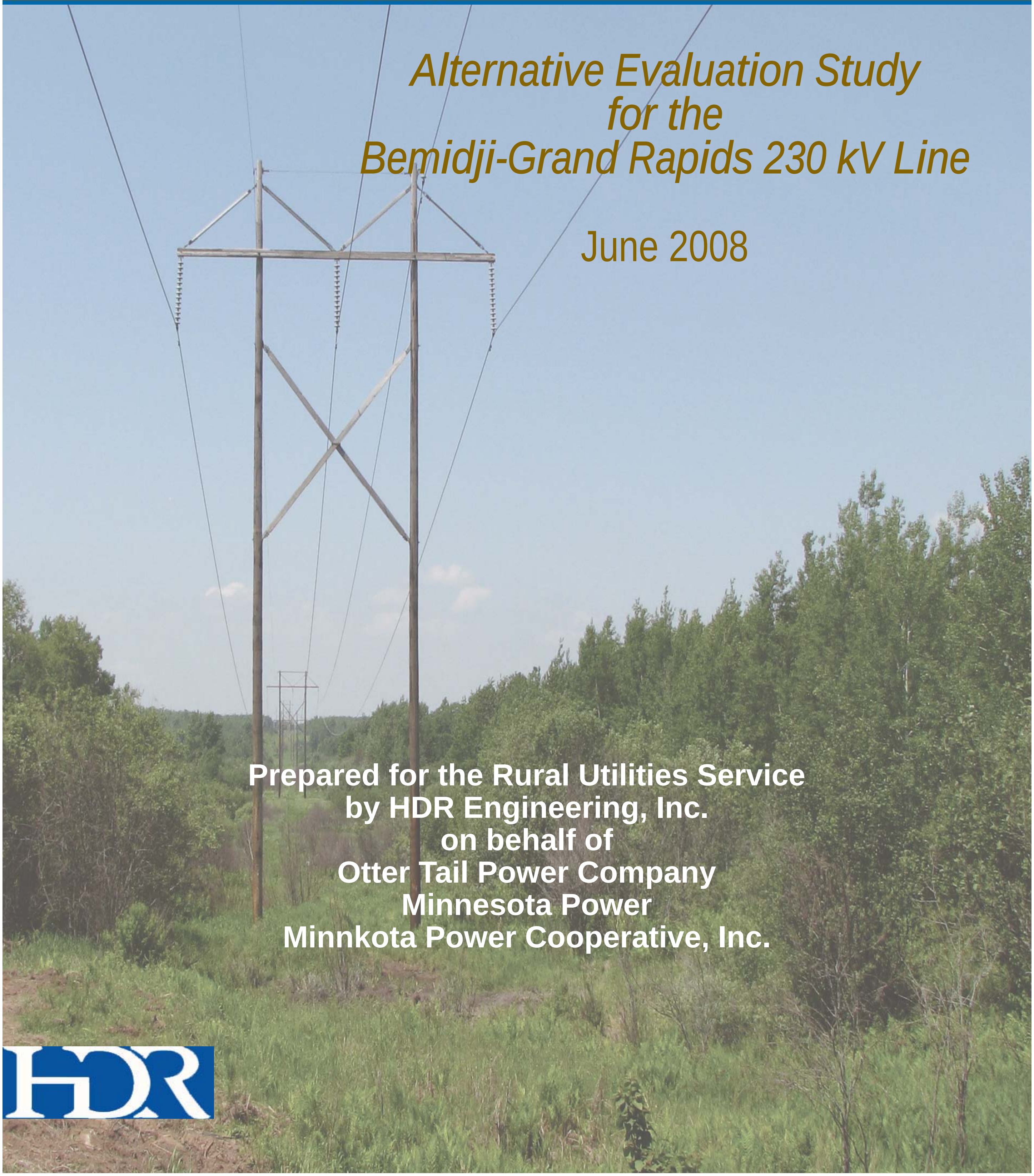
Bemidji-Grand Rapids

230-kV line



Alternative Evaluation Study for the Bemidji-Grand Rapids 230 kV Line

June 2008

Prepared for the Rural Utilities Service
by HDR Engineering, Inc.
on behalf of
Otter Tail Power Company
Minnesota Power
Minnkota Power Cooperative, Inc.

HDR

ALTERNATIVE EVALUATION STUDY

for the

BEMIDJI-GRAND RAPIDS 230 kV LINE

A Minnesota Transmission Project

Prepared by Minnkota Power Cooperative, Inc., Otter Tail Power Company, and Minnesota Power

June 2008

TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF FIGURES AND TABLES

TABLE OF ABBREVIATIONS

ACSR	Aluminum conductor steel reinforced
AES	Alternative Evaluation Study
CapX 2020	Capacity Expansion 2020 initiative
CIP	Conservation Improvement Program
DSM	Demand side management
kV	Kilovolt
kW	Kilowatt
LARR	Levelized annual revenue requirement
MAPP	Mid-Continent Area Power Pool
MPUC	Minnesota Public Utilities Commission
MVA	Megavolt-ampere
MVAR	Megavolt-ampere reactive
MW	Megawatt
MWh	Megawatt hour
N-1	Single contingency
N-2	Double contingency
NDEX	North Dakota Export interface
NERC	North America Electric Reliability Council
P-V	Power-voltage
PVRR	Present value revenue requirements
RUS	Rural Utilities Service
SIL	Surge impedance load
SVC	Static VAR compensator
TIPS	Transmission Improvement Planning Study
Utilities	Minnkota Power Cooperative, Inc., Otter Tail Power Company, and Minnesota Power
VAR	Volt-ampere reactive

SECTION 1
INTRODUCTION

1.1 Summary

This Alternative Evaluation Study (AES) was prepared by Minnkota Power Cooperative, Inc., Otter Tail Power Company, and Minnesota Power (collectively, the Applicants) to support their proposed action to construct an approximately 68-mile 230 kV transmission line between Bemidji and Grand Rapids, Minnesota (Bemidji-Grand Rapids Line or Proposed Project).

Minnkota Power Cooperative, Inc. (Minnkota) is a wholesale electric generation and transmission cooperative headquartered in Grand Forks, North Dakota. Incorporated in 1940, Minnkota provides, on a nonprofit basis, wholesale electric service to 11 retail distribution cooperatives, which are the members and owners of Minnkota. The member systems' service areas encompass 34,500 square miles in northwestern Minnesota and the eastern third of North Dakota. The member systems serve approximately 125,000 of the 300,000 residents in the area.

Otter Tail Power Company (Otter Tail) is an investor-owned electric utility established in 1909 and headquartered in Fergus Falls, Minnesota. The company provides electric service to approximately 128,000 customers in North Dakota, South Dakota, and Minnesota, of which about 58,000 reside in Minnesota.

Minnesota Power, a division of ALLETE Inc., is an investor-owned utility headquartered in Duluth, Minnesota. The Company provides electricity in a 26,000-square-mile electric service territory located in northeastern Minnesota. Minnesota Power supplies retail electric service to 137,000 retail customers, and wholesale electric service to 16 municipalities.

Minnkota intends to obtain financing for its ownership portion of the proposed transmission line from the Rural Utilities Service (RUS). RUS financing of the project constitutes a "federal action," which requires RUS to conduct an environmental review of the project under the National Environmental Protection Act (NEPA). This AES is one of the preliminary documents RUS requires in conducting an environmental review, and it was developed in accordance with the requirements of RUS Bulletin 1794A-603, *Scoping Guide for RUS Funded Projects Requiring Environmental Assessments with Scoping and Environmental Impact Statements* (Feb. 2002). It is designed to provide information about the proposed action to the public to facilitate its participation in the NEPA process.

The AES describes the need for additional transmission to maintain the reliability of the transmission system currently serving the Bemidji area in north central Minnesota, as well as maintaining regional transmission reliability for the larger northwestern Minnesota and eastern North Dakota region. The Bemidji area includes the communities between Winger, Minnesota to the west, Badoura, Minnesota to the south, and Northome, Minnesota to the northeast, as well as a large portion of the Leech Lake Reservation. The Bemidji-Grand Rapids Line is needed for meeting customer demands into the future. The addition of this line will also facilitate the addition of new generation sources in the region. Specifically, portions of the Red River Valley and eastern North Dakota have been identified as areas for the potential development of wind-energy generation sources and the added transmission capacity from the Bemidji–Grand Rapids Line will assist in the development of such resources.

To meet the need of anticipated customer demand into the future, various alternatives to the proposed Bemidji-Grand Rapids 230 kV Line were considered: 1) a "no-action" alternative, which focused on reactive power supply improvements in the Bemidji area and the impact of the Utilities' planned load management/energy conservation programs in the area; 2) a new local generation alternative in the Bemidji area; 3) and alternative transmission lines to the proposed Bemidji-Grand Rapids Line. The evaluation process indicated that the Bemidji-Grand Rapids 230 kV Line is the best way to meet the local electric need, along with providing other regional benefits.

1.2 Project Description

The Applicants propose constructing a 230 kV line from Minnkota Power's 230 kV Wilton Substation located just west of Bemidji, Minnesota, to Minnesota Power's 230 kV Boswell Substation in Cohasset, Minnesota, northwest of Grand Rapids, Minnesota. While final engineering and design has not been completed, the line's construction would likely utilize two-pole, H-frame structures for a majority of the line, which are typical for a 230 kV line located on wooded, rugged topography with wetlands. Each H-Frame structure would average from 70 to 90 feet high and be placed 600 to 900 feet apart. Where conditions warrant it, single-pole construction may be used. The typical right-of-way for a 230 kV line is approximately 120 feet wide. It is anticipated that the project will utilize 954 ACSR conductors (non-bundled), with a capacity of approximately 470 MVA (mega volt-ampere). The conductor size may need to be modified once the ultimate route is selected and additional electrical optimization studies are completed.

The construction of this 230 kV line is estimated to be in the range of $675,000 to $915,000 per mile in 2007 dollars, depending on the terrain crossed (excluding right-of-way, permitting, and other ancillary costs), with 230 kV substation upgrades costing approximately $1 to $1.5 million per substation. The length of the Bemidji-Grand Rapids 230 kV Line along the least cost corridor option is approximately 68 miles, and based on the projected number of miles of the line that would be constructed on wooded and wetland terrain, the estimated cost for line construction is about $58 million, with another $2.5 million estimated to upgrade the Wilton Substation near Bemidji and the Boswell Substation near Grand Rapids, for a total estimated construction cost of $60.5 million. The line is currently projected to be in service by mid-2012.

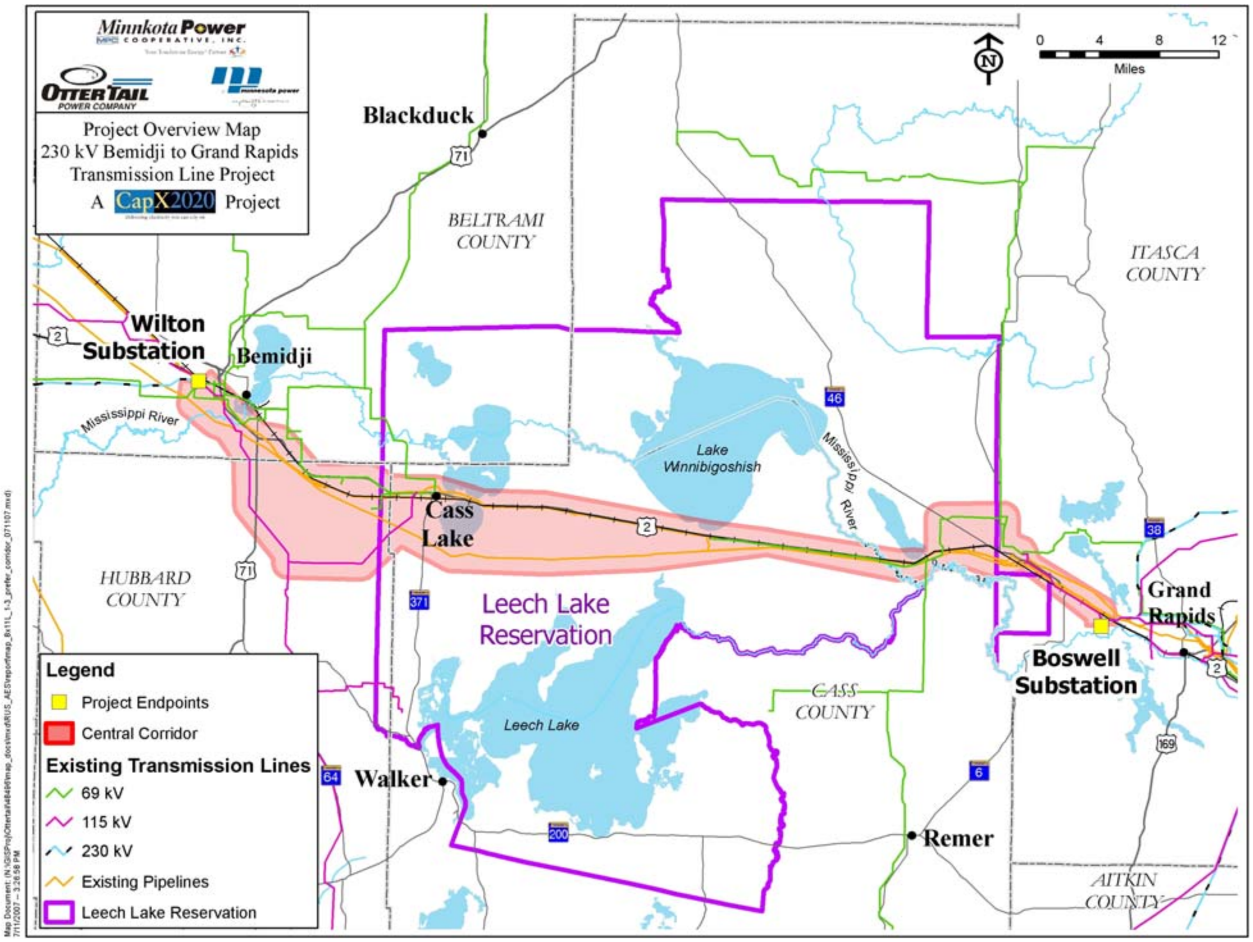
1.3 Central Transmission Line Corridor Alternative

The Applicants have identified a corridor through the central portion of the study area with a number of existing rights-of-way that could be paralleled in whole or in part for the proposed line between Bemidji and Grand Rapids. These include rights-of-way for existing pipelines, transmission lines, and roadways. The Central Corridor option follows 68 miles of existing rights-of-way. The corridor begins at the Wilton Substation northwest of Bemidji and runs southeast through Beltrami County, across the northeast corner of Hubbard County, and into Cass County. The corridor then runs generally due east across Cass County past the City of Cass Lake and through Bena Township to a point between Zemple Township and the City of Deer

River, in eastern Cass County. The corridor then turns southeast and crosses into Itasca County until it reaches the Boswell Substation in Cohasset northwest of Grand Rapids. About 65% of this corridor is located within the Leech Lake Reservation.

Figure 1.3 below depicts the Central Corridor within which the Bemidji-Grand Rapids 230 kV Line could be placed.

Figure 1.3 Central Corridor for the Bemidji-Grand Rapids Line



1.4 Northern and Southern Corridor Transmission Line Alternatives

As a result of discussions with the Leech Lake Band of Ojibwe, the Applicants analyzed two additional alternative corridors for the 230 kV line between Bemidji and Grand Rapids: a 116-mile corridor that runs to the north around the Reservation, and a 99-mile corridor that runs through the southern portion of the Reservation. The U.S. Forest Service requested that an alternative be considered which does not traverse the Chippewa National Forest. In response to its request, a 126-mile sub-corridor of the Southern Corridor has also been added as an alternative. A discussion of electrical performance and cost considerations for the corridor alternatives is presented in Section 3.3.6.

SECTION 2
PURPOSE AND NEED

Analyses of the Minnesota transmission system, as well as the larger regional transmission system, have concluded that the addition of the proposed Bemidji-Grand Rapids 230 kV Line will address three critical issues: (i) improving the voltage stability of the transmission system in the Bemidji area to meet both its current and future load demands; (ii) contributing to increasing the reliability of the entire Red River Valley transmission system to meet the anticipated long-term demand for electrical power; and (iii) facilitating the development of new generation resources in the region, including potential wind energy generation in the Red River Valley and eastern North Dakota. This Section discusses the bases for these conclusions.

2.1 Overview of the Bemidji Area Transmission System

Presently, the Bemidji area electric demand is supplied primarily from remote generation via the bulk transmission system, with some assistance from a local generating facility at Solway, located approximately 15 miles west of Bemidji. The transmission network into the Bemidji area consists of three circuits: the Winger-Wilton 230 kV line, the Winger-Bagley-Solway-Wilton 115 kV line and the Badoura-Akeley-Bemidji-Wilton 115 kV line (which includes a tap to Cass Lake). See Figure 2.1 below.

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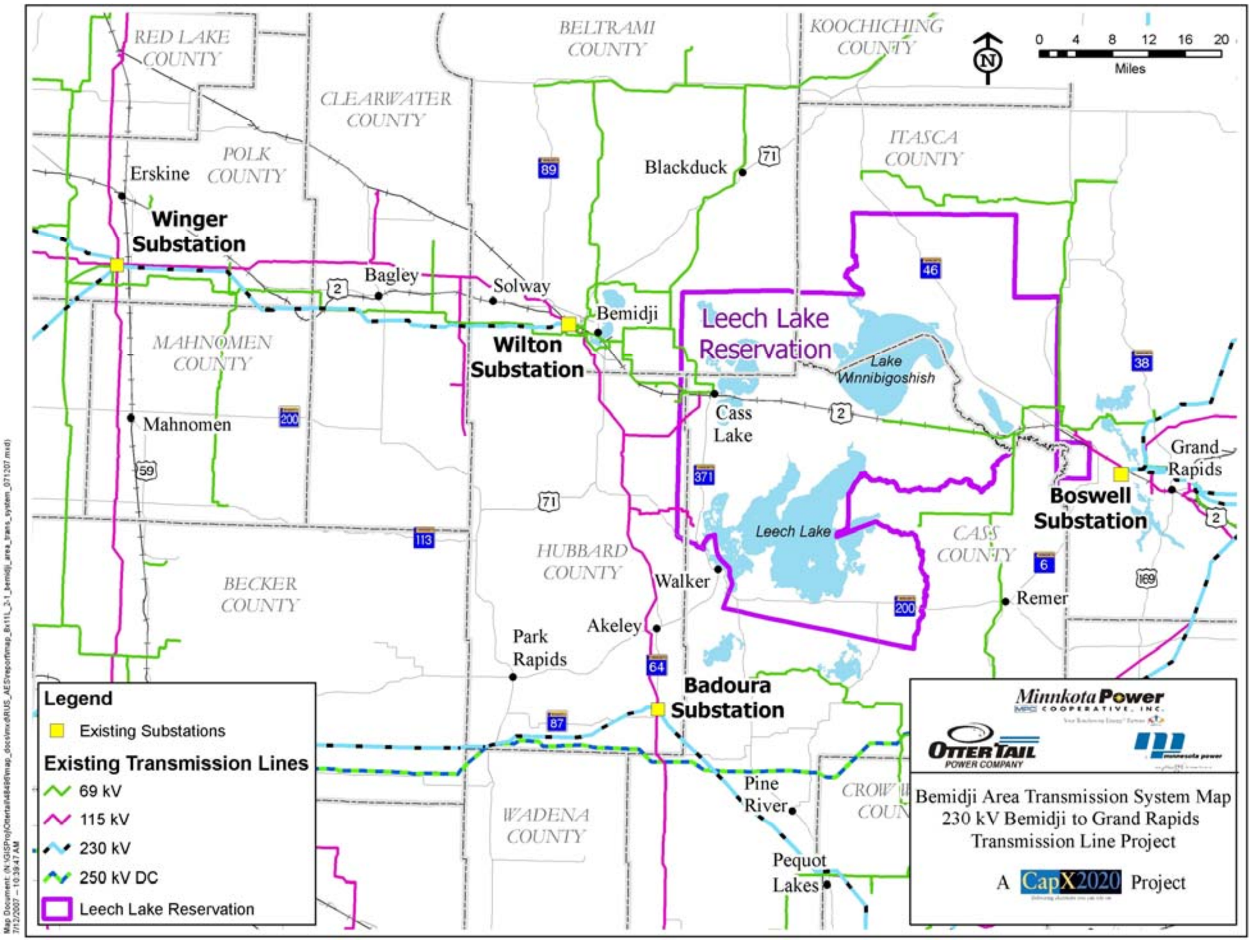
Figure 2.1 Bemidji Area Transmission System



Otter Tail and Minnkota have recently made facility upgrades within the Bemidji area. Minnkota added a second 230/115 kV transformer at the Wilton Substation in 2005 to provide a redundant 230/115 kV delivery from the Winger–Wilton 230 kV line to loads in the Bemidji area. In addition, Minnkota and Otter Tail installed capacitor banks in 2001 and 2002 at both the Wilton and Bemidji 115 kV Substations of approximately 23 MVAR each. However, the reactive support offered by these capacitor banks is now fully consumed by the existing transmission system.

Historically, load-serving capability in the Bemidji area has been constrained primarily by post-contingent voltage inadequacies (rather than line or transformer loadings) for both local and remote transmission contingencies. The most severe local contingency within the Bemidji area is outage of the Winger-Wilton 230 kV line, the only 230 kV source into the Bemidji area. The most severe remote contingency is outage of the Dorsey-Roseau County-Forbes 500 kV line (Dorsey-Forbes Line) connecting the Minnesota transmission system to that of Manitoba Province.

Based on recent studies, thermal problems are expected in the near future on the 115 kV facilities in the Bemidji area. The limiting contingencies are the loss of the 230 kV source from Winger, the Wilton-Bemidji 115 kV line, or the local generation source.

2.2 Overview of Red River Valley Regional Transmission System

The bulk electric transmission system in the Red River Valley primarily consists of a 230 kV network, with a single 345 kV connection between the Red River Valley and western North Dakota. Nearly all of the power supply to the Red River Valley is from remote generation sources. The nearest baseload generation resources are west in North Dakota and north in Manitoba Province, Canada. As a result, power flows through the Red River Valley region are typically west-to-east and north-to-south. However, heavy south-to-north flows are possible during adverse hydrological conditions, when Manitoba Hydro is not able to produce adequate power for its peak demand, which usually occurs during the winter season. Long-term power purchase and capacity exchange agreements between Manitoba Hydro and US power suppliers require that adequate transmission capability be maintained to enable both northward and southward power transfers at all times of the year. During the mid-1990s, large capacitor installations were made at the Prairie 115 kV Substation at Grand Forks, North Dakota (12 x 40 MVAR) and Sheyenne Substation at Fargo, North Dakota (5 x 40 MVAR) to address various regional flow patterns and transmission contingencies. See Figure 2.2 below.

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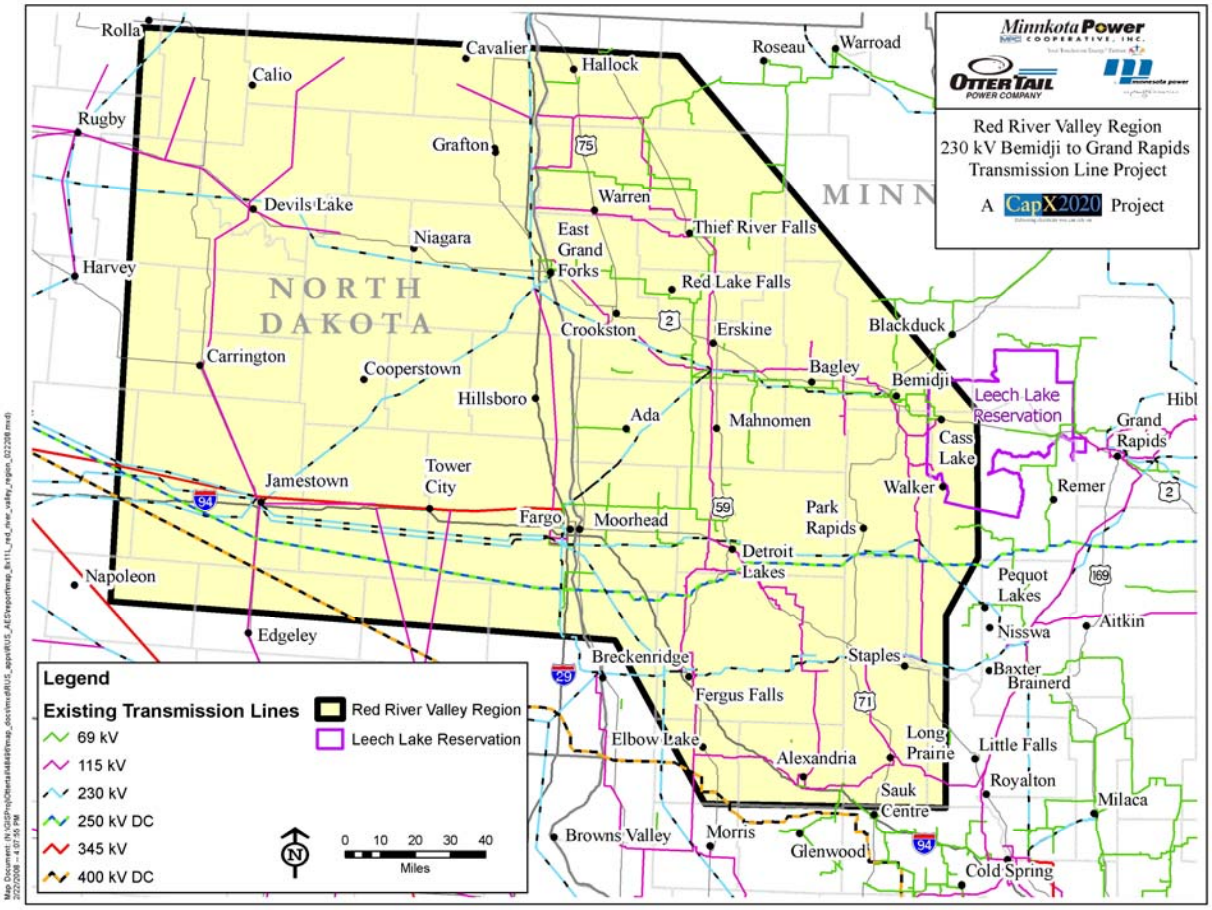
Figure 2.2 Red River Valley Transmission System



As is the case in the Bemidji area, load-serving capability in the Red River Valley has been constrained primarily by post-contingent voltage concerns for both local and remote transmission contingencies. The most severe contingency of local lines connecting the Red River Valley to the generation from the west and north is outage of the Center-Jamestown-Buffalo-Maple River 345 kV line, which is the highest capacity transmission tie between the Red River Valley area and the baseload generation sources to the west. As was discussed above in Section 2.1, the most severe remote contingency for the Red River Valley is outage of the Dorsey-Roseau County-Forbes 500 kV line (Dorsey-Forbes Line). Outage of this 500 kV circuit during northward flow conditions causes significant power to flow through the Red River Valley's transmission system. This "flowthrough" results in high reactive power losses, contributing to the risk of voltage collapse.

2.3 Regional Transmission System Studies and Analyses

The purpose and need for the Bemidji-Grand Rapids 230 kV Line has been the subject of extensive studies over the last five years. A brief history of the studies is provided below.

2.3.1 2002 Red River Valley/West Central Minnesota Transmission Improvement Planning Study (2002 TIPS)

In the summer of 2000, the McHenry–Ramsey 230 kV line, which establishes a 230 kV tie from western North Dakota to Grand Forks, had about 10 miles of structures knocked down by severe storms. A coordinated emergency mobilization of the regional utilities' construction crews enabled the line to be temporarily restored to service in early December of that year to prepare for peak winter loads throughout the region. This sustained outage raised operating concerns, and the Northern Mid-Continent Area Power Pool (MAPP) Operating Review Working Group alerted regional utilities of the potential risk of voltage collapse in the Red River Valley if certain critical combinations of conditions were present.

Recognizing the severity of this outage, local transmission planners in the region came together through the efforts of the Red River Valley Subregional Planning Group to study a long-term transmission solution for the region. The Red River Valley/West Central Minnesota Transmission Improvement Planning Study, completed in 2002 (2002 TIPS), was initiated to identify possible transmission alternatives to address the long-term voltage collapse concern within the region. The analysis completed as part of this effort confirmed that the system was vulnerable to voltage collapse and that improved compensation of reactive loads on the system would improve the situation, but not eliminate it. The 2002 TIPS analysis concluded that new transmission or generation was necessary to remedy the voltage security problems and also maintain reliable service to the region's growing load.

The 2002 TIPS report also included an extensive analysis of the existing transmission system. Based on identified system shortcomings, the report recommended a number of projects to address the Bemidji area's voltage security issues in the short term, including improvement of the distribution system loads' power factor, the addition of 115 kV shunt capacitor banks, and the addition of 230/115 kV transformer capacity. Most of these short-term solutions are underway or have been completed. The reactive support provided by the added capacitor banks is now fully consumed by the existing transmission system. Thus, future load growth requires additional reactive power supplies beyond those already existing in the area, and new transmission or local area generation.

2.3.2 2003 Minnesota Biennial Transmission Projects Report

In 2003, fifteen utilities that own or operate high voltage transmission lines in the state of Minnesota prepared the second Minnesota Biennial Transmission Projects Report (2003 Biennial Report) for the Minnesota Public Utilities Commission (MPUC or Commission). The Biennial Report was prepared pursuant to Minnesota Statutes, Section 216B.2425, which requires utilities owning or operating electric transmission facilities in the State to report on the status of the transmission system, including present and foreseeable inadequacies and proposed solutions.

The 2003 Biennial Report also determined that further upgrades of the Red River Valley's transmission system were necessary to handle the increasing loads in the region and maintain reliable voltage stability margins. The 2003 Biennial Report included preliminary study results of eight new transmission options, which indicated that the combination of a 230 kV line from Bemidji to Grand Rapids and a 345 kV line from Fargo, North Dakota to Monticello, Minnesota would provide the most robust, economic, and efficient transmission solution to address the concerns regarding the Bemidji and Red River Valley areas' voltage stability and load-serving capability.

2.3.3 2005 CapX 2020 Vision Study

Minnesota's largest transmission-owning utilities (including Otter Tail and Minnesota Power) launched the Capacity Expansion 2020 (CapX 2020) initiative in 2004. This initiative focused on prioritizing the transmission infrastructure investments needed in Minnesota to meet the growing demand for electricity in the region, and to ensure timely and efficient regulatory review and approval of those investments. The result was the CapX 2020 Vision Study. This study and other information about this initiative can be found at www.capx2020.com.

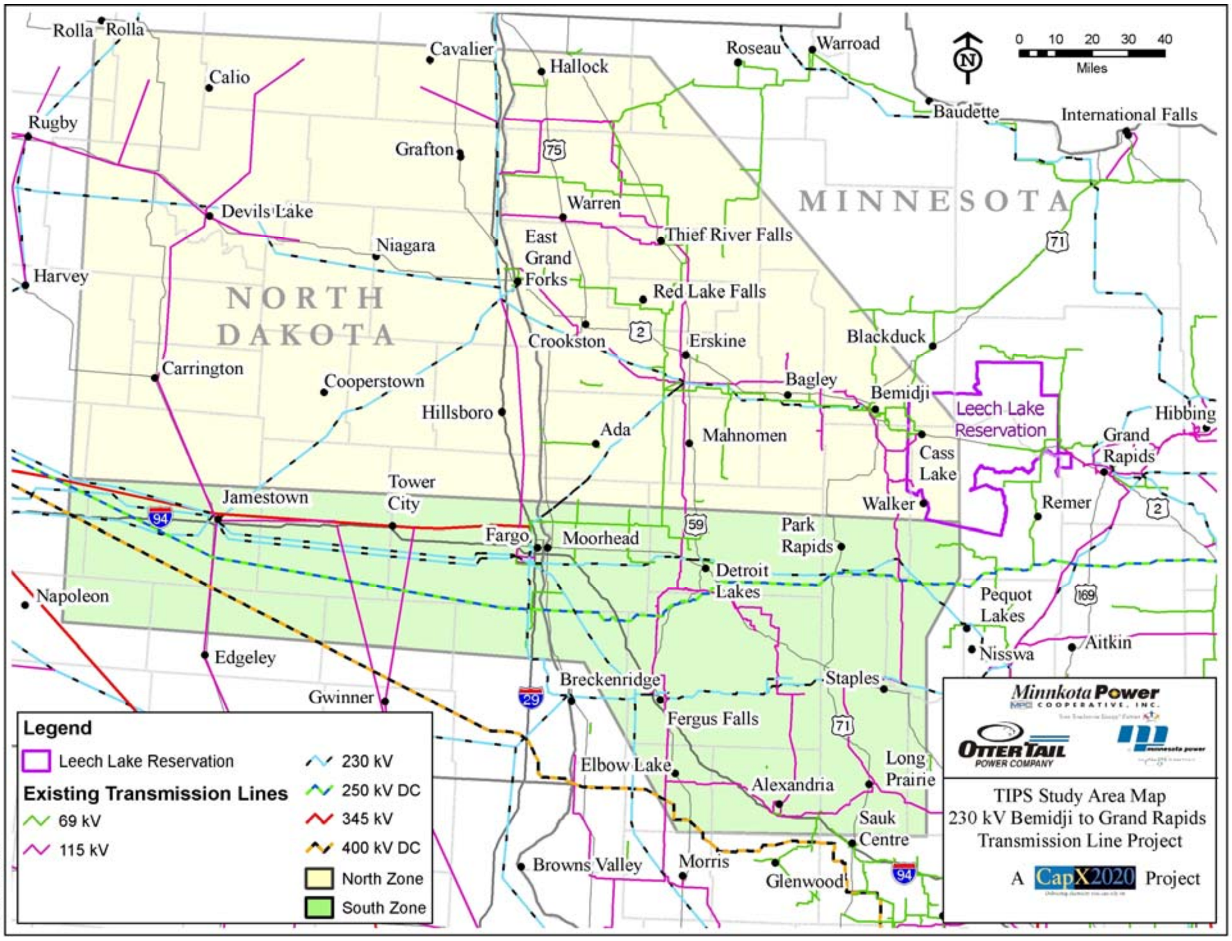
Consistent with the 2003 Biennial Report, the CapX 2020 Vision Study concluded that a number of new high-voltage transmission lines will be required to accommodate the Red River Valley and surrounding region's increasing demand for electricity, and the additional generation capacity required to meet that demand. The CapX 2020 study work found that the Bemidji-Grand Rapids 230 kV Line, along with a Fargo-Monticello 345 kV line, were preferred transmission alternatives for this region because they were effective in: 1) addressing the voltage stability and load serving needs of Bemidji and other principal load centers within the Red River Valley, and 2) improving the load-serving capability of the transmission system in Minnesota and the surrounding region to meet the load growth anticipated by 2020.[1]

2.3.4 2006 Red River Valley/Northwest Minnesota Load-Serving Transmission Study (2006 TIPS Update)

In 2006, the Utilities, along with Xcel Energy, Great River Energy, and Missouri River Energy Services, updated the 2002 TIPS analysis (2006 TIPS Update). The 2006 TIPS Update was undertaken to refine the analysis from the 2002 TIPS report to verify that the best transmission options to address specific voltage stability issues and load serving deficiencies within the Red River Valley hadn't changed since the original 2002 TIPS analysis. In the 2006 TIPS Update, the Red River Valley was divided into three areas (as shown in Figure 2.3.4 below): the northern portion of the Red River Valley region in which Bemidji is located (North Zone), the southern portion of the Red River Valley region (South Zone), and the entire Red River Valley region (Combined Zone).

[1] The 2005 Minnesota Biennial Transmission Projects Report incorporated the finding of the 2003 Biennial Report and the CapX 2020 Vision Study.

Figure 2.3.4 TIPS Study Area



Consistent with previous studies, the 2006 TIPS Update confirmed that the most robust, economic, and efficient upgrades to improve the load-serving capability of the Red River Valley area and local load centers within it are the Bemidji-Grand Rapids 230 kV Line (North Zone); and a 345 kV line between Fargo, North Dakota and Monticello, Minnesota (South Zone).[2] In reaching this conclusion, the 2006 TIPS Update, supplemented by other study work,[3] considered other alternatives including increasing the reactive power supply in the area and other transmission line options.

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[2] The Fargo-Monticello 345 kV Line is one of the CapX2020 projects that is currently the subject of Certificate of Need proceedings before the MPUC.

[3] The supplemental study work was conducted during the period February 2006 to February 2007.

2.3.5 Bemidji, Minnesota Area Electric Transmission System Study: Evaluation of Near-Term Transmission Needs in the Bemidji Area

The Applicants a study in 2006 to focus on the electric infrastructure improvements required to meet the Bemidji area's existing and upcoming load-serving obligations prior to the proposed in-service date for the Bemidji-Grand Rapids Line. As previously discussed in Section 2.1, the Bemidji area is served by three transmission lines and limited generation. The study confirmed the need for another power delivery or supply facility for this load region by 2012, and identifies measures necessary to provide acceptable service until that time.

2.4 Red River Valley/Bemidji Area Need

Based on the 2006 TIPS Update, the 2003/2004 winter peak load within the Red River Valley (Combined Zone) was approximately 1,820 MW. The existing transmission system in the Red River Valley has a maximum load serving capability of around 2,130 MW. The winter peak load within the North Zone of the Red River Valley was about 850 MW. The transmission system in this zone, where the Bemidji area is located, has a maximum load serving capability of approximately 960 MW. Projected peak demand over the next 10-15 years in the North and South Zones of the Red River Valley is projected to be significantly greater than what the current transmission system can handle. With respect to the Bemidji area, the peak load by the winter of 2011/2012 is projected to be about 280 MW, which is 60 MW greater than the current system's maximum load-serving capability in 2011.

SECTION 3
ENERGY ALTERNATIVES EVALUATED

According to RUS Bulletin 1794A-603, § 3.1.1, when there is a need for additional capacity in an area, the Applicants responsible for serving the area may address the need with upgrades of the existing power system, new transmission, new generation, power purchases, load management, or energy conservation. A proposed action to meet the capacity need must be analyzed along with the other relevant alternatives. This section discusses alternatives to the proposed Bemidji-Grand Rapids Line: 1) a no-action alternative that focuses on conservation and system operational improvements; 2) a new generation alternative; and 3) transmission line alternatives to the proposed project. The section explains why all these alternatives are unacceptable or less than optimal in comparison with the proposed transmission line.

3.1 No-Action Alternative

The initial consideration in addressing the reliability of a transmission system strained by increasing load growth is whether both load growth and existing electrical system facilities can be managed to avoid altogether building additional facilities to handle the projected growth. The following discussion of the "no-action" alternative focuses on whether the use of load management and conservation measures to limit energy load growth, and the improvement of local reactive power supply to enable the current transmission system to handle the increase in energy demand, are measures that can successfully address the projected growth in energy demand in the Bemidji area and the Red River Valley over the long term.

3.1.1 Load Management Measures

Pursuant to Minnesota Statutes, Section 216B.2422, each of the Applicants have recently submitted a Resource Plan for review by the MPUC. These Resource Plans detail, among other things, the Utilities' programs to control customer loads. Each of these "demand side management" (DSM) programs are directed at minimizing the peak load at any given moment by reducing or eliminating the load of certain customers at certain times. For example, some residential customers have agreed to have their air conditioners turned off on hot summer afternoons for short periods of time. Similarly, some industrial customers have agreed to curtail their demand for energy during peak periods of energy usage by shifting their work production to other time periods of the day when demand is not so high.

The load growth that the Applicants project for the Bemidji area by 2011/2012 is based on the assumption that they will be successful in reaching the DSM energy savings objectives in their respective Resource Plans. It is not realistic to expect that DSM savings significantly greater than those already reviewed and approved by the MPUC will be achievable and thus eliminate or substantially reduce the projected load growth for the area.

3.1.2 Conservation Measures

The Applicants have also instituted conservation improvement programs (CIP) pursuant to their latest MPUC-approved Resource Plans. These programs focus on increased efficiencies that reduce the amount of energy needed for certain uses. Examples include more energy-efficient lighting for commercial/industrial customers, and more energy-efficient household appliances for residential customers. As with the DSM objectives, the Utilities have assumed that they will meet the CIP objectives in their respective Commission-approved Resource Plans in their estimate of the load growth by 2011/2012 in the Bemidji area. It is not realistic to expect that conservation savings greater than those already reviewed and approved by the MPUC will be achievable and thus eliminate or appreciably reduce the projected load growth for the area.

3.1.3 Reactive Power Supply

Presently, energy demand in the Bemidji area is met primarily by remote generation via the bulk transmission system. The Bemidji area does have two local generating facilities: 1) Otter Tail Power Company's Solway Generating Station located in Lammers Township, Minnesota; which is a 40 MW dual-fuel (natural gas and oil) peaking generator with the ability to operate as a synchronous condenser (dynamic reactive power supply source); and 2) the generator of a large industrial customer, Ainsworth Engineered USA, located near Cass Lake, which is operational only when the plant is running.[4] The current load-serving capability of the Bemidji area is

[4] In September 2006, Ainsworth Engineered USA made a decision to downsize, cutting in half its production of wood products and shutting down its generation facility. The loss of 11.5 MW of generation (and its associated reactive support to the system) with only a 4.5 MW reduction in load will place a greater burden on the local transmission system. Results from the analysis of the Bemidji area have not been updated to quantify the impact of this loss of local generation, but it is known that system performance will be slightly degraded beyond what the existing study results show.

limited by voltage stability concerns following the loss of one of the transmission sources into the area. The present system has a maximum load-serving capability of approximately 220 MW, which is 60 MW less than the anticipated peak load of 280 MW in the 2011/2012 winter season (just prior to when the Bemidji-Grand Rapids Line is expected to be in service). The limiting contingency is the loss of the Winger-Wilton 230 kV line. The location of greatest concern for voltage collapse following this contingency is Cass Lake, which is southeast of Bemidji.

During the initial years of the period between 2006 and 2011, first-contingency requirements to maintain a reliable transmission system could be satisfied with the addition of a third 23 MVAR capacitor bank at the Wilton Substation or forced operation of the Solway generation unit in synchronous condenser mode. During the later years of the 2006-2011 period, however, additional capacitors (possibly at Cass Lake) or another dynamic reactive power source such as a static VAR compensator (SVC) would be required to maintain acceptable voltages in a first-contingency condition.

Double-contingency (N-2) analysis, which focuses on the loss of two critical facilities simultaneously, was conducted to determine the reactive power requirements of the Bemidji area between the years 2006 and 2011.[5] Although the addition of capacitors or a SVC effectively addresses system performance concerns for a number of second-contingency scenarios, it does not fully address all concerns. In many of the second-contingency scenarios, severe line overloading is evident, so even with ample reactive power supplies available, the area's load serving capability is still constrained. Consequently, load shedding must be employed to prevent line overloading during various second-contingency scenarios.

The operation of the 40 MW Solway peaking generator helps improve system performance for most of the contingencies analyzed. However, this requires dispatch of Solway before the contingency occurs. This generator does not help for any scenarios involving the loss of the Solway-Wilton 115 kV line, which separates the generation from the Bemidji load center.

As the 2011/2012 timeframe approaches, Solway will have to be run as a generator for increasing lengths of time on a pre-contingent basis to maintain a reliable transmission system. This is costly, and there are operating limitations on how long it can be run, based on fuel supply and the amount of purified cooling water available. With the Solway generator running at full power, and the aforementioned capacitor additions at the Wilton and Cass Lake Substations, the transmission system in the Bemidji area will have a load-serving capability equal to the projected 2011/2012 peak. When load exceeds its projected level of 280 MW in the 2011/2012 timeframe, the system's voltage stability concerns will need to be addressed by the addition of new transmission or generation into the area.

[5] The standards established by the North American Electric Reliability Council (NERC), which develops and enforces reliability standards to improve the reliability and security of the bulk power system in North America, require consideration of N-2 conditions. See NERC Standard TPL-003-0, Category C (requiring analysis of "event(s) resulting in the loss of two or more (multiple) elements").

System operation beyond the voltage stability limit will result in voltage collapse, evidenced by sustained under-voltages leading to tripping of sensitive loads and reduced life of motors in appliances (refrigerators, furnaces, air conditioners, etc.). These concerns cannot be reliably addressed by more capacitors because when load levels approach the voltage stability limit, capacitor switching results in unacceptably large voltage changes that can result in voltage spikes above acceptable limits. In addition, it is difficult to coordinate automatic controls for the capacitor banks at the higher load levels. Furthermore, the addition of reactive power resources is of limited benefit in addressing the line loading problem that will arise in the near future in the Bemidji area.

3.1.4 Conclusions on No-Action Alternative

The Applicants have and continue to execute DSM and conservation improvement programs to manage the growth of load in the Bemidji area. Their projection of a 280 MW peak load by 2011/2012 already incorporates the energy savings that can be expected to be realized under their latest ten-year Resource Plans. Increasing energy conservation and load management is therefore not a realistic alternative to new transmission or generation to address the area's increasing demand for energy.

The Applicants have also been upgrading existing facilities in the area to meet the increase in demand. The addition of reactive support to area substations, and the increased operation of area generation, will maintain system load-serving capability up to 2011/2012, at which point future load growth will require additional transmission or generation.

3.2 New Generation Alternative

Addition of generation near the load center is a theoretical option for improving the power system's load serving capability. This section discusses the practicality of adding new generation to secure increases in Red River Valley load-serving capability, considering relevant reliability and economic factors.

3.2.1 Type-of-Generation Requirements

Generation can be characterized as either baseload, intermediate, or peaking. Within each type, the generation can be characterized as dispatchable or non-dispatchable. For the Bemidji area, generation output would need to be dispatchable or well correlated with the load level because there is limited transmission capacity for importing energy from other regional generation. Consequently, intermittent resources such as wind generation would not likely be feasible stand-alone solutions.

Baseload generation typically has a high installed cost and low operating costs. Typical units of this type are coal-fired, nuclear, or hydro. The unit is expensive to construct but uses inexpensive fuel, and has relatively high thermal efficiency. Due to strong economies of scale, baseload units generally have 400 to 1000 MW capacities.

In contrast, peaking generation additions have relatively low installed cost but high operating costs. Typical units of this type are gas- or oil-fired combustion turbines. The unit is relatively inexpensive to construct but consumes expensive fuel. Peaking generators such as combustion turbines are commonly available in sizes from 20 MW to 200 MW.

In between the extremes of baseload and peaking generation is intermediate generation. Typical units of this type are "combined-cycle" arrangements consisting of one or two gas-fired combustion turbines with a heat recovery steam generator powering a conventional steam turbine-generator. This blending of technologies captures the low installed cost of the combustion turbine plus the higher efficiency of a steam cycle unit, whose input is recovered waste heat from the combustion turbines. However, fuel costs for gas-fired intermediate generation are volatile and can significantly impact the cost of generation, especially during the winter season when the high demand for gas for home heating affects gas availability and pricing.

In the end, the feasibility of gas-fired generation, even with the economic benefits of intermediate generation efficiency, is less than optimal. Natural gas prices are at their highest during the winter heating season when loads within the Red River Valley are at their highest levels during the year.

3.2.2 Transmission Outlet Requirements

Generation additions in the Bemidji area would be "inside" the North Dakota Export (NDEX) boundary, which is a known transmission constraint in the northern MAPP region. Although the Bemidji area is generation-poor, the NDEX region in which it is located is, as a whole, generation-rich. Addition of new generation in a generation-rich area requires either that existing generation within the area be displaced, or that increased transmission outlet capability be established to allow continued operation of the existing generation.

The existing North Dakota generation is characterized by very low production costs because it is nearly all baseload mine-mouth coal (lignite) or hydroelectric developments on the Missouri River. Consequently, displacement of existing generation is not desirable because displacement of low-cost generation will increase total system production costs.

Since the NDEX boundary is a transfer-limited interface, adding new generation within its boundaries would require transmission additions to increase the existing generation outlet capability. The option of establishing additional NDEX transfer capability would require upgrading existing transmission facilities or adding new transmission lines. Upgrades of existing lines are difficult to achieve due to the constraints on outage scheduling and do not yield significantly increased transfer limits unless conversion to a higher voltage is possible.

The addition of new lines is generally more practical and also tends to reduce system losses. However, new lines constructed to increase existing NDEX generation outlet capability would be similar in length and voltage to the Fargo-Monticello or Bemidji-Grand Rapids lines, whose installation the generation addition is trying to avoid.

3.2.3 Installed Generating Reliability Analysis

In order for a generation addition to the Bemidji area transmission system to provide system reliability enhancement equivalent to that achieved by the addition of a transmission line, the generating facility must be as reliable as the line would be. Based on industry experience of "forced" (unplanned) line unavailability being generally in the range of 1-9 hours per year, a new transmission line can be expected to have an annual availability factor of over 99.9%.

Generators typically have availability in the range of 85 to 95%. It is therefore impossible for the addition of one generating unit to provide service equivalent to that provided by addition of one transmission line. With a generating unit availability in the range of 85 to 95% it is necessary to have four generators each with an 86% availability, or three generators each with a 93% availability, to achieve generation availability equivalent to that of one transmission line.

For the purposes of this analysis, the installation of three combustion turbine units of 60 MW each were assumed to provide for expected load growth as well as achieve required availability. At $400/kW installed, these three units would cost approximately $72 million. This assumes suitable sites and fuel delivery arrangements could be secured. In the case of load centers subject to post-contingent voltage collapse, as is the case in the Bemidji area, one of the local generating units would need to be on line (pre-contingency) during high load conditions, displacing power which would have otherwise come from remote generation resources. The remote generators will as a group have lower energy production costs during nearly all of the hours involved, so system production cost penalties will be accumulated each year.

3.2.4 Conclusions on New Generation Alternative

Adding generation in the Bemidji area is not a practical method of achieving the desired power system load serving capability in lieu of transmission line additions. This is primarily due to the following considerations:

- the Bemidji area is electrically on the generation-rich side of the constrained NDEX boundary, and thus the addition of local generation would displace rather than supplement lower-cost remote generation;

- the relatively low reliability (i.e., availability) of generation compared to that of transmission lines;

- the capital investment required would be of a magnitude equal to if not greater than the transmission facilities they are intended to supplant; and

- the cost of running additional local generation in anticipation of a transmission outage would be significant.

Considering all the above information, installation of local generation in the Bemidji area is not a practical or cost-effective alternative to the construction of adequate transmission facilities.

3.3 New Transmission Alternatives

The Applicants' evaluation process demonstrated that new transmission was the best alternative to address the area's load-serving deficiency. The Utilities evaluated different transmission line options to determine the optimal new transmission alternative to meet the needs of the Bemidji area in particular, as well as the northern Red River Valley region as a whole.

3.3.1 New Transmission Options Evaluated

The Applicants evaluated four new transmission options:

1. Add a Bemidji-Grand Rapids 230 kV line (from Wilton Substation to Boswell Energy Center Substation);

2. Add a second Winger-Wilton 230 line on separate structures from the existing 230 kV line;

3. Add a Badoura-Wilton 230 kV line on separate structures from the existing 115 kV line; and

4. Rebuild the existing 115 kV Bemidji area lines (Badoura-Wilton and Winger-Wilton) to higher capacity (300 MVA).

Figure 3.3.1 below illustrates the four options.

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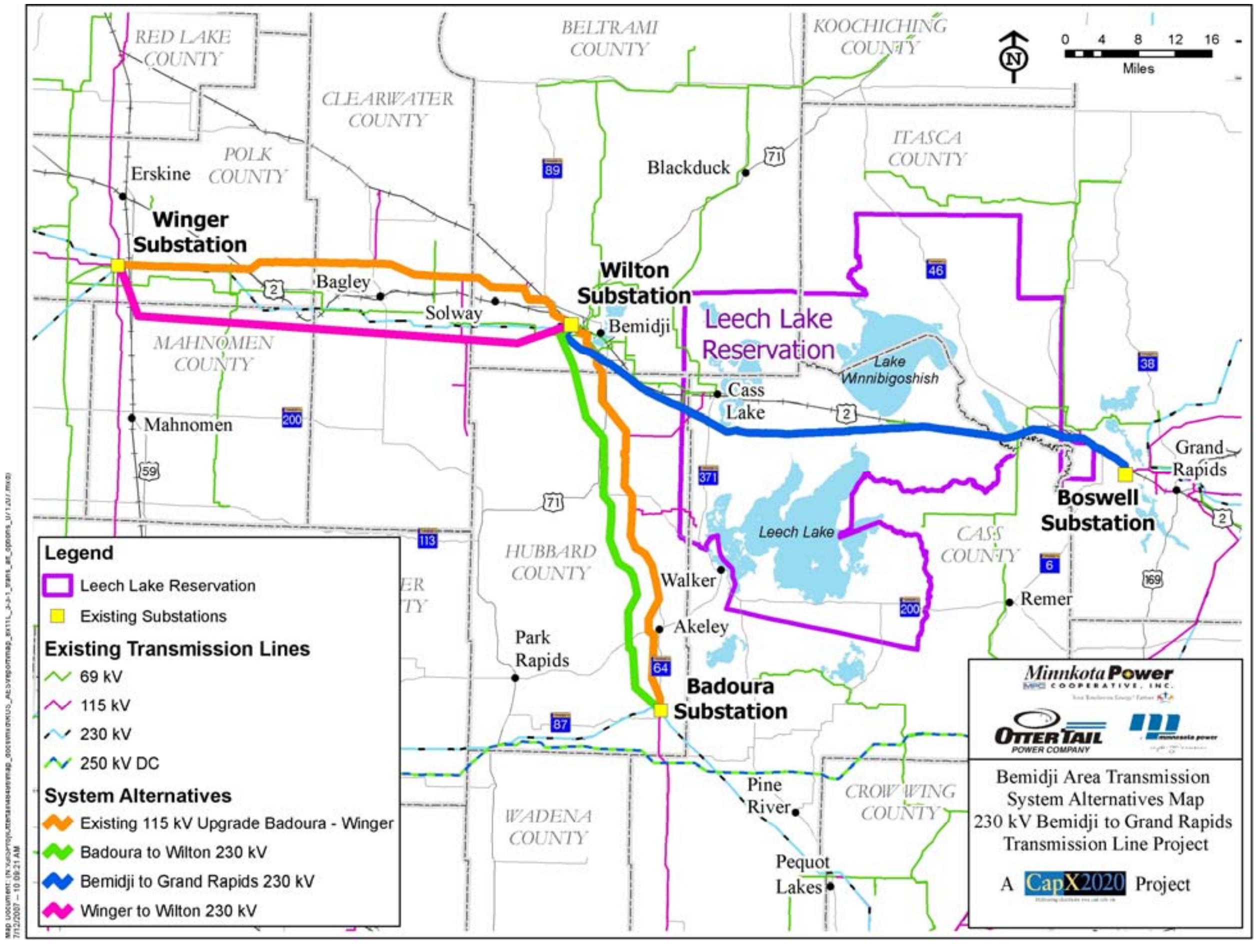
Figure 3.3.1. New Transmission Options



The four options were evaluated to determine which was optimal based on the following analyses: 1) voltage stability (also known as Power-Voltage or P-V) analysis; 2) thermal (line and transformer loading limit) analysis; 3) demand and energy loss analysis; and 4) total cost of ownership analysis. The results from these various analyses of the options' electrical performance and costs are discussed in the following sections.

3.3.2 Voltage Stability and Thermal Limit Analyses

To determine the incremental load-serving capability for the North Zone of the Red River Valley, in which the Bemidji area is located, two types of analyses were performed: (i) a voltage stability (P-V) analysis to examine voltage adequacy as load increases; and (ii) a thermal limit analysis to determine at what point line or transformer overloads (thermal constraints) are experienced as load increases. P-V and thermal limits were analyzed for each option for pre-contingency conditions (i.e., system intact), and after each of the following critical contingencies occurred: a) outage of the Dorsey-Forbes 500 kV line; b) outage of the Wilton-Winger 230 kV line; and (c) coincident outages of the Wilton-Winger 230 kV line and Badoura-LaPorte 115 kV line.

(a) Voltage Stability Analysis Results

As demonstrated by Table 3.3.2.(a) below, the load-serving limits of the North Zone of the Red River Valley as determined by P-V analysis are very different among the various transmission options. All yield at least 290 MW of incremental load serving capability as compared to 230 MW for the existing system.

Table 3.3.2(a) Voltage Stability Limits for Red River Valley North Zone
(Incremental Load-Serving Capability of Red River Valley North Zone Based on 2003/2004 Winter Peak Load of 850 MW)

	Existing System	**Bemidji-Grand Rapids 230 kV Line**	**Winger-Wilton 230 kV Line #2**	**Badoura-Wilton 230 kV Line**	**Rebuild Existing 115 kV Lines**
Condition	**Load Limit (MW)**				
System Intact	525	805	610	650	585
Dorsey-Forbes outage	300*	450	290	370	350
Wilton-Winger outage	230	780	525	590	315
Wilton-Winger & Badoura-LaPorte outage	No solution**	560	415	515	No solution**

* Assumes that currently pending installation of adequate reactive supply in the Winnipeg area to address an outage of the Dorsey-Forbes 500 kV line has been completed.

** Infeasible condition due to voltage collapse

The two options that yield the highest load-serving capability based on P-V analysis are the Bemidji-Grand Rapids 230 kV Line and Badoura-Wilton 230 kV Line (e.g., 450 and 370 MW respectively after an outage of the Dorsey-Forbes 500 kV line). The rebuild of existing 115 kV lines offers no incremental load-serving capability in the event of a Wilton-Winger and Badoura-LaPorte outage.

(b) Thermal Analysis Results

Table 3.3.2.(b) below indicates the best transmission options for increasing the load-serving capability of the North Zone of the Red River Valley based on post-contingent line loading (thermal) concerns are the Bemidji-Grand Rapids and Badoura-Wilton 230 kV Lines. These are also the options with the best voltage stability performance, as discussed above. The worst option is the Winger-Wilton 230 kV Line #2 (e.g., a 25 MW thermal limit for the Dorsey-Forbes

outage). The rebuild of existing 115 kV lines also performs relatively poorly (a 75 MW thermal limit for the Dorsey-Forbes outage).

Table 3.3.2(b) Thermal Limits for Red River Valley North Zone
(Incremental Load-Serving Capability of Red River Valley North Zone Based on 2003/2004 Winter Peak Load of 850 MW)

	Existing System	**Bemidji-Grand Rapids 230 kV Line**	**Winger-Wilton 230 kV Line #2**	**Badoura-Wilton 230 kV Line**	**Rebuild Existing 115 kV Lines**
Condition	**Load Limit (MW)**				
System Intact	350	500	400	500	500
Dorsey-Forbes outage	0	275	25	200	75
Wilton-Winger outage	100	500	350	500	300
Wilton-Winger & Badoura-LaPorte outage	No solution*	500	500	500	No solution*

* Infeasible condition due to voltage collapse

The much higher thermal limit that can be achieved by the Applicants' proposal over the Badoura-Wilton alternative means that once the proposed line is built, any need to add the Badoura-Winger line in the future is significantly postponed. Choosing to build the Badoura-Winger alternative first, however, does not significantly postpone the need for the Applicants' project. That is because if the Applicants' chose to construct the Badoura-Wilton line first, continuing concerns over the system's reliability would be sufficient upon the line's completion to require the Applicants to promptly begin permitting for construction of the Bemidji-Grand Rapids 230 kV Line.

Taken together, the voltage stability (P-V) and thermal analyses show that the best options for providing significant increases in load-serving capability in the North Zone of the Red River Valley (where Bemidji is located) are the Bemidji-Grand Rapids 230 kV Line and Badoura-Wilton 230 kV Line. Compared to one another, the Bemidji-Grand Rapids 230 kV Line option has superior electrical performance based on the voltage stability and thermal analyses summarized above.

3.3.3 Transmission Demand and Energy Loss Analyses

Transmission losses consist of demand (MW) and energy (MWh) losses. The Applicants analyzed the ability of each of the four new transmission options to reduce such losses from the levels experienced for the existing system.

(a) Demand Loss Analysis

Both summer and winter demand losses for the existing system were calculated, and then the reduction of those losses achieved by each of the four options was calculated. The results are provided in Table 3.3.3.(a)(1) below, which show that the Bemidji-Grand Rapids 230 kV Line significantly reduces demand losses over any of the other options.

Table 3.3.3(a)(1) Demand Loss Reductions
Total Eastern Interconnection

	Peak Winter Demand Loss Reduction (MW)	Peak Summer Demand Loss Reduction (MW)
Bemidji-Grand Rapids 230 kV Line	23.9	5.2
Winger-Wilton 230 kV Line #2	0.6	1.2
Badoura-Wilton 230 kV Line	4.3	0.8
Rebuild Existing 115 kV Lines	2.4	1.0

While the upper Midwestern U.S. is strongly summer peaking, the customer load in the northern Red River Valley and the Bemidji area is winter peaking. Thus the reduction in demand losses is greatest during the winter.

The above annual demand loss reduction was then translated into demand-related cost savings, assuming that the capacity savings associated with each option represent an avoided installation of peaking generation capacity. Because the region as a whole is summer peaking, and there is adequate installed generating capacity to meet that peak, the winter peak loss reductions of the four options have little incremental capacity value. The demand loss savings of the options are therefore based on summer demand loss reduction. The value of the demand loss reduction is calculated based on 115% of the actual loss reduction (to cover the reserve sharing pool capacity obligation), an installed cost of $400/kW for the avoided generation, and an annual fixed charge rate of 15%. The cost savings from each option's annual demand loss reduction is provided below in Table 3.3.3(a)(2).

Table 3.3.3(a)(2) Annual Demand Loss Reduction Savings
Total Eastern Interconnection

Transmission Option	Peak Summer Demand Loss Reduction (MW)	Demand Loss Reduction Savings ($000)
Bemidji-Grand Rapids 230 kV Line	5.2	$359
Winger-Wilton 230 kV Line #2	1.2	$ 83
Badoura-Wilton 230 kV Line	0.8	$ 55
Rebuild Existing 115 kV Lines	1.0	$ 69

The demand loss reduction savings of the Bemidji-Grand Rapids 230 kV Line is over four times that of the option with the next greatest savings.

(b) Energy Loss Analysis

The amount of the reduction in winter peak demand losses is used to derive the energy losses associated with each of the transmission options. Basing the energy losses on the winter peak demand losses is appropriate because energy consumption in the Bemidji area is greatest during the winter season. Upon calculating the loss factor for the area transmission system, it was applied to the winter peak demand loss reduction and multiplied by the number of hours per year to obtain the annual energy loss savings in MWh. This was then converted to a dollar value by applying an assumed average annual energy cost of $25 per MWh for replacement energy from existing regional generation resources. The results are shown in Table 3.3.3.(b) below.

Table 3.3.3(b) Annual Energy Loss Savings
(at $25/MWh)

	Winter Peak Loss Reduction (MW)	Loss Factor (%)	Equivalent Hourly Loss Savings (MW)	Annual Loss Savings (MWh)	Annual Loss Savings @ $25/MWh ($000)
Bemidji-Grand Rapids 230 kV Line	23.9	41.5	9.92	86,886	$2,172
Winger-Wilton 230 kV Line #2	0.6	41.5	0.25	2,181	$ 55
Badoura-Wilton 230 kV Line	4.3	41.5	1.78	15,632	$ 391
Rebuild existing 115 kV Lines	2.4	41.5	1.00	8,725	$ 218

The annual energy loss savings resulting from the Bemidji-Grand Rapids 230 kV Line is estimated to be over $2 million per year. All other transmission options yield less than 20% of the savings achieved by the Bemidji-Grand Rapids 230 kV Line.

(c) Cumulative Demand and Energy Loss Savings

The cumulative lifetime economic value of the demand and energy loss reductions was calculated for each transmission option assuming a 20-year period for the duration of the loss differences, and a discount rate of 6% per year. While transmission system economic analyses are ordinarily conducted with longer study periods (30+ years), a 20-year period was selected because the loss differences change over time as transmission system additions are made and as use of the system is modified due to both changes in generation patterns and changes in load levels and locations. Using a 20-year period results in a more conservative statement of the loss savings. Table 3.3.3(c) below shows the present value of the demand and energy losses for each transmission option.

Table 3.3.3(c) Annual and 20-Year Cumulative Present Value of Loss Reductions

	Annual Savings ($000)			Cumulative Present Value ($ Millions)
	Demand Savings	Energy Savings	Total Savings	
Bemidji-Grand Rapids 230 kV Line	$359	$2,172	$2,531	$29.0
Winger-Wilton 230 kV Line #2	$ 83	$ 55	$138	$ 1.6
Badoura-Wilton 230 kV Line	$ 55	$ 391	$446	$ 5.1
Rebuild existing 115 kV Lines	$ 69	$ 218	$286	$ 3.3

The Bemidji-Grand Rapids 230 kV Line yields significantly higher loss savings than any of the other options. (i.e. approximately 5 times greater than the Badoura-Wilton 230 kV Line, which has the next highest loss savings.)

3.3.4 Total Cost Analysis

A final economic analysis was performed to determine whether the impact of the differences in loss savings among the four transmission options is significantly reduced when one considers the options' construction costs. For this analysis, each transmission option's cumulative present value of revenue requirements was calculated based on the construction costs for the option, the option's loss savings, the levelized annual revenue requirement (LARR) factor for the option, a discount rate of 6% per year, and an assumed life for the facilities of 35 years. The construction cost for a 230 kV line is estimated to be between $675,000 and $915,000 per mile, depending on the terrain crossed and excluding right-of-way, permitting, and other ancillary costs. This analysis used an average estimated cost of $795,000 per mile for 230 kV line construction. An estimated cost of $430,000 per mile was used for upgrading 115 kV lines. Table 3.3.4. below shows the transmission options' present value revenue requirements.

Table 3.3.4 Cumulative Present Value of Revenue Requirements (PVRR)
(Including Value of 20-Year Loss Savings)

	Installed Cost ($ millions)	Cumulative PVRR ($ million)		
		Capital Related PVRR	Loss Savings	Net PVRR
Bemidji-Grand Rapids 230 kV Line (68 miles with 2 substation upgrades)	$58	$135	-$29	$106
Winger- Wilton 230 kV Line #2 (53 miles with 2 substation upgrades)	$46	$107	-$ 2	$105
Badoura-Wilton 230 kV Line (48 miles with 2 substation upgrades)	$42	$ 99	-$ 5	$ 94
Rebuilding 115 kV Lines (100 miles with 5 substation upgrades)	$48	$112	-$ 3	$109

Note: The cost to construct a generic 230 kV line is estimated at $795,000/mile; to rebuild a generic 115 kV line is estimated at $430,000/mile; and upgrading a generic 230 kV substation is at $2,000,000, while upgrading a generic 115 kV substation is estimated at $1,000,000.

While the Bemidji-Grand Rapids Line has the highest installed cost, its higher efficiency yields significant electrical loss savings. Consequently, it is tied as the second least-cost option when the total cost of ownership is considered. This economic analysis does not take into account that the options do not provide equivalent load-serving capability, as demonstrated by the voltage stability and thermal analyses in Section 3.3.2 above. The Badoura-Wilton 230 kV option provides only 73% of the load-serving capability of the Bemidji-Grand Rapids 230 kV option (see Table 3.3.2(b)), while costing 89% as much as the Bemidji-Grand Rapids line (see Table 3.3.4 above). The other two options provide significantly less load serving benefit for the Bemidji area.

To illustrate the actual cost-to-benefit profile for all four options, a "Cost of Incremental Load Serving Capability" analysis was done.

3.3.5 Cost of Incremental Load Serving Capability ($/kW)

Using the incremental load serving capabilities reported for each transmission option in Table 3.3.2(b) as a base, both the installed cost and cumulative PVRR for each option was calculated on a per-kW basis. See Table 3.3.5 below.

Table 3.3.5 Incremental Costs of Load Serving Capability

	Incremental Load Serving Capability (MW)	Installed Cost ($ millions)	Installed Cost ($/kW)	Cumulative Net PVRR ($ millions)	Cumulative PVRR ($/kW)
Bemidji-Grand Rapids 230 kV Line (68 miles with 2 substation upgrades)	275	$ 58	$ 211	$ 106	$ 385
Winger-Wilton 230 kV Line #2 (53 miles with 2 substation upgrades)	25	$ 46	$ 1,840	$ 105	$ 4,200
Badoura-Wilton 230 kV Line (48 miles with 2 substation upgrades)	200	$ 42	$ 210	$ 94	$ 470
Rebuilding 115 kV Lines (100 miles with 5 substation upgrades)	75	$ 48	$ 640	$ 109	$ 1,453

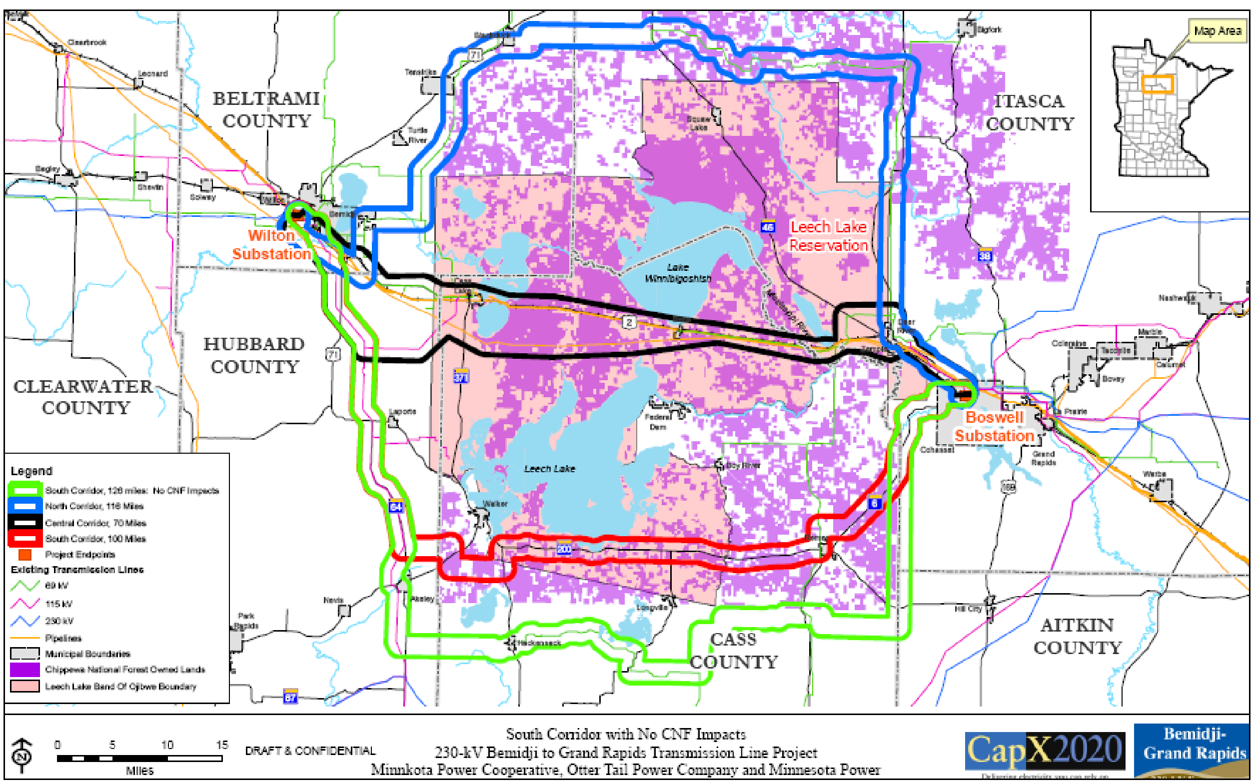
The Bemidji-Grand Rapids and Badoura-Wilton 230 kV Lines have comparable installed costs per kW ($211 vs. $210), but the net PVRR for the Bemidji-Grand Rapids Line is 16% lower than for the Badoura-Wilton Line on a cost per kW basis ($385 vs. $470).

More importantly, as demonstrated in subsection 3.3.2(b) above, the superior thermal performance of the Bemidji-Grand-Rapids Line means that its construction in the timeframe proposed by the Applicants effectively postpones any need for the Badoura-Wilton Line for a much longer period. Choosing instead to construct the Badoura-Wilton Line does not similarly forestall the necessity of building the Bemidji-Grand Rapids, however. Upon completion of the Badoura-Wilton line, the permitting process for the Bemidji-Grand Rapids Line would have to begin almost immediately so that it could be completed by the time it is needed. This would force ratepayers to unnecessarily absorb the cost of two lines over a short period of time when the cost of only one line is necessary.

3.3.6 Corridor Option for the Bemidji-Grand Rapids 230 kV Line

After completing the studies that identify the Bemidji-Grand Rapids 230 kV Line as the best transmission solution to the area's load serving inadequacies, the Applicants discussed the issue of locating the corridor for the line through the Leech Lake Reservation with the Leech Lake Band of Ojibwe. The Band expressed an interest in alternative corridors for the Bemidji-Grand Rapids Line that would avoid passing through the Reservation as much as possible. Two alternative corridors were identified: a 116- mile corridor that runs to the north around the Leech Lake Reservation (Northern Corridor); and a 99-mile corridor that runs through a southern portion of the Reservation (Southern Corridor). Subsequent to this, the U.S. Forest Service requested a corridor option be considered that is not located within the Chippewa National Forest. The non-Chippewa Forest (Non-CNF) corridor alternative located south of the Southern Corridor, is 126 miles in length. Information for this option has not been fully analyzed separately from the Northern corridor option. However, because the Non-CNF corridor is longer than the Northern corridor and it is assumed therefore that the electrical performance of this option is less than or equal to that of the Northern Corridor, and its costs would be greater. Locations of the Northern, Central, Southern, and Non-CNF corridor alternatives are shown in Figure 3.3.6 below.

Figure 3.3.6 Corridor Alternatives for Proposed Bemidji-Grand Rapids Line

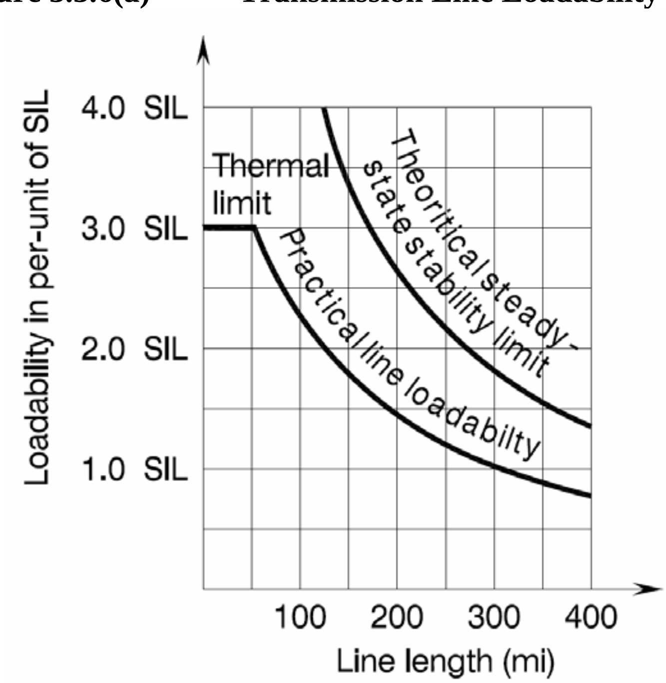


(a) Electrical Performance Issues

Of the four corridors, locating the Bemidji-Grand Rapids 230 kV line in the Central Corridor would provide the most reliable electric service. This is due to the fact that: (i) it maximizes the load serving ability of the line; (ii) it provides the most flexibility to make other reliability improvements in the area, most notably at Cass Lake; and (iii) it results in a system design that minimizes the risk associated with multiple transmission lines in the same corridor.

A transmission line's ability to transport increasing amounts of electric power, referred to as the line's loading limit, is generally constrained by the line's thermal limit. When a transmission line is short, the impedance of the conductor is smaller and therefore the line can be loaded up to its capacity, or thermal limit, and still maintain stable voltage (steady state stability). The longer the transmission line becomes, however, the higher the impedance of its conductor and the lower its ability to maintain acceptable steady state voltage. In short, as a line's length increases its loading limit becomes less than its thermal limit, resulting in a longer line providing less load-serving capacity than a shorter line of the same voltage. Figure 3.3.6(a) below illustrates the relationship between line length and loadability.

Figure 3.3.6(a) Transmission Line Loadability Limits



Note: The above transmission line loadability curve is for 60 Hz uncompensated overhead lines, and based on Figure 6.1.2 from *Power System Analysis and Design*, Glover/Sarma, at 217 (PWS Publishers 1987). "SIL" refers to "surge impedance load," which is the power delivered to an electric load that is equal to a transmission line's characteristic impedance. For a 230 kV line, the SIL is approximately 145 MW.

The Southern Corridor is almost a third again as long as the Central Corridor (99 miles vs. 68 miles), resulting in the loading limit of a 230 kV line in the Southern Corridor being about 85% of the limit of a 230 kV line in the Central Corridor. The 116 mile long Northern Corridor would result in a 230 kV line's loadability of only 75% of what it would be in the Central Corridor. The Non-CNF Corridor is 126 miles long and would result in lower line loadability than the Northern Corridor. The reduced loading limits of transmission facilities in the alternative corridors directly diminishes the lines' ability to effectively address post-contingent voltage concerns in the Bemidji area and reduces the load serving capability of the line.

A further consideration is that there is expected to be a need for additional electric power support in the vicinity of Cass Lake. If the existing 115 kV line between Bemidji and Nary Junction southeast of Bemidji experiences an outage, Cass Lake has only one electrical source remaining, which is from Badoura to the south. Studies show that any significant growth in the Cass Lake area it would be difficult to serve Cass Lake from Badoura alone. The Central Corridor passes very near Cass Lake, making available low-impact options to reinforce electric service performance. This would involve segmenting the proposed Bemidji-Grand Rapids Line with a new 230/115 kV substation located near Cass Lake, or upgrading the existing 115/69 kV Cass Lake Substation to handle the new line. Either of these options can be accomplished with minimal impact on right-of-way requirements, and at relatively low expense compared to what would be required to improve Cass Lake service if the Bemidji-Grand Rapids Line was located in the Northern or Southern Corridors. It would be necessary to build a new 10- to 12-mile 115 kV line in new right-of-way to connect either corridor to Cass Lake, at an estimated cost of $7.5 million, or 36% more than the estimated cost of $5.5 million for an expanded or new substation in the Cass Lake area with no additional right-of-way required. The Applicants address the Cass Lake area electric power support need and solution in more detail in their application to the MPUC for a route permit for the Bemidji-Grand Rapids Line.[6]

System design issues present constraints to locating the Bemidji-Grand Rapids 230 kV Line in the Southern or Non-CNF Corridors. The Non-CNF Corridor overlays the entire route of the existing Wilton-Bemidji-Nary-Laporte-Akeley 115 kV line, while the Southern Corridor overlays the vast majority of that route. Locating the Bemidji-Grand Rapids 230 kV Line along the same route as the Wilton to Akeley 115 kV line would result in 2 of the 4 transmission facilities for the Bemidji area being directed through the same geographic region south of Bemidji. Choosing to configure the system like this heightens the risk that the Bemidji-Grand Rapids and Wilton-Akeley transmission lines could both experience an outage from the same weather-related event along this 45-mile corridor. NERC recognizes the loss of all circuits within a common right-of-way as a credible contingency that must be considered in transmission planning studies. See NERC Standard TPL-004-0, Category D.7.

(b) Cost Issues

The Applicants conducted demand and energy loss and cost of ownership analyses of the Bemidji-Grand Rapids 230 kV line in the Northern, Central and Southern corridors. The same methodologies and cost assumptions were used for these analyses as those discussed in Sections 3.3.3 and 3.3.4 above.

[6] *In the Matter of the Application for a Route Permit for the Bemidji-Grand Rapids 230 kV Transmission Project*, MPUC Docket No. E-017, E015, ET-6 TL-07-1327, Application for a Route Permit (June 4, 2008).

The demand loss reductions of the three corridors are shown in Table 3.3.6(b).1 below for both summer and winter peak conditions.

Table 3.3.6(b)(1) **Demand Loss Reductions**
Total Eastern Interconnection

	Peak Winter Demand Loss Reduction (MW)	**Peak Summer Demand Loss Reduction (MW)**
Northern Corridor (116 miles)	19.2	4.3
Central Corridor (68 miles)	23.9	5.2
Southern Corridor (99 miles)	20.6	4.7

The Northern and Southern Corridors yield smaller loss reductions (19 and 21 MW) than the Central Corridor. The alternative corridors' weaker performance is due to their greater lengths, and therefore higher impedance, which result in less power flow on the line and consequently offer less loading relief for existing transmission sources in the Bemidji area.

The annual summer peak demand loss reductions for the corridors were translated into demand-related cost savings. The results are in Table 3.3.6(b)(2) below, which shows the savings from the Central Corridor are 11% greater than those of the Southern Corridor, and 21% greater than those of the Northern Corridor.

Table 3.3.6(b)(2) Annual Demand Loss Reduction Savings
Total Eastern Interconnection

Transmission Option	Demand Loss Reduction Savings ($000)
Northern Corridor (116 miles)	$ 297
Central Corridor (68 miles)	$ 359
Southern Corridor (99 miles)	$ 324

Annual energy losses and associated cost savings derived from the winter peak demand losses were also calculated for the three corridors, as shown in Table 3.3.6(b)(3) below.

Table 3.3.6(b)(3) Annual Energy Loss Savings
(at $25/MWh)

	Peak Loss Reduction (MW)	Loss Factor (%)	Equivalent Hourly Loss Savings (MW)	Annual Loss Savings (MWh)	Annual Loss Savings @ $25/MWh ($000)
Northern Corridor (116 miles)	19.2	41.5	7.97	69,800	$ 1,745
Central Corridor (68 miles)	23.9	41.5	9.92	86,886	$2,172
Southern Corridor (99 miles)	20.6	41.5	8.55	74,889	$ 1,872

The Central Corridor is projected to allow annual energy loss savings of over $2.1 million, which is 14% greater than the loss savings of the Southern Corridor, and 20% greater than those of the Northern Corridor.

The cumulative lifetime economic value of the demand and energy loss reductions was calculated for each corridor. Table 3.3.6(b)(4) below shows the present value of the demand and energy losses by corridor, which indicate that the Central Corridor offers the greatest opportunity to realize loss savings.

Table 3.3.6(b)(4) Annual and 20-Year Cumulative Present Value of Loss Reductions

	Annual Savings ($000)			Cumulative Present Value ($ Millions)
	Demand Savings	Energy Savings	Total Savings	
Northern Corridor (116 miles)	$ 297	$ 1,745	$ 2,042	$ 23.4
Central Corridor (68 miles)	$ 359	$2,172	$ 2,531	$ 29.0
Southern Corridor (99 miles)	$ 324	$ 1,872	$ 2,196	$ 25.2

To put the loss savings of the corridors into perspective relative to the construction costs of the line for each corridor, the cumulative present value of the revenue requirements to construct the line in each corridor was calculated based on both the construction costs and loss savings associated with the corridor. Table 3.3.6(b)(5) below shows each corridor's present value revenue requirements.

The cost of constructing a line increases when it traverses forested or wetland areas. An estimate of the miles of construction involving forest and wetland was developed in calculating the cost to construct the line within each corridor. Table 3.3.6(b)(5) below shows the cost of constructing the Bemidji-Grand Rapids 230 kV Line in each of the three corridors based on terrain.

Table 3.3.6(b)(5) Bemidji-Grand Rapids 230 kV Line Construction Costs By Corridor

	Central Corridor		Southern Corridor		Northern Corridor	
	Length (miles)	Cost ($ million)	Length (miles)	Cost ($ million)	Length (miles)	Cost ($ million)
Base 230 kV Line Cost	68	$46.9	99	$68.2	116	$79.9
Wetland adder	18	3.5	13	2.5	29	5.7
Wetland Mats	3	3.7	3	3.7	3	3.7
Forest adder	33	4.0	63	7.7	60	7.3
Total Line Cost		$58.1		$82.1		$96.6

Table 3.3.6(b)(6) below shows the present value revenue requirements to construct the Bemidji-Grand Rapids 230 kV Line in each corridor, based on the line construction costs in the above Table plus an estimated $2.5 million for upgrades to the Wilton and Boswell Substations.[7]

Table 3.3.6(b)(6) Cumulative Present Value of Revenue Requirements (PVRR)
(Including Value of 20-Year Loss Savings)

	Installed Cost ($ millions)	Cumulative PVRR ($ million)		
		Capital Related PVRR	Loss Savings	Net PVRR
Northern Corridor (116 miles)	$ 99.1	$ 231	-$ 23	$ 208
Central Corridor (68 miles)	$ 60.6	$ 141	-$ 29	$ 112
Southern Corridor (99 miles)	$ 84.6	$ 196	-$ 25	$ 171

The Central Corridor has a PVRR of $112 million, with the PVRR for the Southern Corridor being 53% higher and the PVRR for the Northern Corridor being 86% higher. The costs of locating the line in the Central Corridor is substantially lower than if it were placed in the Northern or Southern Corridors.

3.3.7 Conclusions on Transmission Alternatives

Taking into consideration all the technical and economic analyses performed on the four possible transmission options for improving the area's load-serving capability, the Bemidji-Grand Rapids Line is the optimal choice. The Bemidji-Grand Rapids Line exhibits the greatest load serving capability based on the P-V and thermal limits for both pre- and post-contingency conditions. The line also outperforms the other transmission options in terms of demand and energy loss reduction savings. Analysis of these operational savings together with the line's construction costs and the amount of load-serving capability achieved shows that the line is the least cost option on a total-cost-of-ownership basis. Analysis shows that among the four line corridor alternatives, locating the Bemidji-Grand Rapids Line in the Central Corridor would provide the best electric performance at the least cost.

[7] The $2.5 million is based on an estimate of the actual substation upgrade work necessary for the Bemidji-Grand Rapids 230 kV Line, not the generic $2 million/substation upgrade used in the transmission options analysis.

SECTION 4
CONCLUSION

The Utilities have studied no-action, new generation, and new transmission alternatives to deal with transmission system deficiencies with increasing customer load in the Bemidji area. This AES demonstrates that the no build alternative for dealing with the growth is not a responsible option for the Utilities given their obligation to provide safe and reliable electrical service to their customers. While the execution of DSM and CIP programs will limit the rate of customer demand for more energy, and existing system upgrades by the Utilities can extend system reliability for the near-term, future load growth is nevertheless projected to reach a point where either new generation or new transmission will be necessary to meet anticipated demand.

Adding new generation in the Red River Valley, however, is not a practical alternative to improving the load serving capability of the electric system. The reliability and economics of adding small, intermediate, or large generation are not favorable in comparison to the alternative of adding new transmission. While the capital investment to add small generators is comparable to the costs of adding new transmission, additional operational costs arise due to the higher energy production costs of the local generation additions compared to those of existing remote generation resources. If large generators were added, generation outlet requirements for the area would increase, requiring additional transmission that the generation was intended to avoid. Intermediate generation has even greater capital investment and operational costs than small generation, and also contributes to an increased need for generation outlet facilities as the addition of large generation would.

The best alternative to address the load-serving concerns of the area is new transmission. In comparison to the four new transmission options that could address the issue, the Bemidji-Grand Rapids 230 kV Line has the best electrical performance and best cost-to-benefit profile. Construction of the proposed line within the study area's Central Corridor would provide the best electrical performance at the least cost in comparison to locating the Proposed Project in the Northern, Southern, or Non-CNF Corridors. The Applicants have also developed a Macrocorridor Study (MCS) which provides information on environmental, social, and cultural resources for each of the four corridor alternatives. RUS makes both the AES and MCS publicly available during the public scoping process to facilitate the participation of interested parties in the environmental review of the proposed action. Input received from the public and interested parties will be used to determine the range of alternatives and impacts to be considered in the scope of the environmental assessment.