the local economy due to the unreliable electrical service in the area.

4.2 Demand Side Management/Conservation alternative

This alternative would seek to address the need of 55 MW with Demand Side Management (DSM). The alternative would use a slate of energy conservation measures that would ultimately reduce load in the area to a level allowing the current system to operate in a reliable manner. This conservation effort would most likely be phased in, and would be above and beyond the companies' current efforts. In addition, any load growth occurring in the area would also need to be met through aggressive conservation efforts.

The information provided on page 47 of the CN application (and also in more detail at Appendix A.1 at page 79 of 102) indicates that peak demand in the area reached 331 MW in 2006. The impact of this load level on the Xcel Energy's system is illustrated in Figure 24 on page 49 of the application (and described in more detail within Appendix A.1 at page 81 of 102).

Under system intact conditions (N-0), there were 12 circuits that were operating at 100 percent or more of their design capacity. Of those 12 circuits, 4 were operating at more than 115 percent of

their capacity. The 12 circuits were loaded to a total of 12.2 MW over 100 percent of capacity. Figure 24 (and Appendix A.1) of the CN application demonstrates that such severe overloading under system-intact conditions goes back to at least the year 2000.

The information provided on page 81 of Appendix A.1 of the CN application show that, during 2006, Xcel's circuits experienced 54.7 MW of load in excess of the threshold (75 percent use under N-0 conditions) established by Xcel's distribution reliability criterion. Thus, DSM would have to actually reduce total load (rather than reduce the rate of growth) by 54.7 MW (representing a 16.5 percent reduction in load in the study area) to enable all circuits to meet Xcel's distribution reliability criterion of 75 percent capacity use under N-0 conditions. This is the minimum reduction necessary. As growth continues in the area, the total load reduction required will grow.

DSM would have to actually reduce total load (rather than reduce the rate of growth) by 12.2 MW (representing a 3.7 percent reduction in load in the study area) to enable all circuits to operate at less than or equal to 100 percent of capacity.

Xcel Energy has obtained significant energy savings from various conservations programs, including the Conservation Improvement Program (CIP) as required by Minnesota Statutes 216B.241. While the company anticipates futures savings from the continuation of these efforts, conservation alone will not be sufficient to address the significant reliability issue that exists in the area.

In comments on the Certificate of Need Application, Department analyst Dr. Steve Rakow states the following:

> *Xcel's CIP provides tremendous value to Xcel's customers because over time it helps the Company defer and even avoid a significant amount of resources. However, energy conservation is not a good option for providing the load reduction needed in the Hiawatha Project area because:*
>
> 1. *The load reduction is too large to be able to be obtained through energy conservation projects in a small geographic area. In other words, demand reductions in St. Paul will not help alleviate the overloading in the Hiawatha area.*
>
> 2. *The load reduction is needed now. Even if energy conservation over time could provide the load reduction, it would not be able to provide it in a timely manner.*

This is not a feasible alternative given that an unrealistic amount of conservation would have to be achieved in the project area to meet the needs that would otherwise be met by the proposed project.

4.3 Purchased Power

Another alternative generally reviewed in a Certificate of Need case is whether the Applicant could purchase power to meet the increased load growth in the area. Typically, this would be more relevant in a power plant application. In this transmission application, purchased power would not solve any system inadequacies in the area. Power, produced or purchased, would have to be transferred and delivered along an arguably inadequate transmission system.

This is not a feasible alternative as there would still be voltage support issues in the area and it is likely that Xcel Energy would have to upgrade the transmission line in order to deliver purchased power to the area.

4.4 Facilities of a Different Size or Type

The metro distribution system is served off of a 115 kV system, fed through the 345 kV loop. This 115 kV system is interconnected to substations that are specifically designed to accommodate the 115 kV voltages. The standard equipment at substations includes 115 kV/13.8 kV transformers to step down the 115 kV voltage to distribution voltage, 13.8 kV.

A higher voltage transmission alternative such as a 161 kV, 230 kV or 345 kV could provide additional capacity, but it is not anticipated that this capacity would be needed within the next 20 years based on current forecasting analyses. In addition, a higher voltage would require an additional transformer or new type of transformer that would add cost and complexity to the electrical system. For example, if a 161 kV transmission line were constructed, a 115 kV/161 kV transformer would be required at Hiawatha to "step up" the voltage from the Elliot Park – Southtown 115 kV transmission line. If the line from the Midtown Substation were to continue on, it would either need to be converted to 115 kV at Midtown or at the new connection point.

There would also be additional costs associated with a higher voltage.

Xcel Energy in its analysis also considered whether the transmission line between the proposed substations should be constructed so that it would be capable of operating at a higher voltage in the future. It was determined that 161 kV and 230 kV alternatives would not be appropriate because they would not fit well with the 115 kV/345 kV system serving the Twin Cities.

Facilities that would be capable of operation at 345 kV would fit within the standard system, but it is unlikely any additional load serving benefit would be achieved in the future. The 345 kV system is designed to carry large amounts of power to the 115 kV system. A 345 kV voltage would not be advantageous here because it would be a radial line into the Midtown Substation.

In comments on the Certificate of Need Application, Department analyst Dr. Steve Rakow concludes:

> *…that Xcel's proposed type is reasonable because:*

- *Use of any other voltage would require the addition of transformers at the Hiawatha substation, substantially increasing the total cost;*
- *Use of a DC design is not a realistic option for short, low voltage transmission lines; and*
- *Use of the Aluminum Conductor Steel Reinforced (ACSR) and potentially composite conductors enables the need to be met within the restricted right-of-way available*

4.5 Upgrading Existing Transmission Lines

While the Hiawatha 115 kV HVTL project would not normally require a CN, Xcel Energy did evaluate the use of non-CN transmission and distribution alternatives to met the identified need. Further, the *South Minneapolis Electric Distribution Delivery System Long-Term Study* (Distribution Study) provided in Appendix A.1 of the CN application reviewed equal and lower voltage alternatives and concluded that the Hiawatha 115 kV HVTL project was the best alternative. Also, the *South Minneapolis Interconnection* Study (Transmission Study) provided in Appendix A.2 of the CN application also reviewed alternatives of an equal or lower voltage and concluded that the Hiawatha project was the best alternative.

In comments on the Certificate of Need Application, Department analyst Dr. Steve Rakow states that the "*lower voltage alternatives are inferior to the Hiawatha Project*" based upon a review of the Distribution Study and Transmission Study.

4.6 Generation Alternatives

Transmission lines have the ability to operate more than 99 percent of the time. This reliability level is one of the benefits of constructing transmission lines as opposed to generation, assuming adequate grid capacity. Any generation alternative to the transmission line would be required to generate approximately 55 MW of capacity for delivery to the area.

Additionally, the generation would also have to be sited locally (i.e., distributed generation) to avoid the need for the transmission lines and substations.

Distributed generation (DG) refers to the placement of individual, smaller sized electric generation units at residential, commercial, and industrial sites of use. Typically, electricity is generated in large, centralized power plants. However, deregulation in the electricity industry, coupled with new technology and environmental regulations have resulted in the development of distributed energy resources. This refers to the practice of generating electricity on-site, instead of in a large centralized power plant. Distributed generation offers opportunities across all sectors, from very small residential and commercial on-site generators, to larger output industrial generators.

DG can take many forms, from small, low output generators used to back up the supply of electricity obtained from the centralized electric utilities, to larger, independent generators that

supply enough electricity to power an entire factory. Distributed generation is attractive because it offers electricity that maybe more reliable, more efficient, and cheaper than purchasing power from a centralized utility, depending on the site specifics situation. DG also allows for increased local control over the electricity supply, and cuts down on electricity losses during transmission.

4.6.1 Fossil Fuel Technologies

Simple Cycle Natural Gas Combustion Turbine

Combustion turbines (CT) are one of the primary workhorses of the power industry. Nearly all new central station power plants use combined cycle combustion turbines. Smaller CTs have characteristics favorable for use in distributed energy resource applications and because of this, are frequently used by independent power producers.

Small combustion turbines are found in a broad array of applications including mechanical drives, base load grid-connected power generation, peaking power, and remote off-grid applications. CTs can also be used in cogeneration applications usually with the addition of a heat recovery steam generator. Combustion turbines are also available in transportable configurations allowing the plant to be moved from one location to another.

The need for the proposed facilities arise under peak conditions, therefore it seems appropriate to evaluate the option of meeting the stated deficiency with a peaking unit such as a natural gas, single cycle combustion turbine (CT) generator.

Conventional combustion turbine generators are a very mature technology. They typically range in size from about 500 kW up to 25 MW for DG, and up to approximately 250 MW for central power generation. They are fueled by natural gas, oil, or a combination of fuels (dual fuel).

Modern single-cycle combustion turbine units typically have efficiencies in the range of 20 to 45 percent at full load. Efficiency is somewhat lower at less than full load.

Table 3. Combustion Turbine Overview

Combustion Turbine Overview	
Commercially Available	Yes
Size Range	500 kW - 25 MW
Fuel	Natural gas, liquid fuels
Efficiency	20-45% (primarily size dependent)
Environmental	Very low when controls are used
Other Features	Cogen (steam)
Commercial Status	Widely Available

There are three main components in a combustion turbine generator:

1. Compressor - incoming air is compressed to a high pressure.
2. Combustor - fuel is burned, producing high-pressure, high-velocity gas.
3. Turbine - energy is extracted from the high-pressure, high-velocity gas flowing from the combustion chamber.

Combustion turbines are available in a wide range of sizes (500 kW - 25 MW) with most commercial products falling in the 1 - 7 MW size range. Simple cycle turbines have efficiencies generally in the range of 20 – 45 percent. Heavy frame turbines have slightly lower efficiencies (20 – 34 percent) than the aero derivative turbines (26 – 45 percent). While several factors influence efficiency, it generally scales proportionately with size; the larger the turbine the higher the efficiency.

Combined cycle combustion turbines can reach efficiencies of up to 55 percent (LHV). However, these are larger units generally utilized in central power plant arrangements, rather than distributed generation.

Uncontrolled emission levels for combustion turbines are approximately 150 - 300 ppm NOx, but domestic regulations prevent such units from operating in the U.S. Emission control systems are used to reduce NOx emissions to approximately 6 ppm for natural gas turbines:

Table 4. Combustion Turbine Emissions

Natural Gas Turbine	NOx Emissions (ppmv - 15% O2)
Uncontrolled	150 – 300
Dry Low NOx	25
Dry Low NOx plus SCR	~ 6

Other performance related items for combustion turbines include:

- Part load efficiencies (50 percent load) are approximately 25 percent lower than full-load efficiencies.
- Start up times range from 2 to 5 minutes.
- Combustion turbines require natural gas pressure range from about 160 psig up to about 610 psig, depending on the manufacturer, type, and size of turbine.
- Most combustion turbine applications require a gas compressor which reduces the plant power output by 2 – 4 percent.
- CTs are rated based on standard conditions at sea level. Output and fuel consumption will decrease about 3.5 percent for every 1000 feet above sea level.
- CTs are rated at a nominal temperature of 59°F, and their output decreases by 0.3 to 0.5 percent per °F increase in ambient temperature.
- Heat rate increases about 0.1 to 0.2 percent for every 1 degree F increase in turbine inlet temperature.

Gas turbines are relatively inexpensive compared with other DER technologies. Capital costs range from $300-$1000/kW and tend to increase with decreasing power output. Compared with reciprocating engines, combustion turbines tend to cost more for smaller sizes and less at the larger sizes. Capital costs have remained fairly stable recently, showing less than a 5 percent increase over the past 3 years.

Installation costs, balance-of-plant equipment costs and other miscellaneous costs increase upfront costs by 30-50 percent. Unless a CT can connect directly to a high-pressure pipeline, a natural gas compressor is needed to meet minimum pressure requirements of the combustion turbine; compressors increase upfront costs by 5-10 percent.

Adding heat recovery capabilities increases the capital cost by $100-$200/kW. Including other balance-of-plant components, the typical installed cost of a mid-sized gas turbine with a heat recovery unit is in the $1,000-$1,200/kW range.

Since a simple cycle combustion turbine generator would be expected to be available (capacity factor) no more than 95 percent of the time, to replicate the 99 percent reliability found in transmission, redundant generation would need to be installed. For example, to achieve the necessary reliability of generation to address the 55 MW deficit identified in the Focused Study Area using simple cycle CT, four units would be required, each with a generation output of 20 MW. At any point in time, three of the four units must be available to provide at least 55 MW of output.

Additional generators would be required as load grows beyond 55 MW.

Xcel Energy has stated that new generation at multiple locations will not correct the distribution feeder circuit overloads. The more than 30 feeder circuit overloads operate as radial circuits and each has a smaller capacity than any of the contemplated 20 MW generators. Generation also would not obviate the need for new facilities. If only generation were installed, the generators would have to connect to the Southtown Substation, which would require expansion of the substation (and possible relocation of adjacent businesses), a step up transformer and a transmission line to connect to the substation.

Xcel Energy concluded that natural gas CTs, would not be a reasonable alternative because of the associated cost. Applying single cycle equipment-only prices from *Gas Turbine World (2010 GTW Handbook)* and assuming typical industry costs of approximately an additional 50 percent for site and plant engineering, labor, and contractor costs, the generation required to achieve comparable reliability to transmission would require a roughly $86 million investment ($2010) (four 20 MW plants at $21.5 million each). These costs do not include the cost of installation of gas lines, the fuel necessary to operate the units, site acquisition costs or annual operating labor and maintenance costs.
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).

Natural Gas Micro-Turbine

Microturbines are small combustion turbines that produce between 25 kW and 500 kW of power. Microturbines were derived from turbocharger technologies found in large trucks or the turbines in aircraft auxiliary power units. Most microturbines are single-stage, radial flow devices with high rotating speeds of 90,000 to 120,000 revolutions per minute. However, a few manufacturers have developed alternative systems with multiple stages and/or lower rotation speeds.

Microturbines are nearing commercial status. Capstone, for example, has delivered over 2,400 microturbines to customers (2003). However, many of the microturbine installations are still undergoing field tests or are part of large-scale demonstrations.

Table 5. Microturbine Overview

Microturbine Overview	
Commercially Available	Yes (Limited)
Size Range	25 – 500 kW
Fuel	Natural gas, hydrogen, propane, diesel
Efficiency	20 – 30% (Recuperated)
Environmental	Low (< 9 – 50 ppm) NOx
Other Features	Cogen (50 – 80°C water)
Commercial Status	Small volume production, commercial prototypes now.

Microturbine generators can be divided in two general classes:

- Recuperated microturbines, which recover the heat from the exhaust gas to boost the temperature of combustion and increase the efficiency, and
- Unrecuperated (or simple cycle) microturbines, which have lower efficiencies, but also lower capital costs.

Microturbines can be used for stand-by power, power quality and reliability, peak shaving, and cogeneration applications. In addition, because microturbines are being developed to utilize a variety of fuels, they are being used for resource recovery and landfill gas applications. Microturbines produce between 25 and 500kW of power and are well-suited for small commercial building establishments such as: restaurants, hotesl/motels, small offices, retail stores, and many others.

Table 6. Microturbine Efficiency

Microturbine Efficiency	
Configuration	**Efficiency**
Unrecuperated	15%
Recuperated	20-30%
With Heat Recovery	Up to 85%

Commercial microturbines used for power generation range in size from about 25 kW to 500 kW. They produce both heat and electricity on a relatively small scale. The fuel-energy-to-electrical-conversion efficiencies are in the range of 20 to 30 percent. These efficiencies are attained when using a recuperator (a device that captures waste heat to improve the efficiency of the compressor stage). Cogeneration is an option in many cases as a microturbine is located at the point-of-power utilization. The combined thermal electrical efficiency of microturbines in such cogeneration applications can reach as high as 85 percent depending on the heat process requirements.

Unrecuperated microturbines have lower electrical efficiencies at around 15 percent.

Table 7. Microturbine Cost

Microturbine Cost	
Capital Cost	$700-$1100/kW
Operation &Maintenance Cost	$0.005-0.016/kW
Maintenance Interval	5000-8000 hrs

Microturbine capital costs range from $700/kW for larger units to approximately $1,100/kW for smaller ones. These costs include all hardware, associated manuals, software, and initial training. The addition of a heat recovery system adds between $75 - $350/kW. Site preparation and installation costs vary significantly from location-to-location but generally add 30-70 percent to the total capital cost.

Microturbine manufacturers are targeting a future capital cost below $650/kW. This appears to be feasible given the market expands and sales volumes increase.

With fewer moving parts, microturbine vendors hope their units can provide higher reliability and require less maintenance than conventional reciprocating engine generators. Manufacturers expect that initial units will require more unexpected visits, but as the technology matures, a once-a-year maintenance schedule should suffice. Most manufacturers are targeting maintenance intervals of 5,000-8,000 hours.

Actual maintenance costs and intervals for mature microturbines are less well known since there is a limited base of empirical data from which to draw conclusions. Estimated forecasts range from $0.005-$0.016 per kWh, which would be comparable to costs for small reciprocating engine systems.

Extensive field test data collected from units currently in use at commercial and industrial facilities will provide manufacturers with the ability to improve the microturbine design, lowering costs and increasing performance, in order to produce a competitive distributed generation product. Utilities, government agencies, and other organizations are involved in collaborative research and field testing. In addition, manufacturers are moving toward packaging microturbine generators with integrated heat recovery equipment to lower both the cost of installation and operation.

Reciprocating Engines

Reciprocating engines are the most common and most technically mature of all DG technologies. They are available from small sizes (e.g., 5 kW for residential back-up generation) to large generators (e.g., 7 MW). Reciprocating engines use commonly available fuels such as gasoline, natural gas, and diesel fuel.

Table 8. Reciprocating Engine Overview

Reciprocating Engines Overview	
Commercially Available	Yes
Size Range	5 kW – 7 MW
Fuels	Natural gas, diesel, landfill gas, digester gas
Efficiency	25 – 45%
Environmental	Emission controls required for NOx and CO
Other Features	Cogen (some models)
Commercial Status	Products are widely available

A reciprocating, or internal combustion engine (ICE) converts the energy contained in a fuel into mechanical power. This mechanical power is used to turn a shaft in the engine. A generator is attached to the ICE to convert the rotational motion into power.

There are two methods for igniting the fuel in an ICE. In spark ignition, a spark is introduced into the cylinder (from a spark plug) at the end of the compression stroke. Fast-burning fuels, like gasoline and natural gas, are commonly used in SI engines. In compression ignition, the fuel-air mixture spontaneously ignites when the compression raises it to a high-enough temperature. Compression ignition works best with slow-burning fuels, like diesel. ICEs are also classified as high-speed, medium-speed, or low-speed:

- High-speed units are derived from automotive or truck engines and operate at 1200-3600 rpm. These engines generate the most output per unit of displacement and have the lowest capital costs, but also have the poorest efficiency.
- Medium-speed engines are derived from locomotive and small marine engines, and operate at 275-1000 rpm, have higher capital costs, but also have greater efficiency.
- Low-speed units are derived from large ship propulsion engines and operate at 58-275 rpm. Low-speed engines are designed to burn low-quality residual fuels and are practical only if there is a large price differential between heavy oil and natural gas and there are no environmental restrictions (not in U.S.).

Reciprocating engines can operate on a wide spectrum of fuels including natural gas, diesel, landfill gas, digester gas, etc. With proper maintenance, large engines can last for 20-30 years while smaller engines (<1 MW) tend to have shorter lifespans.

Reciprocating engines have efficiencies that range from 25 to 45 percent. In general, diesel engines are more efficient than natural gas engines because they operate at higher compression ratios.

In the future, engine manufacturers are targeting lower fuel consumption and shaft efficiencies up to 50-55 percent in large engines (>1 MW) by 2010. Efficiencies of natural gas engines, in particular, are expected to improve and approach those of diesel engines.

Uncontrolled NOx emissions from ICEs (especially diesel engines) are the highest among DER technologies. Emission rates for a particular type and size ranges of engines vary from manufacturer to manufacturer. Similarly, emission rates for each type of engine within a manufacturer's product line may vary considerably from the smallest to the largest units in the line. Reasons for these variations include differences in combustion chamber geometry, fuel air mixing patterns, fuel/air ratio, combustion technique, and ignition timing from model to model. Selected NOx and CO emission levels for reciprocating engines are listed in the table below:

Table 9. Reciprocating Engine Emissions

Reciprocating Engine Emissions		
	Natural Gas ICE	Diesel ICE
	Exhaust gas, ppmv @15% O2	Exhaust gas, ppmv @15% O2
Uncontrolled NOx	45-200	450-1,600
NOx with SCR	4-20	45-160
Uncontrolled CO	140-700	40-140
CO with Oxidation Catalyst	10-70	3-13

Three basic types of post-combustion catalytic control systems for ICEs include:

1. Three-Way Catalyst (TWC) Systems - reduce NOx, CO and unburned hydrocarbons by 90 percent or more. TWC systems are widely used for automotive applications.

2. Selective Catalytic Reduction (SCR) - SCR is normally used with relatively large (>2 MW) lean-burn reciprocating engines. In SCR, a NOx-reducing agent, such as ammonia is injected into the hot exhaust gas before it passes through a catalytic reactor. The NOx can be reduced by about 80-95 percent.
3. Oxidation Catalysts - promote the oxidation of CO and unburned hydrocarbons to CO2 and water. CO conversions of 95 percent or more are readily achieved.

Other performance-related items for reciprocating engines include:

- Startup times range between 0.5 and 15 minutes
- They have a high tolerance for starts and stops
- Compared with combustion turbines, a lower amount of waste heat can be recovered.
- Engine performance ratings are based on an elevation of 1500 feet above sea level. Deratings of about 2-3 percent for each additional 1000 feet are common.
- Deratings of 1-2 percent for every 10°F above the reference temperature (usually 90°F) are common.
- IC engine heads and blocks are rebuilt after about 8,000 hours of operation
- Regular oil and filter changes are required at 700 - 1000 hours of operation

Reciprocating internal combustion engines are the traditional technology for emergency power all over the world. They have the lowest first costs among DG technologies. The capital cost of a basic gas-fueled generator set (genset) package ranges from $300-$900/kW, depending on size, fuel type , and engine type. Overall engine cost ($/kW) increases with size.

The total installed cost can be 50-100 percent more than the engine itself. Additional costs include balance-of-plant equipment, installation fees, engineering fees, and other owner costs.

Natural gas is usually less expensive than diesel fuel for the same heat content. If the IC engine is to be used for a large number of hours per year, the total cost to operate the gas unit may be lower. Natural gas may not be available at all locations, while diesel can be transported anywhere. However, diesel engine emission levels are higher and their use maybe significantly restricted.

Maintenance costs of gas and diesel ICE range between $0.007-$0.015/kWh and $0.005-$0.010/kWh respectively.

Reciprocating engines are a widespread, well-known, and mature DG technology. They currently offer low capital cost, rapid start-up, proven reliability, good load-following characteristics, and heat recovery potential. Significant research and development efforts are underway to continue to improve the efficiency and reduce the emissions of reciprocating engines. Two significant programs are the Advanced Reciprocating Engine Systems (ARES) and the Advanced Reciprocating Internal Combustion Engines (ARICE) programs.

The mission of the ARES program (sponsored by the Department of Energy) is to lead a national effort to design, develop, test and demonstrate a new generation of reciprocating engine systems for DG applications that is cleaner, more reliable, and efficient than products that are commercially available today.

4.6.2 Renewable Resource Technologies

Minnesota Statutes 216B.243, subd. 3a states, in part, that the Commission may not issue a certificate of need for a large energy facility 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 than power generated by a renewable energy source.

For purposes of this subdivision, "renewable energy source" includes hydro, wind, solar, biomass and geothermal energy.

As stated in Section 4.6 of this document, generation alternatives must be sited locally (i.e., distributed generation) to avoid the need for the transmission lines and substations; this would eliminate hydro and wind generation from further consideration.

Solar
Solar energy technologies include two concepts, photovoltaic and solar thermal.

Photovoltaic Cells

Photovoltaic (PV) cells, or solar cells, convert sunlight directly into electricity. PV cells are assembled into flat plate systems that can be mounted on rooftops or other sunny areas. They generate electricity with no moving parts, operate quietly with no emissions, and require little maintenance. However, the cost is currently too high for bulk power applications.

A photovoltaic cell is composed of several layers of different materials. The top layer is a glass cover or other encapsulant to protect the cell from weather conditions. This is followed by an anti-reflective layer to prevent the cell from reflecting the light away.

Table 10. Photovoltaic Overview

Photovoltaic Overview	
Commercially Available	Yes
Size Range	<1 kW -100 kW.
Fuel	Sunlight
Efficiency	5-15%

Environmental	No emissions
Commercial Status	Commercially deployed, advanced PV films under development

Two semiconductor layers in the solar cell create the electron current. Materials, such as silicon, are suitable for making these semiconducting layers, and each has benefits and drawbacks for different applications.

In addition to the semiconducting materials, solar cells consist of two metallic grids or electrical contacts. One is placed above the semiconducting material and the other below. The top grid or contact collects electrons from the semiconductor and transfers them to the external load. The back contact layer is connected to complete the electrical circuit.

Photovoltaic systems are available in the form of small rooftop residential systems (less than 10 kW), medium-sized systems in the range of 10 to 100 kW, and larger systems above 100 kW connected to utility distribution feeders. The U.S. government launched a program to encourage the installation of 1,000,000 roof-top photovoltaic arrays over 10 years.

Commercially available photovoltaic modules range from about 5 to 15 percent efficiency at converting sunlight into energy. Efforts are currently under way to improve photovoltaic cell efficiencies.

An individual photovoltaic cell will typically produce between 1 and 2 watts. To increase the power output, several cells are interconnected to form a module. Similarly, modules can be connected to form an array. A photovoltaic array surface area the size of roughly two football fields could produce 1000 kW DC peak power.

Nationally, PV systems cost between $6,000-$10,000/kW installed. The cost of a PV system depends on the system's size, equipment options and installation labor costs. Prices vary depending on other factors as well, such as the PV provider, whether or not your home is new, if the PV is integrated into the roofing materials or mounted on top of the existing roof, and the PV manufacturer.

The average factory price of PV modules is about $4/watt, excluding balance-of-system costs. BOS costs increase the factory costs by 30-100 percent. Major balance-of-system cost items include:

- Control equipment (e.g. maximum power point trackers, inverters, battery charge controllers, etc.)
- PV array support structures
- PV array to field wiring
- PV panel to array wiring
- Disconnects
- Panel protection diodes

- Batter storage if present
- Installation and fees
- Insurance
- Data acquisition system and sensors

The United States has approximately 1.1 Gigawatts (GW) of installed solar capacity, based on data from 2008, which was a 63 percent increase over 2007. Increases in solar energy development are expected to increase substantially as the cost of technology decreases and as incentives are increased (mostly through investment tax credits and rebate programs). The solar market in the U.S. comprises only 8 percent of cumulative installed solar capacity worldwide.

In Minnesota, the average solar resource is about 4.5 kilowatt-hours per square meter per day. Within the state, solar resources vary only about 10-15 percent, from the highest in the southwest to the lowest in the northeast. Solar energy varies significantly throughout the year, especially in northern climates based on the number of hours of daylight and cloud cover. Solar panels with tilt angles can increase output during winter months.

Minnesota currently has approximately 4 MW of solar PV installations statewide with over 600 installations. Current prices range from approximately $7.50 per watt for smaller systems and $4.50-$5.00 per watt for mid-sized projects (40-100 kW). Generation costs range from .33-.77 cents /kWh for solar compared to .03-.07 cents/kWh for generation from conventional sources. The average ratepayer in Minnesota pays approximately .10-.15 cents/kWh, which includes the cost of generation, transmission, and distribution of electricity.

Minnesota has sufficient solar resources for solar electric generation, and currently available solar technology is widely available for both commercial and residential installation. Based on the analysis performed by the Department of Commerce for the Certificate of Need, DG solar installations of 55 MW would be required to meet the current deficit identified in the study area.

Within the study area, there are 61,121 parcels and 2,293 city blocks. The total area is approximately 24.6 square miles. If a "solar farm" were to be constructed within the area to meet the existing need, approximately 22 city blocks would be required. This assumes a 400 square foot solar array with a capacity of 4.6 kW, or 11.2 watts per square foot. This solar farm would only satisfy existing load need, not future load growth. The cost of a 55 MW solar array would cost approximately $310 million.

Solar Thermal

The simplest form of solar thermal is the solar hot water system; more than one-half million solar hot water systems have been installed in the United States, mostly on single-family homes. The majority of these systems are used to heat swimming pools.
Typically, a homeowner relying on electricity to heat water could save up to $500 in the first year of operation by installing a solar water heating system. The savings over time increases due

to increasing electricity rates. The average solar heating system pays for itself in four to seven years.

Operation involves cold water from the home's regular water line being pumped to the roof mounted unit, where it enters the thermal energy collector. Sunlight strikes the collector, and the sun's heat warms the water. The heated water comes back into the home or business.

Inside, the warmed water from the roof is collected in a "solar" tank, which has temperature sensors and other mechanisms. The warm water from the solar system then goes into the regular hot water system. Because the regular hot water system (either electric or gas heated) is heating warmer water, you don't have to heat it as much as if it were plain cold water. If no one turns on a hot water tap, the water is circulated back to the roof to be heated even more. During the night, the system can be set up so that water is not pumped to the roof, preventing heat loss to the cool outside air.

Roof-mounted solar hot water systems are often designed to look like skylights, making them more pleasing in appearance to homeowners and their neighbors.

The cost of solar water heating systems has declined by 30 percent between 1980 and 1990. Further cost reductions will not be as dramatic, but prices will continue to decrease as demand increases and manufacturers take advantage of economies of scale.

The Southeast Como Neighborhood Improvement Association initiated the Southeast Como Neighborhood Solar Thermal Pilot Project; 16 single-family systems and one multi-family system were installed. Total installed costs for the single-family homeowner participants in the Southeast Como project were between $6,000 and $10,500; many homeowners faced unexpected costs of $2,000 or more above the contractor bid due to required engineering studies and structural improvements for installing the panels on older homes. About 50 percent of the cost is equipment, 40 percent labor, and 10 percent permits and other fees. The largest equipment costs were for the panels ($950) and the solar storage tank ($750). Over the 30+ year lifetime of a solar hot water installation it is estimated that the homeowner will need to replace the water pump after 10-15 years, at a cost of $100-$300. Additionally, excess heat can cause glycol deterioration, and thus the glycol antifreeze must be checked and potentially changed once every 3-5 years at an estimated cost of $100-$200 per time.

Concentrated solar power (CSP) systems, also known as concentrated solar thermal (CST) systems, are systems that use mirrors or lenses to concentrate a large area of sunlight, or solar thermal energy, onto a small area. Electrical power is produced when the concentrated light is converted to heat which drives a heat engine (usually a steam turbine) connected to an electrical power generator.

Concentrating technologies exist in four common forms, namely parabolic trough, dish Stirlings, concentrating linear Fresnel reflector, and solar power tower.

These systems take up large amounts of land, as numerous mirrors are needed to generate enough electricity to make the installation cost effective.

The cost of building a CSP station is approximately $2.50 to $4 per watt. A 250 MW CSP station would be expected to cost between $600–1000 million to build; that would result in a cost of 12 to 18 cents per kilowatt-hour.

Biomass

Biomass consists of organic residues from plants and animals that are obtained primarily from harvesting and processing of agricultural and forestry crops. There are four basic applications: industrial cogeneration, co-fire biomass with coal, biomass direct combustion and biomass gasification.

Examples of some of the biomass residues that are utilized in direct combustion power plants are: forest slash, urban wood waste, lumber waste, agricultural wastes, etc. The components of biomass include cellulose, hemicelluloses, lignin, lipids, proteins, simple sugars, starches, water, hydrocarbons, ash and other compounds.

Except in the case of biomass gasification, the biomass is burned (i.e., combusted), producing heat that is used to create steam to turn turbines to produce electricity. The steam can often be used in cogeneration processes such as drying vegetables or use in a factory.

Industrial biomass facilities typically range between 20 and 50 MW in size; for the most part, this is due to industry requirements for facilities that cogenerate electricity and steam for remote operations. The steam technology used is very dependable, but plant efficiency is limited. Small capacity plants tend to be low in efficiency because it is expensive to install efficiency enhancing equipment.

Biomass electricity generating plants (co-fire with coal or direct biomass combustion) typically provide base-load electricity because of lengthy start-up times that prohibit the unit from changing output frequently. Typically, electricity generation from biomass occurs by direct combustion using piston engines, boilers and steam turbines.

All biomass combustion systems require feedstock storage and handling systems. Biomass fuel is burned in a boiler, which consists of a combustor with one or more heat exchangers to make steam. Typical medium efficiency units utilize steam temperatures and pressures of approximately 500ºC and 6 mega pascal (MPa). The steam is expanded through a turbine that drives an electrical generator. The steam from the turbine exhaust is condensed, and the water re-circulated to the boiler. Combustion products exit the combustor, are cleaned, and vented to the atmosphere. Typical cleaning devices include wet or dry scrubbers for sulfur and chloride control, cyclones, baghouses, or electrostatic precipitators for particulate matter removal and selective or non-selective catalytic reduction of NOx. Low CO and hydrocarbon emissions are maintained by proper control of air-fuel ratio in the furnace and boiler.

There are a number of barriers affecting the widespread use of biomass including high initial capital costs and high operating costs related to the transportation and management of fuels. The cost to generate electricity using biomass is between $0.06 and $0.09 per kWh, which tends to be higher than the cost of electricity produced with coal fuels but lower than the current cost to generate electricity using natural gas. The average biomass plant cost worldwide averages $2,000 per kW, which is higher than the $1,500 per kW cost for coal-fired plants and $1,000 per kW price to construct a combined-cycle, gas-fired facility.

Recent market and regulatory changes may help to revive interest in biomass. Sustained high natural gas prices, the shift away from coal-fired generation construction, and the limited potential of new emerging technologies projects may encourage investment in biomass-fired generation.

In the current market, large-scale biomass generation systems can potentially be competitive relative to conventional generation sources. This is particularly the case when biomass facilities are located near fuel supplies (such as pulp and paper and newsprint operations). As well, new biomass units will likely cogenerate electricity and steam because the value of the process steam will likely make new biomass facilities economically attractive for industries located in remote locations with limited fuel availability.

In response to an information request from the Department of Commerce, Energy Regulation and Planning (ERP), Xcel Energy gathered information regarding a typical waste-wood burning power plant. A copy of the Information Request and the Company's response are included in Appendix C.4 of the CN application.

Biomass gasification works by the partial oxidation of the original fuel into a fuel gas (syngas). Under this process, the carbon reacts with limited oxygen to produce carbon monoxide, while at the same time it also reacts with water to produce hydrogen and additional carbon monoxide. This combination of H_2 and CO is the key component of the syngas. In most processes, the content of the syngas will be at least 80 percent hydrogen and carbon monoxide.

The syngas is then converted into electricity via a combusted gas turbine generator; the excess heat contained in the exhaust from those turbines then heats water to power a steam turbine generator in a combined cycle configuration.

In comments on the Certificate of Need Application, Department analyst Dr. Steve Rakow concludes that the direct combustion biomass alternative is the least cost renewable generation alternative for providing 55 MW of capacity, however, this alternative is not competitive with a wires-based alternative and the less biomass in a combined alternative the better.

Geothermal

Geothermal energy is the heat from the Earth. It's clean and sustainable. Resources of geothermal energy range from the shallow ground to hot water and hot rock found a few miles

beneath the Earth's surface, and down even deeper to the extremely high temperatures of molten rock called magma.

This thermal energy can be tapped to generate electricity or to heat and cool buildings directly.

Almost everywhere, the shallow ground or upper 10 feet of the Earth's surface maintains a nearly constant temperature between 50° and 60°F (10° and 16°C). Geothermal heat pumps can tap into this resource to heat and cool buildings. A geothermal heat pump system consists of a heat pump, an air delivery system (ductwork), and a heat exchanger-and a system of pipes buried in the shallow ground near the building. In the winter, the heat pump removes heat from the heat exchanger and pumps it into the indoor air delivery system. In the summer, the process is reversed, and the heat pump moves heat from the indoor air into the heat exchanger. The heat removed from the indoor air during the summer can also be used to assist with hot water needs.

The two basic types of systems are closed loop and open loop.

Closed-loop geothermal systems usually circulate a heat-transfer fluid, typically food-grade antifreeze, through pipes or coils buried beneath the land surface. The closed-loop geothermal systems can be installed horizontally or vertically beneath the land surface, or even in the bed of a body of water. Homeowners choose one of those systems based on availability of land, cost, soil types, and other factors. A horizontal system may require enough land for a 100- to 300-foot-long trench. A vertical system requires less land but may require numerous well/bore holes drilled deep enough vertically for the geothermal loops.

While more expensive than conventional heating/cooling systems to install (excavation or drilled wells are needed), geothermal systems are cheap to maintain and operate. Efficiencies exceed 300 percent, compared to 96 percent for the highest efficiency furnaces and around 150 percent for air-source heat pumps.

The upper Midwest has a number of installed geothermal systems. The heat pump at the 80,000-sq. ft. elementary school in Onamia, Minnesota extracts 1.75 million BTU from the earth in its heating mode and 230 tons of cooling during the summer. A ton of cooling is equal to 12,000 BTUs. Fangmann Service Center in Garnavillo, Iowa, installed a geothermal system and in-floor heating (also called radiant heat) which cuts utility costs (compared to similar area service stations) in half and cuts insurance costs (no risk of furnace fires). The American Lung Association of Minnesota spent about $8,000 to install a heat pump in its 1996 Health House in Lake Elmo, Minnesota (3,100-sq. ft.) that costs $580/yr. to heat and $210/yr. to cool.

Geothermal water from deeper in the Earth can be used directly for heating homes and offices, or for growing plants in greenhouses. Some U.S. cities pipe geothermal hot water under roads and sidewalks to melt snow.
To produce geothermal-generated electricity, wells, sometimes a mile (1.6 kilometers) deep or more, are drilled into underground reservoirs to tap steam and very hot water that drive turbines linked to electricity generators. The first geothermally generated electricity was produced in

Larderello, Italy, in 1904. Currently, there are over 9,000 MW of installed geothermal electrical generation worldwide. In the United States, geothermal energy produces over 2,000 MW of electricity.

Geothermal power plants require large capital investments, typically in the range of $3,000 to $3,500 per kW of installed capacity. It costs $2 million to $3 million to drill each well, and extensive seismic work must be carried out to fully understand the resource potential. However, fuel costs are very low and operating and maintenance costs are competitive with other technologies in the range of $0.01 to $0.03 per kWh. Once operational, geothermal generation is extremely reliable and is suitable for base load power. The world's largest dry steam facility at the Geysers near Santa Rosa, California, boasts 98 percent reliability – higher than most fossil fuel and nuclear generation plants.

The National Renewable Energy Laboratory (NREL) classifies Minnesota as a "least favorable" (i.e., regions having temperatures less than 150° C at 10 kilometer depth) region for deep enhanced geothermal systems.

4.6.3 Emerging Technologies

Forces of change have fueled the demand for alternative energy sources for the new economy; these forces include: globalization, high energy costs, climate change issues, labor factors, competitive factors, emerging technologies, socio-economic factors, geo-political factors, global financial meltdown, new government regulations, federal stimulus funds, and new business best practices.

To be an effective component in the nation's energy solution; these emerging technologies must be scalable, sustainable and profitable, a goal not yet achieved.

Energy Storage

Energy storage technologies do not generate electricity but can deliver stored electricity to the electric grid or an end-user. Electrical energy is stored during times when production (from power plants) exceeds consumption and the stores are used at times when consumption exceeds production (peak shaving). In this way, electricity production need not be drastically scaled up and down to meet momentary consumption; instead, production is maintained at a more constant level. This has the advantage that fuel-based power plants (i.e. coal, oil, gas) can be more efficiently and easily operated at constant production levels.

Because these energy devices are often located at or near the point of use, they may be included in the distributed energy resources category.

Examples of energy storage technologies include:

- Battery Storage
- Flow Batteries
- Flywheel

- Superconducting Magnetic Energy Storage (SMES)
- Supercapacitor
- Compressed Air Energy Storage (CAES)
- Hydrogen
- Pumped Water
- Thermal

Storage technologies are not only defined by the storage medium, but also by the type of application and the duration of time over which the stored energy is used. Unlike the other DG equipment, whose rating tends to be determined by power generation or electrical efficiency, the performance of energy storage systems is determined by the capacity and duration of the equipment.

Table 11. Storage Technologies Overview

Duration of Energy Storage Capacity at Rated Load of Storage Device	Primary Applications
Extremely short duration (1-10 seconds)	Power quality: provide critical load ride-through during voltage sags and shorter momentary interruptions.
Short duration (10-300 seconds)	Power quality: provide critical load ride-through during longer voltage sags and momentary interruptions. Allow time for alternative power feeds and back-up generators to be energized.
Moderate duration (5-60 minutes)	Power quality/service reliability: all previously described benefits, plus allow for ride-through during longer-duration power interruptions.
Longer duration (1-4 hours)	Power quality/service reliability/ some limited DER applications: all previously described power quality benefits plus some limited load-leveling/peak-shaving capabilities.
Very long duration (4 hours up to several days)	Distributed storage and generation - load-leveling, peak-shaving. Storage for stand-alone PV or wind systems.

While there are a vast array of uninterruptable power supply (UPS) products and applications which utilize energy storage of up to durations of 60 minutes, there are relatively few applications employed for peak shaving and load leveling (Utility Scale).
Utilities typically use batteries to provide an uninterruptible supply of electricity to power substation switchgear and to start backup power systems. However, there are applications which go beyond these tasks by performing load leveling and peak shaving with battery systems that can store and dispatch power over a period of many hours. Batteries also increase power quality

and reliability for residential, commercial, and industrial customers by providing backup and ride-through during power outages.

The standard battery used in energy storage applications is the lead-acid battery. A lead-acid battery reaction is reversible, allowing the battery to be reused. There are also some advanced sodium/sulfur, zinc/bromine, and lithium/air batteries that are nearing commercial readiness and offer promise for future utility application.

A flow battery is a form of rechargeable battery in which electrolyte containing one or more dissolved electroactive species flows through an electrochemical cell that converts chemical energy directly to electricity. Additional electrolyte is stored externally, generally in tanks, and is usually pumped through the cell (or cells) of the reactor, although gravity feed systems are also known. Flow batteries can be rapidly "recharged" by replacing the electrolyte liquid (in a similar way to refilling fuel tanks for internal combustion engines) while simultaneously recovering the spent material for re-energization. The European Patent Organisation classifies flow batteries as a sub-class of fuel cells (see below).

Examples of current battery energy storage applications include:

GNB Lead-recycling, Vernon, California. A 3.5-megawatt valve-regulated lead-acid (VRLA) battery system installed at a lead recycling plant in California provides one hour of energy storage for both peak-shaving and uninterruptible power.

Melink Corporation, Cincinnati, Ohio. Installation of a 50kW, 200kWh grid energy storage and peak shaving system for their corporate headquarters. This peak shaving system will allow Melink to materially lower their electric bill by reducing their peak energy demand and driving down their demand charge premium. Demand charges are premiums attached to electric rates based on the highest use measured.

A flywheel is an electromechanical device that joins a motor generator with a rotating mass to store energy for short durations. Conventional flywheels are "charged" and "discharged" via an integral motor/generator. The motor/generator draws power provided by the grid to spin the rotor of the flywheel. During a power outage, voltage sag, or other disturbance the motor/generator provides power. The kinetic energy stored in the rotor is transformed to DC electric energy by the generator, and the energy is delivered at a constant frequency and voltage through an inverter and a control system.

Traditional flywheel rotors are usually constructed of steel and are limited to a spin rate of a few thousand revolutions per minute (RPM). Advanced flywheels constructed from carbon fiber materials and magnetic bearings can spin in vacuum at speeds up to 40,000 to 60,000 RPM. The flywheel provides power during period between the loss of utility supplied power and either the return of utility power or the start of a sufficient back-up power system (i.e., diesel generator).

Flywheels provide 1-30 seconds of ride-through time, and back-up generators are typically online within 5-20 seconds. Single flywheel units are typically 5kWh/100kW and can be cascaded to achieve utility-scale power and energy ratings.

Superconducting magnetic energy storage (SMES) systems store energy in the field of a large magnetic coil with direct current flowing. It can be converted back to AC electric current as needed. Low temperature SMES cooled by liquid helium is commercially available. High temperature SMES cooled by liquid nitrogen are still in the development stage and may become a viable commercial energy storage source in the future.

A magnetic field is created by circulating a DC current in a closed coil of superconducting wire. The path of the coil circulating current can be opened with a solid state switch which is modulated on and off. Due to the high inductance of the coil, when the switch is off (open), the magnetic coil behaves as a current source and will force current into the capacitor which will charge to some voltage level. Proper modulation of the solid-state switch can hold the voltage across the capacitor within the proper operating range of the inverter. An inverter converts the DC voltage into AC power. S MES systems are large and generally used for short durations, such as utility switching events.

Supercapacitors (also known as ultracapacitors) are DC energy sources and must be interfaced to the electric grid with a static power conditioner, providing 60-Hz output. A supercapacitor provides power during short duration interruptions and voltage sags. By combining a supercapacitor with a battery-based uninterruptible power supply system, the life of the batteries can be extended. The batteries provide power only during the longer interruptions, reducing the cycling duty on the battery. Small supercapacitors are commercially available to extend battery life in electronic equipment, but large supercapacitors are still in development, but may soon become a viable component of the energy storage field.

Compressed air energy storage uses pressurized air as the energy storage medium. An electric motor-driven compressor is used to pressurize the storage reservoir using off-peak energy and air is released from the reservoir through a turbine during on-peak hours to produce energy. The turbine is essentially a modified turbine that can also be fired with natural gas or distillate fuel.
Ideal locations for large compressed air energy storage reservoirs are aquifers, conventional mines in hard rock, and hydraulically mined salt caverns. Air can be stored in pressurized tanks for small systems.

Thermal energy storage (TES) comprises a number of technologies that store thermal energy for later use. They can be employed to balance energy demand between day time and night time. The thermal storage unit may be maintained at a temperature above (hotter) or below (colder) that of the ambient environment. Two forms of TES systems are currently used. The first system uses a material that changes phase, most commonly water and ice. The second type just changes the temperature of a material, most commonly water.

Water storage systems are often used in new large cooling system applications in conjunction with cogeneration and/or district energy systems. Water-ice storage is the most common cooling storage in smaller applications. Because latent heat storage (phase change between water and ice) has a smaller volume, it is often chosen for retrofit applications with limited space.

In general, the buildings that offer the highest potential are offices, retail, and medical facilities. The Dallas Veterans Affairs Medical Center installed a 24,628 ton-hours chilled water TES that resulted in a reduction in demand of 2,934 kW and a reduction in annual electricity cost of $223,650. The local utility provided $500,000 of the total cost of $2.2 million required for design and installation. Savings resulting from installation of the thermal storage technology will allow the VA to recoup its investment within 7 years.

Other examples include:

- Chilled Water Storage, a 2.25 million gallon system at Ft. Jackson, SC -$0.4M/yr savings.
- Diurnal Ice Storage system at Yuma Proving Ground, AZ - $22.5K/yr savings.
- Diurnal Ice Storage, a 30,000 gallon system at U.S. Army Construction Engineering Research Laboratory (CERL), Champaign, IL - $15K/yr savings.

Fuel Cells

While the concept of fuel cells has been around for more than 100 years, the first practical fuel cells were developed for the U.S. space program in the 1960s. The space program required an efficient, reliable, and compact energy source for the Gemini and Apollo spacecraft, and the fuel cell was a good fit. Today, NASA continues its reliance on fuel cells to power space shuttle vehicles. Because of technology improvements in recent years and significant investment by auto companies, utilities, NASA, and the military, fuel cells are now expected to have applications for distributed power generation within the next few years.

Fuel cells differ from batteries in that the active chemical species are stored inside the battery, but they are supplied externally in the case of fuel cells. So, power and energy specifications can be scaled up independently for a fuel cell, while the energy density of a battery is limited by the amount of active material that can be stored inside it.
Because these energy devices are often located at or near the point of use, they are included in the distributed energy resources category.

Table 12. Fuel Cell Overview

Fuel Cells Overview				
	PAFC*	SOFC*	MCFC*	PEMFC*
Commercially Available	Yes	No	Yes	Yes
Size Range	100-200 kW	1 kW - 10 MW	250 kW - 10	3-250 kW

			MW	
Fuel	Natural gas, landfill gas, digester gas, propane	Natural gas, hydrogen, landfill gas, fuel oil	Natural gas, hydrogen	Natural gas, hydrogen, propane, diesel
Efficiency	36-42%	45-60%	45-55%	25-40%
Environmental	Nearly zero emissions	Nearly zero emissions	Nearly zero emissions	Nearly zero emissions
Other Features	Cogen (hot water)	Cogen (hot water, LP or HP steam)	Cogen (hot water, LP or HP steam)	Cogen (80°C water)
Commercial Status	Some commercially available	Likely commercialization 2004	Some commercially available	Some commercially available

*phosphoric acid fuel cells (PAFC), molten carbonate fuel cells (MCFC), solid oxide fuel cells (SOFC), and proton exchange membrane fuel cells (PEMFC).

A fuel cell is similar to a battery in that an electro-chemical reaction is used to create electric current. The charge carriers can be released through an external circuit via wire connections to anode and cathode plates of the battery or the fuel cell. The major difference between fuel cells and batteries is that batteries carry a limited supply of fuel internally as an electrolytic solution and solid materials (such as the lead acid battery that contains sulfuric acid and lead plates) or as solid dry reactants such as zinc carbon powders found in a flashlight battery. Fuel cells have similar reactions; however, the reactants are gases (hydrogen and oxygen) that are combined in a catalytic process. Since the gas reactants can be fed into the fuel cell and constantly replenished, the unit will never run down like a battery.

Fuel cells are named based on the type of electrolyte and materials used. The fuel cell electrolyte is sandwiched between a positive and a negative electrode. Because individual fuel cells produce low voltages, fuel cells are stacked together to generate the desired output for DG applications. The fuel cell stack is integrated into a fuel cell system with other components, including a fuel reformer, power electronics, and controls. Fuel cell systems convert chemical energy from fossil fuels directly into electricity.

The fuel (hydrogen) enters the fuel cell, and this fuel is mixed with air, which causes the fuel to be oxidized. As the hydrogen enters the fuel cell, it is broken down into protons and electrons. In the case of proton exchange membrane fuel cells (PEMFC) and phosphoric acid fuel cells (PAFC), positively charged ions move through the electrolyte across a voltage to produce electric power. The protons and electrons are then recombined with oxygen to make water, and as this water is removed, more protons are pulled through the electrolyte to continue driving the reaction and resulting in further power production. In the case of solid oxide fuel cells (SOFC), it is not protons that move through the electrolyte, but oxygen radicals. In molten carbonate fuel

cells (MCFC), carbon dioxide is required to combine with the oxygen and electrons to form carbonate ions, which are transmitted through the electrolyte.

Fuel cells promise to deliver electrical conversion efficiencies in the range of 40 to 60 percent. Even higher total energy conversion efficiencies (approaching 80 to 90 percent) are possible when used in co-generation applications, where both electricity and the heat of reaction are utilized. Another promising feature of fuel cells is low emissions. Since they produce electricity without combustion, the usual products of combustion are not present. Fuel cells also operate quietly and reliably.

Fuel cells are being developed in the size range of a few kilowatts up to a few megawatts. However, larger units (up to 20 MW, and smaller micro-fuel cells (for portable electronic devices) are also being investigated. The driving force behind fuel cell development is not just the electric power industry but also the automotive/transportation industry. This cross-industry interest has helped to accelerate progress towards commercially available fuel cells.

The capital cost of fuel cells is very high compared to those of other DG technologies. The only product available commercially today is the PureCell 200 (formerly PC-25) built by UTC Power. The cost of the unit is approximately $4,000/kW. The installed cost of the unit approaches $1.1 million. At a rated output of 200kW, this translates to about $5,500/kW, installed. Other fuel cell types are less developed.

Like most new technologies, as more units are installed and new players join the market, prices are likely to fall. Price projections vary among fuel cell developers, but most are targeting costs below $1,500/kW based on volume production. It is highly unlikely that this price target will be achieved in the near future. At the current price, units are only used in high value, "niche" markets where reliability is premium, and in areas where electricity prices are very high and natural gas prices are low.

Fuel cells are expected to have minimum maintenance requirements. The fuel supply systems and reformer system may need periodic (about once a year) inspection and maintenance. The cell stack itself will not require maintenance until the end of its service life. The maintenance and reliability of the system still needs to be proven in a large-scale, long-term demonstration.

Maintenance costs of a fuel cell are expected to be comparable to that of a microturbine, ranging from $0.005-$0.010/kWh (based on an annual inspection visit to the unit).

4.6.4 Feasibility of Technologies and Alternatives

In writing this document, EFP reviewed the CN Application, public comments, peer reviewed literature, and case studies. The project, as proposed by Xcel Energy, meets the goals of providing reasonably priced, reliable energy in an area that is currently exceeding capacity. The community where the proposed project would be sited would like to integrate distributed generation into the proposal. EFP review and analysis finds that while there are many

alternatives for commercial and residential utilization of distributed generation and emerging technologies, implementing any single alternative or combination of alternatives, presents many challenges.

The primary challenge is that many elements or systems needed to integrate and implement a combination of energy sources either do not exist, or are not sufficiently developed to accommodate a mix of energy sources at this time. For example, given the number of solar PV systems needed to meet current and future energy needs, the entire project area would need to undergo a site analysis to determine where there were sufficient solar resources and the structural integrity needed for solar panels. It is beyond the scope of this ER to determine the necessary site characteristics and structural integrity of the proportion of sites available for such development, or the participation levels of those property owners willing to install a solar PV system or lease the space to do so.

Implementing multiple generation alternatives becomes far more complex than simply offsetting the stated energy needs with renewable energy sources.

While the DOC ERP review of the solar alternative presents an unlikely alternative, that of establishing a solar farm somewhere in the project area, it serves to illustrate that the solar farm represents the concept of economy of scale. It also implies single ownership rather than multiple ownerships, and eliminates the challenges of integrating many, dispersed units throughout the area. However, this alternative, due to the significant space requirements needed to site a 55 MW solar farm, is not feasible in this urban setting. A solar farm, with its economy of scale, is still a much more expensive alternative than a transmission line and does not meet future energy needs.

The literature review conducted for this report cites many and varied challenges to integrating distributive generation at larger scales. These range from barriers to market entry, cost recovery, greater incentives for individuals rather than utility companies, and a lack of integrated and coordinated policies needed to promote distributive generation alternatives. In short, meeting all of the energy needs in the area through distributive generation would require changes in policy at every level of government, including zoning and building codes. A quantitative evaluation of the policy changes needed would be necessary to understand the impacts on all stakeholders (utilities, rate payers, local units of government and project developers) before enacting such changes.

As new models for integrating distributed generation at large scales in urban areas become more commonplace and tested, implementing such practices will become easier. Pilot programs like Solar Cities, are testing and evaluating many different solar technologies and policies at varying scales and locations to eliminate barriers to increasing solar resources.[2] Until the economic and political infrastructure is in place to build the energy infrastructure the local community

[2]U.S. Department of Energy Solar Cities program, http://solaramericacommunities.energy.gov/

envisions, the patchwork of grassroots effort, local community groups, and existing incentives are the best method of achieving changes in local energy consumption and generation.

5.0 Potential Impacts of the Proposed Project

The project is located in south Minneapolis, Minnesota, in Hennepin County, and has potential to impact the neighborhoods of Central, Corcoran, Elliot Park, Longfellow, Loring Park, Powderhorn Park, Seward, Stevens Square-Loring Heights, Ventura Village, Whittier, and the Phillips community. The area surrounding the transmission line alternatives varies in use from primarily residential to commercial, light and medium industrial, parks and major transportation corridors. The area surrounding the Hiawatha Substation sites is mainly commercial and industrial on both the eastern and western sides of Hiawatha Avenue. The area surrounding the Midtown Substation sites is light industry, single and multi-unit residential and commercial.

Chapter 5 of the EIS included a discussion of the various resources within the affected environment, the potential impacts to those resources, and mitigative measures that may be incorporated into the design, construction and operation of the project to minimize the identified impacts. The reader is directed to the EIS developed as part of the HVTL Route Permit procedures for a detailed discussion of these issues.

The sub-sections within chapter 5 of the EIS describing the affected environment include a description of the specific resources as they relate to the proposed project and each alternative route considered. The resource categories included: properties in proximity to structures; land use, zoning, and planning; archaeological and historical; socioeconomic; environmental justice; safety and health; recreation and tourism; aesthetics; water resources; flora; fauna; rare and unique natural resources; air quality and climate; noise; utility systems/infrastructure; and transportation and public services.

Potential direct and indirect impacts were identified and evaluated for each of the identified resource categories. The potential impacts of the project and the project route alternatives were discussed in detail in the EIS and are summarized below.

Proximity to Structures

Information was gathered and examined to determine the number and type of existing properties located within specified distances of transmission line towers (i.e., poles) and within alternative substation locations.

No homes would be displaced by any of the alternatives; however, limitations may be placed on existing and future uses of property. Potential impacts to properties that are located on possible substation locations include the demolition of existing structures for placement of project structures and changes or limitations to the existing use.

Impacts to properties related to overhead transmission line towers can essentially be eliminated by developing one of the underground construction transmission line alternatives (Alignments A2 or A3, or Route D). If an overhead route alternative is selected, the final transmission line design could be completed (i.e., micro-siting) with the objective of minimizing the number of

structures within the "fall distance" of the tower to the extent practicable. In some cases, it may be possible to move towers away from homes.

Land Use, Zoning, and Planning

Zoning is used as a means of regulating permitted land uses in the State of Minnesota. Minnesota Statutes provide for this authority to promote the health, safety, morals, and general welfare. Minneapolis regulates zoning within the area covered by the project and analyzed in the EIS.

Potential land use impacts from the project include: incompatibility with local land use, zoning, and comprehensive planning; incompatibility with development; and loss of or restricted use to landowners.

While local approvals are not required for the construction and operation of the transmission line, knowledge of current zoning designations for each transmission line alternative and substation alternative is valuable since zoning can provide insights into the possible impacts of the project on existing and future development plans.

The primary conflict between the project and current land use is associated with the visual impact to the surrounding areas. The transmission line route alternatives would primarily be located along existing rights-of-way. The use of these pre-existing ROWs would limit the disruption to the existing urban fabric.

The majority of visual impacts related to overhead transmission lines can essentially be eliminated by developing one of the underground construction transmission line alternatives (Alignments A2 or A3, or Route D). However, should an aboveground alternative be selected, the use of custom designed structures specific to the area could reduce the visual impacts. In addition, any vegetation that would be removed could be restored with compatible vegetation after the construction of the facilities. In some locations, existing distribution lines also could be placed underground to reduce the over head clutter.

For the substations, low-profile designs and architecturally designed walls would reduce the visual impacts.

Archaeological and Historical Resources

Cultural resources include material remains of past human activities, both prehistoric and historic. Cultural resources management seeks to identify and protect all of these types of cultural resources with the goals of enhancing understanding of human behavior and protecting cultural practices.

Potential impacts to archaeological and/or historic resources includes: disruption or damage to existing archaeological resources not yet identified and impacts associated with views both from and to historic properties.

Placing underground alternatives within previously disturbed and/or public right-of-way is one way of minimizing the potential for adverse effects to archaeological resources. In the event that any archaeological sites, human remains, or associated artifacts were to be discovered during construction, activities would need to cease immediately. The State Historic Preservation Office and other relevant officials would be notified, and if necessary, interested federally recognized tribes.

Strategies for minimizing the visual impacts to or from historic features include: selection of an underground alternative for the transmission line; use of custom designed structures (i.e., towers); use of low-profile design and decorative walls for the substations; and landscaping disturbed areas.

Socioeconomics

Population, housing, employment, and income characteristics make up the socioeconomic fabric of the affected communities.

Potential impacts on socioeconomics include: an increase in local spending during construction activities; an increase to the local tax base from utility property; disruption to local businesses during construction activities; displacement (substation sites) of local businesses; perceived and/or real loss of property values; and the availability of federal assistance mortgage loan insured by the Federal Housing Administration.

Potential impacts on land-based economies, such as mining, fisheries, and agriculture are not anticipated. There is a potential impact to urban forestry as each overhead transmission line alternative that is not co-located or located in place of an existing distribution line would involve the removal or trimming of a varying number of trees. Trees under distribution lines are already trimmed at a lower height than would be required under a transmission line. The impact of the vegetation maintenance within the right-of-way of the transmission lines may include: increased energy cost to home owners whose residences benefited from the cooling effect of affected shade trees and perceived and/or real loss of property values due to loss of large trees.

Environmental Justice

In general, the transmission line route and substation alternatives are located in areas where the minority population exceeds 50 percent and the percentage of low income population generally exceeds the state level by 20 percentage points. As such, these populations would be impacted more often than other non-minority and non-low income property owners and residence.

The project is not expected to result in a direct economic hardship to minority or low income populations. While no individual homes would be displaced by this project, businesses may be relocated due to the construction of the substations. If any property owners are displaced they would be compensated for the property and could be assisted with relocation.

Safety and Health

Potential impacts concerning safety and health issues include: disruption of contaminated soils or building materials during construction; electric and magnetic fields; interference with implantable medical devices; stray voltage; security of equipment; and storm damage.

Depending upon its nature and extent, existing contamination (i.e., soil, groundwater, and building materials) can pose a health and safety hazard to construction workers and nearby public. In addition, soil disturbances required during construction, such as excavation and grading, could result in mobilization of existing soil contamination. Standard practices for the testing, handling, containment, transportation and disposal of hazardous materials do exist and would be employed if such material is encountered.

Electric and Magnetic Fields (EMFs) are invisible regions of force resulting from the presence of electricity. Naturally occurring EMFs are caused by the earth's weather and geomagnetic field. Man-made EMFs are caused from any electrical device and found wherever people use electricity. Estimates of the anticipated strength of the EMF generated from the transmission lines and modeled exposures to the public are within State of Minnesota guidelines for all transmission line alternatives.

Stray voltage is a condition that can occur at the electric service entrances to structures, that is, where distribution lines enter structures. More precisely, stray voltage is a voltage that exists between the neutral wire of the service entrance and grounded objects in buildings. Transmission lines do not, by themselves, create stray voltage because they do not connect to businesses or residences. Transmission lines, however, can induce stray voltage on a distribution circuit that is parallel and immediately under the transmission line. Standard industrial designs, including line configuration, separation and enhanced grounding, can mitigate any potential for stray voltage to impact distribution lines.

Vandalism to towers and substations and theft for copper wire and scrap metal could create serious harm to the individual engaging in the activity, as well as compromise the safety of the affected high voltage equipment and endanger workers who operate or maintain the transmission lines and substations. All substation alternatives would be surrounded by four walls (ranging in height between 12 and 20 feet based on the substation location selected) and include either wood gates or chain-link fence gates. Should vandalism or theft affect the transmission lines, the protective devices (i.e., breakers and relays located where the line connects to the substation) would de-energize the line upon sensing a fault on the system.

Transmission poles and towers are designed and constructed to withstand the extreme wind and weather conditions normally experienced in their area of installation. Should severe weather drop a transmission line, the protective devices (i.e., breakers and relays located where the line connects to the substation) would de-energize the line upon sensing a fault on the system.

Recreation and Tourism

Minneapolis contains a number of recreation and tourism destinations that provide opportunities for active recreation, such as exercise, team sports, and child's play, and for passive recreation, such as picnicking, bird watching, fishing and general enjoyment of one's surroundings.

Potential impacts on recreational opportunities and tourism include: temporary restricted access to trails and pedestrian walk-ways, along with increased noise during construction activities; and changes to visual landscape.

No significant permanent impacts to recreational opportunities are expected; as stated previously, selection of an underground alternative for the transmission line would eliminate the visual impacts of the overhead transmission line alternatives.

Aesthetics

A large proportion of the project area is residential in character, complemented with supporting uses such as churches, schools and corner retail. The residential units are primarily one to two story single family houses and duplexes, but a number of two to three story multifamily buildings also exist. Many of the route alternatives are within a few blocks of, and run parallel to, Lake Street, which is a commercial corridor that spans the full width of south Minneapolis.

The transmission lines and substations would be visible to many residents living in the area, as well as those traveling through the area; potential impacts include changes to the visual landscape.

To minimize the impact of overhead line construction the Applicant has proposed several measures, depending on the route selected. These include: possible relocation of distribution line underground to reduce overhead clutter, use of special structures with narrower bases, and placement of transmission structures to minimize direct impacts.

To minimize the visual impact of the substations, the Applicant has proposed low-profile designs and the construction of decorative, architecturally designed walls.

The selection of an underground alternative for the transmission line would eliminate the visual impacts of the overhead transmission line alternatives.

Water Resources

There are no Public Water Inventory water bodies, National Wetland Inventory wetlands, or floodplains within the project area. Depending on site specific conditions, final design, and the construction methodologies, dewatering of the groundwater may be necessary. Potential impacts to water resources from construction activities include erosion and sedimentation of surface bodies from storm water runoff.

Commonly used best management practices can minimize the potential impacts of erosion and stormwater runoff during construction and dewater activities.

Flora

Potential impacts to flora from the transmission lines primarily result from disturbance required for the construction foot-print (i.e., tower foundations) and the requirement to restrict the height of vegetation within the right-of-way. Substation locations would require clearing of vegetation in preparation for construction. Potential impacts include: loss of individual trees; loss of habitat for wildlife species; loss of atmospheric carbon absorption, increased energy costs from reduced shade; perceived and/or real loss of property values; and loss of visual screening and aesthetics.

Due to urbanization and development of the project area, potential direct and indirect impacts from the project to flora would be limited. Measures to minimize the impacts would include restoration of rights-of-way and temporary work spaces, including re-vegetation to return disturbed areas to their existing condition as far as practicable within the ROW vegetation protocol.

Selection of the underground alternative along 29th Street (Alignment A2) or beneath the existing bike trail in the Midtown Greenway (Alignment A3) would minimize disturbance to the vegetated slopes of the Midtown Greenway during construction and maintenance activities.

Fauna

The project area is a highly developed urban environment with patches of natural areas present in the city parks and the Midtown Greenway. Additionally, trees and shrubs planted along the boulevards and around houses provide wildlife species with habitat and food. Wildlife found in the project area and surrounding vicinity includes species adapted to living in areas disturbed by humans. Small mammals found in the urban environment include mice, voles, raccoons, squirrels, opossums, skunks, and bats. Both migratory and resident birds are found in the area.

There would be no direct or indirect impacts to aquatic wildlife from the transmission lines. Transmission lines would not cross aquatic areas and construction of transmission lines would not impact aquatic habitats.

Potential impacts to wildlife include: loss of habitat; disturbance from construction, clearing, and maintenance activities; and changes in mortality rates due to such things as avian collisions or electrocution. Impacts can be minimized through commonly used construction best management practices and transmission structure design choices.

Rare and Unique Natural Resources

Five state-listed species or special communities have been identified within 1 mile of the Project Area: Blanding's turtle (*Emydoidea blandingii*), Peregrine falcon (*Falco peregrinus*), Eastern pipistrelle (*Pipistrellus subflavus*), Handsome sedge (*Carex formosa*), and Black sandshell (*Ligumia recta*). None of these species have been identified within the rights-of-way of any of the transmission line alternatives; however, the habitat of the Blanding's turtle may be intersected by Route C. No rare or unique species were identified at the sites proposed for development of

substations, and the sites are not considered to be critical habitats for any of the species identified in the area.

Potential impacts to rare and unique natural resources are primarily associated with direct effects, including the taking (removal or loss) of individuals or populations due to habitat destruction; and a change in an individual or population's habitat use due to noise, or disturbance from construction, clearing, and maintenance activities. Given the location of transmission lines and substations relative to identified species and habitat, the project is not expected to significantly impact rare and unique natural resources.

Air Quality and Climate

Air quality is monitored in the project area at H.C. Anderson School, located at approximately 27th Street and 10th Avenue, by the Minnesota Pollution Control Agency (MPCA) as part of its statewide network of monitoring sites designed to determine compliance with national air quality standards. As reported in the MPCA Annual Air Monitoring Network Plan for the State of Minnesota (MPCA, 2009), the entire state of Minnesota, including the Twin Cities area, has been in compliance with national standards since 2002.

Potential impacts to air quality and climate include: temporary changes in air quality due to construction activities; and loss of carbon sequestrating vegetation. Commonly used best management practices can minimize potential for temporary impacts to air quality during construction. Vegetation losses can be minimized through route selection and re-vegetation of disturbed areas.

Noise

Noise is typically defined as "unwanted sound." It may be as mild as a general nuisance, such as a noise causing distraction or masking desired sounds, or severe enough to impede communication, affect behavior, and cause temporary or permanent hearing loss.

Noise generated by construction equipment is likely to constitute the greatest noise impact. Earth moving machinery including bulldozers, front end loaders, and other supporting equipment such as cranes and compressors can generate temporary noise.

Operational noise impacts can potentially occur along the transmission lines and at the substations, but the noise levels produced are not expected to exceed background levels in most cases. Transmission conductors and transformers at substations produce audible noise levels depending upon weather conditions and their design (e.g., conductor conditions and voltage levels). In foggy, damp, or rainy weather conditions, power lines can emit a subtle crackling sound due to the small amount of the electricity ionizing the moist air near the wires.

Sound absorbing panels, proposed by the Applicant, will reduce noise at the substations. Construction activities will comply with Minneapolis' noise ordinance and will be limited in duration.

Utility Systems

The project would be located in a highly developed urban environment, one in which a variety of utility infrastructure already exist and that may be affected during construction or operation of the project, including communications networks, water and wastewater systems, oil and natural gas pipelines, and transmission lines.

Potential impacts to existing utility systems include: interference with communication networks (microwave signals, cellular phones, radio, television, etc.); damage to or disruption in services from construction activities on gas and oil pipelines; and conflicts with existing distribution lines. These impacts can be mitigated by coordinating with the providers of these services during the detailed design and construction phases of the project.

Transportation and Public Services

The project area lies within a fully developed portion of Minneapolis served by many modes of transportation and reliant on numerous transportation facilities. A north-south local street grid with roughly one-tenth mile spacing provides access to parcels, augmented by a system of higher functional streets at the county, state and federal level to provide mobility. Grade-separated light rail transit and pedestrian/bike-ways further enhance transportation options.

Potential impacts to existing transportation and public services include the disruption of roadways, pedestrian paths, and bicycle facilities during construction activities. These can be mitigated through well coordinated road closures and well planned detour routes.

Transmission lines and structure also can interfere with sightlines at alleys and intersections and interfere with pedestrian and wheelchair use of sidewalks, creating safety hazards. These can be mitigated through careful attention to transmission structure placement and eliminated through selection of an underground alternative.

BLANK

Figures

BLANK

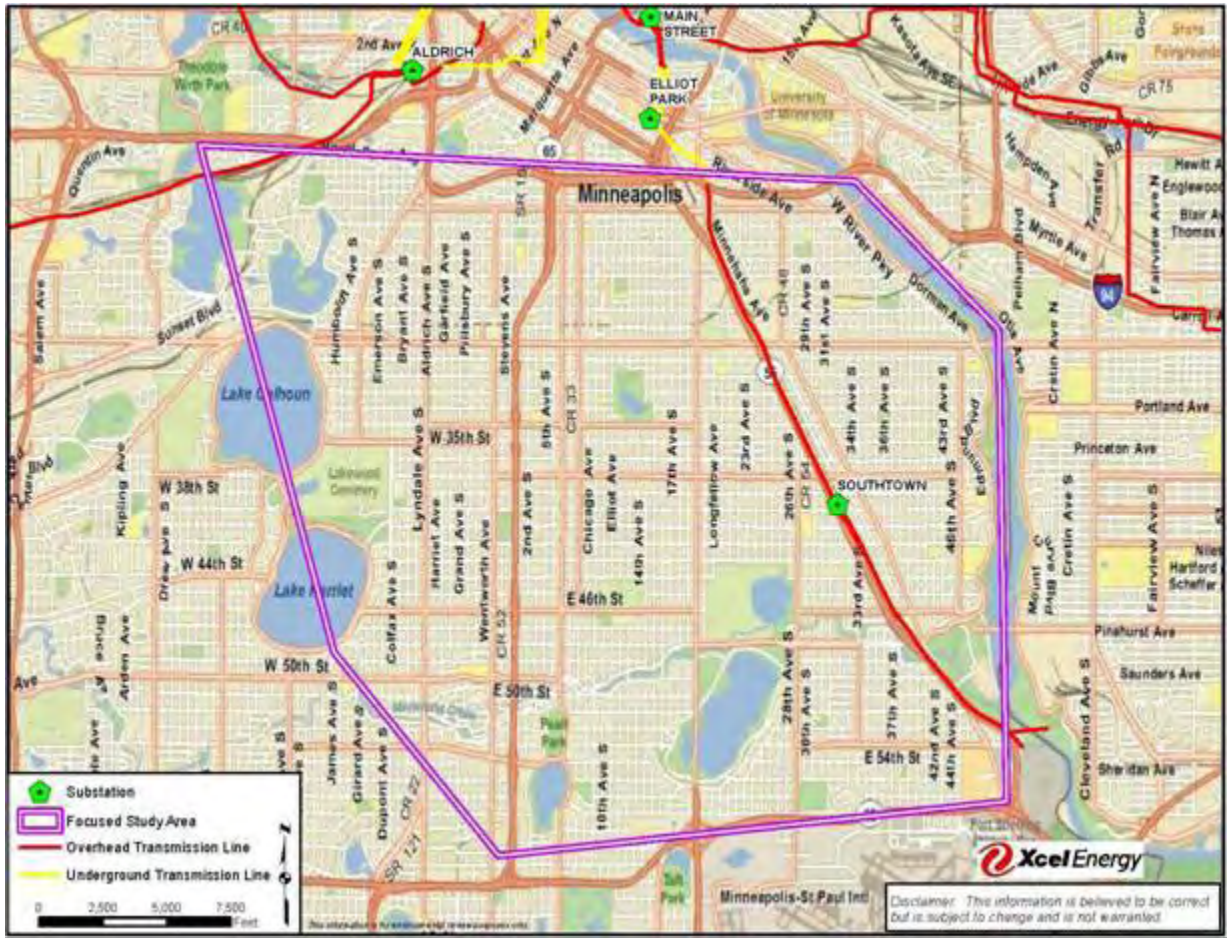

Figure 1 General Area Map

BLANK

Appendix A – Scoping Decision

BLANK

MINNESOTA DEPARTMENT OF COMMERCE

Energy Facility Permitting
85 7th Place East, Suite 500
St. Paul, Minnesota 55101-2198
1.800.657.3794 / 651.296.4026
FAX 651.297.7891 TTY 651.297.3067
http://energyfacilities.puc.state.mn.us

April 20, 2011

TO: William Grant, Deputy Commissioner
Division of Energy Resources
THROUGH: Deborah Pile, Manager
Energy Facility Permitting
FROM: William Cole Storm, Staff
(Tel: 651-296-9535)
RE: Scoping Decision
Xcel Energy Hiawatha HVTL Project CON
PUC Docket Number: E002/CN-10-694

ACTION REQUIRED: Signature of the Deputy Commissioner on the attached Order, "Environmental Report Scoping Decision." Once signed, the Department of Commerce (DOC) Division of Energy Resources (Division) Energy Facility Permitting (EFP) staff will mail the notice of the order to interested parties.

BACKGROUND

On April 24, 2009, Xcel Energy submitted a high voltage transmission line (HVTL) Route Permit application to the Public Utilities Commission (Commission) for the proposed Hiawatha Transmission (Hiawatha) Project. The application was submitted pursuant to the provisions of the Full Permitting Process outlined in Minnesota Rules 7850.1700 to 7850.2700.

The Commission accepted the HVTL Route Permit Application as complete on May 26, 2009, which marked the beginning of the full permitting review process.

At the time of the route permit application acceptance the project did not meet the size and length thresholds definition of a *large energy facility* as described in Minnesota Statutes Section 216B.2421, subd. 2(2) and (3), and did not require the issuance of a Certificate of Need (CON) by the Commission.

However, this project does falls under the recently enacted statutory provision that requires a CON for transmission projects of this size and length if located in an area with high population density and the proposed transmission lines parallel a below-grade bike and walking path (2010 Minn. Laws, ch. 361, art. 5, sec. 19; Effective Date: May 18, 2010).

Therefore, the Commission must determine whether the HVTLs are necessary and in the best interest of the state through the CON process.

The Applicant applied for a Certificate of Need on November 29, 2010.

CERTIFICATE OF NEED

Before any large energy facility, in this case HVTL, can be constructed in Minnesota, the Commission must determine that they are necessary and in the best interest of the state. The certificate of need process includes environmental review and public hearings, and typically takes 12 months. This process is the only proceeding in which a no-build alternative and the size, type, timing, system configuration and voltage of the proposed project will be considered.

A copy of the certificate of need application, along with other relevant documents, can be reviewed at the Energy Facility Permitting web page at:

http://energyfacilities.puc.state.mn.us/Docket.html?Id=30489

The Energy Facility Permitting staff is responsible for administering the environmental review process. The Commission is responsible for determining if the transmission lines proposed are needed.

Potential routes that the transmission lines would follow, if approved, have been put forth and are being evaluated in the HVTL Route Permit proceeding (See Below).

Environmental Review. The environmental review process under the certificate of need procedures includes public information/scoping meetings and the preparation of an environmental review document, the Environmental Report (ER). Minn. Rules 7849.1000 – 7849.1500. The environmental report is a written document that describes the human and environmental impacts of the proposed project, alternatives to the project and methods to mitigate anticipated adverse impacts. The ER must be prepared before the public hearing and before the Commission can make a decision on the certificate of need application.

HVTL ROUTE PERMITTING

Minnesota Statutes Section 216E.03, subd. 2, provides that no person may construct a HVTL without a route permit from the Commission. An HVTL is defined as a transmission line of 100 kV or more and greater than 1,500 feet in length in Minnesota Statutes Section 216E.01, subd. 4. The proposed transmission lines are HVTLs and, therefore, a route permit is required prior to construction.

Xcel Energy's application for a HVTL Route Permit was being reviewed by the Commission under Docket TL-09-38. However, due to the recently enacted legislation requiring a Certificate of Need, the HVTL Route Permit proceedings are on hold pending the outcome of this Certificate of Need filing.

A copy of the HVTL route permit application, along with other relevant documents, can be reviewed at the Energy Facility Permitting web page at:

http://energyfacilities.puc.state.mn.us/Docket.html?Id=19981

The DOC EFP is responsible for evaluating the HVTL route permit application and administering the environmental review process. The Commission is responsible for selecting the transmission lines routes and issuing the HVTL route permit.

PROJECT DESCRIPTION

The total length of the HVTLs would be approximately 1.4 to 3.8 miles long depending on the final route. The stated purpose of the Hiawatha Project is to meet the electrical distribution needs of the Applicant's customers in south Minneapolis, Hennepin County, Minnesota. The Applicant has stated that demand for power has increased beyond the capability of the system due to population growth, higher load density, and recent successful urban revitalization efforts, particularly in the areas along Lake Street, Hiawatha Avenue, and the Chicago and Park Avenue corridors. Additional electrical infrastructure is required to address overload conditions on the local distribution system and to improve the reliability of the power supply to residences and businesses. Without new infrastructure, electrical conditions will worsen with time.

Xcel Energy proposes to construct the following facilities:

- A new 115 kV distribution substation near Hiawatha Avenue and 28th Street (Hiawatha Substation),
- A new 115 kV distribution substation near Oakland Avenue South and 29th Street, including the site of the former Oakland Substation (Midtown Substation), and
- Two 115 kV transmission lines between the two new substations.

Potential routes that the transmission lines would follow, if approved, were put forth in the HVTL Route Permit proceeding which is currently on hold (see above). The transmission line routes will be determined through the HVTL Route Permit process expected to recommence following the certificate of need process, if a CON is granted.

SCOPING PROCESS

On February 11, 2011, EFP sent notice of the place, date and times of the Public Information and Scoping meeting to those persons on the General List maintained by the PUC, the agency technical representatives list and the project contact list. Additionally, on February 11, 2011, Xcel Energy mailed the notice to those persons on their property owners list and local unit of government list.

Notice of the public meeting was also published in local newspapers.

On Wednesday, March 16, 2011, EFP held two public information/scoping meetings at the Plaza Verde Building in Minneapolis. The meetings included two sessions, one starting at 2:00 pm and another starting at 6:00 pm. The purpose of the meetings was to provide information to the public about the proposed project, to answer questions, and to allow the public an opportunity to suggest alternatives and impacts that should be considered during preparation of the environmental review document. Written comments were due no later than Wednesday, April 6, 2011.

Approximately 50 people attended the public information and scoping meetings; 20 individuals took the opportunity to speak on the record. A court reporter was present to document oral statements. Nineteen written comments were received.

A variety of questions were asked and answered during the oral discussion. Topics included: specifics on demand side management (DSM) and conservation efforts (past, present and future), renewable local distributed generation (DG) alternatives, and combining of the various alternatives to meet the stated need; specifics on status of the routing process and weight of the ALJ's report; sources of power generation for this project; and timeline and milestones of the CON application review process.

Written comments included requests that the ER evaluate specific alternatives to the proposed HVTLs, such as, distribution/existing infrastructure solutions, wind power, individual solar installations, combined heat and power, conservation, and energy storage devices.

Many of the written comments also requested that the record (i.e., public comments, environmental report and hearing transcripts) from the routing docket be incorporated into the certificate of need docket.

Division of Energy Resources EFP staff has extracted from the public comments the following items and areas expressed for scoping the ER during the comment period below:

Alternatives

No build alternative
Facility chiller/thermal energy storage
    IceBear Technology
Up-grading existing infrastructure
DSM/Conservation
    Residential refrigeration, AC
Fossil Fuel
    Natural Gas (micro turbine, Bluegen)
Combined Heat and Power
Renewable Technologies
    Solar (PVC and water heating) on individual homes and businesses
    Geothermal Generation
    Thermal Energy Storage (facility chillers, Ice Energy, IceBear)
    Wind Energy
Emerging Technology
    Fuel Cells
    Lithium Ion Battery Storage
    High-Volume Sodium-Sulfur Battery Storage
    Vanadium Redux Battery Storage
Combining alternatives (renewable DG, DSM, emerging technology)

Issues/Impacts
Air quality
Noise
Groundwater
Impacts of the substation on residences living close by
Impacts on property values
Underground HVTLs
Impacts of construction on medical facilities in the area
EMF
Undergrounding of the HVTL
Archaeologically significant sewer lines

Relevant documents and other information on this docket can be viewed at the PUC Energy Facilities website:

http://energyfacilities.puc.state.mn.us/Docket.html?Id=30489

Selected alternatives and impacts, along with those required in rule (Minn. Rule 7849. 1500, subpart 1 and subpart 3), have been incorporated into the proposed Order on the Environmental Report Scoping Decision.

Alternatives identified during the scoping process that failed to eliminate the need for the proposed HVTL were not included in the scoping decision recommendation; an example would include generation that could not be sited locally (i.e., wind farm).

Contested issues or disputes of fact with respect to the representations made in the applicant's CON application (i.e., conflicts with previous transmission planning studies, quantifying the amount of need, SAIDI/SAIFI/CAIDI data, etc.) also are not included in the scoping decision; they are appropriately addressed during the CON hearing process. The Commission released a notice of public comment period on February 17, 2011, on the certificate of need application. The purpose of the notice was to solicit written comments on the merits of the proposed project, particularly whether there are any contested issues of fact with the application. The comment period was open through Thursday, March 31, 20011, with replies through Friday, April 29, 2011.

Impacts identified during the scoping process that were covered in detail in the Environmental Impact Statement (EIS) for the routing docket will only receive a high level environmental analysis in the ER; the reader will be referred to the EIS for route specific impacts (i.e., EMF, noise, substation lighting, undergrounding, environmental justice, etc.). Impacts associated with the alternatives to the HVTL contained within the scoping decision will be discussed in the ER.

STATE OF MINNESOTA

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

In the Matter of Xcel Energy's Application for a Certificate of Need for the proposed Hiawatha HVTL Project.

ER SCOPING DECISION
PUC Docket No. E002/CN-10-694

The above-entitled matter came before the Deputy Commissioner of the Department of Commerce Division of Energy Resources (Division) for a decision on the scope of the Environmental Report (ER) to be prepared on the proposed Hiawatha HVTL Project.

Having reviewed the matter, consulted with the Division's Energy Facility Permitting staff, and in accordance with Minnesota Rule 7849.1400, I hereby make the following Scoping Decision.

I. SUMMARY

On April 24, 2009, Xcel Energy submitted a high voltage transmission line (HVTL) Route Permit application to the Public Utilities Commission (Commission) for the proposed Hiawatha Transmission (Hiawatha) Project. The application was submitted pursuant to the provisions of the Full Permitting Process outlined in Minnesota Rules 7850.1700 to 7850.2700.

The Commission accepted the HVTL Route Permit Application as complete on May 26, 2009, which marked the beginning of the full permitting review process.

At the time of the route permit application acceptance the project did not meet the size and length thresholds definition of a *large energy facility* as described in Minnesota Statutes Section 216B.2421, subd. 2(2) and (3), and did not require the issuance of a Certificate of Need (CON) by the Commission.

However, this project does falls under the recently enacted statutory provision that requires a CON for transmission projects of this size and length if located in an area with high population density and the proposed transmission lines parallel a below-grade bike and walking path (2010 Minn. Laws, ch. 361, art. 5, sec. 19; Effective Date: May 18, 2010).

Therefore, the Commission must determine whether the HVTLs are necessary and in the best interest of the state through the CON process.

The Applicant applied for a Certificate of Need on November 29, 2010. The Commission accepted the CON application as complete on February 15, 2011.

The environmental review process under the certificate of need procedures includes public information/scoping meetings and the preparation of an environmental review document, the Environmental Report (ER). The environmental report is a written document that describes the human and environmental impacts of the proposed project, alternatives to the project and methods to mitigate anticipated adverse impacts. The ER must be prepared before the public hearing and before the Commission can make a decision on the certificate of need application. DOC EFP staff is responsible for conducting the environmental review for CON applications submitted to the Commission (Minn. Rules 7849.1200).

II. MATTERS TO BE ADDRESSED IN THE ER

Selected alternatives and impacts, along with those required in rule (Minn. Rule 7849. 1500, subpart 1 and subpart 3), are incorporated into the Environmental Report Scoping Decision. Impacts identified during the scoping process that were covered in detail in the Environmental Impact Statement (EIS) for the routing docket will receive a high level environmental analysis in the ER; the reader will be referred to the EIS for route specific impacts (i.e., EMF, noise, undergrounding, etc.). Impacts associated with the "alternatives to the proposed HVTL" listed below will be discussed in the ER.

The ER on the proposed Hiawatha HVTL project will address and provide information on the following matters:

- INTRODUCTION
  - Purpose and Need
  - Regulatory requirements
- PROJECT DESCRIPTION
  - General
  - Design
  - Right-of-Way Requirements and Acquisition
  - Construction
  - Operation and Maintenance
  - Permits
- ALTERNATIVES TO THE PROPOSED HVTL
  - No-build Alternative
  - Demand Side Management
  - Purchased Power
  - Up-grading Existing Facilities
  - Size, Type, System Configuration Alternatives
  - Local Generation
    - Fossil Fuel Technologies
      - Micro-Turbines
    - Renewable Resource Technologies
      - Solar
      - Thermal Energy Storage
      - Geothermal
      - Biomass
    - Emerging Technologies
      - Fuel Cells
      - Lithium Ion Battery Storage
      - High-Volume Sodium-Sulfur Battery Storage
      - Vanadium Redux Battery Storage
  - Combining Technologies and Alternatives
- ENVIRONMENTAL AFFECTS
  - Air Quality
  - Biological Resources
  - Culture Resources

Geology and Soils
Health and Safety
Land Use
Noise
Socioeconomics
Transportation
Visual Impacts and Aesthetics
Water Resources (surface, groundwater, wetlands)
Waste Management and Disposal

REQUIRED PERMITS AND APPROVALS

The ER will include a list of permits that will be required for the project.

III ISSUES OUTSIDE THE SCOPE OF THE ER

The following issues will not be considered or evaluated in the ER:

- Route or substation alternatives.
- Generation alternatives that cannot be sited locally (i.e., wind farm).
- Any alternatives that do not meet the underlying need for or purpose of the project.
- The impacts of specific energy sources, such as carbon outputs, from non-local generating facilities.
- The manner in which land owners are paid for transmission rights-of-way easements.
- Contested issues or disputes of fact with respect to the representations made in the CON application.

IV SCHEDULE

Following is the anticipated schedule: July 2011 – ER Available

The above outline is not intended to serve as a "Table of Contents" for the ER document, and as such, the organization (i.e., structure of the document) of the information and the data may not be similar to that appearing in the ER.

Signed this 21st day of April, 2011

STATE OF MINNESOTA
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

William Grant, Deputy Commissioner
Division of Energy Resources

This document can be made available in alternative formats (i.e., large print or audio) by calling 651-296-0391 (voice). Persons with hearing or speech disabilities may call us through Minnesota Relay at 1-800-627-3529 or by dialing 711.