Alternative Evaluation Study

Hampton - Rochester - La Crosse 345kV
Transmission System Improvement Project

Prepared For:

USDA Rural Development

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EDAW | AECOM

May 2009

ALTERNATIVE EVALUATION STUDY

Hampton-Rochester-La Crosse
345 kV Transmission
System Improvement Project

Dairyland Power Cooperative
Northern States Power Company,
a Minnesota corporation
Northern States Power Company,
a Wisconsin corporation
Southern Minnesota Municipal Power Agency
Rochester Public Utilities
WPPI Energy

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ACRONYM LIST

ACSS	aluminum core steel supported
AES	Alternative Evaluation Study
C.F.R.	Code of Federal Regulations
DPC or Dairyland	Dairyland Power Cooperative
DSM	Demand Side Management
EIS	Environmental Impact Statement
IRP	Integrated Resource Plan
kV	kilovolt
LFS	Load Forecast Study
MAPP	Mid-Continent Area Power Pool
MCS	Macro-Corridor Study
MISO	Midwest Independent Transmission System Operator
MN PUC	Minnesota Public Utilities Commission
MVA	million volt-amp
MVAR	megavolt amperes reactive
MW	megawatt
MWh	megawatt hour
NEPA	National Environmental Policy Act
NSPM	Northern States Power Company, a Minnesota corporation
NSPW	Northern States Power Company, a Wisconsin corporation
OES	Minnesota Department of Commerce Office of Energy Security
RES	Renewable Energy Standard
RPU	Rochester Public Utilities
RUS	Rural Utilities Service
SMMPA	Southern Minnesota Municipal Power Agency
Proposal	Hampton–Rochester–La Crosse 345 kV Transmission System Improvement Project
U.S.C.	United States Code
WPPI	WPPI Energy, Inc.

1.0 Introduction

1.1 Environmental Review Requirements

Dairyland Power Cooperative (Dairyland or DPC), Northern States Power Company, a Minnesota corporation (NSPM), and Northern States Power Company, a Wisconsin corporation (NSPW) (collectively, Xcel Energy), Southern Minnesota Municipal Power Agency (SMMPA), Rochester Public Utilities (RPU) and WPPI Energy, Inc. (WPPI) (collectively, Utilities) propose to construct a 345 kilovolt (kV) line project between Hampton, Minnesota (southeast of the Twin Cities) and La Crosse, Wisconsin. The proposed CapX2020 Hampton-Rochester-La Crosse 345 kV Transmission System Improvement Project (Proposal) is needed to maintain reliable community service, improve regional electrical system reliability and support generation development.

This Alternative Evaluation Study (AES) was prepared by Dairyland and its consultant, EDAW | AECOM. Dairyland has requested financial assistance from the Rural Utilities Service (RUS), an agency that administers the U.S. Department of Agriculture's Rural Utilities Programs, for its anticipated 11 percent ownership interest in the Proposal. RUS has determined that its funding of Dairyland's ownership interest in the Proposal would be a federal action and therefore subject to National Environmental Policy Act (NEPA), 42 U.S.C. § 4321, review. See 7 C.F.R. § 1794.3.

Two preliminary documents that RUS requires when conducting an environmental review for proposed transmission lines are the AES and the Macro-Corridor Study (MCS). This AES was developed in accordance with the requirements of 7 C.F.R. § 1794.51 and RUS Bulletin 1794A-603, *Scoping Guide for RUS Funded Projects Requiring Environmental Assessments with Scoping and Environmental Impact Statements* (Feb. 2002).

Dairyland also anticipates that RUS financing will be used to rebuild its Genoa – Alma 161 kV line (Q-1) which is located in the Proposal area. If the new 345 kV line can be co-located with a portion of the Q-1 on the existing route, the costs of rebuilding the Q-1 will be included in the Proposal costs. If the facilities are not co-located, Dairyland will seek additional RUS financing for the Q-1 rebuild in 2012.

This document would also support preparation of a future Environmental Impact Statement (EIS) required for the construction of the transmission facilities pursuant to 7 C.F.R. § 1794. According to RUS guidance § 1794.24(b)(1) the Proposal requires an Environmental Assessment with scoping. However, due to the potential for significant impacts, RUS is requiring that an EIS for this Proposal be prepared prior to granting Dairyland's request for ownership interest funding.

The environmental analysis document for the Proposal will be developed to comply with NEPA, Council on Environmental Quality Regulations (40 C.F.R. §§ 1500–1508), and RUS's Environmental Policies and Procedures for Electric and Telephone Borrowers (7 C.F.R. § 1794). Agency and public input will be accepted throughout the process. RUS and the other federal agencies involved in the NEPA review will jointly prepare the EIS. Then each federal agency will independently develop its own decision document. Each step in this process provides an opportunity for public review and comment. The Utilities will develop documents for the RUS environmental review considering the application requirements for state transmission facilities permits in Minnesota and Wisconsin.

1.2 The Utilities

Dairyland is a generation and transmission cooperative headquartered in La Crosse, Wisconsin, that provides the wholesale electrical requirements and other services for 25 electric distribution cooperatives and 19 municipal utilities in the Upper Midwest. In turn, these cooperatives and municipals deliver electricity to consumers – meeting the energy needs of more than 500,000 people. Today, Dairyland's generating stations (coal, hydro, natural gas, landfill gas and animal waste-to-energy) have more than 1,100 MW of capacity. Dairyland delivers electricity via more than 3,100 miles of transmission lines and nearly 300 substations located throughout the system's 44,500-square-mile service area. Dairyland's service area encompasses 62 counties in four states (Wisconsin, Minnesota, Iowa and Illinois).

NSPM provides electricity services to approximately 1.2 million customers and natural gas services to 425,000 residential, commercial and industrial customers in the state of Minnesota. NSPW provides electricity services to approximately 246,000 customers and natural gas services to 102,000 residential, commercial and industrial customers in the state of Wisconsin.

RPU, a division of the city of Rochester, is Minnesota's largest municipal utility. RPU serves more than 45,000 electric customers and more than 34,000 water customers, and has revenues nearing $100 million annually. Power production stations include a coal-fired generation plant, a hydro station and two combustion turbines fired by natural gas or fuel oil.

SMMPA was created by its members as a joint-action agency in 1977. SMMPA generates and sells reliable wholesale electricity to its 18 non-profit, municipally owned member utilities and develops innovative products and services to help them deliver value to its customers. Though SMMPA member utilities are located throughout the state, most are in southern Minnesota. SMMPA members serve more than 93,000 residential customers and more than 11,000 commercial and industrial customers.

SMMPA's main source of electricity is its 41 percent share of the 884 MW Sherco 3 coal-fired generator near Becker, Minnesota. SMMPA also relies on an array of other generation sources, including biodiesel-fueled engines and its own wind turbines located at member communities.

WPPI is a regional power company serving 49 customer-owned electric utilities. Through WPPI, these public power utilities share resources and own generation facilities to provide reliable, affordable electricity to more than 190,000 homes and businesses in Wisconsin, Upper Michigan and Iowa.

1.3 Document Purpose

The AES describes the three needs for the Proposal. First, the Proposal will strengthen the transmission network to meet several thousand megawatts (MW) of additional demand for electrical power anticipated in Minnesota, Wisconsin and parts of surrounding states between the years 2009 and 2020. Second, the Proposal will address the need for additional transmission facilities to provide reliable service to the growing communities in the Rochester and Winona/La Crosse areas. Third, the Proposal will provide generation outlet support in southeastern Minnesota where interest in wind generation development is increasing.

To meet these needs, various alternatives to the Proposal were considered: 1) alternative transmission lines, 2) a "no-action" alternative and 3) generation alternatives. The evaluation process indicated that the Proposal is the best way to meet the local load serving needs, provide generation outlet support and enhance the regional reliability of the electrical system. This AES explains why the Proposal is preferred over the other alternatives considered.

The public is encouraged to comment on this AES and the associated MCS, which identifies the most feasible alternative corridors that meet the purpose and need of the Proposal. The RUS will accept comments from the public on the preliminary documents and Proposal during a 30-day comment period and at public scoping meetings held in the area of the Proposal.

1.4 Proposal Description

The Utilities propose to construct the following facilities:

- A 345 kV transmission line from the Hampton Substation near Hampton, Minnesota (southeast of the Twin Cities), to a new North Rochester Substation near Rochester, Minnesota, and a 345 kV transmission line from the new North Rochester Substation to a substation in the area of La Crosse, Wisconsin (this transmission line will of necessity include crossing the Mississippi River). The 345 kV line would be approximately 120 to 140 circuit miles depending on where it is routed;

- Two 161 kV transmission lines, one between the new North Rochester Substation and the Northern Hills Substation, and one between the new North Rochester Substation and the Chester Substation. The North Rochester – Northern Hills 161 kV line would be approximately 10 to 15 circuit miles long and the North Rochester – Chester 161 kV line would be approximately 20 to 30 circuit miles in length;

- Modifications to the Hampton Substation to accommodate connection of the Twin Cities – Rochester – La Crosse 345 kV transmission line.[1] This work will be limited to the addition of one circuit breaker, two switches and associated bus and the addition of relaying in the control building. No additional grading will be required;

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[1] The new Hampton Substation will be constructed as part of another CapX2020 345 kV Project, the Brookings County – Hampton 345 kV Project and will include a graded and fenced area approximately four acres in size. The Brookings County – Hampton 345 kV Project is designed to enhance regional reliability, maintain local community reliability and to increase generation outlet capability in southwestern Minnesota and southeastern South Dakota. The Hampton Substation will be constructed as an integral part of the Brookings County – Hampton 345 kV Project which is needed and planned to be constructed regardless of whether the Proposal is built. The substation is expected to be completed in December 2012. The Twin Cities – Rochester – La Crosse 345 kV transmission line, expected to be completed in 2015, will terminate at the Hampton Substation.

- Improvements at the Northern Hills Substation to accommodate the new 161 kV line. These improvements include: an expansion of the existing graded yard by approximately 30 ft, and the addition of 161 kV equipment including one circuit breaker and associated line termination switches and associated controls;

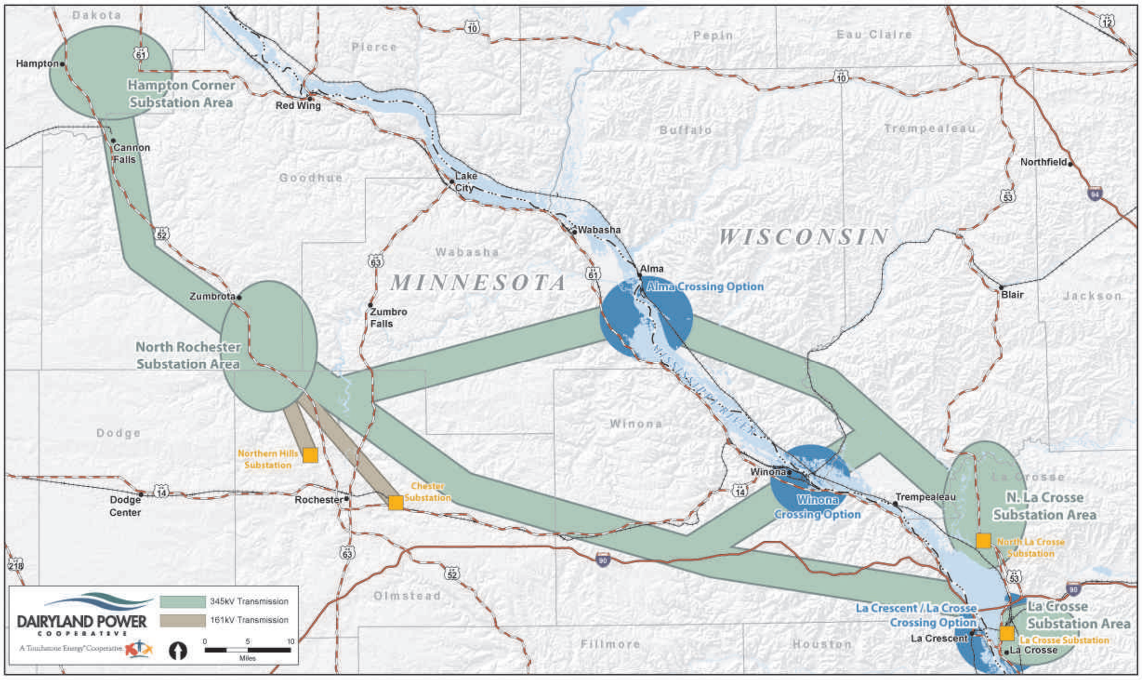
- Improvements at the Chester Substation including expansion of the existing graded yard and the addition of 161 kV equipment such as one steel line terminal structure, one circuit breaker, three voltage transformers, three current transformers, two disconnect switches and all with associated foundations. Other work may include the installation of relaying, communications and control panels inside the existing control building, plus other miscellaneous upgrades;

- Construction of a new North Rochester Substation north of Rochester. This new substation would be approximately 5 acres in size and include six 345 kV circuit breakers, a 345/161 kV transformer, three 161 kV breakers, a control house and associated line termination structures, switches, buswork, controls and associated equipment. The Utilities propose to acquire a parcel of approximately 40 acres to accommodate the fenced area, a buffer and line connections; and

- Depending on the eastern termination, potential improvements at either the La Crosse or North La Crosse substations in Wisconsin to accommodate a termination of the proposed 345 kV transmission line, or construction of a new substation near La Crosse, Holmen, or Galesville Wisconsin. Potential modifications to the existing La Crosse or North La Crosse substations may include one 345 kV breaker, a 345/161 kV power transformer, ten 161 kV breakers, a control house, associated line termination structures, switches, buswork, controls and associated equipment. If a new substation is required, the Utilities propose to acquire a parcel of approximately 40 acres to accommodate the fenced area, a buffer and line connections, and include those items described above.

Figure 1-1 depicts an overview of the Proposal.

Figure 1-1
Proposal Facilities



On the Minnesota side of the Proposal area, Utilities propose to build the 345 kV line with single pole, double circuit steel structures and conductors made up of two 954 aluminum core steel supported (ACSS) cables or conductors of comparable capacity. Up to 150 feet of right-of-way will be required for the 345 kV line. Where the new line is co-located with an existing transmission line, the existing line would be operated at the current voltage, but built capable for 345 kV operation. Where there is no co-location with existing facilities, Utilities would place conductors on one side of the structures for this portion of the Proposal. The second circuit could be added at a later date when conditions justify expansion. In other words, Utilities propose to construct portions of this line to be "double circuit compatible."

For the North Rochester to Northern Hills 161 kV transmission line, the Utilities propose using a single circuit steel pole structures. For the North Rochester to Chester 161 kV line, the Utilities may co-locate the east/west segment of the line with the new 345 kV line and use single circuit steel pole structures for the north/south segment The conductor proposed is 795 ACSS cable or a conductor of comparable capacity. The right-of-way required for the 161 kV lines is up to 80 feet.

On the Wisconsin side of the Proposal, single circuit structures, 161 kV/345 kV double circuit structures or double circuit 345 kV capable structures may be used depending on final route selection.

Where conditions warrant it, wood or steel H-frame structures may be used in some areas and, depending on the route selected, the 345 kV line and an existing transmission line may be placed on the same structures. For example, if an Alma crossing is approved, the new 345 kV line and a portion of the existing Rochester – Alma 161 kV line may be placed on the double circuit compatible structures. From Alma, on the Wisconsin side of the Proposal, 345 kV/161 kV or 345 kV/345 kV structures may also be used to co-locate the new 345 kV line with the existing Alma –Marshland – La Crosse 161 kV line.

The cost of the Proposal can be affected considerably by timing of construction, availability of construction crews and components and the design and final route selected during the various state and federal regulatory processes. Based on the information gathered to date and assumptions about likely structure types and transmission line lengths, the total cost is anticipated to be approximately $380 to $430 million (2007$).[2] The Proposal is currently projected to be in service by third quarter 2015.

[2] These estimates are based on current prices of labor and materials and are stated in 2007 dollars. It is projected that costs of the Proposal may increase approximately five percent per year because of inflation.

2.0 Purpose and Need

2.1 Summary

In the foreseeable future (near-term conditions and up to the year 2020), the demand for electric power in Minnesota and surrounding states will reach levels that cannot be reliably supported by the existing regional electrical system. In several communities, including the Rochester and Winona/La Crosse areas, the demand for power has or will soon exceed the capability of the local transmission systems to reliably provide service in the event one or more transmission lines or generators is out of service. See Section 2.2. Also, to meet this demand for power, the electrical system must be improved to accommodate significant additions of generation. See Section 2.5.

The Proposal is one of four transmission projects (collectively, Group 1 Projects) proposed by the CapX2020 Transmission Expansion Initiative (CapX2020). CapX2020 is a joint initiative (CapX2020 Initiative) of 11 transmission-owning utilities in Minnesota, Wisconsin and the surrounding region whose goal is to study, develop, permit and construct transmission infrastructure needed to implement long-term and cost-effective solutions for customers to meet growing energy demands to the year 2020. The 11 utilities include Utilities, Great River Energy, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Central Minnesota Municipal Power Agency and Otter Tail Power Company.

Each of the three other projects was developed to address specific identified needs. The first of the projects is the Brookings County – Hampton 345 kV Project which was designed to enhance regional reliability, improve local community service and increase generation outlet capability in southwestern Minnesota and southeastern South Dakota. The second project is the Fargo – Monticello 345 kV Project. The Fargo – Monticello 345 kV Project was developed to address load serving needs in the southern Red River Valley, including Alexandria, and St. Cloud, to enhance regional reliability and provide generation outlet support in northwestern Minnesota and southeastern North Dakota. The third project, the Bemidji – Grand Rapids 230 kV Project, will meet community load serving needs in the Bemidji area, improve regional transmission reliability of the larger northwestern Minnesota and eastern North Dakota region, and assist in the potential development of wind-energy resources in portions of the Red River Valley and eastern North Dakota.

All four transmission projects were analyzed individually and each is supported by a separate engineering report: Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study (March 13, 2006); Southwest Minnesota – Twin Cities EHV Development Electric Transmission Study, Volume 1 (November 9, 2005),

Appendix A.2; Red River Valley – Northwest Minnesota Load-Serving Transmission Study (TIPS Update) (February 13, 2006); and Bemidji, Minnesota Area Electric Transmission System Study (January 2007). Each of the four proposals is proposed to be constructed independent of whether the other proposals are built.

This section describes the initial CapX2020 study effort, Technical Update: Identifying Minnesota's Electric Transmission Infrastructure Needs (May 2005) (updated October 2005) (Vision Plan) and the system-wide reliability need. A copy of the Vision Plan is included in Appendix A.1. This section also details the local reliability needs and the timing of those needs. See Section 2.2.1.3. This section further describes the growing demand for additional generation outlet capability in southeastern Minnesota where these facilities will be constructed. The next section, Section 3, discusses the engineering studies that evaluated potential alternative solutions and identified the Proposal as the best performing transmission alternative.

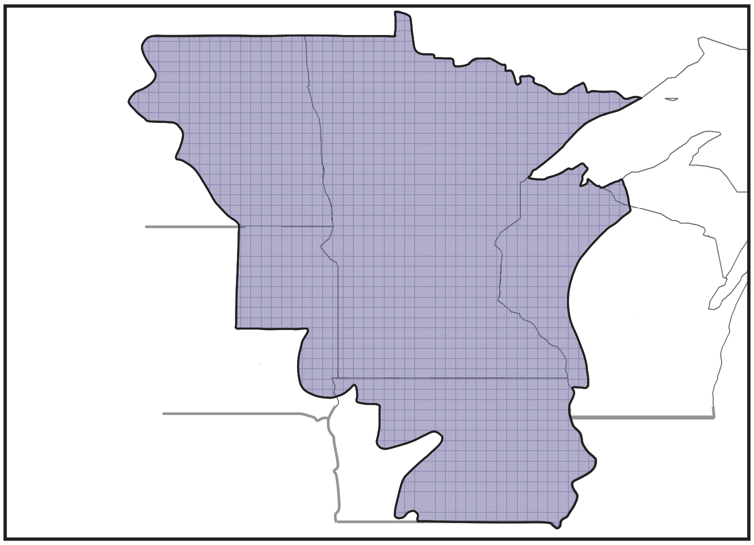
2.2 Regional Need

It has been nearly three decades since the electrical network serving Minnesota and the surrounding area including western Wisconsin has been expanded to any large degree. At the same time, the demand for power has continued to grow. Beginning in 2004, a study effort was undertaken to examine the regional electrical system transmission needs that would be necessary to meet the power requirements of customers anticipated by the year 2020.

2.2.1 The CapX2020 Vision Plan

The CapX2020 Vision Plan was initiated to develop a long-term transmission plan to ensure that load in the region could be served reliably under different generation scenarios. This study was intended to be a high-level study that would provide a blueprint for future transmission development. The study region selected for the Vision Plan was primarily based on the geographic boundaries of the service territories of utilities with customers in Minnesota. Those systems include all of Minnesota and portions of North Dakota, South Dakota, Iowa, Wisconsin and upper Michigan. Figure 2-1 illustrates the geographic area.

Figure 2-1
CapX2020 Study Region



While this footprint was the primary area of focus, transmission is regional in nature, and, as a result, CapX2020 Initiative planning engineers included modeling of a region somewhat larger than the primary study area.

To assess the long-term need, planning engineers developed a load forecast and analyzed three different generation scenarios. Planning engineers contacted energy forecasters (from state and other electric power agencies and groups) for information about the anticipated growth in the demand for electricity. They canvassed generation developers and utilities for information about where power plants might be located to meet growing electricity demand, and relied on forecasts of the growth in electrical demand from generation planners and from proceedings before the Minnesota Public Utilities Commission (MN PUC). Copies of those documents and the associated data are available at the project website: www.CapX2020.com.

Given the uncertainty in where generation will develop, planning engineers created and studied three generation scenarios. These three generation scenarios reflect potential generation development that might influence electric power flows on the regional grid and thus indicate the size and location of new transmission infrastructure needed to deliver this new generation to customers. These three generation scenarios were then compared to determine what transmission facilities were needed under each scenario. This Proposal was one of the facilities that was needed under each of the scenarios studied. See Appendix A-1 at 38.

Since the Vision Plan was published in 2005, further analyses of integrated resource plan and other system planning data (Mid-Continent Area Power Pool (MAPP) Load and Capability) have confirmed that the greater Minnesota area will experience significant load growth by the year 2020.[3] A summary of the Integrated Resource Plan and Load and Capability forecasts as compared to the Vision Plan is shown in Figure 2-1 below.

Figure 2-2
Integrated Resource Plan and Load and Capability Forecasts

Forecast Source	Forecast Scenario	Load Forecast (MW)		Load Growth by 2020 (MW)
		2009	2020	
CapX2020 Vision Plan	Expected Growth	20,201	26,488	6,287
	Slow Growth	20,201	24,701	4,500
Minnesota Integrated Resource Plans	High	22,488	27,392	4,904
	Median	21,332	25,427	4,095
MAPP Load and Capability Data	System Demand	20,783	25,969	5,186

The Vision Plan planning engineers' initial and updated analysis indicate that the region will need to reliably support 4,000 to 6,000 MW of additional load.

2.2.2 Renewable Energy

The need for new high voltage transmission facilities in the region is also driven by the need for significant infrastructure to support renewable energy generation development. One of the many drivers for increased reliance on renewable energy is the Renewable Energy Standard (RES) passed by the Minnesota Legislature in 2007. The renewable

[3] MAPP creates the Load and Capability Report on an annual basis for the purpose of projecting the future resource (generation) and load of each MAPP member in the reserve sharing pool.

standard[4] called by some legislators "the most aggressive renewable energy law in the United States," imposes standards on public utilities providing electric service, generation and transmission cooperative electric associations, municipal power agencies and power districts to generate or buy sufficient renewable energy. Each electric utility serving Minnesota retail customers must meet the following standards for the percentage of its retail sales that must derive from renewable energy sources:

(1) 12% by 2012

(2) 17% by 2016

(3) 20% by 2020

(4) 25% by 2025

The law also specifically sets higher standards for NSPM, which must provide 30% of energy to retail customers from renewable-based generation by the year 2020. The renewable standard will create additional demand for renewable generated power, which includes solar, wind, hydroelectric (limited to facilities that are less than 100 MW), hydrogen or biomass (*e.g.,* landfill gas, anaerobic digester, energy recovery from mixed municipal solid waste or refuse-derived fuel from municipal solid waste).

To satisfy Minnesota's renewable requirements, it is currently estimated that Utilities will need to procure in the range of 5,000 MW of additional installed wind generation along with lesser amounts of biomass and solar generation. Renewable Energy Standards Report 2007 at 34, filed November 1, 2007 in MPUC Docket No. E999/M-07-1028 ("RES Report").

Wisconsin has similarly implemented renewable energy legislation. Wisconsin's renewable legislation requires Wisconsin utilities to meet a gradually increasing percentage of their retail sales with renewable resources. Wisconsin set a goal that that by 2015, 10 percent of the electric energy consumed in the state must be produced by renewable resources. Wis. Stat. § 196.378(2)(a) (2007).

In April 2007, Wisconsin Governor Jim Doyle signed Executive Order 191 which created a Task Force on Global Warming. In July, 2008 the Task Force voted to finalize its report, Wisconsin's Strategy for Reducing Global Warming. In its report, the Task Force

[4] Minn. Stat. § 216B.1691 (as amended 2007).

recommends extensive revisions to Wisconsin's renewable standard. Specifically, the Task Force recommends that, by the dates specified, the following percentages of electric power sold by Wisconsin utilities must come from renewable resources:

(1) 10% by 2013.

(2) 20% by 2020, not less than 6% being from Wisconsin resources.

(3) 25% by 2025, not less than 10% from Wisconsin resources.

The Group 1 Projects, including the Proposal, are a necessary first step toward meeting Wisconsin and Minnesota's renewable energy policy goals.

2.3 Community Reliability Needs

In addition to enhancing the reliability of the regional transmission system, the Proposal will help maintain reliable electrical service in the Rochester and the La Crosse/Winona areas. These communities are experiencing growth in population with a corresponding growth in the demand for power. Without transmission system improvements, these communities are at risk of losing of service, if one or more of the existing transmission lines or power plants serving the area were to be out of service.

The existing electrical system and reliability issues in each of the communities is described below. This section also describes the engineering studies supporting the Proposal which can be found at Appendix A.2 (*i.e*., Southeastern Minnesota-Southwestern Wisconsin Reliability Enhancement Study (March 13, 2006)).

2.3.1 **Rochester Area**

2.3.1.1 **Existing System**

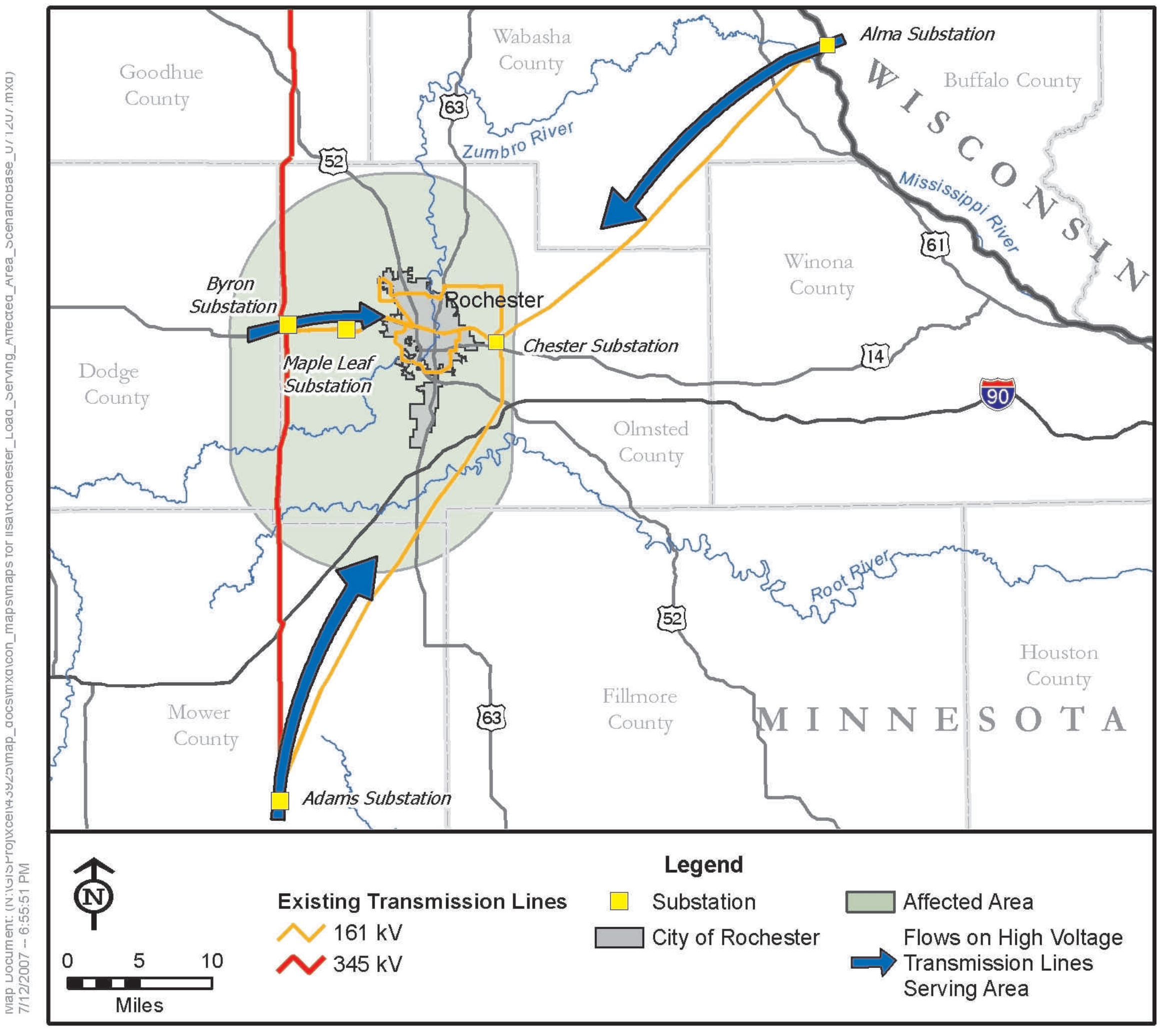
RPU is the municipal electric utility serving the city of Rochester. Dairyland and its member, Peoples Cooperative Services, serve rural customers around the city. This area sees its greatest use of electricity during the summer months. The Rochester area is served by three 161 kV transmission lines: the Byron–Maple Leaf 161 kV transmission line from the west that connects the city to the Prairie Island–Byron 345 kV transmission line, a transmission line from the Alma Substation that enters northeast Rochester and a transmission line entering south Rochester from the Adams Substation.

The transmission system delivers power to several substations in and around Rochester. The substations lower the incoming transmission line voltage and outgoing distribution lines deliver electrical power to customers. The area is also supported by 181 MW of generation located within the city of Rochester: four gas/coal units at Silver Lake totaling

102 MW, two hydro units on the Zumbro River totaling 2.4 MW, and two natural gas/oil units at Cascade Creek totaling 77 MW.

Figure 2-3 shows the affected area and a graphical depiction of the general power flows on these high voltage transmission lines in the Rochester area.

Figure 2-3
Affected Rochester Area and Flows on High Voltage Transmission Lines Serving Area



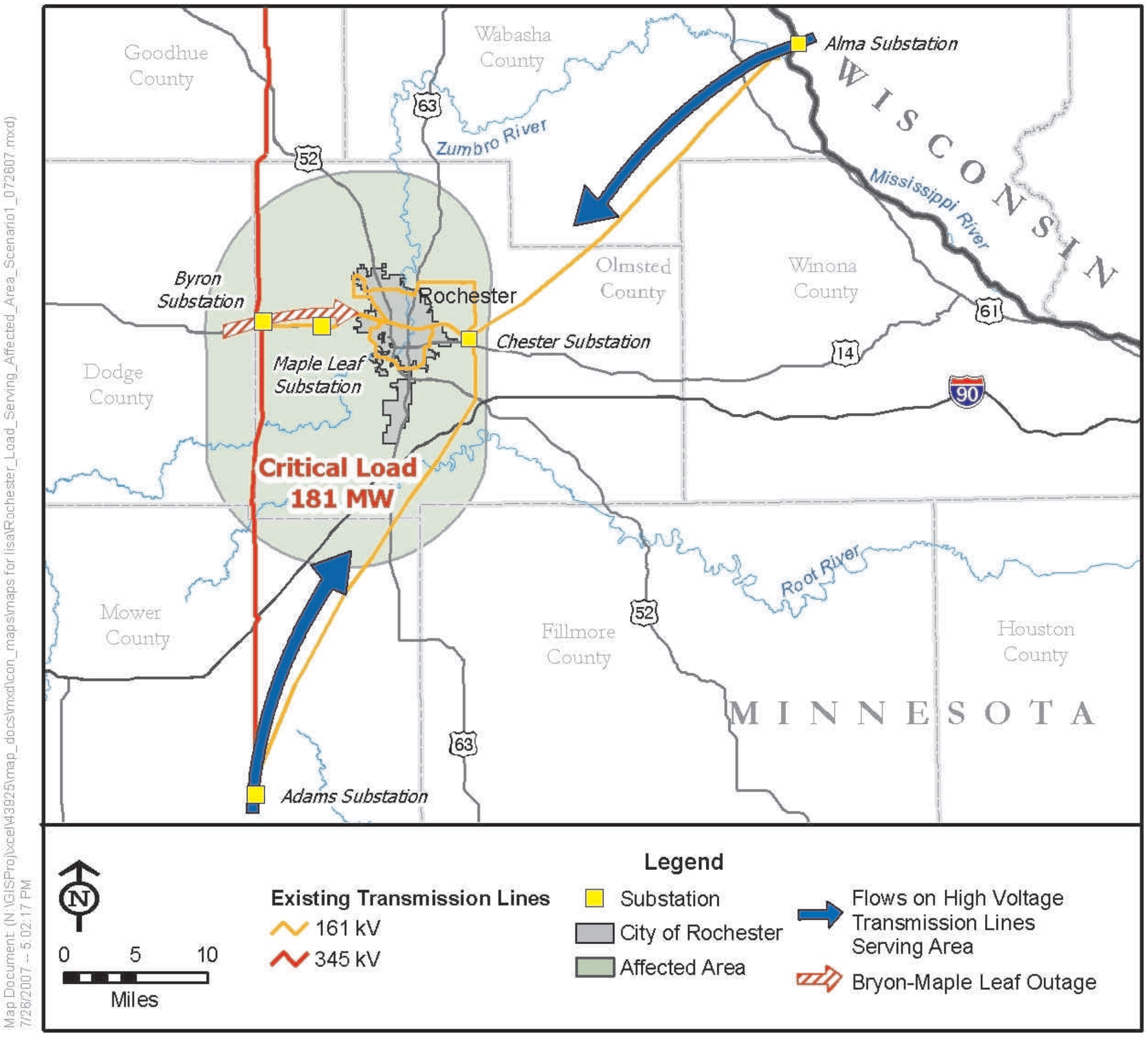
2.3.1.2 **Reliability Issues**

In the Rochester area, electric reliability issues have arisen that are related to population growth and associated increase in electric power demands. The population of the Rochester Metropolitan Statistical Area has grown by 34 percent from 98,400 in 1985, to

131,400 in 2003. During that same period, peak electric power requirements for RPU increased by 88 percent, from 139 MW to 262 MW, and the peak electric power requirements for Peoples Cooperative Services increased 63 percent, from 22.4 MW to 36.7 MW. When the demand for electrical power exceeds 181 MW in the Rochester area, the failure of a single transmission line could cause service interruptions. The actual load at the substations in the Rochester area reached 330 MW in 2006.

Utilities use the term contingency to describe how the system will work when one or more of the existing transmission lines and generators are out of service. If the transmission line from Byron, Minnesota to a substation on the east side of Rochester called Maple Leaf (Byron – Maple Leaf) is out of service, the remaining transmission system can only reliably deliver 181 MW of power to area substations. Figure 2-4 shows the system with the outage of the Byron–Maple Leaf transmission line and the resulting 181 MW critical load level.

Figure 2-4
Affected Rochester Area Under Contingency



Under this critical contingency, there are only two 161 kV ties remaining to serve customers of RPU and Peoples Cooperative Services. The two remaining Dairyland 161 kV lines provide the 181 MW import capability. Due to this limitation, RPU must run local generation when RPU's demand exceeds 145 MW to ensure reliable service to customers should the Byron – Maple Leaf 161 kV line lose service. In 2005, the demand for power on the RPU system exceeded 145 MW for about 5,400 hours.

The system peak occurred in 2006 and reached 330 MW. With all local generation operating, the system can support up to 362 MW of demand in the Rochester area should a transmission line be out of service. While local generation operated in advance of the next line or power plant outage may support additional demand, running generation for system support to prepare for the next line or power plant to go out of service is not a desirable long-term solution because it is less reliable than transmission. In addition, the energy generated from the older facilities is normally more expensive than power purchased from MISO competitive markets.

To alleviate the deficiency, additional power sources into the Rochester area are needed.

2.3.1.3 **Timing of the Need**

To determine the timing of the Rochester area need, planning engineers developed a peak load forecast for the area's distribution substations serving RPU and People's customers. The actual loads from 2002 to 2008 at each of the substations were reviewed and forecasts estimating the amount of electricity that will be used (load) through 2020 were prepared.

The forecast for the Rochester area was based on SMMPA's Integrated Resource Plan for RPU substations. SMMPA's forecast from 2009 – 2035 used a growth rate of 1.92% to 2.84%. For Peoples Cooperative Services substations, the forecast was estimated by first calculating an average load for years 2004 to 2008 and then applying a growth rate of 1.3%. The forecast is consistent with the RUS requirements for Load Forecast Studies (LFS). The forecast data included projected impacts from conservation and load management programs to control customer loads. Each of these "demand side management" (DSM) programs is 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 ultimate objectives of DSM programs are to lower rates, delay the need to construct new power plants, improve system efficiency, stimulate consumer interest in more efficient appliances and reduce harmful environmental emissions associated with electrical generation.

Figure 2-5 shows the actual summer peak demand for power at each substation in 2002, 2006 and 2008 and provides a forecast of annual peak demand at each Rochester area substation for 2010, 2015 and 2020. Appendix A.3 contains the historical peak data and forecast through 2020.

Figure 2-5
Actual and Projected Substation Loads for Rochester Area (Summer Peak)

Rochester Area Load Serving Substations	Actual			Projected		
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2015	Load MW 2020
Airport (DPC)	1.97	3.73	2.94	3.30	3.52	3.75
Bamber Valley (RPU)	25.44	28.67	25.09	26.95	32.84	39.33
Canisteo (DPC)	2.35	2.77	2.61	2.65	2.83	3.02
Cascade Creek (RPU)	48.34	54.47	44.58	47.88	56.11	64.14
Chester (DPC)	2.50	2.80	2.38	2.63	2.80	2.99
Genoa (DPC)	4.54	6.06	6.51	5.64	6.02	6.42
IBM (RPU)	25.44	17.20	14.55	15.63	17.88	20.11
Kalmar (DPC)	2.15	2.70	2.63	2.55	2.72	2.90
Marion (DPC)	3.33	3.01	2.91	2.87	3.06	3.26
Marvale (DPC)	3.29	3.31	2.15	3.05	3.25	3.47
Crosstown (RPU)	15.26	28.67	35.68	38.32	43.85	48.02
Northern Hills (RPU)	25.44	22.94	26.18	28.12	32.35	41.08
Oronoco (DPC)	5.69	8.97	5.49	7.11	7.59	8.09
Pleasant Grove (DPC)	1.63	1.83	1.40	1.51	1.62	1.72
Pleasant Valley (DPC)	1.72	2.04	1.75	1.8	1.93	2.06
Ringe (DPC)	4.85	3.67	5.08	3.98	4.25	4.53
Rock Dell (DPC)	1.76	2.38	2.05	1.99	2.12	2.27
Silver Lake (RPU)	48.34	54.47	52.46	56.35	61.30	66.43
Willow Creek (RPU)	27.98	37.27	35.32	37.94	44.66	51.13
Zumbro River (RPU)	38.16	43.01	36.11	38.79	44.62	50.37
Total (MW)	**290.18**	**329.97**	**307.87**	**329.06**	**375.32**	**425.09**

Critical Load Level = 181 MW (transmission only)						
MW at Risk (rounded)	**109**	**149**	**127**	**148**	**194**	**244**

The historical data and forecast presented above demonstrate that demand in the Rochester area currently exceeds the level at which the electrical system can reliably serve customers during peak demand operating conditions. As a result, system operators must cut service to customers in the event of a critical outage to maintain the stability of the electrical system during peak times. The risk of service interruptions currently exists in the event of a Byron–Maple Leaf 161 kV transmission line outage unless all internal generation is running. As the system is currently configured, that risk is expected to be reached, even if all internal generation is running, as early as 2014.

To reliably serve the Rochester area demand, new power sources are needed. The proposed Northern Hills – North Rochester and Northern Hills – Chester 161 kV lines will provide significant load serving capability to the system.

In addition, there are two other recent transmission proposals that could further enhance the transmissions system's capabilities. These two projects are not related to the Proposal, but are being proposed for the same general geographic area as the two 161 kV lines that are part of the Proposal. These projects do not change the need for the Proposal but may affect the specific timing of when the Northern Hills—North Rochester and Northern Hills—Chester 161 kV lines are constructed. The two transmission proposals are as follows:

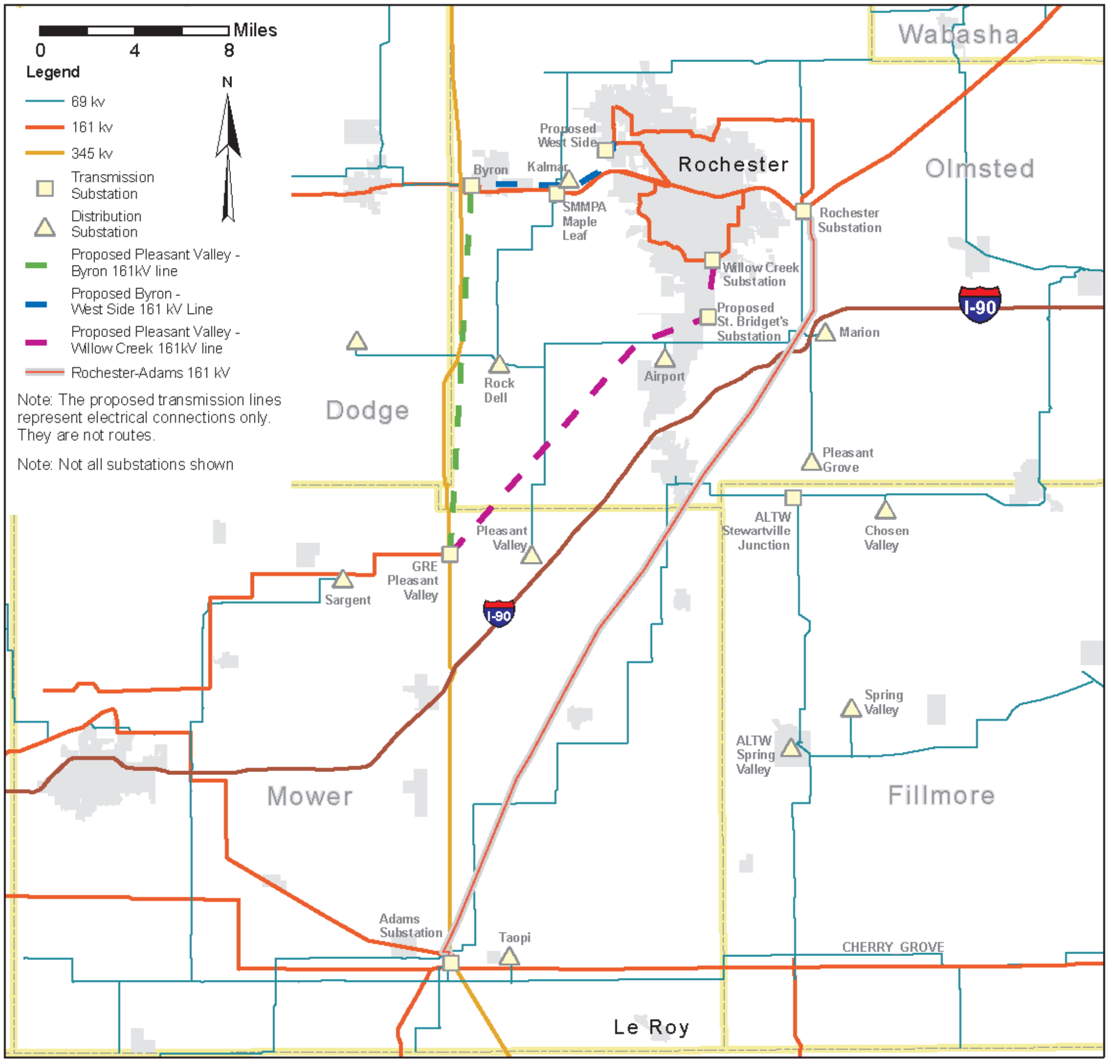
- The Pleasant Valley 161 kV lines: The Pleasant Valley 161 kV lines are a group of three 161 kV transmission lines needed to enable two new wind farms to reliably deliver power and to increase generation outlet capability in the area. One of the 161 kV lines, a proposed connection between Pleasant Valley Substation and Willow Creek Substation, will also provide additional import capability for the Rochester area. The two other lines proposed by NSPM and RPU are: 1) a 161 kV line from Pleasant Valley Substation to Byron Substation; and 2) a 161 kV transmission line connecting the Byron Substation to an RPU planned West Side Substation.

  These improvements were identified by a MISO Interconnection Study dated August 17, 2007 as well as the Regional Incremental Generation Outlet Study dated August 19, 2008. The Regional Incremental Generation Outlet Study is attached as Appendix A.6. Certificates of Need from the Minnesota Public Utilities Commission are required for the first two lines. As of the date of this AES, no Certificate of Need application has been filed.

- The second project is proposed by Dairyland—a reconductor of the Rochester – Adams 161 kV transmission line. The reconductor project, currently planned by Dairyland, will increase the capacity of the line and the capability of the system and is anticipated to be undertaken in 2009. The current proposal is to reconductor the line to 380 million volt-amp (MVA). No RUS funds will be required for this reconductor proposal.

These two transmission proposals are shown in Figure 2-6 below.

Figure 2-6
Transmission Alternatives



As explained in Section 3.1, planning engineers have determined that the Rochester area needs a 345 kV connection to the Twin Cities and two new 161 kV sources to maintain reliable community service through the 2020s. The addition of three 161 kV sources into the area would meet load serving needs past mid-century.

Assuming construction of the 345 kV line from the Twin Cities to La Crosse, if the Northern Hills – North Rochester 161 kV line or the Pleasant Valley – Willow Creek 161 kV line and the Rochester – Adams 161 kV line is reconductored at 380 MVA, the transmission system would have approximately 468 MW of capacity. This level of capacity could potentially meet local Rochester area needs until approximately 2025, if the current SMMPA forecast growth rates of 1.92% to 2.84% are realized. If the higher growth rates that the rapidly expanding Rochester area has experienced historically (more than 3.0 percent) return in the near term, the area load could exceed the improved transmission system's capacity by approximately 2019. To meet demand beyond this time, a second 161 kV source must be added to the system.

The Utilities propose to meet the immediate Rochester needs by constructing the North Rochester—Northern Hills 161 kV transmission line first with the objective of having it in service in 2011. The Utilities also propose to construct the North Rochester – Chester 161 kV line with the 345 kV line by 2015, which would increase the capability of the system to 707 MW and meet area needs until approximately 2050. If the Pleasant Valley – Willow Creek 161 kV line is constructed as part of the Pleasant Valley projects it would provide further robustness to the electrical system serving the Rochester area and could potentially affect the construction dates of the North Rochester – Chester 161 kV line.

2.3.2 La Crosse/Winona Area

2.3.2.1 Existing System

The La Crosse/Winona area, which has its highest electricity demand during the summer, is also facing reliability issues as a result of population growth and the resulting increase in demand for electricity. The area includes the cities of La Crosse, Onalaska and Holmen, Wisconsin and extends east to include Sparta, Wisconsin; northeast to include Arcadia, Wisconsin; northwest to include the area of Winona/Goodview, Minnesota; and southwest to include La Crescent, Houston and Caledonia, Minnesota.

Xcel Energy and Dairyland member distribution cooperatives—Vernon Electric Cooperative, Tri-County Electric Cooperative, Oakdale Electric Cooperative and Riverland Energy Cooperative—serve the La Crosse/Winona area. Power to the area is provided by four 161 kV transmission lines:[5]

- Alma–Marshland–La Crosse 161 kV (Dairyland)
- Alma–Tremval–La Crosse 161 kV (Dairyland and Xcel Energy)
- Genoa–Coulee 161 kV (Dairyland)
- Genoa–La Crosse 161 kV (Dairyland)

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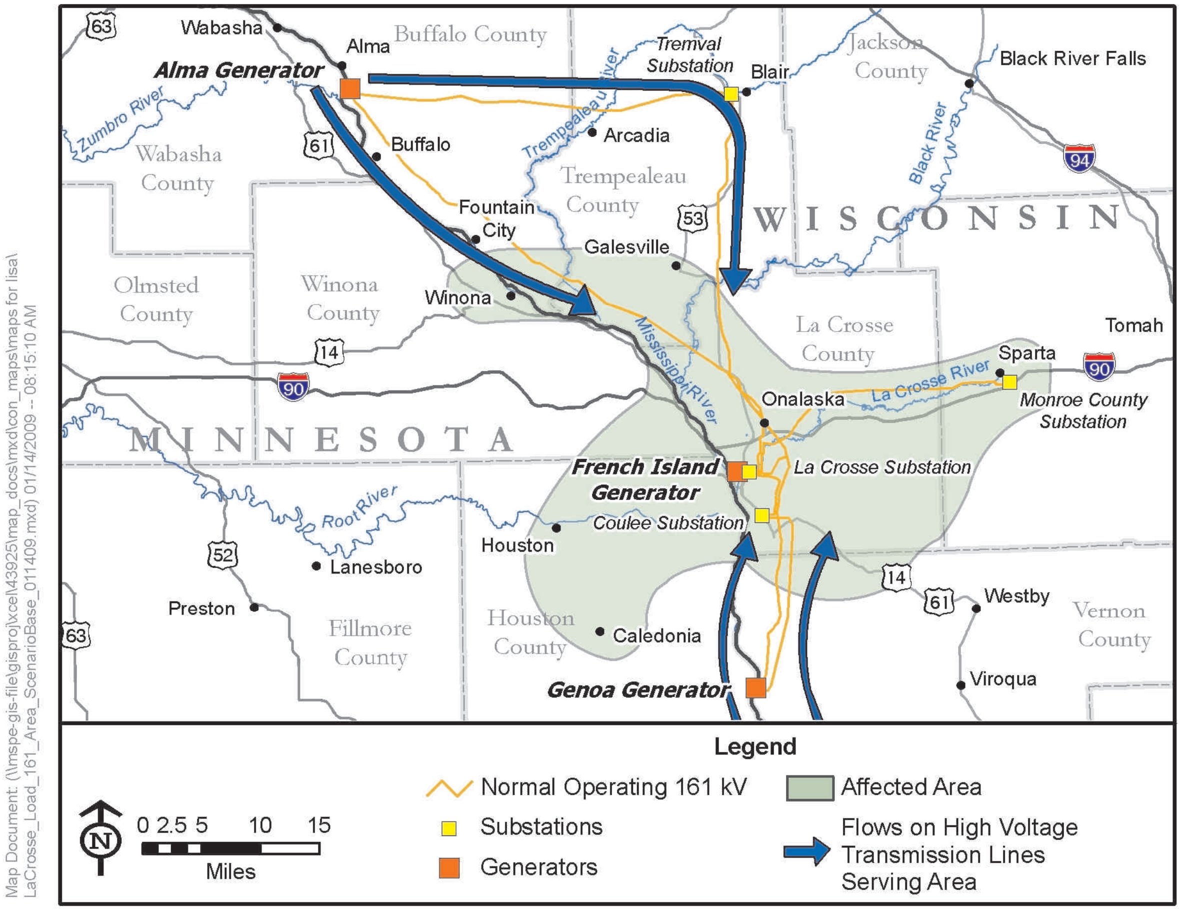
[5] The La Crosse–Monroe County 161 kV line does not provide a meaningful source to the greater La Crosse area. It is not a meaningful source because it is the strongest source for Sparta and Tomah given the relative weak transmission source from the east.

The Alma – Marshland – La Crosse 161 kV portion of the Q-1 transmission line is identified in Dairyland's 2008-2010 work plan (RUS 1071) for rebuild due to the age and condition. One of the routes being considered for the 345 kV line if the Proposal crosses at either the Alma or the Winona river crossings is the Q-1 route. If this route is selected and co-locating the new 345 kV transmission with the existing Q-1 transmission line is determined to be the appropriate configuration, the cost of the Q-1 rebuild will be part of the Proposal costs. If the two lines are not co-located, Dairyland anticipates it will seek additional RUS funds for the Q-1 rebuild project in 2012. A more detailed review of the Q-1 rebuild is discussed in Appendix A.7.

The affected area and a graphical depiction of the general power flows on these high voltage transmission lines in the La Crosse/Winona area are shown in Figure 2-7.

Figure 2-7
Affected La Crosse/Winona Area and Flows on High Voltage Transmission Lines Serving Area



The transmission system's ability to reliably serve the area depends on the status of major power plants in the area. The plants and the summer ratings of the units located at each site are listed below:

<u>Alma Generation Site</u>, located about 40 miles northwest of La Crosse:
John P. Madgett generator (coal, 392.5 MW URGE)
Alma units 1–5 (coal, 190.1 MW URGE)

<u>Genoa</u>, located about 20 miles south of La Crosse:
Genoa Unit 3 (coal, 351.3 MW URGE)

French Island, located within the city of La Crosse:
French Island Units 1 and 2 (refuse burning baseload units 13 MW each, nameplate, 26 MW total, which only run on weekdays when trash pickup service occurs);
French Island Units 3 and 4 (fuel oil, 70 MW each, nameplate, 140 MW total)

The transmission system's ability to reliably serve the area depends on the status of major power plants in the area. If plants at Genoa and Alma are in operation and a transmission source fails, 470 MW of power demand can be met. Transmission support to the area can drop to as low as 330 MW if Alma and/or Genoa generation are not operating. Local generation at French Island in La Crosse totaling 70 MW must be run any time demand exceeds these critical load levels. Peak demand reached 447 MW in 2006. New high voltage transmission in this area will provide transmission support that will alleviate these contingencies.

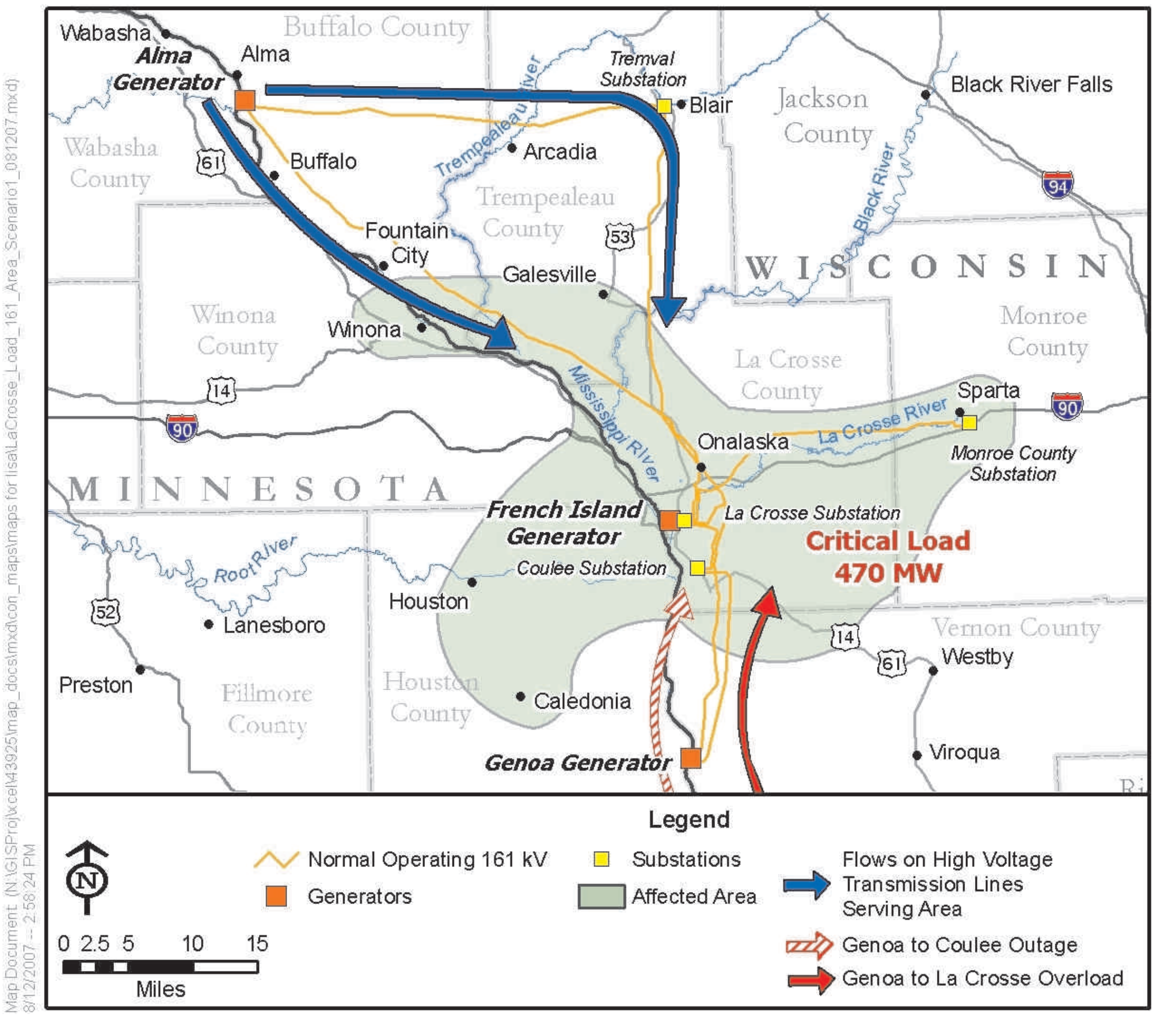
2.3.2.2 **Reliability Issues**

The capabilities and limitations of the electrical system serving La Crosse were studied in the Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study (March 13, 2006) (Rochester/La Crosse Study). A copy of the Rochester/La Crosse Study is found in Appendix A.2. The Rochester/La Crosse Study began by recognizing La Crosse's peak load was 414 MW on August 20, 2003. Planning engineers then modeled how the system would operate during summer 2009. They estimated peak demand to be 494 MW in 2009 by applying a 3 percent annual growth rate to historical peak demand. Planning engineers found that without further improvements, the existing transmission system would not be able to reliably serve customers at the 494 MW level. The critical contingency was the loss of the Genoa–La Crosse–Marshland 161 kV transmission line that resulted in overloading the Genoa–Coulee 161 kV transmission line. The scenario analyzed assumed Alma and Genoa generation were in operation and the French Island peaking units were not operating.

Additional studies were undertaken to further examine performance of the system and identify critical contingencies under varying generation assumptions. The MAPP 2006 Series 2008 Summer Peak model was used to identify the critical La Crosse area load level for these scenarios. The model was modified to reflect recent planned additions such as an upgrade to the Genoa–Coulee 161 kV transmission line. The model was configured to represent the French Island Units 1 and 2 (13 MW each) on-line and the French Island Units 3 and 4 (70 MW each) off-line. Units 1 and 2 are fueled with refuse-derived fuel and generally must be run whenever fuel is available. The La Crosse area load in the 2008 model was scaled upward until transmission power flows were greater than 100 percent of the transmission lines' normal rating and load serving bus voltage was less than 90 percent.

In the event of the loss of the Genoa–Coulee 161 kV transmission line, the La Crosse area system can reliably serve only 460 MW when generators at Alma and Genoa are running. In 2009, two 60-megavolt ampere reactive (MVAR) capacitor banks will be added to the La Crosse area 161 kV system and the system capability will be increased 10 MW to 470 MW. Figure 2-8 illustrates this contingency scenario.

Figure 2-8
La Crosse/Winona Area Genoa–Coulee 161 kV Contingency



The transmission system can be further supported by operating the two 70 MW peaking units at French Island. If these generators were run as system support, the capacity of the system in the event of a Genoa–Coulee 161 kV transmission line outage would increase to approximately 610 MW. Using peaking generation for system support in La Crosse, however, has the same negatives as in the Rochester area. The generators are less reliable than transmission facilities and more expensive to operate than other generation resources. Additionally, the number of hours that French Island units can run may be restricted by environmental permitting limitations.

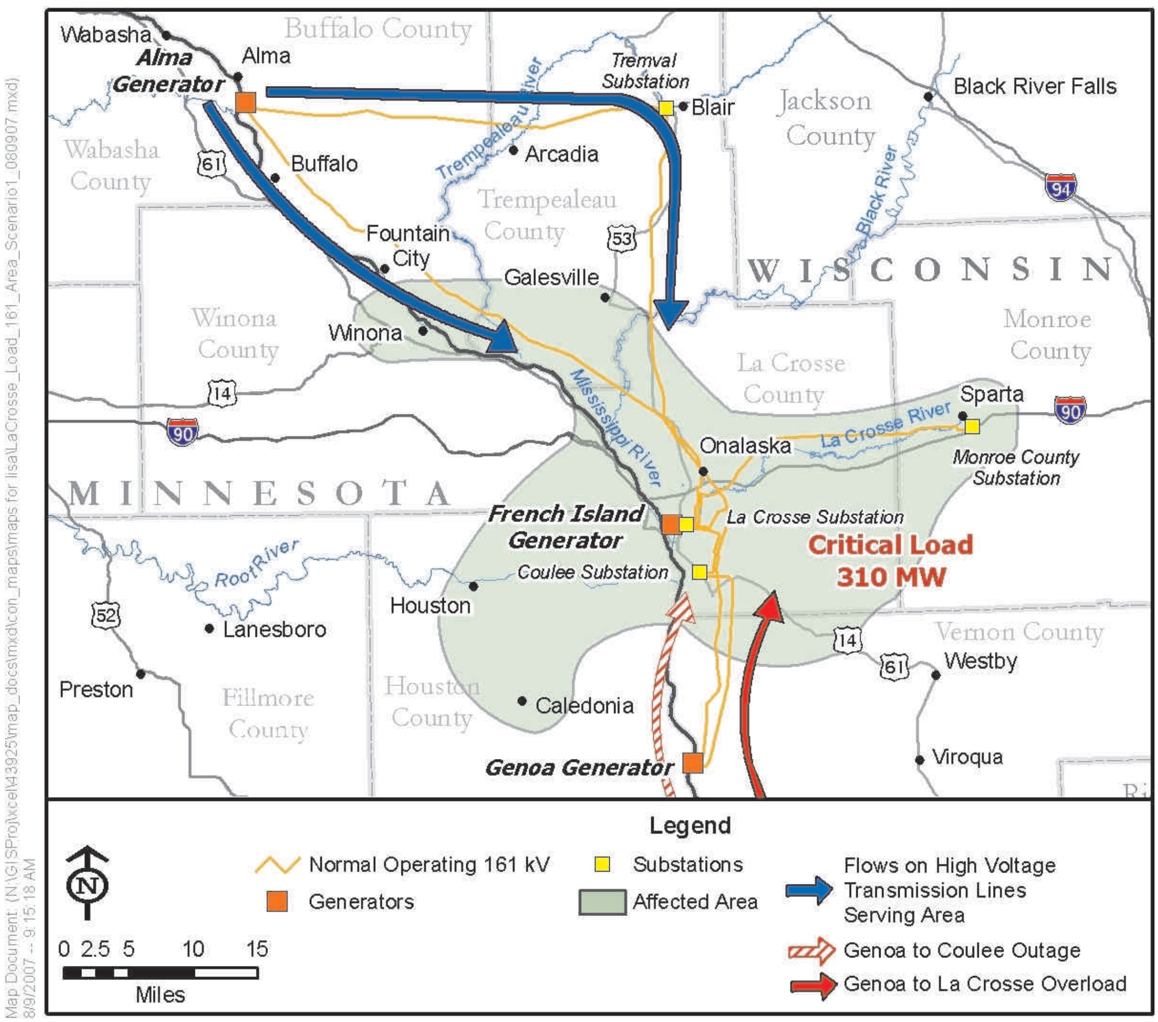
The electrical system's capacity to meet power demands is more limited when generation at Alma or Genoa is off-line. If the Genoa generator is off-line and the Alma–Marshland 161 kV transmission line is disconnected, the La Crosse area experiences low voltage conditions at approximately 430 MW of load. Figure 2-9 shows the system under this contingency scenario.

Figure 2-9
La Crosse/Winona Area Genoa Off-line, Alma–Marshland 161 kV Outage Contingency

Under this contingency, once load reaches 430 MW, the Genoa–Lansing 161 kV transmission line overloads. This level has already been exceeded. On July 17, 2006, actual flows on the transmission lines reached an all-time coincident peak load of 447 MW. If French Island peaking generation is used for system support, the maximum capacity of the system reaches 580 MW.

The system capacity is similarly limited if the John P. Madgett generator is off-line, French Island peaking generation is off-line, and the Genoa–Coulee 161 kV transmission line is lost. In this scenario, the Genoa–La Crosse 161 kV transmission line overloads and the electrical system can reliably serve only 310 MW. Figure 2-10 illustrates this contingency scenario.

Figure 2-10
La Crosse/Winona Area, John P. Madgett Off-line, Genoa-Coulee 161 kV Line Contingency



As in the other two scenarios, French Island generation can supplement the load-serving capability of the system by 140 MW, up to a total of 450 MW.

2.4 Timing of the Need

To better understand the timing of the La Crosse/Winona area need, planning engineers developed a peak load forecast for substations operating in the affected La Crosse/Winona areas. The CapX2020 planning engineers gathered seven years of historical data and estimates of projected peak load growth. For the forecast, Xcel Energy and Dairyland provided the actual loads from 2002 to 2008 at each of the substations and then projected loads at each of the substations.

For substations served by Dairyland distribution cooperatives, the forecast was estimated by first calculating an average load for years 2004 to 2008 for each substation. To create a forecast to the year 2020, planning engineers then applied a growth rate based on the historical peak growth rates of the distribution cooperatives: Vernon Electric Cooperative at 3.4 percent, Oakdale Electric Cooperative at 2.8 percent, Tri-County Electric Cooperative's growth rate at 1.8 percent and Riverland Energy Cooperative at 1.7 percent.

The 2009–2020 forecast for the Xcel Energy substations was based on an analysis of historical loads and anticipated growth rates. Xcel Energy used the peak demand for 2006 and grew that load by 1.2 percent through the year 2020.

Figure 2-11 shows the actual annual peak demand for power at each substation in 2002, 2006 and 2008 and provides a forecast of annual peak demand at each greater La Crosse area substation for 2010, 2015 and 2020.

Appendix A.4 contains the historical peak data and forecast through 2020.

Figure 2-11
Actual and Projected Substation Loads for the La Crosse/Winona Area (Summer Peak)

La Crosse Area Load Serving Substations	Actual			Future		
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2015	Load MW 2020
Bangor	4.08	4.17	3.46	4.22	4.43	4.66
Brice	5.12	6.93	6.36	6.29	6.85	7.45
Caledonia City	3.42	3.90	3.51	3.72	4.06	4.44
Cedar Creek	3.54	5.17	4.93	4.54	4.94	5.38
Centerville	2.79	3.34	4.20	3.46	3.76	4.09
Coon Valley	4.29	5.22	3.96	5.31	5.58	5.86
Coulee	53.50	60.30	52.91	63.96	67.40	71.03
East Winona	8.92	9.47	11.09	11.54	12.74	14.07
French Island	19.50	29.04	24.06	35.44	37.34	39.35
Galesville	6.91	6.89	5.50	7.00	7.36	7.73
Goodview	31.78	35.33	33.61	34.13	36.14	38.27
Grand Dad Bluff	1.67	1.91	1.63	1.70	1.85	2.01
Greenfield	2.85	3.43	3.06	3.12	3.39	3.69
Holmen	14.97	13.16	14.91	15.21	15.99	16.80
Houston	3.61	3.78	3.38	3.55	3.88	4.25
Krause	4.12	4.48	4.54	4.29	4.67	5.08
La Crosse	58.43	50.33	46.98	51.70	54.34	57.11
Mayfair	43.90	46.58	45.39	48.29	51.26	54.44
Mound Prairie	2.18	2.02	2.39	2.27	2.49	2.72
Mount La Crosse	1.64	2.00	2.09	1.95	2.12	2.31
New Amsterdam	3.88	4.66	4.46	4.71	5.12	5.57
Onalaska	11.73	12.93	10.48	13.50	14.54	15.67
Pine Creek	2.03	2.36	1.84	2.01	2.20	2.41
Rockland	4.18	4.14	3.10	3.95	4.15	4.37
Sand Lake Coulee	2.99	2.84	2.59	2.73	2.97	3.24
Sparta	29.65	32.47	31.74	33.27	35.84	38.61
Sparta (DPC)	1.15	1.36	1.16	1.24	1.42	1.63
Swift Creek	17.10	24.80	21.83	28.22	29.65	31.17
Trempealeau	4.43	3.94	3.68	4.00	4.20	4.41
West Salem	23.30	24.52	23.97	25.97	27.63	29.41

La Crosse Area Load Serving Substations	Actual			Future		
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2015	Load MW 2020
Wild Turkey	1.17	1.20	1.35	1.31	1.44	1.57
Winona	46.30	51.91	51.19	51.92	55.23	58.77
Total Load MW:	**425.12**	**464.59**	**435.34**	**484.52**	**514.98**	**547.57**

Critical Load Level = 470 MW (Transmission Only)						
MW at risk				**14.53**	**45.01**	**77.57**

Critical Load Level = 450 MW (With JPM outage and Genoa - Coulee 161 kV outage)						
MW at risk				**34.52**	**64.98**	**97.57**

Forecast information based on substation load data show that the La Crosse/Winona area will begin exceeding the ability of the transmission system alone to provide power in the event of critical transmission line failure beginning in approximately 2009-2010. In 2015, demand will exceed the system's capability by 45 MW (470 MW of capacity versus 515 MW of demand). This means that in 2015, approximately 45 MW of load would be at risk of service interruption.

2.5 Generator Outlet/Renewable Energy Support.

The Proposal is also designed to provide generation support in southeast Minnesota. This area is experiencing considerable growth in generation development, including wind generation. In Mower County, just southwest of Rochester, as of January 2009, there were 1,397 MW of generation projects listed in the MISO Generation Interconnection Queue. For this same time period, there are over 12,000 MW of generation projects in the MISO Generation Interconnection Queue for the counties of Mower, Olmstead, Fillmore, Howard (IA), Mitchell (IA) and Worth.

In southeastern Minnesota, the ability of the electrical system to transmit this new generation is limited because the area transmission system has a deficiency during off-peak, high transfer, conditions. Specifically, in the event of a Byron – Adams 345 kV line outage, there is congestion on the Byron – Maple Leaf 161 kV line which limits the flow on the Prairie Island – Byron – Adams 345 kV line and the North-South transfer between Minnesota and Iowa. The deficiency is significant enough that it has resulted in a documented operating guide that SMMPA has filed with MISO entitled "Byron – Maple Leaf 161 kV Operating Guide, Revision 1." This operating guide limits the amount of power that can flow south on the Prairie Island – Byron 345 kV line to 766 MW when temperatures are greater than 45 degrees Fahrenheit (April, May, June, July, August, September and October) and 835 MW when temperatures are less than 45 degrees Fahrenheit (November, December, January, February and March) to plan for a fault and subsequent outage along the Byron – Pleasant Valley – Adams 345 kV line. The limit is in place so that if this system condition were to occur, the Byron – Maple Leaf 161 kV line would not become overloaded and potentially trip off-line.

The Proposal will address this constraint.

In Wisconsin, the transmission grid in the western portion of the state, along with interface loading levels across Minnesota – Wisconsin border, limit the ability to interconnect new generation in Minnesota as well as generation from points further west. While preliminary stability analysis show that the proposed 345 kV line has no impact on the MWEX interface, it will provide the foundation for future power transfers into Wisconsin. As noted, the need for and configuration of additional transmission facilities to the east is being addressed in a study currently underway by Xcel Energy and American Transmission Company, LLC.

3.0 Alternatives Evaluation

When there is a need for additional transmission capacity in an area, utilities 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. RUS Bulletin 1794A-603, § 3.1.1. A proposed action to meet the capacity need must be analyzed along with the other relevant alternatives. This section discusses alternatives to the Proposal: (1) transmission line alternatives to the Proposal; (2) a no action alternative that focuses on conservation and system operational improvements; and (3) a new generation alternative. This section also explains why all these alternatives are unacceptable or less than optimal in comparison to the Proposal.

3.1 Transmission Alternatives

The Proposal was developed in technical studies that analyzed load-serving needs in the Rochester and La Crosse/Winona areas. In these studies, planning engineers evaluated the needs discussed in Section 2, considered transmission alternatives and identified the selected solution to meet those needs based on electrical performance and cost. The details of these analyses are included in the text of the studies. *See* Appendix A.2. The studies also contain the cost estimates that were prepared based on engineering judgments, assumptions, and projections at the time of the studies. This section generally describes the transmission studies that were undertaken, the transmission alternatives considered, and the support for the proposed configurations for the Proposal.

3.1.1 Local Rochester Area Study

In the local Rochester area load serving study, planning engineers considered four 161 kV options and three 161 kV/345 kV options to meet the growing demand for power.

Planning engineers determined that the best performing 161 kV option in the Rochester area, based on system impact, cost, and reliability, was a new 161 kV transmission line from Pleasant Valley to Quarry Hill, and a 161 kV transmission line from the Byron Substation to the Northern Hills Substation coupled with a new Byron 161/345 kV transformer to eliminate overloads. This option would meet local needs until approximately 2030, based on current load growth trends, after which additional infrastructure would be required to meet power demands.

The 161 kV/345 kV options that the planning engineers examined provided longer lasting solutions than other energy alternatives. The best performing and least cost option was a 345 kV transmission line from Byron to Pleasant Valley and eastward around the city of Rochester. Planning engineers determined that this solution would reliably serve the load until approximately mid century based on current load growth trends in the Rochester area, considerably longer than the best performing 161 kV option.

3.1.2 Local La Crosse/Winona Study

In the local La Crosse/Winona area study, planning engineers analyzed 23 possible 161 kV alternatives to meet identified load-serving needs. Those alternatives were then screened to identify the five options worthy of additional study.

The best performing 161 kV option required operation of the baseload refuse burners at French Island (Units 1 and 2) to maintain system reliability. It also included a 300 MVA phase-shifting transformer at the North La Crosse Substation.

Planning engineers concluded that even the best performing 161 kV option was inadequate to meet identified needs for several reasons. First, the phase-shifting transformer application in the La Crosse area prevented transmission overloads post-contingency in the short term but did not eliminate the need for additional transmission lines because the La Crosse/Winona area load increased. Second, the 161 kV alternative would require more 161 kV transmission facilities in the long term, and, by approximately 2028, a 345 kV transmission line would be required to serve the load. A 161 kV/345 kV solution, therefore, would meet load-serving needs for several decades longer with fewer transmission lines.

3.1.3 Rochester Area and La Crosse Area Regional Evaluation

Given the Rochester study's finding that a 345 kV solution was optimal for the Rochester area and the La Crosse study's determination that 161 kV alternatives could not meet load-serving needs in the La Crosse/Winona area, RPU and Dairyland undertook further study to identify a 345 kV regional solution.

In the regional Rochester/La Crosse Study, planning engineers identified potential regional 345 kV transmission improvements that would meet reliability needs in the Rochester area and the La Crosse/Winona area alike, as well as adding system reliability to the wider southern Minnesota/western Wisconsin region.

To determine potential 345 kV solutions, planning engineers first selected a point of origin for providing this source to the area. Typically, to develop a 345 kV system aimed at supporting a particular area, an extension from other parts of the existing 345 kV system is usually most effective. A number of geographically diverse sources that were connected to the existing 345 kV system were considered for this purpose: Mankato, the Twin Cities and Eau Claire, Wisconsin.

In deciding the best terminus, planning engineers evaluated two key criteria – distance of the source from the community to be served and strength of source. Regarding the distance criterion, the farther the source is from the community, the more the transmission line will cost to build and the greater the system losses will be. In addition, more miles of transmission line increases the potential for environmental impacts due to right-of-way requirements. The following Figure 3.1 compares the distance between the North Rochester endpoint and the three possible sources.

Figure 3-1
345 kV Source Alternatives and Distances

Option	Endpoint	Mileage
Twin Cities	North Rochester	50 miles
Eau Claire	North Rochester	90 miles
Mankato	North Rochester	85 miles

As this chart demonstrates, the Twin Cities source would require the shortest line to North Rochester, approximately 50 miles compared to Mankato (85 miles) and Eau Claire (90 miles). The longer distances would make these two options considerably more expensive than the Twin Cities option and also would require acquisition of more right-of-way with attendant impacts.

Regarding the strength criterion, generally, the more transmission lines and generators in a source area in relation to the demand in the immediate area, the stronger the source will be. The Twin Cities area has multiple 345 kV lines and generation running at all times. In addition, the particular substation being considered for this Proposal, the Hampton Substation, will have at least three 345 kV lines, in addition to the proposed 345 kV line. In comparison, the 345 kV substations in Mankato and Eau Claire only have two existing 345 kV lines and limited generation. A strong source helps to ensure the community being served by such a new transmission line will enjoy the benefit of the electrical support provided by the new transmission line. If the new transmission line goes to a weak source, very little electrical support will be provided to the community by that transmission line, so the new transmission line will be of little value.
Based on these criteria, planning engineers determined that the new 345 kV transmission line should connect with the 345 kV loop surrounding the Twin Cities. This location is close to the Rochester and La Crosse/Winona area and is tied into significant generation on the western side of the Twin Cities, including the Blue Lake generation plant. The location also serves as an effective new 345 kV source location to the Rochester metro area and improve system reliability in that region of Minnesota. The Hampton Substation

will support the two proposed 161 kV transmission lines that leave the North Rochester Substation and tie into two locations on the Rochester 161 kV transmission system.

Planning engineers also considered the need for load serving support to the 161 kV system in the La Crosse/Winona area. In the primary study, planning engineers focused on a Prairie Island Substation source and a substation connection in the La Crosse area to provide area load serving support. Based on these criteria, five potential 345 kV options were initially evaluated:

- Option 1, Prairie Island–Rochester–North La Crosse–Columbia
- Option 2, Prairie Island–Rochester–North La Crosse –West Middleton
- Option 3, Prairie Island–Rochester–Salem
- Option 4, Prairie Island–North La Crosse–Columbia
- Option 5, Prairie Island–North La Crosse–West Middleton

Figure 3-2
Map of System Alternatives

Options 1, 2 and 3 included two 161 kV transmission lines to tie into the RPU system at the Rochester area substations, one at the proposed Northern Hills and one at the Chester Substation.

Planning engineers eliminated Option 3 because it did not address load-serving needs in La Crosse. Options 4 and 5 were eliminated because they did not resolve reliability issues in Rochester. The two remaining options, Options 1 and 2, performed equally well in mitigating contingency overloads during summer off-peak contingency scenarios. Option 1, Prairie Island–Rochester–North La Crosse–Columbia, however, provided better system performance under a summer peak contingency analysis: it eliminated existing overloads and created fewer overloads than Option 2.

The Prairie Island–Rochester–North La Crosse–Columbia 345 kV option was further refined based on additional analysis. On the western end, planning engineers evaluated the effectiveness of a new Hampton Substation.

A Twin Cities source transmission system connection was found to be a better alternative because it provided a more robust transmission system in the Rochester area. The Prairie Island – Byron 345 kV transmission line is currently the primary 345 kV source and a critical transmission line in the area. A new Twin Cities source (Hampton) provides redundancy so that if the Prairie Island – Byron 345 kV transmission line is out of service, the Hampton – North Rochester 345 kV transmission line could be relied upon to provide service. Additionally, by physically separating the two transmission lines, the likelihood of losing both transmission lines in a natural disaster is reduced. The transmission lines would also be electrically separated by a minimum of two breakers, which would reduce the impact of a breaker failure at either location.

Planning engineers also recognized in their study work that the Proposal will meet the identified load serving needs in La Crosse until approximately 2036. After that time, additional transmission facilities will be needed to serve the La Crosse/Winona area.

American Transmission Company, LLC, is currently leading an analysis with Xcel Energy as a main participant of the study team to determine what facilities should be constructed to meet this La Crosse area need and other transmission requirements. This analysis is not associated with the Proposal and no specific project has been identified. The study is scheduled to be released by the end of 2009.

Figure 3-3 shows the proposed configuration. Figure 3-4 shows the Prairie Island–North Rochester–La Crosse configuration considered in the regional study.

Figure 3-3
Hampton–Rochester–La Crosse 345 kV Project, Proposed Configuration

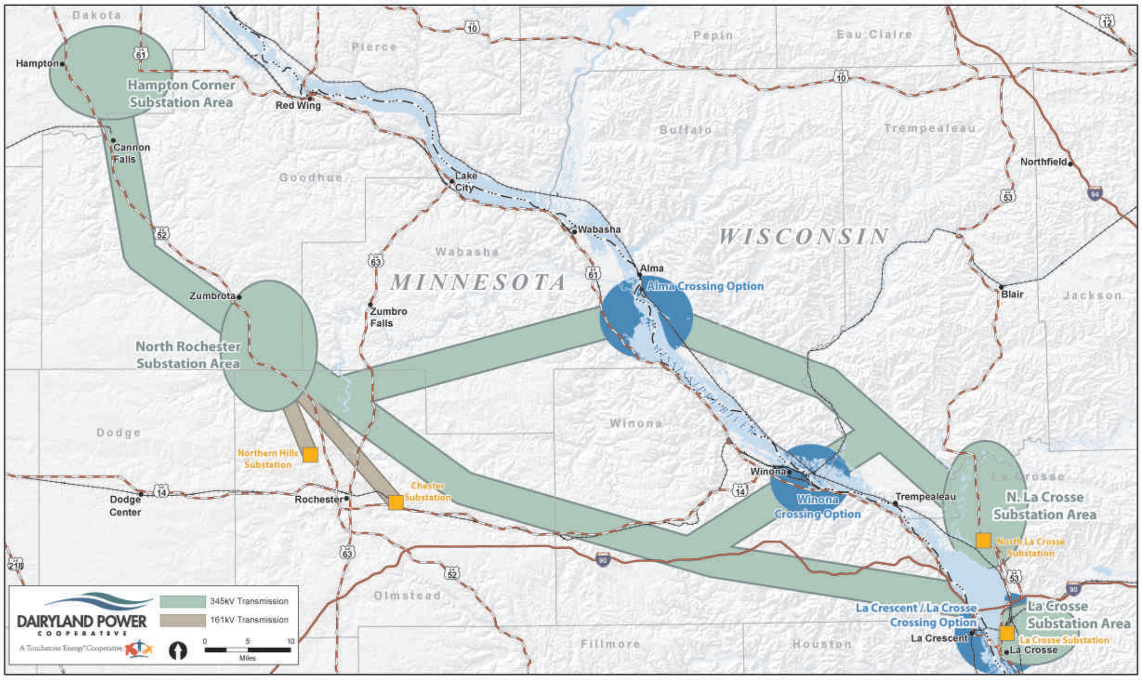
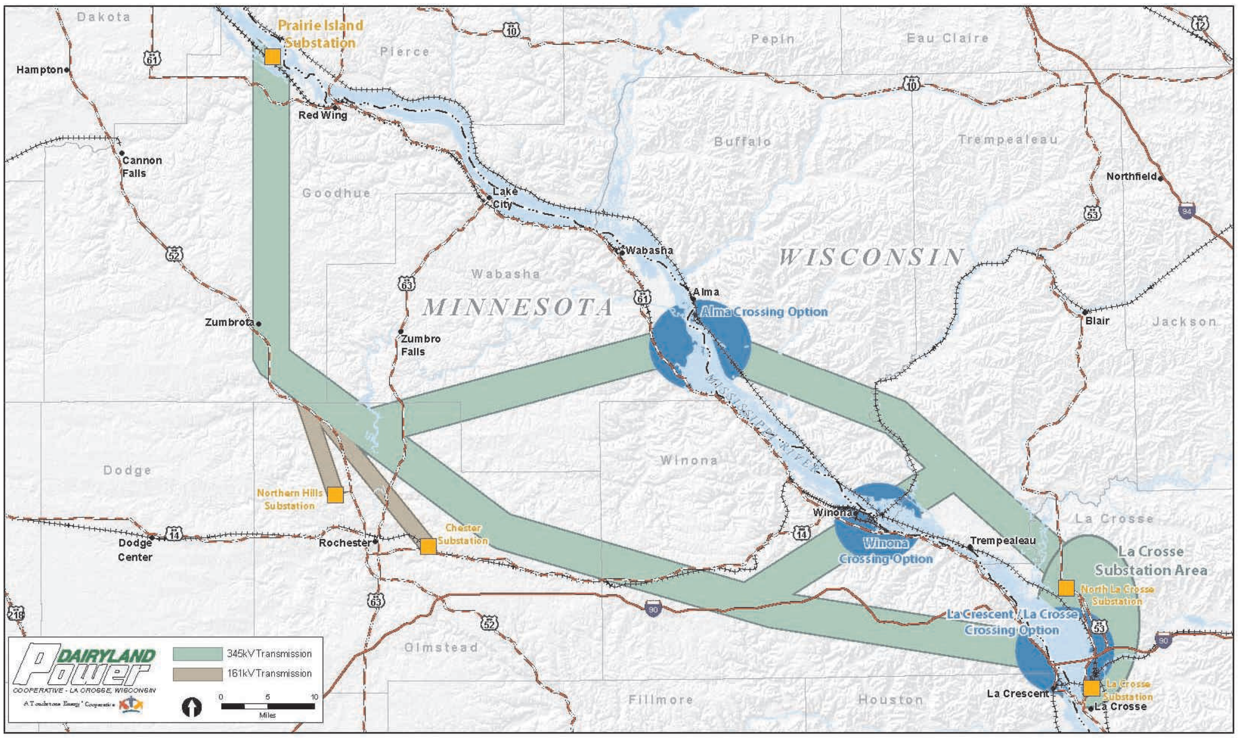


Figure 3-4
Hampton–Rochester–La Crosse, Alternative Configuration (Prairie Island)



The estimated cost of the proposed configuration, with double circuit compatible structures on the Minnesota portion of the Proposal, is $380 million to $430 million (2007$). Without double circuit compatible structures, the estimated cost is $320 million to $380 million. The estimated cost of the Prairie Island configuration, without double circuit compatible structures as proposed for the Proposal, is $310 million to $360 million (2007$).[6] While double circuit capable structures are somewhat taller and more expensive, there is value in building the system in a fashion that will continue to serve

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[6] After completion of the Rochester/La Crosse Study, planning engineers also briefly considered an alternative, called the Byron Alternative, that included a Hampton–Byron 345 kV line, a new North Rochester Substation, the two 161 kV ties into Rochester and a 345 kV line from North Rochester to La Crosse. The Byron Alternative was not pursued because preliminary analysis showed that while the configuration performed electrically as well as the proposed configuration, it required significantly more transmission line miles. The cost of this alternative, without double circuit 345 kV capability, is estimated at $340 to $400 million (2007$).

expanding customer needs for the next few decades. As demand grows and more transmission capacity is needed, a second 345 kV circuit can be added to the system on the same right-of-way at much lower cost than building a new line. And, by deferring some of the capital expenditures for the second circuit, Utilities are able to more closely match that investment with future growth.

The Proposal will restore reliable service to the Rochester area by providing a strong 345 kV source to the Rochester area. The proposal will also provide two needed load serving connections to the City of Rochester from that source through the two proposed 161 kV lines connecting the North Rochester Substation with the Northern Hills Substation and the Chester Substation.[7] The Proposal will also mitigate existing congestion on the Byron – Maple Leaf 161 kV line.

In the La Crosse/Winona area, the Proposal will also restore reliable service by providing a strong 345 kV source to the 161 kV network to the greater La Crosse area, reduce the burden on the four existing 161 kV source transmission lines into La Crosse, and mitigate the risk caused by a contingency loss of any these transmission lines. Finally, a 345 kV transmission line eliminates the risk of interrupted load caused by the loss of a generator and a 161 kV transmission line. More specifically, the three 161 kV contingency scenarios described in Section 2 are mitigated or eliminated:

- Scenario 1 (Post-345 kV project): The system's critical contingency is the loss of the Genoa–La Crosse–Marshland 161 kV transmission line, which would result in the overload of the Genoa–Coulee 161 kV transmission line. The limitations of this contingency are effectively eliminated because the load-serving capability of the transmission system increases from 470 MW to more than 750 MW.

- Scenario 2 (Post-345 kV project): In this scenario, John P. Madgett generation is off-line and the Genoa–La Crosse–Marshland 161 kV transmission line is lost. This results in the overload of the Genoa–Coulee 161 kV transmission line. The load-serving capability of the transmission system increases from 310 MW to 640 MW.

- Scenario 3 (Post-345 kV project): In this scenario, low voltage conditions occur if the Genoa 3 generator is off-line and the Alma–Marshland 161 kV transmission

[7] Depending on ultimate routing for the 345 kV line, the North Rochester – Chester 161 kV line may not be constructed. If the 345 kV line is routed around Rochester to the east and then south, the 345 kV line could potentially connect at the Chester Substation and provide the required second load serving connection for the Rochester area.

line goes down. The new 345 kV transmission line eliminates these low voltage conditions.

Figure 3-5 summarizes the contingencies, existing system capabilities, and capabilities when the Proposal is operational:

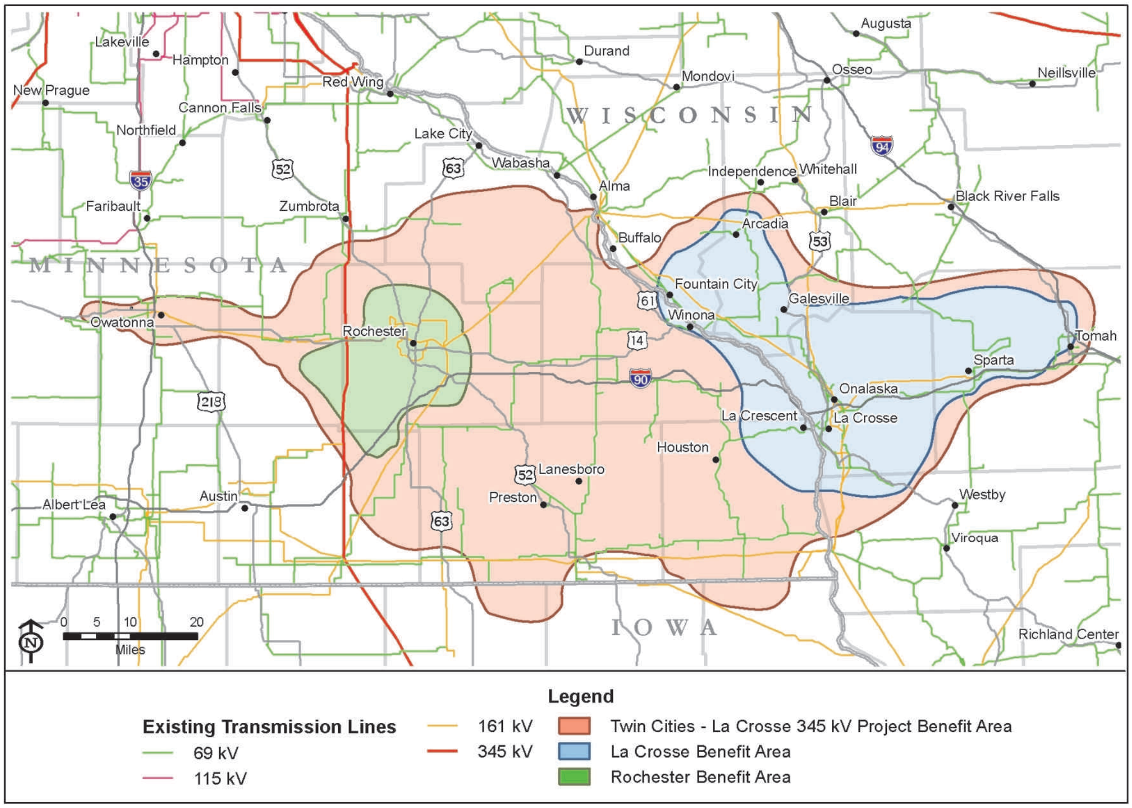
Figure 3-5
La Crosse/Winona Area Contingencies and Transmission System Capabilities

Generator Outage	Contingency	Overloaded Facility	Existing System	Existing System & French Island On-Line 140 MW	Genoa-La Crosse 161 Upgrade & 345 Line In Service*
		La Crosse Critical Load Level (MW)			
None	Genoa-Coulee 161	Genoa-La Crosse 161	470	610	N/A
JPM	Genoa-Coulee 161	Genoa-La Crosse 161	310	450	N/A
G3	Alma-Marshland 161	Low Voltage in La Crosse	430	570	N/A
		La Crosse Critical Load Level (MW)			
None	Genoa-La Crosse 161	Genoa-Coulee 161	N/A	N/A	>750
None	N. Rochester-N. La Crosse 345	La Crosse TX & Coulee TX	N/A	N/A	800
JPM	Genoa-La Crosse 161	Genoa-Coulee 161	N/A	N/A	640
JPM	N. Rochester-N. La Crosse 345	La Crosse TX & Coulee TX	N/A	N/A	800
G3	Alma-Marshland 161	Low Voltage in La Crosse	N/A	N/A	>750 **
G3	N. Rochester-N. La Crosse 345	La Crosse TX & Coulee TX	N/A	N/A	>750 ***

*** In post-project scenario, French Island Units 1 and 2 (26 MW total) assumed online in all cases. French Island Units 3 and 4 (140 MW total) assumed offline in all cases.**
**** Low voltage was eliminated, however the La Crosse 161/69 kV transformers are loaded over 100% but below emergency ratings.**
***** At 700 MW the proposed North La Crosse 112 MVA 161/69 kV transformer overloads at which time the second proposed North La Crosse 112 MVA 161/69 kV transformer is needed. The addition of the second North La Crosse transformer should off load the La Crosse and Coulee transformers extending their load serving capability beyond 750 MW**

The Proposal will also provide transmission system benefits for a larger geographic area served by Xcel Energy, Dairyland, RPU and SMMPA. This area is shown in Figure 3-6.

Figure 3-6
Benefit Area of Twin Cities–La Crosse 345 kV Project



The pink area shows the entire benefit area of the Proposal. After construction, this area will have improved load-serving capability, as well as overall system stability and reliability. The blue area is the La Crosse benefit area of the Proposal. This portion of the La Crosse area electric system is benefited by the 161 kV facilities that are included in the Proposal. The La Crosse benefit area includes a much larger geographical area than greater La Crosse, Wisconsin, including Winona and Goodview on the west and Sparta on the east, due to the location of upgraded 161 kV facilities and existing facilities that are benefited by the proposed facilities.

The green area is the Rochester benefit area. This is the portion of the Rochester area electric system that is benefited by the 161 kV facilities that are included in the Proposal. The Rochester benefit area includes the areas of Rochester and extends north to Oronoco and south and west to Pleasant Valley. This geographic area is served by the 161 kV facilities of RPU, SMMPA and Dairyland as well as the 69 kV facilities of Peoples Cooperative Services.

In the La Crosse/Winona area, the Proposal will restore reliable service by providing a strong 345 kV source to the 161 kV network to the greater La Crosse area. This reduces the burden on the four existing 161 kV source lines into La Crosse and mitigates the risk caused by a contingency loss of any of these lines. Also, a 345 kV line eliminates the risk of interrupted load caused by the loss of a generator and a 161 kV line. In Rochester, the Proposal, and the Dairyland reconductor project will increase system capability to 707 MW which could serve area load until approximately mid-century.

3.1.4 System Losses

The three 345 kV Projects, including the Proposal, will also have a positive effect on system losses. After construction of the CapX2020 proposals, overall system losses are expected to be reduced 234 MW on-peak and 105 MW off-peak. Further discussion of losses follows.

Not all electricity injected onto the transmission system will ultimately be delivered to end-use customers. Due to the resistance of the conductors and transformers, some of the power dissipates as heat energy during operation of the system. Generally speaking, the higher the voltage level of a particular facility, the lower the level of losses for a given amount of power transfer. These transmission losses consist of power ("demand" or "capacity") and energy losses. Every MW of system demand loss has a generating capacity cost associated with it, and every MWh of energy losses has a production cost associated with it. By reducing system losses, a more efficient power system results and the cost to deliver power to the consumer is reduced.

To determine the impact of the three 345 kV Projects, including the Proposal, planning engineers studied the impact of the facilities on the loss profile of the system by modeling power flows on the system without the proposed improvements and then with the improvements. Summer peak load conditions (Year 2012) were modeled in all areas except North Dakota (North Dakota load was reduced to allow higher NDEX). The off-peak case used to derive the loss analysis results below was created by reducing the load in the CapX2020 participant control areas to 70% of peak and turning off generation in those control areas to match the resultant load. The list of generators in those areas was sorted by their output, and those with the smallest outputs were turned off. The power transfers in the case were allowed to change on their own as a result of those load and generation reductions.

The results of the study of system losses before and after the addition of the three 345 kV projects proposed in this Application are shown in Figure 3-7.

Figure 3-7
Electrical System Losses

Configuration	Total On-Peak Model Losses, MW	Total On-Peak Loss Benefit of Facility/MW After 345 kV Projects	Total Off-Peak Model Losses, MW Before 345 kV Projects	Total Off-Peak Loss Benefit of Facility, MW After 345 kV Projects
Before three 345 kV projects	18,087.3	-	17,672.3	-
With three 345 kV projects	17,853.1	234.2	17,567.4	104.9
With Twin Cities – La Crosse 345 kV line and associated improvements except the North Rochester – Chester 161 kV line and the North Rochester – Northern Hills 161 kV line	18,081.1	6.2	17,654.3	18.0

The analysis indicates that, once installed, the facilities will significantly reduce the amount of losses experienced by the system overall. These reductions in losses yield an important economic benefit. Each MW in loss reduction reduces the amount of power that must be generated. The value of the losses has two components: demand and energy. The following paragraphs describe the method by which cumulative present worth of each of these components was computed and the financial parameters applied (discount rate, energy & capacity values, fixed charge rates, *etc.*). An additional benefit of reducing system losses is a reduction in air emissions from generators.

Utilities evaluated the economic benefits for the demand and energy savings using a 20-year time horizon. Economic evaluations of transmission projects typically use longer study periods of 30 to 50 years. However, a conservative 20-year period was selected for this analysis due to uncertainty related to the future operation of the transmission system and capacity and energy prices in the distant future. Utilities calculated the cumulative present value of the demand and energy loss reduction benefits using a discount factor of 7.42 percent per year (the weighted after-tax cost of capital approved in Xcel Energy's 2006 electric rate case), which results in a 20-year "present value of annuity" factor of 10.26. This means that a savings of $1 per year for 20 years has a present value of $10.26.

The economic value of the demand (capacity, or MW) loss reduction benefit was determined by first multiplying the estimated on-peak line loss reduction (234.2 MW) by 1.15 to account for the 15 percent reserve margin required by the MAPP. The 15 percent reserve margin is applied only to on-peak line loss because MAPP requires that the 15 percent reserve requirement be calculated using the utility's seasonal peak. The Utilities calculated the annual value of capacity by using the economic carrying charge value for a 160 MW simple-cycle combustion turbine. A combustion turbine was used because this represents the "lowest installed cost" form of generating capacity.

The economic carrying charge is a $/kW-year value that represents the fixed cost of peaking capacity. For 2007, this value was $51.86/kW-year. Utilities calculated the resultant net present value for demand (capacity) benefits to be $143 million.

The economic value of the energy (MWh) loss reduction benefit was determined based upon the on-peak estimates of the total loss reduction for the proposed facilities (234.2 MW) and a presumed 30 percent annual loss factor (load factor of the losses) for the transmission system. The 234.2 MW loss reduction value was therefore multiplied by 8,760 hours per year, the loss factor of 30 percent at $50 per MWh cost for replacement energy from existing regional generation resources and the $10.26 annuity factor (234.2 x 8,760 x .3 x $50 x $10.26). The resultant 20-year net present value of avoided energy losses is approximately $316 million.

In sum, the net present value of the demand (MW) and energy (MWh) loss reduction benefits for the three 345 kV Projects is estimated to be approximately $143 + $316 = $459 million. This value is considered a conservative (low-end) estimate, as no cost escalation factors were applied to the values of capacity and energy, and only a 20-year term was considered.

3.2 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 measures and conservation measures to limit energy load growth can successfully address the demand needs. This section also discusses whether existing generation can address these needs.

3.2.1 Demand-Side Management

DSM is the process of managing the consumption of energy to optimize available and planned generation resources. According to the U.S. Department of Energy, DSM refers to "actions taken on the customer's side of the meter to change the amount or timing of energy consumption." Utility programs falling under the umbrella of DSM include: load management, strategic energy conservation and strategic energy efficiency. Load management allows utilities to better manage the timing of their consumers' energy use, and thus helps reduce the large discrepancy between on-peak and off-peak demand. Energy conservation can reduce the overall consumption of electricity by reducing the need for heating, lighting, cooling, cooking energy and other functions. Energy efficiency can encourage consumers to use energy more efficiently, and thus get more out of each unit of electricity produced.

3.2.1.1 *Load Management Measures*

Load management DSM programs are directed at minimizing the peak load at any given moment by reducing or eliminating 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, 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 when demand is not so high.

Utilities' consideration of load management is reflected in their forecasts of future load growth in the Rochester and La Crosse areas. It is not realistic to expect that load management DSM savings significantly greater than what has been already forecasted will be achievable and thus eliminate or substantially reduce the projected load growth for the area.

3.2.1.2 *Conservation Measures*

Minnesota utilities, including NSPW and Dairyland, are required to invest in conservation improvement programs and file plans with the Minnesota Department of Commerce Office of Energy Security (OES) in accordance with Minnesota Statutes Section 216B.241 (Energy Conservation Improvement). In addition, the statute establishes an annual energy-savings goal equivalent to 1.5 percent of gross annual retail sales for each utility absent approval of an exemption from the OES. Wisconsin does not have a similar conservation program in place at this time.

Conservation measures will not reduce or obviate the need for the Proposal to address community service reliability, system wide growth, and outlet capacity because the effect of conservation will not appreciably reduce the projected growth in peak electric demand. To be effective, this alternative would need to achieve significant additional savings beyond the current statutory requirements. This alternative is not feasible because it is unreasonable to assume that all utilities would be able to exceed the statutory requirements and achieve sufficient savings to offset the need for several thousand megawatts of power. Therefore, the need for enhanced regional reliability cannot be met by conservation programs.

3.2.2 Existing Generation

The use of existing generation to provide system support is also a poor long-term solution to system deficiencies, particularly in the Rochester area because of the age of the existing generators and anticipated retirements.

In the next 10 to 15 years, significant changes to the internal generation in Rochester are expected. RPU's "Report on the Electric Utility Baseline Strategy for 2005-2030 Electric Infrastructure" (2005) calls for the retirement of the oldest combustion turbine unit, Cascade Creek No. 1 and the retirement or use "only for regulatory reserve service with minimal operating time" of the three oldest steam units, Silver Lake Nos. 1, 2 and 3 by 2015.

After the year 2015, then, the remaining 112.3 MW in resources would consist of Cascade Creek Combustion Turbine #2 (49.9 MW); two hydro generators (2.4 MW combined) and Silver Lake No. 4 (60 MW). It should be noted that the longevity and efficacy of the Silver Lake No. 4 after this date is questionable given it will be 46 years old and its capacity may be reduced by approximately 10 MW based on new emissions controls.

Meanwhile, the ability to use these older units for system support is limited due to their limited ramp rates (*e.g*., the four Silver Lake units were installed between 1949 and 1969). The speed of response, both in magnitude and in time, is severely limited on these small units because frequent ramping up and down of older units can have serious operational and mechanical impacts on the units. As a result, in the event of a system disturbance, these units might not be able to ride through that disturbance and maintain synchronous operation with the bulk transmission system.

Given these factors, relying on generation in the Rochester and Winona/La Crosse areas is not a practical method of achieving the desired power system load serving capability in lieu of transmission line additions due to its higher costs and lower reliability.

The MISO has confirmed the need for additional transmission capacity. The MISO did not complete a published transmission study for this Proposal but as part of the Minnesota Certificate of Need Proceeding, the MISO filed testimony from MISO's Director of Expansion Planning, Jeffrey Webb that summarized MISO's study of this Proposal. A copy of Mr. Webb's Direct Testimony is attached as Appendix A.5. The MISO evaluated several power flow models of the MISO system to study the reliability of the transmission system. Models were prepared for summer and winter peak periods for the planning years 2011 and 2016. The MISO determined that without additional transmission improvements in the area, even with all available generation running, numerous line overload conditions would be caused by forced outages. The Adams – Rochester 161 kV line, for example, would overload under six combinations of line and/or generator forced outages resulting in loading as high as 118 percent of rating for loss of the Byron – Maple Leaf and Alma – Wabaco 161 kV lines.

The Winona/La Crosse area similarly would continue to face reliability issues if no action were taken. Currently, the La Crosse, Wisconsin area is served by four 161 kV lines. From the south, these lines stretch from the Genoa Substation to the Coulee Substation and from Genoa to the La Crosse Substation and on to the Marshland Substation. The remaining two lines connect the Alma Station to the Marshland Substation and the Alma Station to the Tremval Substation to the La Crosse Substation.

Under summer peak loading conditions, if the Genoa – Coulee 161 kV line goes down, the area can serve only 470 MW of load. If this contingency occurs and the John P. Madgett generator is off-line, only 310 MW of power demand can be met.

The French Island peaking units owned by Xcel Energy can be brought on-line to provide additional generation support, but these units are very expensive to run for transmission system support and their operation may be limited by environmental permits.

Doing nothing to resolve these issues and relying on local generation will result in continually higher exposure to periods where loads are high enough to cause interrupted service to customers in the Winona/La Crosse area.

The MISO's analysis confirmed that the transmission system in Winona/La Crosse area has significant reliability issues. For 2011, the worst contingency scenario is the loss of the Genoa – Coulee 161 kV line and John P. Madgett which creates loading on the Genoa – La Crosse 161 kV line of 124 percent. For this same time period, MISO determined that the loss of the Genoa – North La Crosse 161 kV line and the John P. Madgett creates loading on the Coulee – La Crosse 161 kV line of 113 percent and loading on the Genoa –Coulee 161 kV line of 103 percent.

3.2.3 Conclusions on No Action Alternative

The Utilities have and continue to execute DSM and conservation improvement programs to manage load growth in the Rochester and Winona/La Crosse areas. However, the no action alternative cannot meet community reliability needs. In Rochester, demand for power has already exceeded the capacity of the transmission system alone (181 MW) and as early as 2014 will eclipse the capability of transmission and generation run for system support. It is not reasonable to assume that load management and conservation efforts can create a decline in the actual peak demand, and the forecasts demonstrate that even with these DSM measures, demand will continue to outstrip the capability of the electrical system.

In addition, relying on existing generation in the Rochester and Winona/La Crosse areas is not a reasonable method of achieving the desired power system load serving capability in lieu of transmission line additions due to its higher costs and lower reliability.

The no action alternative is also not a feasible alternative to meet the need for additional transmission facilities for regional reliability and to support generation outlet capability in southeastern Minnesota. To meet these needs, transmission facilities must be constructed.

3.3 New Generation Alternative

In evaluating new generation alternatives to the Proposal, Utilities studied the addition of generation (*e.g.*, peaking, baseload, distributed) to meet the three needs identified in this AES (community service reliability, generation outlet and regional reliability). As described in this section, new generation does not satisfy any of these identified needs in a reasonable fashion.

3.3.1 Description of Generation Types

Generation can be characterized as either baseload, intermediate, peaking, or distributed:

- 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 1,000 MW capacities.

- 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.

- Distributed generation is generally considered to be small generation sources, usually less than 10 MW, located close to the ultimate users. However, in some cases generators larger than 10 MW are also considered to be distributed generation.

Within each type, the generation can be characterized as dispatchable or non-dispatchable.

For a generation addition to the Rochester and Winona/La Crosse area 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 one to nine hours per year, a new transmission line can be expected to have an annual availability factor of over 99.9 percent.

Generators typically have availability in the range of 85 to 95 percent. 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 percent it is necessary to have four generators each with an 86 percent availability, or three generators each with a 93 percent availability, to achieve generation availability equivalent to that of one transmission line.

While local generation operated in advance of the next contingency may support additional demand, using generation for system support is not a desirable long-term solution because it is less reliable than transmission and more prone to outages and must be turned on in advance of and operated at a level sufficient to withstand the dynamic impacts of the next contingency, even if the power is not needed locally.

3.3.2 Baseload Generation

Generally, baseload generation has high installation costs due to the fact that it will be operating heavily for most of its life. Construction of a baseload generation, in particular coal-fired generation, could also have considerable environmental impacts in the form of emissions. In addition, a baseload generation facility will not alleviate the need to add new transmission. Unless the new generation can be built to interconnect to existing transmission lines with sufficient capacity, new transmission lines would have to be built to accommodate the new generation. This additional transmission further increases the cost of this generation alternative.

Given the high construction costs, possible environmental impacts, and the need for additional transmission, baseload generation is not a reasonable alternative to the Proposal.

3.3.3 Intermediate Generation

A typical form of intermediate generation plant is a natural gas combined cycle operation. A combined cycle operation consists of one or more combustion turbine generators exhausting to one or more heat recovery steam generators. The resulting steam generated by the heat recovery steam generator is then used to power a steam turbine generator. Most of the power-generation cost for a natural gas combined cycle operation is from the variable fuel cost. Natural gas cost is highly variable and strongly affected by the economy, production and supply, demand, weather, and storage levels. Traditionally, demand for natural gas peaks in the coldest months, but with the nation’s power increasingly being generated by natural gas, demand also spikes in the summer, when companies fire up peaking plants to provide more power for cooling needs. Intermediate generation is generally substantially more costly to construct than peaking generation.

3.3.4 Peaking Generation

Given that the community reliability needs in the Rochester, Winona and La Crosse areas are based on transmission deficiencies in the event of certain contingencies during peak demand times, planning engineers determined that peaking generation sources would be the most appropriate type of generator to evaluate.

To analyze the appropriateness of peaking generation as an alternative for community service reliability, there are three general steps. The first step is to identify the level of the deficiency. This number is calculated by deducting the capability of the transmission system in a community from the forecasted load. Once the deficiency is identified, the second step is to identify reasonable generation technologies that could satisfy the deficiency. In this AES, the community service reliability issues arise in each community under peak conditions. To address that deficiency with generation, it would be appropriate to consider the costs of peaking units, *i.e.*, gas turbines of various sizes. Figure 3-8 summarizes the costs of four typical peaking units:

Figure 3-8
Estimated Costs for Peaking Units

Single Cycle Generators		
Size	**Total Cost**	**$/Kilowatt**
29 MW	$40,896,000	$1,416
41 MW	$49,101,000	$1,206
84 MW	$61,404,000	$729
168 MW	$90,827,000	$541

The third step is to determine the amount of generation that would be necessary to replicate the reliability levels found in transmission lines. It is not sufficient to conclude that if a local area has 41 MW of need that adding a single 41 MW peaking unit would be sufficient. Rather, to provide an accurate comparison, sufficient generation must be considered that will replicate the reliability provided by adding transmission.

If one were trying to address a deficit of the size of the Rochester area in 2015 (194 MW) and the anticipated in the Winona/La Crosse area (45 MW). Multiple generators would be required. In La Crosse, for example, assuming a generation availability of 95 percent (which is on the high end of the spectrum), if four independent units of 41 MW rating were added (such that only two of the four units need to be available at any given moment to provide 82 MW of output), the probability calculation would achieve similar availability results to adding 82 MW of transmission capacity. In this example, the amount of generation required to achieve comparable reliability to transmission is twice the load-serving capacity that is being sought. Applying the cost estimates in Figure 3-8, this would require a roughly $200 million investment (four 41 MW plants at $49 million each). If the availability of the generators is lower, say 90 percent, even more generation would need to be installed to achieve the same 99 percent or better availability that is achieved by transmission.

In Rochester, significantly more generation would need to be constructed. To meet the 194 MW need, four 84 MW units ($61 million each) and four 29 MW units ($41 million each) would be needed. The total cost would be approximately $408 million.

The total costs for generation additions in the Rochester and the Winona/La Crosse areas would cost approximately $608 million. 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.

Another obstacle to installing generation is that transmission typically cannot be avoided altogether. Unless the generation can be built to interconnect to existing transmission lines with sufficient capacity, new transmission lines would have to be built to accommodate the new generation. This needed transmission further increases the cost of that generation alternative.

Finally, when the demand for power increases, new generators must be constructed.

3.3.5 Distributed Generation

Distributed generation is generally considered to be small generation sources, usually less than 10 MW, located close to the ultimate users. However, in some cases generators larger than 10 MW are considered to be distributed generation as well. If distributed generation had similar operating characteristics to the peaking plant scenarios discussed in the prior section, adding such generation would not satisfy the identified customer service needs in a cost-effective manner.

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

There are also emissions concerns associated with distributed generation because distributed generation involves numerous small generators.

3.3.6 Renewable Generation Sources

Renewable energy comes from sources that are essentially inexhaustible. These energy supplies can be endless resources such as the sun, wind, and the heat of the Earth, or they can be replaceable fuels such as biomass, *i.e.*, combustible plants or plant extracts, such as ethanol. The renewable energy sources evaluated in this section include wind, solar, hydroelectric, geothermal and biomass.

3.3.6.1 *Wind*

Wind turbines convert the power in wind into electricity by extracting the kinetic energy in wind, and utilizing the wind turbine to generate mechanical power. The greatest advantage of wind power is that it generates electricity without local emissions of any kind.

Wind energy generation is a “variable” resource that is dependent on the availability of wind to operate. While a wind turbine may have a nameplate capacity of 1.5 MW, its average net operating output may range from 20% to 40% of its nameplate capacity. Wind energy is a “non-dispatchable” resource and cannot be brought on-line quickly and relied on to serve peaking needs in the same way that a conventional generation of the same rating (e.g., natural gas fired) which is a “dispatchable” resource.

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

This operating characteristic creates two separate issues. First, the system must be capable of importing power to the affected community during those hours when sufficient wind energy is not being generated to satisfy the entire need (*i.e.*, high demand/low wind scenario). Second, the system must be capable of exporting power from the affected community during those hours when more wind energy is being generated than can be used by the local community (i.e., low demand/high wind scenario).

Therefore, transmission system improvements are typically required to support wind generation. Because wind power is a non-dispatchable resource, is less reliable than transmission and would require new transmission system improvements for support, the Utilities determined that wind generation was not a reasonable alternative to meet the local community needs.

3.3.6.2 *Solar*

Current technologies allow for the harnessing of solar energy for heating, lighting, cooling and electricity. The sun's energy can be converted to electricity directly through photovoltaic cells (solar cells). However, solar energy varies by location and time of year. Solar resources are expressed in watt-hours per square meter per day ($Wh/m^2/day$). This is roughly a measure of how much energy falls on a square meter over the course of an average day.

There are two types of solar collectors, first is a flat-plate collector and second is a concentrator collector. The flat-plate collectors are generally fixed in a single position, but can be mounted on structures that tilt toward the sun on a seasonal basis, or on structures that roll east to west over the course of the day. The concentrator collectors focus direct sunlight onto solar cells for conversion to electricity. These collectors are on a tracker, so they always face the sun directly and because these collectors focus the sun's rays, they only use the direct rays coming straight from the sun.

Due to the intermittent nature of solar power, economic feasibility strongly depends on the amount of energy it produces. Capacity factor serves as the most common measure of solar power productivity. Estimates of capacity factors range from 20 to 35 percent.

Solar power cannot fulfill the community reliability needs of Rochester and La Crosse due to the fact that power is variable and may not be available when needed to meet demand.

3.3.6.3 *Hydroelectric*

Hydroelectric power (Hydropower) is the kinetic energy of flowing energy. Hydropower is captured and used to power machinery or converted to electricity. Hydropower plants typically dam a river or stream to store water in a reservoir. The water is released from the reservoir and it flows through a turbine causing it to spin and activates a generator to produce electricity. Hydropower is the nation's leading renewable energy source. It accounts for 81% of the nation's total renewable electricity generation.

There are no potential hydropower sites within the project area and therefore hydroelectric power is not a reasonable alternative.

3.3.6.4 *Geothermal*

Geothermal energy is thermal energy from the Earth's interior where temperatures reach greater than 7000 degrees Fahrenheit. The heat is brought to the surface as steam or hot water and used to produce electricity or applied directly for space heating and industrial processes.

There are three types of geothermal energy. The first is power generation (or electric), which utilizes steam turbines natural steam or hot water flashed to steam. Binary turbines then produce mechanical power that is converted to electricity. The second is a direct use application. As a well brings heated water to the surface, a mechanical system delivers the heat to space and a disposal system either injects the cooled geothermal fluid under ground or disposes of it on the surface. The third and most rapidly growing use for geothermal energy is geothermal heat pumps, which transfers heat from the soil to the house in the winter and from the house to the soil in the summer.

Geothermal electric power cannot fulfill the needs served by the Proposal because commercial geothermal resources for generation of electric power are not available in southeastern Minnesota and southwestern Wisconsin.

3.3.6.5 *Biomass Power*

Biomass power (Biopower) which is the second most widely utilized renewable energy behind hydroelectricity, is the generation of electric power from biomass resources including urban waste, wood, crop and forest residues and (in the future) crops grown specifically for energy production. Biomass results in very low carbon dioxide emissions due to absorption of carbon dioxide during the biomass cycle of growing, converting electricity, and re-growing biomass. Nearly all current biomass generation is based on direct combustion in small, biomass-only plants with relatively low electric efficiency. Most biomass direct combustion generation facilities burn biomass fuel in a boiler to produce steam that is expanded in a Rankine Cycle prime mover to produce power. Currently, co-firing is the most cost-effective technology for biomass. Co-firing substitutes biomass for coal or other fossil fuels in existing coal-fired boilers.

The current biomass sector is comprised mainly of direct combustion plans and a small amount of co-firing. Plant size averages 20 MW, and the biomass-to-electricity conversion efficiency is about 20 percent. For biomass to be economical as a fuel for electricity, the source of biomass must be located near to where it is used for power generation. This reduces transportation costs. The most economical conditions exist when the energy used is located at the site where the biomass fuel is generated. The Utilities concluded that biomass was not a reasonable alternative due to its fuel source requirements, typical smaller size and costs.

3.3.7 Conclusions on New Generation Alternative

Adding additional generation to the Rochester and La Crosse areas is not a practical method of meeting the three identified needs in lieu of transmission line additions. This is primarily due to the following considerations:

- Generation cannot meet the needs for enhanced regional reliability and generation outlet support;
- 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 associated with running additional local generation in anticipation of a transmission outage would be significant.
- The proposed transmission facilities will not cause emissions whereas new generation resources would create significant emissions.

Based on the foregoing, Utilities determined that new generation is not a reasonable alternative to the Proposal.

4.0 Required Permits and Approvals

The Utilities are required to obtain approvals from a variety of federal and state agencies. The agencies with primary permitting authority include RUS, the Public Service Commission of Wisconsin and MN PUC. Figure 4-1, Figure 4-2 and Figure 4-3 list the expected permits, studies, consultations and regulatory requirements for the Proposal.

Figure 4-1
Federal Permits and Other Compliance that May Be Required for Proposal

Agency	Permit, Regulatory Compliance, or other
U.S. Department of Agriculture Rural Utilities Service	Alternative Evaluation Study and Macro Corridor Study (7 C.F.R. § 1794) National Environmental Policy Act Compliance (42 United States Code (U.S.C.) § 4321
U.S. Army Corps of Engineers	Section 10 Permit of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403) for crossing the Mississippi River
U.S. Army Corps of Engineers and U.S. Environmental Protection Agency Region 5	Nationwide permit or individual permit under Section 401 and 404 of the Clean Water Act of 1977 (33 U.S.C. § 1344)
U.S. Department of Agriculture Natural Resource Conservation Service	Farmland Conversion Impact Rating (Form AD-1006)
U.S. Fish and Wildlife Service	Use authorization if right-of-way required on National Wildlife Refuge or Wetland Management District lands (Standard Form 299) and Special Use Permit if crossing National Wildlife Refuge Section 7 of the Endangered Species Act 1973 (16 U.S.C. § 1531–1544) Bald and Golden Eagle Protection Act (16 U.S.C. § 668), (50 C.F.R. § 22) Migratory Bird Treaty Act of 1918(16 U.S.C. § 703–712)
Federal Aviation Administration	Form 7460-1 Objects Affecting Navigable Airspace
Federal Highway Administration	Permit required to cross federal highways and interstate highways (usually coordinated through the state Department of Transportation)

Agency	Permit, Regulatory Compliance, or other
National Park Service	Consultation: Wild and Scenic Rivers Act 1968 (if project affects federally designated areas)
Rural Utilities Service	National Historic Preservation Act—Section 106, tribal consultation

Figure 4-2
State of Minnesota Permits and Other Compliance that May Be Required for Proposal

Agency	Permits/Other Compliance
Minnesota Public Utilities Commission	Certificate of Need
Minnesota Public Utilities Commission, Minnesota Environmental Quality Board, Department of Commerce	Route Permit (includes state environmental impact statement requirement)
Minnesota Department of Transportation	Application for Utility Permit on Trunk Highway Right of Way (Long Form No. 2525) Application for Access Driveway Permit Application for Drainage Permit Form
Minnesota Department of Natural Resources	Protected water crossings permits Application for a License to cross Public Lands and Waters Wetland Conservation Act requirements Public Waters Work Permit Program Minnesota Wild and Scenic Rivers Program State Canoe Routes and Trails Minnesota State Forests Endangered Species Statues—Permits and Coordination
Minnesota Pollution Control Agency	Air Quality and Noise Standards and Requirements National Pollutant Discharge Elimination System Stormwater Permits (construction, operation) Section 401 Water Quality Certification (if a 404 permit is required by the U.S. Army Corps of Engineers)
Minnesota Historical Society/Minnesota State Preservation Office	National Historic Preservation Act—Section 106 compliance
Minnesota Department of Agriculture	Agricultural Mitigation Plan (if required)

Figure 4-3
State of Wisconsin Permits and Other Compliance that May Be Required for Proposal

Agency	Permits/Other Compliance
Public Service Commission of Wisconsin	Certificate of Public Convenience and Necessity
Wisconsin Department of Natural Resources	Utility Permit State EIS Joint state-federal application for impacts to waterways and wetlands Indication of Endangered/Threatened Species Incidental Take Authorization Construction Site Erosion Control and Stormwater Discharge Permit General Utility Crossings Permit Section 401 Water Quality Certification (if 404 permit is required by the U.S. Army Corps of Engineers)
Wisconsin Department of Transportation)	Application to Construct and Operate Utility Facilities on Highways Rights-of-Way (Form DT1553) Application for Access Driveway Permit (may be required) Application for Drainage Permit Form (may be required)
Wisconsin Historical Society/Office of Preservation Planning	National Historic Preservation Act, Section 106 consultation
Wisconsin Department of Agriculture, Trade, and Consumer Protection	Agricultural Impact Statement

5.0 Conclusion

It has been nearly three decades since the electrical network serving Minnesota and the surrounding area, including western Wisconsin, has been expanded to any large degree. At the same time, the demand for power has continued to grow, and planning engineers predict that energy demands will increase by several thousand megawatts by the year 2020. The results of the CapX2020 engineering analyses showed that Minnesota and the surrounding region would experience numerous transmission overloads, outages, and voltage problems if no transmission additions were made. The purpose of the CapX2020 Initiative is to plan for and provide infrastructure to meet projected customer demands on a local, as well as regional, basis.

Specific analyses for the Proposal were performed for the Rochester and La Crosse/Winona areas. Forecasting data demonstrates that demand in the Rochester area currently exceeds the level at which the electrical system can reliably serve customers. As growth continues, this deficit will increase.

Forecast information shows that the La Crosse/Winona area will begin exceeding the ability of the transmission system alone to provide power in the event of critical transmission line failure beginning in approximately 2009. The local system also relies heavily on Genoa and/or Alma generation to maintain the reliability of service to the area. The outage of either of those plants severely restricts the amount of power that can be delivered, even with French Island peaking generators on if a transmission line should fail.

Through the Rochester/La Crosse Study efforts, planning engineers developed the Proposal to address local reliability needs, regional reliability needs and generation outlet needs. Planning engineers adequately studied alternatives including different voltages, generation and a no action alternative and concluded that these alternatives cannot meet the identified needs.

The Proposal is the best alternative to address the identified regional, local and generation needs. The Proposal will provide community support for the Rochester area until mid century. The Proposal will provide support for the Winona/La Crosse areas until approximately 2036. The Proposal will also help strengthen the 345 kV backbone regional transmission system. Additionally, the Proposal will support generation outlet capability in the southeastern Minnesota area.

6.0 Bibliography

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Red River Valley—Northwest Minnesota Load-Serving Transmission Study (TIPS Update) (February 13, 2006)

Southeastern Minnesota–Southwestern Wisconsin Reliability Enhancement Study (March 13, 2006)

Southwest Minnesota–Twin Cities EHV Development Electric Transmission Study, Volume 1 (November 9, 2005)

ALTERNATIVE EVALUATION STUDY

Hampton-Rochester-La Crosse
345 kV Transmission System
Improvement Project

APPENDIX

APPENDIX

A.1 CapX2020 Technical Update: Identifying Minnesota's Electric Transmission Infrastructure Needs (October 2005).
A.2 Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study (March 13, 2006).
A.3 Rochester Area Summer Peak Load Information (2002-2020).
A.4 La Crosse Area Summer Peak Load Information (2002-2020).
A.5 Direct Testimony of Jeffrey R. Webb filed on behalf of the Midwest Independent Transmission System Operator in the Minnesota Certificate of Need Proceeding on May 23, 2008.
A.6 Regional Incremental Generation Outlet Study (August 19, 2008).
A.7 Alma – La Crosse – Genoa 161 kV Line History.

CapX 2020 Technical Update: Identifying Minnesota's Electric Transmission Infrastructure Needs

October 2005

EXECUTIVE SUMMARY

Background

Minnesota's electric transmission infrastructure, a network of transmission lines of 230 kilovolts and higher, primarily was designed and built during the 1960s and 1970s. As explained in CapX 2020's December 2004 interim report, the system is adequate to meet today's needs. But to support customers' growing demand for electricity, this high-voltage transmission system in Minnesota and neighboring states requires major upgrades and expansion during the next 15 years.

To ensure that this backbone transmission system is developed and available to serve growing demand for electricity and to plan for major capital expenditures, Minnesota's largest transmission-owning utilities—Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Southern Minnesota Municipal Power Agency, and Xcel Energy—initiated the CapX 2020 project.

CapX 2020's mission is to:

- Create a joint vision of required transmission infrastructure investments needed to meet growing demand for electricity in Minnesota and the region.
- Work to create an environment that allows these projects to be developed in a timely, efficient manner, consistent with the public interest.

The utilities have completed a draft study that defines a vision for transmission infrastructure investments needed in Minnesota through 2020. That technical study, which meets the first part of CapX 2020's mission, is described in this report. Studies will continue to determine which facilities will need to be built first. As other regional transmission studies are completed, they will be integrated into the CapX 2020 study. A report that describes progress on the second part of CapX 2020's mission, including pending legislation, is planned for this summer

Study overview

In developing this long-range plan for major new construction, the CapX 2020 technical team considered two potential scenarios for growth in electricity demand:

1. Anticipated load growth of 2.49 percent annually from 2009 through 2020, for an increase of 6,300 megawatts. This is based on load projections for utilities with customers in Minnesota, published by the Mid-Continent Area Power Pool (MAPP) in the *2004 MAPP Load and Capability Report* and in recent utility resource plan filings. Load growth of 6,300 MW would require over 8000 MW of new generation, given losses that occur when transmitting.
2. Slower load growth—about two-thirds of the published load projections—of 4,500 MW.

Based on information from independent power producers, wind developers, utility resource planning staff, and the Midwest Independent Transmission System Operator's generation interconnection queue, the team also worked out three generation scenarios, each including 2,400 MW of renewable energy, to illustrate potential locations of new electric generating plants or wind farms.

The goals were to identify new transmission *independent* of where plants are located *and* to identify new transmission *specific* to particular electric generation scenarios. The team considered planning requirements for meeting the Minnesota Renewable Energy Objective, addressed issues related to relieving transmission congestion, and focused on high-voltage solutions that best addressed the three different generation scenarios.

Results: The CapX 2020 Vision Plan

Facilities common to two of the three generation scenarios were identified as the cornerstone of the CapX 2020 Vision Plan—1,620 miles of 345 kV transmission lines that total $1.215 billion, about 80 percent of the cost of each scenario individually. The following table identifies these facilities. Any long-range vision plan also will have to include additional unique facilities for each scenario.

Facility Name				
From	**To**	**Volt (kV)**	**Miles**	**Cost ($M)**
Alexandria, MN	Benton County (St. Cloud, MN)	345	80	60
Alexandria, MN	Maple River (Fargo, ND)	345	126	94.5
Antelope Valley (Beulah, ND)	Jamestown, ND	345	185	138.75
Arrowhead (Duluth, MN)	Chisago County (Chisago City, MN)	345	120	90
Arrowhead (Duluth, MN)	Forbes (northwest Duluth, MN)	345	60	45
Benton County (St. Cloud, MN)	Chisago County (Chisago City, MN)	345	59	44.25
Benton County (St. Cloud, MN)	Granite Falls, MN	345	110	82.5
Benton County (St. Cloud, MN)	St. Bonifacius, MN	345	62	46.5
Blue Lake (southwest Twin Cities, MN)	Ellendale, MN	345	200	150
Chisago County (Chisago City, MN)	Prairie Island (Red Wing, MN)	345	82	61.5
Columbia	North LaCrosse	345	80	60

Ellendale, ND	Hettinger, ND	345	231	173.25
Rochester, MN	North LaCrosse	345	60	45
Jamestown, ND	Maple River (Fargo, ND)	345	107	80.25
Prairie Island (Red Wing, MN)	Rochester, MN	345	58	43.5

Total miles	**Total cost**
1620	**$1,215 ($M)**

Conclusion

The CapX 2020 technical team believes the results documented here to be the basis for additional studies to better identify the transmission needs of the study region. The following report details the technical study behind this update. Section headings are:

- Base model assumptions
  (about loads and generation and how scenarios were determined, biases).
- Analysis
  (of study assumptions such as system conditions, contingencies, Big Stone II, and other sensitivities).
- Scenario analysis
  (of existing system performance, transmission alternatives, and line flows on interface and tie lines).
- Slow growth analysis.
- Common facilities.
- Conclusion and next steps.
- CapX 2020 Technical Team members.
- Appendices.

Although the existing transmission system is adequate to meet the reliability needs of customers today, the CapX 2020 study shows that the study region will experience specific and numerous transmission overloads, outages, and voltage problems if we make no transmission additions between now and 2020. Collaborative efforts and plans, such as those identified in this report, are necessary to reduce the risk of investing in new transmission infrastructure and to preserve electric reliability for customers.

~~2.~~1.Base Model Assumptions

The CapX study region encompasses the service territories of electric utilities that have load-serving responsibilities for Minnesota consumers. This region is represented in Diagram 1 below.

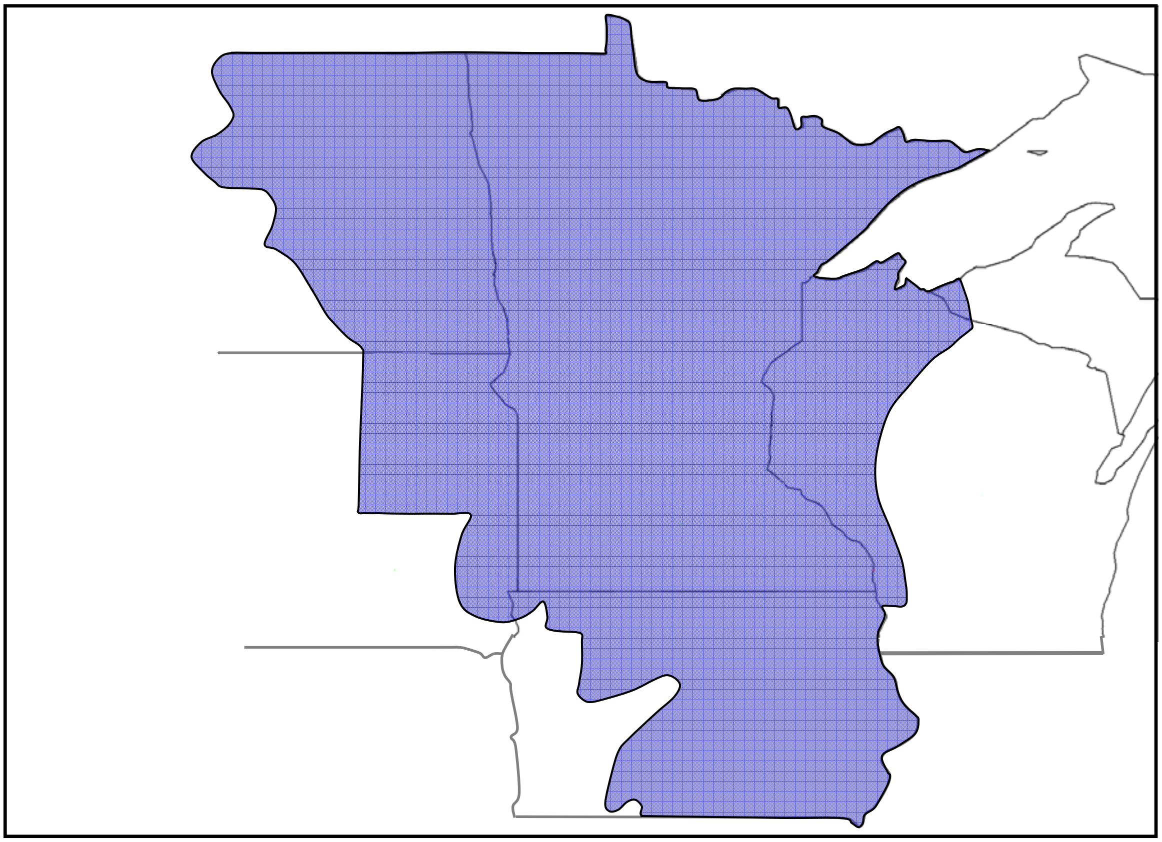

Diagram 1 – CapX 2020 Region

1.1 Loads

The CapX 2020 technical team chose the MAPP 2004 Series, 2009 summer peak model, as the base model to begin scaling loads to the anticipated 2020 load level. To accurately model 2020 loads, the technical team used individual company load growth from the *2004 MAPP Load and Capability Report* for the following control areas: Alliant Energy (west), Xcel Energy (north), Southern Minnesota Municipal Power Agency, Otter Tail Power Company, and Dairyland Power Cooperative.

Note that each control area contains not only load belonging to the control area operator, but also that of other companies. For example, Missouri River Energy Services has load in the Alliant Energy (west), Minnesota Power, Otter Tail Power Company, Western Area Power Administration, and Xcel Energy (north) control areas).

Minnesota Power and Great River Energy's loads were scaled based on their most recent resource plan filings. The growth results are in Table 1

Control area	2009 load level (2004 MAPP Series) (MW)	Yearly growth rate (%)	Calculated 2020 load level (MW)
ALT (West)	3265.3	1.60	3888.2
Xcel Energy (North)	9632.6	2.68	12885.1
MP	1507.3	1.70	1814.4
SMMPA/RPU	330.0	2.70	442.4
GRE	2833.5	3.27	3943.2
OTP/MPC	1677.2	2.70	2248.3
DPC	954.7	2.60	1266.2
Total	20200.6	Ave. = 2.49%	26487.8

Table 1 – CapX 2020 Anticipated Area Growth

Table 1 shows an anticipated load growth of approximately 6300 megawatts (MW) in the CapX 2020 region for the period from 2009 to 2020. The technical team also studied historical loads for Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, and Xcel Energy to determine whether anticipated load growth was consistent with historical load growth in the region. Load growth for these companies averaged 2.64 percent during the period 1980 to 2004. Diagram 2 shows the variability of load growth as well as the continuing upward growth in load for the region. The technical team's forecast from 2009 through 2020 is a slower growth curve than the actual growth in the early 2000's (2.49 percent vs. 2.64 percent).

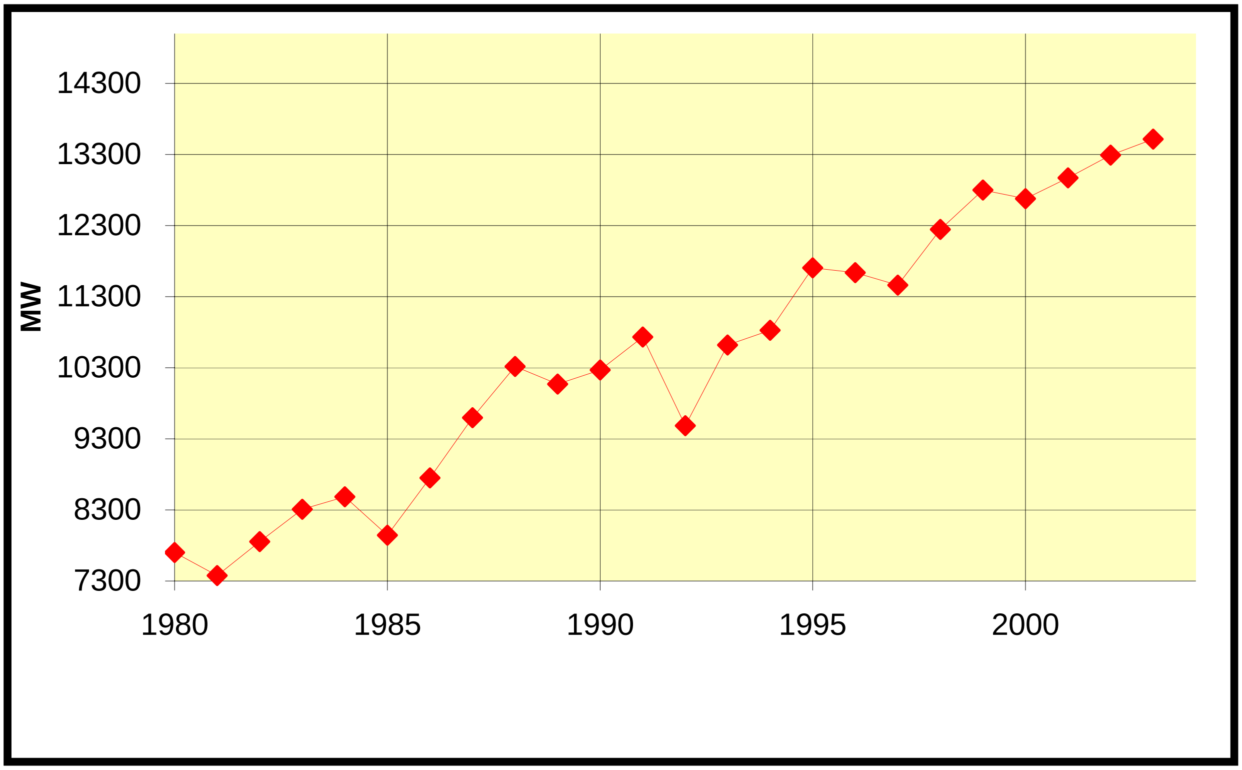

Diagram 2 – Historical Growth

1.2 Generation

The CapX 2020 technical team assumed that the generation modeled in the 2009 summer model would still exist in 2020 and would continue to serve the load modeled in 2009. To address anticipated load growth of 6,300 MW, the technical team solicited information from independent power producers (including wind developers), resource planning entities within various organizations, and the Midwest Independent System Operator's (MISO) generation interconnection queue.

Diagrams 3 and 4 are maps of potential generation addition locations that have been identified either from the MISO queue (Diagram 3) or from Wind on the Wires (which is a wind advocate organization) potential wind sites (Diagram 4).

The technical team combined this information to form potential generation development nodes, independent of fuel type, which they used in the modeling process to supply load increases.

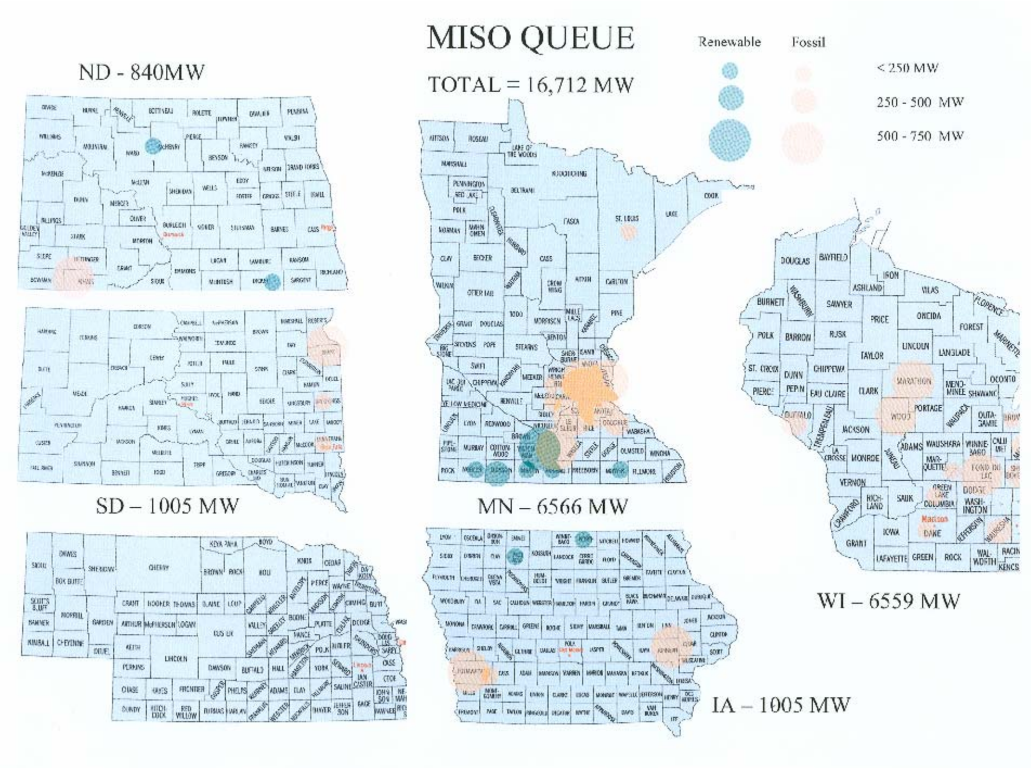

Diagram 3 – Potential Generation Areas

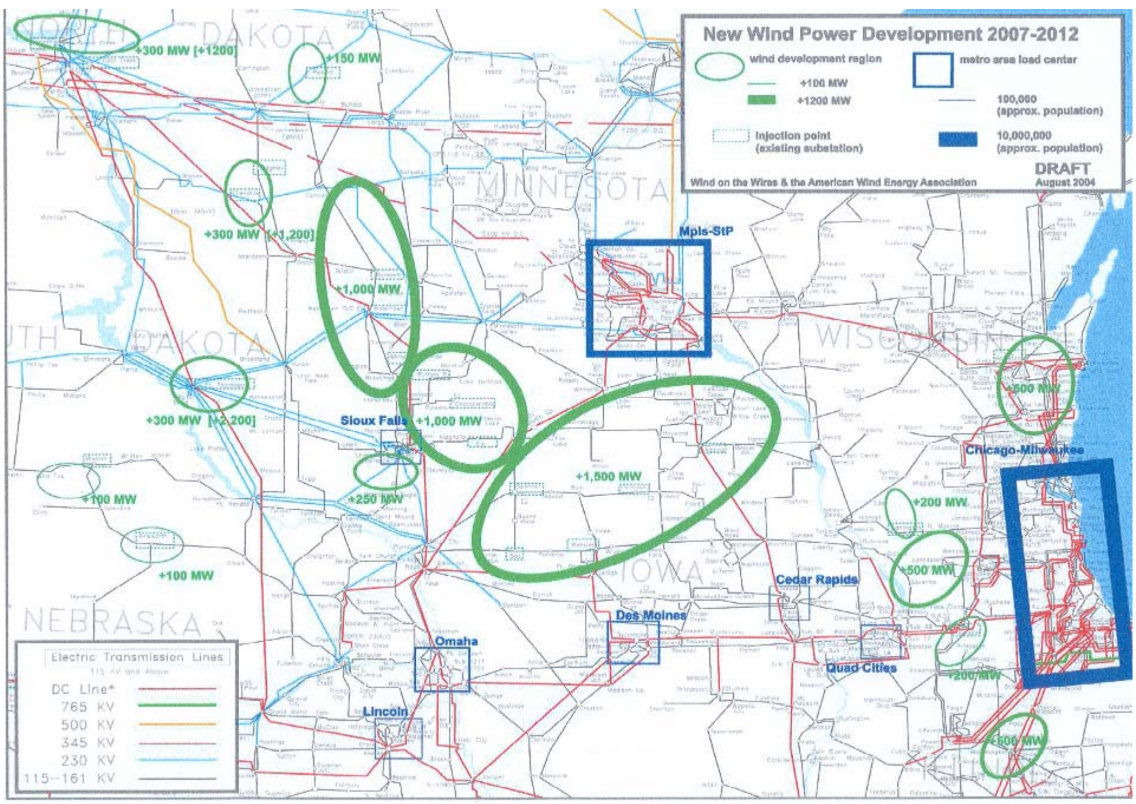

Diagram 4 – Potential Wind Generation Areas

The CapX 2020 technical team mapped the locations of these resources and identified five generation regions: Northern Minnesota, Dakotas (North Dakota and South Dakota), Southern Minnesota/Northern Iowa, Wisconsin and the Metro (Twin Cities Metropolitan) area. These regions are shown in Diagram 5.

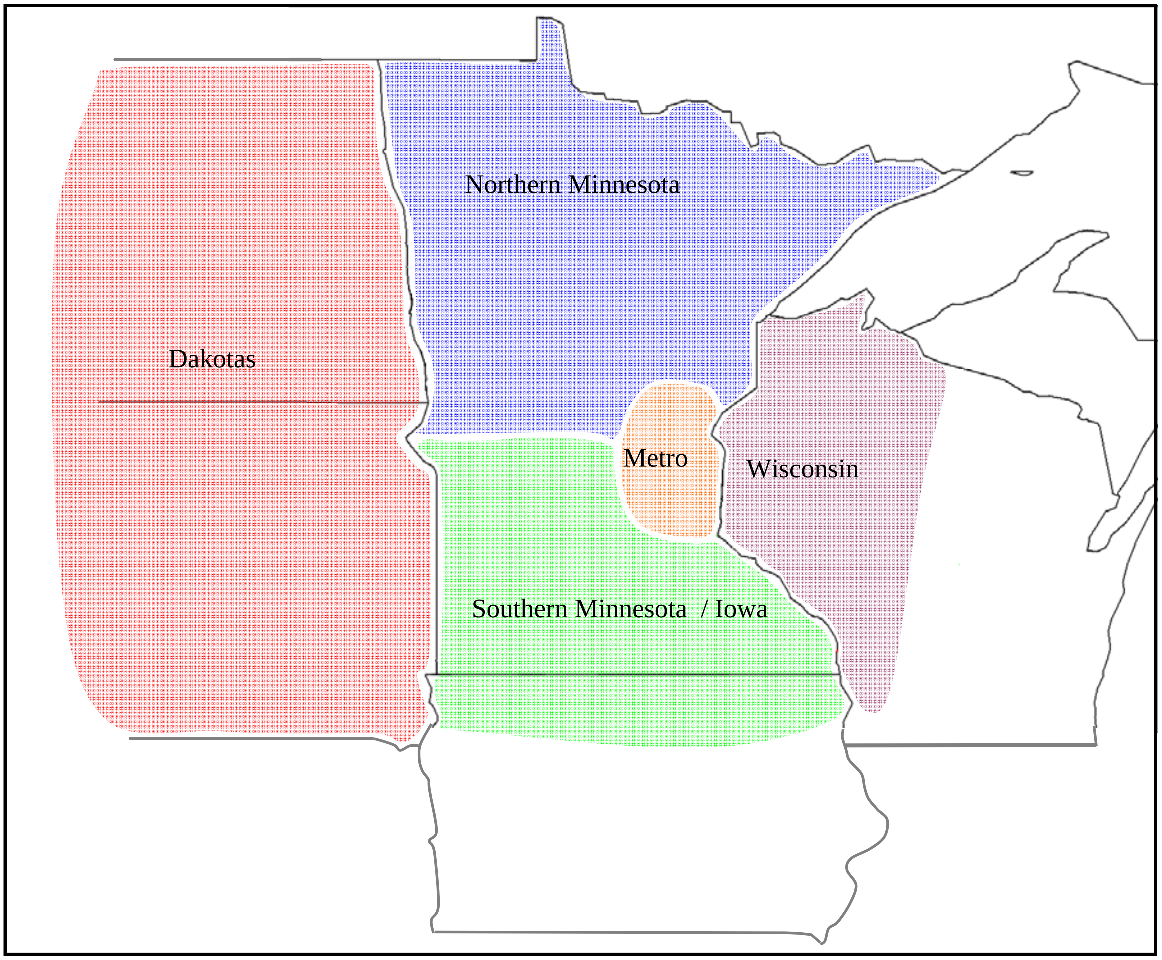

Diagram 5 – CapX 2020 Generation Regions

2.3 Scenario determination

The team modeled three generation scenarios to address the anticipated load growth of 6,300 MW from 2009 to 2020. Each of the scenarios includes sufficient renewable resources to address the Minnesota Renewable Energy Objective of the CapX 2020 participants.

The three generation scenarios consist of a North/West bias, a Minnesota bias, and an Eastern bias. These three generation biases reflect potential generation development that might influence electric power flows on the regional grid and thus indicate the size and location of new transmission infrastructure needed to deliver the generation to customers.

Each of the scenarios includes generation resources from several of the regions. See Table 2.

	Scenario		
Generation areas	North /West Bias	Minnesota Bias	Eastern Bias
Northern MN	1700[1]	1250	550
Dakotas	2100	1000	1600
Southern MN/ Iowa	1875	1875	2175
Metro	650	2200	1000
Wisconsin	0	0	1000
Total	6325	6325	6325

Table 2 – Generation Scenarios

Diagrams 6, 7, and 8 provide geographical representation of the regions for which generation will be modeled in each scenario.

2.3.1 North/West Bias Generation

In the north/west bias generation case the new generation modeled is more heavily based on importing generation into Minnesota from Manitoba, North Dakota, South Dakota, and Iowa.

The generation mix includes 2275 MW to meet Minnesota's Renewable Energy Objective: 975 MW from Minnesota and 1300 MW from outside of Minnesota. It also includes 1950 MW of other Minnesota generation and 2100 MW of other generation from outside of Minnesota.

Chart 1 below illustrates the north/west generation mix.

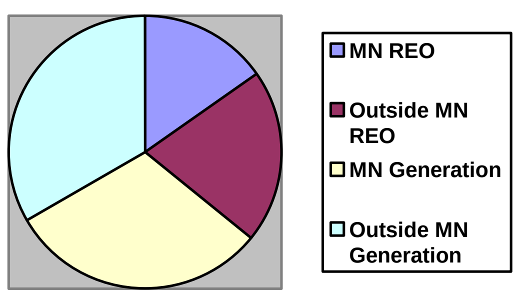

Chart 1 - North/West Bias Generation Mix

[1] This 1700-MW total includes a 1000-MW import from Manitoba.

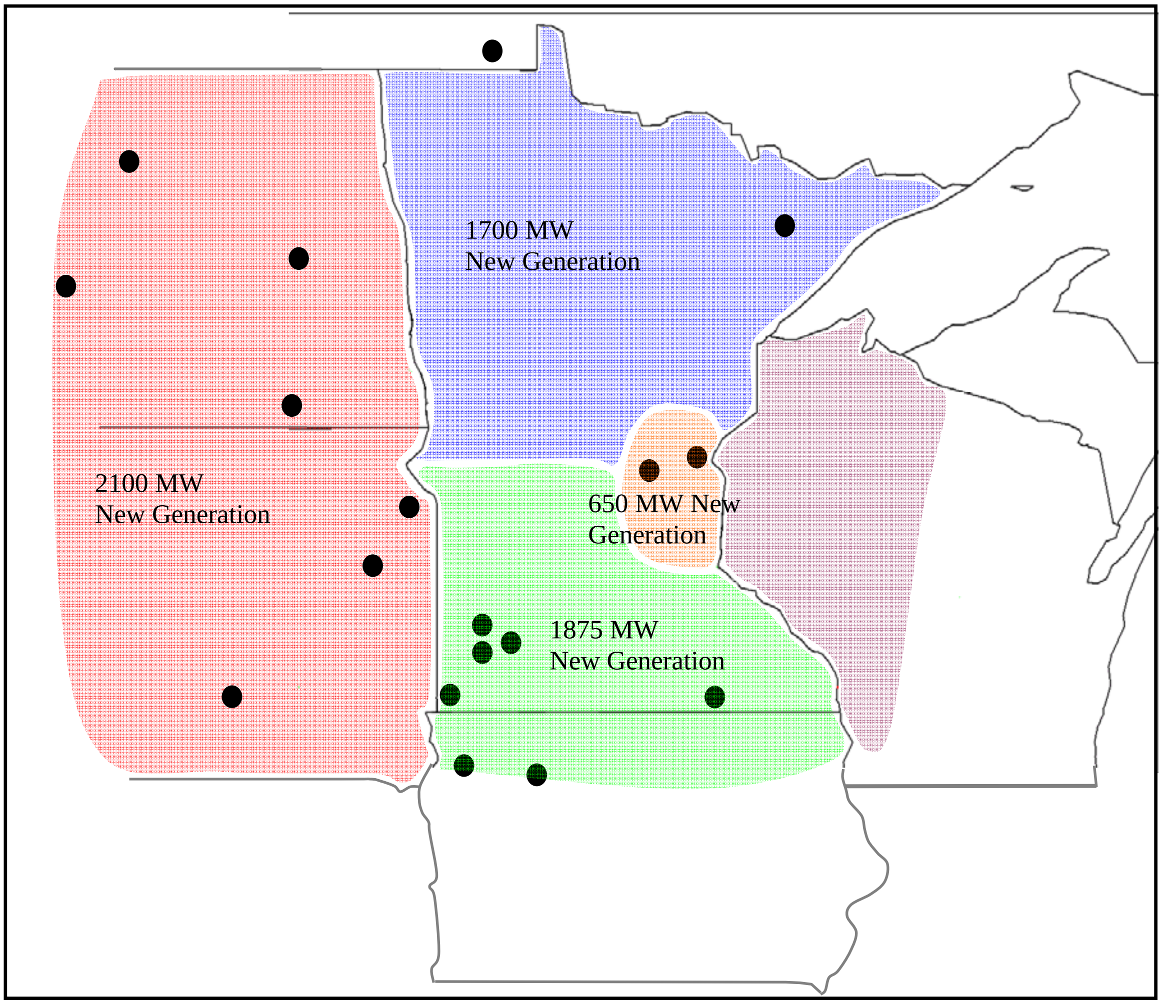

Diagram 6 - North/West Bias Generation Locations

2.3.2 Minnesota Bias Generation

In the Minnesota Bias Generation case all new generation outside of Minnesota (North Dakota, South Dakota, and Iowa) is modeled as 1300 MW of wind generation (REO). The generation modeled inside of Minnesota is a mixture of REO, peaking, and base load generation.

The generation mix includes 2275 MW of Renewable Energy Objective and 4050 MW of Minnesota generation.

Chart 2 below illustrates the Minnesota bias generation mix.

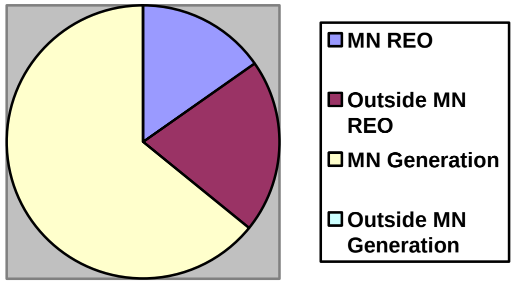

Chart 2 - Minnesota Bias Generation Mix Chart

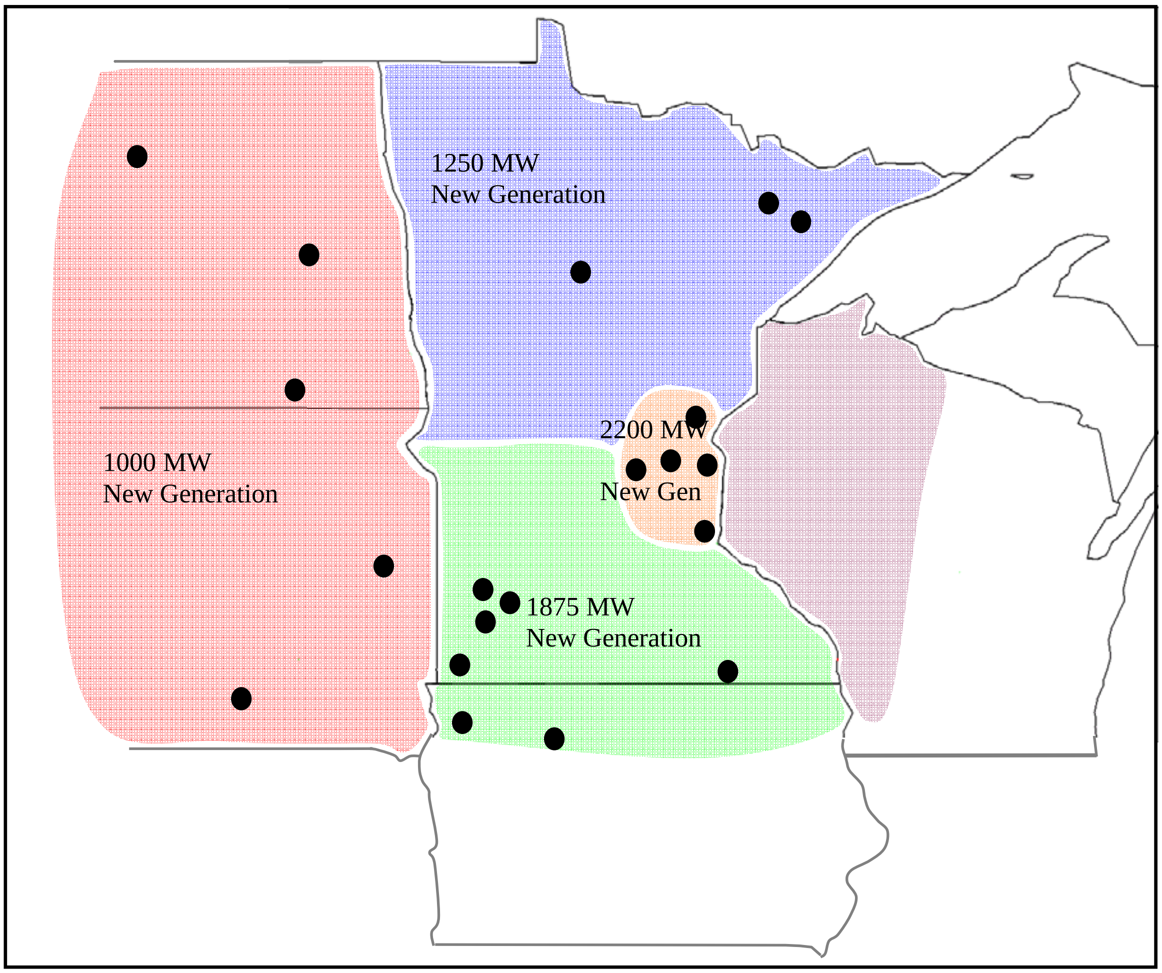

Diagram 7 - Minnesota Bias Generation Locations

2.3.3 Eastern Bias Generation

In the Eastern Bias generation case the new generation modeled is more heavily based on importing generation into Minnesota from Wisconsin and Iowa with 1000 MW new generation modeled in Wisconsin and 1050 MW of new generation modeled in Iowa.

The generation mix includes 2275 MW of Renewable Energy Objective (975 MW of Minnesota REO and 1300 MW from outside of Minnesota REO), 1700 MW of generation from inside of Minnesota, and 2350 MW of generation from outside of Minnesota.

Chart 3 below illustrates the Eastern bias generation mix.

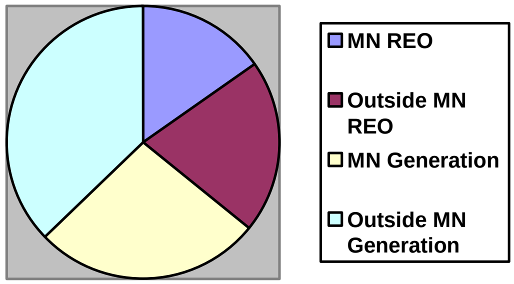

Chart 3 - Eastern Bias Generation Mix

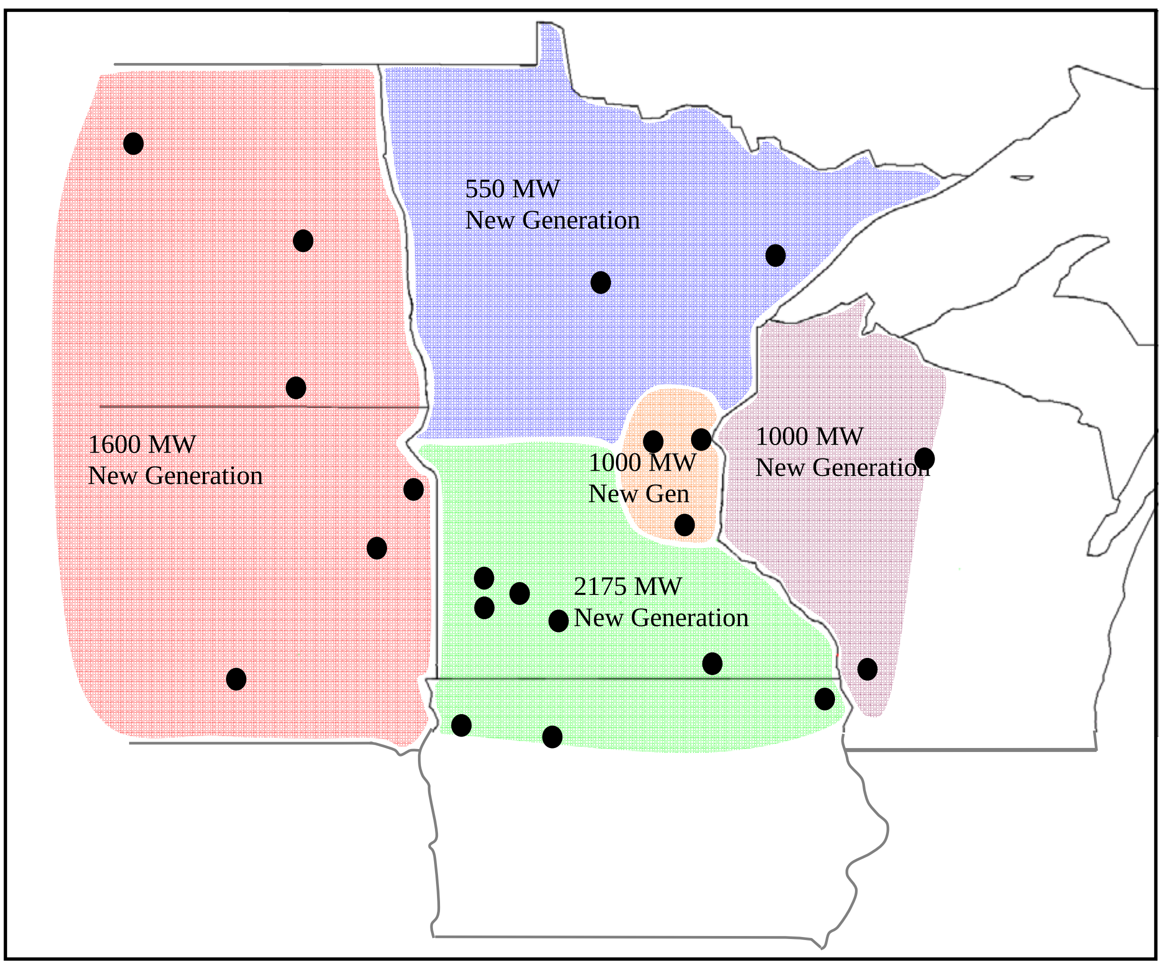

Diagram 8 - Eastern Bias Generation Locations

3 Analysis

The CapX 2020 technical team's primary goal was to create a common transmission backbone that could sustain system growth based on the three generation scenarios. In the future as specific generation is built, other transmission facilities will be required to tie the generation to the transmission backbone system and tie the load-serving centers to the local-serving distribution substations.

With this goal in mind, the team developed an initial list of possible transmission facilities. These facilities are shown in Diagram 9. Diagram 9 was created using inputs from various regional Midwest Independent System Operator (MISO) exploratory studies, the 2004 MISO Transmission Expansion Plan (MTEP '04), as well as input from utility transmission planners in the study area. The team purposely kept lines vague, leaving the routes and endpoints to be determined as study work progressed. Transmission alternatives were limited to facilities 345 kilovolts and larger for the purpose of this vision study of the high voltage bulk transmission study.

The technical team incorporated transmission alternatives identified in on-going studies in conjunction with transmission plans identified by various transmission stakeholders. The goals were to identify transmission improvements that connect remote generation to the load-serving centers in the region and to develop a transmission backbone that supports continued load growth in the various load centers. The transmission improvements focused on high voltage solutions (345 kV lines and 500 kV lines) that best addressed the load areas and the various generation scenarios.

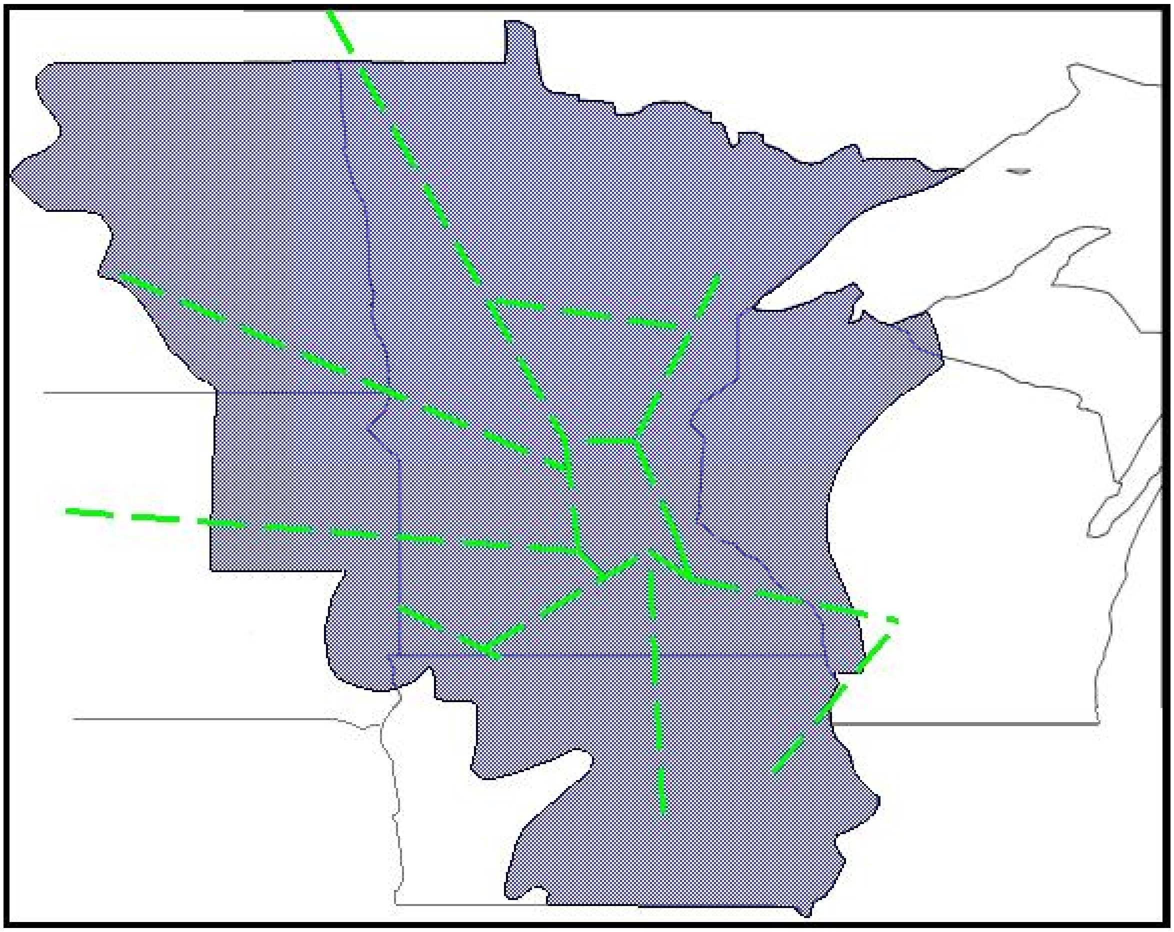

Diagram 9 – Possible Transmission Facilities

As a starting point, the technical team utilized the most probable transmission options from the exploratory studies already underway in the MISO/MAPP footprint, most notably the Southwest Minnesota/ Northern Iowa study and the Northwest Exploratory study. These transmission options are shown below:

- A 345 kV line from the North Dakota coal fields to Fargo and continuing to near St. Cloud, Minnesota
- A 345 kV line from Prairie Island, near Red Wing, Minnesota, to Rochester, Minnesota, and continuing to southwest Wisconsin
- Two 345 kV lines into central Iowa
- A 345 kV or 500 kV line from Manitoba into near St. Cloud, Minnesota.
- Generation outlet transmission facilities presently under study through MISO.

Once these lines were placed on the map, the technical team analyzed the system for the best regional method to tie all these study results together, while maximizing load-serving potential for the entire region well into the future. The team also created a second 345 kV transmission ring around the wider Twin Cities metro area, with "spokes" leading out to the smaller load and/or generation pockets in the region.

A complete list of the potential transmission facilities is included in Appendix A.

3.1 Study Assumptions

3.1.1 System Condition Assumptions

The CapX 2020 study was based on a system snapshot with the best-known 2020 state of the transmission system as of August 2004 for the MAPP region. Since August 2004, very few changes have been made to the base case model. In the last ten months, load, generation and transmission modeling may have been modified in other studies, which the CapX 2020 study does not reflect.

3.1.2 Contingency Analysis Assumptions

The technical team tested several transmission solutions for each generation scenario and performed steady-state powerflow analysis (first contingency simulations) to determine which transmission solution eliminates thermal overloads on transmission lines 161 kV and higher in the region. Because the intent of this study was bulk level load serving, the technical team decided to model all generation on the highest voltage bus available local to the generation, and to run the contingency simulations on a limited list of facilities, namely 161 kV and above.

When reviewing the results of this study, note that only the bulk system overloads and solution are represented. None of the associated substation, generation interconnection facilities, or underlying lower-voltage (below 161 kV) transmission system infrastructure was studied.

3.1.3 Big Stone II Inclusion in the CapX 2020 Vision Study

Interconnection steady-state results from the Big Stone II generation study were completed in the late fall 2004 and, therefore, were included in the CapX 2020 Vision Study. Big Stone II was modeled in the north/west and eastern biases. In the north/west bias, the generator was modeled along with the outlet options that included:

- Big Stone – Canby new 230 kV line
- Canby – Granite Falls 115 kV line converted to 230 kV
- Big Stone – Willmar new 230 kV line

The eastern bias included the generator along with outlet options that included:

- Big Stone – Canby, Minnesota, new 230 kV line
- Canby – Granite Falls, Minnesota, 115 kV line converted to 230 kV
- Big Stone – Ortonville, Minnesota, new 230 kV-line
- Ortonville – Johnson Jct. - Morris, Minnesota, 115 kV line converted to 230 kV

Because the Minnesota bias focused on generation located within state boundaries with the exception of wind resources, Big Stone II, which is a potential coal-fired plant in South Dakota, was not included in this generation bias.

Based on the results from this vision study, the Minnesota and north/west generation biases include a new 345 kV line from Granite Falls, Minnesota, to Benton County (St. Cloud), Minnesota, and all three generation scenarios include a new 345 kV line from Ellendale, North Dakota, to Blue Lake (Mpls/St. Paul), Minnesota, regardless of whether Big Stone II was included. These lines could be instrumental to wind outlet in the North Dakota and South Dakota.

3.1.4 Sensitivities to Current Area Study Work

- Big Stone II was partially included in this vision study as described in section 3.1.3 above. Because the Big Stone II interconnection study was completed during the CapX 2020 technical study timeframe, variations of the interconnection study results were included in the CapX 2020 study. When a certificate of need (CON) is filed for Big Stone II, a vision study sensitivity will be completed to determine how the Big Stone II project proposed facilities fit into the timeline for the CapX 2020 vision study facility additions.
- Buffalo Ridge Incremental Study conducted by Xcel Energy in the winter of 2004 through spring 2005 had no public results available to include during the CapX 2020 case development time. In addition, the Buffalo Ridge study is a lower voltage study than the CapX 2020 focus.

4 Scenario Analysis

The preliminary base case model for the year 2020 includes the 6300 MW of anticipated load growth and the new generation to meet and serve the growth, however the base case doesn't contain any new necessary transmission facilities.[2] The CapX 2020 technical team's preliminary base case analysis of the three generation scenarios identified a significant number of transmission overloads that could occur if no additional transmission is built to serve the projected load growth and the new generation needed by 2020 to meet this growth. The team simulated the loss (outage) of single transmission elements (n-1 analysis) to help determine transmission alternatives to address potential violations of North American Electric Reliability Council criteria, such as low voltages and thermally overloaded facilities.

Power Technology's PSS/E program, Version 29, was used to perform this analysis. Within PSS/E, the activity called ACCC, or AC Contingency Checking, was used as a first check of the entire study area to find problems. ACCC sequentially examines all relevant single contingencies in the region of interest for a given load and transfer base case. Facilities identified in the ACCC outputs were considered limiters if they had line outage distribution factors of 2 percent or greater. Bus voltages lower than 0.9 per unit were also flagged.

For the more detailed analysis of each scenario, the team used a contingency program developed by Great River Energy. The contingency program uses the IPLAN programming language within PSS/E. It performs many functions on the user-defined model, including developing user-defined contingencies with appropriate line-switching procedures, monitoring files for bus voltage and line loading violations, and the output files are then easily imported into Microsoft Excel. Transmission facilities identified in the Excel outputs

[2] Exception: The north/west bias base 2020 case includes a 345 kV facility from Manitoba to near St Cloud, MN

were considered limiters if they had power transfer distribution factors and/or line outage distribution factors of 2 percent or greater. Bus voltages lower than 0.9 per unit were also flagged

For the n-1 analysis, the team ran transmission contingencies and monitored the transmission system in the following control areas:

Control area	**PSS/E area #**
Alliant Energy West	331
Xcel Energy	600
Minnesota Power	608
Southern Minnesota Municipal Power Agency	613
Great River Energy	618
Otter Tail Power Company	626
Dairyland Power Company	680

4.1 Existing System Performance / Base Case Analysis

The ACCC activity performs all contingencies in the area and, therefore, provides an excellent screening tool for determining as to when and where violations of the planning criteria occur.

Initially, the team ran ACCC on the existing system for the three generation scenario bias cases: Peak load with all the Minnesota bias generation on-line at the 2020 load levels, peak load with all the north/west bias generation on-line at the with 2020 load levels, and peak load with all the eastern bias generation on-line at the 2020 load levels. The team temporarily put aside base case results but eventually will compare them with the post-new facility results for each bias to find the most effective set of 345 kV and higher transmission infrastructure additions to meet the 6,300 MW of new load. The base case system n-1 results are included in Appendix B of this report for each bias case.

Table 3 shows the number of overloaded transmission facilities and voltage violations in the base case 2020 models. Sections 4.2 through 4.5 of this report will discuss the results for each scenario in further detail. Again, n-1 contingency output results are tabulated in Appendix B.

Scenario	System Intact Overloads	n-1 Overload Violations[3]	Voltage Violations
North/West Bias[4]	42	142	45
Minnesota Bias	42	187	14
Eastern Bias	42	197	33

Table 3 – Base Case 2020 Transmission System Violations

[3] Outages of individual facilities 161 kV and higher were simulated.

[4] Includes the addition of a 345 kV facility from Manitoba to near St. Cloud, Minnesota

4.2 Transmission Alternatives

As mentioned previously in this report, Appendix A of this report includes a complete list of all transmission facilities 345 kV and higher that the CapX 2020 technical team considered. The team analyzed each generation scenario separately to determine which of these facilities would most effectively solve thermal and voltage violations on the bulk (161 kV and higher) transmission system in the study area. To do this, the team inserted specific facilities or facility groups from Appendix A one at a time into the model to assess each facility's benefits.

The team selected facilities to insert into the model by determining the location of the need for system improvement. The team recommended as facility additions those facilities that had the greatest benefit to the system by reducing the thermal overload and/or solving voltage violations during n-1 contingency.

The results of the facility addition benefits are shown in Appendix B in the n-1 contingency output result tables for each generation scenario.

4.3 Minnesota Bias Scenario Results

4.3.1 Recommended Transmission Vision Facilities

Diagram 10 shows the final compilation of recommended transmission facilities for the Minnesota bias based on the n-1 contingency analysis completed using the facilities in Appendix A and Table 4. All contingency analysis results and PSS/E automaps are included in Appendix B-1.

Ref. Ref.#	Data Source	Facility name				
		From	To	Volt (kV)	Miles	Cost ($M)
F-02	TIPS	Alexandria	Benton County	345	80	60
F-03	TIPS	Alexandria	Maple River	345	126	94.5
F-06	NW	Antelope Valley	Maple River	345	292	219
F-07	CAPX	Arrowhead	Chisago	345	120	90
F-08	CAPX	Arrowhead	Forbes	345	60	45
F-09	CAPX	Benton County	Chisago County	345	59	44.25
F-10	CAPX	Benton County	Granite Falls	345	110	82.5
F-11	MH	Benton County	Riverton	345	78	58.5
F-12	CAPX	Benton County	St. Boni	345	62	46.5
F-13	CAPX	Blue Lake	Ellendale	345	200	150
F-17	CAPX	Boswell	Forbes	345	64	48

F-26	CAPX	Chisago County	Prairie Island	345	82	61.5
F-28	CAPX	Columbia	North LaCrosse	345	80	60
F-30	NW	Ellendale	Hettinger	345	231	173.25
F-32	CAPX	Forbes	Riverton	345	114	85.5
F-36	SMNI	Rochester	North LaCrosse	345	60	45
F-56	SMNI	Prairie Island	Rochester	345	58	43.5
F-63	CAPX	Lakefield Jct	Adams	345	92	69
				Total	**1968**	**1,476**

CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

Table 4 – Minnesota Bias Recommended Facilities

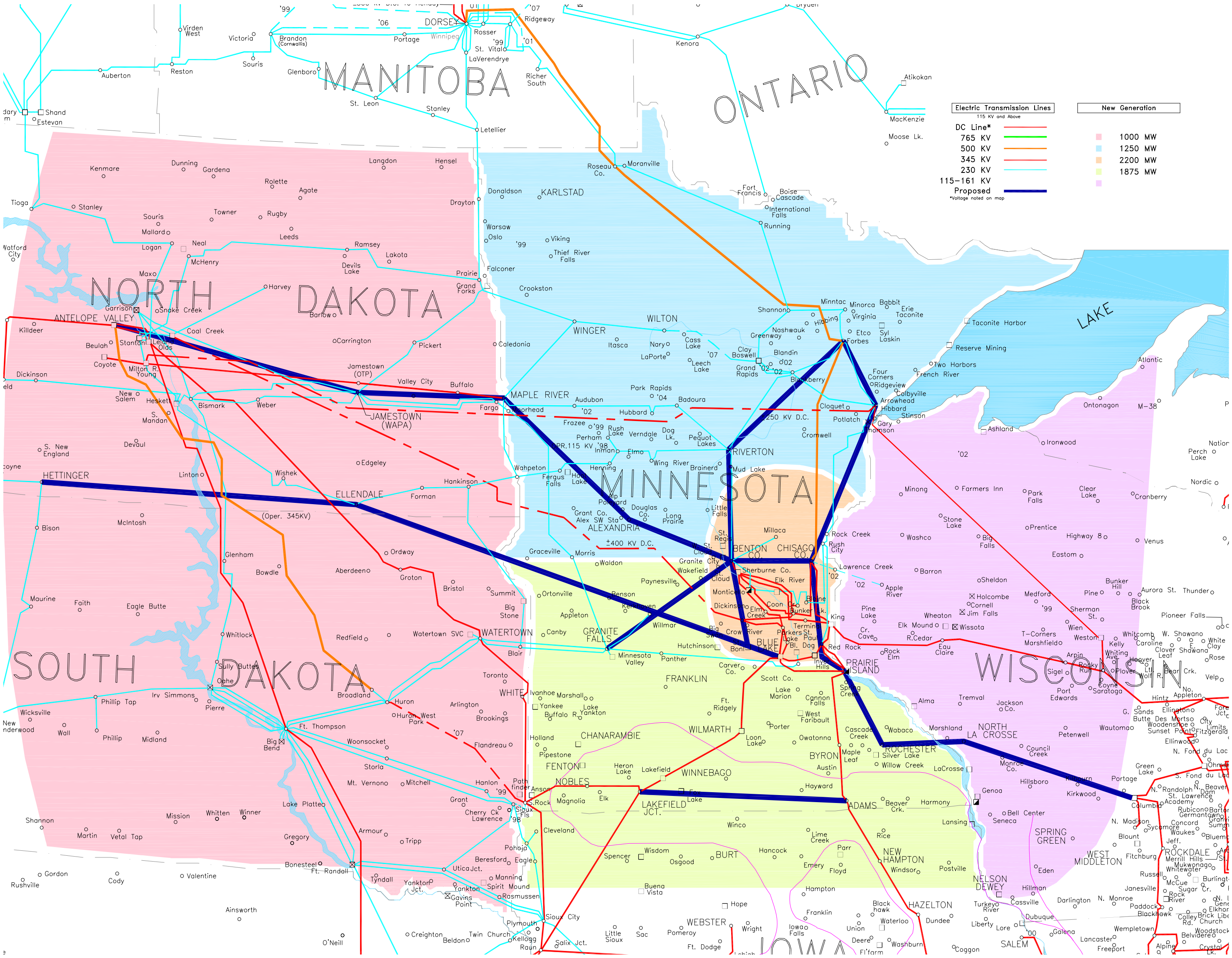

Diagram 10 – Minnesota Bias Recommended Facilities

4.3.2 Line Flows on Interface and Tie Lines

The CapX 2020 technical team collected system intact line flows on a select set of tie lines and interfaces in and around the Minnesota system. Table 5 predominantly focuses on lines coming into and going out of Minnesota, including some lines internal to Minnesota connecting pockets of transmission. Table 5 shows that adding the facilities recommended for the Minnesota bias scenario mostly causes reductions in MW flow over these 230 kV and higher interfaces.

LINE	kV Voltage Level	Base 6300 MW flow (MW)	6300 mw UPGRADE scenario (MW)	Description
Forbes – Chisago	500 kV	870	687	Northern Minnesota to Twin Cities loop
Riel – Roseau	500 kV	1418	1308	Manitoba Hydro to northern Minnesota
Richer – Roseau	230 kV	170	183	Manitoba Hydro to northern Minnesota
Letellier – Drayton	230 kV	325	300	Manitoba Hydro to MN-ND border
Glenboro – Rugby	230 kV	18	2	Manitoba Hydro – North Dakota (this and the 3 lines above are all that ties Manitoba and U.S. as planned of 2009)
Arrowhead – Stone Lake	345 kV	116	97	Duluth area to northwestern Wisconsin (then to Weston)
Eau Claire – Arpin	345 kV	111	87	West to central Wisconsin
Prairie Island – Byron	345 kV	116	320	South of Twin Cities metro to west of Rochester
Adams – Hazelton	345 kV	127	50	Southeastern Minnesota – eastern Iowa
Lakefield Jct. – Wilmarth	345 kV	768	594	Southwestern Minnesota to Mankato area
Split Rock – Nobles County	345 kV	175	159	North of Sioux Falls, SD, to northwest of Worthington, MN
Nobles County – Lakefield Jct.	345 kV	300	285	Northwest of Worthington to Lakefield Jct. sub. (Minnesota)
Watertown – Granite Falls	230 kV	315	292	Eastern South Dakota to western Minnesota
Blair – Granite Falls	230 kV	329	317	Runs parallel with Watertown – Granite Falls
Granite Falls – Minnesota Valley	230 kV	263	220	Western Minnesota
Fargo – Moorhead	230 kV	53	62	Fargo, North Dakota, to Moorhead, Minnesota
Fargo – Sheyenne	230 kV	260	162	North Dakota, Minnesota border
Maple River – Winger	230 kV	76	69	Fargo area to northwestern Minnesota
Prairie – Winger	230 kV	138	84	Grand Forks area to Winger
Wahpeton – Fergus Falls	230 kV	234	153	ND-MN border east to Fergus Falls
Bear Creek – Rock Creek	230 kV	53	51	South of Duluth toward the Twin Cities loop
Blackberry – Riverton	230 kV	220	114	Northern Minnesota towards south
Mud Lake – Benton County	230 kV	10	26	Coming from the north into St. Cloud
Sheyenne – Audubon	230 kV	214	178	Fargo area west into Minnesota
Genoa – Coulee	161 kV	263	204	Western Wisconsin
Boswell – Blackberry Ckt 1	230 kV	291	192	Northern Minnesota
Boswell – Blackberry Ckt 2	230 kV	283	187	Northern Minnesota

Table 5 – Minnesota Bias Tie Line / Interface Flows

4.4 North / West Scenario Results

4.4.1 Recommended Transmission Vision Facilities

Diagram 11 shows the final compilation of recommended facilities for the North/West Bias based on the n-1 contingency analysis using the facilities in Appendix A and Table 6. All contingency analysis results and PSS/E automaps are included in Appendix B-2.

Ref. Ref.#	Data Source	Facility Name				
		From	**To**	**Volt (kV)**	**Miles**	**Cost ($M)**
F-02	TIPS	Alexandria	Benton County	345	80	60
F-03	TIPS	Alexandria	Maple River	345	126	94.5
F-06	NW	Antelope Valley	Maple River	345	292	219
F-07	CAPX	Arrowhead	Chisago	345	120	90
F-08	CAPX	Arrowhead	Forbes	345	60	45
F-09	CAPX	Benton County	Chisago County	345	59	44.25
F-10	CAPX	Benton County	Granite Falls	345	110	82.5
F-12	CAPX	Benton County	St. Boni	345	62	46.5
F-13	CAPX	Blue Lake	Ellendale	345	200	150
F-26	CAPX	Chisago County	Prairie Island	345	82	61.5
F-28	CAPX	Columbia	North LaCrosse	345	80	60
F-29	MH	Dorsey	Karlstad	345	134	100.5
F-30	NW	Ellendale	Hettinger	345	231	173.25
F-36	SMNI	Rochester	North LaCrosse	345	60	45
F-45	MH	Karlstad	Winger	345	91	68
F-40	MH	Winger	Benton Co.	345	162	121.5
F-56	SMNI	Prairie Island	Rochester	345	58	43.5
	Total				**2007**	**1,505**

Table 6 – North/West Bias Recommended Facilities

Key for Table 6:
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

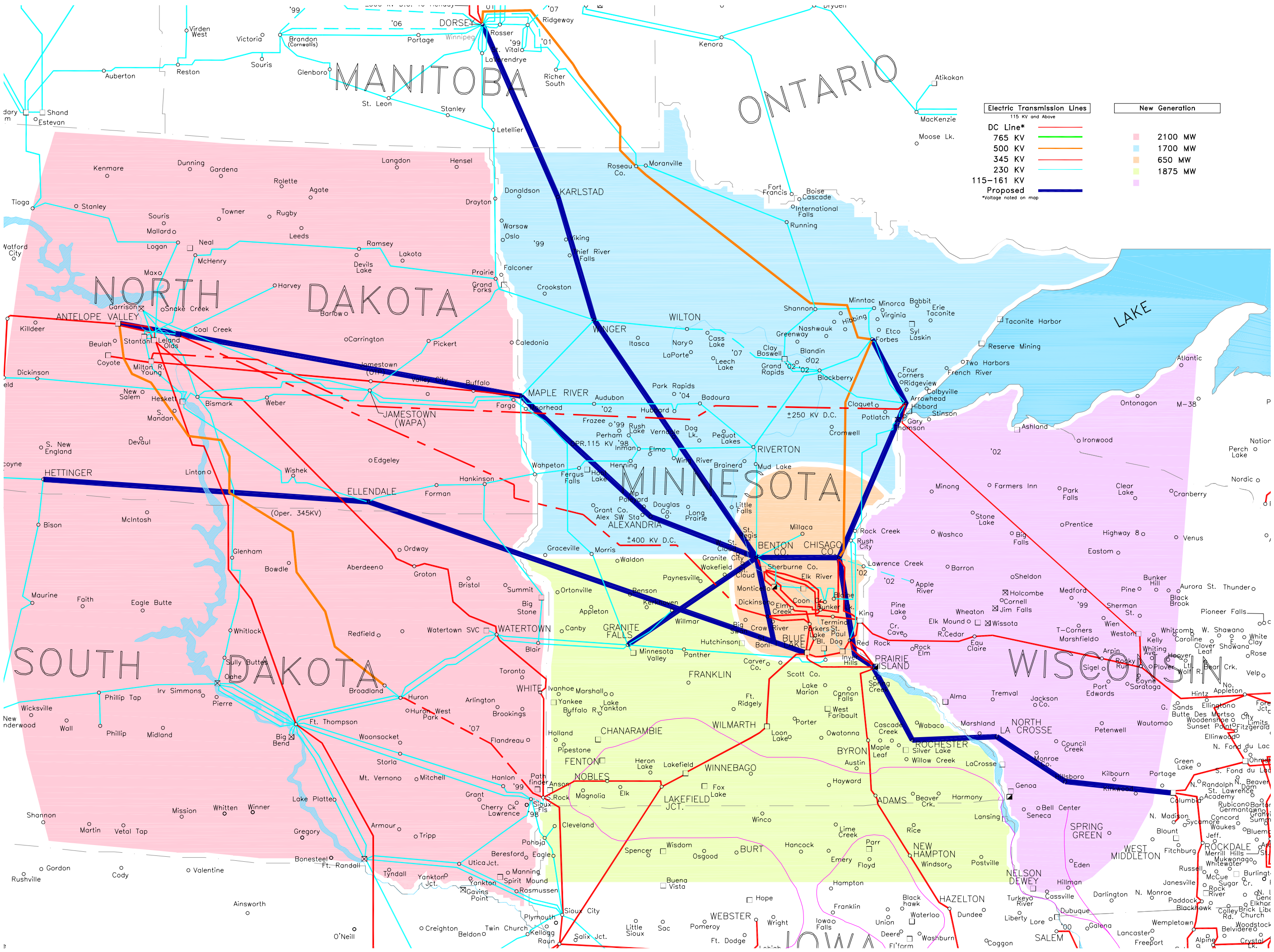

Diagram 11 – North/West Bias Recommended Facilities

4.4.2 Line Flows on Interface and Tie Lines

The Technical Team collected system intact line flows on a select set of tie lines and interfaces in and around the Minnesota system. Table 7 predominantly focuses on lines coming into and going out of Minnesota, including some lines internal to Minnesota connecting pockets of transmission.

The table shows that adding the facilities recommended for the north /west bias scenario causes about equal amounts of reductions and additions in MW flow over these 230 kV-and-higher interfaces. Note that in this north/west scenario the Manitoba Hydro flows are lower than in the slow growth scenario Manitoba Hydro export. The reason for this difference is that the CapX technical team has added the 345 kV line in the 6,300 MW load base case, which has 816 megavolt amperes flowing on it.

LINE	**kV Voltage Level**	**Base 6300 MW flow (MW)**	**6300 MW UPGRADE scenario (MW)**	**Description**
Forbes – Chisago	500 kV	1507.7	1343.3	Northern Minnesota to Twin Cities loop
Riel – Roseau	500 kV	1591.8	1507.5	Manitoba Hydro to northern Minnesota
Richer – Roseau	230 kV	219.2	212.8	Manitoba Hydro to northern Minnesota
Letellier – Drayton	230 kV	286.5	303.7	Manitoba Hydro to MN-ND border
Glenboro – Rugby	230 kV	64.4	10.6	Manitoba Hydro – North Dakota (This and the 3 lines above are all that ties Manitoba and U.S. as planned through 2009.)
Arrowhead – Stone Lake	345 kV	271.0	295.4	Duluth area to northwestern Wisconsin (then to Weston)
Eau Claire – Arpin	345 kV	148.4	71.0	West to central Wisconsin
Prairie Island – Byron	345 kV	284.4	277.3	South of Twin Cities metro to west of Rochester
Adams – Hazelton	345 kV	274.1	156.6	Southeastern Minnesota – eastern Iowa
Lakefield Jct. – Wilmarth	345 kV	978.5	819.3	Southwestern Minnesota to Mankato area
Split Rock – Nobles County	345 kV	350.7	261.6	North of Sioux Falls, SD, to northwest of Worthington, MN
Nobles County – Lakefield Jct.	345 kV	500.7	409.9	Northwest of Worthington to Lakefield Jct. sub. (Minnesota)
Watertown – Granite Falls	230 kV	293.0	245.0	Eastern South Dakota to western Minnesota
Blair – Granite Falls	230 kV	334.5	292.4	Runs parallel with Watertown – Granite Falls
Granite Falls – Minnesota Valley	230 kV	455.5	404.4	Western Minnesota
Fargo – Moorhead	230 kV	50.8	39.1	Fargo, North Dakota to Moorhead, Minnesota
Fargo – Sheyenne	230 kV	286.6	230.0	North Dakota, Minnesota border
Maple River – Winger	230 kV	64.3	20.9	Fargo area to northwestern Minnesota
Prairie – Winger	230 kV	110.0	70.8	Grand Forks area to Winger
Wahpeton – Fergus Falls	230 kV	277.8	213.4	ND-MN border east to Fergus Falls
Bear Creek – Rock Creek	230 kV	89.6	90.0	South of Duluth toward the Twin Cities loop
Blackberry – Riverton	230 kV	203.5	175.0	Northern Minnesota towards south
Mud Lake – Benton County	230 kV	47.6	36.6	Coming from the north into St.Cloud area
Sheyenne – Audubon	230 kV	265.4	233.0	Fargo area west into Minnesota
Genoa – Coulee	161 kV	278.0	212.0	Western Wisconsin

Boswell – Blackberry Ckt 1	230 kV	284.4	276.2	Northern Minnesota
Boswell – Blackberry Ckt 2	230 kV	277.6	269.7	Northern Minnesota

Table 7 – North/West Bias Tie Line/Interface Flows

4.5 Eastern Bias

In the eastern bias scenario, the CapX 2020 technical team added part of the additional generation to the east of Minnesota (part on the border of northeastern Iowa and southwestern Wisconsin, part central Wisconsin), in addition to having generation throughout Minnesota, northern Iowa, North Dakota, and South Dakota as in the other two scenarios.

4.5.1 Recommended Transmission Vision Facilities

Ref. #	Data Source	Facility Name				
		From	To	Volt (kV)	Miles	Cost ($M)
F-56	SMNI	Prairie Island	Rochester	345	58	43.7
F-64	CAPX	Eau Claire	King	345	84	63.1
F-65	CAPX	N. LaCrosse	Eau Claire	345	73	55.1
F-66	CAPX	Genoa	N LaCrosse	345	42	31.7
F-67	CAPX	Genoa	Columbia	345	113	84.8
F-68	CAPX	Genoa	Nelson Dewey	345	70	52.4
F-69	SMNI	Nelson Dewey	Salem	345	34	25.6
F-70	CAPX	Genoa	Lansing	345	21	15.8
F-71	CAPX	Lansing	Rochester	345	89	66.8
F-72	CAPX	Ellendale	Big Stone	345	194	145.8
F-73	CAPX	Big Stone	Blue Lake	345	71	53.4
F-02	TIPS	Maple River	Benton Co	345	206	154.5
F-03	NW	Antelope Va.	Maple River	345	292	218.8
F-07	CapX	Arrowhead	Chisago	345	120	90
F-08	CapX	Arrowhead	Forbes	345	60	45
F-09	CapX	Benton Co	Chisago	345	59	44.2
F-10	CapX	Benton Co	Granite Falls	345	110	82.5
F-12	CapX	Benton Co	St Boni	345	62	46.5
F-26	CapX	Chisago Co	Prairie Island	345	82	61.5
F-30	NW	Ellendale	Hettinger	345	231	218.8
			Total		**2071**	**1,600**

Table 8 – Eastern Bias Recommended Facilities

Key for Table 8:
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study

SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

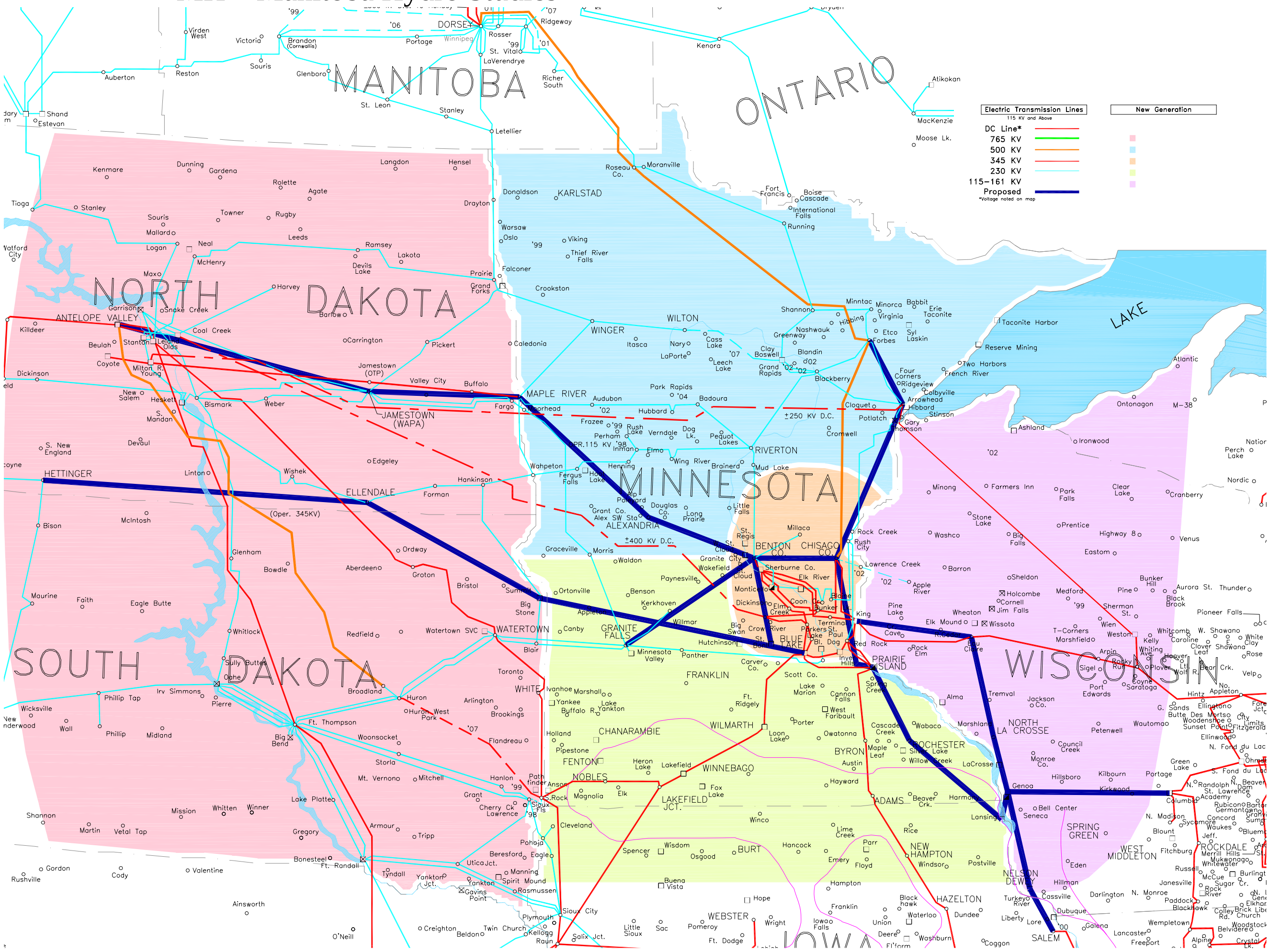

Diagram 12 – Eastern Bias Recommended Facilities

4.5.2 Line Flows on Interface and Tie Lines

The CapX 2020 technical team collected system intact line flows on a select set of tie lines and interfaces in and around the Minnesota system. Table 9 predominantly focuses on lines coming into and going out of Minnesota, including some lines inside Minnesota connecting pockets of transmission.

LINE	kV Voltage Level	Base 6300 MW flow (MW)	6300 MW UPGRADE scenario (MW)	Description
Forbes – Chisago	500 kV	1209.6	1191.7	Northern Minnesota to Twin Cities loop
Riel – Roseau	500 kV	1344.9	1329.6	Manitoba Hydro to northern Minnesota
Richer – Roseau	230 kV	178.8	177.7	Manitoba Hydro to northern Minnesota

Letellier – Drayton	230 kV	306.5	314.1	Manitoba Hydro to MN-ND border
Glenboro – Rugby	230 kV	-26.9	-18.6	Manitoba Hydro – North Dakota (This and the three lines above are all that ties Manitoba and U.S. as planned through 2009.)
Arrowhead – Stone Lake	345 kV	177.1	174.5	Duluth area to northwestern Wisconsin (then to Weston)
Eau Claire – Arpin	345 kV	-174.1	-41.8	West to central Wisconsin
Prairie Island – Byron	345 kV	-380.5	-263.7	South of Twin Cities metro to west of Rochester
Adams – Hazelton	345 kV	-138.5	-12.5	Southeastern Minnesota – eastern Iowa
Lakefield Jct. – Wilmarth	345 kV	724.4	660.1	Southwestern Minnesota to Mankato area
Split Rock – Nobles County	345 kV	97.9	81.1	North of Sioux Falls, SD, to northwest of Worthington, MN
Nobles County – Lakefield Jct.	345 kV	279.4	265.4	Northwest of Worthington to Lakefield Jct. sub. (Minnesota)
Watertown – Granite Falls	230 kV	234.2	224.2	Eastern South Dakota to western Minnesota
Blair – Granite Falls	230 kV	276.8	269.9	Runs parallel with Watertown – Granite Falls
Granite Falls – Minnesota Valley	230 kV	373.6	362.8	Western Minnesota
Fargo – Moorhead	230 kV	-23.1	-21.4	Fargo, North Dakota, to Moorhead, Minnesota
Fargo – Sheyenne	230 kV	305.9	297.2	North Dakota, Minnesota border
Maple River – Winger	230 kV	91.5	88.5	Fargo area to northwestern Minnesota
Prairie – Winger	230 kV	129.2	129.3	Grand Forks area to Winger
Wahpeton – Fergus Falls	230 kV	242.6	234.9	ND-MN border east to Fergus Falls
Bear Creek – Rock Creek	230 kV	93.1	92.5	South of Duluth toward the Twin Cities loop
Blackberry – Riverton	230 kV	227.0	233.4	Northern Minnesota towards south
Mud Lake – Benton County	230 kV	38.3	31.5	Coming from the north into St.Cloud area
Sheyenne – Audubon	230 kV	230.6	222.3	Fargo area west into Minnesota
Genoa – Coulee	161 kV	391.9	210.8	Western Wisconsin
Boswell – Blackberry Ckt 1	230 kV	279.9	280.3	Northern Minnesota
Boswell – Blackberry Ckt 2	230 kV	273.2	273.5	Northern Minnesota

Table 9 – Eastern Bias Tie Line/Interface Flows

4 Slow Growth Analysis

The CapX 2020 technical team performed a sensitivity analysis for a reduced load level of 4,500 MW to determine which facility additions are necessary at this slower growth load level. Assuming the 6,300 MW increased load level is reached in 2020 and using a linear load growth rate, the team determined that the 4,500 MW increased load level would be reached in the year 2016.

To model the 4,500 MW load level, the 6,300 MW load model was scaled down in each control area uniformly by scaling the load growth down by a factor of 2/3 (4500/6300). The scaled down load totals for each control area are shown in Table 10.

Control area	Calculated 2020 load level (6300 MW)	Scaled load level (4500 MW)
Alliant Energy (West) (331)	3888.2	3711.1
Xcel Energy (North) (600)	12885.1	11960.5
Minnesota Power Co. (608)	1814.4	1727.1
Southern MN Municipal Power Agency (613)	442.4	410.4
Great River Energy (618)	3943.2	3627.8
Otter Tail Power (626)	2248.3	2085.9
Dairyland Power Co. (680)	1266.2	1177.6
Total	26487.8	24700.6

Table 10 – CapX 2020 Slow Area Growth

The generation total also was reduced by scaling each generator down by a factor of 2/3 (4500/6300). Table 11 shows the reduced generation totals for each generation bias scenario.

Slow Growth Analysis						
	North/West		**Minnesota**		**Eastern**	
	6300 MW	**4500 MW**	**6300 MW**	**4500 MW**	**6300 MW**	**4500 MW**
Northern Minnesota	1700	1214	1250	893	550	393
Dakotas	2100	1500	1000	714	1600	1143
Southern MN/ Northern Iowa	1875	1340	1875	1340	2125	1554
Metro	650	464	2200	1571	1000	714
Wisconsin	0	0	0	0	1000	714
Total	**6325**	**4518**	**6325**	**4518**	**6325**	**4518**

Table 11 – Slow Growth Generation Scenario

The results for each generation scenario at the slow growth load level will be discussed in detail in sections 5.1 – 5.3 of this report. The n-1 contingency output results tabulated in Appendices B-1 through B-3. For the slow growth n-1 analysis, the same contingencies from the anticipated growth study were run again and the transmission system was monitored in the following control areas:

Control Area	**PSS/E Area #**
Alliant Energy West	331
Xcel Energy	600
Minnesota Power Co.	608
Southern Minnesota Municipal Power Agency	613
Great River Energy	618
Otter Tail Power Company	626
Dairyland Power Company	680

5.1 Transmission Alternatives Considered for Slow Growth

For the slow growth sensitivity the CapX 2020 technical team began the analysis of each generation scenario with the facilities recommended for the 6300-MW vision study. The recommended facilities were individually removed to determine which of the facilities were also necessary at the 4,500 MW load/generation level.

For the Minnesota and North/West biases, the team determined that the majority of the facilities still were necessary even with the load reduced by 33 percent. For the eastern bias case at the slow growth level, there was less justification for some of the various recommended transmission lines. Although, higher voltage lines from the Wisconsin – Iowa border area towards the Twin Cities were still appropriate. It was also still clear that relief of existing facilities is needed on the system between the Dakotas and Minnesota. As explained in section 4.5, additional sensitivity work is still pending for the eastern bias case, both at the 6300 MW level and the slow growth scenario.

5.2 Minnesota Bias Scenario Slow Growth Results

5.2.1 Recommended Facilities

Ref. #	Data Source	Facility Name				
		From	To	Volt (kV)	Miles	Cost ($M)
F-02	TIPS	Alexandria	Benton County	345	80	60
F-03	TIPS	Alexandria	Maple River	345	126	94.5
F-06	NW	Antelope Valley	Maple River	345	292	219
F-07	CAPX	Arrowhead	Chisago	345	120	90
F-08	CAPX	Arrowhead	Forbes	345	60	45
F-09	CAPX	Benton County	Chisago County	345	59	44.25
F-10	CAPX	Benton County	Granite Falls	345	110	82.5
F-11	MH	Benton County	Riverton	345	78	58.5
F-12	CAPX	Benton County	St. Boni	345	62	46.5

F-13	CAPX	Blue Lake	Ellendale	345	200	150
F-17	CAPX	Boswell	Forbes	345	64	48
F-26	CAPX	Chisago County	Prairie Island	345	82	61.5
F-28	CAPX	Columbia	North LaCrosse	345	80	60
F-30	NW	Ellendale	Hettinger	345	231	173.25
F-32	CAPX	Forbes	Riverton	345	114	85.5
F-36	SMNI	Rochester	North LaCrosse	345	60	45
F-56	SMNI	Prairie Island	Rochester	345	58	43.5
				Total	**1876**	**1407**

Table 12 – Slow Growth Load Level Minnesota Bias Recommended Facilities

Table 12 key:
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

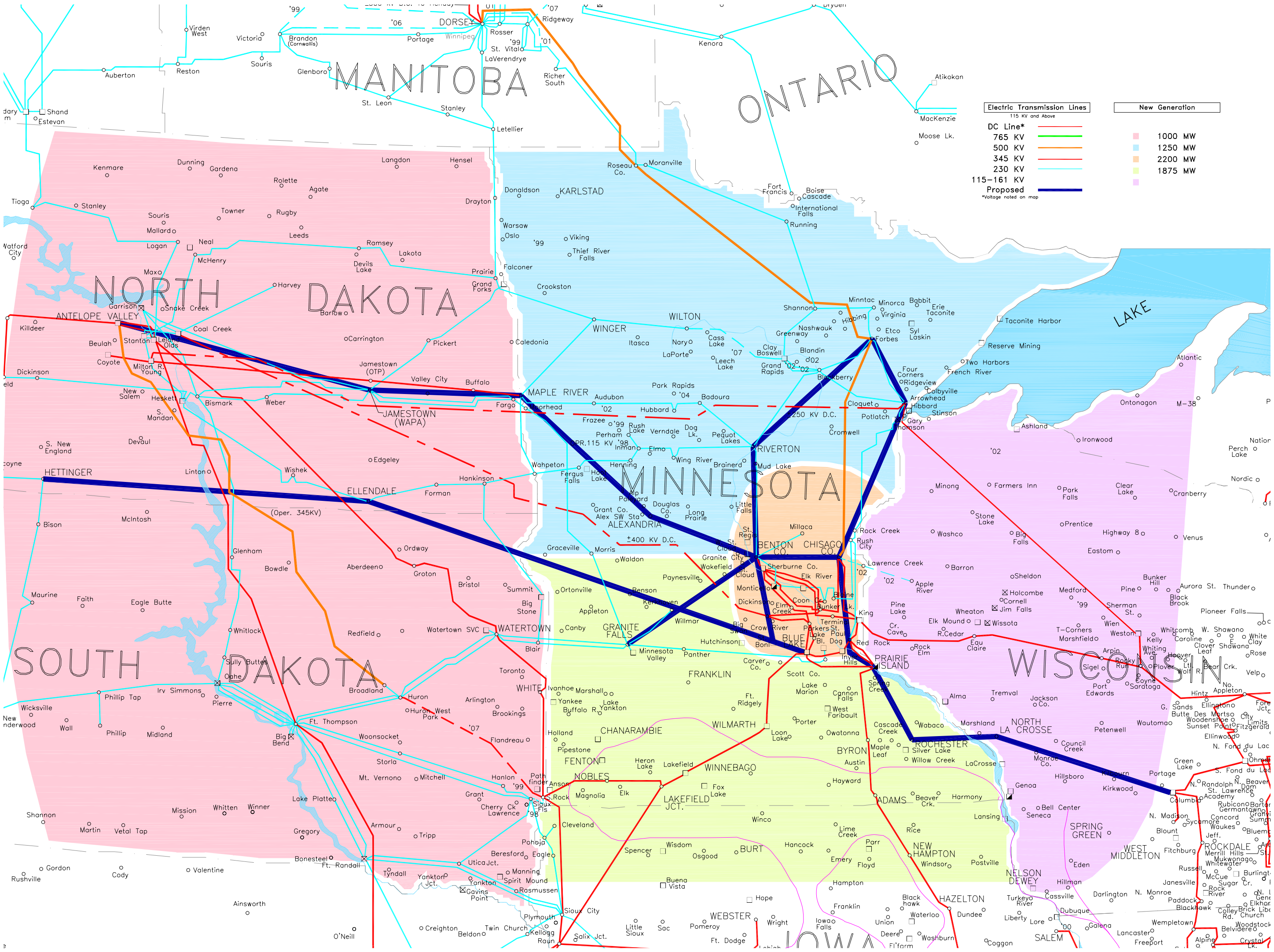

Diagram 13 – Slow Growth Load Level Minnesota Bias Recommended Facilities

5.2.2 Line Flows on Interface and Tie Lines

LINE	kV Voltage Level	Base 4500 MW FLOW (MW)	4500 MW UPGRADE scenario (MW)	Description
Forbes – Chisago	500 kV	1351	1187	Northern Minnesota to Twin Cities loop
Riel – Roseau	500 kV	1228	1224	Manitoba Hydro to northern Minnesota
Richer – Roseau	230 kV	180	184	Manitoba Hydro to northern Minnesota
Letellier – Drayton	230 kV	363	340	Manitoba Hydro to MN-ND border
Glenboro – Rugby	230 kV	17	38	Manitoba Hydro – North Dakota (This and the three lines above are all that ties Manitoba and U.S. as planned through 2009.)
Arrowhead – Stone Lake	345 kV	88	98	Duluth area to northwestern Wisconsin (then to Weston)

Eau Claire – Arpin	345 kV	206	146	West to central Wisconsin
Prairie Island – Byron	345 kV	169	227	South of Twin Cities metro to west of Rochester
Adams – Hazelton	345 kV	260	197	Southeastern Minnesota – Eastern Iowa
Lakefield Jct. – Wilmarth	345 kV	719	622	Southwestern Minnesota to Mankato area
Split Rock – Nobles County	345 kV	175	129	North of Sioux Falls, SD to northwest of Worthington, MN
Nobles County – Lakefield Jct.	345 kV	220	128	Northwest of Worthington to Lakefield Jct. sub. (Minnesota)
Watertown – Granite Falls	230 kV	302	272	Eastern South Dakota to western Minnesota
Blair – Granite Falls	230 kV	317	297	Runs parallel with Watertown – Granite Falls
Granite Falls – Minnesota Valley	230 kV	250	220	Western Minnesota
Fargo – Moorhead	230 kV	54	64	Fargo, North Dakota to Moorhead, Minnesota
Fargo – Sheyenne	230 kV	245	144	North Dakota, Minnesota border
Maple River – Winger	230 kV	75	55	Fargo area to northwestern Minnesota
Prairie – Winger	230 kV	137	78	Grand Forks area to Winger
Wahpeton – Fergus Falls	230 kV	209	136	ND-MN border east to Fergus Falls
Bear Creek – Rock Creek	230 kV	91	80	South of Duluth toward the Twin Cities loop
Blackberry – Riverton	230 kV	227	156	Northern Minnesota towards south
Mud Lake – Benton County	230 kV	1.2	34	Coming from the north into St.Cloud area
Sheyenne – Audubon	230 kV	194	165	Fargo area west into Minnesota
Genoa – Coulee	161 kV	268	206	Western Wisconsin
Boswell – Blackberry Ckt 1	230 kV	288	188	Northern Minnesota
Boswell – Blackberry Ckt 2	230 kV	281	183	Northern Minnesota

Table 13 – Slow Growth Minnesota Bias Tie Line/Interface Flows

5.3 North / West Scenario Slow Growth Results

5.3.1 Recommended Facilities

Ref. #	Data Source	Facility Name				
		From	To	Volt (kV)	Miles	Cost ($M)
F-02	TIPS	Alexandria	Benton County	345	80	60
F-03	TIPS	Alexandria	Maple River	345	126	94.5
F-06	NW	Antelope Valley	Maple River	345	292	219
F-07	CAPX	Arrowhead	Chisago	345	120	90
F-08	CAPX	Arrowhead	Forbes	345	60	45
F-09	CAPX	Benton County	Chisago County	345	59	44.25
F-10	CAPX	Benton	Granite Falls	345	110	82.5

		County				
F-12	CAPX	Benton County	St. Boni	345	62	46.5
F-13	CAPX	Blue Lake	Ellendale	345	200	150
F-26	CAPX	Chisago County	Prairie Island	345	82	61.5
F-28	CAPX	Columbia	North LaCrosse	345	80	60
F-30	NW	Ellendale	Hettinger	345	231	173.25
F-36	SMNI	Rochester	North LaCrosse	345	60	45
F-56	SMNI	Prairie Island	Rochester	345	58	43.5
			Total		**1620**	**1215**

Table 14 – Slow Growth Load Level North/West Bias Recommended Facilities

Table 14 key:
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

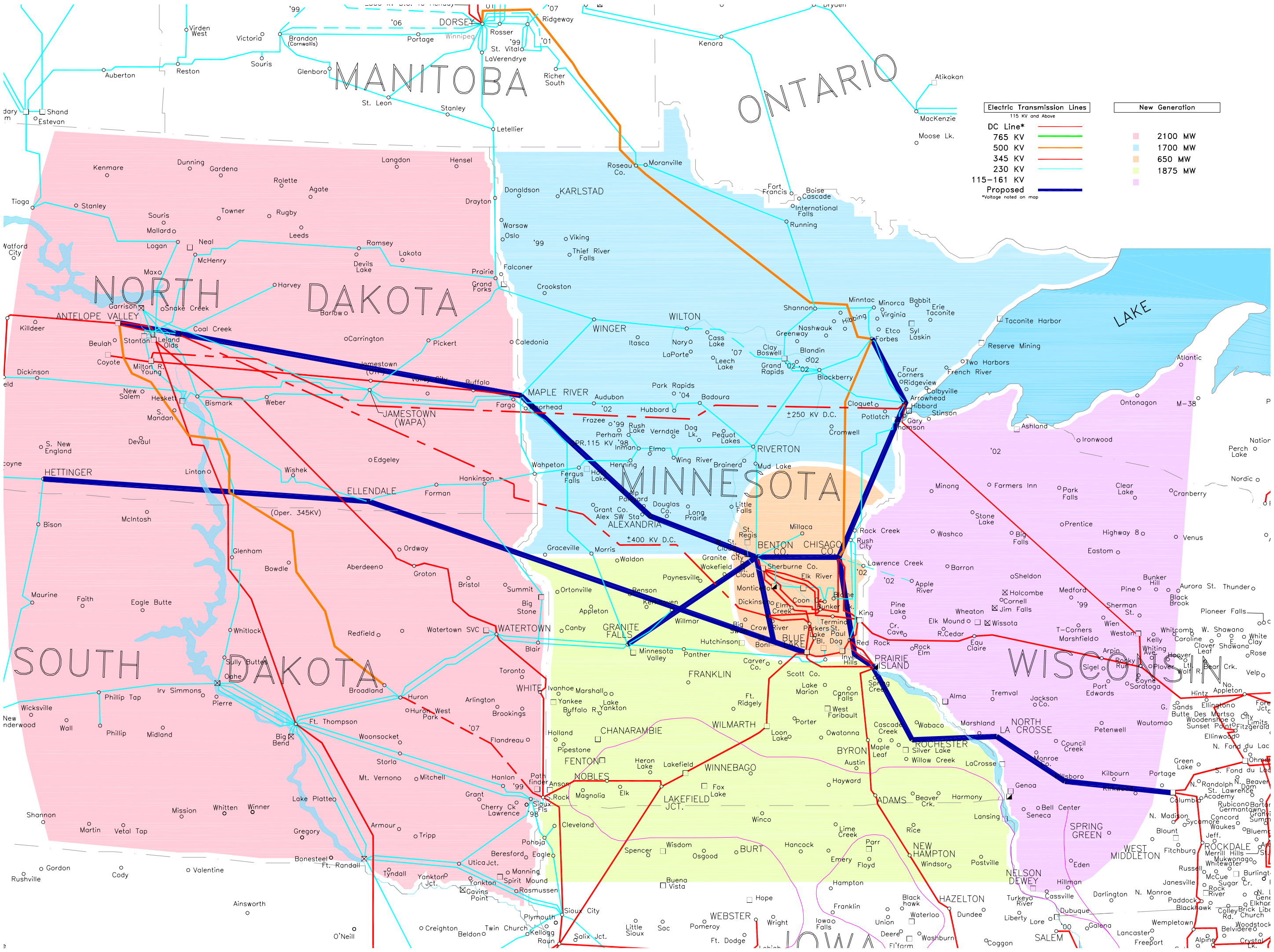

Diagram 14 – Slow Growth Load Level North/West Bias Recommended Facilities

5.3.2 Line Flows on Interface and Tie Lines

LINE	kV Voltage Level	Base 4500 MW FLOW	4500 MW UPGRADE scenario	Description
Forbes – Chisago	500 kV	1540.3	1398.6	Northern Minnesota to Twin Cities loop
Riel – Roseau	500 kV	1842.1	1782.9	Manitoba Hydro to Northern Minnesota
Richer – Roseau	230 kV	228.5	223.5	Manitoba Hydro to Northern Minnesota
Letellier – Drayton	230 kV	392.3	405.6	Manitoba Hydro to MN-ND border
Glenboro – Rugby	230 kV	34.1	81.1	Manitoba Hydro – North Dakota (This and the three lines above are all that ties Manitoba and U.S. as planned through 2009.)

Arrowhead – Stone Lake	345 kV	298.3	310.9	Duluth area to northwestern Wisconsin (then to Weston)
Eau Claire – Arpin	345 kV	72.3	57.8	West to central Wisconsin
Prairie Island – Byron	345 kV	165.4	185.3	South of Twin Cities metro to west of Rochester
Adams – Hazelton	345 kV	173.9	92.9	Southeastern Minnesota – eastern Iowa
Lakefield Jct. – Wilmarth	345 kV	746.1	602.3	Southwestern Minnesota to Mankato area
Split Rock – Nobles County	345 kV	263.9	184.4	North of Sioux Falls, SD, to northwest of Worthington, MN
Nobles County – Lakefield Jct.	345 kV	336.4	252.5	Northwest of Worthington to Lakefield Jct. sub. (Minnesota)
Watertown – Granite Falls	230 kV	248.5	232.0	Eastern South Dakota to western Minnesota
Blair – Granite Falls	230 kV	279.8	270.1	Runs parallel with Watertown – Granite Falls
Granite Falls – Minnesota Valley tap	230 kV	375.4	288.3	Western Minnesota
Fargo – Moorhead	230 kV	54.5	55.4	Fargo, North Dakota, to Moorhead, Minnesota
Fargo – Sheyenne	230 kV	271	200.7	North Dakota, Minnesota border
Maple River – Winger	230 kV	75.1	82.9	Fargo area to northwestern Minnesota
Prairie – Winger	230 kV	168.3	139.6	Grand Forks area to Winger
Wahpeton – Fergus Falls	230 kV	241.8	164.3	ND-MN border east to Fergus Falls
Bear Creek – Rock Creek	230 kV	96.1	95.5	South of Duluth toward the Twin Cities loop
Blackberry – Riverton	230 kV	232.8	216.5	Northern Minnesota towards south
Mud Lake – Benton County	230 kV	63.6	23.9	Coming from the north into St.Cloud area
Sheyenne – Audubon	230 kV	233.9	197.2	Fargo area west into Minnesota
Genoa – Coulee	161 kV	249.8	189.1	Western Wisconsin
Boswell – Blackberry Ckt 1	230 kV	293.9	287.2	Northern Minnesota
Boswell – Blackberry Ckt 2	230 kV	286.9	280.4	Northern Minnesota

Table 15 – Slow Growth North/West Bias Tie Line/Interface Flows

In the eastern bias scenario, the CapX 2020 technical team added part of the additional generation to the east of Minnesota (part on the border of northeastern Iowa and southwestern Wisconsin, part central Wisconsin), in addition to having generation throughout Minnesota, northern Iowa, North Dakota, and South Dakota as in the other two scenarios.

5.4 East Scenario Slow Growth Results

5.4.1 Recommended Facilities

Ref. #	Data Source	Facility Name: From	To	Volt (kV)	Miles	Cost ($M)
F-56	SMNI	Prairie Island	Rochester	345	58	43.7
F-64	CAPX	Eau Claire	King	345	84	63.1
F-65	CAPX	N. LaCrosse	Eau Claire	345	73	55.1
F-66	CAPX	Genoa	N LaCrosse	345	42	31.7
F-67	CAPX	Genoa	Columbia	345	113	84.8
F-68	CAPX	Genoa	Nelson Dewey	345	70	52.4
F-69	SMNI	Nelson Dewey	Salem	345	34	25.6
F-70	CAPX	Genoa	Lansing	345	21	15.8
F-71	CAPX	Lansing	Rochester	345	89	66.8
F-72	CAPX	Ellendale	Big Stone	345	194	145.8
F-73	CAPX	Big Stone	Blue Lake	345	71	53.4
F-02	TIPS	Maple River	Benton Co	345	206	154.5
F-03	NW	Antelope Va.	Maple River	345	292	218.8
F-07	CapX	Arrowhead	Chisago	345	120	90
F-08	CapX	Arrowhead	Forbes	345	60	45
F-09	CapX	Benton Co	Chisago	345	59	44.2
F-10	CapX	Benton Co	Granite Falls	345	110	82.5
F-12	CapX	Benton Co	St Boni	345	62	46.5
F-26	CapX	Chisago Co	Prairie Island	345	82	61.5
F-30	NW	Ellendale	Hettinger	345	231	218.8
			Total		**2071**	**1,600**

Table 15– Eastern Bias Preliminary Recommended Facilities

Key for Table 15:
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

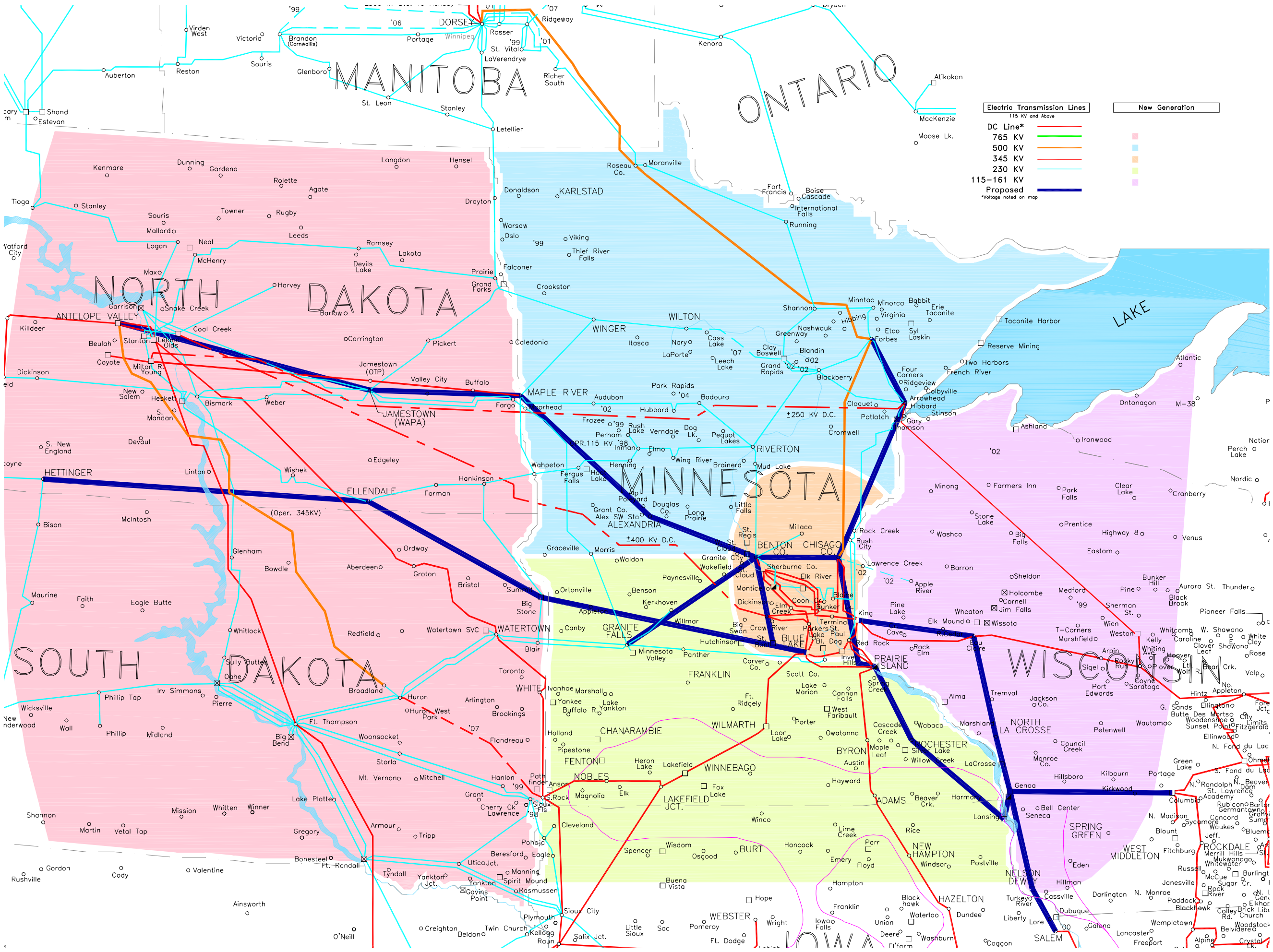

Diagram 15 – Eastern Bias Preliminary Recommended Facilities

6 Common Facilities

The CapX 2020 technical team's primary goal for this initial vision study was to identify a long-range transmission plan that would benefit Minnesota's electric reliability as load continues to grow over the next 15 years and beyond.

6.1 Common transmission alternatives between the Biases

The team found that the biases had 1620 miles of 345 kV transmission lines in common, for a total of $1.215 billion.[5] For comparison, that is a little more than 80 percent of the cost of each scenario individually. The common facilities are shown in Table 18.

[5] When reviewing the results of this study, note that only the cost of transmission line per mile is represented. None of the associated substation, generation interconnection facilities, or underlying lower-voltage (below 161 kV) transmission system infrastructure costs are determined or included in this vision study.

Facility Name				
From	**To**	**Volt (kV)**	**Miles**	**Cost ($M)**
Alexandria	Benton County	345	80	60
Alexandria	Maple River	345	126	94.5
Antelope Valley	Jamestown	345	185	138.75
Arrowhead	Chisago	345	120	90
Arrowhead	Forbes	345	60	45
Benton County	Chisago County	345	59	44.25
Benton County	Granite Falls	345	110	82.5
Benton County	St. Boni	345	62	46.5
Blue Lake	Ellendale	345	200	150
Chisago County	Prairie Island	345	82	61.5
Columbia	North LaCrosse	345	80	60
Ellendale	Hettinger	345	231	173.25
Rochester	North LaCrosse	345	60	45
Jamestown	Maple River	345	107	80.25
Prairie Island	Rochester	345	58	43.5
	Total miles 1620	**Total cost $1,215 ($M)**		

Table 16 – Common Recommended Facilities

6.2 Additional transmission facilities for each scenario

In addition to the common facilities in the above table, the Minnesota bias had three additional unique facilities for a total of 256 miles and $192 million. These facilities are a result of the high concentration of generation in the St Paul/Minneapolis metro area.

The north/west bias also had three unique facilities for a total of 387 miles and $290 million. These facilities are a direct result of the 1000-MW import from Manitoba Hydro, which is included in the north/west generation bias.

The East Bias has unique facilities due to the difficulties sending power from the East to West across minimal river crossings.

7 Conclusion and Next Steps

The CapX 2020 technical team believes these results to be the cornerstone of future studies to better identify the transmission needs of the study region. These results need to be integrated into the MISO Transmission Expansion Plan and ongoing utility load-serving studies.

The team envisions future study efforts to incorporate the results of adjoining regional study efforts, investigate how the bulk transmission solutions can support the load-serving transmission, and investigate how the impacts of new load forecasts and generation interconnections impact the transmission vision. Additional studies to consider include:

- Scaling the 2009 model's load to a point where transmission violations begin to occur and determining which transmission alternative best solves the problem. The study should continue this effort to determine sequence and/or combinations of transmission additions.
- Analyzing the lower voltage system (below 161 kV) for voltage violations and thermal overloads during n-1 contingency analysis.
- Conducting detail studies (including stability analysis) to support a certificate of need for facilities identified as being critical to meet the needs of the transmission customer.
- Identifying bulk substation locations that address overloads on the load-serving transmission system and preparing least-cost planning alternatives that meet the anticipated load growth in the area. Studies would involve detailed load scaling efforts to better model local load growth. The team would review short-term alternatives to address immediate concerns such as switched capacitors, reconductoring, and voltage upgrades on existing corridors.
- Investigating impacts of alternative transmission technology (DC, FACTS, phase shifting transformers, etc.)
- Reconsidering alternative generation locations in each of the biases to determine the sensitivity of generation location on the transmission vision.
- Updating study results based on new generation interconnect/delivery study results.
- Integrating results of adjoining regional and MISO study efforts to determine impacts on transmission vision.

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Appendices

A. Composite List of Transmission Data

B. Tabulated Contingency Results, Load Flow Data and Automaps

B-1. MN Bias
- N-1 Output 6300 MW
- Automaps for 6300 MW Case
- N-1 Output 4500 MW
- Automaps for 4500 MW case

B-2. NW Bias
- N-1 Output 6300 MW
- Automaps for 6300 MW Case
- N-1 Output 4500 MW
- Automaps for 4500 MW case

B-3. Eastern Bias
- N-1 Output 6300 MW
- Automaps for 6300 MW Case
- N-1 Output 4500 MW
- Automaps for 4500 MW case

C. Transmission Characteristics and Cost Estimate Data

Appendix A
Composite List of Transmission Data – Recommended Facilities Include Facility Characteristics

Ref. #	Data Source	Facility Name					Facility Characteristics						
		From Name	To Name	Volt (kV)	Miles	Cost ($M)	From Bus #	To Bus #	R	X	Bch	Rating (MVA)	
												Summer	
F-01	SMNI	Adams	Hayward	345	34	25.3							
F-02	TIPS	Alexandria	Benton County	345	80	59.9	67010	60142	.00299	.03276	.559	1165	
F-03	TIPS	Alexandria	Maple River	345	126	94.2	67010	66792	.00506	.05544	.946	1165	
F-04	CAPX	Alma	Rock Elm	345	60	45							
F-05	CAPX	Alma	Tremval	345	40	30							
F-06	NW	Antelope Valley	Maple River	345	292	219	67101	66792	.01058	.11592	1.978	1165	
F-07	CAPX	Arrowhead	Chisago	345	120	90	61608	60199	.00438	.04718	.80974	1303	
F-08	CAPX	Arrowhead	Forbes	345	60	45	61608	61622	.00191	.02060	.35357	1303	
F-09	CAPX	Benton County	Chisago County	345	59	43.9	60142	60199	.00269	.02890	.49602	1303	
F-10	CAPX	Benton County	Granite Falls	345	110	82.7	60142	66797	.00506	.05449	.93523	1303	
F-11	MH	Benton County	Riverton	500	78	58.5	61620	60142	.00361	.000494	.665	1303	
F-12	CAPX	Benton County	St. Boni	345	62	46.6	60142	62655	.00285	.03068	.52655	1303	
F-13	CAPX	Blue Lake	Ellendale	345	200	150	60192	99990	.014398	.157752	2.6918	1166	
F-14	NW	Blue Lake	Franklin	345	87	65.0							
F-15	NW	Blue Lake	Granite Falls	345	127	95.4							
F-16	CAPX	Blue Lake	West Faribault	345	50	37.5							
F-17	CAPX	Boswell	Forbes	345	64	47.7	61628	61622	.00292	.03142	.53926	1303	
F-18	TIPS	Boswell	Wilton County	230	72	54.3							
F-19	SMNI	Burt	Webster	345	50	37.3							
F-20	SMNI	Burt	Winnebago	345	56	41.9							
F-21	SMNI	Byron	Rochester	345	31	23.6							
F-22	SMNI	Byron	Wilmarth	345	72	54.2							
F-23	SMNI	White	Franklin	345	76	57.2							
F-24	SMNI	Chanarambie	White	345	53	39.8							
F-25	CAPX	Chisago County	King	345	52	39							
F-26	CAPX	Chisago County	Prairie Island	345	82	61.2	60199	60105	.00375	.04031	.69189	1303	
F-27	CAPX	Columbia	Genoa	345	110	83							
F-28	CAPX	Columbia	North LaCrosse	345	80	60	39157	92605	.00316	.04954	.5371	1328	
F-29	MH	Dorsey	Karlstad	345	134	100.5	67625	66750	.00383	.05688	.89380	1295	
F-30	NW	Ellendale	Hettinger	345	231	173.3	99990	67175	.0092	.1008	1.72	1165	
F-31	NW	Ellendale	Watertown	345	131	98.2							

F-32	CAPX	Forbes	Riverton	345	114	85.4	61622	61620	.00522	.05622	.96491	1303	
F-33	CAPX	Franklin	Granite Falls	345	48	36							
F-34	CAPX	Franklin	Lyon County	345	70	52.5							
F-35	CAPX	Franklin	Wilmarth	345	60	45							
F-36	SMNI	Rochester	North LaCrosse	345	60	44.9	69999	92603	.00253	.02717	.46635	2110	
F-37	SMNI	Freemont	Rochester	345	0	0							
F-38	NW	Granite Falls	Watertown	345	93	69.9							
F-39	CAPX	Genoa	Lansing	345	0	0							
F-40	MH	Winger	Benton Co	345	162	121.5	66760	60142	.00735	.10920	1.7157	1295	
F-42	SMNI	Hayward	Winnebago	345	56	41.9							
F-43	SMNI	Hazelton	Salem	345	78	58.1							
F-44	NW	Jamestown	Maple River	345	107	80.4							
F-45	MH	Karlstad	Winger	345	91	114	66750	66803	.00311	.04623	.72631	1295	
F-46	CAPX	King	Rock Elm	345	50	37.5							
F-47	SMNI	Lakefield Junction	Winnebago	345	64	47.9							
F-48	CAPX	Lansing	Rochester	345	100	75							
F-49	CAPX	Lyon County	White	345	50	37.5							
F-50	SMNI	Nelson Dewey	Salem	345	35	25.9							
F-51	SMNI	Nelson Dewey	Spring Green	345	67	50.2							
F-52	SMNI	Nobles	Wilmarth	345	120	89.7							
F-54	SMNI	North LaCrosse	Spring Green	345	105	78.8							
F-55	CAPX	North Lacrosse	Tremval	345	55	41.3							
F-56	SMNI	Prairie Island	Rochester	345	58	43.7	60105	6999	.0046	.0494	.8479	2110	
F-57	MH	Riverton	Wilton County	500	96	72							
F-58	SMNI	Rockdale	West Middleton	345	36	26.7							
F-59	SMNI	Spring Green	West Middleton	345	31	23.2							
F-60	CAPX	West Faribault	Wilmarth	345	45	33.75							
F-61	MH	Wilton County	Winger	345	66	49.5							
F-62	CAPX	Wilmarth	Rochester	345	75	56.25							
F-63	CAPX	Lakefield Jct.	Adams	345	92	69	60331	60102	.00644	.06916	1.187	1303	
F-64	CAPX	Eau Claire	King	345	84	63.1							
F-65	CAPX	North LaCrosse	Eau Claire	345	73	55.1							
F-66	CAPX	Genoa	North LaCrosse	345	42	31.7							
F-67	CAPX	Genoa	Columbia	345	113	84.8							
F-68	CAPX	Genoa	Nelson Dewey	345	70	52.4							
F-69	SMNI	Nelson Dewey	Salem	345	34	25.6							

F-70	CAPX	Genoa	Lansing	345	21	15.8							
F-71	CAPX	Lansing	Rochester	345	89	66.8							
F-72	CAPX	Ellendale	Big Stone	345	194	145.8							
F-73	CAPX	Big Stone	Blue Lake	345	71	53.4							
				Total	**0**	**0**							

CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study

For the rest of the Appendices please refer to www.capx2020.com for the electronic version of the Technical Update report.

Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study

FINAL COPY

Transmission Analysis
for Southeastern Minnesota
and Southwestern Wisconsin

March 13, 2006

Certification

I hereby certify that this plan, specification, or report was prepared by me or under my direct supervision and that I am a duly Licensed Professional Engineer under the Laws of the State of Minnesota

Greg A Woodworth 16999

Greg A. Woodworth
Registration Number 16999
March 13, 2006

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1.0 EXECUTIVE SUMMARY

1.1 Recommendation

This study recommends construction of a radial 345 kV line from Prairie Island to North Rochester to North La Crosse be constructed at this time to solve load-serving reliability issues in the Rochester, MN and La Crosse, WI areas. The estimated cost of this project is $191,631,100, which includes the 345 kV facilities as well as the underlying 161 kV facility new construction and modifications.

The economic analysis performed in Section 12 confirms that due to the simultaneous needs in both areas that a unique opportunity exists to construct a new 345 kV source which is more economical on an equivalent present value basis than constructing two sets of 161 kV facilities at this time. The common 345 kV facilities will form the basis for a reliable long term supply for both areas as opposed to shorter term 161 kV construction which will require construction of more facilities and use of more right-of-way over the equivalent time period.

This study recognizes that the 345 kV radial proposed is only a piece of a more comprehensive solution to additional inter-regional problems. The proposed line can be extended either east to the Madison, WI area or south to the Salem area in Iowa to maximize its performance in inter-regional and non-local load serving functions. Such extension would include more and different participants than the proposed solution. Some incremental transfer studies have been included to demonstrate the effectiveness of the proposed solution and prepare this work for hand off for a Phase 2 study extension.

1.2 Next Steps

The effects of the facilities on the inter-area transfer capability bears further study. Incremental transfer simulation studies that are currently being done may affect the actual facilities constructed. Additional system dynamics (stability) analysis will then be completed on the preferred steady state option to verify that the recommended plan meets the necessary criteria.

1.3 Estimated Quarterly Cash Flows

The estimated quarterly cash flows for the project are shown on the next page and in more detail in Section 11.

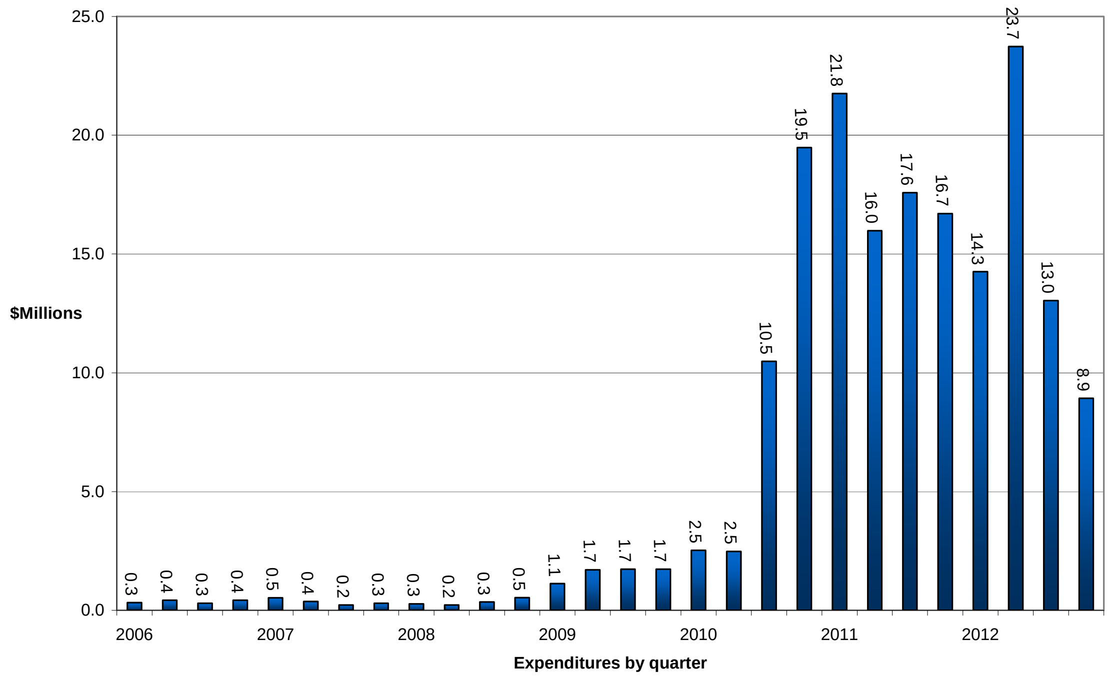


Figure 1.1

1.4 Background

This electric transmission study addresses the development of a transmission solution that will enhance the electric reliability in Southeastern Minnesota and Southwestern Wisconsin. The study effort initially concentrated on developing and evaluating transmission options that would solve the issues caused by the high rate of load growth that has been prevalent in the Rochester, MN area. The peak demand growth for the Rochester Public Utilities load has been 3.46% compounded annually for the last 24 years. The explanation of the current operating situation for the RPU system as well as the consequences of doing nothing to solve the existing issues is detailed in Sections 2 and 3.

Section 4 details other options that were evaluated other than transmission construction and describes the selection process that was pursued prior to studying a transmission construction project. Section 5 of the report deals with RPU's efforts at conservation, alternative energy sources and compliance with the MN Renewable Energy Alternative.

1.5 Initial Rochester and La Crosse area 161 kV Local Studies

The initial Rochester area transmission study dealt only with options that benefited the reliability of the Rochester area. While this initial Rochester area study was being done, Dairyland Power Cooperative (DPC) was doing a similar study for the La Crosse area. The study history, the participants and the scopes for the Rochester and La Crosse area studies are contained in Section 6. The La Crosse area is defined electrically as the area including the cities of Winona, Goodview, and La Crescent, in Minnesota; and Sparta, West Salem, and La Crosse in Wisconsin. 88% of the load is served by Xcel Energy while over 80% of the transmission is owned and operated by DPC. This is due to the proximity of DPC power plants to La Crosse at Alma and Genoa.

The results of these two local studies showed that for the Rochester area, the preferred alternative, 6A, would provide a solution until 2033 for an estimated $23,000,000. The preferred solution involves two new 161 kV lines, 45 miles total, from Pleasant Valley to Rochester's east side and Byron to Northern Hills along with the addition of a second 345 to 161 kV autotransformer at the Byron substation. The Rochester area study and results are detailed in Sections 7 and 8. The La Crosse area study is detailed in Section 9. The La Crosse study showed that the most economical 161 kV solution would cost $61,000,000. For this amount the system would operate acceptably to a load level approximately 50 MW beyond the 2009 load level studied. This would mean that for the La Crosse area either much more extensive 161 kV construction would have to occur or a 345 kV source would have to be built into the La Crosse area by approximately 2014.

1.6 Regional 345 kV Options Studied

With these results for the two local areas, the study group was expanded and higher voltage 345 kV options providing more regional benefit were studied. The five options evaluated are listed in Table 1.1.

Option 1 - Prairie Island to Rochester to North La Crosse to Columbia 345 kV line

Option 2 - Prairie Island to Rochester to North La Crosse to West Middleton 345 kV line

Option 3 - Prairie Island to Rochester to Salem 345 kV line

Option 4 - Prairie Island to North La Crosse to Columbia 345 kV line

Option 5 - Prairie Island to North La Crosse to West Middleton 345 kV line

Table 1.1 – Transmission Addition Options

The regional study is detailed in Section 10. All studies were conducted using the 2009 summer peak and summer off-peak 70% load models from the 2004 MAPP model series.

Power flow contingency analysis was used to screen and compare the proposed alternatives to the existing system in determining the system impact of each transmission option. Each contingency screen was evaluated and documented based on the following.

1. Any and all line overloads that were either mitigated or created due to the addition of each proposed line when compared to the existing system.
2. Any existing line overloads that changed ± 3% due to the addition of each proposed line when compared to the existing system.
3. Any and all bus voltage violations that were either mitigated or created due to the addition of each proposed line when compared to the existing system.
4. Any existing bus voltage violation that changed ± 3% due to the addition of each proposed line when compared to the existing system.

Although Options 1 through 5 all performed well, only Options 1 and 2 mitigated the load service problems in both Rochester and La Crosse areas as well as mitigating a large number of contingency overloads that appeared elsewhere on the transmission system.

A sensitivity analysis was performed on the three radial 345 kV lines listed in Table 1.2. The radial analysis was performed to study the system impact of a radial 345 kV line in the region in the event that the longer regional 345 kV line options discussed above would not be constructed immediately. The radials were built to resolve only the load serving issues involving Rochester, MN and La Crosse, WI. The same contingency power flow analysis was performed on these three radial lines as was performed during the original study.

Option 6 - Radial 345 kV line from Prairie Island to Rochester to North La Crosse.

Option 7 - Radial 345 kV line from Prairie Island to North La Crosse.

Option 8 - Radial 345 kV line from Prairie Island to Rochester.

Table 1.2 – Radial Transmission Addition Options

The radial analysis showed that additional lower voltage system upgrades would be required for any of the options and extensive work would have to be done to modify existing operating guides and in some cases create new operating guides for operation of the system until the radial 345 kV line could be tied into the existing 345 kV system to the east (West Middleton or Columbia) or to the south at Salem. The radial option would, however, be much more economical than implementing the 161 kV local area solutions in the Rochester and La Crosse areas and then constructing a radial 345 kV line from Prairie Island to North La Crosse.

1.7 Preferred 345 kV Option Cost and Schedule

The preferred 345 kV option is radial 345 kV line from Prairie Island to North Rochester to North La Crosse detailed in Section 11. The complete cost of the proposed project, including new 345 kV lines, new and modified substations and new and modified 161 kV line and substation facilities is listed below:

345 kV Construction		
345kV Lines -150 new miles	$129,150,000	
345kV Substations	$12,134,000	
Total 345 kV Construction Cost		**$141,284,000**
Rochester Area 161 kV Construction		
161 kV Lines	$9,700,000	
161 kV Substations	$1,107,000	
Total Rochester Area 161 kV Construction Cost		**$10,807,000**
La Crosse Area 161 kV Construction		
Capacitor Additions	$1,427,000	
161 kV Lines	$32,692,100	
161 kV Substations	$5,421,000	
Total La Crosse Area 161kV Construction Cost		**$39,540,100**
Total Estimated Project Cost		**<u>$191,631,100</u>**

The estimated project costs are in 2005 dollars and assume preparation of a Certificate of Need (CON) before the Minnesota process begins early in the first quarter of 2006. The estimate further assumes that the CON is filed during the second quarter of 2006 so that the facilities can be energized late in the second quarter of 2012.

1.8 Economic Analysis

The preferred 161 kV construction alternatives form the basis for a reliable solution until 2033 in the Rochester area and until approximately 2014 in the La Crosse area depending on load growth. The preferred 345 kV solution is the basis for reliable operation until at least 2051. After equalizing the lives of the 161 kV alternatives to extend until 2051, by the present value method, the equivalent costs detailed in Section 12 show the following equivalent Present Value costs.

Preferred 161 Alternatives	$193,404,380
Preferred Radial 345 Alternative	$191,631,100

These equivalent costs include only construction costs based on load serving requirements. No economic analysis has been included for numerous other factors, all of which would most likely favor the preferred 345 kV alternative. Electrical losses are one of these other factors. Since losses under the same megawatt loading decrease with the square of the voltage, an economic evaluation would most certainly favor the 345 kV alternative for the same megawatt loads.

1.9 Additional Work to be Done

Only minimal system dynamics (stability) analysis has been completed for the study. Due to the great amount of time required, stability analysis will be completed only on the final preferred steady state option selected. Stability studies will be needed for both the final and radial 345 options and operating studies will be needed to be completed as more details of the recommendation become available. Stability studies will be used as a screening tool to verify the recommended plan meets the necessary criteria.

In addition to these technical studies, an immense amount of work needs to be completed for facility siting, routing and environmental aspects of the alternative selected. It is cost prohibitive to complete the siting, routing and environmental work required for all the options although the outcome of these studies will have a great affect on the total project. Significant public input work will also be completed early in the need process.

The effects of the construction of the recommended facilities on the inter-area transfer capability bears further study. Incremental transfer simulation studies (TLTG – Transfer Limit Table Generator studies) are currently being executed to determine the effects of the options on the Minnesota Wisconsin Stability Index (MWSI).

The construction costs must then be evaluated against the lower operating costs that should result from the higher transfer capability and the lowered Locational Marginal Prices for energy in the areas served.

2.0 STATEMENT OF THE PROBLEM

The Rochester, Minnesota area has been growing consistently for decades. The Money magazine Number 1 City ratings that Rochester received in the 1990s helped to fuel that growth. This high growth has created planning problems throughout the City for streets, transportation, roads, sewers and the basic infrastructure required to provide the quality of services and life that area residents have come to expect.

The population of the Rochester Metropolitan Statistical Area, as defined by the 1999 MSA definition, has grown from 98,400 in 1985 to 131,400 in 2003, an increase of 34% in slightly less than 20 years. During that same time the maximum hourly electric demand has grown from 139 Megawatts (MW) to 262 MW, an increase of 88%. Annual energy usage in Rochester has grown from 717,850 Megawatt Hours (MWH) to 1,201,950 MWH, an increase of 67% in energy usage.

Table 2.1 shows the history of electricity usage for RPU. The table shows the maximum hourly demand and the system annual net energy for load for each year from 1979 to 2003. The minimum hourly demand is also listed from 1987 until 2003. 1987 is the first year that records were kept for minimum hourly demand.

YEAR	PEAK DEMAND MW	MINIMUM DEMAND MW	Net Energy for Load MW hrs
1979	109		511,676
1980	117		534,122
1981	120.7		552,343
1982	129.4		589,705,725
1983	134.8		648,063,700
1984	138.6		672,394,600
1985	141.7		716,848,850
1986	148.7		744,084,975
1987	161.7	56.5	780,194,775
1988	176.5	58.1	824,431,113
1989	169.8	61.5	839,195,895
1990	177.8	63.8	875,704,812
1991	184.5	68.0	911,616,842
1992	159.4	52.2	888,313,116
1993	181	51.7	927,144,580
1994	180.4	57.1	931,654,643
1995	204.5	64.2	957,938,061
1996	189.3	63.6	930,477,979
1997	197.5	54.4	948,218,063
1998	208.9	54.2	1,025,481,756
1999	232.2	54.1	1,066,015,490
2000	228.2	75.1	1,129,356,894
2001	250.5	81.7	1,161,742,279
2002	254.4	81.9	1,192,516,517
2003	261.9	84.4	1,201,928,624
2004	248.7	88.6	1,272,766,545
2005	263.8	92.1	1,276,351,875

TABLE 2.1

The annual compound growth rates over the last 26 years listed in Table 2.1 are 3.46% for the Annual Peak Demand, 2.75% for the Annual Minimum Demand, and 3.34% for the Annual Net Energy for Load. The annual values for Annual Maximum and Minimum Demand are shown graphically in Figure 2.1 for the 26 year period. The System Net Energy for Load for the same period is shown in Figure 2.2. The compound growth percentages used for the studies of alternatives are based on historical data.

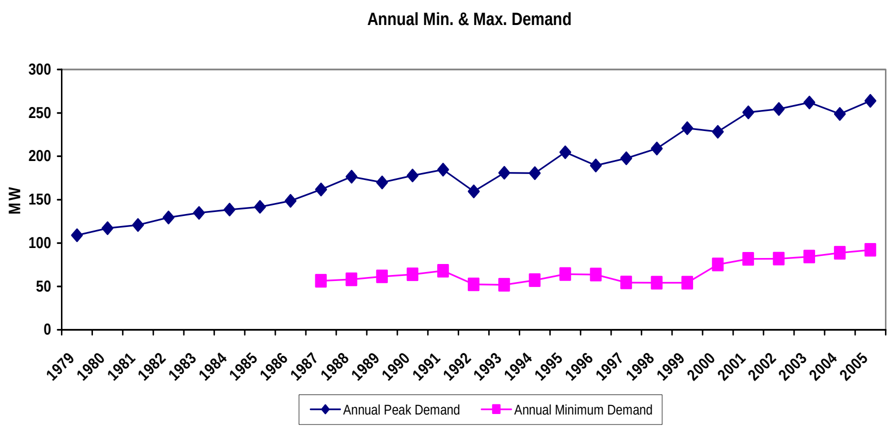


Figure 2.1

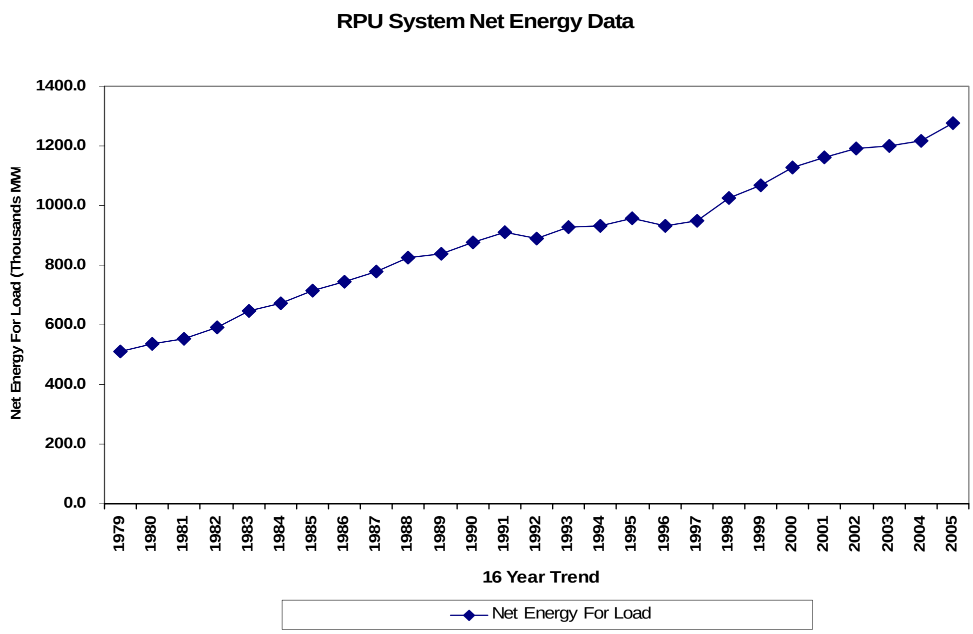


Figure 2.2

1985 is a significant base year for comparison since that is the year that construction of the Southern Minnesota Municipal Power Agency (SMMPA) 161 kV transmission line from Byron to Rochester, the last transmission electric supply addition, was completed and the line was energized. That 161 kV line is now known as the Byron - Maple Leaf – Cascade Creek line. The Maple Leaf Substation was built and energized in the early 1990's to enhance the reliability of the electric supply in the area around Rochester's periphery. The Byron to Rochester line was modified to become the transmission source for the Maple Leaf Substation. The Maple Leaf Substation serves People's Cooperative Services' (PCS) customers. People's Cooperative Services is a member of the Dairyland Power Cooperative (DPC) a generation and transmission cooperative headquartered in La Crosse, Wisconsin.

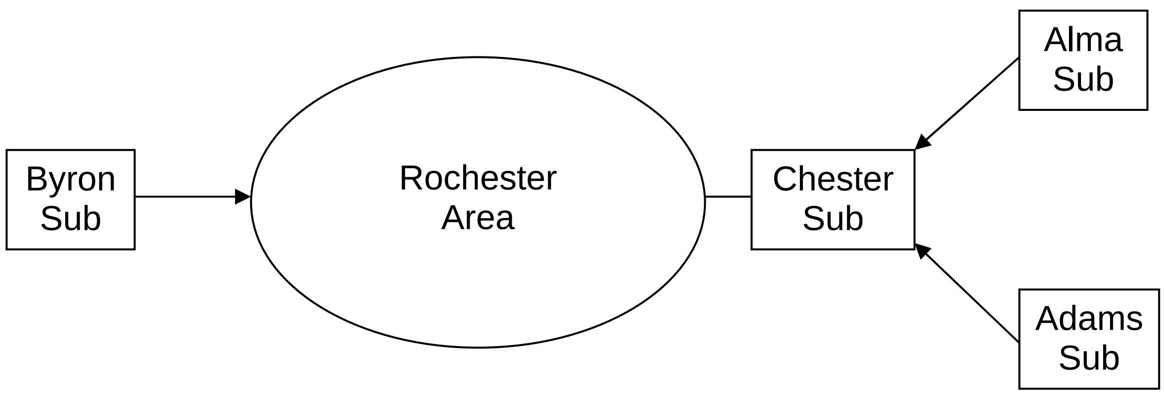
The only major generation addition in the Rochester Area since 1985 to offset the 123 MW increase in demand was the addition of a 49.9 MW combustion turbine at Cascade Creek Substation in 2001. At the same time, for environmental and other reasons, other existing generation in the area has actually been down-rated by several MW.

Three major transmission upgrades have been completed since 1985. The first was to convert the transmission lines within the Rochester system previously operating at 115,000 volts (115 kV) to 161,000 volts (161 kV) increasing their capabilities by about 35%. The second upgrade involved re-routing one line and re-building two other lines to upgrade the supply capacity internal to the RPU system and better supply the additional power requirements within and through the City. The third upgrade was the reconductor of the Alma-Wabaco 161kV line in 2000 to increase the capacity of the line.

Only the combustion turbine addition added supply capability to the Rochester area electric system.

The transmission system conversion from 115 kV to operation at 161 kV reduced transmission system losses by approximately 50% annually while upgrading the line capacities by 40%. The conversion project was completed between 1990 and 2001. Three additional transmission upgrades were completed in 2000 and 2001 which also increased transmission capacity within and through the RPU system.

The Rochester Area is connected to the bulk transmission system by three 161 kV lines, with the primary import source being the Byron-Maple Leaf-Cascade Creek 161 kV line.



The Byron-Maple Leaf-Cascade Creek line is routed on virtually 100% road right- of-way. If the Byron-Maple Leaf-Cascade Creek line is out of service due to a fault or other electrical disturbance, a planned shutdown for highway construction, scheduled maintenance, or some form of highway accident, the Rochester area is limited to importing a maximum of 160 MW from the two remaining 161 kV eastern interconnections to the Alma and Adams Substations by two MAPP and MISO approved standing operating guides. This limitation is a result of a combination of equipment thermal limitations, voltage limitations and compliance with mandatory operating reliability standards. These limits are imposed so that the surrounding electric transmission system remains within voltage stability limits and transmission line thermal sag limits if the next worst contingency occurs. The system is required to be operated in this fashion by the North American Electric Reliability Council (NERC) Reliability Standards.

Studies have shown that operation beyond this 160 MW limit would increase the probability of either cascading transmission outages creating a much larger regional outage and/or local power outages if one of the remaining 161 kV lines serving the Rochester area from the east went out of service. This was essentially what happened during the regional blackout on June 27, 1998, when the transmission lines opened quickly due to severe thunderstorms and repeated lightning strikes not providing the system operating personnel adequate time to prepare for the next contingency.

Rochester Public Utilities has approximately 181 MW of generation available (102 MW of coal, 77 MW of natural gas, and 2 MW of hydro). Therefore, for a prior outage of the Byron-Maple Leaf-Cascade Creek line the remaining (2) 161 kV lines into Rochester in conjunction with all available generation at RPU can support 341 MW of load in the Rochester area and withstand the next contingency. Based on the historical growth rate for the area, the Rochester area summer peak load is expected to exceed 341 MW by 2010.

This analysis assumes that all available RPU generation is online at the time and almost fully loaded for the transmission line outage. This dispatch situation might be economical only during peak loading periods. Peak periods are historically the only times that all of the Silver Lake generating units, as well as the higher-fuel-cost peaking Cascade Creek Combustion Turbine Units, are on line at the same time. Extended operation of the combustion turbines is economically unrealistic due to the high fuel cost. Under normal circumstances, the RPU generation is scheduled to serve the RPU load above the 216 MW firm sale to RPU from SMMPA. The SMMPA power is provided from generation external to the Rochester area.

RPU completed the Phase I, II and III Baseline Electric Infrastructure Studies which showed that the RPU load level is above the 160 MW import level approximately 4,200 hours per year in 2005. By 2010, the RPU system load will be above the 160 MW level over 6,000 hours per year. Stated another way, every daylight hour of the year in 2010, the Rochester area will be at a heightened probability of a major electrical power outage in 2010. This analysis is based on the City of Rochester RPU load only and does not include the Dairyland supplied load for People's Cooperative Services, which was approximately 43.5 MW on peak in 2005. This additional load will only increase the duration of the risk of electrical outage.

3.0 THE "DO NOTHING" ALTERNATIVE

The easiest and cheapest alternative to this problem is to do nothing. Under the do-nothing alternative, the most probable future scenario would be as follows. The electric load will initially continue to grow commensurate with population growth and other demographics but will shift to some generally declining rate of increase since electric service, which has been quite reliable, would become more unreliable over time. The reason for this decreased reliability over time is illustrated in Figure 3.1. Figure 3.1 shows the 2005 load duration curve for RPU load and the sources of power utilized to meet the various load levels.

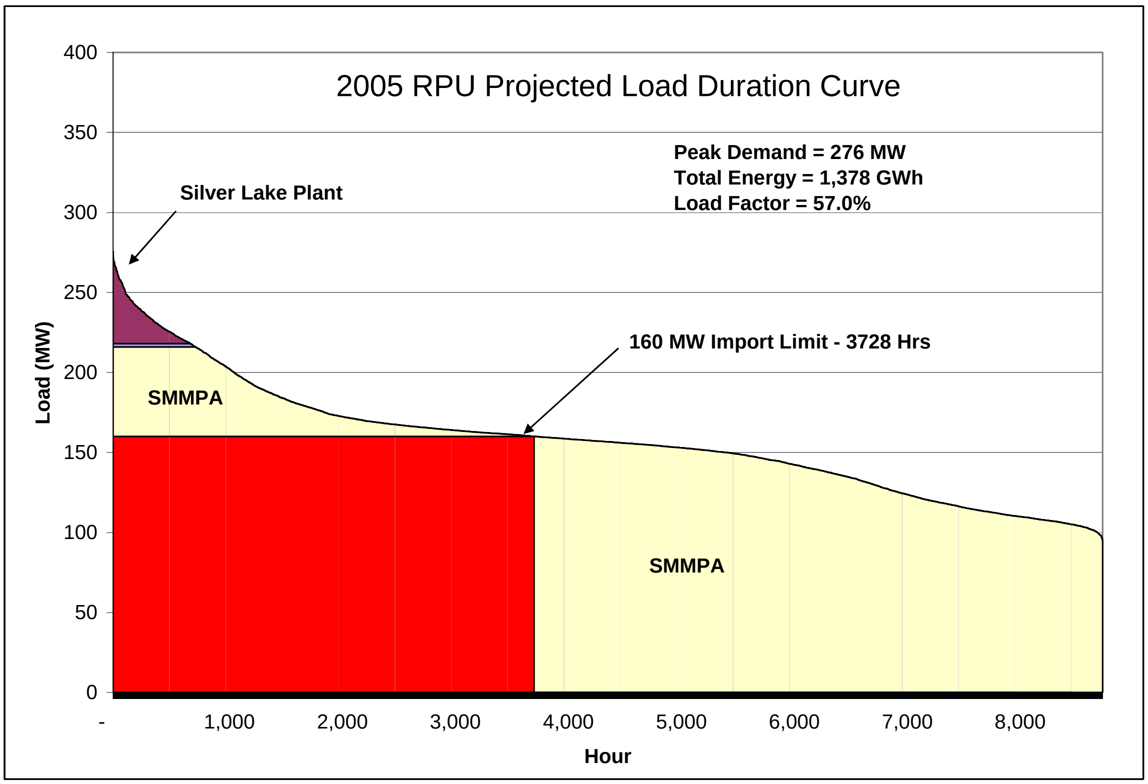


Figure 3.1
2005 RPU Projected Load Duration Curve

The load duration curve shows the number of hours per year that the load is above a specific level. As can be seen in Figure 3.1, the RPU load is expected to be above the 160 MW for 3,728 of the 8,760 hours of 2005, or 43% of the time. This means that integrity of the regional transmission system is a major component of the reliability of the City of Rochester electric supply.

The People's Cooperative Services load of approximately 43.5 MW is a part of the Rochester area load and is supplied by Dairyland Power

Cooperative. If that load were included, it would have the effect of shifting the overall curve up. So when properly viewed from a Rochester area perspective and rather than simply an RPU load perspective, the integrity of the area transmission system is a major component of electric system reliability greater than 43% of the time.

Figures 3.2 and 3.3 show the projected load duration curves for RPU load for the years 2010 and 2015, respectively. The percentage of time that the load exceeds the transmission system supply capacity under a prior outage condition rises from 43% in 2005 to 70% in 2010 and 83% in 2015. The 6,168 hours that the load is greater than 160 MW exceeds the number of daylight hours in the year, which is less than 5,000. Once again adding the People's Cooperative loads would only exacerbate the situation.

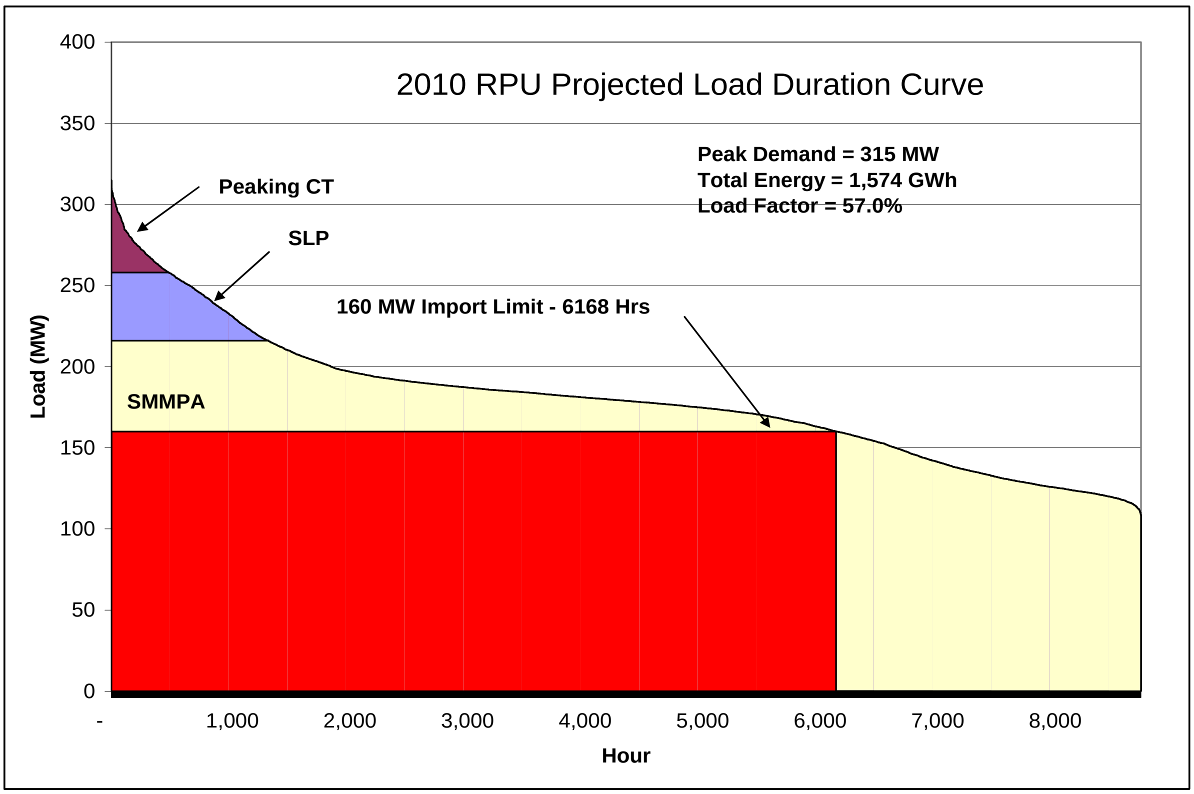


Figure 3.2
2010 RPU Projected Load Duration Curve

The Rochester power supply is based on a 216 MW firm sale from SMMPA. Since SMMPA's generation assets are located outside the Rochester area, bringing this energy to the Rochester area depends exclusively on the transmission system. The same can be said for the supply of Dairyland Power Cooperative electricity to the People's Cooperative Services load since all of the Dairyland Power Cooperative generation is located remotely to the Rochester area.

The increase of load relative to transmission capacity will be the major basis for the reduced reliability in the Rochester area. The reduced reliability could take many forms. The first noticeable difference might be low voltages occurring on the system and/or more frequent outages under contingency operating conditions. These problems would cause electronic equipment to shut down and have to be re-started. If the problems are allowed to continue to escalate so that system intact operation is affected, low voltages would ultimately cause more electric motors to fail due to the motors running hotter as a direct result of the lower system voltages. Small motors such as window air conditioners and sensitive electronic equipment used in the manufacturing and medical industries would probably be the first equipment to show an increased rate of failure.

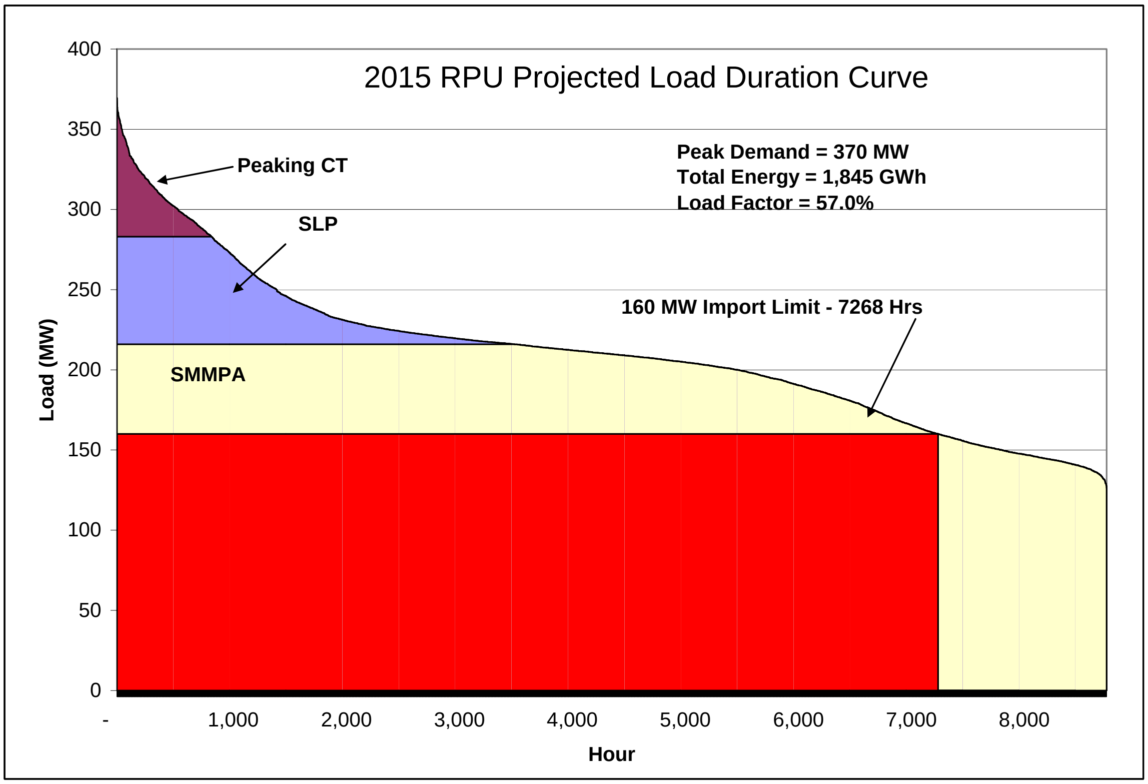


Figure 3.3
2015 RPU Projected Load Duration Curve

This increased rate of failure would increase operating and maintenance costs to local manufacturers and users of electronically controlled equipment throughout Rochester. With rising costs and lowered service quality, profitability of local concerns would decrease slowly at first and at an accelerating rate as time progresses. As the problem became worse, more distributed and emergency generation would need to be installed to maintain proper system voltages. This would start an economic spiral since individual businesses' costs would be increased because of the capital and operating costs of the generation. Operation of this local generation would decrease electric sales, which would increase utility electric rates in the long run.

The longer the situation goes on uncorrected, the more negatively the profitability of local businesses would be affected since there would almost certainly be less construction of new homes and facilities. With less home and business construction, there will be fewer potential workers in the job market. At some time in the future, say five to ten years or more into the future, this effect will be compounded so that the electric load levels would actually decline to manageable levels due to increased outages and lack of economic viability for the local businesses in the area. Ultimately, this will lower tax and business revenues to the point where a local recession would occur as the regional economy would be affected by high costs, low business profits or outright losses, and reduction of the employment pool as the area comes to be seen as an unreliable, high cost area. The affect on local businesses, especially those in the manufacturing, service, medical and medical support industries would be potentially devastating, since a reliable electric supply is basic to supplying timely services as customers demand them.

As the frequency and duration of outages increased as the bulk electric supply became more stressed, the loads would decrease relatively quickly to manageable levels. The ultimate result would be a stagnant level of business activity at a reduced level from the economic peak. Business expansions would generally occur elsewhere since the basic infrastructure would not support the increased level of activity. This would leave a smaller base to pay the existing fixed costs, which would result in higher costs for those remaining in the area and probably an increased rate of bankruptcies.

All of this may be somewhat academic since the electric industry is currently in the process of moving to mandatory standards for electric system operation, required by the North American Electric Reliability Council, all at the behest of the Federal Energy Regulatory Commission. Violations of electric standards will bring about adverse publicity (publicity is one of the sanctions for standard violation) which will have dilatory effects on the ability of RPU to finance system additions and upgrades, in addition to costing the rate payers more dollars deepening the spiral.

4.0 THE ALTERNATIVE SELECTION PROCESS

4.1 Problem Identification and Forecasting

The first step in dealing with power supply and capacity issues is to identify any problems that may exist with present or future power supply. Problems with present power supply usually revolve around power quality (voltage, flicker, etc.) or the unreliable delivery of electricity to customers in specific geographic locations. Problems with future power supply need to be quantified and detailed as much as is economically feasible. There is no comprehensive supply of perfect information when dealing with future conditions.

The electric utility industry in the United States is long term by its nature. Planning and construction of new electric facilities alone can require up to ten years. Electric facilities are depreciated over 20 to 30 or more years. The electric and transmission rates charged and the allowable returns are regulated by government entities, federal, state and local regulations and the facilities constructed are generally permanent land uses. The basis of electric system expansion planning is, in most cases, meeting the obligation to reliably serve which is heavily dependent on the future load forecast.

The objective of energy supply and capacity planning is to ensure that there is adequate, reliable supply available to meet the electric needs presented by electric customers because electric utilities are bound by the obligation to serve. Short term load forecasting can involve multiple input factors in the model, based on indicators of future short term population and economic activity. Because there is no reliable method to predict the direction of societal change or events like the 1974 oil embargo, longer term load forecasting, looking out 20 or 30 years, is generally based on existing conditions with the annual capacity required being increased by a fixed percentage over time and tempered by a dose of conservatism in later years when time exists to react to change.

This method of increasing the annual load by a fixed percentage has historically been used for the following reasons:

1. The further into the future the forecast, the more imprecise forward looking indicators are of future requirements.
2. Bulk generation and transmission facility additions are generally added in relatively large increments.
3. Approval times for bulk supply projects can range from 5 to 10 years or more depending on the size of projects.
4. The United States economy and the electrical usage have historically grown and despite some periods of slower growth, this trend appears to continue over the foreseeable future.

5. Conservation alternatives will generally only retard the annual growth percentage but have not decreased the supply requirements thus becoming an issue of timing, not ultimate need.
6. Technology breakthroughs are not easily forecast.

The primary alternatives to meeting the increased demand are listed below:

1. Installation of additional generation within the Rochester system
2. Conservation programs
3. Installation of a phase shifting transformer in the immediate area
4. Construction of additional transmission into the Rochester area

4.2 Installation of Additional Generation

The additional generation alternative is part of a larger set of issues revolving around what type of investments to make in the Silver Lake Plant for both emissions controls and life extension of individual units. This issue is intertwined with the question of what type of investment to make in the transmission system. The robustness or the weakness of the transmission system has a great affect on the decision regarding the installation of additional resources to maintain or enhance electric reliability. A robust transmission system is critical if the strategy employed is to place more reliance on generating resources outside the RPU system.

Both the installation of additional generation alternative and the construction of additional transmission alternative require an assessment of RPU’s generation capacity internal to the system and what the future generation resource plan identifies for installation of additional generation both internal and external to the system. These questions must be answered in a coordinated fashion in order to minimize the long term cost for maximum supply reliability.

In addition to the simplistic installation of additional large scale generation, many other alternatives exist within this classification. The types of generation can range from central station to distributed generation and can encompass fuel choices from fossil to hydro power to biomass to renewable sources. In short, generation choices are generally the most expensive and most complex. RPU initiated a series of studies in 2002 to assess the additional generation needs. These studies analyze additional generation from the perspectives of economics, emissions, fuels, capacity factors, social, and environmental factors. The results of the studies are available on RPU’s website and were presented in a public meeting on March 29, 2005. The studies analyzed the following topics:

1. Traditional baseline generation options
2. Demand Side Management (DSM) capacity planning

3. Renewable generation options
4. Fuel switching (Coal Types) analysis
5. Emissions testing results
6. Site feasibility study for emissions options

The traditional baseline generation options were analyzed first, with both construction and energy cost estimates completed for differing types of generation. This is referred to as the Phase I study. The Phase II study looked at the affects for demand side management and renewable energy alternatives and how they could improve on the actions of the Phase I study.

Completion of the Phase II demand side management analysis involved the forming of a community task force which provided suggestions and comments on the process and the results. As a part of the Phase II study, an End-Use-Survey was completed to determine the available inventory of residential and commercial appliances available for energy reductions. With this information, a cost benefit analysis was performed which looked at the results from three perspectives; the utility, the customer, and societal.

While the Phase II study concluded that although energy is energy and it can be compared on a one for one basis, capacity of resources is not equivalent and can not be compared on a one to one basis. Wind and solar capacity is not dispatchable, or able to be scheduled, as to when it is available. This energy must be produced and consumed when the wind blows and the sun shines. It should be noted that, at this time, technology does not exist to permit storage of energy for later use. These forces of nature may not occur when the utility needs the capacity.

In the Mid-Continent Area Power Pool (MAPP) region, individual utilities are required to meet minimum capacity obligations. Over time, experience and research has lead MAPP to accredit wind at 15% of nameplate capacity and solar at about 40% of nameplate capacity. This means that, to be equivalent, 1 MW of gas combustion turbine capacity or coal capacity would require 6.67 MW of wind capacity or 2.5 MW of solar capacity to replace it.

The study also compared the existing photovoltaic array output available on both peak and non-peak days in order to gauge the amount of solar array capacity available relative to nameplate capacity for an empirical comparison. This information was used to determine how RPU would meet its Renewable Energy Objective (REO). RPU must provide a minimum of 10% of its energy above the SMMPA purchase from renewables by 2015. 1% of this energy must come from biomass. The existing sources of renewables are:

- Wind Purchases
- Solar Array installations in Rochester
- Olmsted County Waste to Energy Facility (Biomass)
- RPU's 3 MW Zumbro River Hydro facility

Current projections are that the Zumbro River Hydro facility and the Olmsted Waste to Energy Facility will meet the requirements for RPU until about 2022.

After the affects of renewables were factored into the capacity plan, a financial analysis was completed. The forecast considered externalities, renewable energy from the Zumbro River Hydro, Olmsted Waste to Energy Facility (OWEF), wind generation, existing solar generation and included all of RPU's costs.

The externality cost values used for individual externalities are listed below. These values were for Minnesota and were adjusted for 2004 Gross Domestic Product.

Emission	**$/ton – 2004**
PM10	$848.77
CO	$0.37
Nox	$72.04
Pb	$508.95
CO2	$2.04

The conclusion of the above evaluations was that the estimated demand side management energy and demand reductions from DSM and renewables incorporated in the Phase II portion of the study provided significant cost and emission reductions over the Phase I lowest evaluated plan. Of the renewable power supply options, energy from the Zumbro hydro, wind and the OWEF are the lower cost renewable alternatives.

The cost evaluations showed that capacity requirements should continue to be met with traditional capacity sources with energy coming from the lowest cost sources. The results showed that capacity additions may be required before any actual capacity deficit exists to preserve reliability for RPU customers due to the transmission limitations and market changes.

The conclusions of those studies were as follows:

- RPU is in relatively good position to meet projected load requirements.

- For capacity purposes, the first generating resource necessary is a combustion turbine in 2016 according to the Phase I plan. The effect of DSM and renewables is to delay that CT installation by two years.
- Due to transmission limitations, additional internal resources could be needed earlier than the 2016/2018 projection to provide continued reliability to RPU customers.
- Plans must be flexible on installation of additional internal capacity. Based on load growth and loss of load probability, the plan timelines may need to be shifted.
- The MISO market can influence the RPU generation dispatch outside of RPU needs for retail and wholesale loads.
- Transmission upgrades are necessary to reinforce reliability, use all of the Contract Rate of Delivery (CROD) energy on a firm basis, and to access markets.
  - May require installation of a combustion turbine earlier to maintain reliability if upgrades are not complete in next five years (by 2009).
  - Requires the retention of Silver Lake Plant (SLP) for internal generation operation.

- Determination of an emission program investment in SLP is necessary to meet new regulations and keep SLP operational.
- Expected emission system upgrades would be tied to life extension efforts on Unit 4.
- Participation in a coal unit with an in-service date before the 2020 time frame is not warranted.
- The effect of aggressive DSM and renewable strategy could be to delay this new coal unit by up to five years and potentially significantly reduce the size of it.
- Considering the traditional baseline resource plan, RPU will need to begin the process for acquiring capacity in or before the 2016 time frame. The amount would depend on the load growth and if a unit had been installed for reliability purposes because of transmission system inadequacy.
- Upgrades to SLP will be needed, Unit 4 as a minimum, Units 1-3 as compared to alternative capacity technologies at the time.
- Based on a review of the loads, market conditions at the time, etc., RPU should gauge the interest of area utilities in a joint coal facility for an in- service date of approximately 2014 to 2020, depending on the success of the DSM, conservation and renewables programs.
- Depending on area interest and the availability of firm market capacity and energy, RPU should consider an option on approximately 1500 acres for development of a coal unit.
- Install capacity in accordance with the long range plan as adjusted for conditions at the time and impacts from Phase II assessment.

4.3 Conservation

RPU has actively promoted conservation and conservation programs and will continue to do so in the future. In the face of continuing increased population growth and accompanying electric demand, conservation alone will not solve the problem but it will potentially delay the time when the problem becomes critical. Thus, conservation alone is not an alternative that can be chosen. It can, should, and will be used in conjunction with other solution alternatives. RPU's historical and future conservation efforts are detailed in the Alternatives section.

4.4 Phase-Shifting Transformer

A phase shifting transformer (phaseshifter) is a piece of equipment that can be used to control the amount of power flowing on specific AC transmission lines. The installation of a phaseshifter may be utilized to prevent one or more lines from overloading under certain operating conditions. This tool can be quite helpful for dealing with operating conditions that cause recurrent overloads in specific locations.

The positives associated with phase-shifting transformers are that they can usually be installed in existing substations and do not require additional land or right-of-way to be purchased from local residents. A phase shifting transformer can correct overload problems specific to an area without the addition of transmission lines over a larger geographical area.

The negative aspects of phase shifting transformers are that they must be sized and rated for both the total amount of power in MVA they must carry and also for the necessary phase shift that the transformer will need to provide under many different operating conditions to successfully do its job. These two different parameters are subject to change because they can be effected by other independent changes on the power system that effect the maximum amount of power that they will be regulating. Because of these stringent interrelationships they impose added maintenance costs (and generally are a high maintenance frequency item) and they are generally quite noisy for a static piece of equipment. Phase shifting transformers tend to be very large and quite expensive. Phase shifting transformers, therefore are not a good solution to overloading problems that are caused by load growth in the immediate area. As the load continues to grow, it will eventually increase beyond the capacity of the phase shifter to correct the problem.

A phase shifter would be an expensive, temporary solution to a load growth problem that requires a permanent solution. When the growth continues in the area it is usually necessary to install the facilities that were delayed by the phase shifter. To make matters worse, the transmission facilities that need to be installed to solve the problem generally cost more and cause more angst with more landowners since the area is usually more populated when the line is finally built. This is likely to cause more opposition, higher right-of-way costs, and longer construction times. For these reasons, the phase shifting transformer alternative was not chosen.

4.5 Construction of Additional Transmission

The alternative for construction of additional transmission is covered by a separate study from the generation capacity addition studies described above, but is closely related to that set of alternatives.

Decisions on transmission construction depend on a number of variables. The two most important variables are first, the amount and operational cost of internal generation available that does not depend on the condition of the transmission system in order to be delivered to the load. The second variable is the operation of the transmission system under contingency conditions.

NERC Version 0 Reliability Standard TOP-002-0, Section B, Requirement 6 states that "Each Transmission Owner shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 contingency planning) in accordance with NERC, Regional Reliability Organization, Sub region, and local reliability requirements." As noted in the statement of the problem section, unless an additional transmission interconnection is constructed into the Rochester area, the reliable operation of the electricity delivery system will diminish over time and cause economic hardships for the area.

The factors to be taken into account when considering and reviewing transmission alternatives take many forms. Grouped under broad headings, factors to be considered consist of the following items.

4.5.1 Problems that can be solved by a Transmission Alternative

- Voltage levels too low
- Overloads of existing system elements
- Known existing loads that will stress or degrade the operation of the existing system without improvements being made (load under construction: housing developments, manufacturing, ethanol or biodiesel plants)
- Lack of robustness of system (lack of capability to handle new and future loads or)
- Generation outlet (including wind, distributed generation)

- Unreliable performance of the electric system
- Restrictions on maintenance outages due to limited transmission. For example, if DPC decides to rebuild or reconductor Adams-Rochester 161 kV, either limit construction to spring or fall, or RPU would be reliant on internal generation resources for the duration.

4.5.2 Factors in Choosing a Transmission Alternative

- Overall Environmental Impacts and Siting Issues
- Locations of Major River Crossings
- Identifications of sensitive areas
- Major Population Centers
- Overall Cost of individual alternatives
- Feasibility of the alternative based on technology
- Feasibility of acceptance of the alternative by the regulators and the public
- Ability of the alternative to correct the problem or problems defined (low voltage, flicker, capacity delivery, etc.)
- Right-of-Way (R-O-W) limitations (sensitive areas, local restrictions)
- Operational concerns (avoiding complex switching schemes, minimizing maintenance costs, etc.)
- Use of existing R-O-W (including existing non-electric R-O-W such as roads, railroads)
- Use of existing R-O-W limitations (common mode failure outages if lines are on same structure or in the same R-O-W
- Outages needed during construction

In addition to these factors that relate to the alternatives proposed, each alternative can potentially have multiple routes. These routes each have the following routing factors that need to be considered when choosing a route alternative.

Landowner Issues

- Electromagnetic Fields (EMF)
- Stray Voltage
- Radio/Geographic Positioning System/Cell phone interference
- An alternative route would be better
- Land use (including farming or land use) conflicts
- Property values
- Landowner liability for damage caused by or to the line
- Aesthetics

Land use Conflicts

- Farming restrictions (farmability) near transmission line R-O-W
- Damage to farm equipment used near poles
- Farm equipment damage to transmission poles
- Building restrictions
- Aerial spraying
- Airport expansion

Environmental Issues

- Wildlife and waterfowl habitat concerns
- Sensitive environmental area (at risk species of plants, animals, etc.)
- Aesthetics including impacts on scenery due to R-O-W clearing

These factors affecting alternative transmission projects and alternative routes can also change with the passing of time. It is necessary to review possible changes periodically in order to make sure that the environment surrounding the alternatives hasn't changed enough to alter the decision that has been made.

5.0 ALTERNATIVES

RPU actively promotes energy conservation through customer incentives and education. These programs help customers save energy and money and help preserve natural resources. Customer incentives and conservation education opportunities are detailed in this section.

5.1 Conservation

RPU partners with two area municipal utilities to more effectively manage the dollars devoted to the state-mandated Conservation Improvement Program (CIP). Austin Utilities (AU), Owatonna Public Utilities (OPU), and RPU teamed together in 2003 to better serve a total of 65,800 electric customers with energy efficiency incentives by leveraging shared marketing responsibilities and designated energy conservation funds.

5.1.1 Conserve & Save

The three-utility partnership designed the Conserve & Save program in 2002. The Conserve & Save program highlights ENERGY STAR®-labeled appliances, lighting, motors, furnaces, and other energy-using devices that exceed energy codes or standards by a specified amount. The partnership's goals are to heighten awareness and increase the market saturation of ENERGY STAR appliances and high efficiency equipment, achieve measurable energy savings, and impact the southeast Minnesota market long term.

5.1.1.1 History

Since 2002, the Conserve & Save program has continued to promote and increase sales and the installation of ENERGY STAR-labeled products and other higher efficiency equipment. The chief strategy has been to reduce market barriers primarily by offering a rebate to the customer, which reduce the premium price associated with higher efficiency products. The residential offerings include (or have included) the following programs: central and room air conditioners, boilers, furnaces, furnace fan motors, geothermal heat pumps, gas/electric water heaters, dishwashers, clothes washers, compact fluorescent lamps, windows, attic insulation, and custom-designed electric and gas offerings for specific unique needs. The commercial offerings include: lighting, motors, cooling, variable speed drives, geothermal, and custom (a wide range of energy-saving equipment designed specifically to meet unique needs).

5.1.1.2 Results

In 2002, the Minnesota legislature increased utilities' requirement for conservation spending. The state mandated requirement is that each gas and electric utility commit 1.5% of gross electric revenue for conservation programs. The conservation spending must be for projects designed to reduce customers' consumption of electricity and natural gas and to generally improve efficient use of energy resources. The Conserve & Save program at RPU has met the State mandate by investing $1,207,039 in 2002, $1,218,836 in 2003, and $1,257,853 in 2004. That spending achieved savings each year of 3.3 GWh, 5.7 GWh, and 8.2 GWh, respectively as reported to the Minnesota Department of Commerce. The preceding energy savings numbers are not cumulative but rather are the additional savings each year generated by the expenditures each year as required for state reporting purposes.

5.1.2 Demand/Response

5.1.2.1 Interruptible (Commercial and Industrial Interruptible Business PARTNERS)

<u>Interruptible</u>
This program uses either customer-owned generation or customer load interruption to reduce peak demand. The interruption is dispatched by the RPU system operator two hours in advance of the anticipated peak. An incentive rate is provided to the customer for participation.

RPU currently has seven customers with a total of 4,930 KW of potential interruptible service of which 3,255 KW has been committed.

The potential interruptible KW is either the generator capacity or the available load that could be interrupted in a short term emergency. For one particular plant the load is refrigeration or a chiller that can be shut down. A larger load could be interrupted for short periods of time. For others, the generator capacity is much larger than the emergency loads that are served by it.

Business PARTNERS

Commercial load management uses customer defined interruptible time and nameplate data to estimate available kW interruption on an hourly integrated basis. An incentive based on identified load is credited on the customer bill for participation. Communications and control use line carrier signals to load management terminals at the customer premise. Since each of the customer sites and equipment is different, detailed information is not included here but is available.

	Units	kW
Commercial	1	2
Commercial	43	133
Commercial	40	16
Commercial	79	19
	163	170

5.1.2.2 Interruptible (Residential—PARTNERS)

Partners load management provides an incentive credit for allowing RPU to control equipment (A/C and water heaters) at the customer premise. Communications and control use line carrier signals to load management terminals at the customer premise. The demand reduction is based on an estimated load per unit and a control cycle that is conservative.

Residential	Units	kW
A/C	7,813	1,856
1 AC 1 WH	604	246
2 AC	63	24
3 AC	2	1
3 AC 1 WH	1	1
2 AC 1 WH	1	1
WH	335	57
	8,819	2,186

The estimated interruption can be increased by sending a signal that increases the time that units are cycled off. The increase is from about 25% to about 31% off for air conditioner units which make up most of the available interruption on peak.

5.1.2.3 Commercial Time-of-Use Rates

RPU has one customer with a potential of having 400 kW under time of use rates and slightly greater than 280 kW currently operational in this mode.

The potential to interrupt includes two (2) 200 Ton chillers and auxiliaries that can be interrupted for short periods of time. The company uses thermal storage to manage demand and deliver sensible and latent temperature control to their facility. If the thermal storage is used aggressively with both chillers off, the company would require additional demand during the 10 am- 10 pm period to recharge their tanks and to maintain temperature and humidity control.

5.1.3 Conservation Forecasts

Each year the State mandates that RPU spend 1.5 % of its gross electric sales revenue on conservation. Results from a customer survey completed during Phase II of RPU's Infrastructure Plan indicate that customers want more aggressive conservation programs. Many "less than efficient" appliances and other equipment exist in RPU service territory; aggressive DSM helps delay or reduce the need for additional capacity.

For the time period of 2005 through 2015, RPU estimates that with no aggressive DSM program, its required DSM expenditures will be approximately $18,012,802 coupled to an expected energy savings of 85.68 GWH. A plan of aggressive DSM spending is under development that would spend an additional $10,071,356 over the state minimum requirements also thus reducing the required base expenditures because of the lesser energy. This added spending has an added 41.45 GWH of energy saving associated with it. The approximate totals for the planned aggressive DSM spending program from 2005 through 2015 are as follows:

Total DSM Spending =	$28,033,211
Total Expected Energy Savings =	127.13 GWH

5.1.4 Education and Promotion Efforts

To leverage and maximize our efforts in energy conservation, RPU commissioned an appliance and high-efficiency equipment survey in 2002 and an end-use survey in 2004. The results helped establish the Conserve & Save goals. To meet those goals, RPU utilizes the following tactics:

1. Work closely with Southern Minnesota Municipal Power Agency (SMMPA), RPU's wholesale electricity provider.
2. Participate in joint ENERGY STAR efforts with Midwest Energy Efficiency Alliance (MEEA) and Wisconsin Energy Conservation Corporation (WECC).
3. Partner with trade allies to promote ENERGY STAR appliances and other high efficiency equipment.
4. Print and provide point of purchase materials to retailers.
5. Create educational mail stuffers for our customers.
6. Use local advertising channels (e.g. radio, newspapers, and television).
7. Employ a retail support coordinator who serves as the single point of contact between RPU and the trade allies.

5.1.4.1 Events

Events provide the perfect opportunity to educate customers and promote Conserve & Save. RPU participates in several events every year: Rochester Area Builders Inc. Home Show, Olmsted County Fair, Rochester Women's Fall Expo, Rochester Area Chamber of Commerce Business after Hours, Golden Generation Show, RPU sponsored Energy Fair, and other smaller events. These events are opportunities that allow RPU to partner with retailers and contractors to promote various conservation methods, exhibit high-efficiency equipment, share new technologies, and distribute Conserve & Save brochures, applications and give-aways (i.e. ENERGY STAR® Compact Fluorescent Lights), which all promote the Conserve & Save brand.

<u>Arbor Day</u>

Planting trees in our community is a long term investment that provides benefits beyond cost-effective energy savings, and allows RPU to take a civic leadership role in environmental issues, conservation education, and neighborhood revitalization. Beginning in 2003, RPU sponsors an annual Arbor Day Celebration which includes elementary students competing in tree poster contests, partnering with local nurseries in giving away free trees, and providing educational materials outlining the benefits trees provide in reducing the need for space cooling and minimizing urban warming.

ENERGY STAR® *Change A Light, Change The World* Campaign

The *Change A Light, Change The World* national campaign is an EPA-sponsored campaign to reduce energy consumption through replacement of incandescent/standard lighting with energy efficient fluorescent lighting.

The *Change a Light, Change the World* campaign is viewed as an opportunity to promote ENERGY STAR compact fluorescent lights throughout the entire year. Some events include: partnering with specific hardware stores in a summer promotion in all three communities (resulted in savings of 4,524,238 kWh for the three communities), lighting change-outs at the Ronald McDonald House and the Boys and Girls Club in Rochester (combined annual savings of 11,517 watts), teaming up with MEEA & SMMPA for the months of October and November for another hardware store promotion, and printing and distributing approximately 10,000 Conserve & Save rebate coupons (results in approximately 1,497,130 kWh savings).

ENERGY STAR® *Clothes Washer Spring Bonus Promotion*

In 2003 and 2004, from April 15-July 15, the three cities partner with SMMPA and MEEA to promote ENERGY STAR-labeled clothes washers in our service territories. Customers who purchase qualifying clothes washers receive an additional manufacturer's rebate of $25-$50 rebate, bringing their total available rebate to $75-$150. In 2003 and 2004, 451 ENERGY STAR clothes washers were purchased during the promotions. This totaled savings of 16,687 kWh, 3,182,256 gallons of water, and 6,314 CCF of gas. This program may not be offered in 2005 due to the lack of manufacturer participation.

Low Income Programs

RPU's focus is to reduce electrical usage and to educate the low income customer on the benefits of using energy efficient appliances and equipment. Since bills would then be lower, the low income customer's ability to pay would be higher. In Rochester, RPU and Olmsted County Housing & Redevelopment Authority (OCHRA) partnered in 2003 to replace 33 inefficient refrigerators (average annual usage measured over 1400 kWh) with new ENERGY STAR refrigerators (431 kWh/yr) at residences established as low income. The total savings of this project was 33,300 kWh. The customers were also provided with 40 ENERGY STAR CFLs (Compact Fluorescent Light) for each unit, a savings of 3,062 kWh. For 2005, 57 inefficient refrigerators (average usage measured 1000 kWh) are scheduled to be replaced with an ENERGY STAR model (451 kWh/yr). The total 2005 savings will be 32,680 kWh.

5.1.4.2 Education

RPU's year-round program includes educational information as well as incentives for customers to purchase certain ENERGY STAR products and other high efficiency equipment. Conserve & Save promotional materials include ENERGY STAR logos and informational text on all posters, bill stuffers, point-of-purchase displays, rebate applications and coupons, radio and newspaper ads, utility newsletters, web pages, or handouts created for special events like county fairs, open houses, and builder home shows.

5.1.4.2.1 SMMPA seminars, ongoing efforts (bill inserts, advertising, web site), GX seminar

Through SMMPA, RPU invites commercial customers to take accredited classes for lighting technologies, HVAC efficiencies, motors, and more. Presentations on Conserve & Save and the conservation message are given to organizations such as ASHRAE, service clubs, and schools. Beginning in 2005, RPU is sponsoring two Community Education classes for geothermal technology to learn more about the economical and environmental benefits of this heating and cooling technology.

5.1.4.2.2 Trade Ally Relationships

Recognizing that retailers and contractors have a tremendous influence on the purchase habits of customers, RPU and its partner cities created the shared position of retail support coordinator in 2003. This person provides training for the retailers (one-on-one sales training to employees from specific areas, like the lighting department, on the benefits of

ENERGY STAR-qualified products and utility rebate procedures), develops local resources, updates point-of-purchase materials during visits to the stores, and helps the utilities effectively monitor and measure progress in reaching program goals.

In June 2005, RPU and the local natural gas utility partner to offer commercial trade allies an opportunity to learn about program changes and provide input and comments.

5.1.4.2.3 Task Force for Infrastructure Planning

The goal of RPU's Power Supply Study, Phase II, was to focus on renewable energy and demand-side management resources as a piece of our overall power supply for the coming years. A temporary task force, comprised of representatives from the three RPU customer segments and also and industry partner from the gas sector, was created and asked to help measure the effectiveness of RPU's conservation and renewable offerings as well as suggest ideas for potential new offerings. Task Force recommendations included: providing dynamic pricing options, focus more on conservation education, encourage renewable energy participation, provide energy audits at a reasonable rate, and work more with trade allies. RPU has met some of the recommendations, i.e. $25 energy audits and Community Education classes, is implementing a solar program that encourages community support, and is researching various Demand Response programs that incorporate pricing options.

5.1.4.3 Awards

In April 2005, RPU and partners Maier Forest & Tree, Rochester Area Foundation, and Rochester Neighborhood Resources Center, received the "Innovation Award" from the Minnesota Shade Tree Advisory Committee for creating and initiating NeighborWoods, a citizen's forester program.

In December 2003, our three-utility partnership was recognized for its Conserve & Save program as an "exemplary program." This was part of a national awards program to honor America's best natural gas energy efficiency programs by the American Council for an Energy-Efficient Economy (ACEEE), a nonprofit research group based in Washington, D.C.

5.2 Additional Generation

RPU recently released the *Report on the Electric Utility Baseline Strategy for 2005-2030 Electric Infrastructure* prepared by Burns & McDonnell consulting engineers under separate cover. The scope of this report included preparing recommendations for energy supply to serve Rochester Public Utilities electric load through 2030. It contains discussions of both demand side and supply side options and is the most authoritative source for this type of information to date.

The only impact on generation of this report is to call for the early installation of a 50 MW rated combustion turbine, recommended in the above report, ten years earlier than needed to meet generating capacity requirements. This accelerated installation is required to mitigate transmission system reliability shortcomings as documented in the Problem Section of this report.

These transmission needs exist currently and become greater each year exacerbated by continued high load growth and more electric wholesale market activity. The acceleration in time is to mitigate transmission outage risk during the approval process. The transmission risk has also been made more serious by the addition of more and stricter standards regarding transmission operation both here today and forth coming from NERC.

5.3 Research Initiatives

RPU actively participates in research projects to further knowledge and technology in electric energy conservation.

5.3.1 Fuel Cells

The Hybrid Energy System Study (HESS) is a partnership between RPU and the University of Minnesota-Rochester (UMR) that was launched on January 3, 2003. The goal of HESS is to analyze the feasibility of combining a geothermal heat pump and a fuel cell.

The research consists of three phases:

Phase I – To study fuel cell response to variable resistive load monitoring of fuel cell variables. This phase was completed in January of 2004.

Phase II – To integrate a fuel cell system with a geothermal heating system as a hybrid system. This phase is scheduled to be completed sometime in 2007.

Phase III – Will be dependent on the success of Phase II and will evaluate the application of control theory to optimize efficiency of the hybrid system based on current energy prices, using multiple energy sources, like geothermal/fuel cell, natural gas and electric grid, into a residential/commercial energy delivery system. Phase III is scheduled for 2006/2007.

5.3.2 Assisi Wind

From June 2002-May 2003, RPU and the Minnesota Department of Commerce (DOC) partnered in a 12-month feasibility study of the wind at Assisi Heights in northwest Rochester. The study consisted of erecting a test tower equipped with wind information recording equipment. The study showed that this location was not economically viable as a wind turbine site due to lower wind speeds and capacity factors.

5.3.3 Comfort Choice

The three-utility marketing partnership and the local natural gas utility partnered in a residential direct load control pilot project in 2004. This research and development effort targeted a relatively new technology and focused on customers who owned both gas furnaces and central air conditioners. The goals were to measure the savings of different cycling types, customer tolerance and comfort levels, and performance of the technology.

Using a Carrier technology called Comfort Choice, 67 customers received a seven-day programmable thermostat with two-way communications capabilities. Comfort Choice allowed the gas company to control customers' furnaces during critical winter periods and RPU to control the central air conditioners during the summer months. Because of cooler-than-normal temperatures, there were only two electric curtailment (control) days analyzed during the summer of 2004.

The final report supports the conclusion that by using temperature set back and the duty cycle method, load reduction is possible using Comfort Choice. Temperature setback provided the most instantaneous savings but for a shorter duration. This method would be most effective if RPU were nearing a peak energy situation and would need to quickly realize the immediate result of all air conditioners being turned off. The duty cycle method showed savings similar to those RPU achieves with its current load control system. It appears this method would work better for over-all peak reduction (if started early enough) because the units are slowly cycled off as time goes on with the eventual outcome of 50% of the units being off for any given hour.

6.0 BACKGROUND OF THE STUDY

6.1 The Historical Perspective

The last comprehensive study of the Southeast Minnesota area was conducted in the late 1970s with the final report carrying a date of June 1980. The participants were Northern States Power Company (now XCEL), Interstate Power Company (now Alliant West or ALTW), Cooperative Power Association (now GRE), Dairyland Power Cooperative (DPC), Southern Minnesota Municipal Power Agency (SMP) and Rochester Public Utilities (RPU).

The study was commissioned to provide solutions to immediate and near term load service issues in southeast Minnesota and associated transmission needs in the period from 1985 through 2000. A second purpose was to reduce the local area's dependency on oil fired and other older inefficient generation.

The study area was "generally south of the Twin Cities and east of Mankato". The study was partitioned into three relatively distinct transmission system problem areas (Austin-Hayward, Mankato-Kasson and Rochester). The findings and recommendations for the Rochester area are the only ones discussed in this section. The report clearly defined transmission requirements in southeast Minnesota with regard to need and specific facility additions up to 1990. Because of load growth uncertainty the report presented no specific recommendations beyond 1990. However, basic transmission developments discussed were formulated to meet the general area needs through 2000 with a Rochester city load of 283.7 MW.

Only the bulk transmission system developments at 161 kV or greater from the results are listed here. Following is an abbreviated chart of the recommended plan and current status:

1. 1981 Re-conductor 161 kV Alma River Crossing – completed
2. 1982 Construct 161 kV W. Faribault to Owatonna line – completed
3. 1985 Construct 345/161/69 kV Byron Substation – completed
   Construct 161 kV Byron to Cascade Creek line – completed
   Construct 161 kV Byron to Owatonna to Waseca line – completed (Owatonna to Waseca operated at 69 kV)
4. 1986 Assumed 345 kV Adams to La Crosse line – not constructed
5. 1987 Upgrade 161 kV Alma to Wabaco – Reconductored in 2001
   Assumed 345 kV Adams to Mason City – not constructed

6. 1988 Upgrade 161 kV Wabaco to Rochester – 1990
   Increase Minnesota Wisconsin transmission
   capacity in Rochester area – not done

Loads were generally forecast to increase at approximately 5% per year. The area defined as the Rochester Area was somewhat larger than the Rochester area of the current study and was projected to have a 240 MW load in 1985 with Rochester being about 175 MW. The equivalent load today for this area appears to be in the range of 375 MW with Rochester in the range of 270 MW. Rochester was forecast to have a load of 283.7 MW in 2000. Silver Lake #4 (approximately 60 MW) was presumed to be the only available local generation for general use. The Cascade Creek #1 CT (28 MW on oil) was presumed to be available only as a peaking unit and for study work, not generally scheduled online for load service because of cost.

Alternative solutions involved various combinations of the following:

1. 1272 MCM 161 kV line rebuild of Wabaco line (1985)
2. 32.4 MVAR of transmission capacitors (1985 to 1989) – equivalent done
3. Second 161 kV line from Byron to Rochester (1990)
4. 345 kV line Byron to Rochester to Alma (1990)
5. Rebuild Alma to Rochester to Adams 161 kV to 345 kV (1990)
6. Byron to La Crosse 345 kV line (1986) with a Rochester 345/161 kV tap on the east side of Rochester

This study was the basis for the 161 kV additions in southeast Minnesota making the Faribault to Byron to Rochester 161 kV system a reality. The study anticipated further needs in the middle 1980s to 1990. It is noteworthy that the added high voltage development prescribed and found necessary for the later periods has not materialized to support the levels of load observed today. The ability to reasonably support somewhat greater loads in the Rochester area today than the study demonstrated may be partially due to the installation of the RPU 49.9 MW Cascade Creek #2 Combustion Turbine in 2002, the fact that Silver Lake Units 1, 2 and 3 are still in operation, and the completion of upgrades to the Rochester 161 kV transmission system in 2003. None of these three facts were anticipated in the 1970 study as well as the addition of 25MVar of 161kV capacitors in both the Rochester and Maple Leaf Substations.

The study clearly anticipated additional 345 kV development in southeast Minnesota and also specifically recognized the need to enhance the Minnesota/Wisconsin System Interface (MWSI). The study referenced three added 345 kV additions to be necessary in the late 1990s. Those 345kV projects were Adams to La Crosse, Byron to La Crosse and Adams to Mason City. With the exception of the items noted in the above paragraph and on the previous page, there has been no additional new or upgraded transmission facilities constructed or transmission investment in the region. The transmission investments anticipated in the 1994 to 2000 timeframe have not occurred.

6.2 Rochester Area Study History and Participants

The first transmission planning meeting for the Rochester area occurred in June 2002. The meeting was set to document the known and potential deficiencies in the immediate Rochester area so that a study scope could be written for the immediate Rochester area. The area utilities participating in that original meeting were:

1. Xcel Energy
2. Great River Energy
3. Dairyland Power Cooperative
4. Southern Minnesota Municipal Power Agency
5. Rochester Public Utilities

The group met a number of times both in person and via conference calls to refine the scope and then review the study results as the work was completed. The study results are documented in other sections of this report.

6.3 Description of the Rochester Area

Numerous changes in the Rochester system had been completed in the last year before the initial meeting. Those changes consisted of the following upgrades and modifications:

1. A 49.9 MW natural gas or #2 Fuel Oil Combustion Turbine was commissioned in May, 2002 at RPU's Cascade Creek Substation.
2. The conversion of the RPU 115kV system to 161kV was completed in December 2001.
3. The Rochester Silver Lake to Chester Q1 line was rebuilt to 795 ACSR conductor from its previous 477 ACSR conductor.
4. The Rochester Willow Creek to Silver Lake Line was rerouted to Chester Substation from Willow Creek and remained a 556 ACSR conductor line.
5. The DPC Q15 and Q16 lines that connect RPU's Chester Substation to DPC's Rochester substation were partially reconductored from 477 to 954 MCM ACSR. The reconductor was completed in the fall of 2002.
6. The Cascade Creek – Crosstown – Silver Lake lines were upgraded from single 556 ACSR to parallel 556 MCM ACSR with 954 MCM ACSR drops on the last structure into each substation.

7. The SMMPA control area metering CT's in DPC's Rochester Area Substation were changed to 800:5 from 400:5.
8. The RPU Chester substation was converted into a ring bus with the addition of two new SF6 breakers.
9. Xcel Energy added (3) 60 MVAR capacitors in the Byron 161 kV yard during June 2002.
10. With the addition of the new combustion turbine, the available generation in Rochester was raised to 181 MW:

    a. Silver Lake Coal Units 1 through 4 102 MW
    b. Cascade Creek CombTurbine #1 27 MW summer
    c. Cascade Creek Comb Turbine #2 50 MW (summer & winter)
    d. Zumbro River Hydro 2 MW

The load in the Rochester area consists of approximately 263 MW of RPU load and approximately 43.5 MW of People's Cooperative Service load. Both loads are summer peaking, making the Rochester area approximately a 300 MW load at summer peak. The load in the area has consistently grown at a rate of approximately 3.7% for the last decade or more.

6.4 Rochester Area Study Scope

Known problems in the Rochester area were identified as follows:

1. Byron-Maple Leaf-Cascade Creek 161kV line overloads for loss of the Byron-Pleasant Valley 345 kV line.
2. Loading on the 161 kV Rochester-Adams line
3. Loading in the area and the need for a new source to Rochester especially under contingency conditions. The worst contingency was expected to be loss of the Byron-Maple Leaf-Cascade Creek 161kV line.

The following items were noted about the Rochester area and the facilities immediately adjacent to it relative to study conditions:

1. The area has changed significantly since the solution of previous problems with transient voltage stability that occurred in approximately 1990.
2. The maximum transfer level on the 345 kV system were identified as follows:

    a. Between Prairie Island 345 and Byron 345 is 779 MW during off-peak operation.
    b. Between Eau Claire 345 and Arpin 345 is 790 MW (measured at Eau Claire) during off-peak operation.
    c. Minnesota Wisconsin Stability Interface (MWSI) limit is 1480 MW during off-peak operation.

3. The primary limitation for the MWSI is the loss of the Prairie Island-Byron 345 line.
4. A West Owatonna to Hayward 161 line was studied during the Pleasant Valley Generation studies completed by GRE in order to mitigate loss of the Byron-Adams 345.
5. Pleasant Valley Station was designed for an additional 345 kV to 161 kV transformer.
6. Tapping the Adams-Rochester 161 line into Pleasant Valley was discussed. This line would not bring an additional source into the Rochester load area so it was not considered since it would not solve the problem.
7. The People's Cooperative Service (PCS) 69 kV line from their Rochester Airport Substation to the Pleasant Valley Substation was scheduled to be rebuilt in the fairly near future. A double circuit 69 kV – 161 kV line utilizing the existing 69 kV right-of-way was discussed. RPU stated they were willing to be on a double circuit with PCS.
8. The 2003 series of the MAPP models were used for the study. The 2002 models were utilized and comparisons made for changes within a 150 mile radius of Rochester in the 2003 models. The most critical cases were investigated utilizing the 2003 models.
9. The loads were to be scaled up to study the out years. The MAPP 2004, 2007 and 2012 models were not used due to the uncertainty of the out-year projects shown in the models.
10. The models were manually stressed to study the affect on MWSI during peak periods. The cases were manually stressed with both a south and east bias.
11. DPC's Genoa 3 unit was the generator utilized to show variations in area generation. DPC's JP Madgett unit was also varied to perform a sensitivity analysis.

The transmission alternatives studied were the following:

1. Add a new Byron to Pleasant Valley 345 kV line routed around the eastern edge of Rochester, with a 345/161 kV interconnection on the eastern border of Rochester.

2. Byron to DPC Rochester 345 kV line, with a 161 kV line from DPC Rochester to Pleasant Valley.

3. Prairie Island to Adams 345 kV line, with a 345/161 kV interconnection on the eastern border of Rochester.

4. Prairie Island to Quarry Hill 161 kV line.

5. Prairie Island to Frontenac to Alma 161 kV line, with a 161 kV line from Frontenac to Quarry Hill.

6. Pleasant Valley to Quarry Hill 161 kV line.

The goal of the study was to add an additional energy source to the Rochester Area such as additional 345 and/or 161 kV ties from the North (Spring Creek, Frontenac, etc) and/or South (Pleasant Valley). After the options were reduced to the best performing options, a complete contingency analysis was performed. The best performing options were also studied to show their effects on the Constrained Interfaces in the MAPP system.

6.5 La Crosse Area 161 kV Study Scope

During the same time that the Rochester Area study work was being analyzed, Dairyland Power Cooperative (DPC) was performing a study of the La Crosse area transmission system. The purpose of the DPC study was to evaluate the long term load serving requirements of the transmission system serving La Crosse, Wisconsin.

A serious outage for the La Crosse area is the loss of Genoa-La Crosse Tap-Marshland 161 kV which causes the overload of the Genoa-Coulee 161 kV line. Another significant fact is that the Genoa-Alma 161 kV line, the first 161kV line built by DPC, is nearing the end of its useful life. This study was a subset of the SE Minnesota/SW Wisconsin study led by RPU.

Correcting the Genoa-Coulee 161 kV overload is a MAPP Design Review Subcommittee requirement for approval of the 164 MW power transfer from Wisconsin Public Service (WPS) to DPC beginning in 2008. In parallel to this study, DPC, Xcel, and American Transmission Company (ATC) were doing a study of the Tomah, Wisconsin area. The primary alternative to enhancing load-serving capability to Tomah is a new 161 kV line from Monroe County to Council Creek (Tomah) and a 161-138 kV transformer at Council Creek. All alternatives examined to address La Crosse area load-serving issues will include a sensitivity to the Monroe County to Council Creek facility to ensure that the plans are properly coordinated.

6.5.1 Study Area

The study area is bounded by the 161 kV transmission system connected to the La Crosse area; which includes the following substations: Alma, Tremval, Monroe County, Genoa, and Harmony. The monitored systems include DPC, XCEL, Alliant East (ALTE) and Alliant West (ALTW).

6.5.2 Study Participants

This study was led by DPC with primary input from Xcel and secondary input from ATC and ALTW. Xcel serves the majority of the load in the La Crosse-Winona areas and DPC operates the majority of the transmission. ATC and ALTW are on the periphery and, thus, had limited involvement.

6.5.3 La Crosse Area Study Steps

1. Utilize the same 2009 models of the SE MN/SW WI RPU study.

2. Verify modeling of the La Crosse area and make necessary modifications. Report any corrections to RPU. The following items were verified:

    - Chisago to Apple River 115 & 161 modeling.
    - Arrowhead to Weston 345 modeling.
    - Pleasant Valley Station to Austin 161 kV line modeling.
    - Verify the generation schedules of the Pleasant Valley Station and Rochester generation are reasonable and proper.
    - Verify northern Wisconsin Hydro output at 50% of maximum.
    - Verify modeling of the Harmony – Decorah Area (N-8 rebuild and the Waukon Capacitor)
    - Verify Wheaton generation use (model in summer case only).
    - Model the Stoneman plant on-line in the peak case and off-line in the off-peak case.
    - Review DPC generation dispatch. Use Elk Mound generation for DPC spinning reserves (25 MW).
    - Other miscellaneous items for verification phase shifter, future caps, etc.
    - Verify French Island generation on-line is only the Refuse Derived Fuelplant

1. Identify approximate remaining life of the Alma-Marshland-La Crosse-Genoa (Q-1) and Genoa-Coulee (Q-11) 161 kV lines.

2. Perform ACCC analysis of the base case.

3. Identify alternatives and test with ACCC.

4. Check sensitivity to WPS-DPC transfer.

5. Identify R-O-W and construction costs paying particular attention to areas where terrain and land use would cause higher expenditures than average unit costs.

6. Perform economic analysis of alternatives and determine the optimum La Crosse area load serving long-range plan.

7. Select a preferred plan.

8. Perform a construction study with the input of DPC transmission security engineers and XCEL Energy. Recommend a construction sequence and document all findings in a written report.

6.6 Regional Study Basis

Once the results of the Rochester and La Crosse area studies were reviewed and in preliminary form, construction cost estimates were completed for the options that solved the problems for each area. After preliminary economic analysis was completed, the group decided that a more regional 345 solution routed through both Rochester and La Crosse may form the basis for a much better long term solution than two individual 161 kV solutions.

6.7 Regional Study Participants

The group was expanded to include representatives from Alliant West representing the northern Iowa area and American Transmission Company representing Wisconsin transmission interests. The entire list of participants is shown below:

1. Xcel Energy
2. Dairyland Power Cooperative
3. Southern Minnesota Municipal Power Agency
4. Rochester Public Utilities
5. Great River Energy
6. American Transmission Company
7. Alliant Energy

6.8 Regional Study Scope

A regional study scope and options were defined as detailed below:

1. The transmission deficiencies in the Southeastern Minnesota and Southwestern Wisconsin regions were documented:

a. MWSI limitation – Increase by 100, 500 and 1000 MW
   - Study the impact of the MWSI increase on Eau Claire to Arpin 345 kV Line, Prairie Island to Byron 345 kV line, and the Quad Cities Area.

b. Low voltage affecting Red Wing/Hastings/Lake City.
c. Load Service in Rochester Area.
d. Overload/Congestion on the Byron to Cascade Creek 161kV line for loss of the Byron to Pleasant Valley 345 kV line.
e. Load Service in the La Crosse area.
f. Overload/Congestion on the Genoa to Coulee 161 kV line.
g. Transformer overloads at Adams and Hazelton for Contingencies on the Byron to Arnold 345 kV line?
h. Overload/Congestion Southwestern Wisconsin 161 kV System
i. Any issues that develop from the baseline ACCC review.

2. Determine possible SE MN and SW WI regional transmission solutions
   a. Prairie Island to La Crosse to Genoa to Salem 345 kV line
   b. Prairie Island to La Crosse to Genoa to ATC System
   c. Prairie Island to Rochester to La Crosse to ATC System
   d. Prairie Island to Adams to La Crosse to ATC System
   e. Other possible transmission additions to be analyzed to mitigate the deficiencies in 1.)

3. The RPU load serving study found benefits for the deficiencies in the Rochester Area (1a, 1c, and 1d) using the proposed transmission additions 3a – 3d below. These proposed lines or their derivatives were to be used as a subset of the larger region's solutions listed in 2.) to address the deficiencies not resolved by the larger regional solution in the SE MN region.
   a. Prairie Island to Adams 345 kV line.
   b. Prairie Island to Alma 161 kV line with a 161 kV tap to Quarry Hill Sub (RPU).
   c. Prairie Island to Quarry Hill (RPU) 161 kV line plus a Byron to Northern Hills (RPU) 161 kV line
   d. Pleasant Valley to Quarry Hill (RPU) 161 kV line plus a Byron to Northern Hills (RPU) 161 kV line.

4. A baseline ACCC, Load Flow, voltage profile, and stability analyses of the existing transmission system in SE MN and SW WI were performed. These analyses were used to validate the model and be the baseline to evaluate and quantify the improvements resulting from the transmission additions listed in 2.) The models used for this analysis were:
   a. 2009 summer peak
   b. 2009 summer off-peak high transfer

5. Perform the ACCC analysis for all proposed transmission lines listed in item 2 above. Sensitivity analyses were performed for all significant proposed local generation additions.

6. Perform Voltage, Transient, and Small Signal Stability analyses for all proposed transmission lines evaluated including sensitivity analyses for all significant proposed local generation additions.

7. The Arrowhead to Weston 345 kV line was added into the study models.

8. The Sioux Falls to Lakefield 345 kV line was added to the study models.

7.0 ROCHESTER LOCAL AREA STUDY

The Rochester Local Area Load Serving Study was initiated in June, 2002 to identify, study, and evaluate potential transmission additions to mitigate the load service inadequacies in the Rochester, MN area. The Rochester area local load serving problems are explained in more detail in the "Statement of the Problem" section of this document. The study scope is detailed as "Rochester Area Study Scope" in the "Background of the Study" section.

Due to the predominating west to east flow pattern, the basic transmission additions studied were assumed to interconnect on the eastern edge of the City of Rochester at either the planned new Quarry Hill Substation or the existing Chester Substation. The only exception being mitigation for added problems created by the additions studied. This placement would relieve, rather than exacerbate, the predominant west to east flows on the transmission lines in Rochester. This east side connection provides the most efficient connection to the existing Rochester Area 161 kV facilities of RPU and DPC as well as the DPC 69 kV system.

Since 161 kV and 345 kV are the predominant transmission voltages in the Rochester area, the transmission additions considered are either 161 kV or 345 kV options. Both voltage levels are considered to attain the most cost effective solution for the area. The power flow studies document the n-1 contingency system impact with respect to line overload and voltage support each proposed transmission facility addition has on the bulk transmission system in Southeast Minnesota and Southwest Wisconsin.

7.1 Transmission Options Evaluated

The initial Rochester local area study evaluated a total of six options, three 345 kV options and three 161 kV options as listed below. See Appendix A for a map of these options.

Option 1 - New Byron to Pleasant Valley 345 kV line routed around the eastern edge of Rochester, with a 345/161 kV interconnection on the eastern border of Rochester (byrtopv345_rsttap).

Option 2 - Byron to DPC Rochester 345 kV line, with a 161 kV line from DPC Rochester to Pleasant Valley (byrtorst345_rsttopv161).

Option 3 - Prairie Island to Adams 345 kV line, with a 345/161 kV interconnection on the eastern border of Rochester (pitoad345_rsttap).

Option 4 - Prairie Island to Quarry Hill 161 kV line, Byron to Northern Hills 161 kV line added later as discussed below (Pitoes).

Option 5 - Prairie Island to Frontenac to Alma 161 kV line, with a 161 kV line from Frontenac to Quarry Hill, Byron to Northern Hills161 kV line added later as discussed below (pitofrtoalma_frtoes).

Option 6 - Pleasant Valley to Quarry Hill 161 kV line, Byron to Northern Hills 161 kV line added later as discussed below (pvtoes_byrtonh).

Table 7.1 – Transmission Addition Options

During the course of the power flow contingency analysis it was discovered that for the summer-off peak high transfer cases, the addition of any 161 kV transmission line into Rochester (Options 4, 5, and 6 in Table 7.1) did not mitigate the overload on the Byron to Maple Leaf 161 kV line or, in the case of Option 6, the overload was magnified for the multiple tripping contingency of Byron to Pleasant Valley 345 kV line, plus the Pleasant Valley to Adams 345 kV line, plus the Adams 345/161 kV transformer. To mitigate this inadequacy, the Byron to Northern Hills 161 kV line was added to Options 4, 5, and 6.

7.2 Model Development

The Rochester local area study utilized the 2003 summer peak, 2003 summer off-peak, 2007 summer peak, and 2007 summer off-peak models from the Mid-Continent Area Power Pool (MAPP) 2002 series of published power flow models. The base case models were provided by XCEL Energy. The summer off-peak models were modified by XCEL Energy to represent cases where the North Dakota Export (NDEX), Manitoba Hydro Export (MHEX), and Minnesota-Wisconsin System Interface (MWSI) were set to their respective maximums.

During the construction of the summer off-peak high transfer power flow models for each transmission alternative, the generation, load, and area interchange values in the Twin Cities, St. Louis, Kansas City, Chicago, and Milwaukee areas were adjusted to keep all of the export limits at their respective maximums prior to the contingency analysis. The resulting exports levels for all study alternatives are documented in Table 7.2 below. To create the worst case Rochester Area load serving model all local Rochester area generation was turned off in the summer off-peak high transfer cases. This included all RPU generation, GRE's Pleasant Valley Generation, and Dairyland Power's potential 415 MW brown field generation upgrade at Alma. A complete list of the study area generation can be found in Appendix A.

F03suop Export Summaries for the Rochester Area Transmission Planning Study
Without Pleasant Valley Generation

Case Filename	NDEX	MHEX	MWSI	PI to Byron	Notes
Base case (nonewlines)	1950	2214	1481	800	
byrtopv345_rsttap	1951	2208	1481	801	
byrtorst345_rsttopv161	1951	2208	1482	801	
pitoad345_rsttap	1950	2212	1480	387	(PI to Byr + PI to DPC/RST345 = 799.9)
Pitoes	1953	2210	1481	801	
pitofrtoalma_frtoes	1952	2210	1481	801	
Pvtoes	1951	2211	1482	801	
pvtoes_byrtonh	1951	2210	1481	801	
Operational Limits	1950	2175	1480	800	

Table 7.2 Export Criteria

From these base case models, additional changes were made by study participants to their representative systems throughout the course of the study. The list of changes made is as follows:

1. Added Quarry Hill Substation into the RPU System between Silver Lake and DPC Rochester for all 2003 and 2007 models.

2. Changed all the 69 kV lines in SE Minnesota to reside in Zone 100 to ease ACCC monitoring activities for all 2003 and 2007 models.

3. Upgraded the Rate A limit on the Dickenson to St. Boni, St. Boni to Waconia, and the Waconia to Carver County 115 kV lines, southwest of the Twin Cities, to 192 MW for all 2003 and 2007 models.

4. Included the Harvey to Glenboro 230 kV line in central North Dakota in all 2003 and 2007 models and added its flow into the MHEX.

5. Upgraded the Rate A limit on the Austin to Pleasant Valley 161 kV line to 446 MW for all 2003 and 2007 models.

6. Changed the generator voltage schedules for the Silver Lake and Cascade Creek generation plants in the RPU system to 1.0227 and 1.0224 respectively to eliminate the incorrect high flow of VARs through Rochester in all 2003 and 2007 models.

7. Added the proposed 415 MW Alma brown field generating plant upgrade and the localized 161 kV system changes at Alma and North La Crosse to the 2007 models only as requested by DPC.

8. Upgraded the Rate A limit on the Alma to Utica 69 kV lines to 86 MW for the 2007 models only.

9. Added the 300 MW Rice County Peaking Unit and surrounding 161 kV line changes between W. Faribault and Lake Marion to the 2007 Summer Peak model only, as requested by XCEL Energy.

10. Increase the XCEL load by 10% in Southern Minnesota Zone 607 in the 2007 Summer Peak model only at the request of XCEL Energy.

7.3 System Analysis

Power flow contingency analysis was used to screen and compare the proposed alternatives to the existing system in determining the system impact of each transmission option. Each contingency screen was evaluated and documented based on the following.

1. Any and all line overloads that were either mitigated or created due to the addition of each proposed line when compared to the existing system.
2. Any existing line overloads that changed ± 2% due to the addition of each proposed line when compared to the existing system.
3. Any and all bus voltage violations that were either mitigated or created due to the addition of each proposed line when compared to the existing system.
4. Any existing bus voltage violation that changed ± 2% due to the addition of each proposed line when compared to the existing system.

The study area included in the contingency monitoring process consisted of the transmission and generating facilities inside the boundary created by the following:

1. XCEL Energy facilities from the Twin Cities south and east in Minnesota as well as Wisconsin facilities from the Eau Claire Area south.
2. Alliant Energy facilities in Southeast Minnesota and Northern Iowa.
3. MEC facilities in Northern Iowa.
4. All Dairyland Power facilities in Minnesota, Wisconsin, Iowa, and Illinois
5. GRE facilities in Southeast Minnesota
6. SMMPA facilities in Southeast Minnesota
7. All RPU facilities

For contingency monitoring, all lines 115 kV and above were included for the study footprint described with the addition of all Dairyland facilities at

69 kV. The acceptable voltage range used for this study was 1.08 to 0.92 per unit for all load serving and non-load serving buses. A single contingency analysis where each line 161 kV or above is removed from service, one at a time, was performed on the study footprint. Contingency analysis also included analysis of all multiple tripping schemes provided by the study participants for their respective systems. The line overload limit used for this study was 100% of Rate A, the maximum normal rating of the facility. The complete contingency analysis output and system files are included in Appendix A.

7.4 Best Performing 161 kV Option

The result of the contingency analysis, coupled with the economic analysis discussed in the "Initial Rochester Local Area Results" section of this document identified the best performing option to be the Pleasant Valley to Quarry Hill 161 kV line in combination with the Byron to Northern Hills 161 kV line (Option 6 modified). Option 6 provided the most positive system impact by only removing contingency overloads that appear in the existing system from the bulk transmission study footprint for all the study models. Likewise, the addition of Option 6 only reduced other existing overloads that were not completely mitigated for both the 2003 and 2007 Summer Peak models. For the 2003 and 2007 Summer Off-Peak High Transfer models, all of the existing contingency overloads exceeding the ±2% criteria were reduced with one exception. The Byron 345/161 kV transformer overloads for a transfer tripping fault on the Byron to Pleasant Valley 345 kV line which also trips the Pleasant Valley to Adams 345 kV line and the Adams 345/161 kV transformer. This problem is exacerbated approximately 10% in the 2003 and 2007 model. This overload can be mitigated with the addition of a second Byron 345/161 kV transformer.

7.5 Best Performing 345 kV Option

If just the three 345 kV line options were evaluated based upon system impact and economic analysis considerations, the best performing 345 kV line option was the new Byron to Pleasant Valley 345 kV line routed around the eastern edge of Rochester, with a 345/161 kV interconnection on the eastern border of Rochester (Option 1). Option 1 yielded the best performance based on system impact and performance in the study footprint. It did not create any new line overloads under contingency conditions and only mitigated contingency overloads that appeared in the existing system for all study models. It also reduced all existing contingency overloads exceeding the ±2% documentation criteria for all study models.

8.0 INITIAL ROCHESTER AREA STUDY RESULTS

After the initial power flow studies were completed, estimates of the costs for each option were developed. Due to the wide range of routes and options studied, detailed cost estimates could not be cost justified for all options studied. Therefore, estimating rules of thumb were employed in order to assign an approximate cost to each individual option. This allowed some overall conclusions to be made regarding the relative value of each option based on economic analysis.

8.1 Estimating Amounts Used

The estimates were developed using the costs shown in the following table. The costs were planned so that a building block approach could be used to develop comparative costs for the various options involving different voltages.

$861,000	Cost per mile for 345 kV Line
$375,000	Cost per mile for 161 kV Line
$1,100,000	Cost per 345 Ring Bus Bay at an existing 345 site
$600,000	Cost per 161 Ring Bus Bay at an existing 161 site
$1,500,000	Adder for a 345 Substation at a nonexistent site
$1,000,000	Adder for a 161 Substation at a nonexistent site
$1,500,000	345/161 Transformer rated 240/320/400/448 - 55/65 - FOFA
$1,500,000	Additional 345/161 Transformer at Prairie island

Table 8.1

8.2 Costs of Individual Options

Using the costs from Table 8.1, the estimated costs of each of the options are listed below:

Option Studied		**Cost in $1,000's**
1.	Byron to Pleasant Valley 345 kV	$58,100
2.	Byron to Rochester 345 kV and Rochester to Pleasant Valley 161 kV	$43,500
3.	Prairie Island to Adams 345 kV	$79,200
4.	Prairie Island to Quarry Hill 161 kV and Byron to Northern Hills 161 kV	$26,675
5.	Prairie Island to Frontenac to Alma 161 kV, Frontenac to Quarry Hill 161 kV, Byron to Northern Hills 161 kV	$45,200
6.	Pleasant Valley to Quarry Hill 161 and Byron to Northern Hills 161 with the addition of a 2nd Byron 345-161 kV transformer.	$23,000

The detailed estimates for each of the options are shown below in Tables 8.2 through 8.7.

Byron to Pleasant Valley 345	
$21,525,000	25 Miles of 345 from Byron to Rochester Sub
$24,108,000	28 Miles of 345 from Rochester to PV sub
$37,500	0.1 Miles of 161 from Chester2 to Chester 161
$1,500,000	4 Miles of 161 from Chester2 to Quarry Hill
	Byron 345 Sub Expansion Cost
$1,100,000	1 - 345 Ring Bus Bay on existing site (1 new line out)
	Rochester 345 Sub Expansion Cost
$3,300,000	3 - 345 Ring Bus Bays on non-existing site (2 new lines out, 1 new 345/161 transformer)
$1,200,000	2 - 161 Ring Bus Bay on non-existing site (1 new line out to QH, 1 new 345/161 transformer)
$1,500,000	1 - 345/161 240/320/400/448 Transformer
$1,500,000	Adder for a 345 Substation at a nonexistent site
	Chester 161 Sub Cost
$600,000	1 - 161 Ring Bus Bays on existent site (1 new line in)
	Quarry Hill 161 Sub Cost
$600,000	1 - 161 Ring Bus Bays on existent site (1 new line in)
	Pleasant Valley 345 Sub Expansion Cost
$1,100,000	1 - 345 Ring Bus Bay on existing site (1 new line out)
$58,070,500	**Total Estimated Cost**

Table 8.2

Byron to Rochester 345, Rochester to Pleasant Valley 161

$21,525,000	25 Miles of 345 from Byron to Rochester Sub
$10,500,000	28 Miles of 161 from Rochester to PV sub
$37,500	0.1 Miles of 161 from Chester2 to Chester 161
$1,500,000	4 Miles of 161 from Chester2 to Quarry Hill
	Byron 345 Sub Expansion Cost
$1,100,000	1 - 345 Ring Bus Bay on existing site (1 new line out)
	Rochester 345 Sub Expansion Cost
$2,200,000	2 - 345 Ring Bus Bays on non-existing site (1 new lines in, 1 new 345/161 transformer)
$1,800,000	3 - 161 Ring Bus Bay on non-existing site (2 new lines out to QH & PV161, 1 new 345/161 transformer)
$1,500,000	1 - 345/161 240/320/400/448 Transformer
$1,500,000	Adder for a 345 Substation at a nonexistent site
	Chester 161 Sub Cost
$600,000	1 - 161 Ring Bus Bays on existent site (1 new line in)
	Quarry Hill 161 Sub Cost
$600,000	1 - 161 Ring Bus Bays on existent site (1 new line in)
	Pleasant Valley 345 Sub Expansion Cost
$600,000	1 - 161 Ring Bus Bay on existing site (1 new line out)
$43,462,500	**Total Estimated Cost**

Table 8.3

Prairie Island to Adams 345

$32,718,000	38 Miles of 345 from PI to Rochester Sub
$33,579,000	39 Miles of 345 from Rochester to Adams sub
$37,500	0.1 Miles of 161 from Chester2 to Chester 161
$1,500,000	4 Miles of 161 from Chester2 to Quarry Hill
	PI 345 Sub Expansion Cost
$1,100,000	1 - 345 Ring Bus Bay on existing site (1 New line out)
$500,000	Project Coordination/Interface Cost with XCEL
	Rochester 345 Sub Expansion Cost
$3,300,000	3 - 345 Ring Bus Bays on non-existing site (2 new lines out, 1 new 345/161 transformer)
$1,200,000	2 - 161 Ring Bus Bay on non-existing site (1 new line out to QH, 1 new 345/161 transformer)
$1,500,000	1 - 345/161 240/320/400/448 Transformer
$1,500,000	Adder for a 345 Substation at a nonexistent site
	Chester 161 Sub Cost
$600,000	1 - 161 Ring Bus Bays on existent site (1 new line in)
	Quarry Hill 161 Sub Cost
$600,000	1 - 161 Ring Bus Bays on existent site (1 new line in)
	Adams 345 Sub Expansion Cost
$1,100,000	1 - 161 Ring Bus Bay on existing site (1 new line out)
$79,234,500	**Total Estimated Cost**

Table 8.4

Prairie Island to Quarry Hill 161, Byron to Northern Hills 161

$14,250,000	38 Miles of 161 from PI to Quarry Hill Sub
$4,125,000	11 Miles of 161 from Byron to Northern Hills Sub
	PI 161 Sub Expansion Cost
$1,100,000	1 - 345 Ring Bus Bay on existing site (1 new 345/161 transformer)
$1,200,000	2 - 161 Ring Bus Bay on existing site (1 new line out, 1 new 345/161 transformer)
$1,500,000	Cost for additional 345/161 Transformer at PI 345
$1,000,000	Modifications to Existing PI sub and Adder for Local PI Considerations/Issues
$1,200,000	Cost for ring bus bay and modifications required for second transformer
	Quarry Hill 161 Sub Cost
$600,000	1 - 161 Ring Bus Bays on existent site (1 new line in)
	Northern Hills 161 Sub Expansion Cost
$600,000	1 - 161 Ring Bus Bay on existing site (1 new line out)
	Byron 161 Sub Expansion Cost
$600,000	1 - 161 Ring Bus Bay on existing site (1 new line in)
$500,000	Project Coordination/Interface Cost
$26,675,000	**Total Estimated Cost**

Table 8.5

Prairie Island to Frontenac to Alma, Frontenac to Quarry Hill 161, Byron to N. Hills 161

$6,375,000	17 Miles of 161 from PI to Frontenac Sub
$10,875,000	29 Miles of 161 from Frontenac to Alma Sub
$11,625,000	31 Miles of 161 from Frontenac to Quarry Hill Sub
$4,125,000	11 Miles of 161 from Byron to Northern Hills Sub
	PI 161 Sub Expansion Cost
$1,100,000	1 - 345 Ring Bus Bay on existing site (1 new 345/161 transformer)
$1,200,000	2 - 161 Ring Bus Bay on existing site (1 new line out, 1 new 345/161 transformer)
$1,500,000	Cost for additional 345/161 Transformer at PI 345
$1,000,000	Modifications to Existing PI sub and Adder for Local PI Considerations/Issues
$1,200,000	Cost for ring bus bay and modifications required for second transformer
	Quarry Hill 161 Sub Cost
$600,000	1 - 161 Ring Bus Bays on existent site (1 new line in)
$500,000	Project Coordination/Interface Cost with XCEL
	Frontenac 161 Sub Cost
$1,800,000	3 - 161 Ring Bus Bays on non-existent site (3 new lines in)
$1,000,000	Adder for a 161 Substation at a nonexistent site
	Alma 161 Sub Expansion Cost
$600,000	1 - 161 Ring Bus Bay on existing site (1 new line out)
$500,000	Project Coordination/Interface Cost with DPC
	Northern Hills 161 Sub Expansion Cost
$600,000	1 - 161 Ring Bus Bay on existing site (1 new line out)
	Byron 161 Sub Expansion Cost
$600,000	1 - 161 Ring Bus Bay on existing site (1 new line in)
$500,000	Project Coordination/Interface Cost with XCEL
$45,200,000	**Total Estimated Cost**
$25,475,000	**RPU Estimated Portion**
$18,025,000	**XCEL/DPC Estimated Portion**

Table 8.6

Pleasant Valley to Quarry Hill, Byron to Northern Hills 161 with Transformer Addition

$12,375,000	33 Miles of 161 from PV to Quarry Hill Sub
$4,500,000	12 Miles of 161 from Byron to Northern Hills Sub
	PV 161 Sub Expansion Cost
$600,000	1 – 161 Ring Bus Bay on existing site (1 new line out)
$500,000	Project Coordination/Interface Cost with GRE
	Quarry Hill 161 Sub Cost
$600,000	1 – 161 Ring Bus Bays on non-existent site (1 new line in)
	Northern Hills 161 Sub Expansion Cost
$600,000	1 – 161 Ring Bus Bay on existing site (1 new line out)
	Byron 161 Sub Expansion Cost
$600,000	1 – 161 Ring Bus Bay on existing site (1 new line in)
$500,000	Project Coordination/Interface Cost with XCEL
$1,500,000	Cost per 345/161 Transformer rated 240/320/400/448 – 55/65 – FOFA
$1,200,000	Cost for ring bus bay and modifications required for second transformer
$22,975,000	**Total Estimated Cost**

Table 8.7

8.3 Future Performance of the Options

All of the options solved the immediate load serving problems in the Rochester area and did not diminish the performance of any other transmission lines in the region. To economically evaluate the performance of the solutions, estimates were developed of how far into the future each option would meet the local area supply needs using the following methodology:

8.3.1 Assumptions

Rochester area load was escalated by 3.5% per year based on the 2007 summer peak model. The loads in the rest of the system were maintained at their levels as represented in the 2007 summer peak case. Silver Lake plant was on-line generating 50 MW and the Byron-Maple Leaf 161 line was out of service as a prior outage. The Rochester Area load above the 216 MW Contract Rate of

Delivery (CROD) level was imported from the following sources; 50% from the north in Minnesota (Sherco, Monticello and Boswell), 30% from Chicago/Wisconsin (east), and 20% from St. Louis (south). The Rochester area was the monitored zone in all cases.

A search was conducted to determine what the worst common contingency was for the set of options that were studied. It was determined that two critical outages needed to analyzed. The first was the unscheduled loss of the Wabaco to Rochester 161 kV line. The other critical outage for the 161 kV options was the loss of the Byron 345 kV to 161 kV transformer. Since the remaining west 161 kV line into the Byron substation provides very little support for the 161 kV system east of Byron with the Byron 345 kV to 161 kV transformer out of service, the low voltage on the 161 kV system in the Rochester area causes significant outages and the local system is unable to sustain the load. This makes the Byron Transformer outage a critical single point of failure.

Both conditions are an n-2 situation or prior outage with an unscheduled failure case. The area was analyzed at the n-2 level to attain reasonably economically comparable results for all alternatives. Under any less stress condition, the 345 lines were adequately robust to sustain the Rochester area so far into the future that additional assumptions of multiple new 161kV lines being constructed at different times in the distant future become unnecessary. The n-2 criteria forced the earliest failure of the 345 kV options and therefore allowed the time difference between 161 and 345 options to be as short as possible. This permitted the assumption of construction of only one additional 161kV line, thus minimizing the error in our assumptions. The following sections detail the failure mode of each option.

8.4 Performance of the Options

With no new transmission lines, the existing system was unable to sustain load in 2007 due to an overload of the Adams to Rochester 161 kV line for loss of the Wabaco to Rochester 161kV line with a prior outage of the Byron-Maple Leaf 161 kV line. The Rochester area load in 2007 was 331 MW.

8.4.1 Option 1 - Byron to Pleasant Valley 345

With the Byron to Pleasant Valley 345 line the Rochester system was unable to sustain load in 2051. The overloaded line was within the Rochester system. The transmission system did not fail to supply the load in the Rochester area. The load in the Rochester area was 1504.9 MW.

8.4.2 Option 2 – Byron to Rochester 345 and Rochester to Pleasant Valley 161

The Byron to Rochester 345 and Rochester to Pleasant Valley 161 option was also able to sustain load in the Rochester system until 2051. The overloaded line was again within the Rochester system with the transmission system not failing to supply the load to the Rochester area. The load in the Rochester area was again 1504.9 MW.

8.4.3 Option 3 - Prairie Island to Adams 345

The Prairie Island to Adams 345 option was also able to sustain load in the Rochester system until 2051. The overloaded line was again within the Rochester system with the regional transmission system not failing to supply the load to the Rochester area. The load in the Rochester area was again1504.9 MW.

8.4.4 Option 4 - Prairie Island to Quarry Hill 161 and Byron to Northern Hills 161

This option was unable to sustain load in 2027 when the Byron to Northern Hills 161 kV line overloads on peak. The 2027 date is achievable only if the reconductor of the Adams to Rochester 161 kV line is completed in 2023. The load in the Rochester Area was 659 MW in 2027.

8.4.5 Option 5 - Prairie Island to Frontenac to Alma 161, Frontenac to Quarry Hill 161 and Byron to Northern Hills 161

This option had the same success as Option 4 in that it was unable to sustain load in 2027 when the Byron to Northern Hills line overloads on peak. The 2027 date is again achievable only if the reconductor of the Adams to Rochester 161 kV line is completed in 2022. The load in the Rochester Area was again 659 MW.

With the second critical outage, the outage of the Byron 345 to 161 kV transformer, this option was unable to sustain the load in 2028. The 2028 date is again achievable only if the Adams to Rochester line was reconductored in 2023. The year of failure was very close for both critical outages.

8.4.6 Option 6 - Pleasant Valley to Quarry Hill 161kV and Byron to Northern Hills 161 kV with the addition of a 2nd Byron 345-161kV transformer.

Under the first critical outage, this option was unable to sustain load in the Rochester area in 2033 due to the overload of the Pleasant

Valley to Quarry Hill 161 kV line. The load in the Rochester area was 810.1 MW.

With the second critical outage, the outage of the Byron 345 to 161 kV transformer, this option was unable to sustain the load in 2021. Since the Byron transformer is a common point of failure for both the Byron-Maple Leaf-Cascade Creek 161 kV line as well as the Byron-Northern Hills line, this is the most critical outage for this option. Adding a second Byron Transformer to the option moves the failure out to 2033.

8.5 Cost per Incremental MW Supplied

Based on the on peak analysis, the cost per incremental MW supplied by each option was calculated and compared. The pertinent data is shown in Table 8.8.

Options

1. Byron to Pleasant Valley 345
2. Byron to Rochester 345 and Rochester to Pleasant Valley 161
3. Prairie Island to Adams 345
4. Prairie Island to Quarry Hill 161 and Byron to Northern Hills 161
5. Prairie Island to Frontenac to Alma 161, Frontenac to Quarry Hill 161, Byron to Northern Hills 161
6. Pleasant Valley to Quarry Hill 161 and Byron to Northern Hills 161with the addition of a 2^{nd} Byron 345-161 kV transformer.

Option	Year Of Failure	Peak Load (MW)	Estimate System[1] Losses %	Project Cost ($1,000's)	Cost per MWS[2]
Base[3]	2007	331.2	2.53	N/A	N/A
1	2051	1504.9	3.41	58,100	49.5
2	2051	1504.9	5.81	43,500	37.0
3	2051	1504.9	3.51	79,200	67.5
4	2027	659.0	1.96	26,675	81.4
5	2027	659.0	1.90	45,200	137.9
6	2033	810.1	3.91	23,000	48.0

Table 8.8

Notes

[1] System Losses are the losses in the Rochester area plus the tie losses expressed as a percentage of peak load.
[2] Cost per incremental MW supplied in 1,000's of dollars.
[3] Base is the present system with no construction of new transmission lines.

Options 1, 2 and 3, the 345 options, had the highest capital costs but as a group had lower per unit cost based on cost per incremental MW supplied. This would be expected since the capacity of the 345 options to supply additional load exceeds the capacity of any of the 161 kV options. Option 6 had an incremental cost per MW that was comparable to the 345 kV options. Depending on the cost sharing employed for a 345 line, the comparable present value economics of option 6 may or may not be comparable to a 345 solution if the basis of the comparison was to adequately supply the area until 2051. This most economic solution would be dependant on the construction cost of the additional facilities required to be constructed and in service in 2033 or the cost of programs that precluded construction of the facilities.

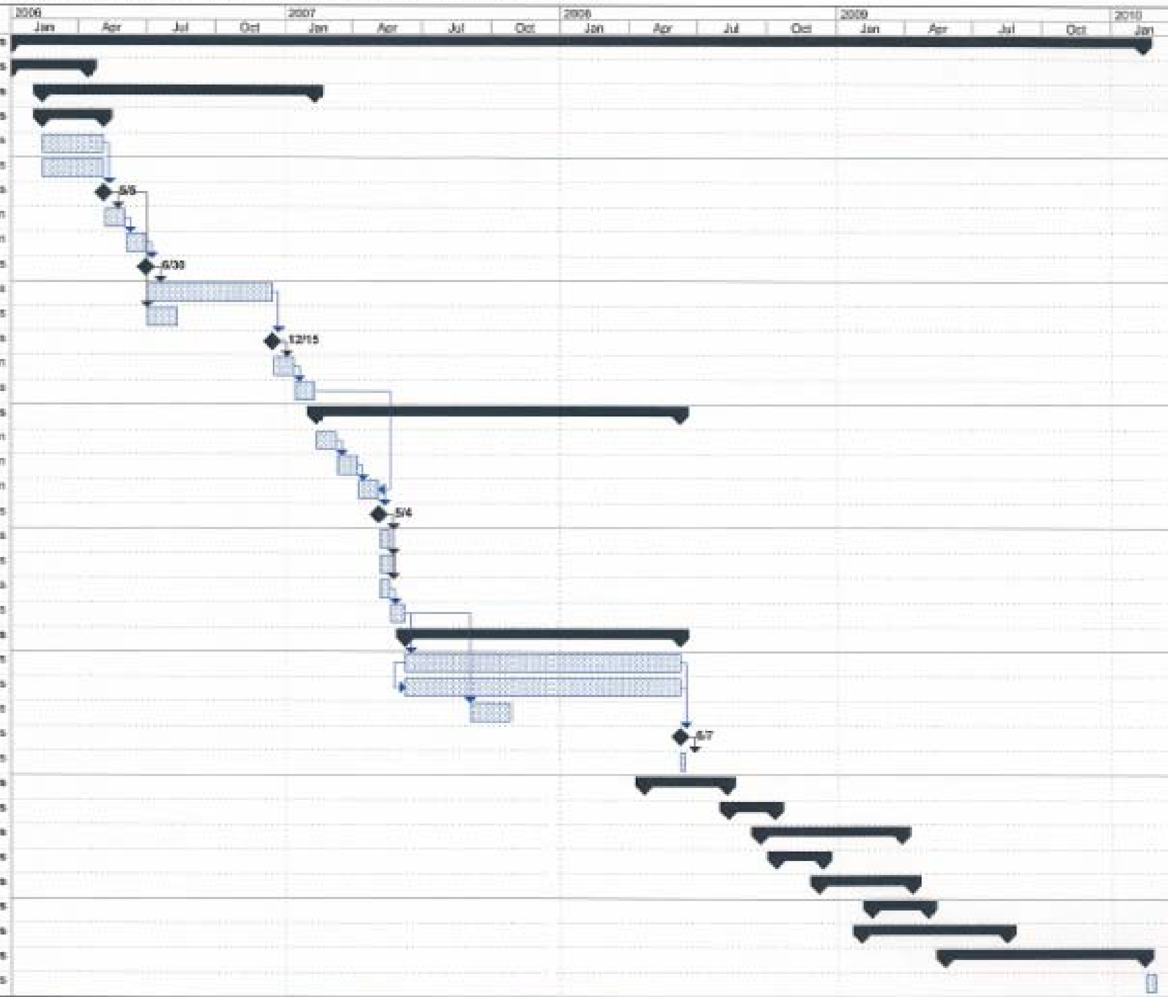
The system losses for the 345 options 1 and 3 are approximately 185% of the losses for options 4 and 5, the lowest-loss 161 kV options, while supplying 228% of the load of those corresponding 161 kV options. 345 kV option 2 has the highest losses of the 345 kV options since the system transmission connection is reduced to 161 kV between Rochester and Pleasant Valley, rather than the complete 345 kV connection of option 1.

8.6 Schedule

The schedule for construction of a 161 kV line into the Rochester area is shown on the next page. The schedule shows that from the selection of the successful 161 kV option until energization of a new 161 kV line the total elapsed time would be approximately 48 months. The 48 month total elapsed time breaks down as into specific increments. The first 2 ½ years are spent obtaining the certificate of need and going through the routing process and the route selection process. The last 1 ½ years would be for the actual right-of-way procurement, final design and construction of the line. Approximately 3 months for preparation and submittal of a certificate of need are shown in the first quarter of 2006. The schedule assumes a somewhat aggressive overlap between the routing and right of way acquisition process, so that the overall time line could be longer than the four years shown.

Rochester Public Utilities - Preliminary 161kV Project Schedule

ID	Task Name	Duration
1	**TRANSMISSION LINES FOR 161KV OPTION**	**1075 days**
2	**PRELIMINARY ROUTE SELECTION AND APPROVAL**	**75 days**
9	**MN PUBLIC UTILITIES COMMISSION APPROVAL**	**280 days**
10	**Prepare application for Certificate of Need (CON)**	**60 days**
11	Statement of Need	3 mons
12	Voltage/Structure Configuration	3 mons
13	Submit application for staff review	0 days
14	Staff reviews application for completeness	1 mon
15	Revise application	1 mon
16	Submit application	0 days
17	PUC review	6 mons
18	Public hearing	6 wks
19	PUC approve or deny	0 days
20	Satisfy modifications contingency	1 mon
21	Issue Certificate of Need	4 wks
22	**MEQB ROUTING APPROVAL**	**345 days**
23	Prepare preferred and alternate route details	1 mon
24	Solicit local input on route selection	1 mon
25	Prepare application for route permit	1 mon
26	Submit application	0 days
27	Publish notice of application in local legal newspapers	2 wks
28	Mail notice of application to each affected landowner	3 wks
29	Application review by MEQB	2 wks
30	Address deficiencies in application	3 wks
31	**MEQB Application Review Process**	**280 days**
32	Application Review	365 edays
33	Environmental Impact Statement	365 edays
34	Public hearings	2 mons
35	Issue route permit	0 days
36	PREPARE PROJECT SCHEDULE	5 days
37	**SURVEY**	**80 days**
44	**PRELIMINARY DESIGN**	**45 days**
50	**RIGHT-OF-WAY**	**135 days**
57	**LOCAL PERMITTING**	**45 days**
60	**FINAL DESIGN**	**90 days**
73	**CONSTRUCTION BID**	**55 days**
80	**PURCHASING**	**140 days**
85	**CONSTRUCTION**	**190 days**
89	JOB CLOSING	10 days



Project: RPU - SE Minnesota 345kV -
Date: Fri 3/25/05

Task	Progress	Summary	External Tasks	External Milestone
Split	Milestone	Project Summary	External Milestone	Deadline

La Crosse 161 kV Load Serving Study

Prepared by

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Power Delivery Planning & Operations
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August 3, 2005

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1.0 Executive Summary

This study the La Crosse 161 kV Load Serving Study (LAX 161) evaluates 161 kV solutions to the long term load serving requirements of the transmission system serving La Crosse, Wisconsin. This study provides a backup plan in case regional planning work fails to bring a 345 kV line into the La Crosse area. This study also gives an idea of the cost of a 161 kV solution and a sense of its longevity.

Independent of any 345 kV solution for the La Crosse area is the preexisting overload of the Genoa-Coulee 161 kV (Q-11) line for the loss of the Genoa-La Crosse Tap-Marshland 161 kV line. The upgrade of the Q-11 line is a prerequisite for the rebuild of the Genoa-La Crosse Tap-Marshland-Alma 161 kV Line (Q-1).

Alternative D - Figure 6, at a cost of $61 million, is the recommended plan. Alternative D consists of the following facility upgrades:

Reconductor Genoa-Coulee 161 kV
Reconductor Adams-Harmony 161 kV
Convert Monroe Council Creek 69 kV to a 161/69 kV double circuit*
Rebuild Alma-Marshland-North La Crosse-La Crosse Tap-Genoa 161 kV**
New Alma-Good View-Marshland-North La Crosse 161 kV
New Goodview 161 kV Substation with 112 MVA 161/69 kV Transformer
New North La Crosse 161 kV Substation with 112 MVA 161/69 kV Transformer
North La Crosse 300 MVA Phase Angle Regulator
84 MVARs of Capacitors

*The Monroe County-Council Creek conversion is an American Transmission Company (ATC) responsibility which solves a through flow problem of power into the ATC system.

**The cost of the Rebuild Alma-Genoa 161 kV does not include the cost of relocating residential properties adjacent to and within the existing rights-of-way. This is because the number of residential properties [if any] which would require relocation in accordance with the Wisconsin Administrative Code has not yet been ascertained by Dairyland Power Cooperative's legal counsel.

2.0 Introduction

The La Crosse 161 kV Load Serving Study (LAX 161) is a subset of Rochester Public Utility's (RPU) SE Minnesota – SW Wisconsin Transmission Study (RPU Study). LAX 161 explores 161 kV load serving solutions in the Greater La Crosse area, Appendix B – Figure 1, in the event the RPU Study fails to provide a regional 345 kV transmission solution. It also quantifies the cost of a 161 kV solution for comparison to the costs of any 345 kV solutions generated by the RPU Study.

A preexisting condition in the La Crosse area is the main driver behind this study. The preexisting condition is the overload of Q-11 for the loss of the Genoa-La Crosse tap-Marshland 161 kV line . The upgrade of Q-11 is a prerequisite for the rebuild of DPC's Q-1. Furthermore, the MAPP Design Review Subcommittee (DRS) has the mitigation of the Q-11 overload as a condition for the transfer of 164 MW from Weston 4 into the DPC control area. This is because this 164 MW transfer aggravates the above mentioned overload. This transfer is scheduled to commence in June, 2008. Finally, for the DPC system, Genoa-Coulee 161 kV line has had the most Transmission Loading Relief (TLR) called on it. Since August, 2003 up to the date of this study, TLR has been called 116 times. Details of TLR since August, 2003 is contained in Appendix A – DPC NERC TLR Activity.

3.0 Model Development and Assumptions

For consistency, LAX 161 utilizes the same 2009 summer peak model of the RPU Study; the *2003 MISO MODEL (JANUARY 2003), UPDATED BY RSGS (12/12/03)*. The LAX 161 study area is bounded by the 161 kV transmission system connected to the La Crosse area; which includes the following substations: Alma, Tremval, Monroe County, Genoa, and Harmony. Appendix B - Figure 1 illustrates the La Crosse study area. Monitored systems include DPC, XCEL, ALTE and ALTW. Appendix C – Modeling , lists the modeling checks and modifications made to the case.

Twenty alternatives were explored, of those eight showed promise. All of these alternatives have some common facility upgrades. These common facility upgrades include 84 MVAR of capacitors mainly on the 161 kV system. These capacitors were needed to free up reactive capacity of Genoa Unit 3 (G-3). Details of capacitor size and placement is left to a subsequent La Crosse area reactive study. Other common facility upgrades include the Reconductor of Q-11, as well as the rebuild of Q-1. Table 1 – Alternative Modeling Upgrades below lists the changes made to the model for each alternative. Alternative diagrams are found in Appendix B - List of Figures.

Table 1 – Alternative Modeling Upgrades

Alternative/Figure	Upgrades
Existing/fig. 2	None
Alternative 7/fig. 3	New Genoa-North La Crosse 161 kV
Alternative 8/fig. 4	New Genoa-La Crosse 161 kV
Alternative 9/fig. 5	New North La Crosse Phase Angle Regulator (PAR) and New Alma-North La Crosse 161 kV
Alternative D/fig. 6	New North La Crosse PAR and New Alma-Goodview-North La Crosse 161 kV
Alternative E/fig. 7	New North La Crosse PAR and New Rochester-Goodview-North La Crosse 161 kV
Alternative F/fig. 8	New Rochester-Goodview-North La Crosse 161 kV
Alternative G/fig. 9	New Alma-Goodview-North La Crosse 161 kV
Alternative H/fig.10	New Rochester-La Crescent-La Crosse 161 kV

4.0 System Analysis

PSS/E activity ACCC was used to screen the existing system and planned alternatives. Overloads and low voltages not related to The greater La Crosse area were ignored. The ACCC results identified two alternatives which provided adequate service to the greater La Crosse area for the 2009 summer peak load plus an additional 50 MW. Appendix D – ACCC/Powerflow Results lists the loading and voltage violations. The planning criteria used was 100% line loading of rate A and voltages less than 0.92 per unit for load serving buses and 0.90 per unit for non load serving buses. The two suitable alternatives are listed below:

- **Alternative D**
  New Alma-Goodview-Marshland 161 kV
  New Marshland-North La Crosse 161 kV double circuit
  Rebuild Alma-Marshland 161 kV
  Rebuild North La Crosse-Genoa 161 kV
  Reconductor Genoa-Coulee 161 kV
  Reconductor Adams-Harmony 161 kV
  Convert Monroe County-Council Creek 69 kV to 161/69 kV double circuit *
  New Goodview 161 kV Substation with 112 MVA 161/69 kV transformer
  New North La Crosse 161 kV Substation with 112 MVA 161/69 kV transformer
  New North La Crosse 300 MVA 161 kV PAR
  18 MVAR 161 kV capacitor at North La Crosse
  {2} 18 MVAR 161 kV capacitors at La Crosse
  18 MVAR 161 kV capacitor at Hillsboro
  18 MVAR 161 kV capacitor at Bell Center
  14.4 MVAR 69 kV capacitor at Monroe County

- **Alternative E**
  New Rochester-Goodview-Marshland 161 kV
  New Marshland-North La Crosse 161 kV double circuit
  Rebuild Alma-Marshland 161 kV**
  Rebuild North La Crosse-Genoa 161 kV**
  Reconductor Genoa-Coulee 161 kV
  Reconductor Adams-Harmony 161 kV
  Convert Monroe County-Council Creek 69 kV to 161/69 kV double circuit *
  New Goodview 161 kV Substation with 112 MVA 161/69 kV transformer
  New North La Crosse 161 kV Substation with 112 MVA 161/69 kV transformer
  New North La Crosse 300 MVA 161 kV PAR
  18 MVAR 161 kV capacitor at North La Crosse
  (2) 18 MVAR 161 kV capacitors at La Crosse
  18 MVAR 161 kV capacitor at Hillsboro
  18 MVAR 161 kV capacitor at Bell Center
  14.4 MVAR 69 kV capacitor at Monroe County

*ATC's responsibility, this project solves an unrelated through flow condition

**The cost of the Rebuild Alma-Genoa 161 kV does not include the cost of relocating residential properties adjacent to and within the existing rights-of-way. This is because the number of residential properties [if any] which would require relocation in accordance with the Wisconsin Administrative Code has not yet been ascertained by Dairyland Power Cooperative's legal counsel.

In addition to the ACCC analysis, additional powerflow was run on some contingencies unique to the La Crosse area. These contingencies are combinations of large generators offline or a large generator offline with a select 161 kV line out. These powerflow contingencies are listed below in Table 2 - Powerflow Contingencies:

Table 2 – Powerflow Contingencies

Contingency	Description
G-3 and JPM	Both G-3 and Alma J.P. Madgett Station (JPM) offline
G-3 and LSG	Both G-3 and Lansing Unit 4 offline
G-3 and ALM-MRS	G-3 offline and Alma-Marshland 161 kV out
JPM and GEN-LAX-MRS	JPM offline and Genoa-La Crosse Tap-Marshland 161 kV out
JPM and GEN-COU	JPM offline and Genoa-Coulee161 kV out

5.0 Analysis of Alternatives

The Alternatives tested fell into three categories. The first category is the disqualified alternatives. Disqualified alternatives are the ones which require more than one French Island CT on line for a contingency at 2009 summer peak loading plus 50 MW. The second category were alternatives with pitfalls. Pitfalls include alternatives which require some but less than 70 MW of French Island generation for a contingency (one French Island CT) or have power flow between 90% to 99% on a 161 kV line for a contingency at 2009 summer peak loading plus 50 MW. The third category is the suitable alternatives listed above. These suitable alternatives did not require any French Island generation for a contingency, rather powerflow was adjusted preventing overloads via the North La Crosse PAR.

Both Alternative D and Alternative E are suitable alternatives for the 2009 summer peak La Crosse area load plus an additional 50 MW. Alternative D performed better than Alternative E because it required less regulation of the PAR (175 MW for Alterative D and 225 MW for Alternative E). A question arose about the loss of the new 161 kV double circuit between Marshland and North La Crosse being problematic. Three additional contingencies were tested at the 2009 summer peak load plus 50 MW; The Marshland-North La Crosse 161 kV double circuit out, JPM offline and the Marshland-North La Crosse 161 kV double circuit out, and G3 offline and the Marshland-North La Crosse 161 kV double circuit out. These double circuit outages did not create any overloads or low voltages.

6.0 Sensitivity to Construction on Existing Rights-of-Way

LAX 161 explored if a solution to the La Crosse Area load serving needs could be found using existing Rights-of Way (R/W) in order to avoid the need of the North La Crosse PAR. Based on the findings of LAX 161 three additional alternatives were examined:

Table 3 – Existing R/W Alternatives

Alternative/Figure	Upgrades
Alternative I/fig.11	New Genoa-North La Crosse 161 kV & Alma-Genoa 161 kV Double Circuit
Alternative J/fig. 12	New Rochester La Crescent-La Crosse 161 kV Genoa-La Crosse 161 kV Double Circuit Genoa-Coulee 161 kV Double Circuit Coulee-La Crosse 161 kV Rebuild
Alternative K/fig. 13	Genoa-La Crosse 161 kV Double Circuit Genoa-Coulee 16 kV Double Circuit

Alternative I includes the rebuild of the La Crosse-Coulee 161 kV line, a new Genoa-North La Crosse 161 kV line (on new R/W) constructed with 954 ACSR, and the conversion of the entire Q-1 to a steel tower double circuit; each circuit conductored to 954 ACSR. It should be emphasized this alternative includes 37 miles of new R/W in addition to the double circuit lines.

Alternative J includes the rebuild of the La Crosse-Coulee 161 kV line, a new Rochester-La Crescent-La Crosse 161 kV line, a conversion of Genoa-La Crosse 161 kV line to a steel tower double circuit; and the conversion of Genoa-Coulee 161 kV line to a steel tower double circuit each circuit conductored to 954 ACSR.

Alternative K includes the rebuild of the La Crosse-Coulee 161 kV line, a conversion of Genoa-La Crosse 161 kV line to a steel tower double circuit; and the conversion of Genoa-Coulee 161 kV line to a steel tower double circuit each circuit conductored to 954 ACSR.

Only alternative I with the 37 miles 161 kV line on new R/W performed adequately for the 2009 summer peak loading plus 50 MW. The cost of Alternative I was $69 million. Alternatives J and K had significant overloading problems for the loss of the double circuits. Details of the ACCC and power flow results are found in Appendix D – ACCC/Powerflow Results

7.0 Economic Comparison

Common to all plans were $13.5 million in upgrades (except for Alternatives I-K). These upgrades include capacitors for reactive support and several 161 kV rebuilds and up rates. Appendix E - Economic Comparison contains details of the upgrades and costs in 2005 dollars.

8.0 Conclusion

LAX 161 examined 161 kV load serving solutions for the La Crosse Area in the absence of a 345 kV line being built. Twenty-three alternatives were studied. Because some of these alternatives did not perform well, not all of them were included in this document. Alternative D - Figure 6, at a cost of $61 million, is the recommended plan. Alternative D consists of the follow facility upgrades:

Reconductor Genoa-Coulee 161 kV
Reconductor Adams-Harmony 161 kV
Convert Monroe Council Creek 69 kV to a 161/69 kV double circuit*
Rebuild Alma-Marshland-North La Crosse-La Crosse tap-Genoa 161 kV**
New Alma-Good View-Marshland-North La Crosse 161 kV
New Goodview 161 kV Substation with 112 MVA 161/69 kV Transformer
North La Crosse 161 kV Substation with 112 MVA 161/69 kV Transformer
North La Crosse 300 MVA Phase Angle Regulator
84 MVARs of Capacitors

*The Monroe County-Council Creek conversion is an American Transmission Company (ATC) responsibility which solves a through flow problem of power into the ATC system.

**The cost of the Rebuild Alma-Genoa 161 kV does not include the cost of relocating residential properties adjacent to and within the existing rights-of-way. This is because the number of residential properties [if any] which would require relocation in accordance with the Wisconsin Administrative Code has not yet been ascertained by Dairyland Power Cooperative's legal counsel.

Regardless of any remedy to the La Crosse area load serving problems two 161 kV upgrades are necessary. Q-11 requires a reconductor with 605 MCM ACSS. This reconductor of Q-11 is due to its preexisting overload for the loss of the Genoa-La Crosse tap-Marshland 161 kV. Furthermore, the upgrade of the Q-11 is a prerequisite for the planned rebuild of Q-1 which is approaching the end of its useful life.

It is noted that Alternative D includes a North La Crosse 161 kV PAR. Efforts were made to avoid this PAR. Of these efforts, Alternative I performed the best, but due to a significantly higher cost and 37 miles of new right-of–way, it was not selected as the recommended plan.

Also the voltage support recommended by this plan was just adequate to move the G-3 reactive power output inside of its D-Curve. Nor has the viability of the suggested positioning or values of the 161 kV capacitors has been verified. Therefore a full La Crosse area reactive study is still required once the long term transmission solution is more fully developed.

Appendix A – DPC NREC TLR Activity

TLR Level	Facility Name	Number of times in 2003*
1	Genoa-Coulee FLO Genoa-La Crosse-Marshland 161kV	**33**
3a	Genoa-Coulee FLO Genoa-La Crosse-Marshland 161kV	**20**
3b	Genoa-Coulee FLO Genoa-La Crosse-Marshland 161kV	**2**
5	Genoa-Coulee FLO Genoa-La Crosse-Marshland 161kV	**1**

*** Since August, 2003**

TLR Level	Facility Name	Number of times in 2004
1	Genoa-Coulee FLO Genoa-La Crosse-Marshland 161kV	**21**
1	Alma - Wabaco 161kV (flo) Eau Claire - Arpin 345 kV	**1**
3a	Genoa-Coulee FLO Genoa-La Crosse-Marshland 161kV	**2**
3b	Alma - Wabaco 161kV (flo) Eau Claire - Arpin 345 kV	**1**

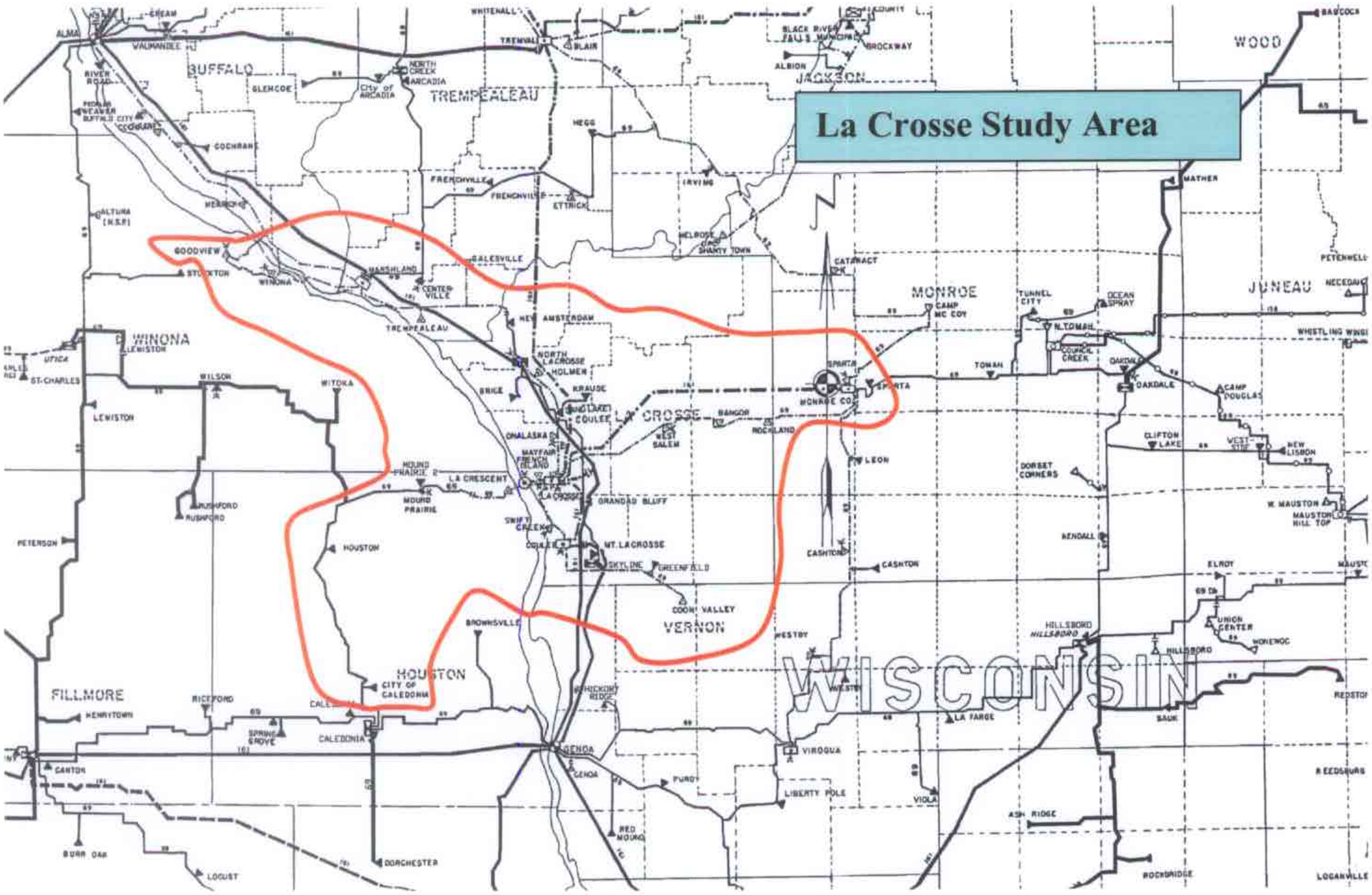
TLR Level	Facility Name	Number of times in 2005 **
1	Genoa-Coulee FLO Genoa-La Crosse-Marshland 161kV	**25**
1	Alma - Wabaco 161kV (flo) Eau Claire - Arpin 345 kV	**0**
3a	Genoa-Coulee FLO Genoa-La Crosse-Marshland 161 kV	**10**
3b	Alma - Wabaco 161kV (flo) Eau Claire - Arpin 345 kV	**0**
	Genoa-Coulee FLO Genoa-La Crosse-Marshland 161kV	**2**

**** As of August 1, 2005**

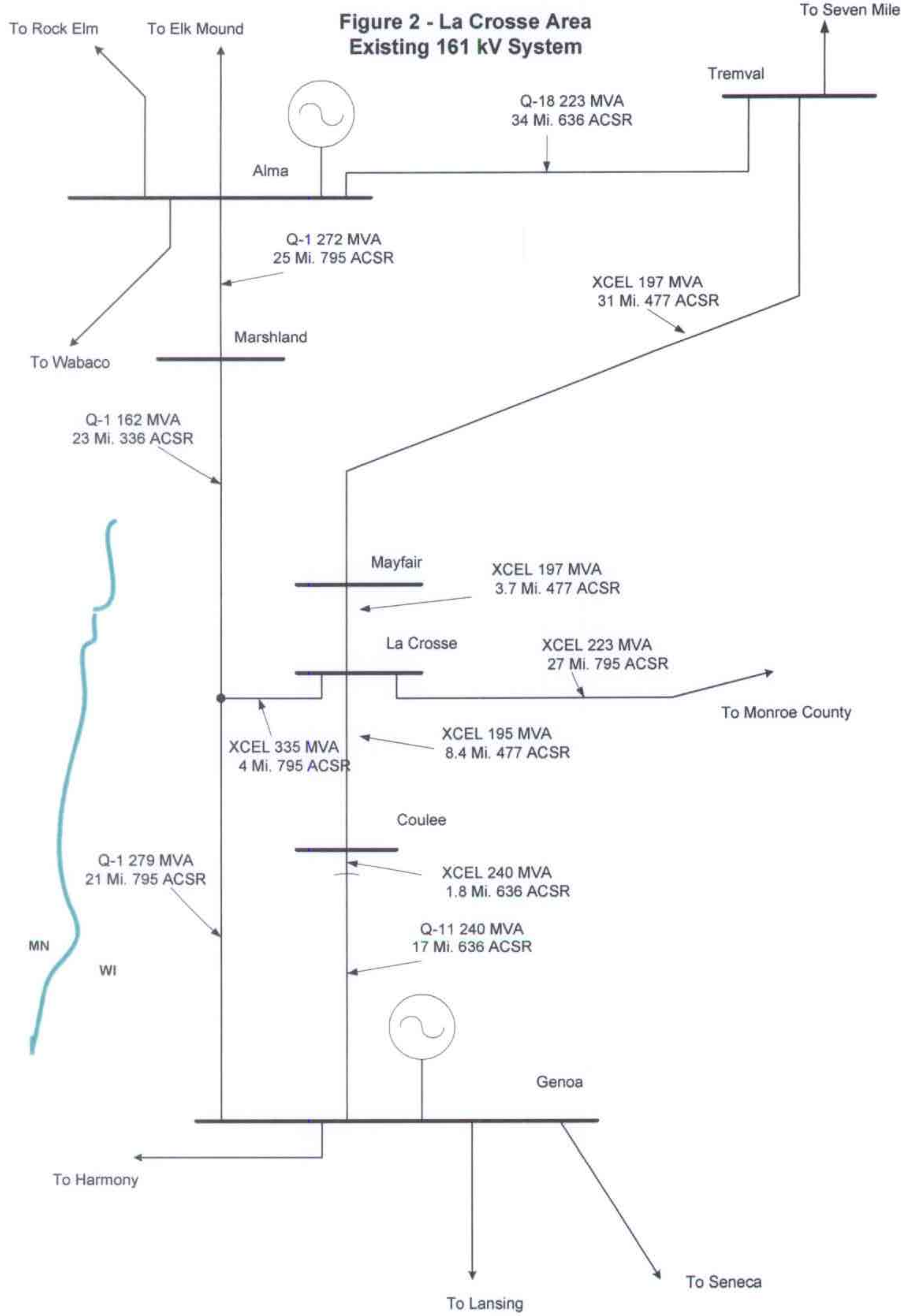
Appendix B – List of Figures

Figure 1 - La Crosse Study Area

Appendix B – List of Figures Cont.



Appendix B – List of Figures Cont.



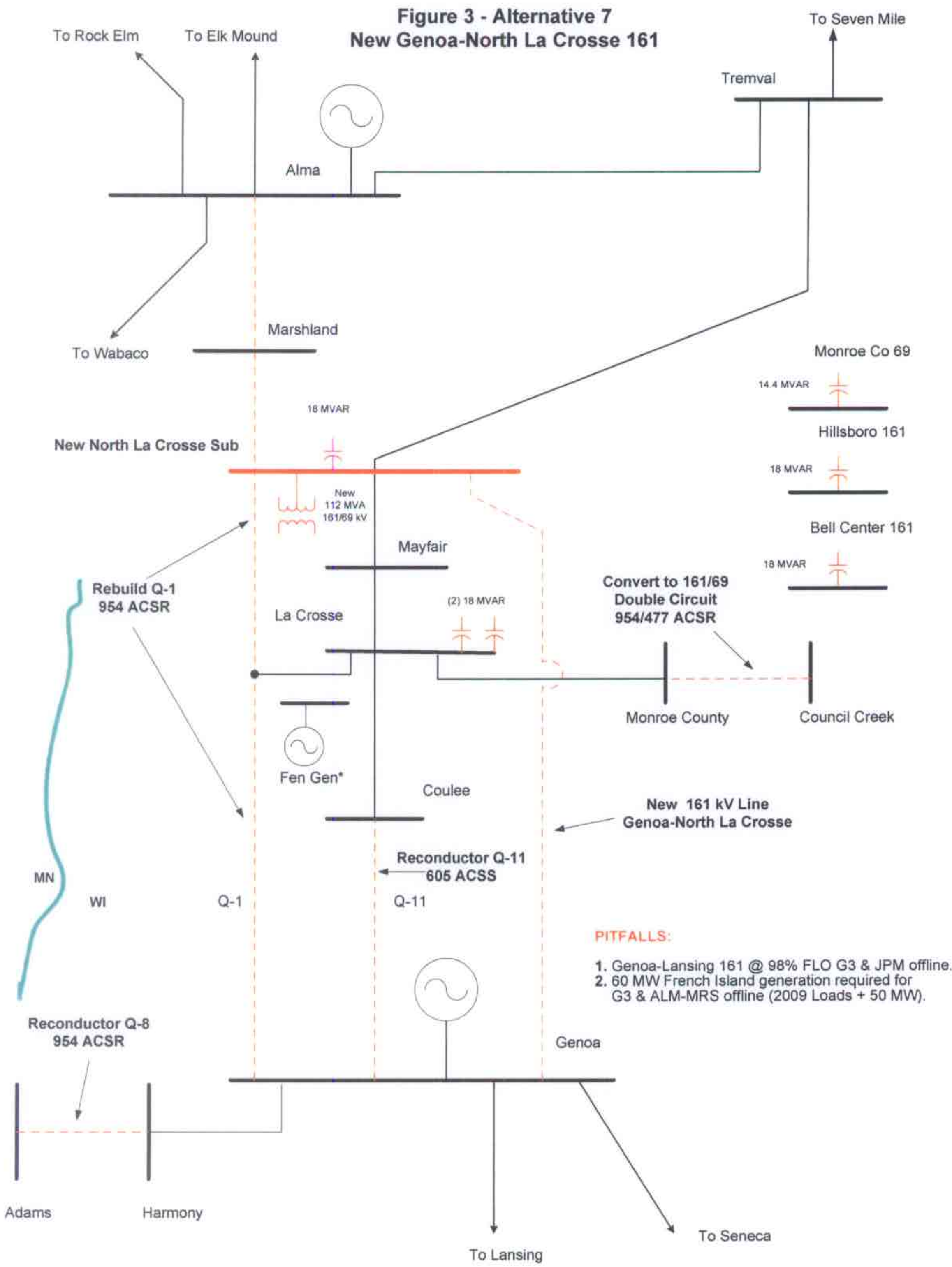
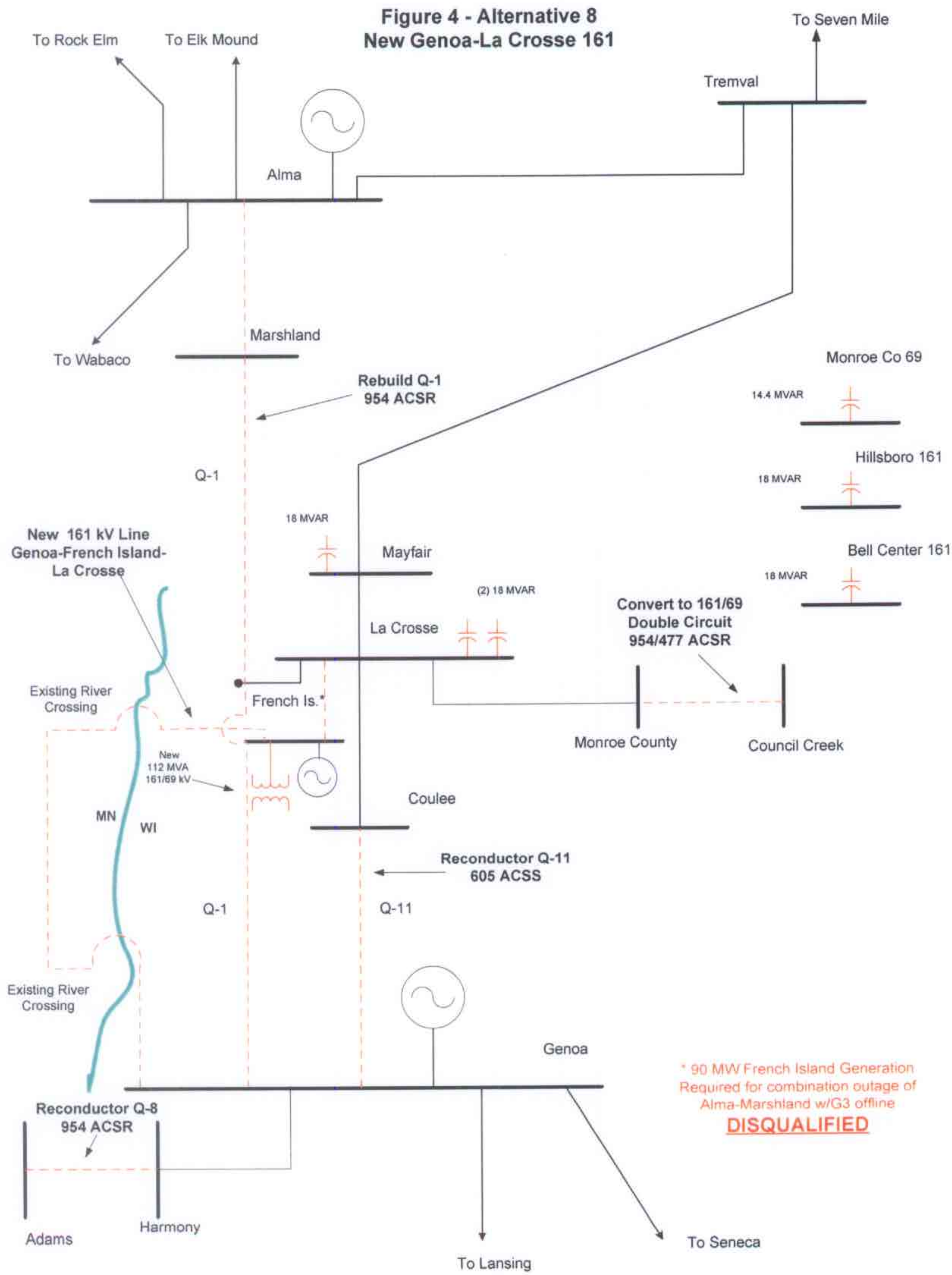
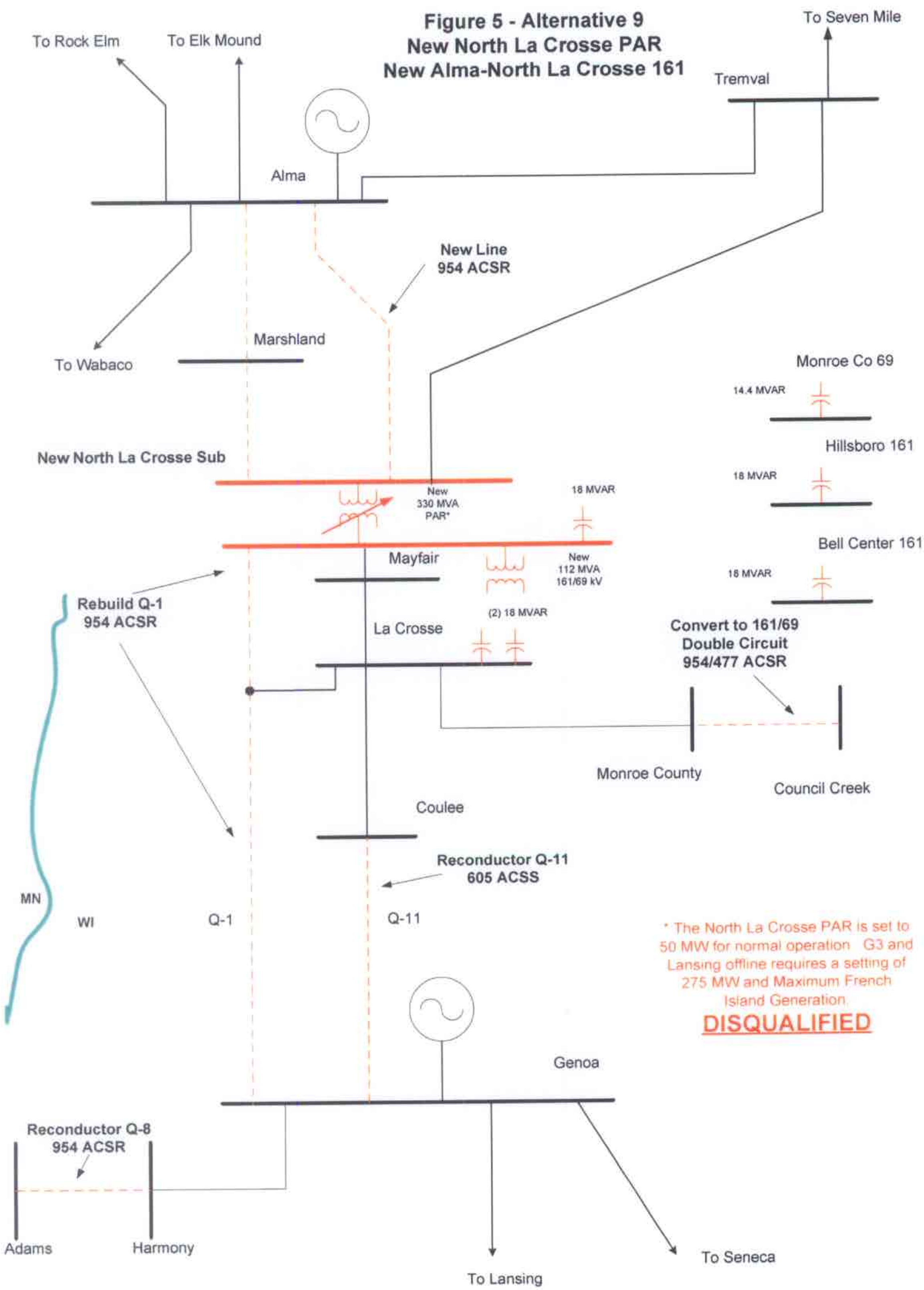


Figure 3 - Alternative 7
New Genoa-North La Crosse 161
To Rock Elm
To Elk Mound
To Seven Mile
Tremval
Alma
Marshland
To Wabaco
Monroe Co 69
14.4 MVAR
18 MVAR
New North La Crosse Sub
Hillsboro 161
18 MVAR
New
112 MVA
161/69 kV
Bell Center 161
Mayfair
18 MVAR
Rebuild Q-1
954 ACSR
Convert to 161/69
Double Circuit
954/477 ACSR
La Crosse
(2) 18 MVAR
Monroe County
Council Creek
Fen Gen*
Coulee
New 161 kV Line
Genoa-North La Crosse
Reconductor Q-11
605 ACSS
MN
WI
Q-1
Q-11
PITFALLS:
1. Genoa-Lansing 161 @ 98% FLO G3 & JPM offline.
2. 60 MW French Island generation required for G3 & ALM-MRS offline (2009 Loads + 50 MW).
Reconductor Q-8
954 ACSR
Genoa
Adams
Harmony
To Lansing
To Seneca

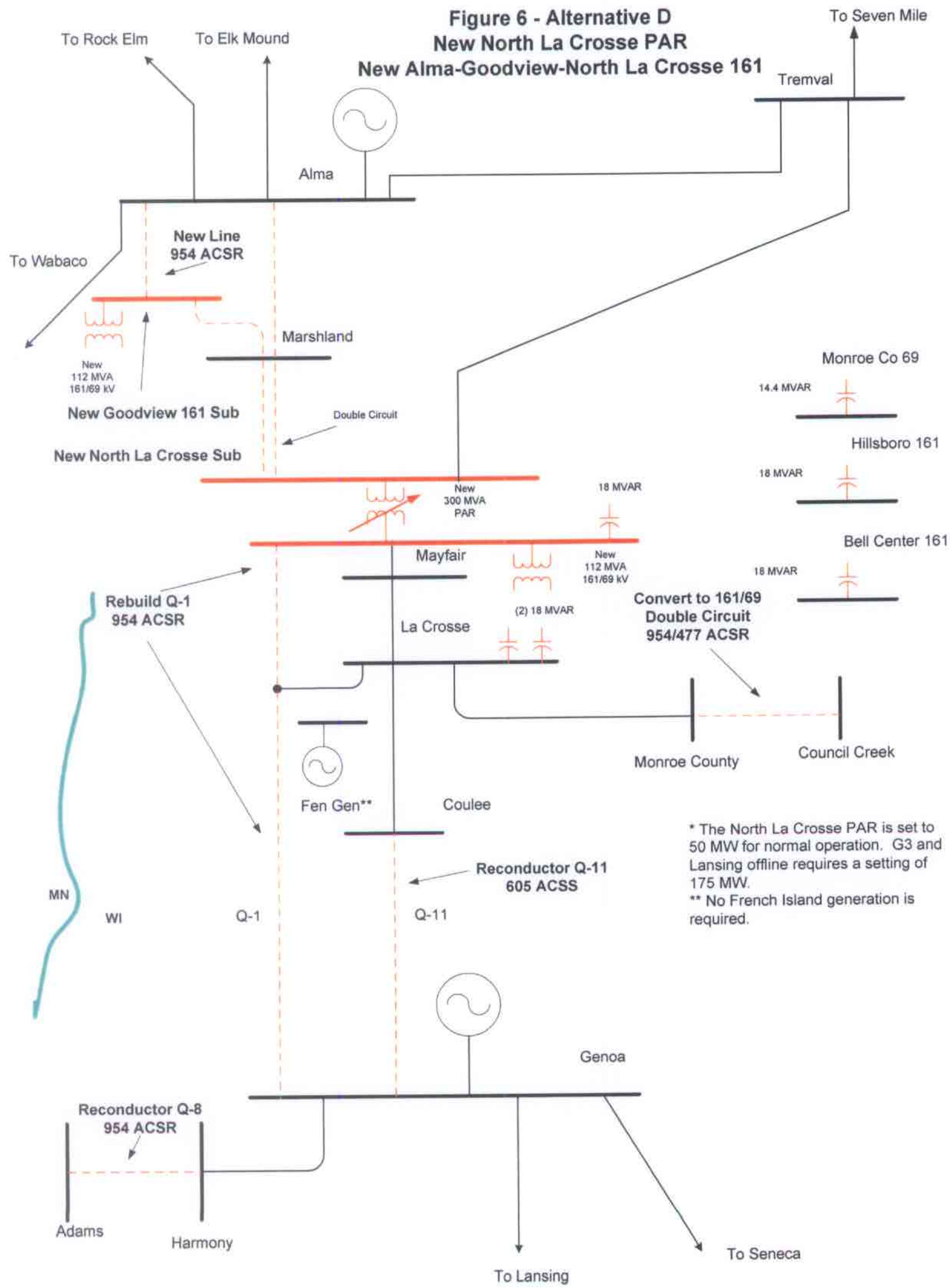
Appendix B – List of Figures Cont.



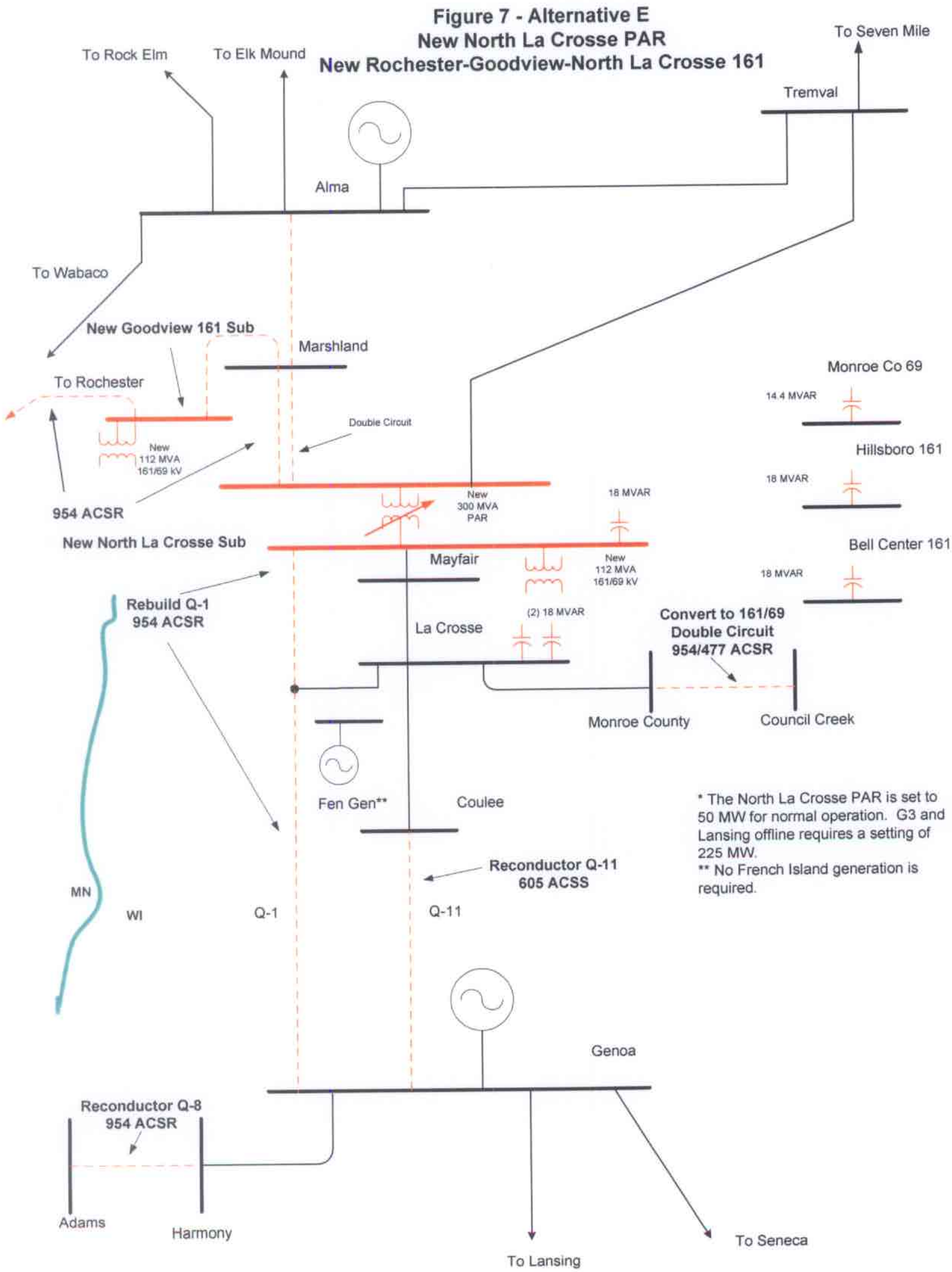
Appendix B – List of Figures Cont.



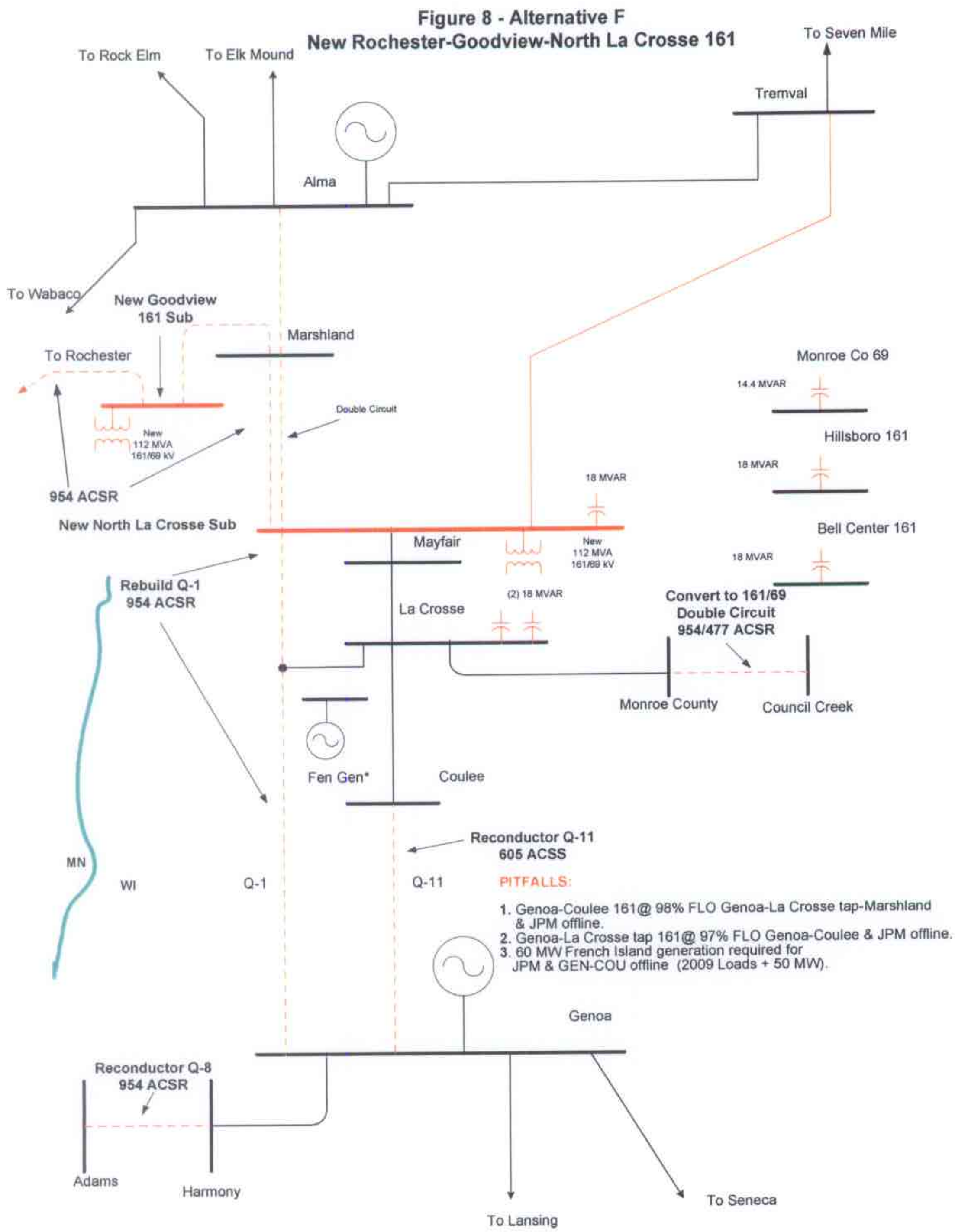
Appendix B – List of Figures Cont.



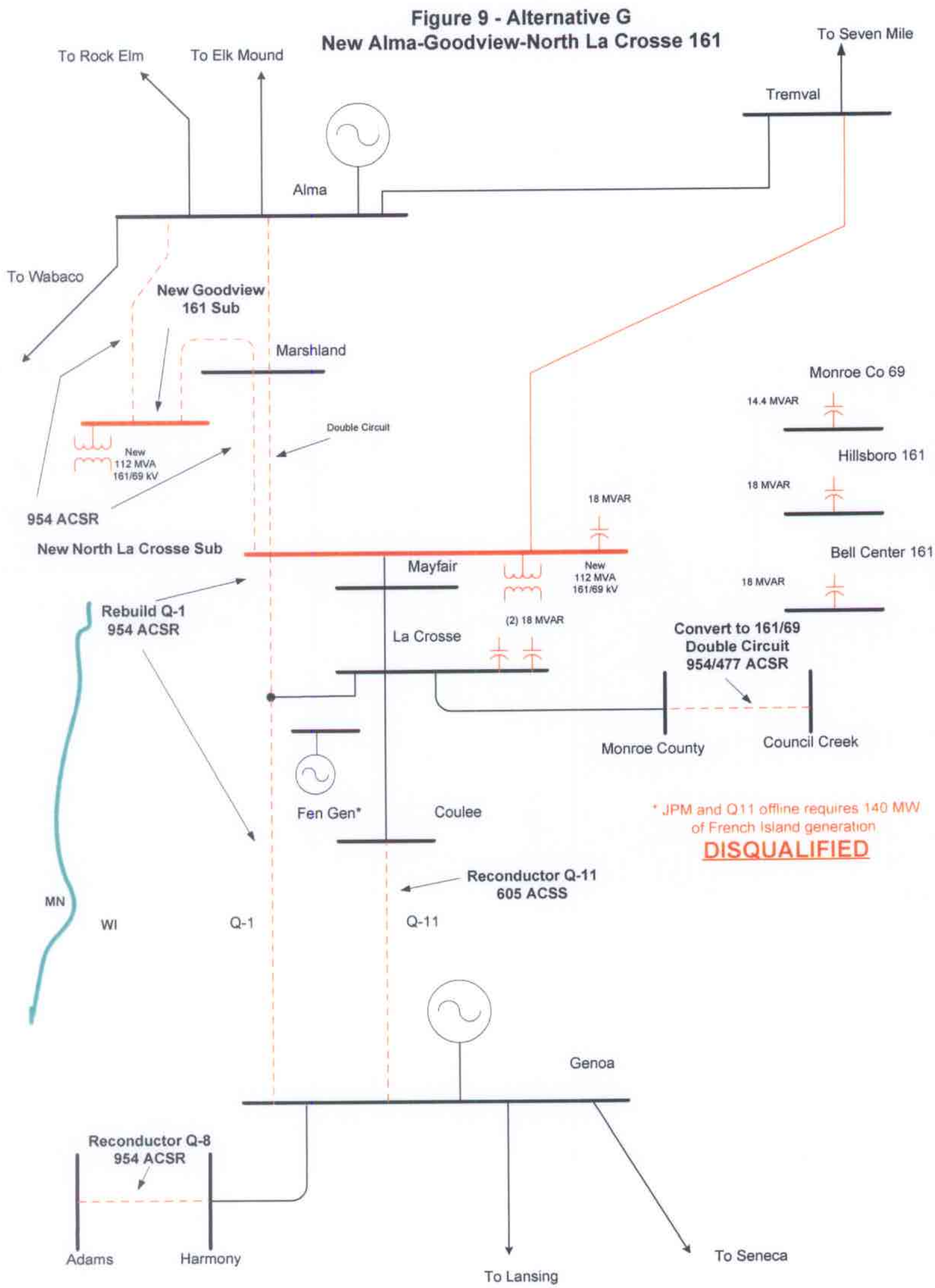
Appendix B – List of Figures Cont.



Appendix B – List of Figures Cont.

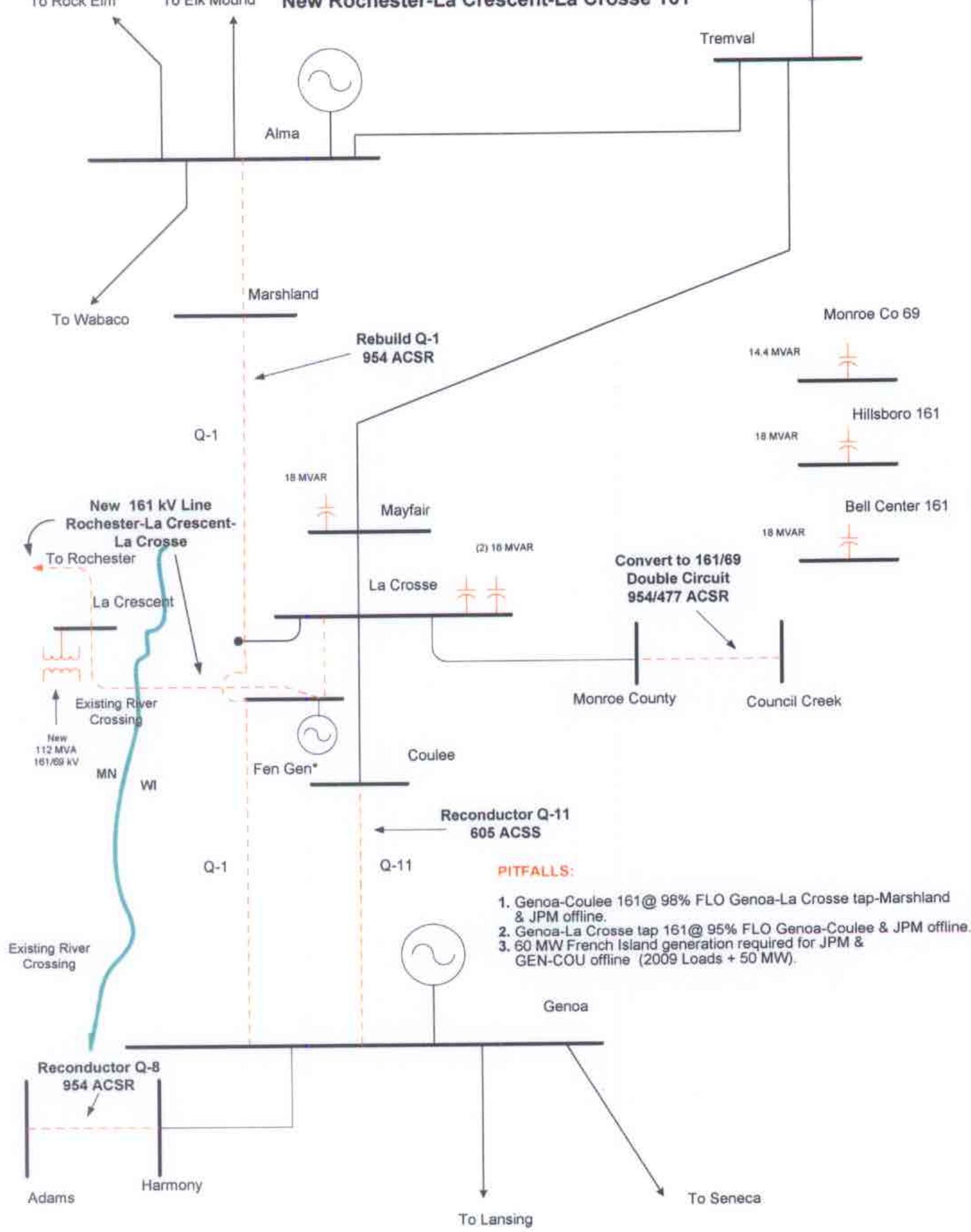


Appendix B – List of Figures Cont.



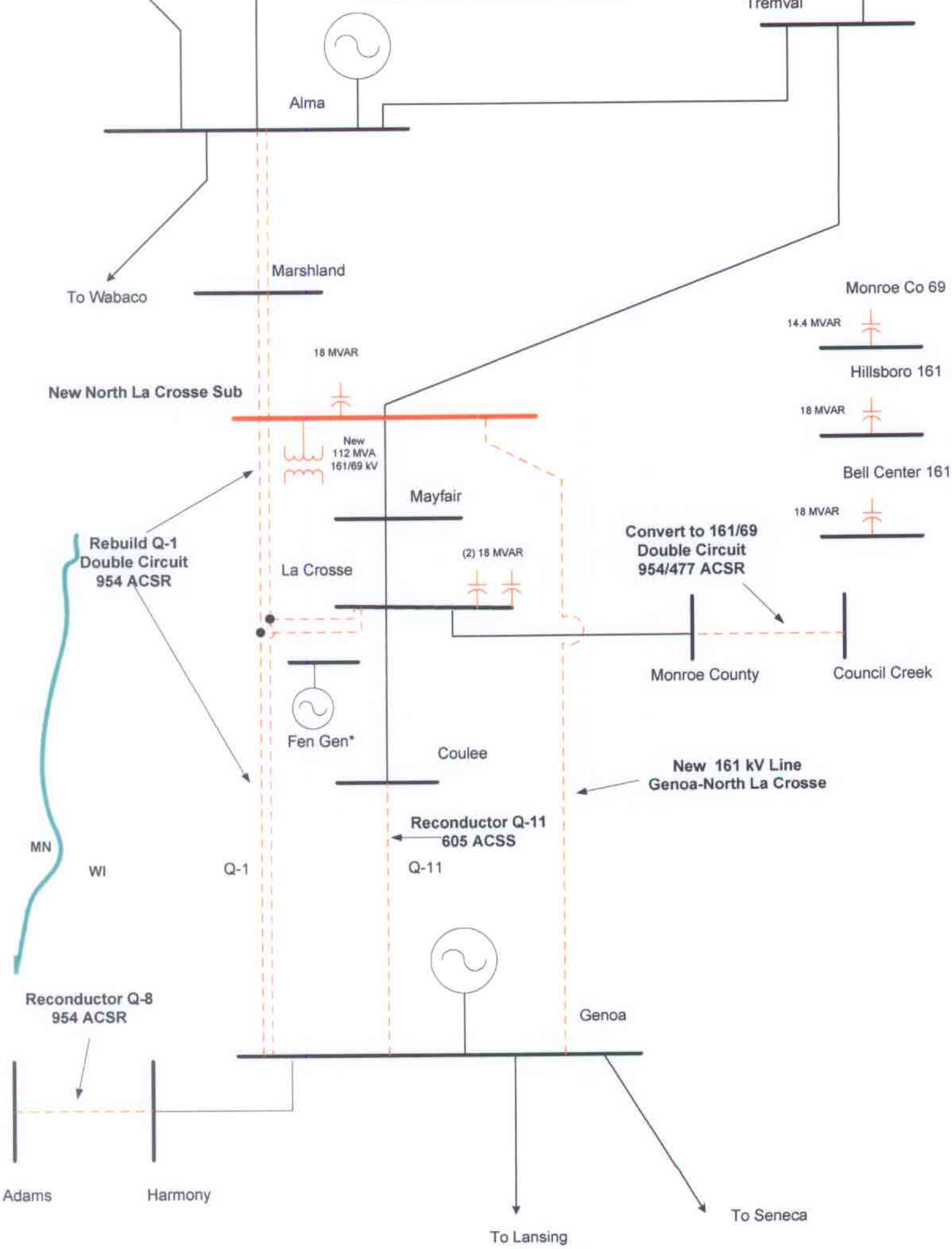
Appendix B – List of Figures Cont.

Figure 10 - Alternative H
New Rochester-La Crescent-La Crosse 161

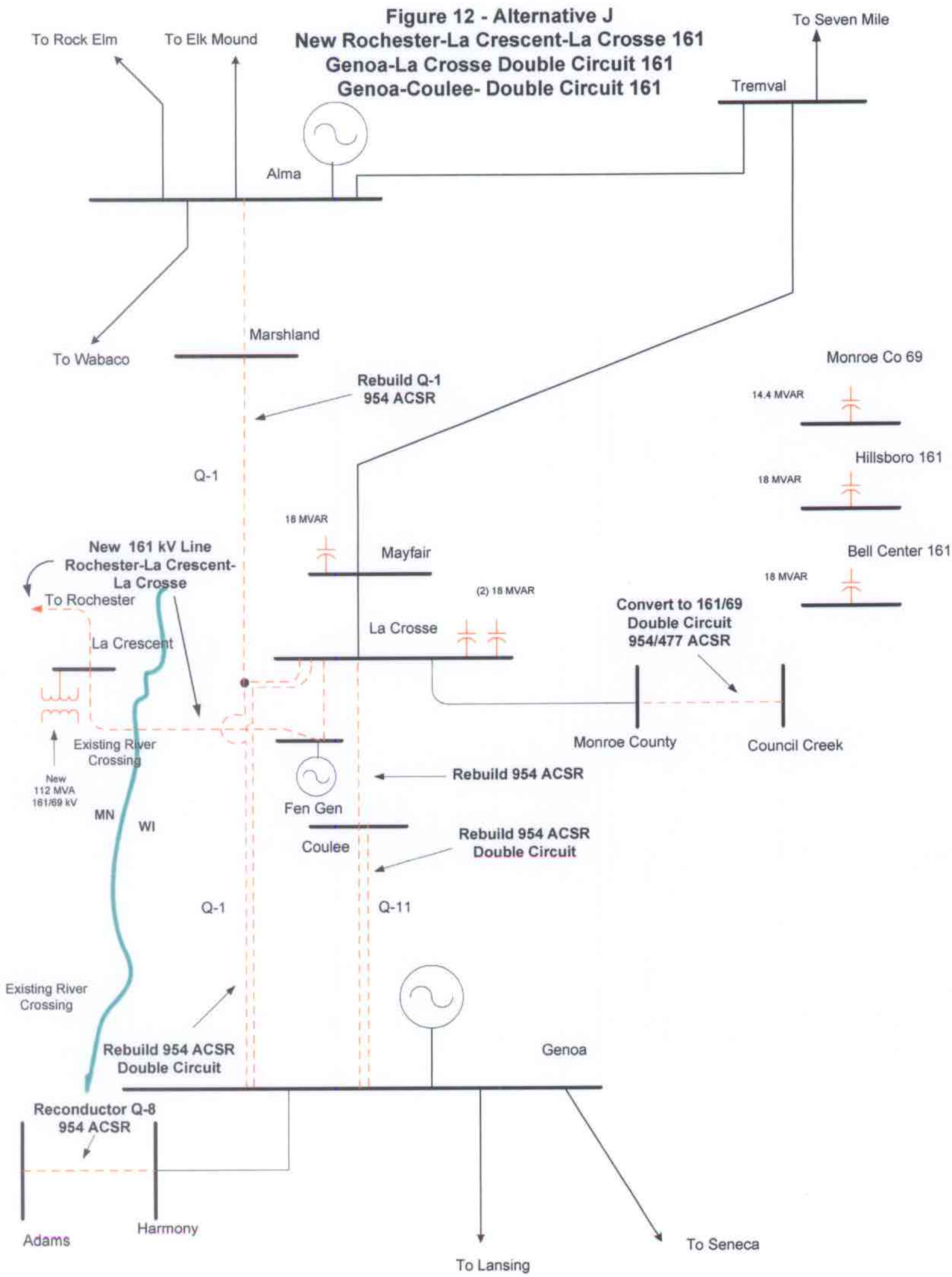


Appendix B – List of Figures Cont.

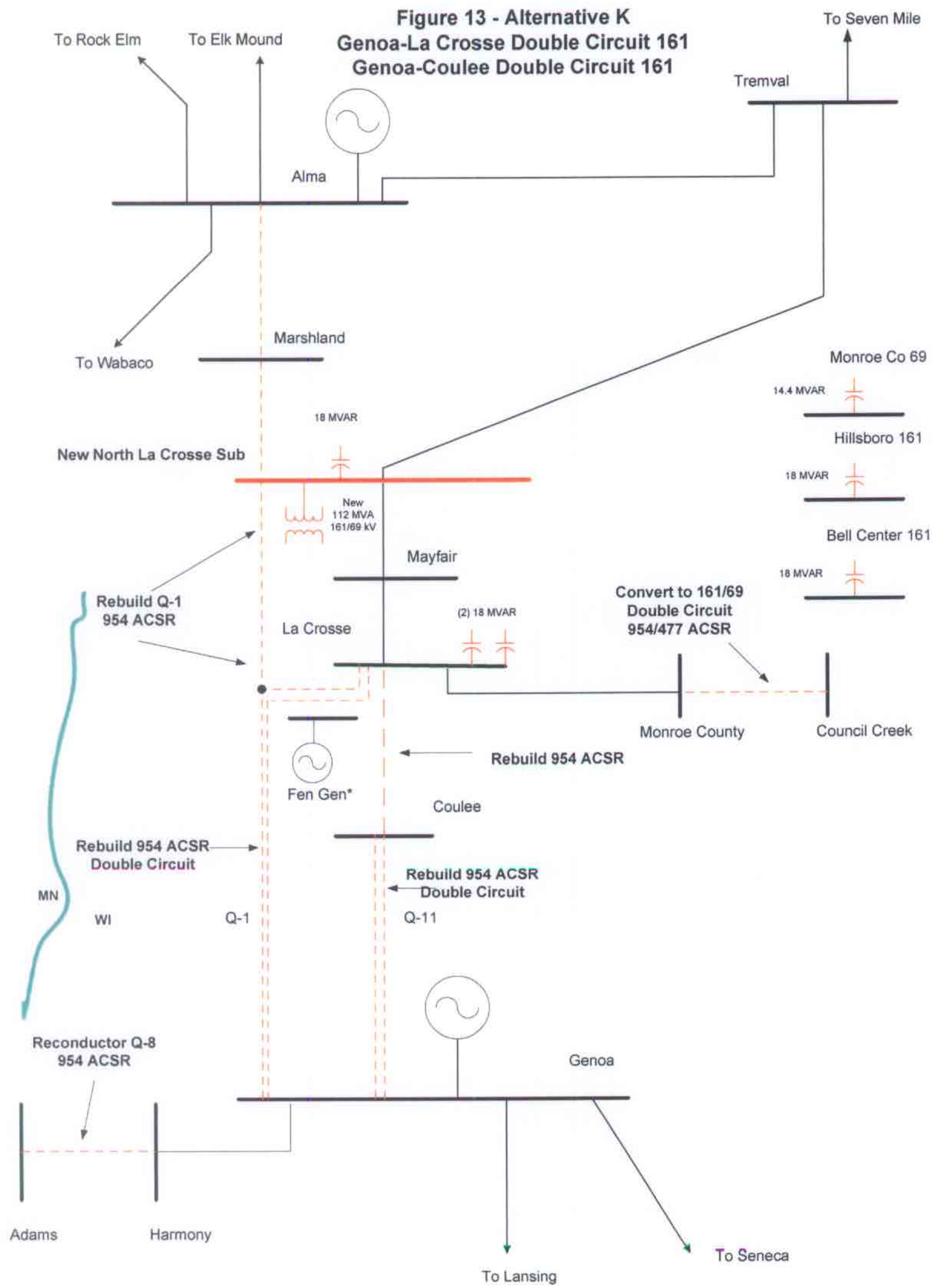
Figure 11 - Alternative I
New Genoa-North La Crosse 161
Alma-Genoa Double Circuit 161



Appendix B – List of Figures Cont.



Appendix B – List of Figures Cont.



APPENDIX C – MODELING

2009 Summer Peak Case

- Check the Chisago to Apple River 115 & 161 modeling. In model.
- Check the Arrowhead to Weston 345 modeling. Not in Model.
- Check modeling of PVS-AUS 161. Line rated 473 MW.
- Check the reasonability of the PVS and Rochester generation. 423 MW on line.
- Check/Place northern Wisconsin Hydro output at 50% of maximum. Ok.
- Check modeling of the Harmony – Decorah Area (N-8 rebuild and the Waukon Capacitor). Missing in RPU model, added with i-har-dec.idv & har-dec rdch.
- Check modeling of the Alma-Utica-Harmony Ok.
- Check modeling of Genoa-Hillsboro-Oakdale Upgrade ok
- Restore Liberty Pole-Viroqua-Viola tap to 477 ACSR. i-vir.idv
- Check Wheaton generation (model in summer case only). 342 MW on line.
- Model Stoneman on in the peak case and off in the off-peak case. 54 MW on line.
- Review DPC generation dispatch. Use Elk Mound generation to model spinning reserves (25 MW). 82.5 MW on line.
- Other miscellaneous items like STS phase shifter, future caps, etc.
- Increase Lone Rock PS from 25 MVA to 35 MVA to offset load growth. i-lrps.idv
- Model Fennimore to Castle Rock tap N.O. line. i-fenn.idv
- Check that French Island generation on-line is only the RDF plant. 22 MW on line.
- Upgrade T Corners 115/69 kV 47 MVA transformer to 112 MVA
- Model Alma generation near its summer limit.
- Change Holcombe-Cornell 115 kV to 113 MVA, its conductor limit
- Change Stone Lake-Washco-Barron 161 kV from 120 MVA to 133 MVA
- Model La Crosse area load based upon DPC 8/20/03 peak. (Sp09 La Crosse area load increased to 494 MW [SP09 base case load 422.8 MW]).
- Model WPS-DPC 150 MW transfer to handle load increase (sp09rw).
- Up rate Alma-Tremval from 223 MVA to 240 MVA.
- Up rate Alma-Tremval from 223 MVA to 240 MVA.
- Loop Tremval-Melrose-Jackson County; open Melrose tap Cataract (with NLAX PAR cases).
- Model Apple River-Big Sand 86 MVA.
- Model Washco-Barron 86 MVA, upgrade Barron 67 MVA Tx to 112 MVA and move this 67 MVA Tx to Washco.

APPENDIX D – ACCC/Power Flow Results

2009 Summer Peak (sp09rwn) - Criteria: Lines over 100% Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Existing System Critical Contingency	Affected Facility	Facility Rating MVA	% OL/PU
Genoa-La Crosse tap-Marshland 161	Genoa-Coulee 161	240	127.3
Coulee 161/69 #1	Coulee 161/69 #2	112	107.9
Coulee 161/69 #2	Coulee 161/69 #1	70	134.3
	La Crosse 161/69 #1	70	106.6
	La Crosse 161/69 #2	70	107.1
Genoa-Coulee 161	Monroe County 161	n/a	0.89
La Crosse 161/69 #1or #2	La Crosse 161/69 #1	70	111.2
	Coulee-Swift Creek 69	66	102.7
Coulee-Swift Creek 69	La Crosse 161/69 #2	70	100.2
Coulee-Mt La Crosse 69	Coulee-Swift Creek 69	66	100.6
	Coon Valley 69	n/a	0.91
Holmen-Onalaska 69	Coulee-Mt La Crosse 69	47	101.5
Onalaska-La Crosse 69	Coulee-Mt La Crosse 69***	47	145.4
	Holmen 69 *	n/a	0.88
Rice-Beaver Creek 161	Rice 161	n/a	0.88
Seneca-Bell Center 161	Bell Center 161	n/a	0.88
Bell-Center-Hillsboro 161	Hillsboro 161	n/a	0.88
G3 and JPM off-line	North La Crosse 69 **	N/A	0.88
	Adams-Beaver Creek 161	223	108.0
	Bell Center-Soldiers Grove 69	25	100.6
G3 and Lsg off-line	North La Crosse 69 **	N/A	0.87
	Adams-Beaver Creek 161	223	130.3
	Bell Center-Soldiers Grove 69	25	101.1
	Harmony-Beaver Creek 161	223	108.5
	Monroe County 161/69	70	100.4
G3 off-line and Alm-Mrs	Goodview 69 **	N/A	0.78
	Genoa-Lansing 161	240	106.5
	Adams-Beaver Creek 161	223	115.5
	Bell Center-Soldiers Grove 69	25	108.1
G3 off-line and Alm-Trm 161	North La Crosse 69 **	N/A	0.88
	Adams-Beaver Creek 161	223	102.2
	Monroe County 161/69	70	103.7
JPM off-line and Gen-Lax tap-Mrs 161	Genoa-Coulee 161	240	135.9
JPM off-line and Gen-Cou 161	New Amsterdam 69 **	N/A	0.90
	Bell Center-Soldiers Grove 69	25	105.8
	Genoa-La Crosse tap 161	279	110.3

* Other low voltages in the Holmen area

** Widespread low voltages in the La Crosse area.

*** Close 4L176 @ Galesville Haas

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwcmtn) - Criteria: Lines over 100% Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Lax Capacitors Added, Monroe Co-Council Creek 161			
Critical Contingency	**Affected Facility**	**Facility Rating MVA**	**% OL/PU**
Genoa-La Crosse tap-Marshland 161	Genoa-Coulee 161	240	128.4
Coulee-La Crosse 161	Coulee-Swift Creek 69	66	101.8
Coulee 161/69 #1	Coulee 161/69 #2	112	108.3
Coulee 161/69 #2	Coulee 161/69 #1	70	134.8
	La Crosse 161/69 #1	70	106.5
	La Crosse 161/69 #2	70	107.0
La Crosse 161/69 #1or #2	La Crosse 161/69 #1	70	111.1
	Coulee-Swift Creek 69	66	102.0
Coulee-Swift Creek 69	La Crosse 161/69 #1	70	100.0
	La Crosse 161/69 #2	70	100.5
Coulee-Mt La Crosse 69	Coulee-Swift Creek 69	66	100.7
Holmen-Onalaska 69	Coulee-Mt La Crosse 69	47	101.4
Onalaska-La Crosse 69	Coulee-Mt La Crosse 69	47	137.7
Rice-Beaver Creek 161	Rice 161	n/a	0.88
G3 and JPM off-line	Adams-Beaver Creek 161	223	108.2
G3 and Lsg off-line	Adams-Beaver Creek 161	223	128.8
	Harmony-Beaver Creek 161	223	107.0
G3 off-line and Alm-Mrs	Goodview 69 *	N/A	0.90
	Adams-Beaver Creek 161	223	112.6
G3 off-line and Alm-Trm 161	Adams-Beaver Creek 161	223	102.6
JPM off-line and Gen-Lax tap-Mrs 161	Genoa-Coulee 161	240	135.4
JPM off-line and Gen-Cou 161	Bell Center-Soldiers Grove 69	25	101.5
	Genoa-La Crosse tap 161	279	109.4

* Other low voltages in the Winona area.

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwan) - Criteria: Lines over 100% Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Lax Capacitors Added, Monroe Co-Council Creek 161 Adams-Harmony 161 Uprated Critical Contingency	**Affected Facility**	**Facility Rating MVA**	**% OL/PU**
Genoa-La Crosse tap-Marshland 161	Genoa-Coulee 161	240	128.5
Coulee-La Crosse 161	Coulee-Swift Creek 69	66	102.0
Coulee 161/69 #1	Coulee 161/69 #2	112	108.3
Coulee 161/69 #2	Coulee 161/69 #1	70	134.8
	La Crosse 161/69 #1	70	106.4
	La Crosse 161/69 #2	70	106.9
La Crosse 161/69 #1or #2	La Crosse 161/69 #1	70	111.0
	Coulee-Swift Creek 69	66	102.0
Coulee-Swift Creek 69	La Crosse 161/69 #2	70	100.4
Coulee-Mt La Crosse 69	Coulee-Swift Creek 69	66	100.7
Holmen-Onalaska 69	Coulee-Mt La Crosse 69	47	101.4
Onalaska-La Crosse 69	Coulee-Mt La Crosse 69	47	137.7
Rice-Beaver Creek 161	Rice 161	n/a	0.88
G3 and JPM off-line	N/A		
G3 and Lsg off-line	N/A		
G3 off-line and Alm-Mrs	Goodview 69 *	N/A	0.91
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	Genoa-Coulee 161	240	135.6
JPM off-line and Gen-Cou 161	Bell Center-Soldiers Grove 69	25	101.5
	Genoa-La Crosse tap 161	279	109.5

* Other low voltages in the Winona area.

APPENDIX D – ACCC/Power Flow Results

2009 Summer Peak (sp09rwn) - Criteria: Lines over 100%, Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Existing System w/French Island Gen 70 MW			
Critical Contingency	**Affected Facility**	**Rating MVA**	**% OL/PU**
G3 and JPM off-line	Adams-Beaver Creek 161	223	101.9
	Monroe County 161/69	70	101.3
G3 and Lsg off-line	Adams-Beaver Creek 161	223	123.3
	Harmony-Beaver Creek 161	223	108.5
	Monroe County 161/69	70	101.1
G3 off-line and Alm-Mrs	Goodview 69 *	N/A	0.88
	Adams-Beaver Creek 161	223	106.0
G3 off-line and Alm-Trm 161	Monroe County 161/69	70	104.4
JPM off-line and Gen-Lax tap-Mrs 161	Genoa-Coulee 161	240	120.3
JPM off-line and Gen-Cou 161	Bell Center-Soldiers Grove 69	25	102.1
	Genoa-La Crosse tap 161	279	101.4

* Widespread low voltages in the La Crosse area.

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwcmtn) - Criteria: Lines over 100%, Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Lax Capacitors Added, Monroe Co-Council Creek 161 w/French Island Gen 70 MW			
Critical Contingency	**Affected Facility**	**Rating MVA**	**% OL/PU**
G3 and JPM off-line	Adams-Beaver Creek 161	223	102.7
G3 and Lsg off-line	Adams-Beaver Creek 161	223	123.0
G3 off-line and Alm-Mrs	Adams-Beaver Creek 161	223	106.3
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	Genoa-Coulee 161	240	124.7
JPM off-line and Gen-Cou 161	Genoa-La Crosse tap 161	279	103.7

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwan) - Criteria: Lines over 100%, Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Lax Capacitors Added, Monroe Co-Council Creek 161 Adams-Harmony 161 Uprated, w/French Island Gen 70 MW			
Critical Contingency	**Affected Facility**	**Rating MVA**	**% OL/PU**
G3 and JPM off-line	N/A		
G3 and Lsg off-line	N/A		
G3 off-line and Alm-Mrs	N/A		
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	Genoa-Coulee 161	240	124.8
JPM off-line and Gen-Cou 161	Genoa-La Crosse tap 161	279	101.4

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwn) - Criteria: Lines over 100%, Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Existing System w/French Island Gen 140 MW			
Critical Contingency	**Affected Facility**	**Rating MVA**	**% OL/PU**
G3 and JPM off-line	N/A		
G3 and Lsg off-line	Adams-Beaver Creek 161	223	116.9
G3 off-line and Alm-Mrs	N/A		
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	Genoa-Coulee 161	240	107.4
JPM off-line and Gen-Cou 161	Bell Center-Soldiers Grove 69	25	100.0

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwcmtn) - Criteria: Lines over 100%, Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Lax Capacitors Added, Monroe Co-Council Creek 161 w/French Island Gen 140 MW			
Critical Contingency	**Affected Facility**	**Rating MVA**	**% OL/PU**
G3 and JPM off-line	N/A		
G3 and Lsg off-line	Adams-Beaver Creek 161	223	117.5
G3 off-line and Alm-Mrs	Adams-Beaver Creek 161	223	100.3
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	Genoa-Coulee 161	240	114.5
JPM off-line and Gen-Cou 161	N/A		

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwan) - Criteria: Lines over 100%, Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Lax Capacitors Added, Monroe Co-Council Creek 161 Adams-Harmony 161 Uprated, w/French Island Gen 140 MW			
Critical Contingency	**Affected Facility**	**Rating MVA**	**% OL/PU**
G3 and JPM off-line	N/A		
G3 and Lsg off-line	N/A		
G3 off-line and Alm-Mrs	N/A		
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	Genoa-Coulee 161	240	114.7
JPM off-line and Gen-Cou 161	N/A		

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwan) - Criteria: Lines over 100% Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Option 7-New Genoa-Nlax 161 Lax Capacitors Added, Adams-Harmony 161 Monroe Co-Council Creek 161 Critical Contingency	Affected Facility	Facility Rating MVA	% OL/PU
Coulee 161/69 #2	Coulee 161/69 #1	70	101.3
Rice-Beaver Creek 161	Rice 161	n/a	0.88
G3 and JPM off-line*	N/A		
G3 and Lsg off-line	N/A		
G3 off-line and Alm-Mrs	N/A		
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	N/A		
JPM off-line and Gen-Cou 161	N/A		

PITFALLS:

**1. ***Genoa-Lansing 161@ 98% FLO G3 & JPM offline.

2. 60 MW French Island generation required for G3 & ALM-MRS offline (2009 Loads + 50 MW)

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwan) - Criteria: Lines over 100%				
Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu				
Option d-Nlax PAR		Facility		
Lax Capacitors Added, Adams-Harmony 161, Alma-Goodview-N. Lax 161				
Monroe Co-Council Creek 161				
Critical	**Affected**	**Rating**		**PAR Adj**
Contingency	**Facility**	**MVA**	**% OL/PU**	**MW**
Coulee 161/69 #2	Coulee 161/69 #1	70	105.2	TDB*
Genoa-Coulee 161	Genoa-La Crosse tap 161	304	100.5	TDB*
Rice-Beaver Creek 161	Rice 161	n/a	0.88	TDB*
G3 and JPM off-line	N/A			
G3 and Lsg off-line	Adams-Beaver Creek 161	304	112.0	TDB*
G3 off-line and Alm-Mrs	N/A			
G3 off-line and Alm-Trm 161	N/A			
JPM off-line and Gen-Lax tap-Mrs 161	Genoa-Coulee 161	304	103.4	TDB*
JPM off-line and Gen-Cou 161	Genoa-La Crosse tap 161	304	100.4	TDB*
* Should be less than 175 MW in worse contingency				

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwan) - Criteria: Lines over 100% Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Option e-Nlax PAR Lax Capacitors Added, Adams-Harmony 161, Rochester-Goodview-N. Lax 161 Monroe Co-Council Creek 161 Critical Contingency	**Affected Facility**	**Facility Rating MVA**	**% OL/PU**	**PAR Adj MW**
Coulee 161/69 #2	Coulee 161/69 #1	70	104.8	TDB*
Genoa-Coulee 161	Genoa-La Crosse tap 161	304	100.5	TDB*
Rice-Beaver Creek 161	Rice 161	n/a	0.88	TDB*
Genoa-La Crosse tap-Marshland 161	Genoa-Coulee 161	304	103.3	TDB*
G3 and JPM off-line	N/A			
G3 and Lsg off-line	N/A			
G3 off-line and Alm-Mrs	N/A			
G3 off-line and Alm-Trm 161	N/A			
JPM off-line and Gen-Lax tap-Mrs 161	Genoa-Coulee 161	304	102.9	TDB*
JPM off-line and Gen-Cou 161	N/A			

* Should be less than 225 MW in worse contingency

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwan) - Criteria: Lines over 100%			
Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu			
Option f			
Lax Capacitors Added, Adams-Harmony 161, Rochester-Goodview-N. Lax 161			
Monroe Co-Council Creek 161		**Facility**	
Critical	**Affected**	**Rating**	
Contingency	**Facility**	**MVA**	**% OL/PU**
Coulee 161/69 #2	Coulee 161/69 #1	70	104.4
Rice-Beaver Creek 161	Rice 161	n/a	0.88
G3 and JPM off-line	N/A		
G3 and Lsg off-line	N/A		
G3 off-line and Alm-Mrs	N/A		
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161*	N/A		
JPM off-line and Gen-Cou 161**	N/A		

PITFALLS:

**1. ***Genoa-Coulee 161@ 98% FLO Genoa-La Crosse tap-Marshland & JPM offline.

**2. ****Genoa-La Crosse tap 161@ 97% FLO Genoa-Coulee & JPM offline.

60 MW French Island generation required for JPM & GEN-COU offline (2009 Loads + 50 MW).

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwan) - Criteria: Lines over 100% Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Option h-Rochester-Lax 161 Lax Capacitors Added, Adams-Harmony 161, French Is-La Cresent 69 upgrade Monroe Co-Council Creek 161, T-Corners TX upgrade Critical Contingency	**Affected Facility**	**Facility Rating MVA**	**% OL/PU**
Coulee 161/69 #2	Coulee 161/69 #1	70	114.7
Holmen-Onalaska 69	Coulee-Mt La Crosse 69	47	100.8
Onalaska-La Crosse 69	Coulee-Mt La Crosse 69	47	137.7
Rice-Beaver Creek 161	Rice 161	n/a	0.88
G3 and JPM off-line	N/A		
G3 and Lsg off-line	N/A		
G3 off-line and Alm-Mrs	N/A		
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161*	N/A		
JPM off-line and Gen-Cou 161**	N/A		

PITFALLS:

**1. ***Genoa-Coulee 161@ 98% FLO Genoa-La Crosse tap-Marshland & JPM offline.

**2. ****Genoa-La Crosse tap 161@ 95% FLO Genoa-Coulee & JPM offline.

60 MW French Island generation required for JPM & GEN-COU offline (2009 Loads + 50 MW).

APPENDIX D – ACCC/Power Flow Results Cont.

Option I-New Genoa-Nlax 161 Alma-Genoa 161 Double Circuit Lax Capacitors Added, Adams-Harmony 161 Monroe Co-Council Creek 161 Critical Contingency	**Affected Facility**	**Facility Rating MVA**	**% OL/PU**
Rice-Beaver Creek 161	Rice 161	n/a	0.87
G3 and JPM off-line	N/A		
G3 and Lsg off-line	N/A		
G3 off-line and Alm-Mrs	N/A		
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	N/A		
JPM off-line and Gen-Cou 161	N/A		
JPM off-line and Gen-Lax tap-Mrs Dbl Crt 161	N/A		
2009 Summer Peak + 50MW			
Coulee 161/69 #2	Coulee 161/69 #1	70	107.7
Rice-Beaver Creek 161	Rice 161	n/a	0.87
G3 and JPM off-line	N/A		
G3 and Lsg off-line	N/A		
G3 off-line and Alm-Mrs	N/A		
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	N/A		
JPM off-line and Gen-Cou 161	N/A		
JPM off-line and Gen-Lax tap-Mrs Dbl Crt 161	N/A		
JPM off-line and Gen-Cou Dbl Crt 161	N/A		

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwan) - Criteria: Lines over 100% Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Option J-Rochester-Lax 161 Genoa-Coulee DBL & Genoa-La Crosse tap-La Crosse DBL Lax Capacitors Added, Adams-Harmony 161 Monroe Co-Council Creek 161 Critical Contingency	Affected Facility	Facility Rating MVA	% OL/PU
Genoa-La Crosse tap-Marshland 161	Coulee-Swift Creek 69	66	103.5
Genoa-Coulee Dbl Crt 161	La Crosse 161/69 #1	70	110.2
	La Crosse 161/69 #2	70	110.7
	Coulee-Swift Creek 69	66	115.8
	La Crosse-Swift Creek 69	66	156.6
Genoa-La Crosse tap-Marshland Dbl Crt 161	Coulee 161/69 #1	70	118.7
	Coulee 161/69 #2	112	129.0
	Coulee-Swift Creek 69	66	180.6
	La Crosse-Swift Creek 69	66	141.7
Coulee-Mt. La Crosse 69	Coulee-Swift Creek 69	66	107.7
Coulee 161/69 #2	Coulee 161/69 #1	70	117.6
La Crosse-Onalaska 69	Coulee-Mt. La Crosse 69	47	135.6
Rice-Beaver Creek 161	Rice 161	n/a	0.88
G3 and JPM off-line	N/A		
G3 and Lsg off-line	N/A		
G3 off-line and Alm-Mrs	N/A		
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	Coulee-Swift Creek 69	66	110.6
JPM off-line and Gen-Cou 161	N/A		
JPM off-line and Gen-Lax tap-Mrs Dbl Crt 161	Coulee 161/69 #1	70	123.1
	Coulee 161/69 #2	112	133.8
	Coulee-Swift Creek 69	66	193.8
	La Crosse-Swift Creek 69	66	155.5
JPM off-line and Gen-Cou Dbl Crt 161	La Crosse 161/69 #1	70	108.2
	La Crosse 161/69 #2	70	108.7
	Coulee-Swift Creek 69	66	115.5
	La Crosse-Swift Creek 69	66	156.3
2009 Summer Peak + 50MW			
Genoa-La Crosse tap-Marshland 161	Coulee 161/69 #2	112	101.4
	Coulee-Swift Creek 69	66	106.0
Genoa-Coulee Dbl Crt 161	La Crosse 161/69 #1	70	119.1
	La Crosse 161/69 #2	70	119.7
	La Crescent 161/69	112	105.9
	Coulee-Swift Creek 69	66	128.9
	La Crosse-Swift Creek 69	66	174.3
Genoa-La Crosse tap-Marshland Dbl Crt 161	Coulee 161/69 #1	70	124.6
	Coulee 161/69 #2	112	135.5
	Coulee-Swift Creek 69	66	184.0
	La Crosse-Swift Creek 69	66	141.2
Coulee 161/69 #1	Coulee 161/69 #2	112	121.8
Coulee 161/69 #2	Coulee 161/69 #1	70	153.2
Coulee-Mt. La Crosse 69	Coulee-Swift Creek 69	66	112.3
Holmen-Onalaska 69	Coulee-Mt. La Crosse 69	47	108.9
La Crosse--Onalaska 69	Coulee-Mt. La Crosse 69	47	149.3
Rice-Beaver Creek 161	Rice 161	n/a	0.87
G3 and JPM off-line	N/A		
G3 and Lsg off-line	N/A		
G3 off-line and Alm-Mrs	N/A		
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	Coulee 161/69 #2	112	103.6
	Coulee-Swift Creek 69	66	113.3
JPM off-line and Gen-Cou 161	N/A		
JPM off-line and Gen-Lax tap-Mrs Dbl Crt 161	Coulee 161/69 #1	70	129.5
	Coulee 161/69 #2	112	140.8
	Coulee-Swift Creek 69	66	197.9
	La Crosse-Swift Creek 69	66	155.5
JPM off-line and Gen-Cou Dbl Crt 161	La Crosse 161/69 #1	70	118.6
	La Crosse 161/69 #2	70	119.2
	La Crescent 161/69	112	105.6
	Coulee-Swift Creek 69	66	129.1
	La Crosse-Swift Creek 69	66	174.5

APPENDIX D – ACCC/Power Flow Results Cont.

2009 Summer Peak (sp09rwan) - Criteria: Lines over 100% Load serving buses <0.92 pu, and Non-Load serving buses <0.90 pu Option K-Genoa-Coulee DBL & Genoa-La Crosse tap-La Crosse DBL Lax Capacitors Added, Adams-Harmony 161 Monroe Co-Council Creek 161 Critical Contingency	**Affected Facility**	**Facility Rating MVA**	**% OL/PU**
Genoa-La Crosse tap-Marshland 161	Coulee-Swift Creek 69	66	118.2
Genoa-Coulee Dbl Crt 161	La Crosse 161/69 #1	70	104.7
	La Crosse 161/69 #2	70	105.1
	La Crosse-Swift Creek 69	66	113.5
Genoa-La Crosse tap-Marshland Dbl Crt 161	Coulee 161/69 #1	70	123.4
	Coulee 161/69 #2	112	134.1
	Coulee-Swift Creek 69	66	201.8
	La Crosse-Swift Creek 69	66	162.2
Coulee 161/69 #1	Coulee 161/69 #2	112	108.7
Coulee 161/69 #2	Coulee 161/69 #1	70	135.3
La Crosse 161/69 #1 or #2	Coulee-Swift Creek 69	66	108.8
Coulee-Mt. La Crosse 69	Coulee-Swift Creek 69	66	103.7
Holmen-Onalaska 69	Coulee-Swift Creek 69	66	104.2
Rice-Beaver Creek 161	Rice 161	n/a	0.88
G3 and JPM off-line	N/A		
G3 and Lsg off-line	N/A		
G3 off-line and Alm-Mrs	N/A		
G3 off-line and Alm-Trm 161	N/A		
JPM off-line and Gen-Lax tap-Mrs 161	Coulee-Swift Creek 69	66	126.3
JPM off-line and Gen-Cou 161	N/A		
JPM off-line and Gen-Lax tap-Mrs Dbl Crt 161	Coulee 161/69 #1	70	132.9
	Coulee 161/69 #2	112	144.4
	Coulee-Swift Creek 69	66	221.3
	La Crosse-Swift Creek 69	66	181.5
JPM off-line and Gen-Cou Dbl Crt 161	La Crosse 161/69 #1	70	104.2
	La Crosse 161/69 #2	70	104.7
	La Crosse-Swift Creek 69	66	115.3

APPENDIX E – ECOMONIC COMPARISON

La Crosse Area 161 kV Load Serving Study: Study Costs Common to all Options:			
Bell Center 161 kV 18 Mvar Capacitor	1	265	265.0
Hillsboro 161 kV 18 Mvar Capacitor	1	265	265.0
La Crosse 161 kV 18 Mvar Capacitor	2	331	662.0
Monroe Co 69 kV 14.4 Mvar Capacitor	1	235	235.0
Rebuild Q1 Genoa-La Crosse tap 161kV[1]	20.7	350	7,245.0
Reconductor DPC Portion Q11 Genoa-Coulee 161kV	16.9	93	1,571.7
Rebuild/Reconductor XEL Portion Q11 Genoa-Coulee 161kV	1.8	116	208.8
Upgrade XEL Coulee sub to 2000 Amps	1	500	500.0
Uprate Q8 Adams-Harmony 161kV	35.6	71	2,527.6
Costs Common to all Options:			**13,480.1**
[1] Additional R/W costs may occur depending on routing			
Note: ATC assumes Cost of Monroe County-Council Creek			

APPENDIX E – ECOMONIC COMPARISON Cont.

Option 7 New Genoa-North La Crosse 161 Facility 2005	Units	Unit Cost $ 1000's	Cost $ 1000's
Costs Common to all Options:			**13,480.1**
New Genoa-North La Crosse 161 kV	37.0	234	8,658.0
New Double Circuit tapping Tremval-Mayfair 161 kV	0.5	558	279.0
Rebuild Q1 Alma-Marshland 161kV	25.4	350	8,890.0
Rebuild Q1 Marshland-North La Crosse 161kV	15.4	350	5,390.0
Rebuild Q1 North La Crosse-La Crosse tap 161kV	8.8	350	3,080.0
North La Crosse 161 kV Transmission Sub	1	638	638.0
North La Crosse 161 kV Circuit Breakers	10	369	3,690.0
North La Crosse 161 kV 18 Mvar Capacitor	1	265	265.0
North La Crosse 161/69 kV 112 MVA Transformer	1	1189	1,189.0
North La Crosse 69 kV Circuit Breakers	1	246	246.0
Option 7 costs:			**32,325.0**
Total Costs:			**45,805.1**
PITFALLS:			
1. Genoa-Lansing 161@ 98% FLO G3 & JPM offline.			
2. 60 MW French Island generation required for G3 & ALM-MRS offline (2009 Loads + 50 MW).			

APPENDIX E – ECOMONIC COMPARISON Cont.

Option 8 New Genoa-La Crosse 161 Facility 2005	Units	Unit Cost $ 1000's	Cost $ 1000's
Costs Common to all Options:			**13,480.1**
Rebuild Q1 Alma-Marshland 161kV	25.4	350	8,890.0
Rebuild Q1 Marshland-La Crosse tap 161kV	24.2	350	8,470.0
New Genoa-French Island 161 kV	33.0	350	11,550.0
Reconductor French Island-La Crosse 161 kV	1.4	72	100.8
La Crosse 161 kV Circuit Breakers	1	369	369.0
French Island 161 kV Transmission Sub	1	638	638.0
French Island 161 kV Circuit Breakers	3	369	1,107.0
French Island 161/69 kV 112 MVA Transformer	1	1487	1,487.0
French Island 69 kV Circuit Breakers	1	246	246.0
Mayfair 161 kV 18 Mvar Capacitor	1	331	331.0
Option 8 costs:			**33,188.8**
Total Costs:			**46,668.9**
DISQUALIFIED - 90 MW French Island generation required for G3 & ALM-MRS offline (2009 Loads + 50 MW).			

APPENDIX E – ECOMONIC COMPARISON Cont.

Option D New North La Crosse PAR & New Alma-Goodview-N. La Crosse 161			
Facility 2005	Units	Unit Cost $ 1000's	Cost $ 1000's
Costs Common to all Options:			**13,480.1**
New Alma-Goodview 161 kV	33.0	350	11,550.0
Goodview 161 kV Transmission Sub	1	638	638.0
Goodview 161 kV Circuit Breakers	3	369	1,107.0
Goodview 161/69 kV 112 MVA Transformer	1	1189	1,189.0
Goodview 69 kV Circuit Breakers	1	246	246.0
Rebuild Goodview tap 161kV	3.1	350	1,085.0
Rebuild Q1 Alma-Buffalo Town 161kV	20.6	350	7,210.0
New Goodview tap-Buffalo Town 161 kV	2.5	350	875.0
New Double Circuit Buffalo Town-Marshland 161 kV	4.8	465	2,232.0
Convert Q1 to Double Circuit Marshland-North La Crosse 161kV	15.4	465	7,161.0
Rebuild Q1 North La Crosse-La Crosse tap 161kV	8.8	350	3,080.0
New Double Circuit tapping Tremval-Mayfair 161 kV	0.5	558	279.0
North La Crosse 161 kV Transmission Sub	1	638	638.0
North La Crosse 161 kV Circuit Breakers	9	369	3,321.0
North La Crosse 69 kV Circuit Breakers	1	246	246.0
North La Crosse 161 kV 18 Mvar Capacitor	1	265	265.0
North La Crosse 161/69 kV 112 MVA Transformer	1	1189	1,189.0
North La Crosse 300 MVA Phase Angle Regulator	1	5500	5,500.0
Option d costs:			**47,811.0**
Total Costs:			**61,291.1**
No French Island generation required for this option (2009 Loads + 50 MW).			

APPENDIX E – ECOMONIC COMPARISON Cont.

Option E New North La Crosse PAR & New Rochester-Goodview-N. La Crosse 161			
Facility 2005	**Units**	**Unit Cost $ 1000's**	**Cost $ 1000's**
Costs Common to all Options:			**13,480.1**
New Rochester-Goodview 161 kV	35.0	350	12,250.0
Goodview 161 kV Transmission Sub	1	638	638.0
Goodview 161 kV Circuit Breakers	3	369	1,107.0
Goodview 69 kV Circuit Breakers	1	246	246.0
Goodview 161/69 kV 112 MVA Transformer	1	1189	1,189.0
Goodview 69 kV Circuit Breakers	1	246	246.0
Rebuild Goodview tap 161kV	3.1	350	1,085.0
Rebuild Q1 Alma-Buffalo Town 161kV	20.6	350	7,210.0
New Goodview tap-Buffalo Town 161 kV	2.5	350	875.0
New Double Circuit Buffalo Town-Marshland 161 kV	4.8	465	2,232.0
Convert Q1 to Double Circuit Marshland-North La Crosse 161kV	15.4	465	7,161.0
Rebuild Q1 North La Crosse-La Crosse tap 161kV	8.8	350	3,080.0
New Double Circuit tapping Tremval-Mayfair 161 kV	0.5	558	279.0
North La Crosse 161 kV Transmission Sub	1	638	638.0
North La Crosse 161 kV Circuit Breakers	9	369	3,321.0
North La Crosse 161 kV 18 Mvar Capacitor	1	265	265.0
North La Crosse 161/69 kV 112 MVA Transformer	1	1189	1,189.0
North La Crosse 69 kV Circuit Breakers	1	246	246.0
North La Crosse 300 MVA Phase Angle Regulator	1	5500	5,500.0
Option e costs:			**48,757.0**
Total Costs:			**62,237.1**
No French Island generation required for this option (2009 Loads + 50 MW).			

APPENDIX E – ECOMONIC COMPARISON Cont.

Option F New Rochester-Goodview-N. La Crosse 161 Facility 2005	Units	Unit Cost $ 1000's	Cost $ 1000's
Costs Common to all Options:			**13,480.1**
New Rochester-Goodview 161 kV	35.0	350	12,250.0
Goodview 161 kV Transmission Sub	1	638	638.0
Goodview 161 kV Circuit Breakers	3	369	1,107.0
Goodview 161/69 kV 112 MVA Transformer	1	1189	1,189.0
Goodview 69 kV Circuit Breakers	1	246	246.0
Rebuild Goodview tap 161kV	3.1	350	1,085.0
Rebuild Q1 Alma-Buffalo Town 161kV	20.6	350	7,210.0
New Goodview tap-Buffalo Town 161 kV	2.5	350	875.0
New Double Circuit Buffalo Town-Marshland 161 kV	4.8	465	2,232.0
Convert Q1 to Double Circuit Marshland-North La Crosse 161kV	15.4	465	7,161.0
Rebuild Q1 North La Crosse-La Crosse tap 161kV	8.8	350	3,080.0
New Double Circuit tapping Tremval-Mayfair 161 kV	0.5	558	279.0
North La Crosse 161 kV Transmission Sub	1	638	638.0
North La Crosse 161 kV Circuit Breakers	10	369	3,690.0
North La Crosse 161 kV 18 Mvar Capacitor	1	265	265.0
North La Crosse 161/69 kV 112 MVA Transformer	1	1189	1,189.0
North La Crosse 69 kV Circuit Breakers	1	246	246.0
Option f costs:			**43,380.0**
Total Costs:			**56,860.1**
PITFALLS:			
1. Genoa-Coulee 161@ 98% FLO Genoa-La Crosse tap-Marshland & JPM offline.			
2. Genoa-La Crosse tap 161@ 97% FLO Genoa-Coulee & JPM offline.			
60 MW French Island generation required for JPM & GEN-COU offline (2009 Loads + 50 MW).			

APPENDIX E – ECOMONIC COMPARISON Cont.

Option G Alma-Goodview-N. La Crosse 161 Facility 2005	Units	Unit Cost $ 1000's	Cost $ 1000's
Costs Common to all Options:			**13,480.1**
New Alma-Goodview 161 kV	33.0	350	11,550.0
Goodview 161 kV Transmission Sub	1	638	638.0
Goodview 161 kV Circuit Breakers	3	369	1,107.0
Goodview 161/69 kV 112 MVA Transformer	1	1189	1,189.0
Goodview 69 kV Circuit Breakers	1	246	246.0
Rebuild Goodview tap 161kV	3.1	350	1,085.0
Rebuild Q1 Alma-Buffalo Town 161kV	20.6	350	7,210.0
New Goodview tap-Buffalo Town 161 kV	2.5	350	875.0
New Double Circuit Buffalo Town-Marshland 161 kV	4.8	465	2,232.0
Convert Q1 to Double Circuit Marshland-North La Crosse 161kV	15.4	465	7,161.0
Rebuild Q1 North La Crosse-La Crosse tap 161kV	8.8	350	3,080.0
New Double Circuit tapping Tremval-Mayfair 161 kV	0.5	558	279.0
North La Crosse 161 kV Transmission Sub	1	638	638.0
North La Crosse 161 kV Circuit Breakers	10	369	3,690.0
North La Crosse 161 kV 18 Mvar Capacitor	1	265	265.0
North La Crosse 161/69 kV 112 MVA Transformer	1	1189	1,189.0
North La Crosse 69 kV Circuit Breakers	1	246	246.0
Option g costs:			**42,680.0**
Total Costs:			**56,160.1**
DISQUALIFIED-140 MW French Island generation required for JPM & GEN-COU offline (2009 Loads + 50 MW).			

APPENDIX E – ECOMONIC COMPARISON Cont.

Option H Rochester-La Crescent-N. La Crosse 161			
Facility 2005	**Units**	**Unit Cost $ 1000's**	**Cost $ 1000's**
Costs Common to all Options:			**13,480.1**
New Rochester-La Cresent 161 kV	60.0	350	21,000.0
La Crosse 161 kV Circuit Breakers	1	369	369.0
La Cresent 161 kV Transmission Sub	1	638	638.0
La Cresent 161 kV Circuit Breakers	3	369	1,107.0
La Cresent 161/69 kV 112 MVA Transformer	1	1189	1,189.0
La Cresent 69 kV Circuit Breakers	1	246	246.0
Rebuild La Cresent-French Island 161kV	3.1	350	1,085.0
Reconductor French Island-La Crosse 161 kV	1.4	72	100.8
Rebuild Q1 Alma-Marshland 161kV	25.4	350	8,890.0
Rebuild Q1 Marshland-La Crosse tap 161kV	24.2	350	8,470.0
Mayfair 161 kV 18 Mvar Capacitor	1	331	331.0
Option h costs:			**43,425.8**
Total Costs:			**56,905.9**
70 MW French Island generation required for JPM & GEN-COU offline (2009 Loads + 50 MW).			

APPENDIX E – ECOMONIC COMPARISON Cont.

Option I New Genoa-North La Crosse 161 Alma-Genoa Double Circuit Facility 2005	Units	Unit Cost $ 1000's	Cost $ 1000's
Bell Center 161 kV 18 Mvar Capacitor	1	265	265.0
Hillsboro 161 kV 18 Mvar Capacitor	1	265	265.0
La Crosse 161 kV 18 Mvar Capacitor	2	331	662.0
Monroe Co 69 kV 14.4 Mvar Capacitor	1	235	235.0
Reconductor DPC Portion Q11 Genoa-Coulee 161kV	16.9	93	1,571.7
Rebuild/Reconductor XEL Portion Q11 Genoa-Coulee 161kV	1.8	116	208.8
Upgrade XEL Coulee sub to 2000 Amps	1	500	500.0
Upgrade XEL Coulee Transformer #2 to 112 MVA	1	923	923.0
Uprate Q8 Adams-Harmony 161kV	35.6	71	2,527.6
New Genoa-North La Crosse 161 kV	37.0	350	12,950.0
North La Crosse 161 kV Transmission Sub	1	638	638.0
North La Crosse 161 kV Circuit Breakers	13	369	4,797.0
North La Crosse 161 kV 18 Mvar Capacitor	1	265	265.0
North La Crosse 161/69 kV 112 MVA Transformer	1	1189	1,189.0
North La Crosse 69 kV Circuit Breakers	1	246	246.0
New Double Circuit tapping Tremval-Mayfair 161 kV	0.5	558	279.0
Rebuild La Crosse tap 161 kV Dbl Ckt Steel Tower	4.0	465	1,860.0
Rebuild Q1 Genoa-La Crosse tap 161kV Dbl Ckt Steel Tower	20.7	465	9,625.5
Rebuild Q1 Alma-Marshland 161kV Dbl Cktt Steel Tower	25.4	465	11,811.0
Rebuild Q1 Marshland-North La Crosse 161kV Dbl Ckt Steel Tower	15.4	465	7,161.0
Rebuild Q1 North La Crosse-La Crosse tap 161kV Dbl Ckt Steel Tower	8.8	465	4,092.0
Alma 161 kV Circuit Breaker	1	369	369.0
Marshland 161 kV Circuit Breaker	2	369	738.0
La Crosse 161 kV Circuit Breaker	1	369	369.0
Genoa 161 kV Circuit Breaker	1	369	369.0
North La Crosse 161 kV Circuit Breakers	10	369	3,690.0
North La Crosse 161 kV 18 Mvar Capacitor	1	265	265.0
North La Crosse 161/69 kV 112 MVA Transformer	1	1189	1,189.0
North La Crosse 69 kV Circuit Breakers	1	246	246.0
Option I costs:			**69,306.6**
Note: ATC assumes Cost of Monroe County-Council Creek			

10.0 REGIONAL 345 OPTION ANALYSIS

The Southeast Minnesota, Southwest Wisconsin Regional 345 Transmission Planning Study was initiated in January, 2004 to identify and evaluate potential transmission additions to mitigate several regional bulk transmission system inadequacies. These inadequacies include resolving Rochester, MN and La Crosse, WI area load serving and congestion issues as well as increasing the Minnesota-Wisconsin System Interface limit. The Rochester area local load serving problems are explained in more detail in the “Statement of the Problem” section of this document. Likewise, the La Crosse load serving issues are explained in more detail in Section 9 of this document.

For load serving purposes, two new 345/161 kV substations will be added into the region. One substation will be located in Rochester, MN area and the other in the La Crosse, WI area. Due to the predominating west to east flow pattern, the basic transmission additions studied were assumed to interconnect into the new Rochester, MN area substation on the north side of the city with two new 161 kV ties to existing substations. One 161 kV interconnection will be to the Northern Hills Substation in northwest Rochester and a second 161 kV tie to the existing Chester Substation, located on the eastern edge of the City of Rochester. This placement would relieve, rather than exacerbate the predominant west to east flows on the transmission lines in Rochester. This connection provides a functional and reliable connection to the existing Rochester Area 161 kV facilities of RPU and DPC as well as the DPC 69 kV system. The new North La Crosse, WI area substation will be located north of the city at an existing 69 kV switching station named North La Crosse.

The exact location of a 345 kV substation in the La Crosse area will be determined after the siting study for the 345 kV line is completed. For the purpose of the study, it was assumed to be located at the DPC North La Crosse 69 kV switching station site, near Holmen, WI. The DPC 161 kV line from Marshland to La Crosse is near the perimeter of the the site. DPC owns sufficient land in the area to accomodate the development of a 345/161 kV site. Further, XCEL's 161 kV line from Tremval to Mayfair is within 0.5 miles of this substation. This would allow for the termination of four 161 kV lines in addition to the 345 kV line from Rochester. Further, the location of the 69 kV switching station allows for additional 161-69 kV transformer capacity to serve the local load in the Onalaska-Holmen areas providing a third major source to the greater La Crosse area. Termination of the 345 kV line could also be at the La Crosse 161 kV substation with four 161 kV line terminations. However, that location is adjacent to a wetland on the north side of La Crosse, thus, expansion of the substation could be an issue as well as routing a major line through the City of La Crosse. Termination of the 345 kV line at Alma or Genoa would not address load-serving issues in the La Crosse area as it is not close enough to the load center.

As part of the transmission planning process, certain endpoints must be used to determine the general viability of a project. As such, the North La Crosse switching station has been identified as the endpoint for this study. There are numerous issues associated with the siting of any line, but especially a line from Rochester to the La Crosse area. This includes the availability of corridor sharing, routing a major line through the Mississippi bluff lands, routing a line across the Mississippi River and siting a major 345 kV substation a rapidly expanding area in the La Crosse area. A more detailed analysis of the siting issues will be undertaken by the utilities involved in this project. This analysis will include discussions with major agencies in the siting and routing discussions: the Public Service Commission of Wisconsin, the Minnesota Public Utilities Commission, the United States Fish and Wildlife Services regarding the National Wildlife Refuges, the Wisconsin and Minnesota Departments of Natural Resources, the US Army Corps of Engineers, etc. as well as the transmission planning engineers, transmission design engineers, ROW managers, community relations representatives and other internal parties.

The power flow studies document the n-1 contingency system impact regarding line overloads and voltage support each proposed transmission facility addition has for the bulk transmission system in Southeast Minnesota and Southwest Wisconsin. This analysis coupled with the economic analyses located in Sections 12 and 13 of this document will be evaluated to attain the most cost effective solution for the region.

10.1 Transmission Options Evaluated

The Southeast Minnesota, Southwest Wisconsin Regional Transmission Study evaluated a total of five 345 kV options as listed below. See Appendix B for a map of these options.

Option 1 -	Prairie Island to Rochester to North La Crosse to Columbia 345 kV line (PI-RST-NLAX-COL).
Option 2 -	Prairie Island to Rochester to North La Crosse to West Middleton 345 kV line (PI-RST-NLAX-WM).
Option 3 -	Prairie Island to Rochester to Salem 345 kV line (PI-RST-SAL).
Option 4 -	Prairie Island to North La Crosse to Columbia 345 kV line (PI-WI-NLAX-COL).
Option 5 -	Prairie Island to North La Crosse to West Middleton 345 kV line (PI-WI-NLAX-WM).

Table 10.1 – Transmission Addition Options

10.2 Model Development

The Southeast Minnesota, Southwest Wisconsin Regional Transmission Study utilized the 2009 summer peak and 2009 summer off-peak models from the Mid-Continent Area Power Pool (MAPP) 2004 series of published power flow models. The base case models were downloaded from the MAPP ftp site. The summer off-peak models were modified to represent cases where the North Dakota Export (NDEX), Manitoba Hydro Export (MHEX), and Minnesota-Wisconsin System Interface (MWSI) were set to their maximums, which are 1950 MW, 2175 MW, and 1480 MW respectively. One additional export limit, requested by Minnesota Power (MP) and American Transmission Company (ATC), was a combined 1250 MW limit on the combined flows of the Arrow Head to Gardner Park 345 kV line and the Eau Claire to Arpin 345 kV line on exports into central, eastern, and southeastern Wisconsin. Generation, load, and interchange values were scaled in the base case model to attain this export level in conjunction with NDEX, MHEX, and existing MWSI limits.

During the construction of the summer off-peak high transfer power flow models for each transmission alternative no generation, load, and area interchange values where changed after the new line was added into the base case model. The result of this was the NDEX and MHEX were unchanged, but the flow on the two existing MWSI lines (Eau Claire - Arpin 345 kV plus Prairie Island – Byron 345 kV lines) were reduced with the addition of a new 345 kV line crossing the inter-area boundary. However, with the addition of a new 345 kV tie out of the area, new operating guides and limits will need to be created to manage the

MWSI. To create the worst case for the Rochester Area load serving model, all local Rochester area generation was turned off in the summer off-peak high transfer cases including all RPU generation and GRE's Pleasant Valley Generation. An outline of the procedure followed to create the summer off-peak high transfer case along with a list of regional generation levels are included in Appendix B.

From the base case models additional changes were made by study participants to their representative systems to properly condition the model for the study. The typical changes made were transmission and generation facility upgrades previously planned and scheduled for completion prior to 2009. The other major model changes were the replacement of the entire 2009 summer peak power flow model representation of the ATC and Alliant West systems with that from the published 2004 Midwest Independent System Operator (MISO) power flow models. Further changes were made to the summer peak model to create the 70% load summer off-peak case. Since the changes to the base case models were extensive, the entire list will not be documented in this section. However, the entire model change list can be found in Appendix B.

10.3 System Analysis

Power flow contingency analysis was used to screen and compare the proposed alternatives to the existing system in determining the system impact of each transmission option. Each contingency screen was evaluated and documented based on the following.

1. Any and all line overloads that were either mitigated or created due to the addition of each proposed line when compared to the existing system.
2. Any existing line overloads that changed $\pm$ 3% due to the addition of each proposed line when compared to the existing system.
3. Any and all bus voltage violations that were either mitigated or created due to the addition of each proposed line when compared to the existing system.
4. Any existing bus voltage violation that changed $\pm$ 3% due to the addition of each proposed line when compared to the existing system.

The study area included in the contingency monitoring process consisted of the transmission and generating facilities inside the boundary created by the following:

1. XCEL Energy facilities from the Twin Cities south and east in Minnesota as well as Wisconsin facilities from the Eau Claire Area south.
2. Alliant Energy facilities in Southeast Minnesota and Northern Iowa.
3. MEC facilities in Northern Iowa.
4. All Dairyland Power facilities in Minnesota, Wisconsin, Iowa and Illinois.
5. GRE facilities in Southeast Minnesota
6. SMMPA facilities in Southeast Minnesota

7. ATC facilities in Southwestern Wisconsin from the Madison Area west and from the Wausau Area south.
8. All RPU facilities

For contingency monitoring, all lines 100 kV and above were included for the study footprint described with the addition of all Dairyland and ATC facilities at 69 kV as well as the 69 kV facilities along the Mississippi River from Alma to Hastings. The acceptable voltage range used for this study was 1.08 to 0.92 per unit for all load serving and non-load serving buses. A single contingency analysis where each line 100 kV or above is removed from service, one at a time, was performed on the study footprint with the addition of the 69 kV facilities along the Mississippi River. Contingency analysis also included analysis of all multiple tripping schemes provided by the study participants for their respective systems. The line overload limit used for this study was 100% of Rate A, the maximum normal rating of the facility. The complete contingency analysis output and system files are included in Appendix B.

10.4 Best Performing Option

Upon first inspection of the five 345 kV line options studied for the Southeast Minnesota, Southwest Wisconsin Regional Transmission Study three options can be eliminated for consideration since they do not resolve all of the transmission inadequacies set out in the scope of the study. Both line options that leave Prairie Island and route to North La Crosse on the Wisconsin side of the Mississippi River (Options 4 and 5 in Table 10.1 above) do not resolve any of the long term load serving need in the Rochester Area. Likewise, the transmission option that is routed from Prairie Island to Rochester to Salem (Option 3 in Table 10.1) does not resolve any of the load serving issues in the La Crosse Area. The remaining two options for consideration are the Prairie Island to Rochester to North La Crosse to Columbia 345 kV line (Option 1 in Table 10.1) and the Prairie Island to Rochester to North La Crosse to West Middleton 345 kV line (Option 2 in Table 10.1).

The results of the 2009 summer off-peak high transfer contingency analysis showed that both Option 1 and Option 2 performed equally as well on system impact in mitigating a large number of contingency overloads that appeared on the existing transmission system, while creating only a few new overloads listed in Table 10.2 below. Likewise, with the additions of either Option 1 or Option 2, all of the existing contingency overloads exceeding the $\underline{+}$3% criteria were reduced without exception.

Case	Monitored Element	Contingency	Rating	Post Contingent Flow
PI-RST-NLAX-COL	La Crosse – Mayfair 161 kV	North La Crosse – Hilltop 345 kV	197	217.6
PI-RST-NLAX-COL	Mayfair –North La Crosse 161 kV	North La Crosse – Hilltop 345 kV	197	252.7
PI-RST-NLAX-COL	Maple Leaf – Byron 161 KV	Prairie Island – Rochester 345 kV	302	328.6
PI-RST-NLAX-COL	Maple Leaf - Cascade Creek 161 kV	Prairie Island - Rochester 345 kV	302	317.7
PI-RST-NLAX-COL	Mayfair – North La Crosse 161 kV	Genoa Generator Unit 3	197	217.2
PI-RST-NLAX-COL	Mayfair – North La Crosse 161 kV	Coulee – La Crosse 161 kV, plus Genoa – La Crosse Tap 161 kV, plus La Crosse – La Crosse Tap 161 kV	197	205.9
PI-RST-NLAX-WM	Mayfair -North La Crosse 161 kV	North La Crosse – Spring Green 345 kV	197	205.1
PI-RST-NLAX-WM	Marshland - North La Crosse 161 kV	Rochester - North la Crosse 345 kV	162	166.4
PI-RST-NLAX-WM	Maple Leaf – Byron 161 KV	Prairie Island – Rochester 345 kV	302	327.2
PI-RST-NLAX-WM	Maple Leaf -to Cascade Creek 161 kV	Prairie Island - Rochester 345 kV	302	316.8
PI-RST-NLAX-WM	Mayfair - North La Crosse 161 kV	Coulee – La Crosse 161 kV, plus Genoa – La Crosse Tap 161 kV, plus La Crosse – La Crosse Tap 161 kV	197	205.1

Table 10.2 Created Contingency Overloads – 2009 Summer Off-Peak

To mitigate the overloads listed above in Table 10.2, the following system improvements are proposed to be made:

1. La Crosse – Mayfair 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.

2. Mayfair – North La Crosse 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.
3. Marshland – North La Crosse 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.
4. Maple Leaf to Cascade161 kV line – the existing operating guide will need to be modified to mitigate the contingency overload on this line.
5. Maple Leaf to Byron161 kV line – the existing operating guide will need to be modified to mitigate the contingency overload on this line.

The results of the 2009 summer peak contingency analysis showed that Option 1 provided better system performance than did Option 2. Option 1 mitigated more contingency overloads that existed on the existing transmission system than did Option 2. Option 1 also created fewer new overloads on the bulk transmission system as shown in Table 10.3 below. Both Option 1 and Option 2 did however reduce all existing contingency overloads exceeding the ±3% criteria without exception.

Case	Monitored Element	Contingency	Rating	Post Contingent Flow
PI-RST-NLAX-COL	Mayfair - North La Crosse 161 kV	Genoa Generator Unit 3	197	217.9
PI-RST-NLAX-COL	Mayfair - North La Crosse 161 kV	Coulee – La Crosse 161 kV, plus Genoa – La Crosse Tap 161 kV, plus La Crosse – La Crosse Tap 161 kV	197	200.0
PI-RST-NLAX-COL	Waupaca 138/69 kV Transformer	White Lake - Waupaca 138 kV	46.7	50.7
PI-RST-NLAX-WM	Mayfair - North La Crosse 161 kV	Genoa Generator Unit 3	197	216.3
PI-RST-NLAX-WM	Mayfair - North La Crosse 161 kV	Coulee – La Crosse 161 kV, plus Genoa – La Crosse Tap 161 kV, plus La Crosse – La Crosse Tap 161 kV	197	230.4
PI-RST-NLAX-WM	Petenwell 138/69 kV Transformer	POE- SAL 138 kV	33	33.6
PI-RST-NLAX-WM	Wabasha- Lake City 69 kV	Prairie Island 345/161 kV Transformer	34	35.0
PI-RST-NLAX-WM	Mayfair - North La Crosse 161 kV	Coulee – Genoa 161 kV	197	197.9
PI-RST-NLAX-WM	Hillsboro – T Sauk 69 kV	Jackson – Tremval 161 kV	25	25.3
PI-RST-NLAX-WM	Mayfair - North La Crosse 161 kV	La Crosse – La Crosse Tap 161 kV	197	226.1

Table 10.3 Created Contingency Overloads – 2009 Summer Peak

To mitigate the overloads listed above in Table 10.3, the following system improvements are proposed to be made.

1. Mayfair – North La Crosse 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.
2. Waupaca 138/69 kV Transformer – the size of the transformer will either need to be increased or a second transformer should be placed in parallel to handle the increased contingency flow. One recommendation is to replace the 46.7 MVA transformer with a 60 MVA transformer.
3. Petenwell 138/69 kV Transformer – the size of the transformer will either need to be increased or a second transformer should be placed in parallel to handle the increased contingency flow. An operating guide can also be developed to mitigate this contingency overload.

4. Wabasha – Lake City 69 kV line - If the planned new Zumbro Falls to Lake City 69kV line is completed this overload will not be an issue. If it is not completed an operating guide will need to be developed to mitigate the contingency overload on this line until the Zumbro Falls to Lake City 69kV line is in service.
5. Hillsboro – T Sauk 69 kV line - an operating guide will need to be developed to mitigate the contingency overload on this line.

XCEL Energy performed a transmission interchange limit analysis (TLTG) on each of the study options listed in Table 10.1 to determine which option has the greatest potential to increase the export on the MWSI during the summer off-peak under contingency operating conditions. Since only Options 1 and 2 of Table 10.1 provide load service for both Rochester and La Crosse, only the results of these options are listed below in Table 10.4. Table 10.4 lists the incremental MWSI transfer capability increases as a result of adding one of the specified 345 kV transmission line for various system contingencies that result in limiting MWSI transfer capability. Each line was evaluated up to five (5) system limiting factors, which is possible if all of the prior system limiting factors were mitigated. The incremental improvements were normalized to the Original System so the increments shown below in Table 10.4 would be the power increases that Option1 or 2 provide to MWSI when system improvements for each limiter was mitigated at each step in all models. The TLTG data can be found in Appendix B.

		System Limiter Number				
Option		**1**	**2**	**3**	**4**	**5**
Original System	**Transfer Increase**	**0 MW**	**0 MW**	**0 MW**	**0 MW**	**0 MW**
	Limiter	**Hazelton -Dundee 161 kV**	**Adams-Beaver Creek 161 kV**	**Maple Leaf-Cascade 161 kV**	**Arpin-Sigel 138 kV**	**Seneca-Gran Grae 161 kV**
	Contingency	**Hazelton – Arnold 345 kV**	**Adams-Hazelton 345 kV**	**Byron-Pleasant Valley-Adams 345 kV, plus Adams 345/161 kV transformer**	**Arpin-Rocky Run 345 kV**	**Adams-Hazelton 345 kV**
PI-RST-NLAX-COL	**Transfer Increase over Original System**	**315 MW**	**692 MW**	**608 MW**	**395 MW**	**728 MW**
	Limiter	**Hazelton -Dundee 161 kV**	**Maple Leaf-Cascade 161 kV**	**Mayfair-North La Crosse 161 kV**	**Adams-Beaver Creek 161 kV**	**Arpin-Sigel 138 kV**
	Contingency	**Hazelton – Arnold 345 kV**	**Prairie Island-Rochester 345 kV**	**La Crosse-La Crosse Tap – Genoa 161 kV**	**Adams-Hazelton 345 kV**	**Arpin-Rocky Run 345 kV**
PI-RST-NALX-WM	**Transfer Increase**	**357 MW**	**274 MW**	**699 MW**	**416 MW**	**567 MW**
	Limiter	**Hazelton -Dundee 161 kV**	**Maple Leaf-Cascade 161 kV**	**Seneca-Gran Grae 161 kV**	**Adams-Beaver Creek 161 kV**	**Arpin-Sigel 138 kV**
	Contingency	**Hazelton – Arnold 345 kV**	**Prairie Island-Rochester 345 kV**	**North La Crosse – Spring Green 345 kV**	**Adams-Hazelton 345 kV**	**Arpin-Rocky Run 345 kV**

Table 10.4 – TLTG Results – 2009 Summer Off-Peak

The results of the TLTG analyses shows that with the addition of Option 1 or Option 2 from Table 10.1, the MWSI has the ability to increase 728 MW and 567 MW respectively, when normalized to the existing system, under contingency conditions up to the fifth limiter.

10.5 Sensitivity Analysis - Radials

As a subset of the larger Southeast Minnesota, Southwest Wisconsin Regional Transmission Study, a sensitivity analysis was performed on the three radial 345 kV lines listed in Table 10.5 below. The radial analysis was performed to study the system impact of a radial 345 kV line in the region in the event that the regional 345 kV loop options discussed above would not be constructed immediately. The radials were built to resolve only the load serving issues at Rochester, MN and La Crosse, WI. The same contingency power flow analysis was performed on these three radial lines as was performed during the original study as documented above, with the same study footprint, contingency list, and result criteria. This power flow analysis was performed using the summer off-peak high transfer model only.

Option 6 - Radial 345 kV line from Prairie Island to Rochester to North La Crosse (PI-RST-NLAX).
Option 7 - Radial 345 kV line from Prairie Island to North La Crosse (PI-WI-NLAX).
Option 8 - Radial 345 kV line from Prairie Island to Rochester (PI-RST).

Table 10.5 Radial Transmission Addition Options

Upon inspection of the three radial line options, Option 7 is eliminated from consideration since it does not include a branch into the Rochester Area to resolve that load serving issue. Option 8 however will be considered in this study in the event that a Prairie Island to Rochester leg of a larger regional solution could be put into service as soon as it is completed, thus allowing a phased approach. While some of the existing system contingency overloads were either eliminated or reduced with the addition of the new radial line options, as expected, there were several contingencies that created new overloads. Since the list is extensive in length, Table 10.6 below will not identify all the contingencies that created overloads, but list only the individual lines where the contingency overloads were created along with the range of overloads that were seen. Similarly Table 10.7 lists the existing contingency overloads that increased more than the 3% limit. The power flow data for the radial analysis can be found in Appendix C.

Case	Monitored Element	Rating	Minimum Created Contingency Overload	Maximum Created Contingency Overload
PI-RST-NLAX	La Crosse - Monroe County 161 kV	223	225.4	265.7
PI-RST-NLAX	Mayfair - North La Crosse 161 kV	304	307.6	321.9
PI-RST-NLAX	Bell Center – Steuben 69 kV	25	26.1	26.7
PI-RST-NLAX	Bell Center 161/69 kV Transformer	67	83.7	83.7
PI-RST-NLAX	Seneca – Genoa 161 kV	304	310.4	310.4
PI-RST-NLAX	Seneca – Gran Grae 161 kV	201	203.6	234.8
PI-RST	Eldora – IA Falls Ind 115 kV	97	98.9	100.3
PI-RST	Adams – Beaver Creek 161 kV	223	228.8	230.3
PI-RST	Beaver Creek – Harmony 161 kV	223	226.8	226.8

Table 10.6 Created Contingency Overloads – Radial Sensitivity Analysis

Case	Monitored Element	Contingency	Rating	Existing System Overload	Overload With Proposed Line	% Increase
PI-RST-NLAX	La Crosse – Monroe County 161 kV	Eau Claire – Arpin 345 kV	223	220.4	264.9	20.19%
PI-RST-NLAX	Seneca – Gran Grae 161 kV	Pleasant Valley – Adams 345 kV, plus Adams 345/161 kV Transformer, plus Adams – Hazelton 345 kV	201	204.1	235.6	15.43%
PI-RST-NLAX	La Crosse – Monroe County 161 kV	Eau Claire – Arpin 345 kV, plus Stratford – Wien 115 kV	223	224.7	269.4	19.89%
PI-RST-NLAX	Bell Center 161/69 kV Transformer	Seneca – Gran Grae 161 kV, plus Gran Grae 161/689 kV Transformer, plus Gragrae – Nelson Dewey 161 kV	67	76.0	83.7	10.13%
PI-RST-NLAX	Seneca – Gran Grae 161 kV	Adams – Hazelton 345 kV	201	206.6	236.4	14.42%
PI-RST-NLAX	Seneca – Gran Grae 161 kV	Pleasant Valley – Adams 345 kV, plus Adams – Hazelton 345 kV	201	204.1	235.6	15.43%
PI-RST-NLAX	Bell Center 161/69 kV Transformer	Seneca – Gran Grae 161 kV	67	74.7	82.8	10.84%
PI-RST	Adams – Beaver Creek 161 kV	Genoa Generator Unit 3	223	240.1	247.4	3.04%

PI-RST	**Adams – Beaver Creek 161 kV**	**Pleasant Valley – Adams 345 kV, plus Adams 345/161 kV Transformer, plus Adams – Hazelton 345 kV**	**223**	**273.4**	**284.1**	**3.91%**
PI-RST	**Adams – Beaver Creek 161 kV**	**Pleasant Valley – Adams 345 kV, plus Adams – Hazelton 345 kV**	**223**	**273.4**	**284.1**	**3.91%**

Table 10.7 Increased Contingency Overloads – Radial Sensitivity Analysis, 2009 Summer Off-Peak

To mitigate the overloads listed above in Tables 10.6 and 10.7, the following system improvements are proposed to be made:

1. La Crosse – Monroe County 161 kV line – The line currently is 795 ACSR with a maximum rating of 279 MVA. Terminal equipment limitations lower the summer rating of this line to 223 MVA. The recommendation is to replace the terminal equipment with higher rated equipment so the thermal limit on the transmission line is the limiting factor, thus raising the rating of this line to 279 MVA.
2. Mayfair - North La Crosse 161 kV line - an operating guide will need to be developed to mitigate the contingency overload on this line unless the line is rebuilt with a conductor larger than 954 ACSR. One possible solution is to trip the Rochester to North La Crosse 345 kV branch when contingency flow on the Mayfair – North La Crosse line exceeds its 304 MVA rating. The cost data shows the cost of a line rebuild to attain a rating greater than 304 MW.
3. Bell Center – Steuben 69 kV line - an operating guide will need to be developed to mitigate the contingency overload on this line. One possible solution is to close the Fennimore – Castle Rock 69 kV line that is normally open to create a parallel flow when contingency flow on this line exceeds its 67 MVA rating. This normal open is remotely controlled by DPC.
4. Bell Center 161/69 kV Transformer – the size of the current two transformer bank will need to be increased since the current second transformer, which is about half the size of the larger transformer, should be replaced with a transformer of equal or greater size than the larger of the two transformers.
5. Seneca – Genoa 161 kV line – an overcurrent relay is in place such that if the flow on the Seneca-Gran Grae 161kV line exceeds 220 MVA, the low side breakers at Gran Grae open. This operating guide is not part of this study. This operating guide needs to be tested to verify that this overload is mitigated with the use of that operating guide.

6. Seneca – Gran Grae 161 kV line – Same as #5 above
7. Eldora – Iowa Falls Industrial 115 kV line - an operating guide will need to be developed to mitigate the contingency overload on this line.
8. Adams – Beaver Creek 161 kV line - the line should be reconductored with 954 ACSR to increase the line rating to 304 MVA summer rating.
9. Beaver Creek - Harmony 161 kV line - an operating guide will need to be developed to mitigate the contingency overload on this line unless this line is also reconductored with 954 ACSR to increase the summer rating to 304 MVA.

10.6 Sensitivity Analysis – La Crosse Area

As a subset of the larger Southeast Minnesota, Southwest Wisconsin Regional Transmission Study, a sensitivity analysis was performed using multiple facility outages in the La Crosse Area for the original five 345 kV line options analyzed in the original study listed in Table 10.1. The multiple contingencies consisted of a combination of either two generation facilities off-line at the same time or a generation facility off-line with a transmission line contingency. A list of contingencies used for this sensitivity analysis is documented below in Table 10.8. The same study footprint, monitoring area, and result criteria utilized in the original study was used for this study as well as. This power flow analysis was performed using the summer off-peak high transfer model only.

Contingency	Description
g3-jpm	Removed JPM #6 (-414.41 MW)
	Removed Genoa #3 (-368.0 MW)
	Added Elk Mound #1 and #2 (84 MW total)
	Adjusted Area 600 (XCEL) Interchange +698.41 MW (from -1417.6 MW to -719.19 MW)
	Adjusted Area 680 (DPC) Interchange -698.41 MW (from 162.7 MW to -535.71 MW)
g3-lsg	Removed Lansing #4 (-192.24 MW)
	Increased Ottumwa Generation +192.24 MW (from 208.51 MW to 400.75 MW)
	Removed Genoa #3 (-368.0 MW)
	Added Elk Mound #1 and #2 (84 MW total)
	Adjusted Area 600 (XCEL) Interchange +284 MW (from -1417.6 MW to -1133.6 MW)
	Adjusted Area 680 (DPC) Interchange -284 MW (from 162.7 MW to -121.3 MW)

g3-q1	Removed Genoa #3 (-368.0 MW)
	Added Elk Mound #1 and #2 (84 MW total)
	Adjusted Area 600 (XCEL) Interchange +284 MW (from -1417.6 MW to -1133.6 MW)
	Adjusted Area 680 (DPC) Interchange -284 MW (from 162.7 MW to -121.3 MW)
	Removed 69543 Alma 161 to 60309 Marshland 161 Line
g3-q18	Removed Genoa #3 (-368.0 MW)
	Added Elk Mound #1 and #2 (84 MW total)
	Adjusted Area 600 (XCEL) Interchange +284 MW (from -1417.6 MW to -1133.6 MW)
	Adjusted Area 680 (DPC) Interchange -284 MW (from 162.7 MW to -121.3 MW)
	Removed 69543 Alma 161 to 60316 Tremval 161 Line
jpm-q1	Removed JPM #6 (-414.41 MW)
	Added Elk Mound #1 and #2 (84 MW total)
	Adjusted Area 600 (XCEL) Interchange +330.41 MW (from -1417.6 MW to -1087.19 MW)
	Adjusted Area 680 (DPC) Interchange -330.41 MW (from 162.7 MW to -167.71 MW)
	Removed 69523 Genoa 161 to 69535 Lac Tap 161 Line
	Removed 69535 Lac Tap 161 to 60308 La Crosse 161 Line
jpm-q11	Removed JPM #6 (-414.41 MW)
	Added Elk Mound #1 and #2 (84 MW total)
	Adjusted Area 600 (XCEL) Interchange +330.41 MW (from -1417.6 MW to -1087.19 MW)
	Adjusted Area 680 (DPC) Interchange -330.41 MW (from 162.7 MW to -167.71 MW)
	Removed 69523 Genoa 161 to 60302 Coulee 161 Line

Table 10.8 La Crosse Area Multiple Contingencies

As in the original study, upon inspection of the five 345 kV line options under analysis three options can be eliminated for consideration since the inadequacies set out in the scope of the study are not mitigated. Both line options that leave Prairie Island and route to North La Crosse on the Wisconsin side of the Mississippi River (Options 4 and 5 in Table 10.1 above) do not resolve any of the long term load serving requirements in the Rochester Area. The transmission option that is routed from Prairie Island to Rochester to Salem (Option 3 in Table 10.1) does not resolve any of the load serving issues in the La Crosse Area. The remaining two options for consideration are the Prairie Island to Rochester to North La Crosse to Columbia 345 kV line (Option 1 in Table 10.1) and the Prairie

Island to Rochester to North La Crosse to West Middleton 345 kV line (Option 2 in Table 10.1).

The results of the La Crosse Area Sensitivity Analysis showed that both Option 1 and Option 2 performed equally as well on system impact in the both mitigating most of the existing contingency overloads in the La Crosse Area that appeared on the existing transmission system, while creating only a few new overloads documented in Table 10.9 below. Likewise, with the additions of either Option 1 or Option 2, all of the existing contingency overloads exceeding the ±3% criteria were reduced without exception. The power flow data for the La Crosse Area analysis can be found in Appendix D.

Case	Monitored Element	Contingency	Rating	Post Contingent Flow
PI-RST-NLAX-COL	Mayfair -North La Crosse 161 kV	G3-JPM	197	211.2
PI-RST-NLAX-COL	La Crosse - Mayfair 161 kV	G3-LSG	197	224.1
PI-RST-NLAX-COL	Mayfair -North La Crosse 161 kV	G3-LSG	197	256.2
PI-RST-NLAX-COL	Mayfair - North La Crosse 161 kV	G3-Q1	197	207.8
PI-RST-NLAX-COL	Mayfair - North La Crosse 161 kV	G3-Q18	197	225.6
PI-RST-NLAX-WM	Mayfair -North La Crosse 161 kV	G3-LSG	197	223.3
PI-RST-NLAX-WM	La Crosse Tap - North La Crosse 161 kV	G3-LSG	162	176.3
PI-RST-NLAX-WM	Mayfair - North La Crosse 161 kV	G3-Q18	197	199.0

Table 10.9 Created Contingency Overloads – La Crosse Area Sensitivity Analysis, 2009 Summer Off-Peak

To mitigate the overloads listed above in Table 10.9, the following system improvements are proposed to be made.

1. Mayfair – North La Crosse 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.
2. La Crosse – Mayfair 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.

3. La Crosse Tap to North La Crosse 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.

10.7 Sensitivity Analysis – Mason City Area

As a subset of the larger Southeast Minnesota, Southwest Wisconsin Regional Transmission Study, a sensitivity analysis was performed on several 161 kV transmission facilities in and around the Mason City Iowa area. In the original study 1,057 MW of wind and 600 MW of combustion turbine generation was added mostly in the Mason City Area with some in southern Minnesota. This generation was added into the base case models with no transmission upgrades in the area to handle the increased power flow. As a result multiple 161 kV lines in the Mason City area become over loaded in the base case model and an exorbitant number did so in the contingency analysis. To clean up the contingency analysis in the base case, the ratings on the 161 kV lines in the Mason City were increased to 1000 to affectively remove them from showing up on in the contingency results. Because of this, the Mason City Sensitivity analysis will now study the affect the new 345 kV transmission options (See Table 10.1) have on the 161 kV lines in the Mason City Area. A complete list of the Mason City generation additions and transmission facilities changes for the original study can be found in the Summer Peak and Summer Off-Peak Model Change Documents located in Appendix B. The same study footprint, contingency list, and result criteria utilized in the original study was used for this study as well as. The two differences being that the ratings of Mason City area 161 kV lines were restored to their original thermal ratings and the monitoring area was narrowed to only include Alliant West facilities. This power flow analysis was performed using both the summer peak and summer off-peak high transfer models.

For the summer peak case, after the original line ratings were reinstated, three lines were overloaded in the base case model prior to the contingency analysis. These lines were as listed in Table 10.10. So that these lines did not appear as overloaded in the contingency analysis report for roughly all 1200 contingencies, the line ratings for these three lines were increased to +3% of the base case flow on the lines. Thus these lines would only appear overloaded if a contingency would increase the flow on the line by more than 3%, which is the documentable criterion for this report.

Line	Rating	Base Case Flow	New Rating
Emery – Hampton 161 kV	**304**	**316.9**	**326.4**
Henry County – Denmark 161 kV	**112**	**167.4**	**172.4**
Henry County – Jeff 161 kV	**112**	**127.0**	**130.8**

Table 10.10 Line Rating Increases – Mason City Sensitivity Analysis

For the summer off-peak case, after the original line ratings were reinstated, only one line was overload in the base case model prior to the contingency analysis. This line was the Emery to Hampton 161 kV line that had a base case flow of 351.4 MW on a 304 MVA line. The rating of this line was increased, as done in the summer peak model, to 361.9

Again, as in the original study, upon inspection of the five 345 kV line options under analysis three options can be eliminated for consideration since each do not resolve all of the transmission inadequacies set out in the scope of the study. Both line options that leave Prairie Island and route to North La Crosse on the Wisconsin side of the Mississippi River (Options 4 and 5 in Table 10.1 above) do not resolve any of the long term load serving need in the Rochester Area. Likewise, the transmission option that is routed from Prairie Island to Rochester to Salem (Option 3 in Table 10.1) does not resolve any of the load serving issues in the La Crosse Area. The remaining two options for consideration are the Prairie Island to Rochester to North La Crosse to Columbia 345 kV line (Option 1 in Table 10.1) and the Prairie Island to Rochester to North La Crosse to West Middleton 345 kV line (Option 2 in Table 10.1).

The results of the 2009 summer off-peak high transfer contingency analysis showed that both Option1 and Option 2 performed equally as well on system by not creating any new contingency overloads on any Alliant West transmission facilities. Likewise, with the additions of either Option 1 or Option 2, all of the existing contingency overloads exceeding the ±3% criteria were reduced with the exception of the following overload increase list in Table 10.11. The power flow data for the Mason City analysis can be found in Appendix E.

Case	Monitored Element	Contingency	Rating	Existing System Overload	Overload With Proposed Line	% Increase
PI-RST-NLAX-COL	**Worth County – Hayward 161 kV**	**Emery – Floyd 161 kV**	**279**	**282.8**	**291.5**	**3.08%**
PI-RST-NLAX-WM	**Worth County – Hayward 161 kV**	**Emery – Floyd 161 kV**	**279**	**282.8**	**291.3**	**3.01%**

Table 10.11 Increased Contingency Overloads – Mason City Sensitivity Analysis, 2009 Summer Off-Peak

The results of the 2009 summer peak contingency analysis showed that both Option1 and Option 2 performed equally as well on system by not creating any new contingency overloads on any Alliant West transmission facilities. Likewise, with the additions of either Option 1 or Option 2, all of the existing contingency overloads exceeding the ±3% criteria were reduced without exception. The power flow data for the Mason City analysis, which is located in Appendix E, however does document the following overloads in Table 10.12.

Case	Monitored Element	Contingency	Rating	Post Contingent Flow
PI-RST-NLAX-COL	**Lime Creek – Emery 161 kV**	**Emery – CGordo 161 kV, plus CGordo – Hampton 161 kV**	**223**	**231.7**
PI-RST-NLAX-COL	**Lime Creek – Emery 161 kV**	**Emery – CGordo 161 kV**	**223**	**232.8**
PI-RST-NLAX-WM	**Lime Creek – Emery 161 kV**	**Emery – CGordo 161 kV, plus CGordo – Hampton 161 kV**	**223**	**231.8**
PI-RST-NLAX-WM	**Lime Creek – Emery 161 kV**	**Emery – CGordo 161 kV**	**223**	**232.9**

Table 10.12 Created Contingency Overloads – Mason City Sensitivity Analysis, 2009 Summer Peak

Even though these lines show up in the contingency analysis, each contingency was run individually to calculate what percentage increase on the power flow the contingency created form the base case system. When this analysis was done the following data was collected in Table 10.13.

Case	System Intact	Contingency: Emery – CGordo 161 kV	Contingency: Emery – CGordo 161 kV, plus CGordo – Hampton 161 kV
Existing System	199.5	227.2	226.4
PI-RST-NLAX-COL	202.9	230.5	229.3
PI-RST-NLAX-WM	203	230.6	229.8

Table 10.13 Created Contingency Overloads – Mason City Sensitivity Analysis – Individual Analysis

Examining the table above and comparing the new 345 line addition cases to the existing system, it is evident that for both contingencies the loading of the Lime

Creek to Emery line does not change more than 3% (3% over 227.2 for contingency 34017-34-016 = 234 and 3% over 226.4 for contingency 34017-34-016 plus 34017-34139 = 233.2). By current MAPP study guideline requirements, this overload does not need be listed as a problem created by the addition of the 345 kV line options.

10.8 Sensitivity Analysis – Hampton Corners

As a subset of the Southeast Minnesota, Southwest Wisconsin Regional Transmission Study, a sensitivity analysis was performed to document the system impact of starting the new 345 kV line addition at Hampton Corners instead of Prairie Island. For this study the system impact of adding a Prairie Island to Rochester to North La Crosse to Columbia 345 kV transmission line, Option 1 listed in Table 10.1, is compared to the system impact of adding a Hampton Corners to Rochester to North La Crosse to Columbia 345 kV transmission line, Option 9 listed in Table 10.14. This new Hampton Corners line was developed by moving the starting substation from Prairie Island to Hampton Corners, then adjusting the transmission line characteristics to account for the extra five (5) miles of length required for the route south to Rochester associated with starting at Hampton Corners. The same contingency power flow analysis was performed on the Hampton Corners Line as was performed during the original study as documented above, with the same study footprint, contingency list, and result criteria. This power flow analysis was performed using both the 2009 summer off-peak high transfer and 2009 summer peak models. The power flow data for the Hampton Corners analysis can be found in Appendix B.

Option 9 – Hampton Corners to Rochester to North La Crosse to Columbia 345 kV line (HC-RST-NLAX-COL).

Table 10.14 Hampton Corners Radial Transmission Option

The results of the 2009 summer peak contingency analysis showed that both Option 1 and Option 9 performed nearly equally as well as one another on system impact by mitigating a large number of contingency overloads that appeared on the existing transmission system, while creating only a few new overloads. The Hampton Corners line created one more contingency overload than did the Prairie Island line. The contingency overload occurred on the Wabasha to Lake City 69 kV line for a contingency of the Prairie Island 345/161 kV transformer. The other three contingency overloads created by the addition of the Prairie Island line were also created by the Hampton Corners line. The contingency overloads created by the addition of the Hampton Corners Line are listed in Table 10.15 below. Likewise, with the additions of either Option 1 or Option 9, all of the existing contingency overloads exceeding the ±3% criteria were reduced without exception.

Case	Monitored Element	Contingency	Rating	Post Contingent Flow
PI-RST-NLAX-COL	Mayfair - North La Crosse 161 kV	Genoa Generator Unit 3	197	217.9
PI-RST-NLAX-COL	Mayfair - North La Crosse 161 kV	Coulee – La Crosse 161 kV, plus Genoa – La Crosse Tap 161 kV, plus La Crosse – La Crosse Tap 161 kV	197	200.0
PI-RST-NLAX-COL	Waupaca 138/69 kV Transformer	White Lake - Waupaca 138 kV	46.7	50.7
HC-RST-NLAX-COL	Mayfair - North La Crosse 161 kV	Genoa Generator Unit 3	197	214.2
HC-RST-NLAX-COL	Mayfair - North La Crosse 161 kV	Coulee – La Crosse 161 kV, plus Genoa – La Crosse Tap 161 kV, plus La Crosse – La Crosse Tap 161 kV	197	196.9
HC-RST-NLAX-COL	Waupaca 138/69 kV Transformer	White Lake - Waupaca 138 kV	46.7	50.6
HC-RST-NLAX-COL	Wabasha – Lake City 69 kV	Prairie Island 345/161 kV Transformer	34	34.5

Table 10.15 Created Contingency Overloads – Hampton Corners Sensitivity Analysis, 2009 Summer Peak

To mitigate the overloads listed above in Table 10.15, the following system improvements are proposed to be made.

1. Mayfair – North La Crosse 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.
2. Waupaca 138/69 kV Transformer – the size of the transformer will either need to be increased or a second transformer should be placed in parallel to handle the increased contingency flow. One recommendation is to replace the 46.7 MVA transformer with a 60 MVA transformer.
3. Wabasha – Lake City 69 kV line - If the planned new Zumbro Falls to Lake City 69kV line is completed this overload will not be an issue. If it is not completed an operating guide will need to be developed to mitigate the contingency overload on this line until the planned Zumbro Falls to Lake City 69kV line is completed.

The results of the 2009 summer off-peak high transfer contingency analysis showed that both Option 1 and Option 9 performed nearly equally as well as one another on system impact by mitigating a large number of contingency overloads that appeared on the existing transmission system, while creating only a few new overloads. The Hampton Corners line created one more contingency overload than did the Prairie Island line. The contingency overload occurred on the La Crosse to Mayfair 161 kV line for a contingency of the Genoa Unit #3. The other six contingency overloads created by the addition of the Prairie Island line were also created by the Hampton Corners line. The contingency overloads created by the addition of the Hampton Corners Line are listed in Table 10.16 below. Both Option 1 and Option 9 did also reduce all existing contingency overloads exceeding the ±3% criteria without exception

Case	Monitored Element	Contingency	Rating	Post Contingent Flow
HC-RST-NLAX-COL	La Crosse – Mayfair 161 kV	North La Crosse – Hilltop 345 kV	197	213.8
HC-RST-NLAX-COL	Mayfair -North La Crosse 161 kV	North La Crosse – Hilltop 345 kV	197	248.6
HC-RST-NLAX-COL	Maple Leaf - Cascade Creek 161 kV	Hampton Corners - Rochester 345 kV	302	329.1
HC-RST-NLAX-COL	Maple Leaf - Cascade Creek 161 kV	Hampton Corners - Rochester 345 kV	302	318.3
HC-RST-NLAX-COL	Mayfair - North La Crosse 161 kV	Genoa Generator Unit 3	197	247.1
HC-RST-NLAX-COL	La Crosse – Mayfair 161 kV	Genoa Generator Unit 3	197	213.6
HC-RST-NLAX-COL	Mayfair - North La Crosse 161 kV	Coulee – La Crosse 161 kV, plus Genoa – La Crosse Tap 161 kV, plus La Crosse – La Crosse Tap 161 kV	197	201.8

Table 10.16 Created Contingency Overloads – Hampton Corners Sensitivity Analysis, 2009 Summer Off-Peak

To mitigate the overloads listed above in Table 10.16, the following system improvements are proposed to be made:

1. La Crosse – Mayfair 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.
2. Mayfair – North La Crosse 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.
3. Maple Leaf to Cascade161 kV line – the existing operating guide will need to be modified to mitigate the contingency overload on this line.
4. Maple Leaf to Byron161 kV line – the existing operating guide will need to be modified to mitigate the contingency overload on this line.

10.9 Sensitivity Analysis – RPU Underlying System

A sensitivity analysis was performed to document the system impact of adding the underlying 161 KV system that will interconnect the proposed Hampton Corners to Rochester to North La Crosse to Columbia 345 kV transmission addition in Southeast Minnesota, Southwest Wisconsin Regional Transmission Study. In the original study, the proposed 345 kV transmission line was interconnected into RPU 161 kV system at the Chester substation located on the eastern border of the City of Rochester. To more accurately model what is planned for construction the new 345 kV substation that will interconnect RPU system to the proposed transmission addition will be located on the northern border of the City of Rochester. Three new 161 KV transmission lines will run out of the new 345 kV substation interconnecting within the RPU system. The facilities added for this sensitivity analysis are listed below in Table 10.17. Adjustments were also made to proposed 345 kV transmission line impedance characteristics since the Hampton Corners to Rochester segment shortened by twelve (12) miles, while the Rochester to North LA Crosse segment lengthened by twelve (12) miles. The exact same contingency power flow analysis was performed on the RPU 161 kV underlying model as was performed during the original study as documented above, with the same study footprint, contingency list, and result criteria. This power flow analysis was performed using both the 2009 summer off-peak high transfer and 2009 summer peak models. The power flow data for the Hampton Corners analysis, with RPU 161 kV infrastructure added can be found in Appendix B.

1. New 345/161 kV Substation named RPU 345.
2. New 161 kV Load Serving Substation named West Side 161.
3. New 6.30 mile 161 kV Transmission Line from RPU 345 kV Sub to West Side 161 kV Sub.
4. New 3.35 mile 161 kV Transmission Line from RPU 345 kV Sub to Northern Hills 161 kV Sub.
5. New 16.63 mile 161 kV Transmission Line from RPU 345 kV Sub to Chester 161 kV Sub.
6. New 2.95 mile 161 kV Transmission Line from West Side 161 kV Sub to IBM 161 kV Sub.
7. Remove existing 161 kV Transmission Line from Northern Hills 161 kV Sub to IBM 161 kV Sub.

Table 10.17 RPU Underlying 161 kV Additions

The results of the 2009 summer peak contingency analysis showed that the model representing the RPU interconnection performed nearly equally as well as the original Hampton Corners line on system impact by mitigating a large number of contingency overloads that appeared on the existing transmission system, while creating only a few new overloads. The RPU interconnection model created one less contingency overload than did the original Hampton Corners line. The contingency overload created on the Mayfair to North La Crosse 161 kV line in the original Hampton Corners model for a multiple contingency of the Coulee to La Crosse 161 kV, plus Genoa to La Crosse Tap 161 kV, plus La Crosse to La Crosse Tap 161 kV did not appear in the RPU interconnection model. The other three contingency overloads created by the addition of the original Hampton Corners line were also created by the RPU underlying model. The contingency overloads created by the addition of the Hampton Corners Line are listed in Table 10.18 below. Likewise, by utilizing either the original Hampton Corners and RPU interconnection models, all of the existing contingency overloads exceeding the ±3% criteria were reduced without exception.

Case	Monitored Element	Contingency	Rating	Post Contingent Flow
HC-RST-NLAX-COL with RPU underlying	**Mayfair – North La Crosse 161 kV**	**Genoa Generator Unit 3**	**197**	**212.2**
HC-RST-NLAX-COL with RPU underlying	**Waupaca 138/69 kV Transformer**	**White Lake - Waupaca 138 kV**	**46.7**	**50.6**
HC-RST-NLAX-COL with RPU underlying	**Wabasha – Lake City 69 kV**	**Prairie Island 345/161 kV Transformer**	**34**	**34.6**
HC-RST-NLAX-COL original	**Mayfair – North La Crosse 161 kV**	**Genoa Generator Unit 3**	**197**	**214.2**
HC-RST-NLAX-COL original	**Mayfair – North La Crosse 161 kV**	**Coulee – La Crosse 161 kV, plus Genoa – La Crosse Tap 161 kV, plus La Crosse – La Crosse Tap 161 kV**	**197**	**196.9**
HC-RST-NLAX-COL original	**Waupaca 138/69 kV Transformer**	**White Lake - Waupaca 138 kV**	**46.7**	**50.6**
HC-RST-NLAX-COL original	**Wabasha – Lake City 69 kV**	**Prairie Island 345/161 kV Transformer**	**34**	**34.5**

Table 10.18 Created Contingency Overloads – RPU Underlying System Sensitivity Analysis, 2009 Summer Peak

To mitigate the overloads listed above in Table 10.13, the following system improvements are proposed to be made.

1. Mayfair – North La Crosse 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.
2. Waupaca 138/69 kV Transformer – the size of the transformer will either need to be increased or a second transformer should be placed in parallel to

handle the increased contingency flow. One recommendation is to replace the 46.7 MVA transformer with a 60 MVA transformer.

3. Wabasha – Lake City 69 kV line – If the planned new Zumbro Falls to Lake City 69kV line is completed this overload will not be an issue. If it is not completed an operating guide will need to be developed to mitigate the contingency overload on this line until the planned Zumbro Falls to Lake City 69 kV line is completed.

The results of the 2009 summer off-peak high transfer contingency analysis showed that both the model representing the RPU interconnection and the original Hampton Corners line performed exactly equal to one another on system impact by mitigating a large number of contingency overloads that appeared on the existing transmission system, while creating only a few new overloads. Both model created seven contingency overloads in total as listed below in Table 10.19. Likewise, by utilizing either the original Hampton Corners and RPU interconnection models, all of the existing contingency overloads exceeding the ±3% criteria were reduced without exception.

Case	Monitored Element	Contingency	Rating	Post Contingent Flow
HC-RST-NLAX-COL RPU underlying	**La Crosse – Mayfair 161 kV**	**North La Crosse – Hilltop 345 kV**	**197**	**214.8**
HC-RST-NLAX-COL RPU underlying	**Mayfair –North La Crosse 161 kV**	**North La Crosse – Hilltop 345 kV**	**197**	**249.8**
HC-RST-NLAX-COL RPU underlying	**Maple Leaf - Byron 161 kV**	**Hampton Corners - Rochester 345 kV**	**302**	**322.2**
HC-RST-NLAX-COL RPU underlying	**Maple Leaf - Cascade Creek 161 kV**	**Hampton Corners - Rochester 345 kV**	**302**	**311.1**
HC-RST-NLAX-COL RPU underlying	**Mayfair – North La Crosse 161 kV**	**Genoa Generator Unit 3**	**197**	**245.3**
HC-RST-NLAX-COL RPU underlying	**La Crosse – Mayfair 161 kV**	**Genoa Generator Unit 3**	**197**	**211.7**
HC-RST-NLAX-COL RPU underlying	**Mayfair – North La Crosse 161 kV**	**Coulee – La Crosse 161 kV, plus Genoa – La Crosse Tap 161 kV, plus La Crosse – La Crosse Tap 161 kV**	**197**	**200.8**

Table 10.19 Created Contingency Overloads – RPU Underlying System Sensitivity Analysis, 2009 Summer Off-Peak

To mitigate the overloads listed above in Table 10.19, the following system improvements are proposed to be made:

1. La Crosse – Mayfair 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.
2. Mayfair – North La Crosse 161 kV line - the line should be rebuilt to increase the line rating. One recommendation is rebuild with 954 ASCR with a summer thermal rating of 304 MVA.

3. Maple Leaf to Cascade161 kV line – the existing operating guide will need to be modified to mitigate the contingency overload on this line.
4. Maple Leaf to Byron161 kV line – the existing operating guide will need to be modified to mitigate the contingency overload on this line.

10.10 Stability Analysis

Only minimal stability analysis has been completed for the study to date. Due to the amount of time required, stability analysis will be completed on the final option selected to be built. This will ensure that the modeling of the facility additions and modifications to existing facilities will be as accurate as possible to ensure accurate results.

11.0 REGIONAL 345 kV ESTIMATED COST

Conceptual cost estimates were developed for the preferred 345 kV transmission alternative, a line from the Hampton Corners to Rochester to North La Crosse.

11.1 Facilities Planned

These estimates are based on a route that starts at the assumed to be existing Hampton Corners 345/161 Substation north of Hampton, Minnesota. This substation is planned to be constructed as part of the SW Minnesota to the Metro 345 kV project. The approximate location of the Hampton Corners Sustation is shown by the blue arros in Figure 11.1. Approximately 50 miles of transmission line would connect the Hampton Corners Substation to a new North Rochester Substation that is assumed to be located on the North side of Rochester, Minnesota. Approximately 100 miles of transmission line would connect the new Rochester Substation to the North La Crosse Substation. The North La Crosse Substation is located just west of US Highway 53 near Holmen, WI near the point where the La Crosse-Tremval and Marshland-La Crosse 161 kV lines intersect in Figure 11.1. The North La Crosse Substation is an existing 69 kV switching station that was built with future provisions which allow it to be upgraded to a 345 kV/161 kV/69 kV substation.

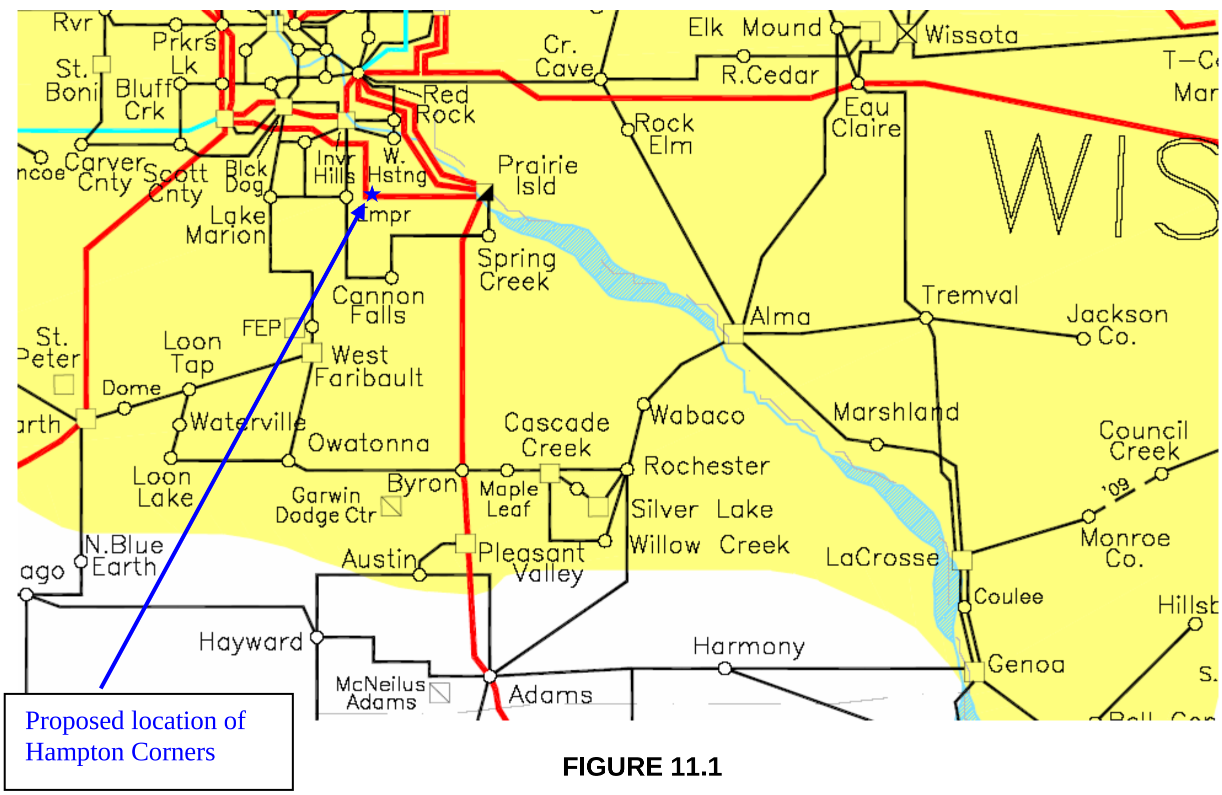


FIGURE 11.1

11.2 Scope of the Estimate

The conceptual estimates provide for a total project that addresses the load serving needs of the Rochester, MN and the Greater La Crosse areas. The scope of the project included in these estimates is listed below.

11.2.1 345 kV Transmission Facilities

- 345kV transmission line from Hampton Corners Substation to a new North Rochester Substation
- 345kV transmission line from a new North Rochester Substation to North La Crosse Substation
- 345/161kV, 240/320/400/448 MVA transformer (2) one at the both the North La Crosse Substation and the other at the new North Rochester Substation

11.2.2 161kV Transmission Facilities in the Rochester Area

- 161kV transmission line from a North Rochester Substation to Northern Hills Substation
- 161kV transmission line from the North Rochester Substation to Chester Substation

11.2.3 161 kV Transmission Facilities in the La Crosse area

- Reconductor 161 kV transmission line from Genoa-La Crosse tap
- Rebuild 161 kV transmission line from Alma-Genoa
- Add 86.4 MVAR of capacitors to the 161 kV transmission system in the Greater La Crosse area
- New double circuit 161 kV transmission line from North La Crosse tapping Tremval-Mayfair line
- Rebuild Xcel North La Crosse-La Crosse 161kV
- Reconductor 161 kV transmission line from Adams-Harmony

11.3 Assumptions

These conceptual estimates were produced prior to any engineering design being done. The estimates are based on typical conditions encountered on past projects and a reasonable familiarity with the facilities and the Southeastern Minnesota and Southwestern Wisconsin region. Numerous assumptions were made in the development of these estimates. The major assumptions are listed below:

1. 345 kV transmission line design will be monopole steel on concrete foundations.

2. Right-Of-Way widths will be 150 feet for 345 kV and 100 feet for 161 kV.
3. New transmission line lengths are based primarily on the length of north-south and east-west corridors shown in Figure 11.2. In order to approximate the cost of the final route, we included a 20% adder to allow for reroutes around sensitive areas. The potential route is unknown until the completion of a significant public routing process. A preliminary corridor map is shown in Appendix K.
4. Some double circuiting will be required on the 345 kV line with new and existing 161 kV and/or 69 kV circuits; the exception will be that the new 345 kV line will not be double circuited with the existing Prairie Island to Byron 345 kV line due to reliability concerns documented in the NERC Standards for planning and operating electrical systems.

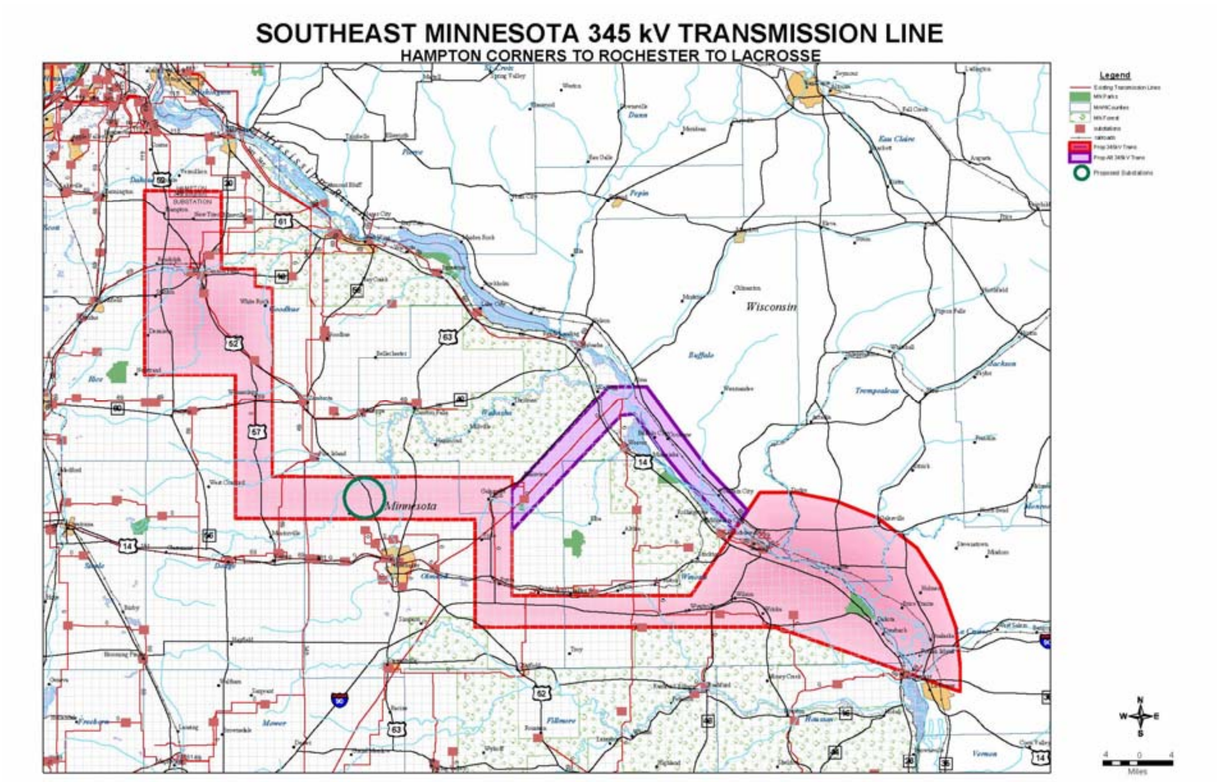


FIGURE 11.2

5. Some distribution underbuild will be required on the 161 kV lines.
6. Space for the line terminations and associated facilities required in the affected substations are available. Presently this expansion space exists but if other unknown projects change this, the costs could be significantly different than those listed.
7. Modifications to existing lines assume that the existing Rights-of-Way are re-used for the modified line.

11.4 Summary of Conceptual Costs

345 kV Lines

Line Segment	No of Miles	Cost per Mile ($)	Estimated Cost ($)
Hampton Corners to Rochester	50	861,000	43,050,000
Rochester to North La Crosse	100	861,000	86,100,000
345kV Line Segment Sub-Total			**129,150,000**

345 kV Substation

Substation	Estimated Cost ($)
Hampton Corners	1,133,000
North Rochester	6,854,000
North La Crosse	4,147,000
345kV Substation Sub-Total	**12,134,000**

Rochester Area 161 kV Lines

Line Segment	No of Miles	Cost per Mile ($)	Estimated Cost ($)
N Rochester to Northern Hills	2	485,000	970,000
North Rochester to Chester	18	485,000	8,730,000
Rochester Area 161 kV Line Segment Sub-Total			**9,700,000**

Rochester Area 161 kV Substation

Substation	Estimated Cost ($)
Northern Hills	337,000
Chester	770,000
Rochester Area 161 kV Substation Sub-Total	**1,107,000**
Rochester Area 161 kV Sub-Total	**10,807,000**

La Crosse Area 161 kV Facilities

Potential Capacitor Additions[1]	No	Cost/ Each	Est Cost ($1000's)
Bell Center 161kV 18 Mvar Capacitor	1	265	265
Hillsboro 161kV 18 Mvar Capacitor	1	265	265
La Crosse 161kV 18 Mvar Capacitor	2	331	662
Monroe County 69kV 14.4 Mvar Capacitor	1	235	235

La Crosse Area Capacitor Addition Subtotal **1,427,000**

[1] Capacitor locations are approximate and require further study before final placement.

La Crosse Area 161 kV Lines

Line Segment[2]	No of Miles	Cost/ Mile	Est Cost ($1,000s)
Reconductor DPC portion of Q11Genoa-Coulee 161kV	16.9	93	1,571.7
Reconductor Xcel portion of Q11Genoa-Coulee 161kV	1.8	116	208.8
Rebuild Q1 New Alma to Marshland 161kV	25.4	350	8,890.0
Rebuild Q1 Marshland-North La Crosse 161kV	15.4	350	5,390.0
Rebuild Q1 North La Crosse-La Crosse Tap 161kV	8.8	350	3,080.0
Rebuild Q1 La Crosse Tap-Genoa 161kV	20.7	350	7,245.0
Rebuild Xcel North La Crosse-La Crosse 161kV	10.0	350	3,500.0
New Double Circuit tapping Tremval-LaCrosse 161 kV @ North La Crosse	0.5	558	279.0
Reconductor Adams-Harmony 161kV	35.6	71	2,527.6
			32,692.1

La Crosse Area 161kV Lines Sub-Total **32,692,100**

[2] The cost of the Rebuild Alma-Genoa 161 kV does not include the cost of relocating residential properties adjacent to and within the existing rights-of-way. This is because the number of residential properties [if any] which would require relocation in accordance with the Wisconsin Administrative Code has not yet been ascertained by Dairyland Power Cooperative's legal counsel.

La Crosse Area 161 kV Substation

Substation	Estimated Cost $1,000s)
Upgrade Xcel Coulee Substation to 2000 Amps	500
North La Crosse 161 kV Transmission Sub	638
North La Crosse 161 kV Circuit Breakers (7 @ 369 each)	2,583
North La Crosse 69 kV Circuit Breakers (1 @ 246 each)	246
North La Crosse 161kV 18 Mvar Capacitor	265
North La Crosse 161/69 kV 112 MVA Transformer	1,189
La Crosse Area 161kV Substation Sub-Total	**5,421,000**
La Crosse Area 161kV Sub-Total	**39,540,500**

The totals by voltage classification and area for the entire project are shown below:

345 kV Construction

345kV Lines $129,150,000

345kV Substations $12,134,000

Total 345 kV Construction Cost $141,284,000

Rochester Area 161 kV Construction

161kV Lines $9,700,000

161kV Substations $1,107,000

Total Rochester Area 161 kV Construction Cost $10,807,000

La Crosse Area 161 kV Construction

Capacitor Additions $1,427,000

161kV Lines $32,692,100

161kV Substations $5,421,000

Total La Crosse Area 161kV Construction Cost $39,540,500
Total Estimated Project Cost $191,631,100
The detailed breakdown of these conceptual cost summaries are contained in the tables on the following pages.

Southeast Minnesota 345kV Project
Budgetary Level Estimated Cost Per Mile Components

345kV Lines

		Cost/mile	Miles	Cost
Basic Installed cost		$600,000	150	$90,000,000
Adder for double circuit		$150,000	75	$11,250,000
Adder for difficult terrain		$400,000	30	$12,000,000
Total				$113,250,000
Average line cost per mile	$755,000			
Permitting costs				$3,000,000
Right-of-way costs				$12,900,000
Total 345kV Line costs				**$129,150,000**
Total average cost per mile	**$861,000**			
Hampton Corners to North Rochester		$861,000	50	**$43,050,000**
North Rochester to North La Crosse		$861,000	100	**$86,100,000**

161kV Lines

		Cost/mile	Miles	Cost
Basic Installed cost		$350,000	20	$7,000,000
Adder for underbuild		$50,000	10	$500,000
Total				$7,500,000
Average line cost per mile	$375,000			
Permitting (Incremental to 345)				$300,000
Right-of-way costs				$1,900,000
Total 161kv Line costs				**$9,700,000**
Total average cost per mile	**$485,000**			
North Rochester to Northern Hills		$485,000	2	**$970,000**
North Rochester to Chester		$485,000	18	**$8,730,000**

TABLE 11.1
345 kV and 161kV Transmission Line Costs

Hampton Corners Substation (Xcel Ownership)
Add 345 kV Line Terminal

This preliminary estimate provides for the costs for adding a 345 kV line terminal to the Hampton Corners Substation.

Quantity	Item Description	Material	Labor
Lot	Mobilization/Demobilization	$0	$10,000
2	345kV Breakers	$381,000	$35,200
4	345kV Switches w/insulators	$73,500	$22,800
1	Wave Trap	$12,000	$1,500
3	Surge Arrestors	$44,000	$1,700
1	Relay & Control Panel - Pri and Sec w/ Carrier	$40,000	$4,000
Lot	Buswork & Fittings	$10,000	$15,000
Lot	Construction Equip Rental	$10,000	$0
Lot	Control Cable, Trenching and Conduit	$14,200	$32,600
Lot	Grounding	$2,000	$3,500
Lot	Foundations	$8,000	$25,000
Lot	Steel	$53,000	$13,200
Lot	Shielding	$1,200	$2,500
Lot	Testing & Commissioning	$1,000	$40,000
	Subtotals for Material and Labor	$649,900	$207,000

Total Material and Labor:	$856,900
Contingency @ 15%:	$128,600
Engineering Design:	$147,500
Total Component Cost:	**$1,133,000**

Table 11.2
Hampton Corners 345 kV Substation Modification

North Rochester Substation

This preliminary estimate provides for the cost of building a new 345 kV substation north of the city of Rochester. The substation would have two 345 kV lines and two 161 kV lines with space provided for an added 345 kV line and 2 added 161 kV lines.

Quantity	Item Description	Material	Labor
LOT	Mobilization/Demobilization	$0	$10,000
1	Transformer - 345/161kV	$2,500,000	$50,000
3	345kV Breakers	$565,770	$52,800
3	161kV Breakers	$181,125	$3,000
7	345kV Switches w/insulators	$128,000	$40,000
7	161kV Switches w/insulators	$60,000	$32,000
2	Wave Trap	$20,000	$1,200
12	Surge Arrestors	$98,500	$7,000
2	Relay & Control Panel – Primary and Secondary w/ Carrier	$82,000	$5,500
2	Panel - Pri and Sec with Tone TT	$60,000	$5,472
1	PLC Panel with PLC	$10,000	$2,400
2	Panel - bus and/or transformer differential	$27,600	$2,300
1	Auto Transfer Switch - 400A	$3,000	$800
6	Potential Transformers - 345kV	$60,000	$5,600
6	Potential Transformers - 161kV	$30,000	$5,600
1	Remote Terminal Unit	$4,000	$2,000
Lot	Control House - with equipment	$24,000	$36,800
Lot	Buswork & Fittings	$33,600	$53,000
Lot	Construction Equip Rental	$15,000	$0
Lot	Control Cable, Trenching and Conduit	$15,700	$36,800
Lot	Grounding	$3,500	$3,800
Lot	Foundations	$54,300	$210,000
Lot	Steel	$232,000	$95,000
Lot	Shielding	$3,000	$5,000
Lot	Testing & Commissioning	$1,000	$60,000
Lot	Grading	$250,000	$100,000
Lot	Substation Fence	$30,000	$20,000
Lot	Land	$200,000	
	Subtotals for Material and Labor	$4,692,095	$846,072

Total Material and Labor:	$5,538,167
Contingency @ 15%:	$830,800
Engineering:	$485,000
Total Component Cost:	**$6,854,000**

Table 11.3
North Rochester 345 kV Substation (New)

North La Crosse Substation (DPC Ownership)
Add 345kV

This preliminary estimate provides for the costs for adding 345kV to existing North La Crosse 69kV Substation.

Quantity	Item Description	Material	Labor
Lot	Mobilization/Demobilization	$0	$10,000
1	345/161kV Transformer	$2,500,000	$50,000
1	345kV Breaker	$188,600	$20,000
1	161kV Breaker	$60,375	$3,000
1	345kV Switches w/insulators	$18,000	$5,500
1	161kV Switch	$10,000	$5,000
1	Wave Trap	$12,000	$600
1	Relay & Control Panel - Pri and Sec w/Carrier	$40,700	$2,700
1	Panel - transformer differential	$27,600	$2,300
Lot	Buswork & Fittings	$12,500	$25,000
Lot	Construction Equip Rental	$14,000	$0
Lot	Control Cable, Trenching and Conduit	$7,500	$20,000
Lot	Grounding	$3,000	$5,000
Lot	Foundations	$12,000	$40,000
Lot	Steel	$80,000	$25,000
Lot	Shielding	$1,200	$2,500
Lot	Testing & Commissioning	$1,000	$40,000
Lot	Grading	$70,000	$30,000
	Subtotals for Material and Labor	$3,058,475	$286,600

Total Material and Labor Costs:	$3,345,075
Contingency @ 15%:	$501,800
Engineering:	$300,000
Total Component Cost:	**$4,147,000**

TABLE 11.4
North La Crosse 345kV Substation Modification

Northern Hills Substation (RPU Ownership)
Add 161 kV Line Terminal

This preliminary estimate provides for the addition of a 161kV line terminal to Northern Hills Substation.

Quantity	Item Description	Material	Labor
Lot	Mobilization/Demobilization	$0	$10,000
1	161KV Circuit Breaker	$60,375	$3,000
1	161kV Switch	$10,000	$5,000
3	161kV CCVT	$12,000	$3,000
3	161kV Surge Arresters	$3,600	$2,000
1	Relay & Control Panel - Pri and Sec w/Tone	$35,000	$3,200
Lot	Buswork & Fittings	$1,400	$3,900
Lot	Control Cable, Trenching and Conduit	$5,400	$6,500
Lot	Grounding	$1,400	$2,000
Lot	Foundations	$5,400	$22,000
Lot	Steel	$30,000	$12,500
Lot	Testing & Commissioning	$1,000	$15,000
	Subtotals for Materials and Labor	$165,575	$88,100

Totals for Material and Labor:	$253,675
Contingency @15%:	$38,100
Engineering:	$45,000
Total Component Cost:	**$337,000**

TABLE 11.5
Northern Hills 161 kV Substation Modification

Chester Substation (RPU Ownership)
Add 161 kV Line Terminal

This preliminary estimate provides for the cost of adding a 161kV line to Chester substation. Please note that this does NOT cover any costs related to property acquisition for the project.

Quantity	Item Description	Material	Labor
Lot	Mobilization/Demobilization	$0	$10,000
1	161KV Circuit Breaker	$60,375	$3,000
3	161kV, 1200A Switches w/insul	$30,000	$15,000
3	161kV CCVT	$12,000	$3,000
3	161kV Surge Arresters	$3,600	$2,000
1	Relay & Control Panel - Pri and Sec w/Tone	$35,000	$3,200
Lot	Relocation of Equipment	$1,000	$10,000
Lot	Buswork & Fittings	$12,000	$20,700
Lot	Control Cable, Trenching and Conduit	$6,500	$14,000
Lot	Grounding	$10,000	$5,000
Lot	Foundations	$21,000	$85,000
Lot	Steel	$95,000	$40,000
Lot	Shielding	$1,200	$2,500
Lot	Testing & Commissioning	$1,000	$30,000
Lot	Grading	$35,280	$15,120
	Subtotals For Material and Labor	$323,955	$258,520

Total Material and Labor: $582,475

Contingency @ 15%: $87,371

Engineering: $100,000

Total Component Cost: $770,000

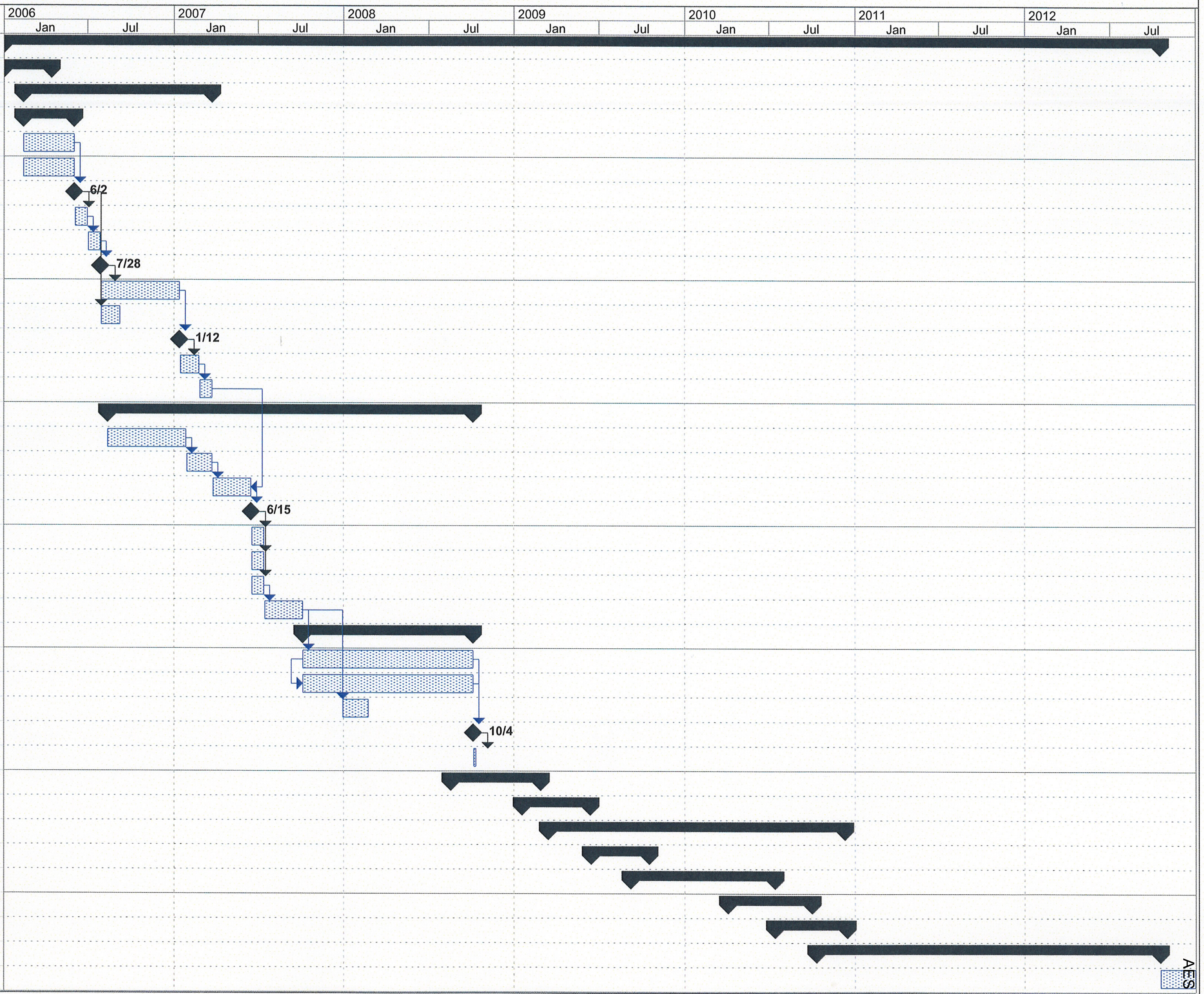
TABLE 11.6
Chester 161kV Substation Modification

11.5 Schedule

The schedule for construction of the 345 KV line from Hampton Corners to North Rochester to North La Crosse is shown on the following page. The schedule assumes that if the preparation of a Certificate of Need for the Minnesota process begins early in the first quarter of 2006, the facilities can be energized late in the second quarter of 2012.

Rochester Public Utilities - Preliminary 345kV Project Schedule

ID	Task Name	Duration
1	**TRANSMISSION LINES FOR 345KV OPTION**	**1773 days**
2	**PRELIMINARY ROUTE SELECTION AND APPROVAL**	**75 days**
9	**MN PUBLIC UTILITIES COMMISSION APPROVAL**	**290 days**
10	**Prepare application for Certificate of Need (CON)**	**80 days**
11	Statement of Need	4 mons
12	Voltage/Structure Configuration	4 mons
13	Submit application for staff review	0 days
14	Staff reviews application for completeness	1 mon
15	Revise application	1 mon
16	Submit application	0 days
17	PUC review	6 mons
18	Public hearing	6 wks
19	PUC approve or deny	0 days
20	Satisfy modifications contingency	6 wks
21	Issue Certificate of Need	4 wks
22	**MEQB ROUTING APPROVAL**	**560 days**
23	Prepare preferred and alternate route details	6 mons
24	Solicit local input on route selection	2 mons
25	Prepare application for route permit	3 mons
26	Submit application	0 days
27	Publish notice of application in local legal newspapers	4 wks
28	Mail notice of application to each affected landowner	4 wks
29	Application review by MEQB	4 wks
30	Address deficiencies in application	3 mons
31	**MEQB Application Review Process**	**260 days**
32	Application Review	365 edays
33	Environmental Impact Statement	365 edays
34	Public hearings	2 mons
35	Issue route permit	0 days
36	PREPARE PROJECT SCHEDULE	5 days
37	**SURVEY**	**140 days**
44	**PRELIMINARY DESIGN**	**105 days**
50	**RIGHT-OF-WAY**	**455 days**
57	**LOCAL PERMITTING**	**90 days**
60	**FINAL DESIGN**	**223 days**
73	**CONSTRUCTION BID**	**130 days**
80	**PURCHASING**	**110 days**
83	**CONSTRUCTION**	**528 days**
87	JOB CLOSING	53 days

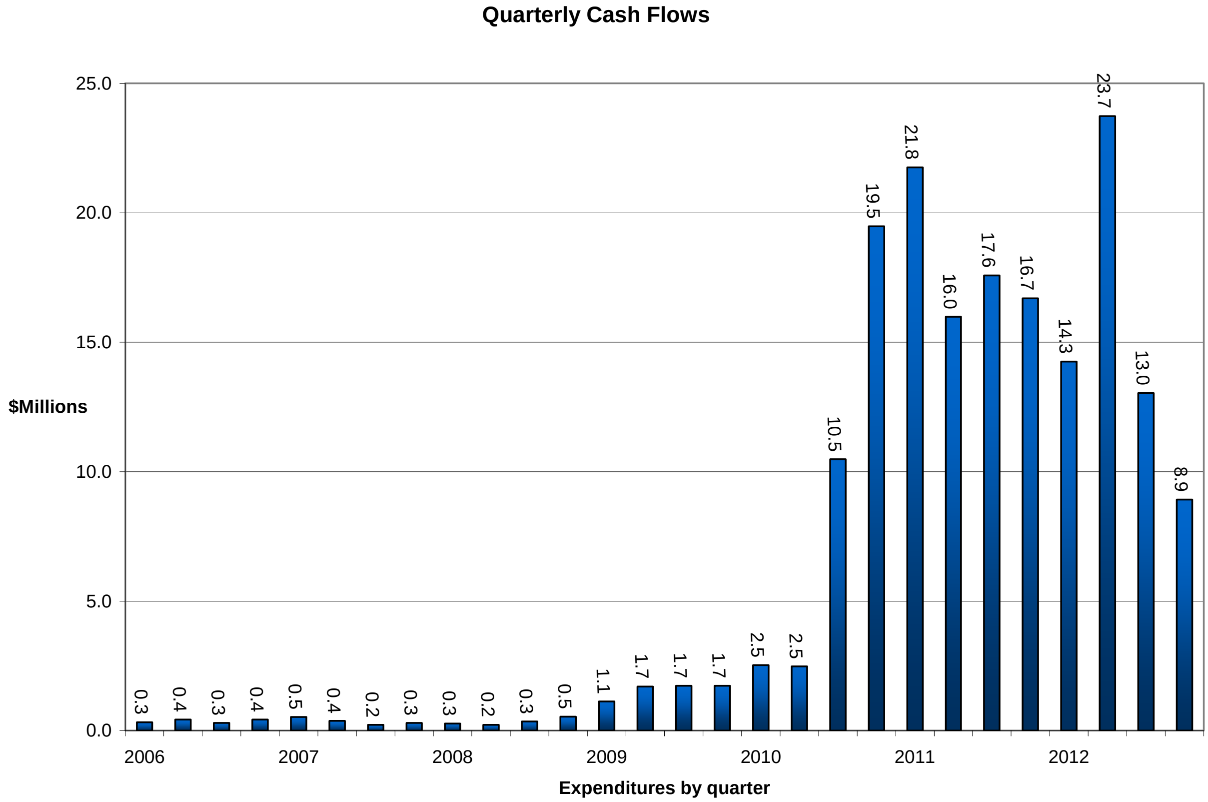


Project: RPU - SE Minnesota 345kV
Date: Fri 3/25/05

Task | Progress | Summary | External Tasks | External Milestone
Split | Milestone | Project Summary | External Milestone | Deadline

11.6 QUARTERLY CASH FLOWS

Based on the proposed schedule, the overall quarterly cash flows have been estimated and are shown on the following page. The estimated cash flows are shown in millions of dollars per quarter. The basis for the chart is contained in the spreadsheet file in Appendix F along with other charts.



12.0 ECONOMIC ANALYSIS OF ALTERNATIVES

The alternatives studied have widely differing supply capabilities and significantly different lives based on the ability of the various plans to serve the local load service needs. The power flow results show that the best performing 345 kV alternative will supply Rochester until 2051. In point of fact, the 345 kV alternative will form the basis for supply for at least that length of time. The overloads and additional construction to be performed over time are mainly in the lower voltage 161 kV and 69 kV systems. For the sake of analysis, the supply life for the 345 kV alternative was assumed to end in 2051. To compare the 345 kV alternative with the best performing 161 kV alternative, the present 161 kV transmission construction plan must provide the basis for reliable supply until 2051. Because the best performing 161 alternative fails in 2033, an adjustment for the differing lives must be made.

The second major difference is that the regional nature of the 345 kV plan has more participants, so some assumptions for the individual participant's share of the overall project costs must be made for the comparison. A method that has been used in the past is to use a load ratio cost sharing methodology. The load ratio methodology of cost sharing will be assumed and explained in this section as it relates to the Rochester Public Utilities economic analysis for proceeding with the 345 kV alternative.

12.1 Benefit Areas for the Load Ratio Methodology

The proposed approach for the load ratio methodology of cost determination starts with the conceptual estimate for the work to be completed. The costs in this case are broken down by the following methods. Figure 12.1 shows in red the overall area that is benefited by the overall 345 kV and 161 kV lines and substation facilities. This area was selected based on the configuration of the transmission system and the historical operating conditions that have been encountered. Within that overall area, local benefit areas are defined for Rochester and La Crosse.

The blue area denoted as number 2 in Figure 12.1 is the La Crosse benefit area. This is the portion of the electric system that is benefited by the 161 kV facilities included in the project in the La Crosse area. The La Crosse benefit area includes a much larger geographical area than greater La Crosse, WI; this is due to the location of upgraded or newly constructed 161 kV facilities and the existing facilities that are benefited by the proposed facility additions. The area includes Winona and Goodview, MN on the western boundary and extends eastward to the Sparta, WI area. In the La Crosse benefit area, 88% of the load is Xcel energy load, while over 80% of the transmission in the benefit area is owned by Dairyland Power Cooperative.

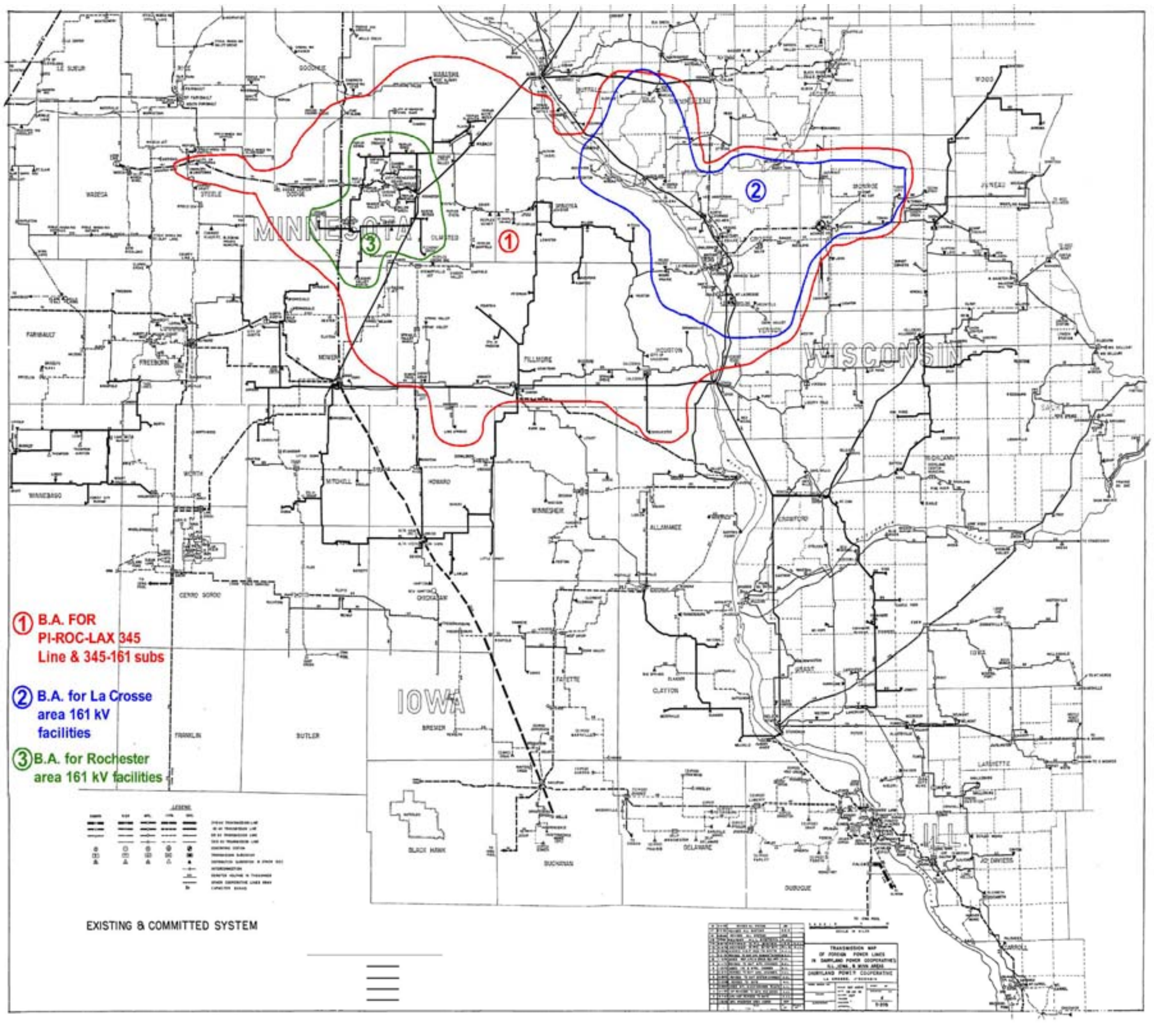


Figure 12.1

The green area denoted as number 3 in Figure 12.1 is the Rochester benefit area. This is the portion of the electric system that is benefited by the 161 kV facilities included in the project in the Rochester area. The Rochester benefit area includes the area of Rochester and extends north to Oronoco and south and west to Pleasant Valley. This geographic area is served by the 161 kV facilities of RPU, SMMPA and DPC as well as the 69 kV facilities of DPC.

A larger copy of Figure 12.1 is contained in Appendix G.

12.2 Loads in the Benefit Areas

Tables 12.1, 12.2 and 12.3 show the load in Megawatts (MW) for each utility in each benefit area described above as well as the total load in each benefit area and the percentage of total load in the benefit area for each utility.

Benefit Area 1 (Red)
Overall Benefit Area

Load Owner	Load (MW)	Percentage
Alliant West	47.2	4.14
Dairyland	175.5	15.39
RPU	109.4	9.59
SMMPA	303.4	26.60
Xcel Energy	505.0	44.28
Total	1,140.5	100.00

Table 12.1

Benefit Area 2 (Blue)
La Crosse Benefit Area

Load Owner	Load (MW)	Percentage
Alliant West	0	0
Dairyland	62.9	11.93
RPU	0	0
SMMPA	0	0
Xcel Energy	464.2	88.07
Total	527.1	100.00

Table 12.2

Benefit Area 3 (Green)
Rochester Benefit Area

Load Owner	Load (MW)	Percentage
Alliant West	0	0
Dairyland	38.5	10.58
RPU	109.4	30.06
SMMPA	216	59.36
Xcel Energy	0	0
Total	363.9	100.00

Table 12.3

The loads shown in Tables 12.1, 12.2 and 12.3 were tabulated as shown in the detailed sheet in Appendix G and are based on the 2009 Summer Peak Model described previously.

12.3 Example Allocation of Costs Based on Loads

The final allocation of costs depends on a myriad of factors such as the electrical benefit actually derived, the presence of any shared transmission system agreements between individual participants, or the presence of any other transmission or construction agreements between the project participants. This is simply an example of potential cost allocations assuming all other factors are not present. The final cost to individual participants will be based on final overall negotiations after the agreement of the participating parties to construct the facilities. This example simply approximates what those costs may be.

Based on the loads presented here and the costs presented in the previous section, the cost allocation for the La Crosse area 161 kV facilities would be as shown below:

12.3.1 La Crosse Benefit Area 161kV Facility Cost Allocation

Total La Crosse area 161 kV Construction Cost $39,540,100

Participant	Percentage	Allocated Cost
Dairyland Power	11.93%	$ 4,717,134
Xcel Energy	88.07%	$34,822,966

12.3.2 Rochester Benefit Area 161 kV Facility Cost Allocation

Based on the loads presented here and the costs presented in the previous section, the cost allocation for the Rochester area 161 kV facilities would be as shown below:

Total Rochester area 161 kV Construction Cost $10,807,000

Participant	Percentage	Allocated Cost
Dairyland Power	10.58%	$1,143,362
RPU	30.06%	$3,248,930
SMMPA	59.36%	$6,414,707

12.3.3 Rochester Benefit Area 161kV Facility Cost Allocation

Based on the loads presented here and the costs presented in the previous section, the cost allocation for the overall 345 kV facilities would be as shown below:

Total 345 kV Construction Cost $141,284,000

Participant	Percentage	Allocated Cost
Alliant West	4.07	$5,747,986
Dairyland Power	14.53%	$20,526,750
RPU	9.59%	$13,552,363
SMMPA	27.18%	$38,402,490
Xcel Energy	44.63%	$63,054,411

12.4 Total Example Individual Allocated Costs Based on 2009 Loads

Based on the above calculations, the total individual allocated costs for the project would be as follows:

Total 345 kV Project Construction Cost $191,631,100

Participant	Percentage	Allocated Cost
Alliant West	3.24	$6,208,848
Dairyland Power	13.92%	$26,675,049
RPU	9.47%	$18,147,465
SMMPA	25.26%	$48,406,016
Xcel Energy	48.12%	$92,212,885

12.5 Cost of Best Performing 161Options

The cost of Option 6, the best performing 161 kV option for the Rochester area, was $23,000,000 as listed in Section 8. Option 6, would support the Rochester area under a system normal scenario until the year 2033. How long the Rochester area would be supported under contingency conditions was not studied extensively.

Alternative D at a cost of $61,000,000 was the best performing 161 kV option for the La Crosse area, as stated in Section 9. Under contingency conditions Alternative D will support the La Crosse area for a load of 50 MW above the 2009 load level in the La Crosse area. The 2009 La Crosse area load level was 527 MW. This means that at a 1.8% per year load growth, in 2014 the La Crosse area would require additional transmission construction.

12.6 Economic Comparison for Equivalent Lives

The preferred 345 kV regional solution was a 345 kV line from Hampton Corners to Rochester to North La Crosse at a cost of $191,631,100. This line provides the basis for load growth until the year 2051 in the Rochester area, which is well beyond the capacity of the best performing 161 kV solution, which is 2033. The preferred 345 kV solution will also perform adequately in the La Crosse area longer than 2014, which is the approximate time the Alternative D will perform reliably. It is without question that additional transmission construction will be required in both the Rochester and La Crosse areas in order to bring equal lives to the comparison.

Since the preferred 345 kV option is the least cost 345 kV option for the load serving issues of both areas, we must assume that different solutions are built in different time frames in each area.

12.6.1 Rochester Area 2033 Construction

The shortest line to a 161 kV source that will adequately serve the Rochester area would be a 161 kV line from Rochester to Prairie Island. This is not a viable alternative due to the contingency case of the loss of the Prairie Island to Byron 345 kV line. The 161 kV Prairie Island to Rochester line would overload for this condition and have to be taken out of service to avoid cascading outages. The proposed transmission construction for the Rochester area in 2033 would be a 161 kV line to the Mankato, MN area to either Eastwood or Wilmarth substations. This was chosen since it would be the closest 161 kV connection that has the ability to meet the bulk power supply needs and would appear to perform satisfactorily under contingency conditions, although there may be some transformer capacity issues and access problems at Wilmarth. The length of the line would be 100 miles and would have the following total costs, including substation construction and the addition of a future 161 kV plan.

2033 Project Costs

161 kV Transmission Line Cost 100 Miles at $485,000 per mile	$48,500,000
Substation Cost	$4,500,000
Total Cost estimated in 2005 dollars	$53,000,000
Cost of Construction in 2033 (Inflation = 3.0%)	**121,260,200**
Present Worth of 2033 Project at a 5.0% Discount Factor	**$30,932,700**

The equivalent present value 161 kV construction costs in the Rochester area comparable to the 345 kV regional solution would include the following project costs. The first project would be the construction of Option 6 at a current cost of $23,000,000. The second project cost would be the 2033 construction of a 161 kV line from Mankato to Rochester. The 2005 present value of the 2033 construction would be $30,392,700. This would make the total equivalent present value cost of 161 kV construction $53,932,700 in the Rochester area.

12.6.2 La Crosse Area 2014 Construction

Following the same logic for the La Crosse area, we start and assume that Alternative D is constructed at a cost of $61,000,000. The assumption for a further solution beyond 2014 is as follows. First a 161kV line from Prairie Island would be constructed into the La Crosse area. We have assumed a line length of 90 miles for the constructed length. In order to reach a somewhat equivalent life to the 345 kV option it would also be necessary to build a 161kV line from La Crosse to the Kilbourne Substation. This line would route through the Monroe County and Hillsboro Substations. The total length of this line would also be 90 miles. This configuration of construction was chosen since it would be the least amount of 161 kV connection that has the ability to meet the bulk power supply needs and would appear to perform satisfactorily under contingency conditions. The total length of 161kV line to be constructed would be 180 miles and would have the following total costs, including substation construction and the addition or uprating of a 345 to 161 kV autotransformer at Prairie Island.

2014 Project Costs

161 kV Transmission Line Cost 180 Miles at $485,000 per mile	$87,300,000
Substation Cost	$6,000,000
Total Cost estimated in 2005 dollars	$93,300,000
Cost of Construction in 2014 (Inflation = 3.0%)	**$121,735,000**
Present Worth of 2014 Project at a 5.0% Discount Factor	**$78,471,680**

The equivalent present value 161 kV construction costs in the La Crosse area comparable to the 345 kV regional solution would include the following project costs. The first project would be the construction of Alternative D at a current cost of $61,000,000. The second project cost would be the 2014 construction of a 161 kV line from Prairie Island to La Crosse and La Crosse to Kilbourne. The 2005 present value of the 2014 construction would be $78,471,680. This would make the total equivalent present value cost of 161 kV construction $139,471,680 in the La Crosse area.

12.7 Comparison of Equivalent Present Value Costs

The present value cost of 161 kV construction equivalent to the 345 kV preferred solution would have two cost components. They would be the present value cost of 161 kV construction in both the Rochester and La Crosse areas. The cost in the Rochester area would be $53,932,700 while the present value cost of 161 kV construction in the La Crosse area would be $139,471,680 for a total of $193,404,380. This equivalent cost is higher than the preferred 345 kV solution cost of $191,631,100. Thus, the 345 kV alternative is the preferred solution.

12.8 Other Economic Factors

These equivalent costs include only construction costs based on load serving requirements. No economic analysis has been included for numerous other factors, all of which would most likely favor the 345 kV alternative. Electrical losses are one of these other factors. Since losses under the same loading decrease with the square of the voltage, an economic evaluation would certainly favor the higher voltage alternative for the same loading.

These analyses were performed based solely on load serving issues. The system benefits involving inter and intra regional transfers of power were assigned no value. Inter area transfer capability (Minnesota to Wisconsin or, historically MAPP Region to MAIN Region) can have a great economic impact on a system and has become more important in recent times. The transfer capacity of the single 345 kV alternative would be greater than the combined benefit of the 161 kV alternatives. Further, assuming the construction of the 345 kV transmission segments proposed by this study, provides significant incentives for others to build additional 345 kV transmission to meet this radial line, proceeding on either south or east. Any future additions spawned by this 345 kV construction will have large impacts on the transfer capabilities mentioned above. Under market theory, greater transfer capacity should also lead to a lower operating cost due to lower Locational Marginal Prices on the transmission system.

The following pages contain the contents of the Appendices. The actual data is contained on the CD enclosed, attached to the inside rear cover.

APPENDIX A – ROCHESTER LOCAL AREA STUDY
Table of Contents

1. 2003 and 07 Local Gen Supk and Suophx.xls – A spreadsheet of the generation levels in the Rochester area used in the 2003 and 2007 summer peak and summer off-peak high export power flow models.

2. ACCC Contingency Results F03suophx.xls – A spreadsheet of the power flow contingency analysis on the 2003 summer off-peak high export model.

3. ACCC Contingency Results F03supk.xls – A spreadsheet of the power flow contingency analysis on the 2003 summer peak model.

4. ACCC Contingency Results F07suophx.xls – A spreadsheet of the power flow contingency analysis on the 2007 summer off-peak high export model.

5. ACCC Contingency Results F07supk.xls – A spreadsheet of the power flow contingency analysis on the 2007 summer peak model.

6. F03suop Export Summaries.xls – A spreadsheet documenting the North Dakota Export, Manitoba Hydro Export, and the Minnesota Wisconsin System Interface levels used in all of the 2003 summer off-peak high export study models.

7. F07suop Export Summaries.xls – A spreadsheet documenting the North Dakota Export, Manitoba Hydro Export, and the Minnesota Wisconsin System Interface levels used in all of the 2007 summer off-peak high export study models.

8. Map – Existing System.doc – A map of the existing transmission and generation facilities in the Rochester area.

9. Map – Option 1.doc – A map of the existing transmission and generation facilities in the Rochester area, with the study option that added a 345 kV line from Byron to Pleasant Valley.

10. Map – Option 2.doc – A map of the existing transmission and generation facilities in the Rochester area, including the study option that added a 345 kV line from Byron to DPC Rochester plus a 161 kV line from DPC Rochester to Pleasant Valley.

11. Map – Option 3.doc – A map of the existing transmission and generation facilities in the Rochester area, including the study option that added a 345 kV line from Prairie Island to Adams.

APPENDIX A – ROCHESTER LOCAL AREA STUDY
Table of Contents – (cont)

12. Map – Option 4.doc – A map of the existing transmission and generation facilities in the Rochester area, including the study option that added a 161 kV line from Prairie Island to Quarry Hill, plus an additional 161 kV line from Byron to Northern Hills.

13. Map – Option 5.doc – A map of the existing transmission and generation facilities in the Rochester area, including the study option that added a 161 kV line from Prairie Island to Frontenac to Alma, plus a 161 kV line from Frontenac to Quarry Hill, plus an additional 161 kV line from Byron to Northern Hills.

14. Map – Option 6.doc – A map of the existing transmission and generation facilities in the Rochester area, including the study option that added a 161 kV line from Pleasant Valley to Quarry Hill, plus an additional 161 kV line from Byron to Northern Hills.

15. rpu.con – The contingency text file used for the 2003 and 2007 summer peak power flow contingency analyses.

16. rpu.sys – The system text file used for all power flow contingency analyses.

17. rpu.mon – The monitoring text file used for all power flow contingency analyses.

18. rpuhx.con – The contingency text file used for the 2003 and 2007 summer off-peak high export power flow contingency analyses.

APPENDIX B – REGIONAL 345 OPTION ANALYSIS
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19. 2009 Case Transfer Levels.xls – A word file documenting the procedure followed for setting the North Dakota Export, Manitoba Hydro Export, and the Minnesota Wisconsin System Interface levels used in the 2009 summer off-peak high export study model.

20. 2009 Summer Off-peak Export Summaries.xls – A spreadsheet documenting the North Dakota Export, Manitoba Hydro Export, and the Minnesota Wisconsin System Interface levels used in all of the 2009 summer off-peak high export study models.

21. 2009 Summer Off-peak Generation Levels.xls – A spreadsheet of the generation levels in the Rochester area used 2009 summer off-peak high export power flow model.

22. 2009 Summer Off-peak Screen All Options_060705.xls – A spreadsheet of the power flow contingency results on the 2009 summer off-peak high export model.

23. 2009 Summer Peak Screen All Options_102704.xls – A spreadsheet of the power flow contingency results on the 2009 summer peak model.

24. Model Change Documentation Summer Off-Peak Model 012205.doc – A word file documenting all the changes that were made to the published 2004 Series, 2009 Summer Off-Peak Model to create the base case high export power flow model used in the contingency analysis.

25. Model Change Documentation Summer Peak Model 102704.doc – A word file documenting all the changes that were made to the published 2004 Series, 2009 Summer Peak Model to create the base case power flow model used in the contingency analysis.

26. Regional Map.ppd – A map of the existing transmission and generation facilities in Southeast Minnesota and Southwest Wisconsin that also shows the basic routing of all the study options.

27. rpu.con – The contingency text file used for the 2009 summer peak power flow contingency analyses.

28. rpu.sys – The system text file used for all power flow contingency analyses.

29. rpu.mon – The monitoring text file used for all power flow contingency analyses.

APPENDIX B – REGIONAL 345 OPTION ANALYSIS
Table of Contents – (cont)

30. rpuhx.con – The contingency text file used for the 209 summer off-peak high export power flow contingency analyses.

APPENDIX C – RADIAL SENSITIVITY ANALYSIS TO THE REGIONAL 345 OPTION ANALYSIS

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31. 2009 Summer Off-peak Screen All Options_radial_022105.xls – A spreadsheet of the power flow contingency results on the radial 345 kV segments of the longer study options of the regional study, utilizing the 2009 summer off-peak high export model.

APPENDIX D – LACROSSE AREA MULTIPLE CONTINGENCY SENSITIVITY ANALYSIS TO THE REGIONAL 345 OPTION ANALYSIS

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32. 2009 Summer Off-peak Screen All Options_DPC Multiple Contingency Screen_041205.xls – A spreadsheet of the power flow contingency results using multiple and prior outage contingencies in the La Crosse Area on the 345 kV study options of the regional study, utilizing the 2009 summer off-peak high export model.

APPENDIX E – MASON CITY AREA SENSITIVITY ANALYSIS TO THE REGIONAL 345 OPTION ANALYSIS

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33. 2009 Summer Off-peak Screen All Options_masoncity.xls – A spreadsheet of the power flow contingency results of only the Mason City Area for the 345 kV study options of the regional study utilizing the 2009 summer off-peak high export model.

34. 2009 Summer Peak Screen All Options_masoncity.xls – A spreadsheet of the power flow contingency results of only the Mason City Area for the 345 kV study options of the regional study utilizing the 2009 summer peak model.

APPENDIX F – ESTIMATED QUARTERLY CASH FLOWS FOR THE PREFERRED REGIONAL 345KV SOLUTION

1. QuarterlyCashFlows.xls – A spreadsheet and charts of the estimated quarterly Cash Flows for the recommended 345kV project.

APPENDIX G – BENEFIT AREA INFORMATION FOR THE EXAMPLE COST ALLOCATION IN THE ECONOMIC ANALYSIS OF ALTERNATIVES

1. Benefit Area-RochLaxStudy.xls - A spreadsheet containing backup information for the load benefit methodology calculation and the cost allocation methodology.

2. BenefitAreaMap Roch-Lax.pdf – An Adobe .pdf final showing the benefit area listed in the example.

ELECTRIC TRANSMISSION PLANNING
GLOSSARY OF TERMS AND ACRONYMS

AC: Alternating current.

Btu: British thermal unit. The amount of heat required to raise the temperature of one pound of water one degree Fahrenheit under stated conditions of pressure and temperature (equal to 252 calories, 778 foot-pounds, 1,005 joules and 0.293 watt-hours.). It is the U.S. customary unit of measuring the quality of heat, such as the heat content of fuel.

Bulk Power Supply: Often this term is used interchangeably with wholesale power supply. In broader terms, it refers to the aggregate of electric generating plants, transmission lines, and related equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission lines are interconnected.

Capacity: Check Demand

Contingency: Outage of a transmission line, generator, or other piece of equipment which affects the flow of power or the transmission network.

Control Area: An electric system bounded by transmission lines that are equipped with metering and telemetry equipment to track and report power flows with adjacent control areas. A control center for each control area controls the operation of generation within its portion of the transmission grid, schedules interchanges with other control areas, and helps to stabilize the frequency of alternating current in the interconnection. Control centers are currently operated by individual utilities, power pools, ISOs or RTOs.

Cooperative electric associations: Democratic organizations controlled by their members, who actively participate in setting policies and making decisions. The elected representatives are accountable to the membership. Cooperative electric associations are not regulated by the PUC except in certain defined areas related to service standards and practices. With the exception of Dakota Electric Association, which elected to be subject to rate regulation, the rates of cooperative electric associations are not regulated by the PUC.

DC: Direct current.

DOC: The Minnesota Department of Commerce

DOE: U.S. Department of Energy

DSM: Demand Side Management. Programs to influence the amount or timing of customers' energy use.

Demand: The measure of power needed by equipment to operate, usually shown as a KW rating.
Demand charge: A fee based on the peak amount of electricity used during the billing cycle.

Distribution: The delivery of electricity to the retail customer's home or business through low voltage distribution lines.

EMF: Electromagnetic fields.

EPA: U.S. Environmental Protection Agency

EQB: The Minnesota Environmental Quality Board.

Electric Energy: The generation or use of electric power by a device over a period of time, expressed in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh).

Electric System Losses: Total electric energy losses in the electric system. Losses are primarily due to electric resistance within electrical conductors or wires and transformers.

Eminent Domain: The process by which rights to land needed for public interest facilities are acquired regardless of objection by the landowner. Eminent domain is generally applied by or through the power of the relevant siting authority that found the facilities to be in the public interest.

Energy Policy Act: This 1992 federal legislation provides for the deregulation of wholesale power markets, i.e., utilities and other marketers purchasing and selling electricity from one another (as opposed to selling to the end-use customer.)

FERC: Federal Energy Regulatory Commission. Regulates the price, terms and conditions of power sold in interstate commerce and regulates the price, terms and conditions of all transmission services. FERC is the federal counterpart to state utility regulatory commissions.

GWH: Gigawatt-hour. The unit of energy equal to that expended in one hour at a rate of one billion watts. One GWH equals 1,000 megawatt-hours.

Grid: A system of interconnected power lines and generators that is managed so that power from generators is dispatched as needed to meet the requirements of the customers connected to the grid at various points. Gridco is sometimes used to identify an independent company responsible for the operation of the grid.

High-voltage Transmission Line (HVTL): (a) Any transmission line with capacity of 200 kV or more, or (b) Any transmission line with capacity of 100 kV or more with more than 10 miles of its length in Minnesota or that crosses a state line.

ISO: Independent System Operator. A neutral and independent organization with no financial interest in generating facilities. An ISO administers the operation and use of the transmission system. ISOs exercise final authority over the dispatch of electricity from generators to customers to preserve reliability and facilitate efficiency, ensure non-discriminatory access, administer transmission tariffs, ensure the availability of ancillary services, and provide information about the status of the transmission system and available transmission capacity. An ISO may make some transmission investment decisions.

Import/Export: Ability of the transmission system to bring power into or out of an area in order to serve load.

Interconnected System: A system consisting of two or more individual electric systems that have connecting tie lines and whose operations are synchronized.

Interconnection: When the word "Interconnection" is capitalized, it means any one of the five major electric system networks in North America: Eastern, Western, ERCOT (Texas), Quebec, and Alaska. When not capitalized, "interconnection" means the facilities that connect two systems or control areas. Additionally, an "interconnection" refers to the facilities that connect a nonutility generator to a control area or system.

Investor-owned utility: Common term for a privately owned (shareholder-owned) gas or electric utility regulated by the Minnesota Public Utilities Commission as to the services they provide and the rates they may charge to their customers. (Referred to as "public utilities" in Minnesota statutes.)

Kilovolt (Kv): Equal to 1,000 volts.

Kilowatt (KW): A measure of demand for power. The rate at which electricity is used during a defined period (usually metered over 15-minute intervals).

Kilowatt-hour (KWH): A measure of the amount of electricity that is used. Customers are charged a rate per KWH of electricity used.

Load: All the devices that consume electricity on a specific electric system at any given moment.

MAPP: Mid-Continent Area Power Pool. A NERC subregional organization that includes Minnesota; a voluntary association of electric utilities and other electric industry participants. MAPP's offices and control center are in St. Paul. Responsible for the safety and reliability of the bulk electric system, including system-wide planning functions; responsible for facilitating open access of the transmission system; provides a power and energy market where MAPP members and non-members may buy and sell electricity at wholesale. MAPP's approximate 107 members include investor-owned utilities, electric cooperatives, municipal utilities and public power districts, a federal power marketing agency, private power marketers, regulatory agencies, and independent power producers.

MAPP Regional Plan: Also called the “Regional Plan”. A regional transmission plan developed by MAPP’s TPSC (Transmission Planning Sub-committee) for all transmission facilities 115 kV and higher in the MAPP regional.

MBWG: MAPP’s Modeling Building Working Group. Maintains what is essentially a power flow, base case transmission model library. The library includes a series of power system models that simulate the behavior of the bulk electric system over a ten-year period. The models are designed to represent accurately all major generation, load, and transmission facilities in MAPP.

MinnElecTrans: MinnElecTrans is a short-hand term used to describe the process under which utilities that own and/or operate electric transmission facilities in Minnesota hold public meetings, prepare and receive information, review and develop facility alternatives, and otherwise meet their transmission planning requirements under Minnesota law.

MISO: Midwest Independent System Operator

Megawatt (MW): 1,000 kilowatts or 1 million watts.

Megawatt-hour (MWH): The unit of energy equal to that expended in one hour at a rate of one million watts. One MWH equals 3,414,000 Btus.

Minnesota Energy Security and Reliability Act: Minnesota Statutes Chapter 216B. Comprehensive energy legislation that addresses a wide range of energy issues, including energy planning, conservation and infrastructure. Minn. Stat. §216B.245 requires the state’s electric utilities to file a state “transmission projects report” by November 1 of each odd-numbered year.

Municipal utilities: Managed by their city councils or other governmental agencies, which are responsible to voters who are also the customers. Not regulated by the PUC, except on complaint about services or discriminatory prices, but do report certain types of information to the PUC and DOC.

N-1 Contingency: See Prior Outage

NERC: North American Electric Reliability Council, a not-for-profit corporation. The coordinating arm of the ten member regional reliability councils. The principal mission of NERC is to promote the reliability and adequacy of electric supply. Establishes standards to ensure adequate reliability of the electric grid system. (See also Reliability Councils.)

NESC: National Electric Safety Code. Governs the design, construction and operation of electric utility transmission facilities to ensure public and employee safety.

Network: A system of interconnected lines and equipment.

OASIS: Open Access Same-Time Information System. Gives transmission users the same access to transmission information that the wholesale merchant function of a utility enjoys. A utility's wholesale merchant function is limited to receiving from a utility's transmission function only such transmission information that is posted on an OASIS, and is thereby publicly available on a simultaneous basis to third-party transmission customers.

Order No. 888: FERC Order that requires all transmission owners to (1) offer comparable open-access transmission service for wholesale transactions under a tariff of general applicability on file at FERC and (2) take transmission service for their own wholesale sales under the same tariff.

Order No. 889: FERC Order that requires public utilities to functionally separate their transmission and reliability functions from their wholesale power marketing functions and to develop and maintain an Open Access Same-Time Information System (OASIS) to give transmission users the same access to transmission information that the wholesale merchant function of a utility enjoys.

Order No. 2000: FERC Order issued in 1999, encouraging transmission-owning utilities to voluntarily join large regional transmission organizations.

Overload: Power flowing through the wires/equipment is more that they can carry without damage.

PPSA: Power Plant Siting Act. Minnesota legislation enacted in 1973 governing location of large electric power facilities in Minnesota.

Prior Outage: Generally applies to system studies. The system is studied with an element (transmission line, transformer, generator, etc.) out of service to make sure the rest of the equipment on the system can be operated within individual equipment rating parameters. A prior outage is also sometimes referred to as an N-1 condition, i.e. one element of the N in the system out of service.

PUC: The Minnesota Public Utility Commission. The state agency with regulatory jurisdiction over certain Minnesota utilities

Parallel Path Flows: When electricity flows from a power plant over the transmission system, it obeys the laws of physics and flows over the paths of least resistance. Though there may be direct connection between a power plant and a particular load area, some of the power will flow over other network lines.

Peak Load or Peak Demand: The electric load that corresponds to a maximum level of electric demand within a specified time period, usually a year.

Power Flows: Electricity moving through lines or other transmission equipment.

Power Pool: Two or more interconnected electric systems planned and operated to supply power for their combined demand requirements.

Public Utility: By Minnesota Statute, an investor-owned utility regulated by PUC. “Public utility” excludes municipal utilities cooperatives, and power marketing authorities.

REIS: Regional Energy Information System. The Minnesota Department of Commerce's computerized state energy data collection and information system required under Minnesota Statutes. It includes energy data the DOC collects directly from energy suppliers as well as data collected by other state departments such as the Minnesota Department of Revenue, Petroleum Taxation Division. It also includes energy data specific to Minnesota collected by the U.S. Department of Energy, the U.S. Department of Commerce, Bureau of Census, and the U.S. Department of Transportation.

RRC: Regional Reliability Council. Organized after the 1965 Northeast blackout to coordinate reliability practices and avoid or minimize future outages. Voluntary organizations of transmission-owning utilities and in some cases power cooperatives, power marketers, and nonutility generators. Membership rules vary from region to region. They are coordinated through NERC. There are ten major regional councils plus the Alaska Systems Coordinating Council.

RTC: MAPP’s Regional Transmission Council. The Transmission Planning Sub-committee (TPSC), which reviews sub-regional plans, is a sub-committee of the RTC.

RTO: A regional transmission organization designed to operate the grid and its wholesale power market over a broad region and with independence from commercial interests. Facilitates independent system operations and stimulates development of large wholesale energy market areas. An RTO would also coordinate with other RTOs.

Reliability: Electric system reliability has two components – adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electric demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities. Reliability also refers to the security and availability of natural gas and petroleum supply, transportation and delivery.

Reserve Margin: Capacity over and above anticipated peak loads, maintained for the purpose of providing operational flexibility and for preserving system reliability. Reserve margins cover for planned and unplanned outages of generation and/or transmission facilities.

SPG: Sub-regional Planning Group. The four SPGs in MAPP provide a forum to coordinate the individual member plans and facilitate the coordination of plans among SPGs and neighboring non-member utility systems. Each SPG develops a coordinated 10-year sub-regional transmission plan for all transmission facilities in the sub-region at a capacity of 115 kV or greater.

Substation: A facility where transmission lines connect to each other and where protective equipment is located. Also where transformers are located to "step" the voltage up or down in order to put power into or take power out of the transmission network.

TPSC: MAPP's Transmission Planning Sub-Committee, which reviews sub-regional plans.

Transformer: Device that changes voltage levels.

TRANSlink: TRANSlink Transmission Co., LLC. An independent transmission company in the process of formation in order to take on some of the function that FERC envisions being performed by a Regional Transmission Operator and to satisfy FERC requirements that electric utilities separate their transmission operations from their power supply (generation plants or power purchases) and wholesale and retail load serving functions. Core participants in formation of TRANSlink are Xcel Energy, Interstate Power and Light Company, MidAmerican Energy (mostly an Iowa utility), Nebraska Public Power, Omaha Public Power, and Corn Belt Power (an Iowa cooperative)

Transmission system: the high voltage power lines that transmit electric energy from generation plants to local load and among utilities to ensure a high degree of reliability.

Transmitting Utility (Transco): A regulated entity that owns, and may construct and maintain, wires used to transmit wholesale power. It may or may not handle the power dispatch and coordination functions. It is regulated to provide nondiscriminatory connections, comparable service and cost recovery.

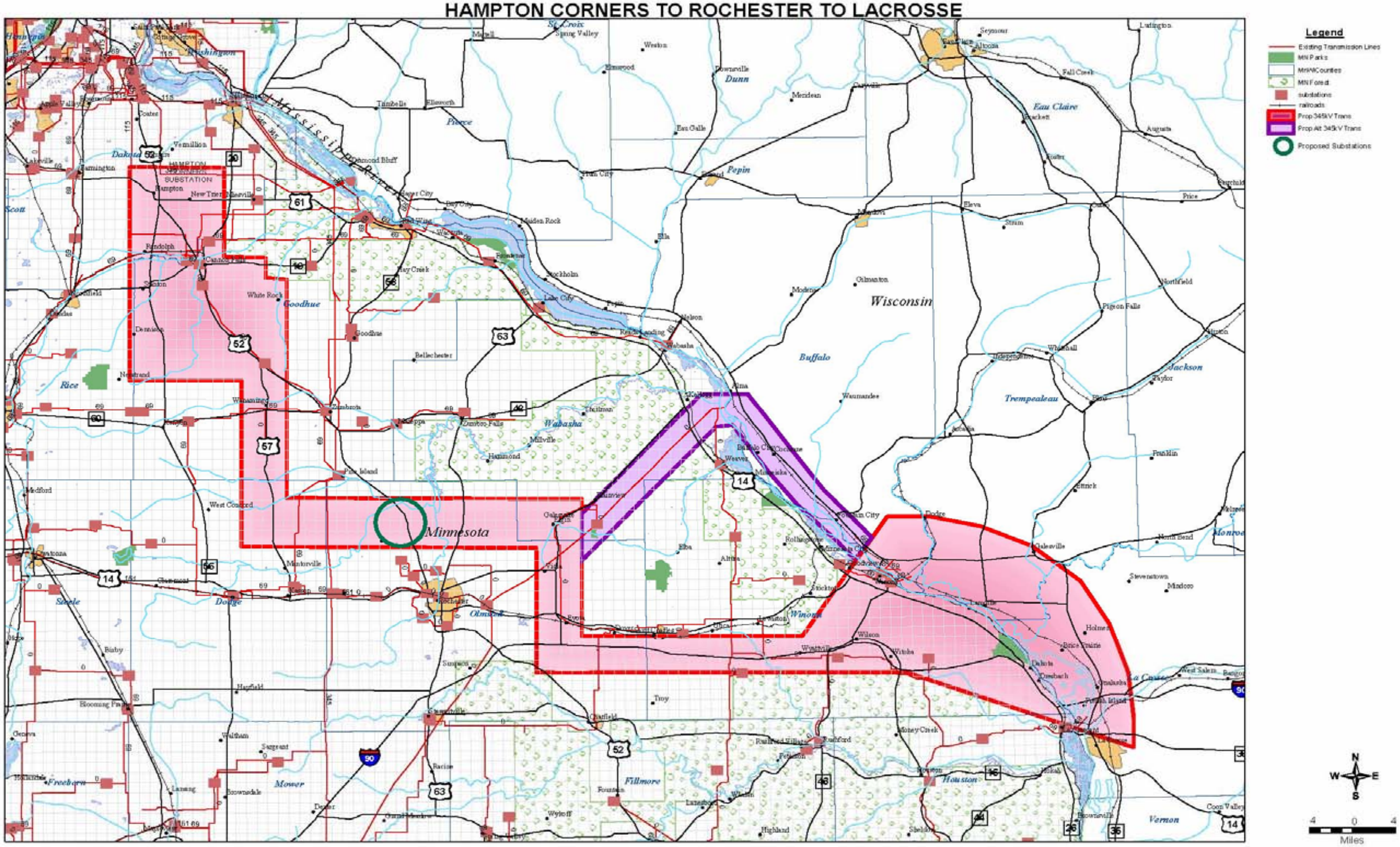
Utility: A corporation, person, agency, authority, or other legal entity that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy or natural gas primarily for use by the public and is defined as a utility under the statutes and rules by which it is regulated. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system that serves retail customers.

Watt: The unit of measure for electric power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing under pressure of one volt.

Wholesale Competition: Power producers competing to sell their power to a variety of distribution companies.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (who sell to retail customers and/or other resellers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

SOUTHEAST MINNESOTA 345 kV TRANSMISSION LINE
HAMPTON CORNERS TO ROCHESTER TO LACROSSE



Rochester Area Summer Peak Load Information (2002-2020)

AES Appendix A.3

Rochester Area Distribution Sub	Load MW 2002	Load MW 2003	Load MW 2004	Load MW 2005	Load MW 2006	Load MW 2007	Load MW 2008	Load MW 2009	Load MW 2010	Load MW 2011	Load MW 2012	Load MW 2013	Load MW 2014	Load MW 2015	Load MW 2016	Load MW 2017	Load MW 2018	Load MW 2019	Load MW 2020
Airport	1.97	2.13	2.66	3.40	3.73	3.33	2.94	3.25	3.30	3.34	3.38	3.43	3.47	3.52	3.56	3.61	3.66	3.70	3.75
Bamber Valley	25.44	26.19	24.87	26.38	28.67	25.37	25.09	26.88	27.45	28.04	28.63	29.21	30.35	32.18	32.97	34.18	35.25	36.22	37.04
Canisteo	2.35	2.30	2.28	2.68	2.77	2.59	2.61	2.62	2.65	2.69	2.72	2.76	2.79	2.83	2.87	2.90	2.94	2.98	3.02
Cascade Creek	48.34	44.52	47.25	50.12	54.47	46.84	44.58	47.76	48.78	49.82	50.86	51.91	53.35	54.99	56.03	57.04	58.61	59.49	60.41
Chester	2.50	2.71	2.68	2.52	2.80	2.42	2.38	2.60	2.63	2.66	2.70	2.73	2.77	2.80	2.84	2.88	2.92	2.95	2.99
Genoa	4.54	4.57	4.33	5.19	6.06	5.40	6.51	5.57	5.64	5.72	5.79	5.87	5.94	6.02	6.10	6.18	6.26	6.34	6.42
IBM	25.44	28.81	14.92	15.83	17.20	14.97	14.55	15.59	15.92	16.26	16.60	16.94	17.28	17.52	17.89	18.02	18.26	18.65	18.94
Kalmar	2.15	2.14	1.87	2.63	2.70	2.59	2.63	2.52	2.55	2.58	2.62	2.65	2.68	2.72	2.76	2.79	2.83	2.86	2.90
Marion	3.33	3.32	2.88	2.63	3.01	2.55	2.91	2.83	2.87	2.91	2.94	2.98	3.02	3.06	3.10	3.14	3.18	3.22	3.26
Marvale	3.29	3.27	2.84	3.45	3.31	3.11	2.15	3.01	3.05	3.09	3.13	3.17	3.21	3.25	3.29	3.34	3.38	3.42	3.47
Crosstown	15.26	18.33	24.87	26.38	28.67	33.22	35.68	38.22	39.04	39.88	40.71	41.54	42.68	42.97	43.21	43.97	44.05	44.67	45.23
Northern Hills	25.44	28.81	19.90	21.10	22.94	25.72	26.18	28.05	28.65	29.26	29.87	30.63	31.09	31.71	33.32	34.59	36.23	37.44	38.69
Oronoco	5.69	5.87	5.09	7.48	8.97	7.62	5.49	7.02	7.11	7.20	7.30	7.39	7.49	7.59	7.68	7.78	7.89	7.99	8.09
Pleasant Grove	1.63	1.95	1.17	1.64	1.83	1.33	1.40	1.50	1.51	1.53	1.55	1.57	1.60	1.62	1.64	1.66	1.68	1.70	1.72
Pleasant Valley	1.72	1.81	1.60	1.80	2.04	1.62	1.75	1.78	1.81	1.83	1.85	1.88	1.90	1.93	1.95	1.98	2.00	2.03	2.06
Ringe	4.85	4.87	4.63	3.02	3.67	3.01	5.08	3.93	3.98	4.04	4.09	4.14	4.20	4.25	4.31	4.36	4.42	4.48	4.53
Rock Dell	1.76	1.72	1.58	1.73	2.38	1.96	2.05	1.97	1.99	2.02	2.04	2.07	2.10	2.12	2.15	2.18	2.21	2.24	2.27
Silver Lake	48.34	52.38	47.25	50.12	54.47	54.81	52.46	56.20	57.40	58.63	59.86	59.86	60.05	60.08	60.15	60.51	61.14	61.97	62.57
Willow Creek	27.98	34.05	32.33	34.29	37.27	37.55	35.32	37.84	38.65	39.47	40.30	42.04	42.95	43.77	44.86	45.78	46.28	47.15	48.16
Zumbro	38.16	28.81	37.31	39.57	43.01	38.42	36.11	38.68	39.51	40.36	41.20	42.21	42.89	43.73	44.82	45.47	46.05	46.58	47.44
Total (MW)	**290.19**	**298.57**	**282.32**	**301.96**	**329.97**	**314.43**	**307.87**	**327.82**	**334.49**	**341.33**	**348.14**	**354.98**	**361.81**	**368.66**	**375.50**	**382.36**	**389.24**	**396.08**	**402.96**
Critical Load Level with all generation on 362 MW	**MW at risk**									-20.67	-13.86	-7.02	-0.19	6.66	13.50	20.36	27.24	34.08	40.96
Critical Load Level transmission only 181 MW	**MW at risk** 109.19	117.57	101.32	120.96	148.97	133.43	126.87	146.82	153.49	160.33	167.14	173.98	180.81	187.66	194.50	201.36	208.24	215.08	221.96

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La Crosse Area Summer Peak Load Information (2002-2020)

La Crosse Area Distribution Sub	Load MW 2002	Load MW 2003	Load MW 2004	Load MW 2005	Load MW 2006	Load MW 2007	Load MW 2008	Load MW 2009	Load MW 2010	Load MW 2011	Load MW 2012	Load MW 2013	Load MW 2014	Load MW 2015	Load MW 2016	Load MW 2017	Load MW 2018	Load MW 2019	Load MW 2020
Bangor	4.08	3.82	3.53	4.14	4.17	4.21	3.46	4.18	4.22	4.26	4.30	4.35	4.39	4.43	4.48	4.52	4.57	4.61	4.66
Brice	5.12	5.63	5.09	5.95	6.93	6.10	6.36	6.19	6.29	6.40	6.51	6.62	6.73	6.85	6.96	7.08	7.20	7.32	7.45
Caledonia City	3.42	3.47	3.12	3.24	3.90	4.16	3.51	3.65	3.72	3.78	3.85	3.92	3.99	4.06	4.14	4.21	4.29	4.36	4.44
Cedar Creek	3.54	3.62	3.06	4.22	5.17	4.58	4.93	4.47	4.54	4.62	4.70	4.78	4.86	4.94	5.03	5.11	5.20	5.29	5.38
Centerville	2.79	3.59	2.61	3.32	3.34	3.25	4.20	3.40	3.46	3.52	3.58	3.64	3.70	3.76	3.82	3.89	3.96	4.02	4.09
Coon Valley	4.29	4.80	4.08	5.28	5.22	4.62	3.96	5.26	5.31	5.36	5.42	5.47	5.53	5.58	5.64	5.69	5.75	5.81	5.86
Coulee	53.50	57.94	50.14	58.98	60.30	57.09	52.91	63.29	63.96	64.63	65.31	66.00	66.70	67.40	68.11	68.83	69.55	70.29	71.03
East Winona	8.92	9.31	8.82	9.03	9.47	10.58	11.09	11.32	11.54	11.77	12.01	12.25	12.49	12.74	13.00	13.26	13.52	13.79	14.07
French Island	19.50	30.02	29.92	30.18	29.04	30.20	24.06	35.07	35.44	35.81	36.19	36.57	36.95	37.34	37.73	38.13	38.53	38.94	39.35
Galesville	6.91	6.57	5.95	6.82	6.89	6.82	5.50	6.93	7.00	7.07	7.14	7.21	7.28	7.36	7.43	7.50	7.58	7.65	7.73
Goodview	31.78	34.79	31.46	31.92	35.33	34.06	33.61	33.74	34.13	34.52	34.92	35.32	35.72	36.14	36.55	36.97	37.40	37.83	38.27
Grand Dad Bluff	1.67	1.63	1.35	1.73	1.91	1.60	1.63	1.67	1.70	1.73	1.76	1.79	1.82	1.85	1.88	1.91	1.95	1.98	2.01
Greenfield	2.85	3.20	2.67	2.99	3.43	2.92	3.06	3.06	3.12	3.17	3.22	3.28	3.33	3.39	3.45	3.51	3.57	3.63	3.69
Holmen	14.97	13.52	14.03	15.20	13.16	13.42	14.91	15.06	15.21	15.36	15.52	15.67	15.83	15.99	16.15	16.31	16.47	16.63	16.80
Houston	3.61	3.58	3.02	3.57	3.78	3.40	3.38	3.49	3.55	3.62	3.68	3.75	3.82	3.88	3.95	4.03	4.10	4.17	4.25
Krause	4.12	4.82	3.07	4.26	4.48	4.38	4.54	4.22	4.29	4.36	4.44	4.51	4.59	4.67	4.74	4.83	4.91	4.99	5.08
La Crosse	58.43	44.98	41.52	45.31	50.33	46.79	46.98	51.19	51.70	52.22	52.74	53.27	53.80	54.34	54.89	55.43	55.99	56.55	57.11
Mayfair	43.90	45.08	45.14	46.05	46.58	46.64	45.39	47.72	48.29	48.87	49.46	50.05	50.65	51.26	51.88	52.51	53.14	53.79	54.44
Mound Prairie	2.18	1.96	2.05	2.33	2.02	2.19	2.39	2.23	2.27	2.32	2.36	2.40	2.44	2.49	2.53	2.58	2.62	2.67	2.72
Mount La Crosse	1.64	1.76	1.54	1.99	2.00	1.82	2.09	1.92	1.95	1.99	2.02	2.05	2.09	2.12	2.16	2.20	2.23	2.27	2.31
New Amsterdam	3.88	4.18	4.30	5.31	4.66	4.05	4.46	4.63	4.71	4.79	4.87	4.95	5.04	5.12	5.21	5.30	5.39	5.48	5.57
Onalaska	11.73	11.86	12.48	12.74	12.93	13.25	10.48	13.30	13.50	13.28	13.48	13.69	13.93	14.54	14.76	14.98	15.21	15.44	15.67
Pine Creek	2.03	2.19	1.75	1.90	2.36	1.87	1.84	1.98	2.01	2.05	2.09	2.12	2.16	2.20	2.24	2.28	2.32	2.36	2.41
Rockland	4.18	3.14	4.14	4.14	4.14	3.89	3.10	3.91	3.95	3.99	4.03	4.07	4.11	4.15	4.20	4.24	4.28	4.32	4.37
Sand Lake Coulee	2.99	3.08	2.81	2.50	2.84	2.48	2.59	2.69	2.73	2.78	2.83	2.88	2.92	2.97	3.03	3.08	3.13	3.18	3.24
Sparta	1.15	1.25	1.04	1.21	1.36	1.10	1.16	1.21	1.24	1.27	1.31	1.35	1.38	1.42	1.46	1.50	1.55	1.59	1.63
Sparta (DPC)	29.65	31.16	30.90	34.06	32.47	31.51	31.74	32.78	33.27	33.77	34.28	34.79	35.31	35.84	36.38	36.92	37.48	38.04	38.61
Swift Creek	17.10	21.07	20.11	22.32	24.80	23.74	21.83	27.94	28.22	28.50	28.78	29.07	29.36	29.65	29.95	30.25	30.55	30.86	31.17
Trempealeau	4.43	4.21	4.05	4.93	3.94	3.54	3.68	3.96	4.00	4.04	4.08	4.12	4.16	4.20	4.24	4.28	4.33	4.37	4.41
West Salem	23.30	23.62	22.40	27.10	24.52	22.96	23.97	25.65	25.97	26.29	26.62	26.96	27.29	27.63	27.98	28.33	28.68	29.04	29.41
Wild Turkey	1.17	1.13	0.87	1.33	1.20	1.60	1.35	1.29	1.31	1.34	1.36	1.39	1.41	1.44	1.46	1.49	1.52	1.54	1.57
Winona	46.30	46.75	45.67	46.75	51.91	49.61	51.19	51.29	51.92	52.57	53.22	53.88	54.55	55.23	55.92	56.62	57.33	58.04	58.77
Total Load MW:	**425.13**	**437.73**	**412.69**	**450.80**	**464.58**	**448.43**	**435.35**	**478.69**	**484.52**	**490.05**	**496.08**	**502.17**	**508.33**	**514.98**	**521.35**	**527.77**	**534.30**	**540.85**	**547.57**
Critical Load Level Transmission Only 470 MW	**MW at risk**							**8.69**	**14.52**	**20.05**	**26.08**	**32.17**	**38.33**	**44.98**	**51.35**	**57.77**	**64.30**	**70.85**	**77.57**
Critical Load Level with JPM outage and Genoa - Coulee 161kV outage 450 MW	**MW at risk**						**-14.65**	**28.69**	**34.52**	**40.05**	**46.08**	**52.17**	**58.33**	**64.98**	**71.35**	**77.77**	**84.30**	**90.85**	**97.57**

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St Paul, MN 55101-2147

IN THE MATTER OF THE PETITION
FOR CERTIFICATES OF NEED FOR
THREE 345 kV TRANSMISSION LINE
PROJECTS WITH ASSOCIATED
SYSTEM CONNECTIONS

MPUC No. ET2, E-002 *et al*/CN-06-1115; OAH No. 15-2500-19350-2

DIRECT TESTIMONY OF JEFFREY R. WEBB

ON BEHALF

OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR

MAY 23, 2008

Q: Please state your name, title and business address.

A: My name is Jeffrey R. Webb, I am the Director of Expansion Planning for the Midwest Independent Transmission System Operator, Inc. (hereinafter the "Midwest ISO"). My business address is P.O. Box 4202, Carmel, Indiana.

Q: What are your duties with the Midwest ISO?

A: My duties include directing the evaluation of reliability studies in support of development of the Midwest ISO Transmission Expansion Plan, and the overall coordination of planning study results into a cohesive regional transmission expansion plan.

Q: Please describe your education and professional background.

A: I hold a bachelor's degree and a master's degree in electrical power engineering from Rensselaer Polytechnic Institute. I have also taken a variety of courses and seminars in utility planning and engineering during my career. I have taught courses in circuit analysis, distribution system analysis and electric power system analysis at the Illinois Institute of Technology. In addition, I have served on national and regional groups dedicated to ensuring transmission system reliability. I have served as a member of the Planning Committee of the Mid-America Interconnected Network ("MAIN") a Regional Reliability Organization that has now merged to form the Reliability First Corporation. I have served as past Chairman of the Transmission Task Force, the Data Bank Group, and Standards Compliance Task Force of MAIN. I have served as a member of the NERC Planning Committee representing the RTO sector, and the NERC Planning Standards Subcommittee

("NERC PSS"). As a member of the NERC PSS, I have participated in the development of the NERC Reliability Standards related to transmission planning. I facilitate a number of stakeholder groups related to transmission planning at the Midwest ISO including the Planning Subcommittee and the Regional Expansion Criteria and Benefits Task Force that developed the present transmission investment cost allocation mechanism in place today under the Midwest ISO Energy Markets Tariff. Throughout my career, I have analyzed and planned electric transmission and distribution systems, with a focus on transmission. I began my professional career working for Commonwealth Edison Company ("ComEd") in 1976 as a transmission planning engineer. Between 1988 and September of 2000, I held a variety of supervisory and management positions in the bulk power planning area of ComEd, including Technical Studies Supervisor, Bulk Power Planning Supervisor, System Planning Engineer, and Transmission Planning Manager. As Transmission Planning Manager, I led a department responsible for analyzing the transmission lines, substations, and interconnections that form ComEd's bulk-power transmission network in order to determine when modifications and reinforcements are necessary to maintain adequate, efficient and reliable service to customers. My Responsibilities as Transmission Planning Manager included ensuring that ComEd's transmission grid could meet regional and national adequacy and reliability standards, and whenever appropriate, developing and analyzing cost effective available alternatives for modifications or expansion that best meet those requirements. I have provided testimony before the Illinois Commerce Commission in several dockets involving transmission line certification. I have also provided testimony before the Wisconsin Public Service Commission involving certification of the Arrowhead to Weston 345 kV transmission line certification.

Q: What is the Midwest ISO?

A: The Midwest ISO is the nation's first Federal Energy Regulatory Commission ("FERC") approved Regional Transmission Organization ("RTO"). It encompasses 1.1 million square miles of member transmission systems from Manitoba, Canada to Kentucky and from western Pennsylvania to eastern Nebraska.

Q: What are the Midwest ISO's responsibilities?

A: As an RTO, the Midwest ISO is responsible for operational oversight and control, market operations, and planning of the transmission systems of its member Transmission Owners. Among many other responsibilities, the Midwest ISO also monitors and calculates Available Flowgate Capability ("AFC"), and provides tariff administration for its Open Access Transmission Tariff ("OATT"). The Midwest ISO is the Reliability Coordinator for its footprint, providing real-time operational monitoring and control of the transmission system. The Midwest ISO operates a real-time and a day-ahead locational marginal price based energy market in which each market participant's offer to supply energy are matched to demand and are cleared based on a security constrained economic dispatch process. In addition the Midwest ISO operates a market for Financial Transmission Rights which are used by market participants to hedge against congestion costs. The Midwest ISO is responsible for approving transmission service, new generation interconnections, and new transmission interconnections to and within the Midwest ISO footprint, and for ensuring that the system is planned to reliably and efficiently provide for existing and forecast uses of the transmission system. The Midwest ISO is the Planning Coordinator for the footprint and performs planning functions collaboratively with its Transmission Owners with stakeholder input throughout, while also providing an independent assessment and perspective of the needs of the transmission system overall.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to describe the planning functions performed by the Midwest ISO, including the results of computer simulations that the Midwest ISO performed as a part of our planning responsibilities. Those particular efforts were to review and assess the need and effectiveness of the proposed transmission facilities that are the subject of this hearing. In addition, my testimony describes the Midwest ISO's planning processes and the impact of the proposed CapX facilities on regional system performance.

MIDWEST ISO TRANSMISSION EXPANSION PLAN

Q: With regard to the Midwest ISO's planning activities, does the Midwest ISO have a transmission construction and upgrade plan for the entire Midwest ISO footprint?

A: Yes. The Board of Directors of the Midwest ISO approves updates to the Midwest ISO Transmission Expansion Plan ("MTEP") annually. Since start of operations at the Midwest ISO, we have produced four region plan reports known as MTEP 03, MTEP 05, MTEP 06, and MTEP 07. The most recently approved MTEP is MTEP 07 that was approved by the Board of Directors on December 13, 2007. The approved MTEP 07 Plan can be viewed in its entirety on line at: http://www.midwestiso.org/publish/Folder/193f68_1118e81057f_-7f900a48324a .

Q: What is the purpose of MTEP?

A: The objective of the MTEP is to identify transmission system expansions that will ensure the reliability of the transmission system that is under the operational and planning control of the Midwest ISO, and to identify expansion that is critically needed to support the competitive supply of electric power by this system.

Q: What does it mean for a project to be approved by the Midwest ISO Board of Directors as a part of the MTEP?

A: In accordance with the *Agreement Of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc. a Delaware Non-Stock Corporation* ("TOA" or "Midwest ISO Agreement"), approval of the Midwest ISO Plan by the Board certifies it as the Midwest ISO's plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities.

Q: How does the Midwest ISO develop the MTEP?

A: The Midwest ISO uses a "bottom-up, top down" approach in developing this plan. The "bottom-up" portion relies on the ongoing responsibilities of the individual Transmission Owners to continuously review and plan for reliably meeting the needs of their local systems. The Midwest ISO then reviews these local planning activities with stakeholders and performs a top-down review of the adequacy of and appropriateness of these local plans in meeting needs. In addition, the Midwest ISO considers together with stakeholders, opportunities for expansions that would reduce consumer costs by providing access to new low cost resources that are consistent with and required by evolving energy legislative policies. Our planning process examines congestion that may limit access to the most efficient resources, and considers upgrades that may be needed to meet applicable statutory energy requirements. In the initial stages of developing the MTEP, the Midwest ISO Transmission Owners ("TOs") provide the Midwest ISO with proposed transmission plans necessary to ensure system performance meets the applicable planning criteria of the TO. The TOs provided descriptions of the projects, anticipated service dates and estimated costs, and summary support and rationale for the need for the projects and alternatives considered. The Midwest ISO then prepares several models of the power system in order to establish recommended transmission system expansions. These models include power flow simulation models, economic generation expansion models, and production cost models.

Q: In preparing the MTEP regional plans, what considerations are taken into effect by the Midwest ISO?

A: There are numerous considerations in planning for a regional transmission system, however two considerations are crucial. First, the security of the transmission system must be maintained, that is, the transmission system must be able to withstand disturbances (generator and/or transmission facility outages) without interruption of service to load. This is achieved, in part, by assuring that disturbances do not lead to cascading loss of other generator and transmission facilities. Second, the transmission system must be adequately planned to be able to accommodate load growth and/or changes in load and load growth patterns, as well as changes in generation and generation dispatch patterns without causing equipment to perform outside of design capability. In addition to these two crucial considerations a third consideration in the regional planning process is the identification of transmission constraints to the most efficient regional generation dispatch patterns and that limit access to potential future generation development scenarios, along with devising and implementing solutions to those constraints.

Q: What planning horizon does the Midwest ISO consider and employ in its planning process?

A: We plan the system to meet objectives I've outlined in the short, intermediate and long-range planning horizons. By this I mean over the 1-5 year, 6-10 year, and 10-20 year horizons, respectively.

Q: What factors come into play in developing transmission plans in each of these planning horizons?

A: All of the considerations I have mentioned are considered to various degrees over the entire planning horizon. However, generally speaking, in the short and intermediate term plans tend to focus on ensuring system reliability and efficiency in meeting load growth with existing generation, or generation that is emerging as committed generation via the generation interconnection request process under the tariff. The longer term plans beyond about 10 years must consider possible generation expansion patterns that are not as definitive as for the earlier periods.

Q: How does the Midwest ISO plan for this entire period in a manner that will produce near term plans that will be consistent with an efficient an reliable plan that meets the longer term needs?

A: The planning process is a series of continuous cycles, and we work the development of plans for these various time periods in parallel, with input and guidance from stakeholders to the Midwest ISO planning process. Results of analyses of needs for the short term planning cycle informs the longer term planning process, becoming base plans upon which the longer term plans are developed. In turn, once longer term planning concepts are developed and sufficiently analyzed to demonstrate preferred options these options provide a blueprint to guide the construction of more near term projects as the planning cycles proceed.

Q: Please describe the Midwest ISO efforts to develop a long range transmission plan for the region?

A: This effort is underway and has been since late 2006. We described the evolving planning process in our MTEP 06 report and have been working with stakeholders to develop long term planning concepts that are based on several different possible "futures". These futures differ in certain basic assumptions that could impact decisions about the most prudent transmission expansion that should be developed in order to most efficiently and reliably deliver future generation to meet future demand levels. Four possible futures have been developed. Among the variables that define these futures are 1) capital costs of resource technologies; 2) load and energy growth forecasts; 3) fuel price and availability; 4) environmental costs and initiatives; 5) economic conditions such as inflation, discount rates, wind credits etc. Preliminary transmission concepts have been developed that are postulated to be necessary and sufficient to meet the underlying assumptions about demand, generation fuel mix that is economic and meets regulatory assumptions, and generation siting assumptions based on a variety of indicators. These concepts are in the process of being tested for relative value in terms of energy costs, and performance in reliably delivering projected generation to load under the various future scenarios.

Q: How do the CapX2020 projects that are the subject of this Docket fit into these planning horizons and with the long-range planning concepts?

A: Based on our analyses, these three projects fall into what we would call the short to intermediate term planning horizons, meaning that they will be needed within the next 5 to 7 years. In addition, there are fundamental near term local reliability needs that are the primary drivers for two of the three projects, and the third is needed to reliably deliver new generation developments for the near term as well. As such, in developing our long range planning concepts we have included these projects as a part of the base plans upon which the longer term plans are being developed and analyzed.

Q: Do the longer term conceptual plans that have been developed to date indicate that any of the CapX projects should be built any differently than as being proposed?

A: No, they do not. First, the longer term plans are not sufficiently developed at this stage to dictate definitively that the proposed projects should be altered. Second, the long term plan concept as presently viewed, will require in addition to higher voltage facilities, a build-out of additional 345 kV as well to collectively meet large volume long distance transfers of power, along with more sub regional power transfers and local reliability needs. While meeting longer term needs with a higher voltage system such as 765 kV may prove to be an efficient solution to longer term needs, the underlying 345 kV system will still need to be robust enough to handle flow patterns resulting from contingent conditions affecting the higher voltage grid. Moreover, the conceptual higher voltage plans developed to this point do not propose to occupy the same rights-of-way for the higher voltage lines as would be occupied by the CapX projects proposed in this Docket, and so the CapX projects are compatible with these future conceptual plans.

Q: What is the status of the CapX projects that are the subject of this docket with respect to the MTEP regional plan?

A: These projects were introduced to the regional planning process in MTEP 05 which had a planning horizon through the summer peak of 2009 and which was published in June of 2005. They were described as proposed plans in MTEP 05 that were expected to have a service date beyond the 2009 planning horizon, and that were undergoing analysis to establish their need and final design. They were also included in MTEP 06 and MTEP 07 which provided recommended regional plans for the years 2011 and 2013 respectively. As of MTEP 07, published in December of 2007, the CapX projects were listed as Appendix B projects meaning again that full analysis of the projects had not been completed and the project were not yet being recommended to the Midwest ISO BOD for approval. The Midwest ISO is currently developing MTEP 08 which covers a planning horizon through 2018. We expect to seek BOD approval for MTEP 08 in October of 2008 and the CapX 2020 projects will be included as a part of the MTEP 08 regional plan as recommended plans.

Reliability Planning Considerations

Q: What factors must be considered in planning, operating and maintaining an adequate, efficient, and reliable transmission system?

A: A transmission system must have capacity sufficient to meet projected power flows while maintaining required voltage levels and system stability.

Q: How do you determine if a transmission system has capacity sufficient to meet projected power flows while maintaining required voltage levels and stability?

A: This requires an engineering evaluation of the system as a whole, as well as of critical individual system components (transformers, lines, switchgear), under both normal and contingency conditions (conditions where one or more system components are out of service). Power system simulation models are developed for use in these analyses. Projected peak load power flows for each major component are checked to ensure that rated capacities are not exceeded. Voltage levels are also checked to ensure that voltage levels are maintained above the minimums required for safe operation of the system and above the minimums required for supply of adequate voltage to customers. The model system is tested for both generator and voltage stability following severe disturbances.

Q: Why is it necessary to provide capacity to meet projected power flows?

A: Several reasons. First, overloaded equipment threatens the system's ability to continue to provide adequate and reliable service to its customers. Overloaded equipment can fail and cause brownouts and blackouts (which, for major transmission components, can be widespread and extended) as well as potentially dangerous conditions. In addition, overloads reduce the service life of equipment and tend to increase the probability of component failure in the future.

Q: Why is it necessary to ensure that voltage levels are maintained?

A: Transmission voltages must be maintained within specified tolerances both to ensure that adequate customer voltage is maintained and to ensure that relays and other voltage-sensitive equipment operate properly. Customer voltage is dependent on a number of variable factors, which include transmission voltage level, load magnitude, and load power factor. In the case of the 230 kV and 100 kV class systems, voltage generally must be maintained between 0.92 and 1.05 of nominal.

Q: Why is it necessary to ensure that system stability is maintained?

A: Certain conditions could cause a generating unit to lose synchronism with the rest of the system or cause bulk power voltages to decline rapidly in an uncontrolled manner. These severe contingencies, while unlikely, must be tested for to ensure that the transmission system is strong enough to prevent their occurrence, or that in such instances protective systems act to regain control of the system, either by rapid tripping of the out-of-step generator, or by controlled shedding of load to arrest voltage decline. Without these measures in place, such disturbances could affect the secure operation of wide areas of the inter-connected transmission systems of the state and of the nation.

Q: Why do you study contingency conditions as well as normal operating conditions?

A: Generating units and major transmission system components cannot be assumed to be in operation 100% of the time. In addition to scheduled maintenance requirements, unscheduled outages can occur. Therefore, a level of reliability must be maintained appropriate to the number of customers at risk to possible system failures, balanced by providing service at a reasonable cost. For example, the transmission system must, at a minimum, continue to operate adequately with any single line or transformer in an area out of service. In addition, where the behavior of the transmission system in an area is heavily dependant on the output of a particular generating unit or units, it is necessary to consider the ability of the system to continue to operate when those generating unit are unavailable.

Q: Are there any other factors which must be considered in evaluating alternative plans, once the need for transmission system reinforcement is demonstrated?

A: Yes. Effects on other portions of the existing transmission system must be considered. A plan must also be capable of being constructed and operated within the time required to meet the need. For example, required real estate must be available. The plan should avoid excessive equipment damage or widespread service outages in case events more severe than planned occur. Finally, a suitably robust plan should also consider longer-range requirements for system operation with future growth, and should be compatible with or support energy supply policies such as state renewable energy standards (RES).

Q: Does the Midwest ISO regularly assess the adequacy and reliability of the transmission system within its area including within the State of Minnesota?

A: Yes. The Midwest ISO constantly monitors data on the power flows and voltage levels on all major components of its transmission system. In addition, planners collect data on the forecast loads to be experienced in the future and prepare system models that extend over the planning horizon. These models are used to perform a variety of studies like those that I outlined above to determine if and when changes are required to the transmission system.

Q: What actions are taken based upon these studies?

A: When the data and analysis shows that a change is required, Midwest ISO employees in the planning area consider information provided from our member Transmission Owners about transmission expansion plans that the Transmission Owners are considering to meet their local system needs. When a proposed local plan exists that appears to be effective in addressing identified system needs, the Midwest ISO tests the effectiveness of these plans in meeting applicable planning criteria. The Midwest ISO then considers other potentially feasible means of meeting the need that are consistent with sound engineering and system planning practices. Depending on the nature of the need, there may be many or few such alternative plans. We then determine which of the alternatives are technically feasible, legal, consistent with the Midwest ISO and the member Transmission Owner's obligations to provide efficient and reliable service to its customers. Where there is more than one such option, we assess the advantages and disadvantages of the various alternatives and select as the proposed plan the preferred option that would provide adequate, efficient, and reliable service to customers.

Q: How is the effectiveness of a proposed project evaluated against system reliability criteria?

A: Among the models prepared are power flow models that are used primarily to identify system contingency conditions that may result in reliability of service below reliability criteria. These models are generally developed for the five-to-ten year planning horizon. In order to evaluate the need and effectiveness of proposed projects, the Midwest ISO tests models both without and with the proposed projects to see if there are projected reliability issues that demonstrate the need for possible expansions, and to see if proposed expansions are suitable solutions to issues identified. Similar tests are applied to alternative proposals until the preferred alternative is selected.

MIDWEST ISO ANALYSIS OF AREA RELIABILITY NEEDS

Q: Has the Midwest ISO performed an analysis of the need and effectiveness of the CapX2020 projects that will support the inclusion of these projects into the regional plan?

A: Yes.

Q: Please describe that analysis.

A: The Midwest ISO evaluated several different power flow models of the Midwest ISO transmission system in order to study the reliability of the transmission system. Models were prepared for summer and winter peak periods for the planning years of 2011 and 2016.

Q: What assumptions were applied about generation, load and system topology in those models?

A: Generation supplies were assumed to be generators existing in 2007 plus generally any new generators that have proceeded through the Midwest ISO generation interconnection queue process and that have executed Interconnection Agreements with the Midwest ISO. Load modeled was provided by the Midwest ISO Transmission Owners through power flow models of their respective systems for the study periods. Transmission system topology in the area of study was consistent with the MTEP 07 2013 planning model and included all existing transmission plus any expansions approved by the Midwest ISO BOD for service on or before the study periods.

TWIN CITIES TO FARGO 345 KV PROJECT

Q: What did the study show with respect to the Twin Cities – Fargo proposed transmission project?

A: Our study evaluated three general load serving area along the path of this proposed line; the Red River Valley Area ("RRV Area"), the Alexandria Area, and the St. Cloud Area. In the RRV Area our models demonstrated that under peak load conditions, and absent the construction and operation of the Twin Cities – Fargo line, there are numerous contingency conditions involving the forced outage of existing transmission facilities that will result in loadings on other existing facilities beyond their safe design capability. In addition other conditions will result in transmission level voltages below design criteria, and for certain conditions could result in voltage instability with resultant wide-area loss of load. Each of these conditions fall within the conditions prescribed by the North American Electric Reliability Council ("NERC") to be tested for and for which the system should perform within design standards and/or remain in stable operation.

Q: What kind of problems did the Midwest ISO identify in the Red River Valley area?

A: The Red River Valley is a winter peaking area with an approximate load of 2,200 MW modeled in the Midwest ISO 2011 model, and 2,367 MW in the 2016 model. There is about 565 MW of generation within this area, and therefore the area relies on power transported into the area on the single Jamestown-Maple River 345 kV line and other 230 kV transmission lines in the area, in order to meet the majority of its load serving needs. The Midwest ISO analyzed the loss of the single 345 kV line supporting the area at Maple River near Fargo, along with one of these 230 kV lines and found that this condition could lead to an unstable decline in voltages in the region, with the potential for uncontrolled loss of large amounts of load across the region.

Q: Could operators take reasonable operating steps after the loss of one of these lines that would mitigate the severity of the loss of the second line?

A: No. The unstable condition can result even with all available generation within the area on-line, so that generation redispatch is not a solution here. Instability could be averted by the controlled interruption of load by operator action after the first contingency, but the amount of load that would need to be interrupted to avert this condition in 2016 would be excessive. Analysis showed that an area load level of about 545 MW less than the 2016 load levels modeled can be supported for this severe contingency condition. This difference represents about a 23% reduction in load within the Red River Valley area. Although with targeted controlled load shedding less load reduction may be needed to secure the system, it is the opinion of the Midwest ISO that this indicates that an excessive and unacceptable amount of load would need to be curtailed after a single transmission line outage.

Q: How does the proposed line resolve these conditions?

A: The proposed project provides a second 345 kV supply to the Maple River 345 kV bus in the Fargo area, so that the system will remain secure for contingent loss of the single existing 345 kV supply to the area.

Q: Are there any other reliability issues projected for the RRV area?

A: Yes. We also found that the Fargo 230 kV to 115 kV transformers will overload for the 2016 winter peak conditions for four conditions involving two transmission elements out of service. In addition, under single contingency conditions the Mud Lake to Brainerd 115 kV line would overload, and six 115 kV substations would experience low voltage conditions.

Q: **Did the Midwest ISO consider alternative transmission upgrade solutions?**

A: Yes. The Midwest ISO considered the addition of voltage support equipment in the area such as capacitor banks. However, the area already has a very large amount of such voltage support devices in the area, more in fact than the amount of reactive load in the area. When a system is so heavily compensated with reactive support devices, it can become susceptible to voltage collapse without a significant drop in voltage preceding the collapse. Our analyses indicated that by 2016, for the critical contingency, voltage instability could occur when the voltage in the area as high as

98% of nominal. A system in this state is sometimes referred to as voltage "brittle" and is a concern because, with voltages at this level, operators may have little indication that there is a critical voltage condition existing on the grid, and may fail to take appropriate action. It is also an indication that the addition of further reactive supplies in the area such as capacitor banks will have little or no effect on the potential for voltage instability. In addition to considering the addition of capacitors in the area, the Midwest ISO considered the addition of a second 230 kV line between the Boswell, Wilton, and Winger substations. This line addition would also mitigate the voltage collapse condition, but with not as much margin as the proposed line. In addition, this alternative is estimated to cost about $161 M and would not provide any relief to other areas along the route of the proposed line such as in the Alexandria and St. Cloud areas. We also considered alternative new 345 kV transmission line extensions that would similarly support the Maple River 345 kV bus, such as a second Center to Jamestown to Maple River 345 kV circuit, or a new Dorsey to Maple River line. These alternatives would involve about the same or more miles of new 345 kV circuit, at similar costs, and would also not provide necessary relief to the Alexandria and St. Cloud areas that the proposed project will.

Q: Please describe the reliability issues in the Alexandria area that the Midwest ISO identified would also be resolved by the proposed transmission line.

A: The Alexandria area is described electrically by the demand at 12 substations in and around Alexandria. This area is served by three 115 kV transmission lines: Inman to Elmo; Douglas County to Long Prairie, and; Grant County to Elbow Lake. The

Midwest ISO looked at the conditions in this area for projected 2011 winter peak conditions and for 2016 winter peak conditions. This analysis showed that for the modeled 2011 conditions there will be severe line overloads as high as 154% of design capability, and critically low voltages of 52% of design in this area for loss of two of the three 115 kV lines I mentioned. These conditions will deteriorate as load grows in the area beyond 2011. For example, by the winter peak of 2016, even a single contingency loss of the Grant County to Elbow Lake line will result in voltage below design at Elbow Lake. Should the double contingency outage occur in 2016, without the proposed project, voltages at Elbow Lake and surrounding areas would be as low as 47% of nominal, and the Long Prairie to Douglas line would overload by 60%. At these voltage levels, load service could not be sustained in the area.

Q: You mention problems for double line outages. Isn't this a low probability event?

A: It is. However, in actual operations, NERC reliability standards require that the system be adjusted in order to withstand the "next" contingency. This means that after the loss of a single line, system adjustments must be made in order to withstand the next event. Since the next event in this case could result in voltages as low as 47% and loadings and 160% of rating, some action would need to be taken pre-contingency to mitigate the amount of load that could be impacted should the next contingency occur. As there is not sufficient generating facilities in the affected area to mitigate conditions, load shedding of up to 50 MW would be required after a single contingency in order to withstand the next contingency to avoid line overloads. This represents about 27% of the total load in the area for projected 2016 winter. Furthermore, to withstand the next contingency while maintaining adequate system voltages, load shedding of up to 61 MW or nearly one-third of the area load would be required after a single contingency.

Q: How does the proposed Twin Cities to Fargo line resolve the reliability problems identified in the Alexandria area?

A: The project extends a 345 kV line supply from Monticello through St. Cloud to Alexandria, and then continues this line to connect to the Fargo area 345 kV substation. At the Alexandria substation a new step down transformer will be installed that will directly inject into and support the heavily stressed 115 kV system in the area.

Q: After the project is installed, what are the resulting loading and voltage levels for the single and double contingency conditions on the Alexandria area 115 kV lines?

A: For the worst single line loss condition in 2016 I described, the post-project voltage is increased from 89.5% to 100% of nominal. For the double line outage condition line loadings are reduced from 160% to under 65% of rating, and voltage is improved from 47% to 100% of nominal, providing a secure system and substantial margin for load growth for many years in this area.

Q: Did the Midwest ISO consider alternative solutions to resolving the Alexandria area reliability issues you identified?

A: Yes. Redispatch of generation is not an option since there is very little generation available in the area to support the load. We considered the addition of capacitor banks in the Alexandria area as a means of improving voltage conditions. We have already assumed that a 25 Mvar capacitor bank will be installed at Alexandria by 2011 and the effects of this improvement were included in the case results I have already described. If a second 25 Mvar capacitor bank were installed voltages would improve from 47% to 52% of design for the worst condition I have described in 2016, and would still be well below design. The capacitor bank would not materially reduce the line overload conditions expected. We conclude that at best the addition of capacitor banks in the area would only minimally forestall the need for additional means of increasing the supply capability to the area. Therefore, we considered alternative ways to provide additional support to the area instead of extending the Monticello 345 kV to Alexandria. One consideration was to provide the support from the nearest available 230 kV supply points. This would involve extending a 230 kV line from either the Henning 230 kV substation approximately 45 miles to the north of Alexandria, or from the Morris substation about 63 miles to the southwest of the Alexandria 115 kV substation. When we tested these alternative supply options, we found that the reliability margin provided by these solutions was far short of the proposed project. With a new 230 kV support line from the Henning substation alone, which would be the less expensive of the two options, the loading and voltage conditions for the critical single and double contingencies were marginal in the 2011 winter peak case. For example with the 230 kV option in place, voltages at Elbow Lake are improved from 89.5% to 96.1%

for the single 115 kV line outage of Grant County to Elbow Lake, and from 47% to 93.7% for the double line outage of Grant County to Elbow Lake and Inman to Elmo. Because this alternative 230 kV solution does not provide the strength of support that the 345 kV proposal provides, it would be a shorter lived solution. For example, the proposed line can support a load level in the area of about 293 MW before double contingency conditions result in future reliability concerns, while the alternative 230 kV solution could support only 212 MW in the area. This is a difference of about 23 years at an estimated 1.6% load growth rate.

Q: Are there any other reliability issues needing resolution for which the proposed Twin Cities to Fargo line provides the best solution?

A: Yes there are. The St. Cloud area is vulnerable to a number of different contingency conditions that can cause overloading of existing supply lines, low voltage conditions, and loss of load service. Under the present configuration at the Granite City substation, if there was a loss of the Benton County to Granite City tower line involving both circuits, the St. Regis load of approximately 89 MW would be automatically isolated from supply, and in addition, the St. Cloud to Sauk River line would overload to 133% of rating. Lesser overloads would also occur on three other 115 kV lines between St. Cloud and W. St. Cloud and between W. St. Cloud and Granite City. Low voltage will also occur on several 115 kV buses, for example, the Crossroads 115 kV bus would have a voltage of 86.8% of design. If the Granite City substation was re-configured such that the St. Regis load could be maintained for this outage, this additional load during the contingency condition would cause line overloads approaching 233% of rating, unless an additional source of power is introduced into this area.

Q: Are there other conditions of concern in the St. Cloud Area?

A: Yes. We also project that again for 2011 summer peak conditions, in the event of the loss of two Benton 230/115 kV transformers the St. Cloud to Wakefield 115 kV line would overload by 42% of its design rating, as would the St. Cloud to Benton County line by 6%. Voltages at eighteen 115 kV buses would be below design with one as low as 81%.

Q: Describe how the proposed project will mitigate the St. Cloud area reliability issues you have identified.

A: The Twin Cities to Fargo 345 kV line will be tapped at a new Quarry substation on the west side of the city of St. Cloud, and a new 345/115 kV transformer will be installed to support the area. After this project is in service, Granite City substation can be reconfigured to maintain the St. Regis load connection for the double line outage condition I have described. The post contingency line loadings are improved from 133% with the St. Regis load not served, to less than 65% with the St. Regis load intact, and voltage is improved from 86.8% to 101% for these conditions, providing substantial margin for load growth for many years in this area.

Q: Are there any comparable alternative ways of resolving the reliability risks in the area other than the proposed Twin Cities to Fargo transmission line project?

A: No. There are four peaking units at the Granite City substation totaling 77 MW. However, even if all of these units were available and operating during the critical contingency identified, loading on the St. Cloud to Sauk River line segment would still be 104% of rating and this is with the St. Regis 89 MW load still required to be dropped. Reconductoring the overloaded line segments was considered, but we found that even if the overloaded lines were increased in capacity, the entire load in the area can not be served without exceeding equipment ratings at 2011 projected load levels unless at least three of the Granite City generating units were operated pre-contingency. For example, the Crossroads to Westwood line would still be overloaded to 131% for the most critical contingency, if the Granite City generation was off-line. If two of the generating units were operated in anticipation of the contingency, the critical line loading would be 105% of its rating. Finally, we considered how much load would need to be dropped in the area to maintain existing facilities within design capability and found that about 85 MW would need to be shed in the area in addition to the automatic dropping of the 89 MW St. Regis load, which represents about 42% of the total load in the area and is an excessive amount of load shed for the contingencies studied.

TWIN CITIES TO LA CROSSE 345 KV PROJECT

Q: Turning to the proposed Twin Cities to La Crosse 345 kV line project, please describe the Midwest ISO evaluation of the need for and effectiveness of this aspect of the CapX2020 project?

A: We reviewed the projected loadings and voltage conditions in the Rochester and La Crosse areas for the 2011 summer peak period, and also at load levels somewhat higher than the projected 2011 peak as I will describe. That analysis demonstrates that both of these areas can be expected to experience significant reliability problems unless new capacity is introduced into the area.

Q: Please describe these reliability issues.

A: The Rochester area is supplied by three 161 kV lines and supported by 181 MW of installed generation at the Silver Lake and Cascade Creek stations, and two small hydro units on the Zumbro river. Some of this generation can reasonably be assumed to be available to support the system locally in the 2011 timeframe. However, the older less efficient local generating units may be retired in the future, or may not be available for service to relieve contingent conditions in all circumstances. Therefore we evaluated the area reliability with all available generation assumed to be on, and also with the Silver Lake 1, 2 and 3 units and the Cascade 1 unit unavailable to provide local support as a potential scenario. In our 2011 peak period study, even with all local generation on we found numerous line overload conditions will result for various combinations of facility forced outages. For example, the Adams to Rochester 161 kV line will overload for six different combinations involving line and/or generator forced contingencies, with loading as high as 118% of rating for the loss of the Byron to Maple Leaf 161 kV line and the Alma to Wabaco 161 kV line. The same line will be overloaded at 116% of rating for the loss of the Byron to Maple Leaf 161 kV line during the longer duration outage of the Alma JPM generating unit. For the same generator off-line condition, the subsequent loss of a Byron 345/161 kV transformer would also overload this line. The prior outage of the Silver Lake #4 generating unit will cause the Adams to Rochester line to load to 95% of its rating in 2011 for the next contingency loss of the Byron to Maple Leaf line, and would exceed its rating about two years later. The supply line from Alma may also experience overload conditions in the event that the other two supply line routes from Byron and Adams are out of service, even with all local generation in the area assumed available.

If the smaller peaking units that may potentially be retired earlier (Silver Lk 1,2,3 and Cascade 1) are not available, the worst double contingency condition I have described could result in loadings as high as 173% in the 2011 timeframe, and in addition the Adams to Rochester 161 kV line will be loaded to 97% of rating for the single contingency loss of either the Byron to Maple Leaf line, or the Byron 345/161 kV transformer.

Q: How does the proposed project resolve the reliability issues you have identified?

A: The project will install a new North Rochester 345 kV to 161 kV substation with a step down transformer between the 345 kV Prairie Island to Byron 345 kV line and the 161 kV. A 10.5 mile 161 kV line will be built between the new substation and the Northern Hills substation in Rochester. This new transformer and line will parallel the Byron transformer, and the Byron to Maple Leaf 161 kV line which is a critical outage for the area as I have described. When this line is out, the new parallel line will carry additional flow to Rochester to reduce loadings on otherwise overloaded existing 161 kV supply lines remaining in service. The worst overloaded line for example, the Adams to Rochester line will be loaded to only 71% even with none of the local generation on, as compared to 173% for this same condition without the project.

Q: What alternative solutions did the Midwest ISO consider to address the reliability issues you have identified in the Rochester area?

A: Since the reliability issues will begin to occur in the future even with all local generation available, there are no local generation dispatch options that will provide solutions into the future. Other than dropping load, which we estimate would require up to 55 MW or more than 14% of the entire Rochester load in order to maintain a secure system post contingency, we considered uprating of the existing 161 kV supply system. One alternative that would provide relief to the Rochester area issues I have identified would be to install a second Byron transformer, and a new Byron to Northern Hills 161 kV line. This alternative would be very similar in cost to the Rochester area upgrades provided by the proposed project, but would not address any of the reliability issues in the La Crosse area as the proposed project will.

Q: Please describe the projected reliability conditions in the La Crosse area that the proposed project will address.

A: This area is supplied primarily by four 161 kV lines: Alma - Marshland – La Crosse; Alma – Tremval – La Crosse; Genoa – Coulee: and Genoa – La Crosse. There is 1144 MW of generation in and adjacent to the load area, with 610 MW at Alma to the north, 368 MW at Genoa to the south of Lacrosse, 26 MW of refuse burning units, and 140 MW of gas turbine peaking units at French Island in central La Crosse. The load projected for the 2011 summer peak is 492 MW. For this load level, the Midwest ISO analysis found numerous reliability issues associated with serving this area with the existing system. Table 1 in my direct testimony summarizes some of the problem conditions we found.

Table 1

2011 Summer Peak French Island 3& 4 Peakers off		**Loading Level (% Rating)**	
Critical Facility	**Contingency Event**	**Without Project**	**With Project**
Genoa – La Crosse 161 kV Line	Genoa – Coulee 161 kV Line	104%	<65%
Genoa – La Crosse 161 kV Line	Alma JPM Unit + Genoa – Coulee 161 kV Line	124 %	<65%
Coulee – La Crosse 161 kV Line	Alma JPM Unit + Genoa – N. La Crosse 161 kV Line	113%	<65%
Genoa – Coulee 161 kV Line	Alma JPM Unit + Genoa – La Crosse 161 kV Line	103%	<65%
Lansing – Genoa 161 kV Line	Genoa #3 + Genoa – Harmony 161 kV Line	109%	<65%
	Genoa #3 + Alma - Marshland 161 kV Line	105%	<65%
	Genoa #3 + Alma JPM Unit	100%	<65%
Alma – Marshland 161 kV Line	Genoa – Coulee 161 kV Line + Genoa – La Crosse 161 kV Line	100%	<65%
	Genoa #3 + Alma - Tremval 161 kV Line	97%	<65%
Alma – Tremval 161 kV Line	Genoa #3 + Alma - Marshland 161 kV Line	100%	<65%

Q: How does the proposed project resolve these issues?

A: The project will introduce a strong 345 V source into the area by terminating the 345 kV N. Rochester to N. Lacrosse line with a 345/161 kV transformer that will tie into this area centrally. With this new source the worst loading conditions that I described will be relieved for many years into the future, as shown in Table 1. For example the 104% single contingency overload anticipated on the Genoa – La Crosse line would be reduced after the project to less than 65% of capability. Similarly the 124% overload anticipated for the Genoa – Coulee line while the Alma JPM generator is off line would be reduced after the project to less than 65% as well.

Q: What alternatives did you consider for resolving the reliability issues you have identified in the La Crosse area?

A: We considered the effect of operating the only remaining generators in the area that were modeled off-line in the study; the two oils fired peaking units at French Island. However, this option will not relieve all of the overload conditions identified in the area for projected 2011 conditions. We also considered a 161 kV rebuild option for the area. Because each of the four supply routes are subject to overloading this would require a near complete rebuild of the local area system at an estimated cost of more than $173 million. This expenditure would not provide the level of support that is provided by the proposed project nor the ability to accommodate future load growth in the area to a comparable degree. As an example, for the worst loading condition that I have described, the 124 % loading level on the Genoa – La Crosse line, this loading would be reduced after rebuilding to 86% of loading as compared to 48% with the proposed project. This means that loadings on these same upgraded lines will become problematic in the future long before they would with the proposed project in place. In addition, other lines around the area would reach their limits even before these upgraded lines did, which would add to the cost of the alternative in this area.

Q: How would you summarize the effectiveness of both the Twin Cities to Fargo line, and the Twin Cities to La Crosse line in meeting expected local reliability needs?

A: These two 345 kV projects are especially effective in addressing future reliability needs in the Twin Cities and surrounding areas and will provide for sustained reliability for many years. The projects will provide for long term local reliability in both the northern and southern the Red River Valley areas, as well as in the Alexandria, St. Cloud, Rochester, and La Crosse areas. As such, the projects represent a prudent application of higher voltage supply solutions to address a variety of reliability needs in many different areas of the system simultaneously and to provide for those needs for the foreseeable future.

TWIN CITIES TO BROOKINGS COUNTY 345 KV PROJECT

Q: Has the Midwest ISO considered the needs and benefits of the Brookings to Twin Cities 345 kV project proposed by the Applicants?

A: Yes we have.

Q: What, in your opinion, is the primary issue driving the need for this project?

A: The Twin Cities to Brookings County Project ("Brookings project") is essential to the delivery of renewable energy resources requesting interconnection to the transmission system in the vicinity of this project.

Q: Approximately how many generation interconnection requests are pending in the Midwest ISO interconnection queue at this time related to this portion of transmission system?

A: There are nearly 60 generator interconnection requests along or near the counties where the Brookings County - Twin Cities 345 kV line is intended to be routed. This represents a total of approximately 15,940 MW of requests in the general area of project, with over 7,460 MW specifically within the counties along the preliminary Brookings to Twin Cities project route.

Q: Please explain your understanding of why there are so many requests?

A: The State of Minnesota has mandated the local utilities to meet a newly enacted renewable energy standard (RES) requiring 25% of the energy in the state to be generated by renewable resources by 2025 is surely a contributing factor. Xcel Energy, the state's largest utility, has additional requirements. Additionally, Southwestern Minnesota is the strongest area for wind resources within the State of Minnesota; therefore, generation developers are making generation interconnection requests in this area in anticipation of being available and selected by the utilities to meet these new renewable energy standards.

Q: To what extent will the proposed Brookings to Twin Cities project provide necessary incremental capacity to support the delivery of renewable energy that is requesting to be interconnected in the vicinity of the project?

A: Studies by the Applicants have indicated that the project will provide firm incremental power transfer of about 700 MW, taking into account contingency conditions.

Q: What percentage of Minnesota RES could be delivered by the Brookings project?

A: About 700 MW of the estimated 5600 MW of equivalent wind capacity requirement, or about 13% of the RES requirement. This assumes a 35% average capacity factor for the wind turbines in the area, and appropriately sited renewable resources to take advantage of the full 700 MW of incremental transfer capability that the project would provide.

Q: What has been the assumption about this project that the Midwest ISO has applied when studying recent interconnection requests that are in proximity to the route of the line?

A: We have studied these requests both with and without this transmission line in service as a base case project to see how the project impacts the ability of the generators to interconnect and deliver their output to the grid reliably.

Q: To your knowledge, how many interconnection studies and associated generation capacity in MW have been studied assuming the Brookings line project was a part of the base plan conditions?

A: To date, 58 projects have been or are being studied with the Brookings line project as part of the base case. These projects represent 4358 MW of generation.

Q: Why did you make that assumption?

A: The Applicants have indicated the need for and convictions to support he statutory mandates and that based on studies that they have performed and the Twin Cities to Brookings county line is a critical component in meeting the obligations under the RES. We also reviewed their analysis and also believe that the Brookings to Twin Cities line is necessary to accommodate the extensive amount of new generation request we are seeing in that area.

Q: Has MISO been able to confirm that there would be a material impact on the reliability of the system if these new generators are connected and the Brookings to Twin Cities line does not go into service?

A: Yes we have.

Q: Please explain?

A: For some of these new generators requesting interconnection, shorter term solutions may be able to be identified that will enable interconnection and operation for a limited period of time. For others there may be no possible alternative upgrades that can be identified unless and until this Brookings to Twin Cities line is built and placed into service.

Q: How does this project fit into the long-term plan for the area?

A: As I described earlier, this project is needed to reliably deliver new generation developments in the near term, as there are many more interconnection requests in queue today in the area of the line than the present transmission system can reliably accommodate. As such, in developing our long range planning concepts we have included the CapX projects as a part of the base plans upon which the longer term plans are being developed and analyzed. Simply stated, the Brookings County - Twin Cities 345 kV line is, in our opinion necessary to reasonably meet the milestone targets of the Minnesota Renewable Energy standard. Additional facilities will be required to meet the total requirements of the RES which, in our estimation, will require approximately 5,600 MW of total nameplate capacity from renewables. The additional longer term facilities will be designed to work in concert with existing system and expansion plans in the area, including the proposed lines.

Q: Are there other system needs that the new Brookings to Twin Cities line will address?

A: Yes. The line will also provide local reliability benefits to the area.

Q: How will these additional local reliability benefits be achieved?

A: In addition to transferring renewable energy from the wind resource-rich southwest Minnesota area to the 345 kV grid in the Minneapolis area, the project will support the underlying lower voltage transmission systems along the route by installing step-down transformers at Lyon County, Franklin, and Lake Marion, and at a new Hazel Creek substation near Granite Falls. These step-down transformers will reduce loadings on 115 kV and 69 kV circuits extending into these areas from more distant supply sources by injecting a strong source of power at these step-down points along the route. Voltages on these systems will also be supported to provide for better service quality under contingent conditions involving the local transmission systems.

<u>ADDITIONAL BENEFITS OF THE PROPOSED PROJECTS</u>

Q: In your opinion, are there other benefits that you believe the three projects that are the subject of this docket will provide beyond addressing local reliability needs, load growth, and interconnection of renewable resources as you have discussed?

A: Yes. The combined projects connect the Twin Cities area to adjacent areas of the transmission system either directly at or near to existing 345 kV networks and in geographically diverse directions to the northwest, southwest and southeast. This design will provide for a great deal of flexibility in providing access to both existing and future resources within the Midwest ISO market. This high capacity interconnectivity can be expected to have a lowering effect on average marginal energy prices in the upper Midwest part of the Midwest ISO market in the near term. In the long term, this interconnectivity will help to ensure adequate supplies will be available to market participants in the Twin Cities and surrounding areas, and will provide for more options in selection by those market participants of preferred sources of supply.

Q: Does this conclude your testimony?

A: Yes it does.

Regional Incremental Generation Outlet Study (RIGO)

Transmission System Planning and Reliability Assessment

Prepared by:
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8/___/2008

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1: Background & Scope of Study

This electric transmission study was conducted by Northern States Power Company, a Minnesota corporation (“NSPM” or “Xcel Energy”), and addresses the development of transmission outlet capacity for additional electric generation. The generation pattern assumed for the purpose of this study is based on Midwest Independent Transmissions System Operator (“MISO”) queue data relating to interconnection requests outside of the “Buffalo Ridge Area”, primarily in the western and southeastern portion of Minnesota. The study effort concentrated on developing and evaluating smaller scale (115-161 kV) transmission options that could:

- provide several hundred megawatts (“MW) of incremental generation outlet capacity
- be implemented by the 2010 timeframe; and
- integrate well with the proposed CapX2020 Group 1 projects[1]

The existing transmission system and several transmission system improvement options were evaluated to identify the steady-state (thermal and voltage) limitations that would be successively encountered if additional increments of generation capacity were installed in the southeastern and western portions of Minnesota, subject to the following principal assumptions:

- a total of 1175 MW of generation (nameplate rating) has already been installed in the Buffalo Ridge area prior to the period of interest;
- 1175 MW of generation has been integrated into the power system by construction of the Buffalo Ridge Incremental Generation Outlet (“BRIGO”) transmission facilities:
  -- Fenton-Nobles 115 kV #2
  -- Lake Yankton-Southeast Marshall 115 kV #1
  -- Nobles 345/115 kV transformer #2
  -- Yankee-Brookings County 115 kV #2
  -- Brookings County 345/115 kV transformer #2
  -- related 161, 115 & 69 kV line reconductors & rebuilds
  -- related substation upgrades
- it is desired to identify the limiters that would be incrementally encountered with additional wind generation;
- under both system intact and first-contingency (N-1) conditions, facility loadings and bus voltage levels will be maintained within applicable established performance criteria, for both peak and off-peak load conditions, without resorting to tripping of generation or curtailment of deliveries to load;

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[1] The CapX2020 Group 1 projects include four projects: 1) Bemidji – Grand Rapids 230 kV line; 2) Twin Cities-Fargo Project; (3) Twin Cities-Brookings County 345 kV Project and (4) Twin Cities-La Crosse 345 kV Project. Certificate of need applications are pending for all four projects in two separate dockets. The Bemidji – Grand Rapids 230 kV Project is pending in Docket No. E017, E015, ET-6/CN-07-1222. The other three projects are pending in Docket No. E002/CN-06-1115.

- all new generation located in southeastern and western Minnesota will have dynamic and steady-state reactive power control characteristics (power factor controllable in range of .90 lead to .90 lag) in conformance with the 1999-vintage NSP reactive power/voltage control standard; and
- Present Midwest Reliability Organization ("MRO") and MISO standards and policies will continue to apply with respect to constrained interface impacts, non-degradation of existing transfer capabilities, and generation accreditation procedures.

This Study's analysis also does not address mitigation of all remote interface impacts. Although interfaces traditionally of relevance to the Minnesota area were monitored, it is possible that incremental loading of remote interfaces, (either existing or defined in the future) may require mitigation.

The technical and economic analyses were performed for the purpose of identifying a preferred plan to achieve the specific goal of providing generation outlet capacity for several hundred MW of additional generation development "off Ridge" in the greater Minnesota area. It is recognized that many other potential generation developments--possibly aggregating to thousands of MW--are in preliminary stages of study by various entities. Generation developments may significantly affect overall future transmission requirements in this region.

2: Conclusions & Recommended Plan

The Preferred Plan is Option 1213BCC which adds the following facilities:

- Pleasant Valley-Byron 161 kV line
- Pleasant Valley 345/161 kV transformer #2
- Pleasant Valley-South Rochester Substation 161 kV line
- Double Circuit 161 kV line from Byron-Maple Leaf-West Side Energy Park

This option appears to offer the best overall results with respect to:

- power system performance (system intact & contingent loadings & voltages)
- practicality (logistics of construction and operation)
- price (cumulative present worth cost)
- consistent with off ridge generation assumption

These facilities provide the bulk system improvements to make the interconnection possible for energy resource. There are other limiters that show up in the Transfer Limit Table Generator ("TLTG") analysis and there will likely be other upgrades required for specific projects to deliver power to specific customers.. It assumed that those limiters and deliverability would be handled through the MISO interconnection studies.

3: Study History & Participants

Following an introduction meeting in July 2007, progress review meetings were held periodically during the study:

July 16, 2007	Minneapolis, MN	Xcel Energy's Office (Missouri Basin SPG meeting)
September 20, 2007	Elk River, MN	Great River Energy's Offices
October 3, 2007	Sioux Falls, SD	Missouri River Energy Services Offices
December 4, 2007	Elk River, MN	Great River Energy's Office

In addition to the Study Group meetings, updates were also presented to the Mid-Continent Area Power Pool ("MAPP") Missouri Basin ("MB") and Northern MAPP ("NM") Sub-regional Planning Groups ("SPGs") during their regularly scheduled meetings.

The study group benefited from participation of technical staff of the following transmission entities:

MISO	Midwest Independent System Operator	Carmel, IN
DPC	Dairyland Power Cooperative	La Crosse, WI
RPU	Rochester Public Utility	Rochester, MN
SMMPA	Southern Minnesota Muni Power Agency	Rochester, MN
GRE	Great River Energy	Elk River, MN
OTP	Otter Tail Power Co	Fergus Falls, MN
XEL	Xcel Energy	Minneapolis, MN

Xcel Energy technical staff and consultants performed the powerflow simulations, economic analyses, and tabulation of results. These results were presented and reviewed at the study group's meetings, at which comments, conclusions, and recommendations were developed to guide each successive stage of analysis.

4: Analysis

4.1: NERC Criteria

In conducting the Study, planning engineers evaluated the electrical system for conformance with the applicable North American Electric Reliability Council ("NERC") criteria described below.

The Category A i.e., NERC Standard TPL-001, planning standard requires analysis on the power flow base case system violations without any contingency conditions. The PSS™E and MUST reports of the load flow case were used to identify any system violations in the system models.

The Category B i.e., NERC Standard TPL-002, planning standard requires analysis on n-1 single contingencies. A Category B contingency file was developed for Category B analysis for the RIGO study.

The Category C i.e., NERC Standard TPL-003 planning standard requires analysis multiple contingencies that would produce the most severe system conditions. MISO has created and maintained a file for assessing the power system and determining the Category C (and in some cases Category D) contingencies that the operations planning staffs in the region have determined to be the most detrimental to the reliability of the system. The Category C contingency files were originally defined by the Northern Mid-Continent Area Power Pool ("MAPP") Operations Review Group and included the Xcel Energy portion of the system.

4.2: Models employed

4.2.1: Steady State models

The powerflow models employed were developed by the MRO model building group. The models are based on the 2006 Series MRO models, Year 2011 and 2016 summer peak and summer off peak, as updated:

- to reflect system changes by appropriate study year.
- to reflect the Post CAPX2020 Group 1 facilities by appropriate study year.

A post Group 4 MISO study case model was also used to compare results gained in the MRO models.

4.2.2: Dynamics models

Stability analysis was performed on a model adapted from the MISO Group 4, G362 interconnection study effort. This model represents Year 2010 peak load conditions. Because this was a MISO Group stability model, there are numerous hypothetical queued generation projects present in the case.

The dynamic stability analysis effort utilized the Northern MAPP Operating Review Working Group ("NMORWG") 2005 Study Package, developed from the previous NMORWG 2003 Study Package and from the 2004 Series MAPP models:

PSS/E Rev 29.4, PC Platform Version (Compaq 6.6B Compiler)
Works on Rev 29.5

Current Version: 09/28/05 PRELIM Approval Status: Preliminary;
Not yet approved by NMORWG

The dynamic stability analysis included the regional faults for the northern MAPP region, plus several new faults related to the new transmission facilities involved in each of the transmission configurations under evaluation.

All disturbances simulated during the transient stability study are identified by a three-letter name. These fault abbreviations, along with their corresponding fault descriptions can be found in Appendix J.

The export levels across the North Dakota (“NDEX”), Manitoba (“MHEX”), and Minnesota-Wisconsin (“MWSI”)[2] interfaces were set to their maximum simultaneous transfer limits of 2080 MW, 2175 MW, and 1480 MW, respectively prior to the proposed Big Stone II generation and transmission additions. This ensures that power system stress is at levels corresponding to present-day “maximum simultaneous levels”, regardless of the actual flows that may be measured on the NDEX ties following the addition of the Big Stone outlet transmission.

4.3: Conditions studied

4.3.1: Steady-state modeling assumptions

The technical analysis was performed based upon year 2011 and 2016 summer peak and off peak cases from the 2006 MRO series powerflow models. The base models were adjusted to represent the latest available forecast data for summer season peak (100%) and off-peak (70%) load conditions. The off-peak model simulates a high transfer condition corresponding to approximately 100% of the presently-recognized simultaneous North Dakota/Manitoba transfer limit as established by the NMORWG, while the on-peak model represents only identified firm power transactions. Table 1 shows these modeling assumptions.

Table 1 Modeling Assumptions

					Net generation, MW				
Condition	Load Level	NDEX[1]	MHEX[2]	MWSI[3]	Wind	Anson	MEC	Lake Field	Cannon Falls
Peak	100%	587	1467	1271	1175	377	379	550	357
Off-peak (NMORWG LIMIT)	70%	2080	2175	1480	1175	417	379	550	357

Relevant contingencies are provided in Appendix C.

Notes
1) NDEX= sum of flows on the 18 lines comprising the “North Dakota Export” boundary;
2) MHEX= sum of flows on the 4 Manitoba Hydro-U.S. 230 & 500 kV tie lines;
3) MWSI = sum of flows on Minnesota-Wisconsin Stability Interface (Prairie Island-Byron, Eau Claire Arpin 345 kV)

In addition, the MISO Group 4, 2010 summer peak model was used to verify options and results to ensure consistency.

4.3.2: Steady state contingencies modeled

2 The MWSI was defined as the sum of flows on the Minnesota-Wisconsin Stability Interface (Prairie Island-Byron, Eau Claire-- Arpin 345 kV) This interface was in the process of being reevaluated to include the Arrowhead-Weston 345 kV line during this study.

For this study we included all N-1 and tie line contingencies for the Xcel Energy, SMMPA, GRE, WAPA, OTP, DPC and Alliant West areas. In addition, we ran all the Category C contingencies listed in the wind1225.con file based on the MISO.con file.

4.4: Options evaluated

The following transmission improvement options were evaluated:

Option 1 "Morris-Kerkhoven-Willmar 115 kV & Paynesville-Wakefield 230 kV conversion"
This option establishes a new 115 kV line from the Morris substation to the Kerkhoven substation to the Willmar substation. This option includes operating the Paynesville-Wakefield 115 kV line at 230 kV (currently operated at 115 kV operation, but built to 230 kV specifications).

Option 2 "Waldon-Paynesville 115 kV"
This option establishes a new 115 kV line from the Waldon substation to Paynesville substation.

Option 3 "Waldon-Willmar-Big Swan 115 kV"
This option establishes a new Waldon-Willmar-Big Swan 115 kV line.

Option 4 "Waldon-Willmar 115 kV"
This option establishes a new 115 kV line from Waldon to Willmar.

Option 5 "Owatonna-Austin Corner 161 kV"
This option constructs a new 161 kV line from Owatonna to Austin Corner. Austin Corner is a new 161 kV substation that taps the 161 kV line between Austin and Hayward.

Option 6 "Pleasant Valley Radial 161 kV"
This option adds a 161 kV radial tap from Pleasant Valley.

Option 7 "Byron Radial 161 kV"
This option adds a 161 kV radial tap from Byron.

Option 8 "Blue Earth-Loon Lake 161/115 kV"
This option establishes a new Blue Earth to Loon Lake 161 kV line. This option also includes a new 161/115 kV transformer at the Loon Lake substation.

Option 9 "Pleasant Valley-Blue Earth 161 kV"
This option establishes a new 161 kV line from Pleasant Valley to the Blue Earth substation.

Option 10 "Morris-Paynesville 230 kV"
This option establishes a new 230 kV line from the Morris substation to the Paynesville substation.

Option 11 "Jackson-Loon Lake 161 kV"
The option establishes a new 161 kV line from the new City of Jackson substation to the Loon Lake 115 kV substation. This option includes a 161/115 kV transformer at Loon Lake.

Option 12 "Pleasant Valley-Byron 161 kV"
This option adds a new 161 kV line from the Pleasant Valley substation to the Byron substation. This line originated from the MISO interconnection study G362.

Option 13 "Pleasant Valley-South RPU and Double Circuit Byron-Maple Leaf-West Side Sub 161 kV"
This option adds a new 161 kV line from Pleasant Valley-New South RPU substation. This option also includes a double circuit 161 kV line from Byron-Maple Leaf-new West Side substation.

Option 5b9 "Owatonna-Austin Corner 161 kV and Pleasant Valley-Blue Earth 161 kV, with a 2nd Pleasant Valley 345/161 kV transformer"
This is a combination option to see if there is any benefit to generation outlet by adding two 161 kV lines in the southeastern Minnesota area. The second Pleasant Valley 345/161 kV transformer was included because showed up as a limiter in almost all the southeastern options.

Option 89 "Blue Earth-Loon Lake 161 kV and Pleasant Valley-Blue Earth 161 kV"
This is a combination option to see if there is any benefit to generation outlet by adding two 161 kV lines in the southeastern Minnesota area.

Option 5b12 "Owatonna-Austin Corner 161 kV and Pleasant Valley-Byron 161 kV"
This is a combination option to see if there is any benefit to generation outlet by adding two 161 kV lines in the southeastern Minnesota area.

Option 58 "Owatonna-Austin Corner 161 kV and Blue Earth-Loon Lake 161 kV"
This is a combination option to see if there is any benefit to generation outlet by adding two 161 kV lines in the southeastern Minnesota area.

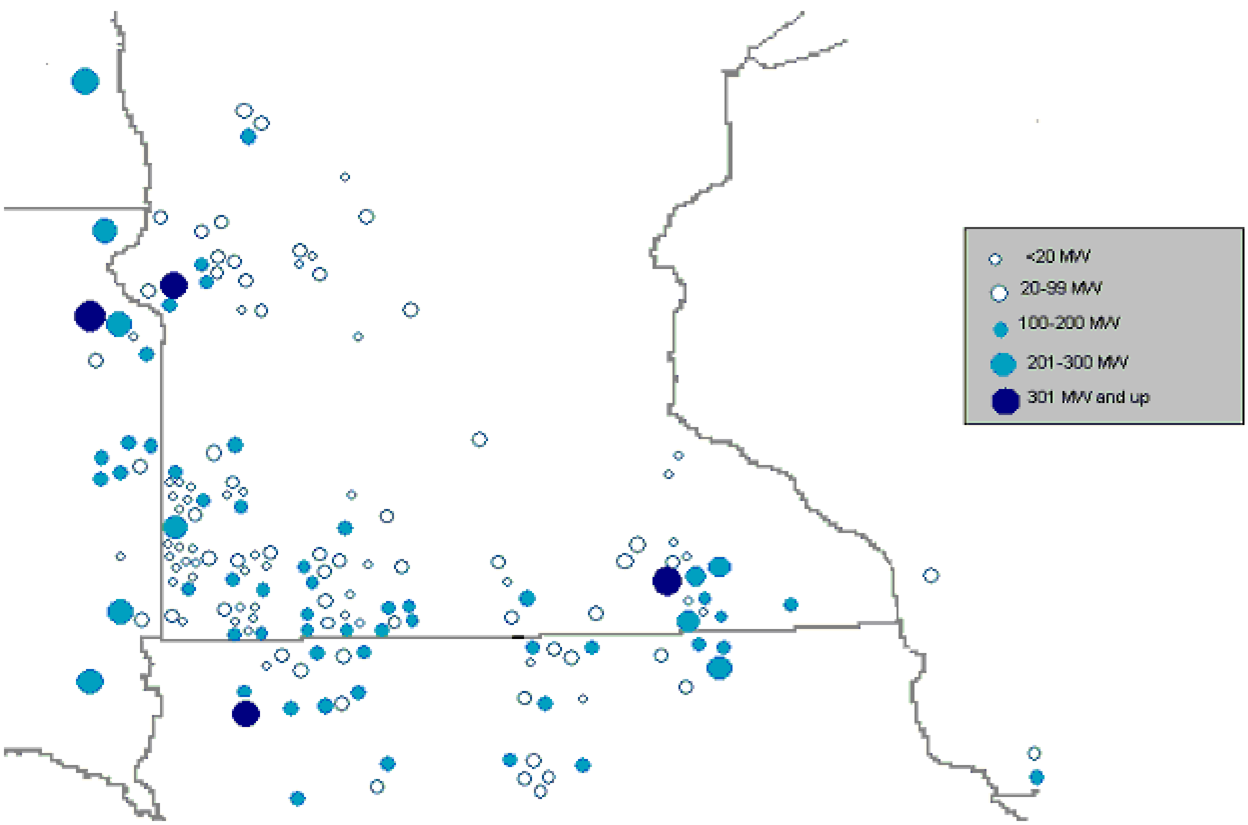
Option 1213 "Pleasant Valley-Byron 161 kV and Pleasant Valley-South RPU substation and Dbl Ckt Byron-Maple Leaf-Cascade Creek (new West Side substation)"
This option of 161 kV line additions was examined to see if greater outlet capabilities could be achieved by a comprehensive plan for the Pleasant Valley area.

The above transmission options were designed to be representative of a broad range of theoretically possible power system improvement strategies that would meet the "modest, quickly implementable" objective. In addition to these "simple" options, several "combination" options were also developed, following the "first cut" evaluation of the above options. The combination options were examined to determine whether it may be advantageous to implement more than one of the originally identified transmission options.

4.5: Selection of termini and intermediate connection points

The selection of the termination points for each of the options evaluated was based on generation assumptions. Planning engineers used the MISO interconnection queue map to determine where the greatest number of MW of generation requests were grouped to come up with the most logical outlet points. See Map 1 below. There are large amount of requests in the western portion of Minnesota/South Dakota and well as southeastern Minnesota/Iowa. Keeping in the spirit of "off Ridge" outlet solutions, we chose options that would provide the most outlet capability with the fewest line additions.

Map 1 – MISO Queue Requests by Area



4.6: Performance evaluation methods

Power system performance simulation was performed with the aid of the Managing and Utilizing System Transmission ("MUST") digital computer powerflow program (Version 8.1) as supplied by Power Technologies, Inc. System intact and first-contingency analysis was performed primarily using PSS™E-MUST (Version 8.1) activity TLTG. TLTG performs automated contingency analysis while progressively incrementing power transfer between a defined "source" and "sink" location.

For both the TLTG analyses, the following apply:

Monitored facilities:

All transmission lines and transformers 69 kV and above in the model areas:

NSP	WAPA
Alliant	OTP
GRE	SMMPA
DPC	

Study area (facilities subject to outage):

All transmission lines and transformers 69 kV and above in the model zones:

NSP	WAPA
Alliant	OTP
GRE	SMMPA
DPC	

Activity TLTG achieves computational efficiency by extensive use of Power Transfer Distribution Factors ("PTDFs") and Line Outage Distribution Factors ("LODFs"), concepts applicable to linear, time-invariant systems. These methods are appropriate for power system analysis, provided it is recognized their accuracy is constrained by their inherent limitations arising from non-linear effects such as exhaustion of reactive power supply and LTC transformer range limits. Consequently, the resultant reported transfer limits from TLTG are thus approximate.

Facilities identified in the TLTG outputs are considered valid limiters if they:

- have a PTDF of 5.0% or greater (system intact) or
- have an OTDF of 3.0% or greater (outage condition)

The 5.0% PTDF selected in accordance with the MISO's cutoff level for system impact analyses. Very large reductions in generation (greater than 50:1) are required in order to achieve a perceptible amount of loading relief. Consequently, PTDFs lower than 5.0% strongly indicate that other power system adjustments are likely to be much more effective in producing the desired ameliorative effect than would generation adjustments in the study area. Refer to Section 5.2 for further discussion on evaluation of incremental loadings on constrained interfaces ("flowgates") and non-flowgate facilities.

The 3.0% OTDF…..[Jason Insert]**]**

5: Results of detailed analyses

5.1: Powerflow (system intact & contingency)

Appendix B provides the "raw" TLTG outputs for the transmission Options. Appendix B also contains a summary table derived from the “raw” TLTG outputs. This table lists only limiting facilities exceeding the 5% PTDF/3% OTDF cutoffs.

For this study an overall MW level was not identified because of the differences in geographic location for each of the options. TLTG was used to evaluate each option to determine a natural stopping point. Both pre- and post-CapX 2020 Group 1 projects scenarios were evaluated as well as summer peak and off peak conditions to determine the true outlet capability of each option and to determine how each option would function in a post-Group 1 case.

For example, in Option 5 for the summer peak, pre-Group 1 projects scenario, the raw TLTG output an outage shows that outage of the 345/161 kV transformer at the Pleasant Valley Substation results in an overload of the Austin Corner-Pleasant Valley 161 kV line at the 53.4 +200 (assumed at Pleasant Valley) = 253.4 MW level. By adding a second 345/161 kV transformer at Pleasant Valley, it would push the next limiter to loss of the Blue Earth Tap-Winnebago 161 kV line, thereby increasing the outlet capability to 507.8 + 200 (assumed at Pleasant Valley) = 707.8 MW for a summer peak, pre-Group 1 case. Examining the same option in an off peak case yields a –38 MW reduction in outlet capability, so –38 + 200 MW = 162 MW of overall outlet capability from the area.

5.2: “First Cut” Screening

To keep the amount of technical analysis required at a manageable level, a "first cut" screening analysis was undertaken to identify any options that were technically or economically significantly weaker than the others, and for which further detailed analysis would not be warranted.

Table 2 below shows a summary TLTG table for all the options examined. The bold numbers are the maximum MW outlet achieved for each of the options and variations.

Table 2 TLTG Summary

		Pre CapX		Post CapX	
		sp	op ht	sp	op ht
Option		Capacity (MW)		Capacity (MW)	
Option 1	Morris-Kerkhoven-Willmar 115 kV line, 230 conversion	105	19	105	**7**
1a	above w/reconductor Grant Co-Morris 115 kV	204	19	105	**7**
1ab	above w/Reconductor Morotp-Morris 115 kV	236	**19**	105	198
1abc	above w/Reconductor of Kerkhoven-Kerkhoven Tap 115	237	**19**	105	198
1c	1 w/Reconductor of Kerkhoven-Kerkhoven Tap 115	237	**41**	204	55
1cd	1c w/Reconductor of Minn Valley-Red Falls Tap 115 kV	237	**41**	204	195
Option 2	Waldon-Paynesville 115 kV line	168	**50**	212	89
Option 3	Waldon-Willmar-Big Swan 115 kV line	163	**54**	196	72
3a	above w/Reconductor of Kerkhoven-Kerkhoven Tap 115	163	**76**	298	139

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Option 4	Waldon-Willmar 115 kV line	142	**49**	215	63
Option 5	Owatonna-Austin Corner 161 kV line	**53**	105	54	101
5a	5 w/trip og generation for loss of Pl Valley 345/161 tx	53	**138**	406	**138**
5b	5 w/Pleasant Valley 345/161 tx #2	508	**308**	508	528
Option 6	Pleasant Valley Radial = 0, for this study’s purpose.				
Option 7	Byron Radial = 0, for this study’s purpose.				
Option 8	Blue Earth-Loon Lake 161 kV line	362	232	349	**220**
Option 9	Pleasant Valley-Blue Earth 161 kV line	338	**43**	278	59
9a	above w/Austin-Pl Valley 161 kV ckt 2	338	**174**	278	182
9b	9 w/Pleasant Valley 345/161 tx #2	531	**368**	278	792
Option 10	Morris-Paynesville 230 kV line	158	**101**	146	**70**
10a	above w/reconductor of Minn Valley-Red Falls Tap 115	158	102	146	**82**
10ab	above w/Reconductor of Kerkhoven-Kerkhoven Tap 115	188	**110**	204	192
10abc	above w/Reconductor Kerkhoven-Benson 115 kV	260	102	260	**195**
10abcd	above w/Reconductor Morotp-Morris 115 kV	236	102	219	**219**
10abcde	above w/reconductor Grant Co-Morris 115 kV	204	**102**	223	222
Option 11	Jackson-Loon Lake 161 kV line	394	130	**124**	165
11a	option 11 w/reconductor Lakefield-Triboji 161	394	**255**	124	388
11ab	above w/reconductor Traverse-Travers S 69 kV	478	**312**	124	388
11abc	above w/reconductor NWSWDTP-Travers S 69 kV	564	**345**	124	388
11d	Option 11 w/reconductor Heron Lk-Lakefield 161	394	130	**145**	165
11de	11d w/reconductor of Lake Marian-Kenrick	394	130	443	**306**
Option 5b9	Option 5b and Option 9	583	**268**	583	429
5b9a	above w/building second line to Maple Leaf-Byron 161	583	**412**	583	429
5b9b	5b9 w/trip og generation for loss of Pl Valley 345/161 tx	583	412	583	**689**
Option 89	Option 8 and Option 9	360	**47**	357	61
	above w/Pleasant Valley 345/161 tx #2	672	**365**	681	685
	above w/Maple Leaf-Byron ckt 2	672	**572**	681	685
Option 12	Pleasant Valley-Byron 161 kV line	508	**158**	234	299
12a	above w/Maple leaf-Byron 161 kV ckt 2	508	326	**234**	299
12ab	above w/Pleasant Valley 345/161 tx #2	508	**334**	508	853
12abc	above w/Maple leaf-Cascade Creek 161 kV ckt 2	**508**	589	**508**	853
Option 5b12	Byron-Pleasant Valley, Austin Corner-Owatonna 161 kV line	508	**158**	509	518

5b12a	above w/Maple leaf-Byron 161 kV ckt 2	508	**323**	509	518
5b12ab	above w/Maple leaf-Cascade Creek 161 kV ckt 2	**508**	567	509	518
5b12abc	above w/reconductor Pleasant Valley-Austin Corners 161 kV	**508**	643	509	518
5b12abcd	above w/gen tripping or Pleasant Valley tx 3	**508**	816	509	891
Option 13	Pleasant Valley-South RPU 161 kV line, Dbl Ckt fix	868	627	821	**570**
Option1213BCC	Option12&13 w/ Byron-Cascade Ck double ckt	1110	779	1081	**722**
Option1213IBM	Option12&13 w/ Byron-IBM tap double ckt	1124	756	1083	**724**
Option1213WNH	Option12&13 w/ Byron-Nothhills double ckt	1124	756	1083	**724**
Option 58	Blue Earth-Loon Lake Austin Corners-Owatonna	**53**	107	**54**	106
	w/Pleasant Valley tx 2	723	**308**	696	**529**

The bold numbers represent the level of outlet capability at the natural stopping point for each option, after which level some major “fix” is needed to increase outlet. For example, with the option 1213BCC, the natural stopping point was a third 345/161 transformer located at Pleasant Valley. For some of the options, there were prior limiters, but they were not considered the outlet limit for an option because they are of a smaller size such that would typically be handled through the MISO interconnection process.

This analysis showed that the western options, 1, 2, 3, 4, and 10, provide very little outlet relative to the other options. The main problem with adding another line or lines stern part of the state is the through flow on the Dorsey-Forbes 500 kV line which limits generation outlet capability. Without a major new bulk transmission addition in the southwest part of the state, the 500 kV loading issue will continue to be a limiter. The analysis also showed that the other options, located in the southeastern portion of the State, generally provided the greatest amount of generation outlet. Consequently the western options were dropped from further analysis.

5.3: Dynamic Stability

Dynamic stability performance was examined with the PSS™E Revision 30.3 stability program using a model derived from the MISO Group 4, G362 interconnection stability model. The three proposed lines were added and the generation was adjusted to the 900 MW level. A summary of the faults and the results are listed in Vol. 3 Appendix J.

Please also reference the R39-07 MISO G362 Stability Report_8_10_2007.pdf report for the G362 Grand Meadows interconnection.

5.4: Constrained Interface Analysis

Constrained interface analysis was not performed as part of this study. Constrained interface analysis will be performed during the MISO system impact study.

5.5: Reactive Power Requirements

AC Contingency Checker ("ACCC") analysis was conducted at the 200 MW and 900 MW outlet levels to determine if any voltage support is needed. It was observed through the ACCC analysis that there were no reactive requirements needed as a result of adding option 1213BCC at the 200 MW or 900 MW level.

These findings are consistent with the results of the MISO G362, 200 MW system impact study that found no voltage violations. Please reference the G362_Draft_SIS_Thermal_Report_20070817.pdf for the Grand Meadows interconnection for more information.

5.6: Losses: Technical Evaluation

An analysis was performed on all post first-cut options to determine the effects on the overall transmission system losses. A base case without any improvements was used for a comparison case. A losses analysis showed that the impact of each option on the system losses are within the solution tolerances for PSS™E and are not statistically significant. This result is consistent with what would be expected of modest 115-161 kV improvements. Larger bulk transmission lines typically provide a larger transmission loss reduction by unloading the underlying transmission system.

5.7: Losses: Economic Evaluation

Because the technical losses evaluation showed no statistically significant differences in losses between the options identified, no economic evaluation was performed.

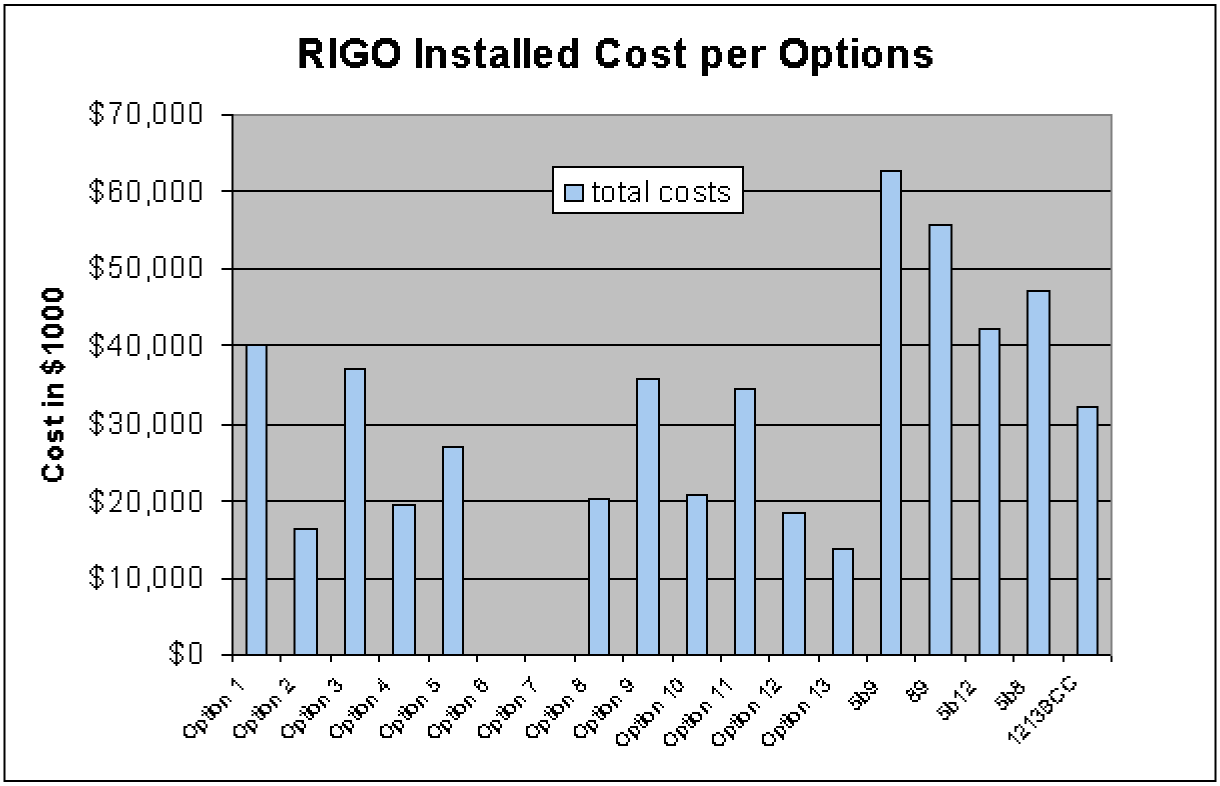
6: Economic Analysis

Economic analyses were undertaken on the basis of installed cost of required facilities. Present value analysis was not necessary, as it is presumed that the in-service dates (and hence expenditure patterns) do not vary significantly (more than 1 year) among the options.

6.1: Installed Cost

Graph 1 shows the installed costs of each of the RIGO options that were evaluated.

Graph 1



Options 1-4 and option 10 were based on a western flow assumption. The other options were based on a southeastern flow assumption. Because of these different flow assumptions it is impossible to compare them against each other one on one. The western options have a different set of limiters and natural stopping points than the southeastern options.

Consequently, planning engineers calculate a cost per MW for each of the options for comparison purposes. Table 2 shows the total installed cost per MW gain.

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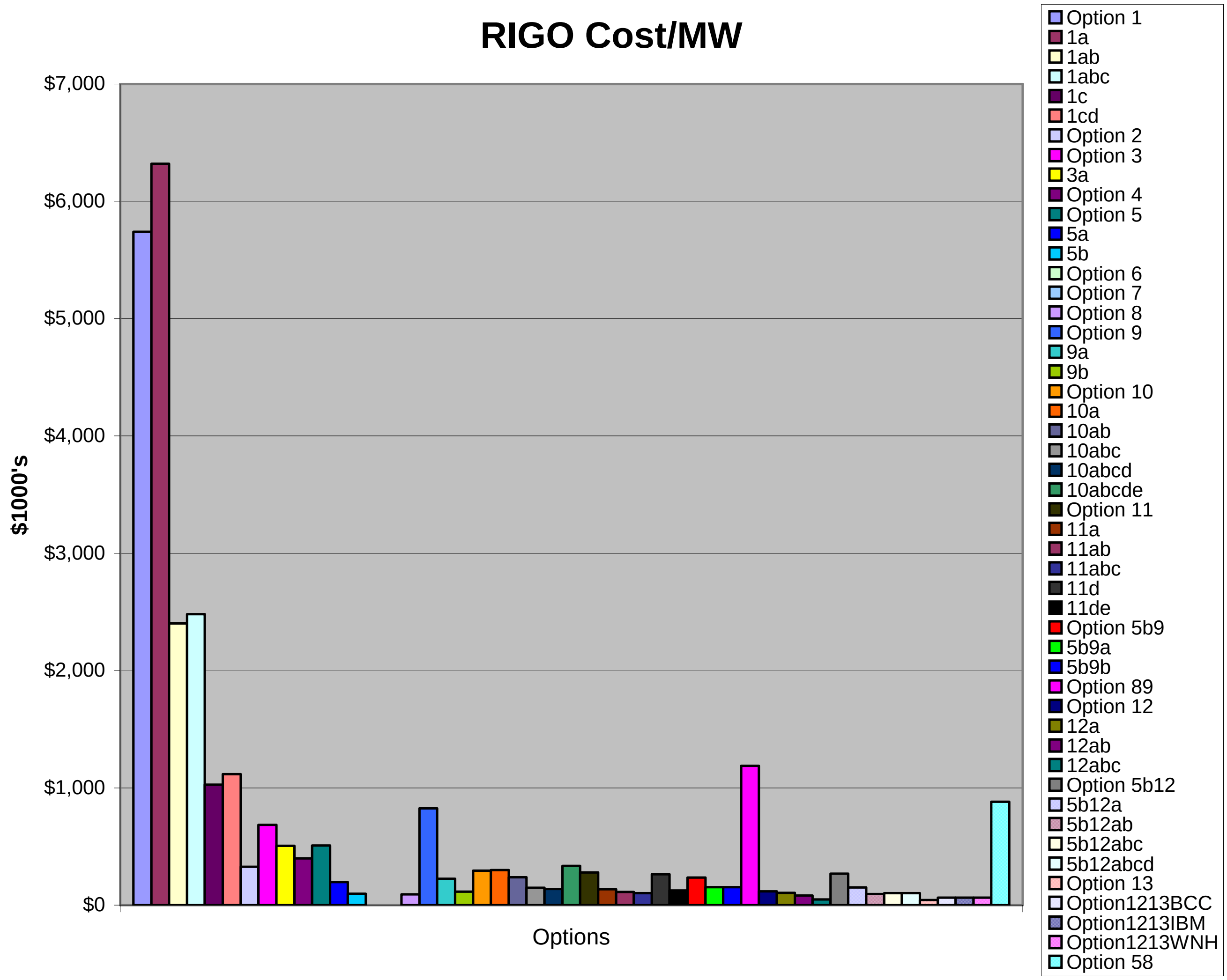


From this graph, it is observed that

- Western options have the highest cost/MW.
- Options 12, 13, and the combination of both provide the greatest amount of outlet per installed costs.

As a result of this analysis and the p

6.2: Evaluated Cost (with losses)

Evaluated costs with losses were not relevant to this study since the overall loss reductions observed were not statistically significant.

7: Relevant Concerns

7.1: Load-Serving Issues

Rochester Public Utilities ("RPU"), Dairyland Power Cooperative (“Dairyland”) and Dairyland’s distribution cooperative, Peoples Cooperative Services, provide retail electrical service to the Rochester area. Power is transmitted to the area by three 161 kV transmission lines, one from the west, Byron – Maple Lake 161 kV transmission line that connects the city to the Prairie Island – Bryon 345 kV transmission line; another from the northeast from the Alma Substation, and one from the south from the Adams Substation. The area also has 181 MW of generation located within the City of Rochester that can provide temporary support to the transmission system: four gas/coal units at Silver Lake totaling 102 MW, two hydro units on the Zumbro River totaling 2.4 MW and two natural gas/oil units at Cascade Creek totaling 77 MW. The Peoples Cooperative Services load is served out of the Rochester Substation (Dairyland owned) and the Maple Leaf Substation owned by Southern Minnesota Municipal Power Agency (“SMMPA”) through 69 kV transmission lines which are routed to the North and South of the City of Rochester.

Anytime the demand for electrical power exceeds 181 MW in the Rochester area, the failure of a single transmission line could cause service interruptions. This limitation occurs if the Byron – Maple Leaf 161 kV line is out of service, because the remaining transmission system can only reliably deliver 181 MW of power to area substations. RPUS’s ability to import power to serve its load during certain contingencies is restricted by the “Rochester Area Import Prior Outage Standing Operating Guide” of the MISO, which requires RPU to use local generation when their system demand exceeds 145 MW to prepare for the next contingency.

While local generation operated in advance of the next contingency may support additional demand, using generation for system support is not a desirable long-term solution because it is less reliable than transmission and more prone to outages and must be turned on in advance of and operated at a level sufficient to withstand the dynamic impacts of the next contingency, even if the power is not needed locally. Even if all 181 MW of generation were operated for system protection, the electrical system could only reliably serve 362 MW.

In Rochester, demand for power has already exceeded the capacity of the transmission system alone (181 MW) and will soon exceed the capacity of the existing transmission system fully supported by area generation (362 MW).

The preferred alterative in this Study will alleviate certain limitations on the transmission system in the area to allow for additional generation development in a wind-rich area of the State. If constructed, it is estimated that the transmission system would be able to serve approximately 65 MW of additional load for a total of 246 MW, a level that exceeds the current load in the area. A project being planned by Dairyland will add further support. Dairyland intends to reconductor the Rochester – Adams 161 kV line to facilitate wind outlet. If the RIGO lines and the reconductor project were constructed, the transmission system would be able to reliably service approximately 468 MW in the Rochester area, a level expected to be reached in approximately 2018.

One of the Group 1 projects, the 345 kV line from a new Hampton Corner Substation in southeastern Twin Cities to the La Crosse area, will further enhance the load serving ability of the system beyond the year 2040.

7.2: Constructability & Schedule Considerations

The transmission options under evaluation differ significantly with respect to the number and type of construction activities required. These differences have ramifications with respect to the lead times involved in implementing the series of improvements required.

Simpler options are easier to build. Options which require large amounts of reconductoring and rebuilding require disproportionately more time. This difference arises because power system reliability considerations limit the number of circuits within a geographical sub-area that can be simultaneously out of service for upgrade or replacement, since many of the circuits involved are to some degree electrically in parallel. Construction cannot be undertaken simultaneously on more than a few existing circuits per season; rather, sequential construction is required. In contrast, options that rely less heavily on reconductors and rebuilds encounter fewer construction outage constraints.

Table 7 summarizes the types of transmission line work involved for the best performing options and gives an estimated duration of work, based on a January, 2009 start date.

Table 7
Constructability & Schedule Considerations

		miles of transmission				
Option	Description	New	Record	Rebuild	Total	Years
5	Owatonna-Austin Corner 161 kV	34	0	0	34	2.0
8	Blue Earth-Loon Lake 161 kV	40	0	0	400	2.0
9	Pleasant Valley-Blue Earth 161 kV	90	0	0	90	2.5
11	Jackson-Loon Lake 161 kV	80	0	0	80	2.5
12	Pleasant Valley-Byron 161 kV	25	0	0	24	2.0
13	Pleasant Valley-South RPU 161 kV	22	0	0	22	2.0
5b9	5b + 9	124	0	0	124	2.5
89	8 + 9	130	0	0	130	2.5
5b12	5b + 12	59	0	0	59	2.0
1213BCC	12 + 13	47	0	0	47	2.0
58	5 + 8	74	0	0	74	2.0

Notes:

1. The reconductor and rebuild transmission line mileage is assumed zero for the base options. These numbers would largely depend on how much outlet was desired from each option.

2. The smaller reconductor or rebuild projects would be handled through the MISO interconnection study process.

7.3: Double-Circuit Line Considerations

Option 1213BCC, which has been identified as the "Preferred Plan", involves adding a second Byron-Maple Leaf-West Side 161 kV line and a parallel 161 kV line from Byron-Pleasant Valley. Implementation of these circuits requires consideration of whether it is desirable or acceptable to construct these pairs of circuits on double-circuit structures.

Double-circuit construction is acceptable if the power system can reliably withstand simultaneous failure of both circuits. Double circuit construction therefore can be appropriate in situations where the two circuits serve different functions, connect different pairs of substations, split away and proceed in different directions, or where high capacity (but not redundancy) is required.

NERC Planning Standards recognize double-circuit line outages as a "single-contingency" type of event ("Category C-5") because both lines are at risk of a "common-mode" failure. Such failures include:

- electrical failure of line insulation due to lightning strike;
- mechanical failure of one or more structures;
- broken shield wire falling into power conductors;
- wind-blown debris causing conductor-conductor short circuits;
- insulator contamination due to road salt, soot, or agricultural chemicals;
- wind/sleet/ice conditions
- contact with aircraft or construction equipment (crane, dump truck)
- protective relaying malfunction ("sympathetic tripping" due to fault on adjacent circuit)

These common-mode failure mechanisms have all been experienced on the Xcel Energy/NSP transmission system, on double-circuit lines at all voltage levels from 69 kV to 345 kV.

Consequently, evaluation of electric transmission system capability is performed considering failure of both circuits of a double-circuit line as being a single-contingency event. Double-circuit lines therefore are not appropriate in situations where two independent circuits are required for reliability purposes.

The conclusion is that in the case of Byron-Pleasant Valley 161 kV line it is inappropriate to have these circuits on the same structures because the new line is designed to back up the Byron-Pleasant Valley 345 kV line. The system with Option 1213BCC is adequate to provide sufficient outlet in the event of an outage of the 345 kV line from Byron to Pleasant Valley. If Option 1214BCC facilities and the Byron – Pleasant Valley 345 kV were lost, outlet capability would be limited. Consequently, the 161 kV line from Byron-Pleasant Valley must be constructed in a manner that minimizes exposure to "common-mode" failures, which would simultaneously render both circuits unusable.

8: Detailed Listing of Recommended System Facilities

The Recommended Plan is the 1213BCC option. A total SE Minnesota-->Twin Cities power transfer capability of approximately 900 MW is expected to be achievable with installation of the following improvements:

Lines—new			
Byron-Pleasant Valley 161 kV		34	1 x 795 ACSS
Pleasant Valley-South RPU 161 kV		22	1 x 795 ACSS
Byron-Maple Leaf-West Side 161 kV (double circuited)		10	1 x 954 ACSR
	Total	66	
Lines-reconductor or rebuild			
None		0	
	Total	0	

Transformers		MVA
Pleasant Valley 345/161 kV transformer #2		1 x 500
	Total Increase	500

Reactive (voltage control) facilities

Shunt Capacitors		MVAR
None		0
	Total Increase	0

Shunt Reactors		MVAR
None		0
	Total	0

Substations--new

South RPU 161 kV Substation (south on existing Rochester 161 kV loop)
West Side 161 kV Substation (west side on existing Rochester 161 kV loop)

Substations--modified

Pleasant Valley	add breakers (161 and 345 kV), modify bus configuration, 345/161 kV transformer #2
Byron	add breakers (161 kV), modify bus configuration
Maple Leaf	none

Year 2011 facilities presumed to be "existing system" as part of earlier improvements

Buffalo Ridge Incremental Generation Outlet (BRIGO) facilities

- Eagle Lk (Xcel Energy & GRE substations) 69 kV switches (replace with 1200 amp)
- Paynesville-Roscoe Tp-Munson Tp-Farm Tp 69 kV: rebuild 13.5 mi (future double circuit 115/69 kV)
- Winnebago Jct 161 kV shunt capacitors (2 x 30 MVAR)
- Nobles Co 345/115 kV transformer #2 (672 MVA)
- Nobles Co-Fenton 115 kV #2 (620 MVA)
- Lk Yankton-Marshall SW 115 kV

- Granite Falls-Willmar 230 kV uprate to 388 MVA

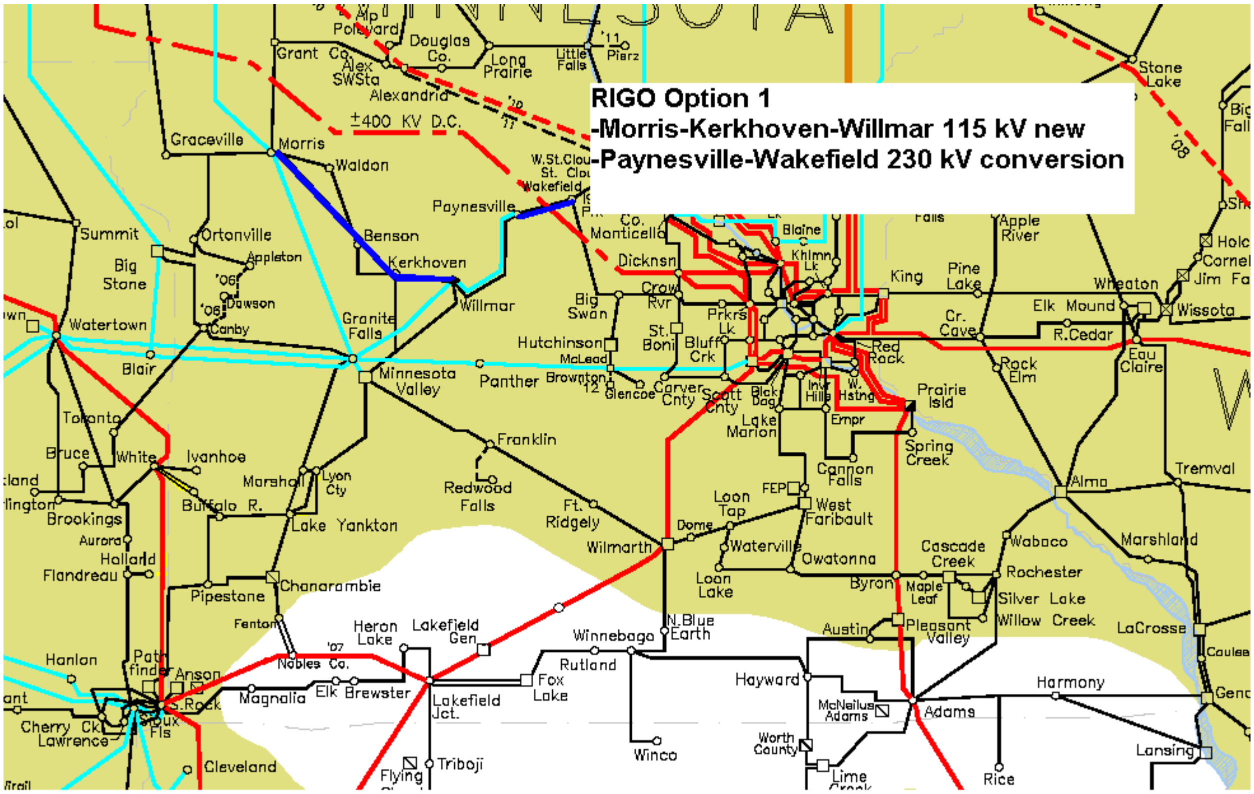
Southeast Minnesota facilities

- Cannon Falls generation interconnection upgrades (refer to MISO G405 study for full details.

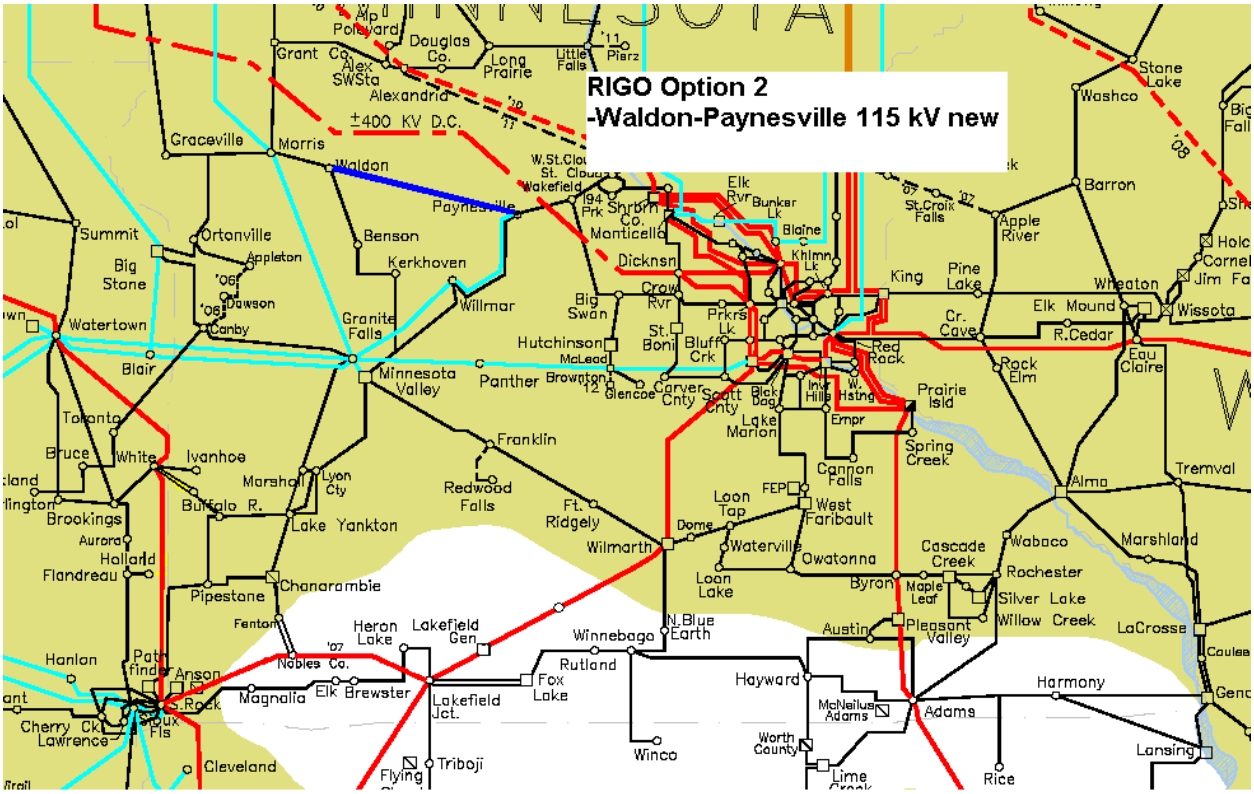
Local load-serving improvements

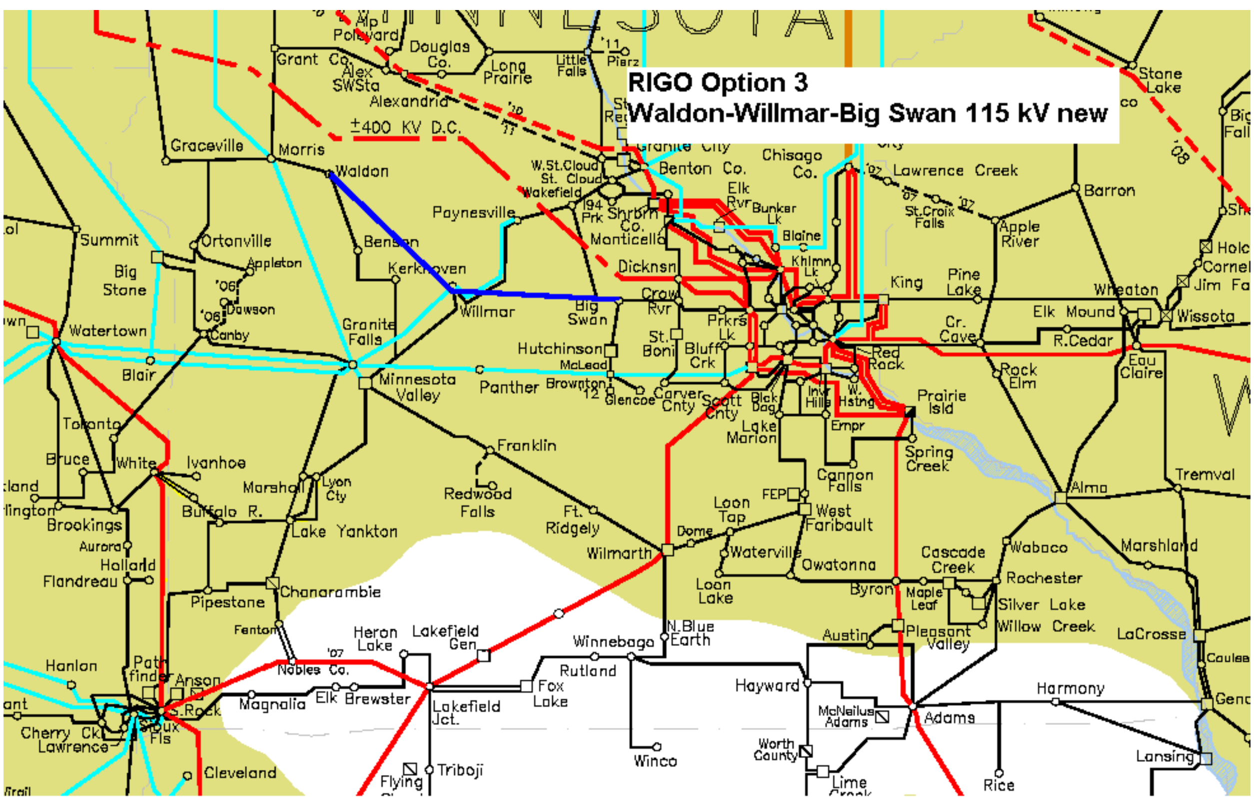
- Mankato 115 kV loop upgrade.

Appendix A: Maps (Base Plan & System Alternatives)



Xcel Energy Services, Transmission Reliability and Assessment. RIGO 7-16-2008.





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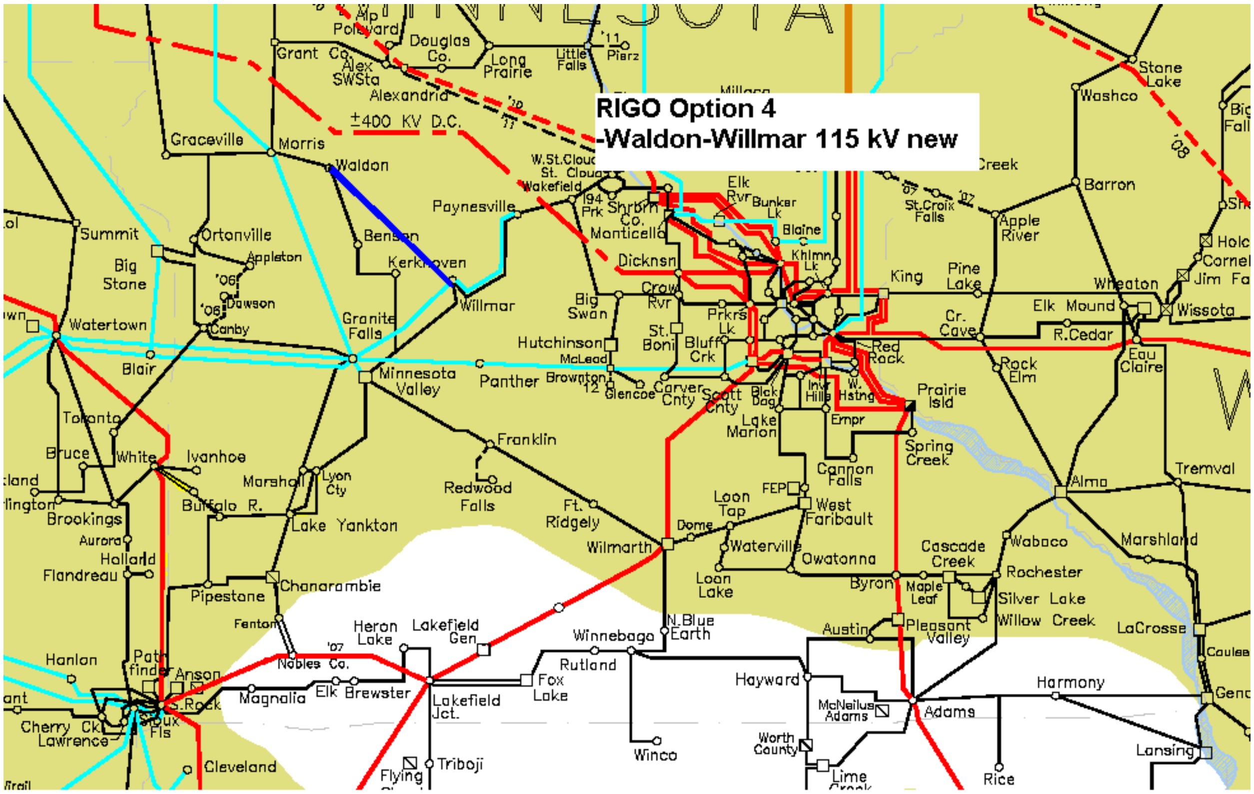

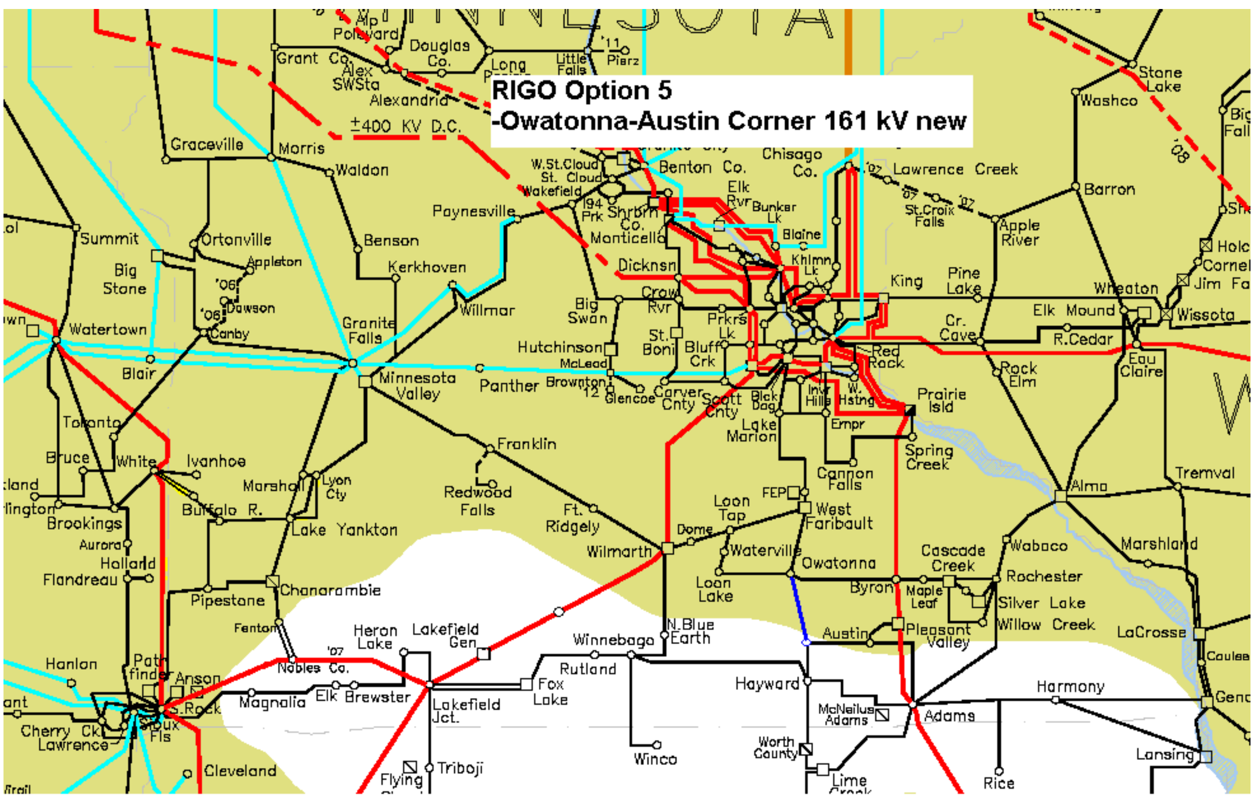

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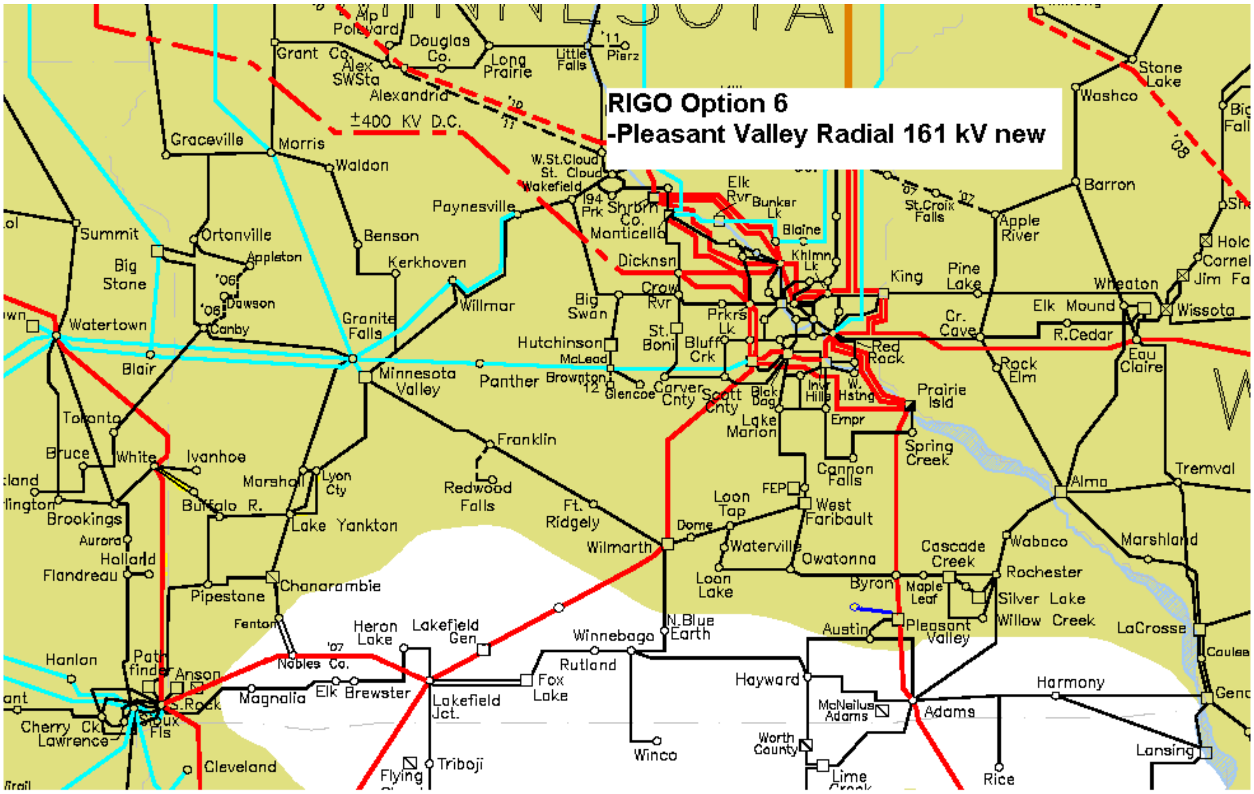

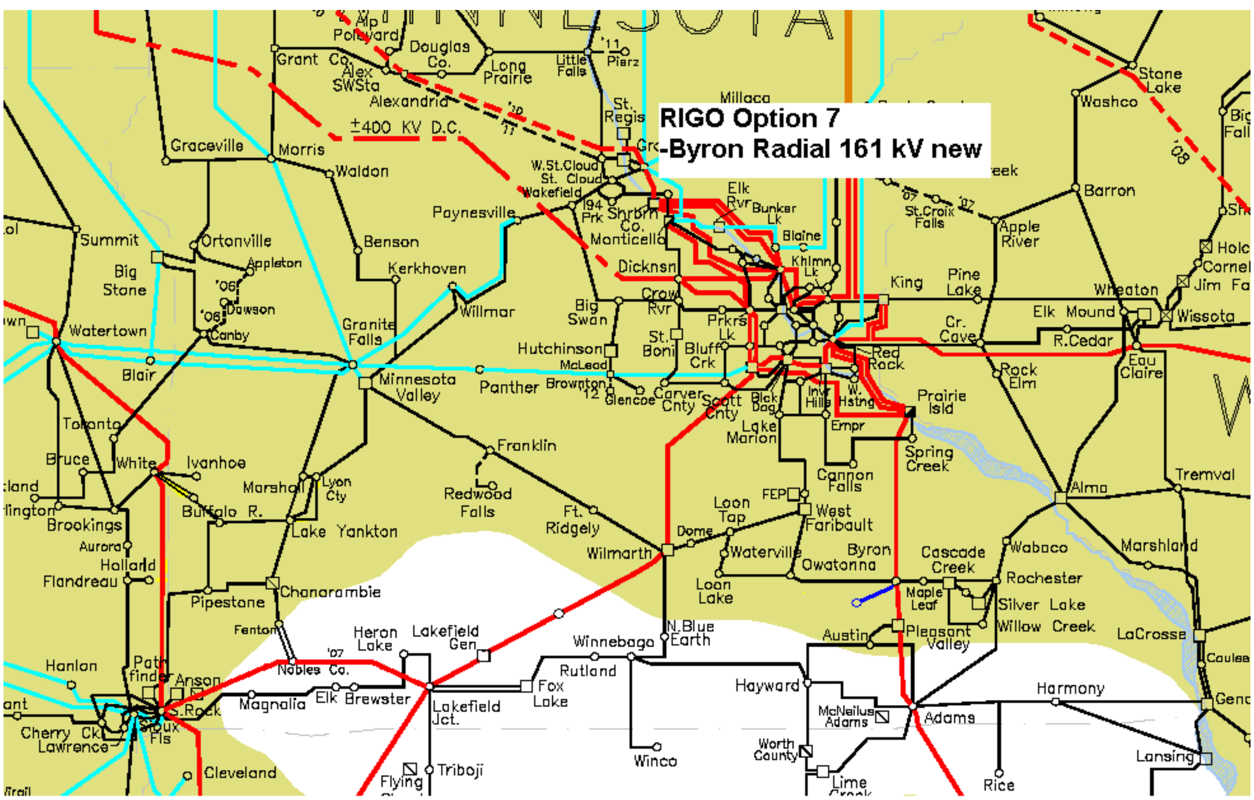

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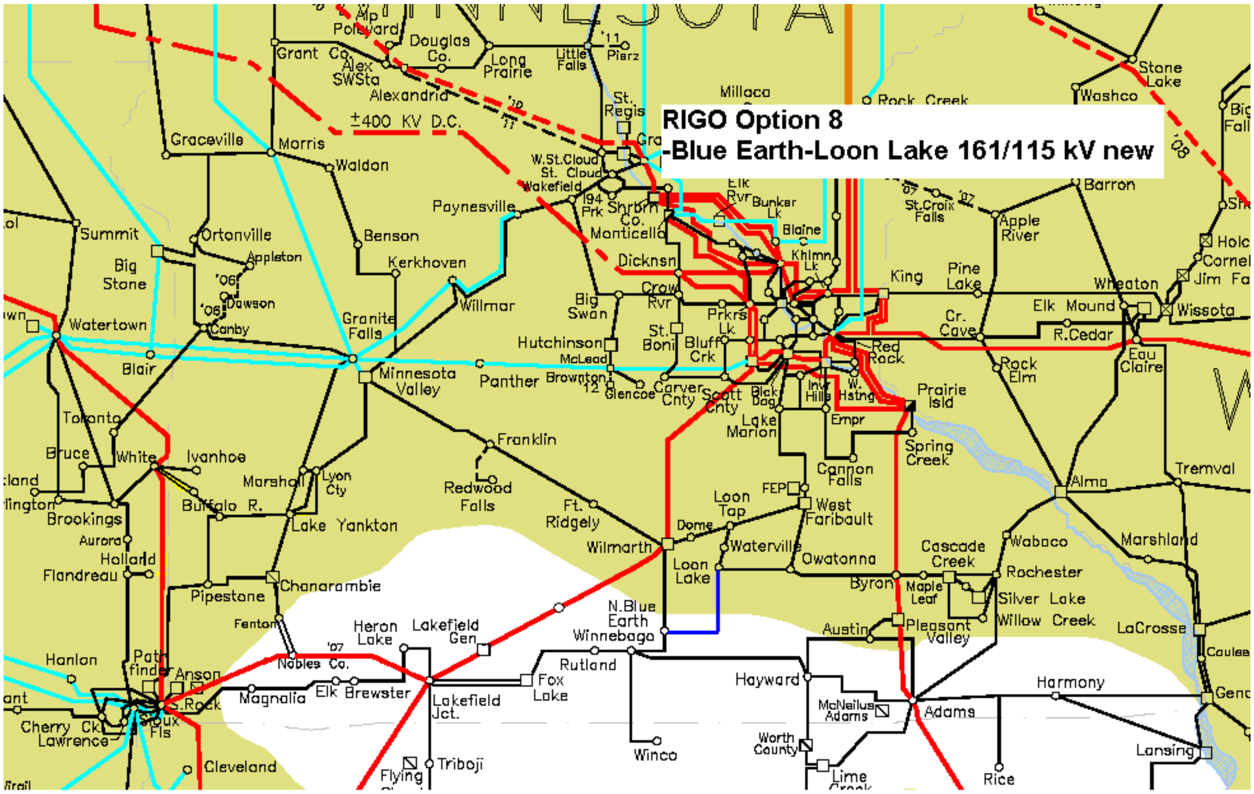

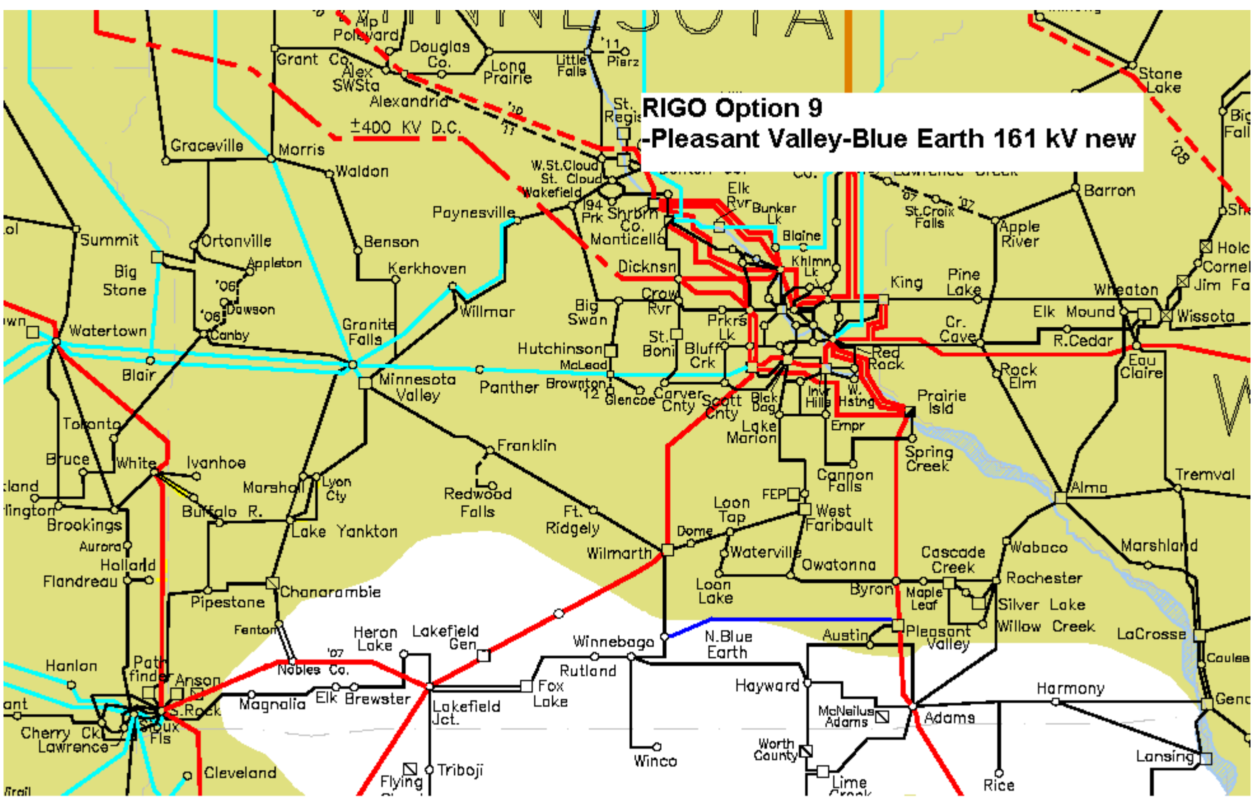

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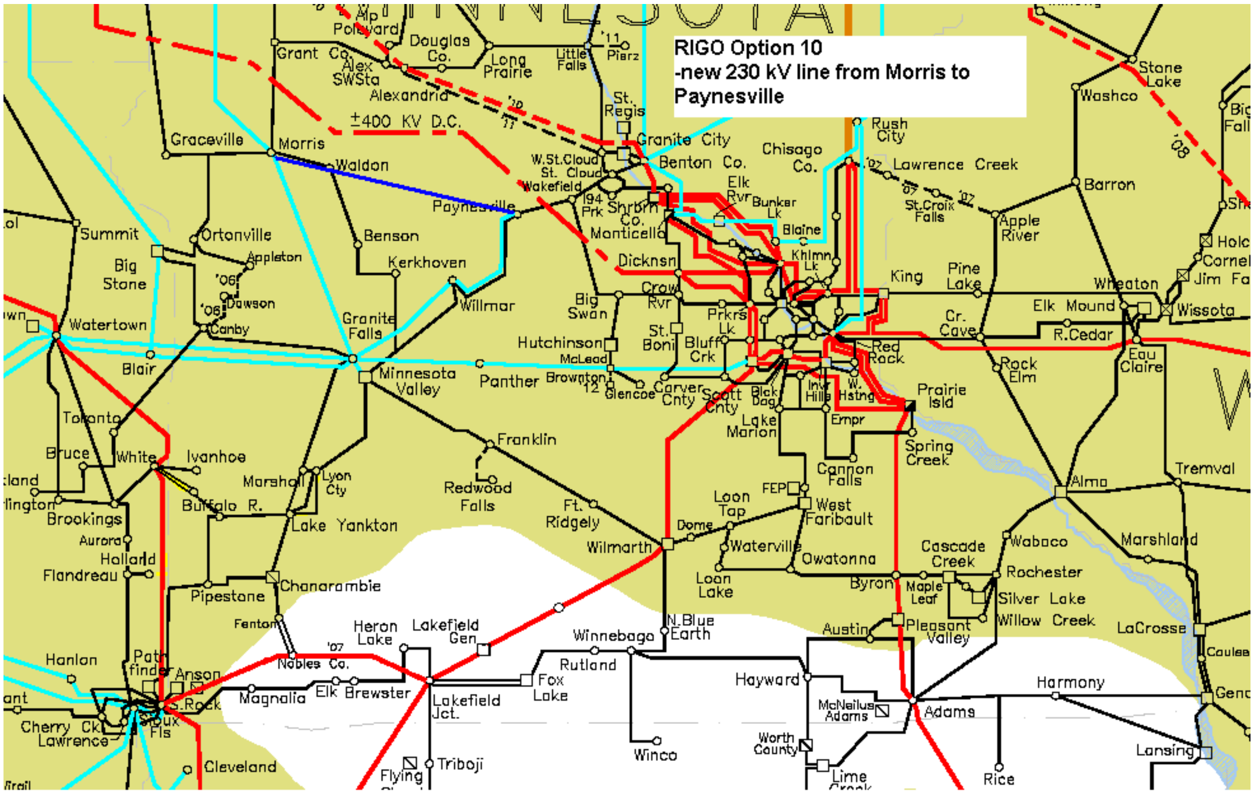

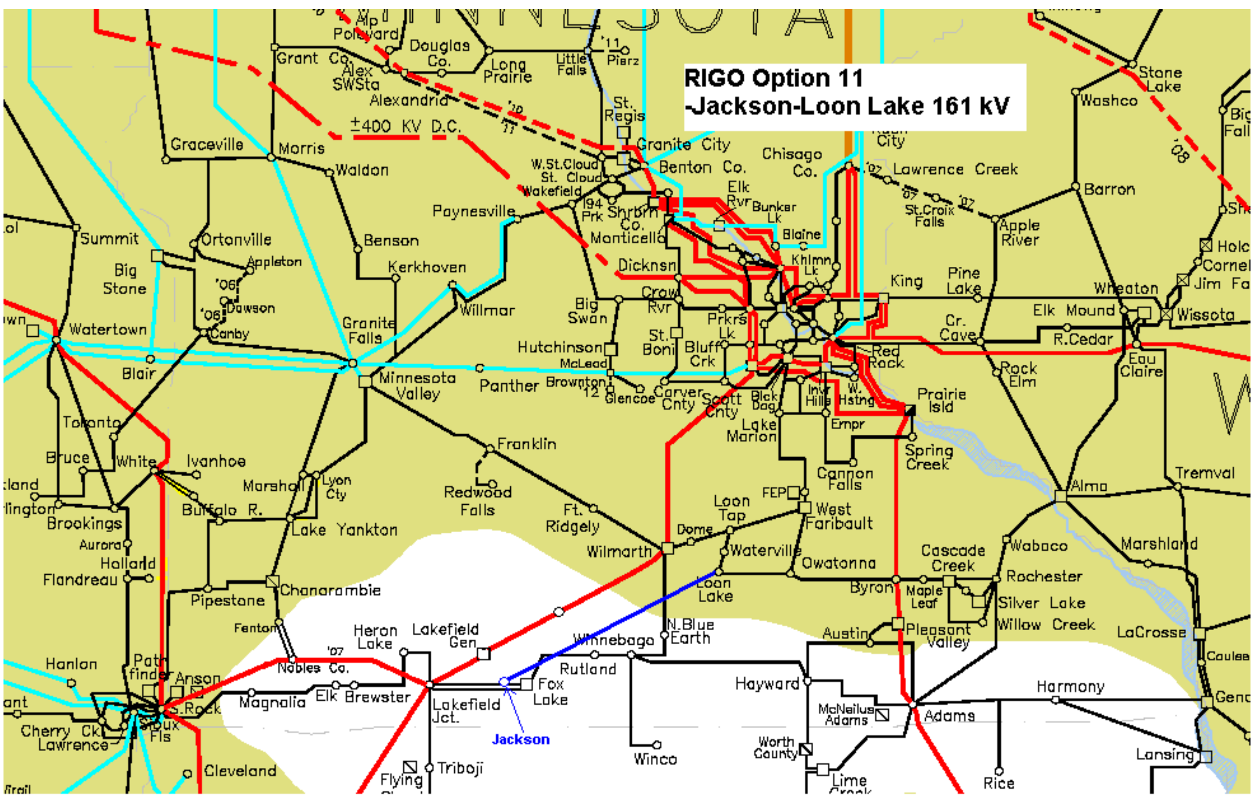

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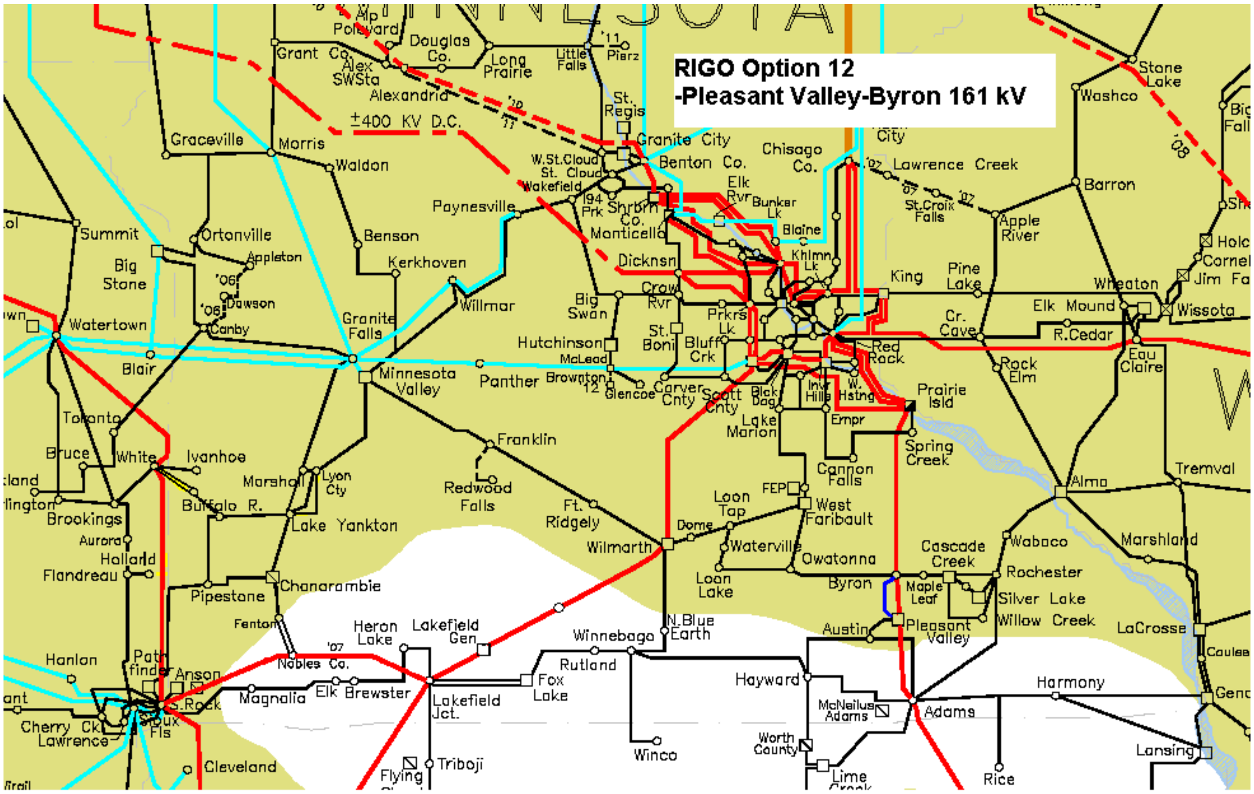

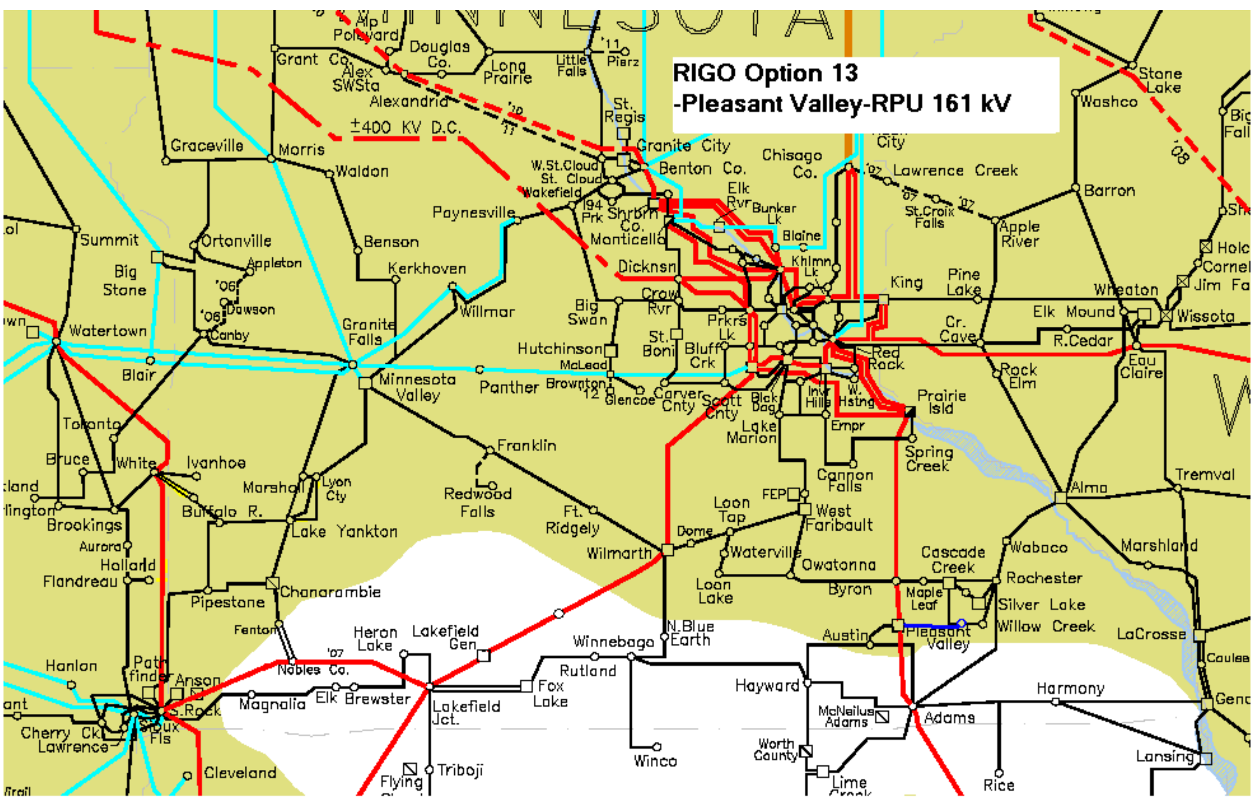

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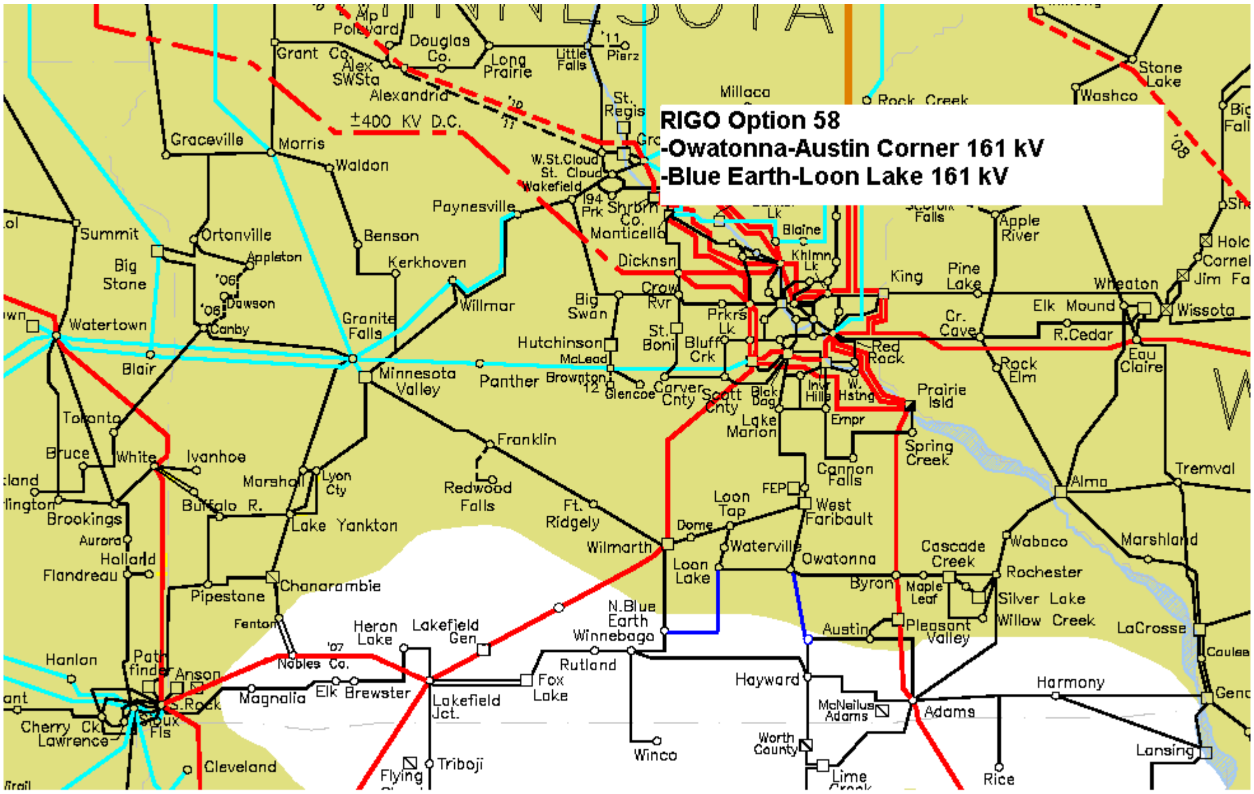

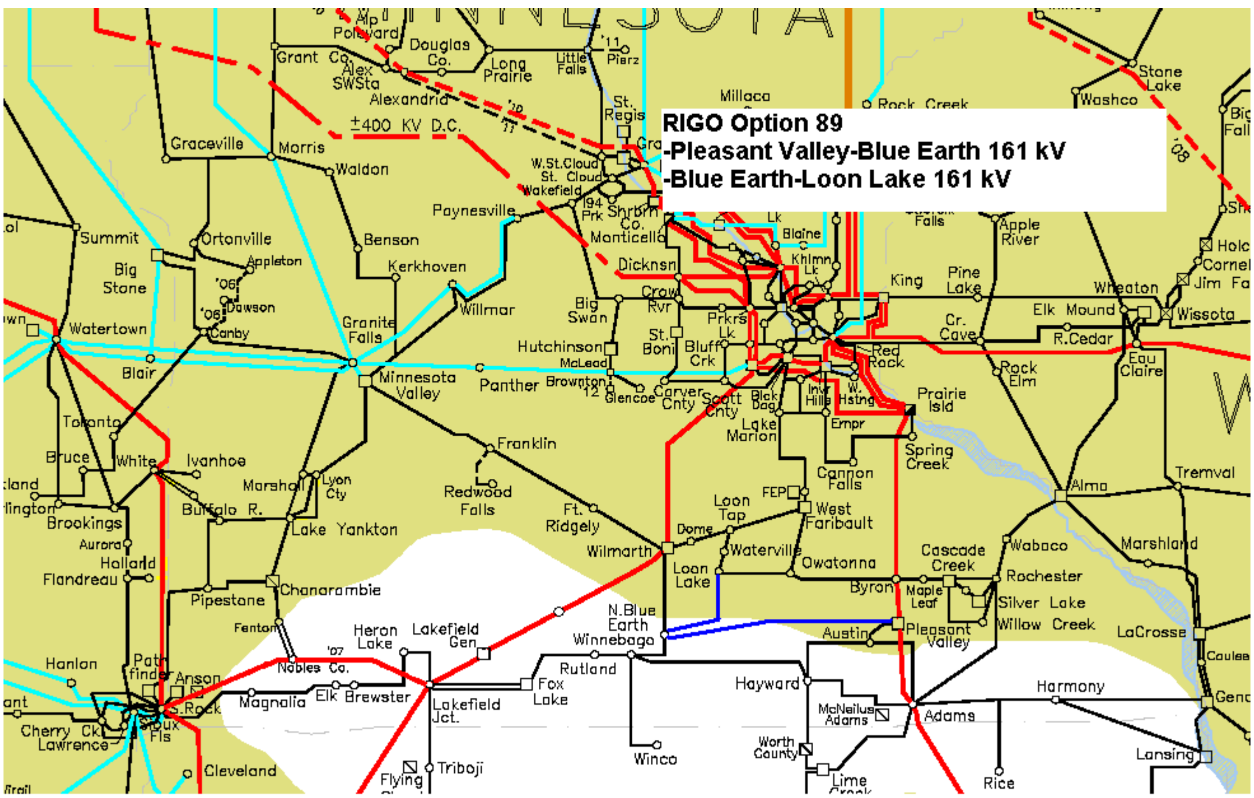

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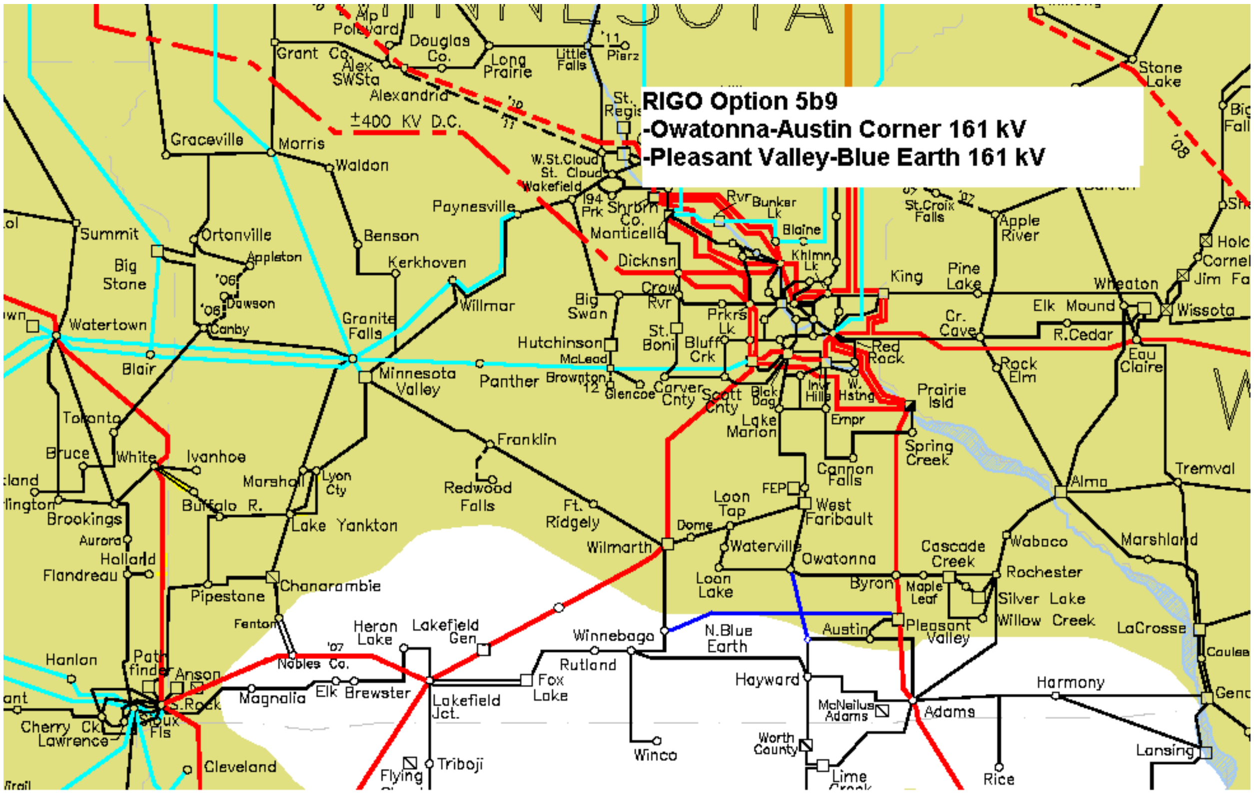

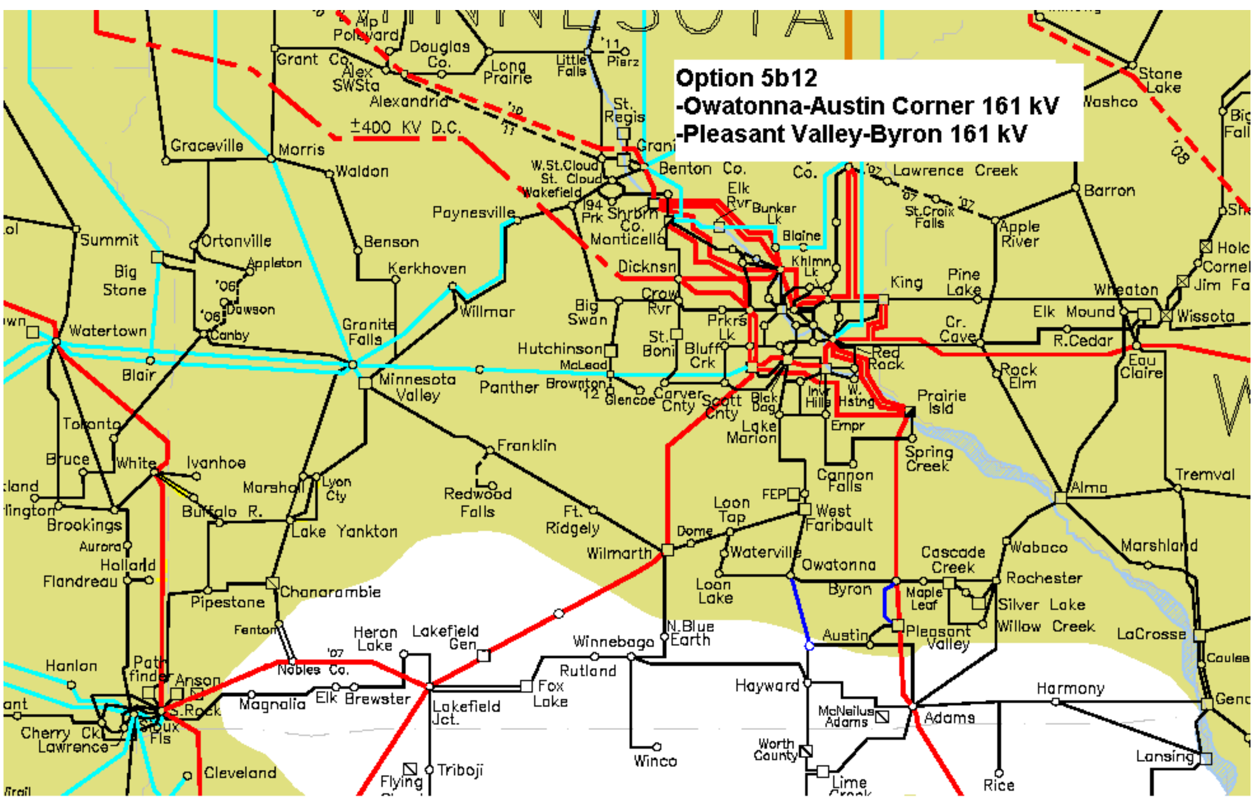

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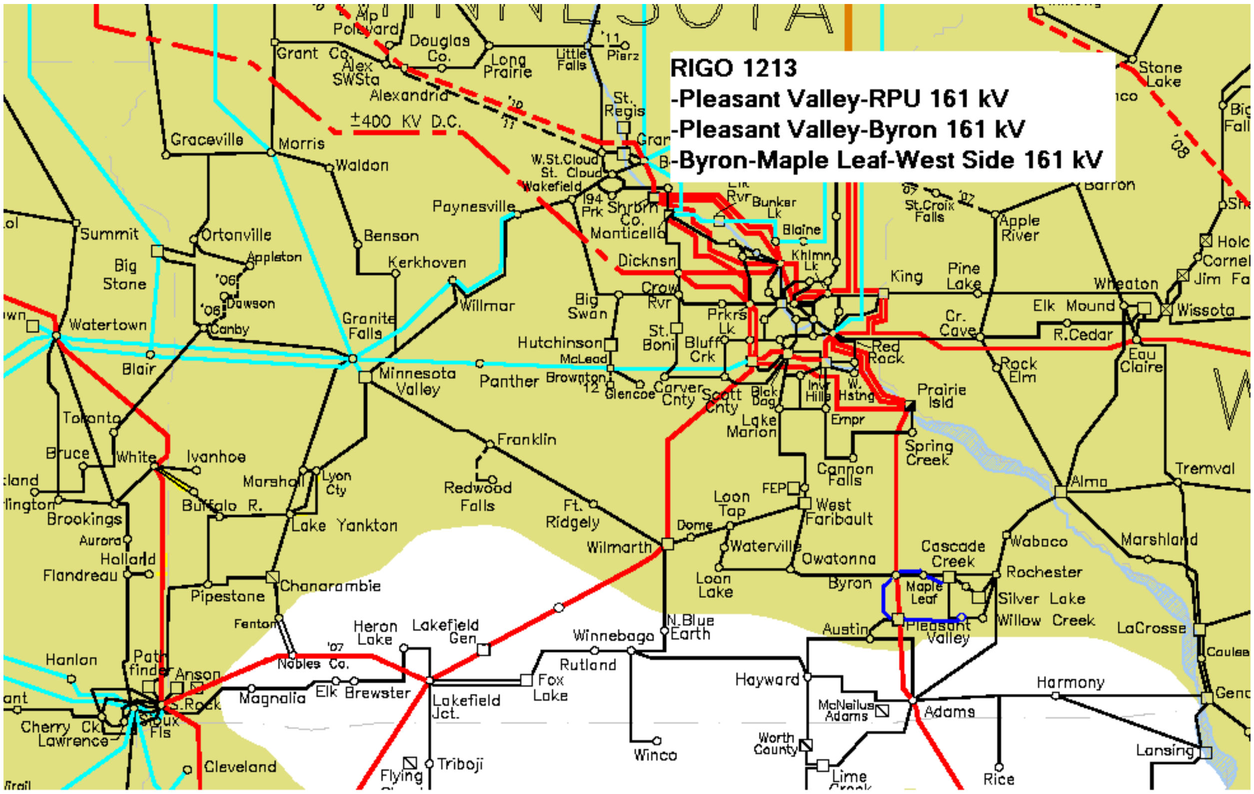

Q-1 Rebuild

The Genoa – La Crosse – Alma 161 kV line (Q-1) was built in 1951 and upgraded to a higher capacity in 1988. The line is reaching the end of its useful life. Dairyland Power Cooperative (Dairyland) has been working with Northern States Power Company, a Wisconsin corporation (Xcel Energy), and other utilities through the CapX2020 group to plan for a new 345 kV source into the La Crosse area. The Q1 has been divided into three segments for permitting and construction:

- North La Crosse Substation – La Crosse Tap (9 miles);
- Alma – Marshland – North La Crosse Substation (41 miles); and
- Genoa – La Crosse Tap (20.7 miles).

With the completion of the Genoa – Coulee 161 kV reconductor in 2007, the Genoa – La Crosse Tap 161 kV line is most limiting for transfers south to north through the La Crosse area. The Genoa – La Crosse Tap line received RUS approval on March 16, 2007. Engineering and right-of-way activities will start in 2010 with construction slated for 2011.

Depending on the route selected for the SE Twin Cities – Rochester – La Crosse 345 kV line, the Alma – Marshland – North La Crosse segment of the Q1 may be co-located with the new facilities or rebuilt as a separate project. However, none of the routes currently contemplated for the Proposal would impact the Genoa— La Crosse Tap section of the Q-1.

Due to the uncertainty of the ultimate route for these Twin Cities – Rochester – La Crosse 345 kV Line, Dairyland is deferring a decision on upgrading the North La Crosse Substation – La Crosse Tap 161 kV lines until the 345 kV route is selected, as double circuit options are being evaluated.

The North La Crosse Substation – La Crosse Tap would be the last segment built. It has been deferred due to it being a possible route for a 345 kV line being studied by Xcel Energy and American Transmission Company. It is not anticipated that this project would be proposed until 2016-2020.